Entergy

Entergy Services, Inc.
639 Loyola Avenue (70113)
P.O. Box 61000
New Orleans, LA 70161-1000
Tel 504 576 3101
Fax 504 576 5579

Edward R. Wicker, Jr.
Senior Counsel
Legal Services - Regulatory

August 3, 2015

Via Hand Delivery
Ms. Terri Lemoine Bordelon
Records and Recording Division
Louisiana Public Service Commission
Galvez Building, 12th Floor
602 North Fifth Street
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 the Companies' 2015 Integrated Resource Plan (the "2015 IRP"). Also enclosed is a red-lined version that reflects certain changes to the previously-filed draft report. Please retain an original and two copies for your files and return a date-stamped copy to our by-hand courier.

Appendix B submitted with the 2015 Draft IRP contains information that is designated Highly Sensitive Protected Materials ("HSPM"), which are being provided to you under seal pursuant to the provisions of the LPSC General Order dated August 31, 1992, and Rules 12.1 and 26 of the Commission's Rules of Practice and Procedure. The confidential materials included in the filing consist of confidential and market-sensitive financial information.

Please retain the original HSPM materials for your files and return a date-stamped copy to our by-hand courier. The HSPM materials are being produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect in this docket.

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)*

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:

Melanie A. Verzwyvelt
Staff Attorney
Louisiana Public Service Commission
P.O. Box 91154
Baton Rouge, LA 70821-9154

Tulin Koray
Economics Division
Louisiana Public Service Commission
P.O. Box 91154
Baton Rouge, LA 70821-9154

Donnie Marks
LPSC Utilities Division
Louisiana Public Service Commission
P.O. Box 91154
Baton Rouge, LA 70821

James M. Ellerbe
Marathon Petroleum Company LP
539 South Main Street
Findlay, Ohio 45840-3295

Katherine W. King
J. Randy Young
Carrie R. Tournillon
Kean Miller LLP
P.O. Box 3513
Baton Rouge, LA 70821

Kimberly A. Fontan
Entergy Services, Inc.
4809 Jefferson Highway
Mail Unit L-JEF-357
Jefferson, LA 70121

Kathryn J. Lichtenberg
Karen H. Freese
Edward R. Wicker, Jr.
Entergy Services, Inc.
639 Loyola Avenue, 26th Floor
P.O. Box 61000
Mail Unit L-ENT-26E
New Orleans, LA 70161-1000

John H. Chavanne
Chavanne Enterprises
111 West Main Street, Suite 2B
P.O. Box 807
New Roads, LA 70760-0807

Chairman Eric F. Skrmetta
Office of the Commissioner
District I – Metairie
433 Metairie Road, Suite 406
Metairie, LA 70005

Commissioner Scott A. Angelle
Office of the Commissioner
District II – Baton Rouge
Post Office Box 2681
Baton Rouge, LA 70821

Commissioner Lambert C. Boissiere, III
Office of the Commissioner
District III – New Orleans
1450 Poydras Street, Suite 1402
New Orleans, LA 70112

Vice-Chairman Clyde C. Holloway
Office of the Commissioner
District IV – Forest Hill
11098 Hwy. 165 South
Forest Hill, LA 71430

Commissioner Foster L. Campbell
Office of the Commissioner
District V – Shreveport
Post Office Drawer E
Shreveport, LA 71161

Rebecca E. Turner
Vice President
Regulatory Affairs & Market Design
Entegra Power Group LLC
100 South Ashley Drive, Suite 1400
Tampa, FL 33602

Casey DeMoss Roberts
Executive Director
Alliance for Affordable Energy
2372 St. Claude Ave., #300A
New Orleans, LA 70117

Gordon D. Polozola
NRG Energy, Inc.
General Counsel—South Central Region
112 Telly Street
New Roads, LA 70760

Joshua Smith, Staff Attorney
Casey Austin Roberts
Sierra Club Environmental Law Program
85 Second St., Second Floor
San Francisco, CA 94104

C. Tucker Crawford
President, GSREIA
643 Magazine Street
Suite 102
New Orleans, LA 70130

Mr. Simon A. Mahan
Southern Wind Energy Association
C/O SACE
P.O. Box 1842
Knoxville, TN 37901

Philip Hayet
Lane Kollen
Randy A. Futral
J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

Thomas W. Milliner
Anzelmo, Milliner & Burke, LLC
3636 S. I-10 Serv. Rd., Suite 206
Metairie, LA 70001

Michelle Bloodworth
Senior Director, Power Generation
America's Natural Gas Alliance
710 8th Street NW, Suite 800
Washington, DC 20001

Robert P. Larson
Douglas A. Spaulding
Manager
Nelson Energy LLC
8441 Wayzata Blvd., Suite 101
Golden Valley, MN 55426

Haywood Martin
Sierra Club Delta Chapter Chair
P.O. Box 52503
Lafayette, LA 70505

Mandy Mahoney
Abby Schwimmer
Southeast Energy Efficiency Alliance
50 Hurt Plaza SE, Suite 1250
Atlanta, GA 30303

New Orleans, Louisiana, this 3rd day of August, 2015.

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Edward R. Wicker, Jr.

2015 Integrated Resource Plan

Entergy Gulf States Louisiana, L.L.C.

and

Entergy Louisiana, LLC

LPSC Docket No. I-33014

Draft Report: Filed January 30, 2015
Draft Report Revision 1: Filed April 15, 2015
Final Report: Filed August 3, 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:
  - Seeking certification of self-build CCGT that was market tested in the 2014 Amite South RFP.
  - Issuing the 2015 WOTAB RFP to solicit proposals 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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INTRODUCTION

This 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. It should be noted that the data and assumptions reflected in this IRP largely reflect the best information available during the initial development of the Data Assumptions for the draft report in late 2013-early 2014. During the 18 months over which this report was developed, some information, forecasts, and assumptions may have changed. While this report does not attempt to address all such changes, key changes have been noted throughout the document. As a long-term planning document, the IRP is intended to provide guidelines for resource planning and decisions, but actual decisions will be made based on the best information available at the time such decision is made.

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 report, residential, commercial, and industrial load growth, unit deactivations, and purchased power agreement (“PPA”) expirations, will require the Companies to add significant transmission and 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.

[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.

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.

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.

[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.

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; [5] 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 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").[6] On February 14, 2014, EGSL and ELL provided written notice to the other EOCs of the termination of their participation in the System Agreement.[7] 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[8]. 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.

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

[5] An uncontested stipulation recommending approval of the Business Combination was filed with the Commission on July 13, 2015, and a settlement hearing was held on July 24, 2015. The Commission is expected to consider the stipulation at the August 2015 Business and Executive Session.

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

[7] 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).

[8] 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.

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.

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[9] 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

[9] 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.

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[10] ("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 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").[11] 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 presented to the Commission in a certification filing pursuant to LPSC General Order No. R-26018, is anticipated to provide

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

[11] 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.

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.[12]

Additionally, EGSL recently filed an Application for certification pursuant to LPSC General Order No. R-26018 for a portfolio of four transmission projects referred to as the Lake Charles Transmission Project ("LCTP").[13] Entergy Services, Inc. ("ESI") and MISO have determined that the LCTP is the most effective project to meet the reliability needs of the Lake Charles area and will be necessary to serve the forecasted load growth there by the summer of 2018. The portfolio of transmission projects that comprise the LCTP is currently estimated to cost up to $187 million and will provide the injection of a new 500 kilovolt ("kV") transmission source into the area.

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.

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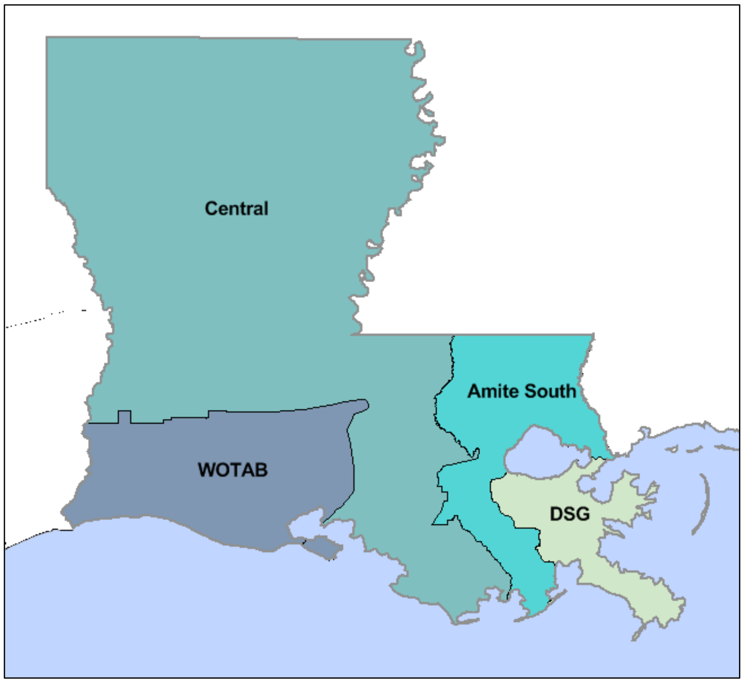
[12] *Joint Application Of Entergy Gulf States Louisiana, L.L.C. And Entergy Louisiana, LLC For Certification Of The Louisiana Economic Transmission Project In Accordance With Louisiana Public Service Commission General Order Dated October 10, 2013*, filed April 21, 2015, LPSC Docket No. U-33605.

[13] *Application Of Entergy Gulf States Louisiana, L.L.C. For Certification Of The Lake Charles Transmission Project In Accordance With Louisiana Public Service Commission General Order Dated October 10, 2013*, filed June 16, 2015, LPSC Docket No. U-33645.

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

As part of this IRP 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[14]		No CO_2 ($/MWh)			CO_2 Beginning 2023 ($/MWh)		
Technology	Capacity Factor[15]	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[16]	34%	$109	$109	$109	$109	$109	$109
Wind w/ Production Tax Credit	34%	$102	$102	$102	$102	$102	$102
Solar PV (fixed tilt)[17]	18%	$190	$190	$190	$190	$190	$190
Solar PV (tracking)[18]	21%	$179	$179	$179	$179	$179	$179
Battery Storage[19]	20%	$217	$217	$217	$217	$217	$217

[14] A general discount rate (7.656%) was used in order to accurately model these resources in the Market Modeling stage of the IRP.
[15] Assumption used to calculate life cycle resource cost.
[16] Includes capacity match-up cost of $18.76/MWh due to wind's 14.1% capacity credit in MISO.
[17] Includes capacity match-up cost of $30.93/MWh assuming a 25.0% capacity credit in MISO.
[18] Includes capacity match-up cost of $26.51/MWh assuming a 25.0% capacity credit in MISO.
[19] 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[20] ("SPO") prepared the natural gas price forecast[21] 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[22] (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%

[20] System Planning and Operations is a department within 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.

[21] 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.

[22] "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 approved a long-term gas hedging pilot program in General Order No. R-32975. However, no adjustments are warranted to the Companies' long-term natural gas forecasts at this time. If the Commission approves any long-term gas transactions for the Companies, the expected price from such transactions will be considered in the Companies' future resource planning decisions.

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.[23] 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.[24]

AURORA[25] 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

[23] Includes a discount rate of 7.656%.
[24] The AURORA model replaces the PROMOD IV and PROSYM models that the Companies previously used.
[25] 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

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 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[26]

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.

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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.

[26] The four scenarios and their general assumptions have remained constant throughout the IRP process. However, in the November 2014 filing, two of the scenarios were renamed from the May 2014 filing. "Scenario One" was renamed "Industrial Renaissance." The "Industrial Renaissance" Scenario in the May 2014 was renamed "Business Boom" in the November 2014 filing.

- 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)[27]	~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-

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

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.

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		4,027		10,561 [28]	

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.[29]

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);

[28] Total resources include the addition of Ninemile 6.

[29] *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).

- 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.

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®[30] and the MetrixLT™[31] programs are used widely in the

[30] MetrixND by ITron is an advanced statistics program for analysis and forecasting of time series data.

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 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 and expirations. For the purpose of developing this IRP, assumptions must be made about the future of generating units currently in the portfolio.

[31] MetrixLT™ by ITron is a specialized tool for developing medium and long run load shapes that are consistent with monthly sales and peak forecasts.

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 and expirations is approximately 6,859 MW relative 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."[32] 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.[33] The overall net effect would reduce EGSL's portfolio position by roughly 700 MW in 2018 based on ETI's terminating participation[34] 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. <u>The load forecast necessarily has changed during the 18 month period in which this IRP was developed and can be expected to change in the future.</u> As contemplated

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[32] 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.

[33] *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).

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

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 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.[35] 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.

[35] 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 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.

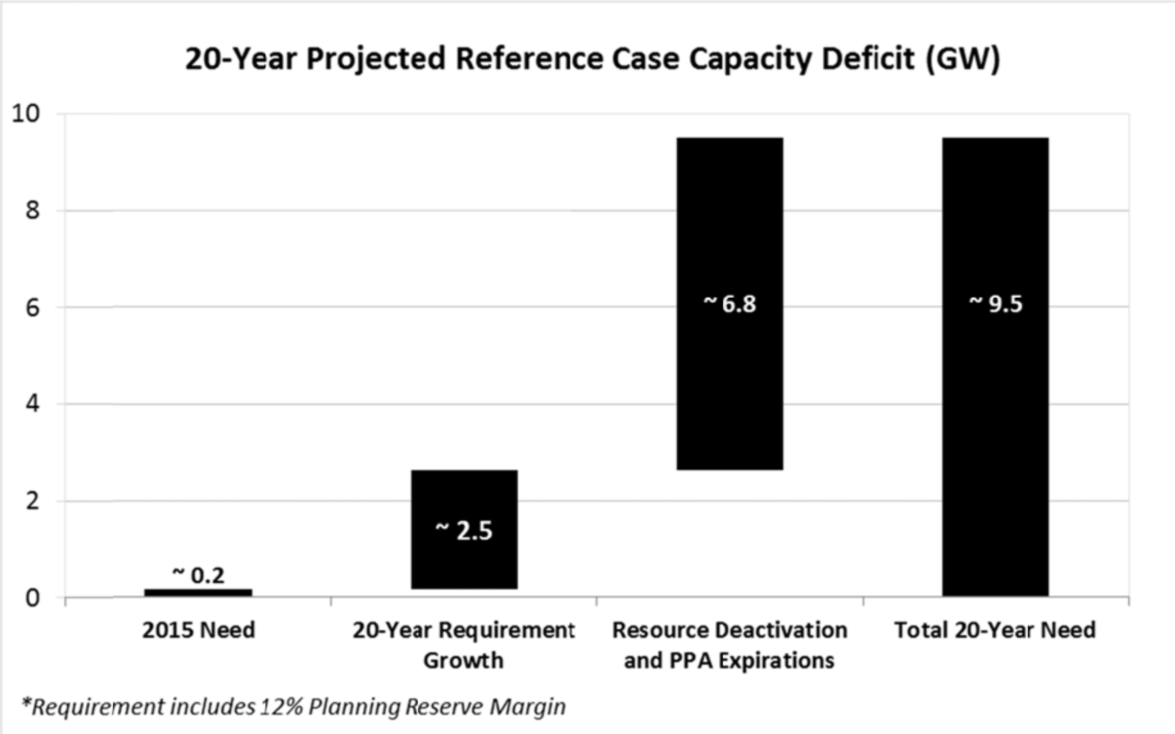
As shown in Tables 6 and 7 below, by 2034, the combination of load growth, resource deactivations and PPA contract expirations may result in approximately 9.5 GW of capacity needed for the Industrial Renaissance Scenario. By 2024, the capacity deficit could be as high as 3.6 GW under the current load 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
  - Acquisitions
  - 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.[36] 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.

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)[37]	497	407	539	467
CTs/CCGTs (MWs)	7,348	8,404	6,876	6,512
Wind (MWs)	0	0	0	4,000[38]

[36] 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.

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

[38] 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%.

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[39] [40]

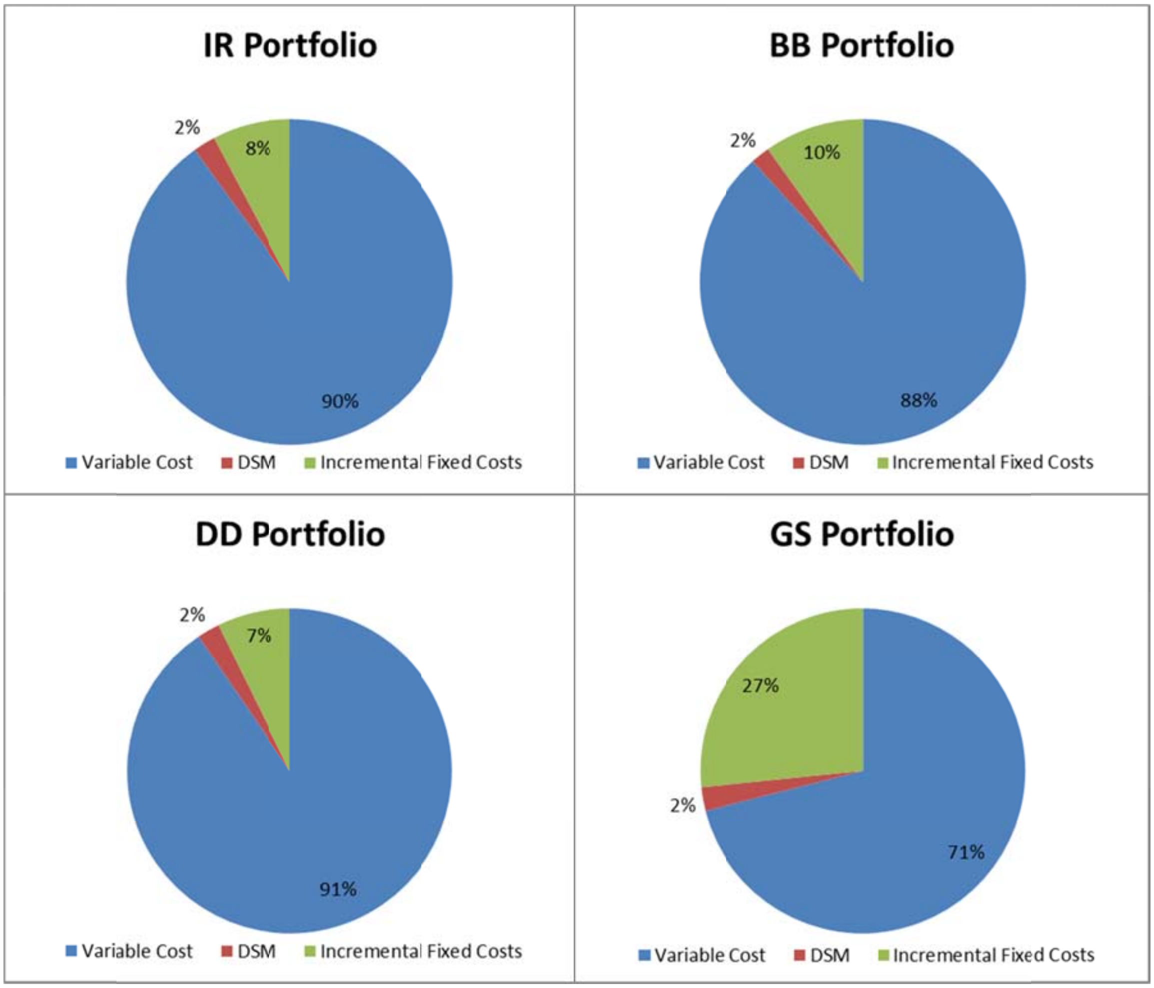
PV of Forward Revenue Requirements ($B) (2015-2034)				
	IR Scenario	**BB Scenario**	**DD Scenario**	**GS Scenario**
Industrial Renaissance Portfolio	$36.0	$32.5	$36.1	$46.4
Business Boom Portfolio	$36.2	$32.2	$36.3	$46.3
Distributed Disruption Portfolio	$36.0	$32.2	$36.2	$46.3
Generation Shift Portfolio	$37.9	$35.1	$37.4	$43.1

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.

[39] The forward revenue requirements are intended to provide the best available estimate of overall portfolio cost given the long term nature of the IRP process and the fact that customer class bill and rate effects will be determined through certification proceedings associated with particular resources.
[40] The table reflects the correct input of nominal DSM program costs as opposed to levelized DSM program costs.

Table 12: Portfolios by Cost Components in the Industrial Renaissance Scenario (2015-2034)[41] [42] [43]



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

[41] Variable cost represents the load payment net of generation energy margins.
[42] Incremental fixed cost is the fixed cost revenue requirement of the incremental supply-side resource additions in each portfolio.
[43] The table reflects the correct input of nominal DSM program costs as opposed to levelized DSM program costs.

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[44]	4
Business Boom Portfolio	3	1[45]	3	3
Distributed Disruption Portfolio	2	2	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[46] 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

[44] 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.
[45] As with Tables 11 and 12 above, this table reflects the correct input of nominal DSM program costs as opposed to levelized DSM program costs. This correction resulted in the Business Boom Portfolio having the lowest total supply cost in the Business Boom Scenario.
[46] A combination of natural gas prices and CO_2 costs involved adjustment of two variables at the same time.

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

Table 14: Natural Gas Sensitivity in the Industrial Renaissance Scenario

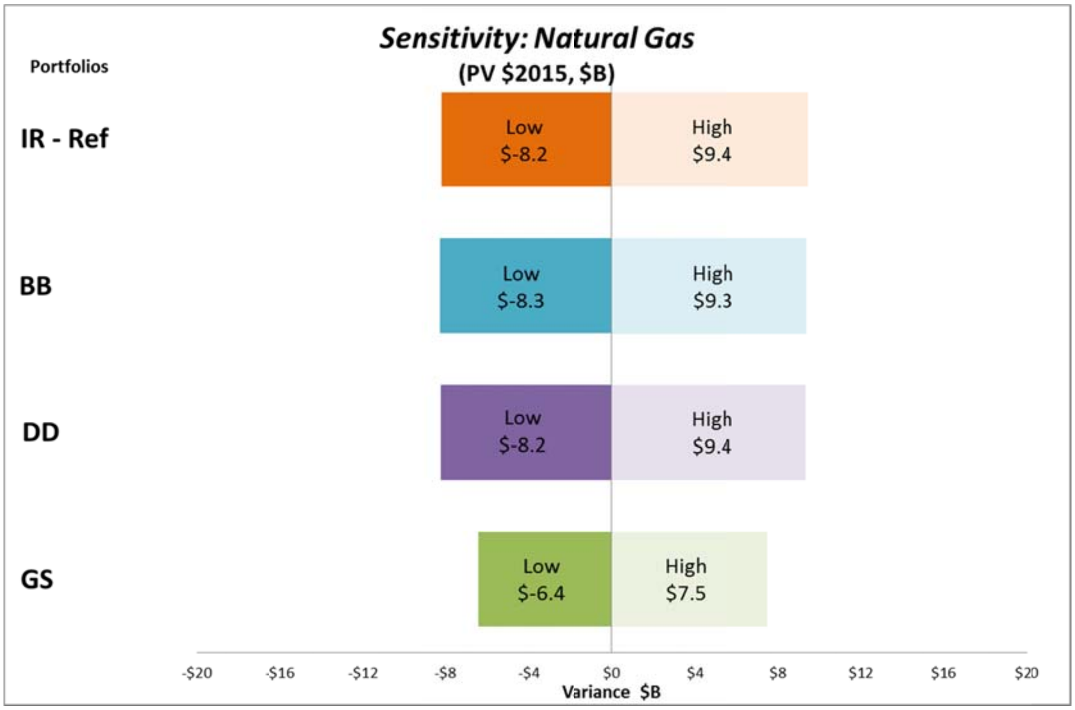


Table 15: CO_2 Price Sensitivity in the Industrial Renaissance Scenario

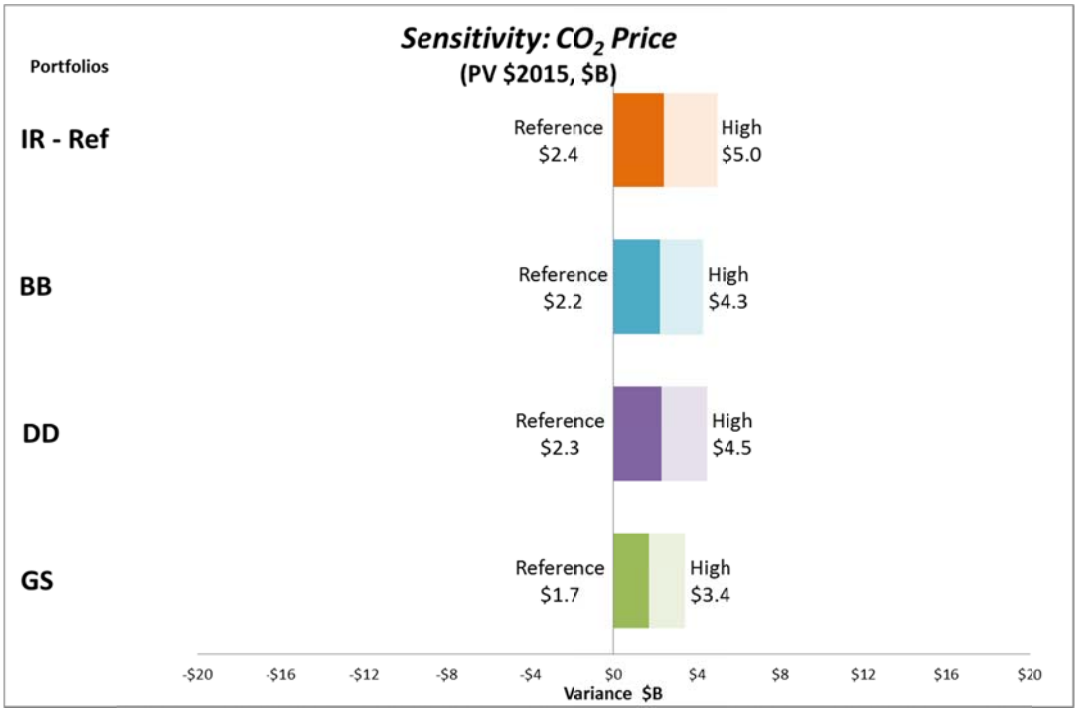


Table 16: Natural Gas and CO_2 Combination Sensitivity in the Industrial Renaissance Scenario

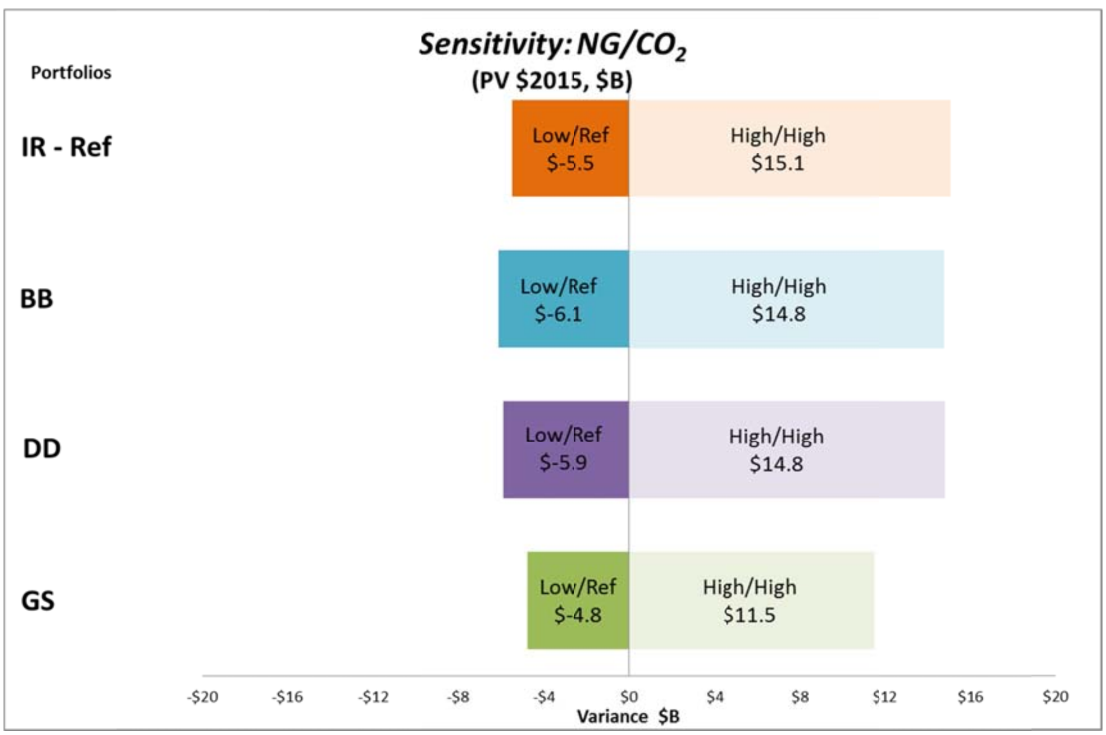


Table 17: Cost of Capital Sensitivity in the Industrial Renaissance Scenario

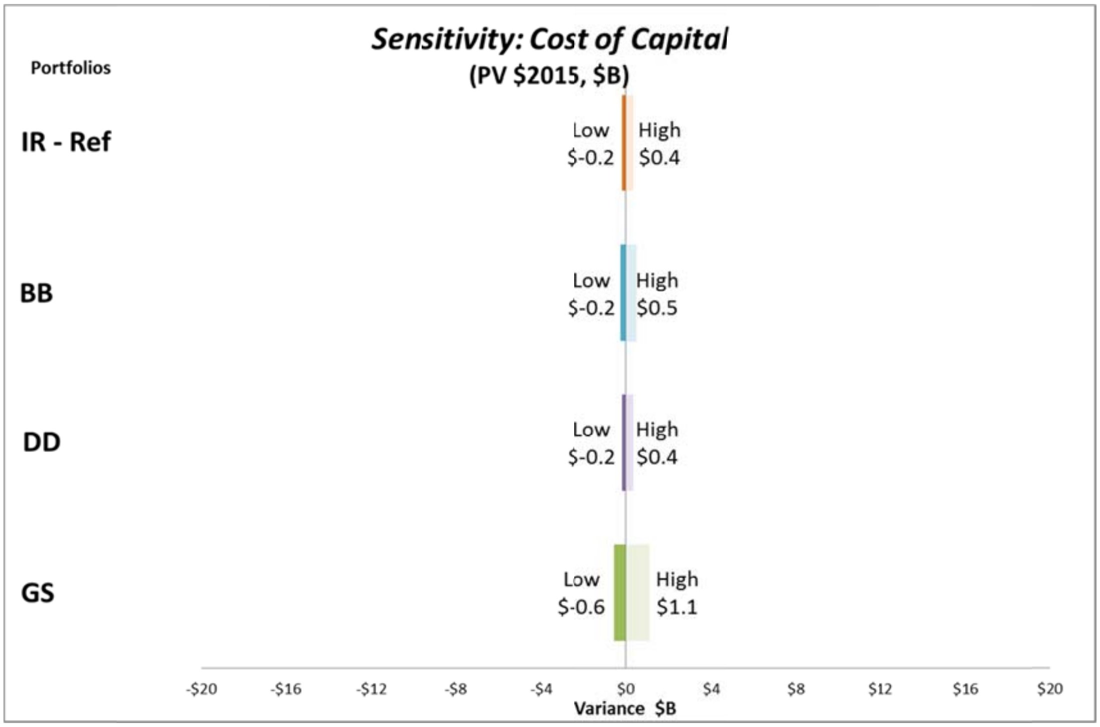
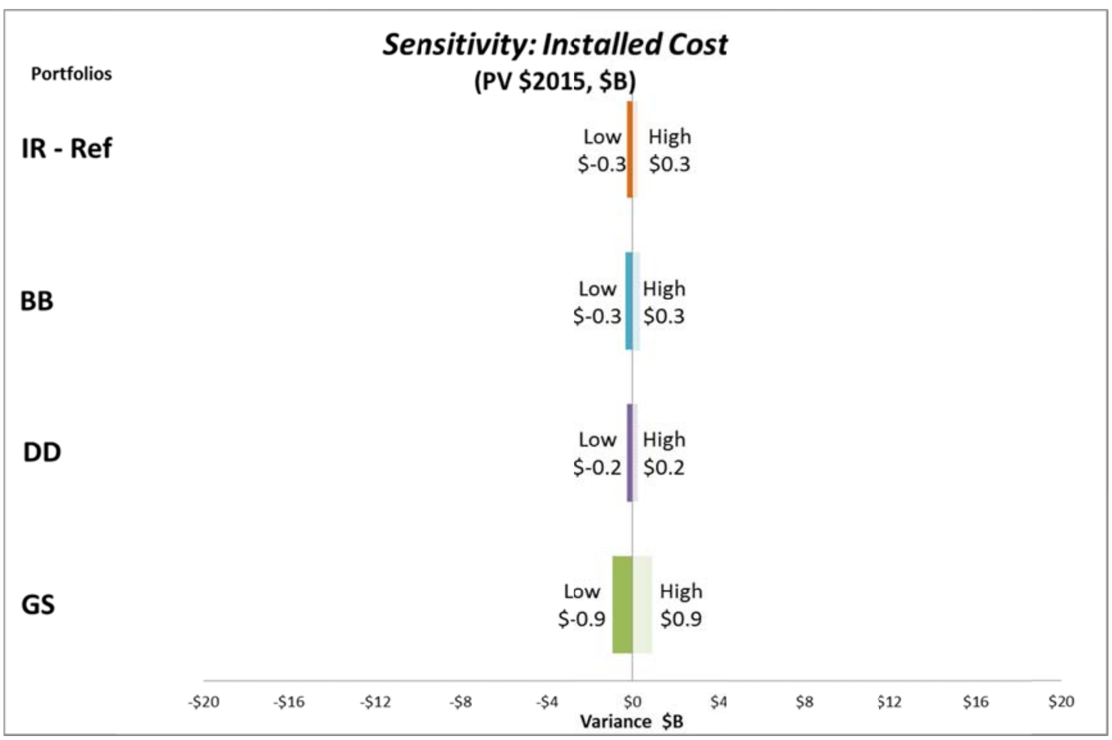


Table 18: Installed Cost Sensitivity in the Industrial Renaissance Scenario



Results of the sensitivity assessments indicate that the installed cost, cost of capital, and coal prices[47] 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.

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[48] 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.

[47] 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.

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

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.

- 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.

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[49]	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[50]	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[51]	-	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816
Amite South CCGT[52]	-	-	-	-	-	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560
Other Planned Resources																				
DSM[53]	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

[49] Total load requirement adjusts for the peak load diversity between the two companies.

[50] The JSP PPAs are included in the Owned Resources row.

[51] Union plant acquisition is completed pending regulatory approvals. 816 MW is two trains of the facility less 20% allocation to ENO. Given changes to the ownership of the other trains, it is expected that EGSL will retain 100% of its two trains.

[52] 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. Given changes to the ownership of the other trains, it is expected that ELL/EGSL will retain 100% of the resource selected through this RFP.

[53] 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; however, given changes to the ownership of the other Union Power units, it is expected that EGSL will retain 100% of its two trains.
	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. - In Q3 2015, file an application and supporting testimony with the Commission seeking certification for the St. Charles Power Station self-build CCGT resource selected through the 2014 Amite South RFP. Complete the certification process in order to support an in-service date by 2020. - In September 2015, issue the WOTAB RFP to solicit proposals for a new CCGT facility (approximately 800-1000 MWs) in the Lake Charles area by 2020 to maintain reliable and economic service to customers given the industrial load growth, PPA expirations and terminations, and anticipated unit deactivations expected in that area. Obtain certification for any resource selected through the RFP in order to facilitate an in-service date by 2020. - 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	DSM and Energy Efficiency	- Evaluate the results of the Quick Start Energy Efficiency programs in Louisiana.

Alternatives	Programs	- 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**			

APPENDIX B: ACTUAL HISTORIC LOAD AND LOAD FORECAST

Historic Peak Demand and Energy[1]

Table 1: Historic Total Annual Energy (MWh)

	ELL	EGSL
2004	29,718,031	21,149,604
2005	28,303,405	20,541,702
2006	29,080,987	20,732,221
2007	29,773,354	20,964,467
2008	29,198,107	21,537,359
2009	29,894,169	21,395,660
2010	32,085,692	22,224,858
2011	33,164,859	21,531,721
2012	32,989,327	21,074,484
2013	33,456,578	21,400,699
2014	33,859,482	22,460,701

Table 2: Historic Total Monthly Energy (MWh)[2]

Month/Year	ELL	EGSL
01/2004	2,311,537	1,601,028
02/2004	2,136,717	1,524,442
03/2004	2,164,832	1,577,645
04/2004	2,176,831	1,593,903
05/2004	2,596,835	1,781,548
06/2004	2,741,239	1,864,531
07/2004	2,932,780	2,024,939
08/2004	2,881,298	2,012,446
09/2004	2,593,513	1,862,491
10/2004	2,624,031	1,996,075
11/2004	2,168,018	1,596,355
12/2004	2,390,400	1,714,201
01/2005	2,255,883	1,672,997
02/2005	2,031,011	1,453,530
03/2005	2,235,818	1,548,045
04/2005	2,261,162	1,553,197
05/2005	2,559,331	1,784,569
06/2005	2,769,785	1,904,194

[1] Actuals are not available for revenue classes.
[2] Data for November and December 2014 is preliminary and subject to change.

07/2005	2,906,955	2,008,777
08/2005	2,834,534	2,037,849
09/2005	2,087,842	1,806,263
10/2005	2,211,131	1,597,883
11/2005	2,001,850	1,554,430
12/2005	2,148,103	1,619,968
01/2006	2,033,144	1,556,821
02/2006	1,980,652	1,385,554
03/2006	2,117,934	1,571,043
04/2006	2,221,653	1,653,726
05/2006	2,537,231	1,816,740
06/2006	2,789,737	1,940,443
07/2006	2,875,996	2,023,795
08/2006	2,997,500	2,097,955
09/2006	2,646,658	1,873,176
10/2006	2,398,857	1,677,934
11/2006	2,169,848	1,527,102
12/2006	2,311,777	1,607,932
01/2007	2,371,678	1,703,012
02/2007	2,162,670	1,500,588
03/2007	2,221,530	1,601,057
04/2007	2,190,694	1,608,715
05/2007	2,492,526	1,913,330
06/2007	2,734,552	1,902,830
07/2007	2,816,853	1,938,451
08/2007	3,099,329	2,107,737
09/2007	2,697,947	1,876,642
10/2007	2,455,856	1,687,020
11/2007	2,170,803	1,521,490
12/2007	2,358,917	1,603,595
01/2008	2,432,139	1,852,720
02/2008	2,118,960	1,603,295
03/2008	2,236,831	1,690,728
04/2008	2,291,841	1,668,177
05/2008	2,626,717	1,954,253
06/2008	2,786,255	2,080,007
07/2008	2,995,936	2,259,714
08/2008	2,842,596	2,158,308
09/2008	2,078,546	1,467,917
10/2008	2,350,752	1,750,564
11/2008	2,144,427	1,474,222
12/2008	2,293,108	1,577,453

01/2009	2,343,883	1,690,184
02/2009	1,985,991	1,411,601
03/2009	2,172,280	1,587,727
04/2009	2,298,941	1,572,658
05/2009	2,616,182	1,823,800
06/2009	2,837,246	2,124,410
07/2009	2,963,590	2,173,590
08/2009	2,891,459	2,215,597
09/2009	2,685,899	1,907,629
10/2009	2,461,316	1,735,890
11/2009	2,201,431	1,478,599
12/2009	2,435,951	1,673,975
01/2010	2,623,187	1,759,164
02/2010	2,276,565	1,646,248
03/2010	2,342,863	1,666,681
04/2010	2,336,778	1,679,509
05/2010	2,832,878	2,025,872
06/2010	3,032,288	2,129,334
07/2010	3,106,097	2,091,799
08/2010	3,161,069	2,140,429
09/2010	2,921,662	1,993,046
10/2010	2,554,847	1,760,973
11/2010	2,300,971	1,596,121
12/2010	2,596,486	1,735,682
01/2011	2,653,798	1,740,261
02/2011	2,412,060	1,562,619
03/2011	2,407,898	1,614,158
04/2011	2,508,947	1,740,579
05/2011	2,794,626	1,909,373
06/2011	3,089,584	2,021,022
07/2011	3,248,003	2,079,774
08/2011	3,488,051	2,185,171
09/2011	2,874,991	1,793,410
10/2011	2,579,222	1,649,351
11/2011	2,410,048	1,600,386
12/2011	2,697,629	1,635,616
01/2012	2,531,135	1,608,977
02/2012	2,412,094	1,454,687
03/2012	2,593,042	1,631,738
04/2012	2,574,452	1,696,105
05/2012	2,982,002	1,957,034

06/2012	3,111,340	1,922,590
07/2012	3,245,996	2,024,525
08/2012	2,991,951	2,024,343
09/2012	2,841,400	1,832,743
10/2012	2,639,342	1,735,547
11/2012	2,404,111	1,525,234
12/2012	2,662,463	1,660,961
01/2013	2,746,176	1,615,504
02/2013	2,340,010	1,461,945
03/2013	2,549,999	1,631,898
04/2013	2,510,550	1,673,465
05/2013	2,846,703	1,817,896
06/2013	3,105,051	2,006,778
07/2013	3,111,886	2,049,357
08/2013	3,307,459	2,106,366
09/2013	3,056,761	1,938,448
10/2013	2,539,617	1,741,513
11/2013	2,513,983	1,609,732
12/2013	2,828,381	1,747,795
01/2014	2,918,373	1,861,032
02/2014	2,457,101	1,626,956
03/2014	2,558,374	1,752,514
04/2014	2,533,237	1,707,600
05/2014	2,810,857	1,892,237
06/2014	3,067,230	2,073,054
07/2014	3,237,304	2,077,909
08/2014	3,265,719	2,170,383
09/2014	3,008,222	1,997,183
10/2014	2,745,633	1,841,000
11/2014	2,567,031	1,721,727
12/2014	2,690,401	1,739,106

Table 3: Historic Total Summer & Winter Peaks (MW)[3]

	ELL	EGSL
Winter 2004[4]	4,636	3,119
Summer 2004	5,091	3,555
Winter 2005	4,943	3,314
Summer 2005	5,236	3,583
Winter 2006	4,550	3,311
Summer 2006	5,257	3,639
Winter 2007	4,395	3,383
Summer 2007	5,341	3,676
Winter 2008	4,653	3,609
Summer 2008	5,234	3,912
Winter 2009	4,558	3,256
Summer 2009	5,252	4,046
Winter 2010	5,060	3,496
Summer 2010	5,492	3,747
Winter 2011	5,174	3,400
Summer 2011	5,766	3,787
Winter 2012	5,343	3,412
Summer 2012	5,706	3,694
Winter 2013	5,045	3,386
Summer 2013	5,773	3,776
Winter 2014	5,382	3,459
Summer 2014	5,518	3,752

[3] Summer is defined as June-November. Winter is defined as December-May.
[4] Winter 2004 is defined as January 2004-May 2004.

Load Forecast

Table 4: EGSL Monthly Energy Forecast (GWh), Industrial Renaissance Case

REDACTED MATERIAL

REDACTED MATERIAL

REDACTED MATERIAL

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REDACTED MATERIAL

REDACTED MATERIAL

Table 5: ELL Retail Monthly Energy Forecast (GWh), Industrial Renaissance Case

REDACTED MATERIAL

REDACTED MATERIAL

REDACTED MATERIAL

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REDACTED MATERIAL

Table 6: Forecasted Retail Summer & Winter Peaks (MWs)[5]

	ELL	EGSL
Winter 2015	5,294	3,666
Summer 2015	5,863	3,861
Winter 2016	5,382	3,766
Summer 2016	5,950	3,983
Winter 2017	5,548	3,933
Summer 2017	6,115	4,232
Winter 2018	5,619	4,345
Summer 2018	6,174	4,567
Winter 2019	5,752	4,501
Summer 2019	6,292	4,723
Winter 2020	5,784	4,372
Summer 2020	6,332	4,601
Winter 2021	5,828	4,402
Summer 2021	6,372	4,630
Winter 2022	5,869	4,428
Summer 2022	6,413	4,658
Winter 2023	5,909	4,455
Summer 2023	6,456	4,688
Winter 2024	5,950	4,484
Summer 2024	6,492	4,719
Winter 2025	5,990	4,515
Summer 2025	6,532	4,752
Winter 2026	6,029	4,544
Summer 2026	6,574	4,785
Winter 2027	6,069	4,573
Summer 2027	6,614	4,816
Winter 2028	6,108	4,601
Summer 2028	6,659	4,847
Winter 2029	6,146	4,628
Summer 2029	6,693	4,877
Winter 2030	6,185	4,655
Summer 2030	6,732	4,905
Winter 2031	6,223	4,683
Summer 2031	6,771	4,935
Winter 2032	6,261	4,710
Summer 2032	6,810	4,965
Winter 2033	6,299	4,738
Summer 2033	6,851	4,995

[5] Summer and winter coincident peak demands for each customer class are not developed.

Winter 2034	6,337	4,766
Summer 2034	6,893	5,026

Table 7: Forecasted Load Factors

	ELL	EGSL
2015	69%	69%
2016	70%	70%
2017	70%	72%
2018	70%	76%
2019	71%	78%
2020	71%	76%
2021	71%	76%
2022	71%	77%
2023	71%	77%
2024	71%	77%
2025	71%	77%
2026	71%	77%
2027	71%	77%
2028	71%	77%
2029	71%	77%
2030	71%	77%
2031	71%	77%
2032	71%	77%
2033	71%	77%
2034	71%	77%

APPENDIX C: RESPONSE TO STAKEHOLDER COMMENTS

General

Comment	Response (January 2015)
Staff - Provide rationale for selection of the proxy generating unit used for the projected long-term capacity prices and describe how that compares to other market capacity prices for MISO RTO	MISO does not have projected long-term capacity prices; only annual market capacity prices are developed. For long-term planning, a CT is used as the proxy generating unit for projected-long term capacity prices as it is the lowest cost source of capacity.
Staff - Identify units selected for deactivation and reason for deactivation and when	For the purpose of developing this IRP, assumptions must be made about the future of generating units currently in the Companies' 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 the years 2015-2034, the total assumed reduction in the Companies' generating capacity from these unit deactivations and PPA terminations is approximately 6,100 MW, which considers the addition of Ninemile Point 6, relative to the Companies' current combined resources of approximately 10,915 MW.
Sierra Club - Not clear "how the Company will model the possible retirement of existing coal resources. Moreover, it appears Entergy has ignored the possibility of retiring any of its coal-fired facilities."	Throughout the planning period all Entergy coal units are assumed to continue to operate. These units will continue to operate as long as it is economic to do so.

Staff - Identify and describe future known and/or planned changes in capacity, availability, etc.	There are no known future and/or planned changes in the capacity and the availability of existing resources.
Staff - Identify and describe new resources the company plans to build or acquire, including those planned for WOTAB transmission region.	As described in the Action Plan, EGSL is in the process of obtaining regulatory approval to acquire two units of the Union Plant near El Dorado, Arkansas. This acquisition would add approximately 816 MWs net of a 20% PPA to ENO to the Companies' current capacity. Similarly, the Companies are currently conducting the Amite South RFP to obtain a new CCGT by 2020.
Staff - Identify and describe future known and/or planned changes in transmission capacity, including new lines and upgrades, and effect on new resources.	This information is available under the Transmission Planning Section in the IRP. Specific details about future changes in transmission is in Appendix A.
Sierra Club - Disclose how ELL and EGSL will affect resource plans	As part of the IRP, an Action Plan was developed that describes the Companies plan for specific resources at certain times.
SWEA - Recommends that data assumptions regarding O&M only use fixed O&M costs, instead of fixed and variable O&M costs together.	All relevant costs are included in the IRP, which includes both fixed and variable O&M. The IRP is developed from a customer perspective. That is, the Companies' planning process seeks to design a portfolio of resources that reliably meets customer power needs at a reasonable cost while considering risk, which is why it is necessary to include variable O&M costs.
SWEA - Data assumptions should include greater transparency and citation so all stakeholders can conduct data quality control.	All input assumptions were filed with the LPSC through a series of filings in 2014, with the most recent in October.
Sierra Club - Entergy should "treat distributed generation like any other available resource and pursuing programs that are available and beneficial to ratepayers."	The effect of distributed generation is accounted for in the load forecast. Currently, this is the best available method to account for distributed generation given its non-dispatchable nature.

Comment on Draft IRP Report	Response (August 2015)
Alliance for Affordable Energy – Were upgrade costs for nuclear modeled in AURORA or were new nuclear costs modeled?	Upgrade costs for nuclear were not modeled. New nuclear was evaluated in the screening level analysis phase of the Technology Assessment and found to be a viable technology, but was not selected by AURORA as a cost competitive resource in the detailed analysis phase.
Alliance for Affordable Energy – Was generation from the Union Power Station included in the modeling or after the modeling was complete?	Union Power Station was included in the AURORA modeling as a resource.
Alliance for Affordable Energy – Please explain the match up fee used in connection with wind resources.	The "match up" reflects the fact that wind receives partial capacity value in MISO due to wind's intermittent nature. The capacity match-up fee was only applied in the initial screening analysis phase of supply-side resources in the technology assessment. Once it was selected for further analysis and modeling in AURORA, wind was evaluated relative to other resources without the capacity match up fee added.
LEUG – Explain the process by which the companies continue to evaluate unit deactivations.	For the purpose of developing the IRP, assumptions are made about the future of the units in the current portfolio. 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. In the IRP, a total assumed net reduction in the Companies' generating capacity from unit deactivations and PPA terminations is approximately 6,100 MW over the planning horizon. This assumption has not changed since the November 3, 2014 Inputs filing.
LEUG – Provide additional information on the process for evaluation of new transmission options to ensure lowest reasonable costs.	Transmission alone is not an alternative to generation, but rather transmission in conjunction with generation allows customers to be served reliably and economically. The Companies and other load serving entities in MISO are required to provide generation capacity equal to their load obligation plus a MISO-determined reserve margin to comply with MISO Resource Adequacy requirements. Therefore, when the Companies need to add a new generating unit, the location is chosen to best meet the planning objectives

	based on consideration of factors needed to support new generation including, but not limited to fuel supply, transmission, water supply, environmental permitting, and proximity to load. This process considers both generation and transmission and allows the Companies to meet the planning objectives of serving its customers reliably at the lowest reasonable cost while considering risk.
Staff—Discuss whether there are any economic opportunities to include CHP in the portfolio and reduce need for other capacity-related capital expenditures	The Companies' favorable commercial and industrial rates makes CHP deployment uneconomic for most existing customers except those with over 20 MW of load that also have an operational need for process steam. Even if CHP is economic, many industrial customers prefer to utilize the Companies' reliable and competitively priced electrical power rather than commit their limited capital resources to constructing their own power generation projects that have a mid to long-term payback and are a non-core business. This is very much the case when the industrial customer's cost of electricity is small compared to its total cost of doing business. The considerable amount of industrial CHP already connected to the Companies' electrical grid indicates that the base of existing industrial customers for whom that technology makes economic sense have already elected to deploy CHP.
Staff—Regarding Action Plan, provide information on timelines for acquiring the New Resources discussed as well as any reasons why competitive solicitation might not be used.	Additional information regarding timelines has been provided in the Action Plan in the report.
Staff—Explain whether analysis has been performed to determine if it would be beneficial to EGSL customers for JSP PPAs to remain in effect and how that would affect the Reference Plan.	Because LPSC Consolidated Order Nos. U-21453, U-20925 and U-22092 (Subdocket J) requires the termination of these PPAs upon removal of the JSP PPA resources from Entergy System dispatch, such analysis has not been performed in developing the Companies' IRP. In general, the termination of the JSP PPAs would cause EGSL, on a net basis, to lose approximately 700 MW of capacity from legacy gas generation resources. This assumption is reflected in the Reference Plan. There is no basis to assume a different outcome given the LPSC Order.

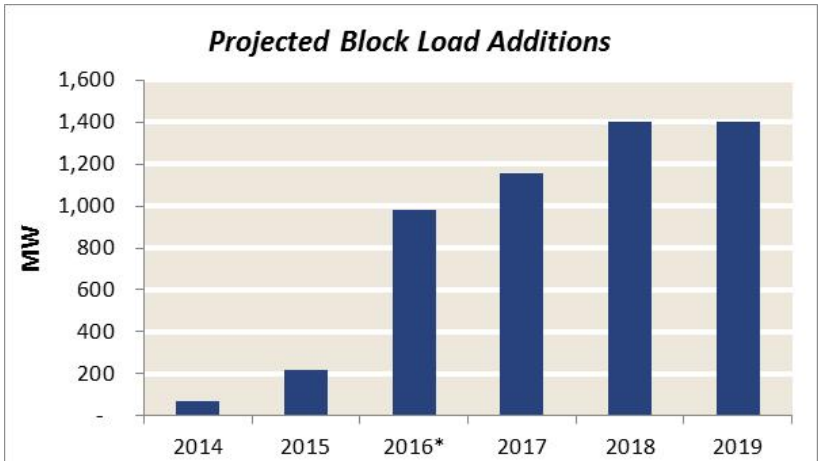
Load

Comment	Response (January 2015)
Staff - Identify and describe known or anticipated major load additions	Load additions include individual customer information, which is confidential.
Staff - Address how price elasticity incorporated in projected peak loads and energy, and how this effects resource portfolio	Price elasticity is an input into the energy forecasting models. The peak load forecast uses the output from the energy models as an input so the impacts of price elasticity indirectly influence the peak load. Resource portfolios are then developed after the load forecast is complete.

<table>
<tr><th>Comment on Draft IRP Report</th><th>Response (August 2015)</th></tr>
<tr><td>Staff-How did actual load compare to the load forecast in the Companies' 2012 IRP filings?</td><td>The following table provides a comparison of actual annual energy sales, or cumulative hourly load, to the 2012 IRP forecast.

Amounts in GWh
<table>
<tr><th></th><th>EGSL</th><th></th><th></th><th>ELL</th><th></th><th></th></tr>
<tr><th></th><th>2012</th><th>2013</th><th>2014</th><th>2012</th><th>2013</th><th>2014</th></tr>
<tr><td>IRP Forecast[1]</td><td>19,298</td><td>19,659</td><td>19,925</td><td>31,373</td><td>32,130</td><td>32,482</td></tr>
<tr><td>Weather Adjustment</td><td>124</td><td>48</td><td>-87</td><td>178</td><td>142</td><td>-275</td></tr>
<tr><td>Non Weather Adjusted Actuals</td><td>19,581</td><td>19,663</td><td>20,823</td><td>31,710</td><td>32,220</td><td>32,905</td></tr>
<tr><td>Forecast Error %</td><td>1.5%</td><td>0.0%</td><td>4.5%</td><td>1.1%</td><td>0.3%</td><td>1.3%</td></tr>
<tr><td>Weather Adjusted Error %</td><td>2.1%</td><td>0.3%</td><td>4.1%</td><td>1.6%</td><td>0.7%</td><td>0.5%</td></tr>
</table>

[1] Final Retail Forecast from the 2012 IRP Base Case; Assumes normal weather</td></tr>
<tr><td>Staff – Add a more detailed description of the assumptions used to develop the load forecast and distributed generation.</td><td>Rooftop solar's forecasted growth is based on a 12 month average of installation rates and average system size. No specific additional growth is assumed after 2017 due to the expiration of investment tax credits; however, growth in solar along with other items is embedded in the reduction of sales within organic energy efficiency assumptions.</td></tr>
<tr><td>Staff – Add a more</td><td>In an effort to avoid long-term resource shortages, projects within the Companies' Economic Development pipeline were added to the forecast. In</td></tr>
</table>

detailed description of the assumptions used to develop the load forecast, including major load additions.	recognition of the uncertainty inherent in forecasting new load, the added projects were risk adjusted to reflect an internally assigned probability of the new customer completing the pending project. For example, assume that customer ABC has informed Entergy of a new 80 MW project being considered in Entergy's service territory. Based upon conversations with the customer and previous experiences, the Companies' Account Manager assigned a probability of 50% to this project being completed. Thus, the load forecast would assume a 40 MW (80 MW x 50% = 40 MW) project is added. Projects for which the customer has executed an electric service agreement are not risk-adjusted and would be included in the load forecast at the full projected MW load. A large industrial addition of approximately 10 MW was also included in Louisiana to account for projects that had not been explicitly identified. The capacity of the large industrial load additions assumed in the forecast is identified in the chart below.  *2016 includes approximately 10 MW of a generic large industrial adder to account for projects not explicity identified in Entergy's Economic Development pipeline
Alliance for Affordable Energy – Does weather forecasting used by SPO and Metrix use historic data or climate impacted projections?	Historic data is used in the weather forecasting.

Fuel Inputs

Comment	Response (January 2015)
Staff - Use consistent assumptions for coal-price input. If there are discrepancies between plants, explain.	The Delivered Plant Coal Prices were developed using two different methodologies: Entergy Operating Company ("EOC") and Market Plants. The SPO Delivered to EOC Units Coal Price Forecast is a long-term delivered price forecast created from consultant commodity price forecast, forecasted burn, transportation costs, and contract information. The delivered prices for Market Resources were derived from a consultant forecast. Different plants may have Delivered Coal Price Forecasts because of differences in the timing and volumes for commodity and transportation contracts. Moreover, it is expected that various scenarios have different coal price inputs as a result of different fuel assumptions (*e.g.,* low, reference, and high).
Sierra Club - Assumptions are biased towards natural gas, instead of lower-cost options; Entergy should consider a "gas price volatility adder" to reflect risk of price fluctuation	The sensitivity analysis conducted in the IRP evaluated a range of natural gas prices across each scenario to capture the risk related to fluctuating natural gas prices.

MISO

<table>
<tr><th>Comment</th><th>Response (January 2015)</th></tr>
<tr><td>Entegra - Coordinate with MISO on generation unit retirement assumptions and transmission studies (e.g. for Amite South and WOTAB areas)</td><td rowspan="3">There are established procedures for the Companies' work with MISO, which is beyond the scope of the IRP process.</td></tr>
<tr><td>Entegra - Perform a transmission topology sensitivity analysis of its preliminary IRP results once MISO makes recommendations</td></tr>
<tr><td>Louisiana Energy Users Group - Coordinate with MISO on generation unit retirement assumptions and</td></tr>
</table>

transmission projects (*e.g.,* Amite South and WOTAB)	
Louisiana Energy Users Group - Compare AURORA modeling to MISO recommendations; perform a transmission topology sensitivity analysis	

Energy Efficiency

Comment	Response (January 2015)
Alliance for Affordable Energy - DSM benefits should include indirect utility system benefits resulting from lower capacity and energy loads, reduced reserve requirements, marginal line losses instead of average, and avoided T&D expenses.	As part of the IRP process, the Companies engaged ICF to prepare a demand side management potential study for use in the IRP. The study was filed in October. All programs that had a TRC ratio of 1.0 or greater were evaluated in the AURORA Market Model before consideration of supply side resource options.
Southeast Energy Efficiency Alliance (“SEEA”) - Need to disclose assumptions for cost and availability of energy efficiency for DSM (“Demand Side Management”) study – such as direct savings from installed measures and system benefits, lower capacity and energy loads, reduced reserves requirements, reduction in marginal line losses, and avoided transmission and distribution expenses	
SEEA - Energy efficiency “is not only a least-cost resource, but also a mechanism for deferring additional supply-side generation, avoiding new transmission and distribution infrastructure, and buffering against compliance costs from future environmental regulations.”	

Sierra Club - Treat energy efficiency as a resource, or par with supply-side resources.	
Sierra Club – Energy Efficiency should be accounted as a resource.	
Sierra Club - Model distributed generation and energy efficiency as supply-ride resources.	In the IRP, distributed generation is accounted for in the load forecast for the Companies. Moreover, energy efficiency is evaluated as a resource alternative in the IRP.

Comments on the Draft IRP Report	**Response (August 2015)**
Alliance for Affordable Energy – ICF modeled three cases based on incentive level. Which one of these cases was modeled in AURORA?	The incentive level varied by program. The incentive level with the highest TRC ratio for each program was selected to be modeled in AURORA. As such, the incentive level varied for each program. However, the reference program tended to have the highest TRC ratio for most programs.
Alliance for Affordable Energy – Why didn't ICF include ENO in the benchmarking data?	ENO and the ELL/EGSL service territories have significantly different customer bases. ELL/EGSL are heavily industrial, while ENO has very little industry. As such, comparing performance at the portfolio level between ENO and ELL/EGSL is problematic.
Alliance for Affordable Energy – Why are the payback acceptance curves different from the New Orleans data?	The same set of payback acceptance curves was used to estimate participation for ELL/EGSL as was used for ENO for the Entergy Study.
Alliance for Affordable Energy – Why are the net to gross ratios different from ENO?	The same set of program net-to-gross ratios were used for ELL/EGSL as were used for the ENO study.
Alliance for Affordable Energy –In Appendix F [of the November 3, 2014 Inputs Filing], it looks like avoided costs do not include fuel.	Yes, fuel is included in the avoided costs in Appendix F.

Environmental Regulation

Comment	Response (January 2015)
Staff – Address how [CSAPR] affects amount and timing of planned deactivations.	The Companies continue to evaluate the recent Supreme Court decision to allow the EPA to enforce CSAPR, but to date, none of the Companies' units have been identified for deactivation because of this rule. However, there are different assumptions for other load serving entities in the market based upon the different scenarios. Industrial Renaissance and Distributed Disruption assume non-Entergy units retire at the age of 60 years; Business Boom assumes 70 years; and Generation Shift assumes 50 years.
Sierra Club – Unclear how environmental compliance costs regarding carbon pollution and other environmental regulations will be incorporated.	The IRP does evaluate a range of environmental compliance costs in regards to CO_2, SO_2, and NO_x.
Gulf States Renewable Energy Industries Association ("GSREIA") - Fails to "recognize inherent problems with traditional sources such as price volatility and reduced capacity of life"; "sustainability" and environmental impact are other issues.	The IRP does consider all known and expected environmental cost of resources including carbon.
Alliance for Affordable Energy - Use one robust reference case that includes CO_2 and Section 111(d) compliance with more focus on sensitivities instead of multiple scenarios.	A range of CO_2 price assumptions are included in the IRP across the four scenarios. Moreover, the sensitivity analysis evaluates the effects of different CO_2 prices for each scenario.
SEEA – Assumptions regarding CO_2 policy are unrealistic.	
Sierra Club – "Ignores" the costs of new EPA regulations in Section 111(d) regarding carbon pollution standards coming in June 2014.	
Sierra Club – Use "non-zero CO_2 price"	

Comment	Response (August 2015)
Staff - Include an evaluation of the effects of environmental regulations or future regulations on the operation of the Companies' existing Units.	ESI coordinates internally to identify, assess, and respond to environmental issues arising from federal regulatory and legislative proceedings. ESI tracks issues and analyzes impacts using a combination of internal corporate and business function staff and external organizations. Subject matter experts participate in industry associations and organizations, interact with federal and state agency staff, and monitor the trade press regarding environmental issues. Information gathered is shared through technical peer groups and the Environmental Lead Team, and a consolidated point-of-view is formed based on Entergy's overall business strategy, as needed. Unless otherwise noted below, expected capital expenditures and increases to O&M costs from many of these proposals are not yet fully developed due to uncertainty regarding the outcome of regulatory, legislative, and litigation proceedings. A brief summary of issues which potentially have the highest operational impact on the Companies follows: Clean Air Act Regulations – Consistent with the President's Clean Power Plan announced in June 2013, EPA is expected to finalize in August 2015 regulations for new, existing, and modified/reconstructed sources of CO2 under the Clean Air Act. ESI developed an engagement plan and is actively engaged with industry groups, regulatory agency staff, and other external parties to analyze the impact of these proposed rules, comment on policy and technical issues, and advocate for reasonable approaches. Performance standards for existing sources, once final, will initiate state plans for compliance which could be due as early as September 2016. Regulations to address traditional pollutants have evolved due to court rulings, state implementation planning, and EPA actions. EGSL installed controls at the R.S. Nelson power plant pursuant to EPA regulations regarding mercury and other air toxics, but a recent Supreme Court ruling remanding this rule may result in a different compliance requirement. ESI also is implementing compliance measures for the Cross State Air Pollution Rule (CSAPR) and continues to monitor issues

	regarding regional haze and National Ambient Air Quality Standard (NAAQS) development. Solid/Hazardous Waste Regulations – EPA finalized regulations for coal ash and management structures in December 2014. The rule regulates coal ash disposal and impoundments/landfills under the non-hazardous section of the solid waste regulations. The R.S. Nelson power plant is the only EGSL-owned facility affected by the rule. ESI continues to participate with industry groups to advocate for reasonable implementation approaches in order to minimize compliance costs. Litigation on this rule may result in a different compliance strategy. Aquatic Protection Regulations – EPA finalized the 316(b) rule in May 2014. The final rule affects several EGSL/ELL facilities and provides flexibility on both the schedule and technology approaches for complying with the standards for impingement and entrainment. ESI's Environmental Strategy & Policy group has coordinated between the Entergy Fossil and Nuclear organizations to assess plant needs for responding to the new regulation. Consultants have been retained and compliance activities are underway to conduct the necessary technical studies and compile the existing technical data for submission to the appropriate regulatory agencies. EPA also has proposed new effluent (discharge) guidelines for electric generating units that may require modified waste water treatment procedures; these guidelines are not expected to be finalized until late 2015.
Staff - Include more clarification on the methodology of the CO_2 forecast, particularly around why the carbon costs start in 2023. Include supporting studies from other organizations.	The reference case price stream is based on a probability-weighted forecast of a utility-only sector cap and trade program being implemented starting in 2023. The utility program is based on the reductions required under the Kerry-Lieberman legislative proposal, and prorated to the power sector emissions levels. Offsets are also allowed. The assumed probability of a national, utility-only program is 33 percent in 2023 and 66 percent by 2040. The forecast is updated annually by the ESI Environmental Strategy and Policy group, or more

	often as conditions warrant. The updated forecast is reviewed by the Companies' Environmental Lead Team with their recommendation being used as the Companies' CO_2 Point of View. The forecast is based on the Q1 2014 Strategic Outlook (formerly the Integrated Energy Outlook) dated January 2013 by ICF International.

Renewable Resources

Comment	Response (January 2015)
Sierra Club – Solar and wind installation costs will decrease.	The Technology Assessment indicates that solar cost are likely to decline over the next five years, however, wind cost and performance are not expected to materially improve or decline over this time period. If wind and solar cost and performance improve more than expected in this IRP, then future IRPs will capture that. LA IRP cycle time is every four years.
GSREIA - Common expectation for solar and wind energy leveled costs to reach grid parity in many areas within 5-10 years. A lack of early first-hand experience by EGSL and ELL with integration, these technologies will be a liability to ratepayers, keeping costs and volatility high unnecessarily. Declining price of renewable energy sources must be included in the modeling of any forward-looking resource plan.	
Alliance for Affordable Energy - Wind resources: model Louisiana coastal, upland, and out of region projects separately and use 40%+ capacity factor.	The Companies prefer technologies that are proven on a commercial scale. Some technologies lack the commercial track record to demonstrate their technical and operation feasibility. A cautious approach to technology development and deployment is therefore reasonable and appropriate in order to
Alliance for Affordable Energy – Renewable resource: in state and out of state and a broad range of project sizes should be considered.	

SWEA - Consider "importing Southwest Power Pool [SPP] wind" at low cost. Recommends "MISO West wind energy resources be modeled in IRP process as a separate resource. If possible, EGSL/ELL should model transmission interconnections and upgrades that may grant greater flexibility in accessing low cost energy resources, like SPP or MISO wind energy." Entergy could also "procure wind resources in Northern MISO." Within Louisiana, wind farms can be constructed in the coastal zone offshore and can be considered resources for MISO South Price points and capacity factors are different for Louisiana-based resources and must be modeled as a separate resource in this IRP process. Encourage a clearer explanation of how EGSL/ELL plans to conduct capacity value analyses for all generation resources. Currently, the capacity value provided to wind energy in the MISO system is 14.1%, and because EGSL/ELL is now a member of MISO, this is a reasonable figure for inclusion in the IRP process. Even so, this value may be conservative. Analysis of wind resources available in SPP and for HVDC transmission suggests a capacity value of 40% based on TVA's capacity value methodology. Used wind costs that are too high: "A major reason for EGSL/ELL's unrealistically high LCOE [Levelized Cost of Energy] for wind energy is a	maintain System reliability and to protect Operating Company customers from undue risks. The Entergy Operating Companies generally do not plan to be the "first movers" for emerging, unproven technologies. The IRP seeks to identify generation technologies that are technologically mature and could reasonably be expected to be operational in or around the Companies' regulated service territory. The Companies use a 34% capacity factor assumption for wind resources that could be developed in or around the Entergy regulated service territory. As part of MISO, the Companies are required to adhere to MISO's capacity values for wind, which is 14.1% as outlined in MISO's Resource Adequacy Tariff (Module E) and Resource Adequacy Business Practice Manual. The Companies' use of a capacity "match up" reflects the fact that wind receives partial capacity value in MISO due to wind's intermittent nature. The capacity match-up is only used in the screening analysis of supply-side resources in the technology assessment. When modeled in AURORA, wind is evaluated without the capacity match up relative to other resources.

spurious use of a 'match up' fee…" It is recommended that the total all-in, delivered costs of wind energy for out-of-state resources be roughly \$40-50/MWh and approximately \$44/MWh for resources within Louisiana	

Comment on Draft IRP Report	Response (August 2015)
Staff-Concerned about lack of fuel diversity in the Reference Case. Should discuss fuel diversity and comments from the 2009 SRP regarding appropriateness of including renewables in the System portfolio.	The 2009 System SRP included the statement on page 1-10 that "renewable generation has a place in the portfolio. Inclusion of modest levels of the most economically priced renewable generation alternatives can reduce cost and minimize total supply cost risk especially in light of the potential RPS and carbon legislation. However, the amount of renewable generation that can be cost effectively added is limited." The "expected" gas forecast shown on Figure 4:3 of that SRP over the 20 year horizon (ending 2030) in real 2008\$ was \$8.66/MMBTU, significantly above the Reference Case Real Levelized forecast of \$4.87 in this 2015 IRP. Based on that point of view, it was possible to foresee 2 GW of cost-effective renewables being added to the Entergy System portfolio (as stated on page 1-11) and a System renewables RFP being issued in the 2009-2010 timeframe (in fact, the RFP issued in 2010 was limited to ELL/EGSL). While renewables would increase fuel diversity in the portfolio, the analysis conducted for the 2015 IRP shows that the cost of renewables compared to natural gas generation is such that they are not competitive in the absence of a RPS. Likewise, the costs associated with new nuclear and coal render them uncompetitive with natural gas at this time. While fuel diversity is a concern of the IRP process, natural gas generation offers the best way to provide the lowest reasonable cost portfolio that can reliably serve the customers' needs.

Hydroelectric

Comment	Response (January 2015)
Nelson - Fails to recognize…that conventional hydroelectric generation is an option for Entergy, from new hydroelectric projects that would be located in or near the Companies' service areas." Hydroelectric generation resources are well below costs of other renewable options Should study hydroelectric generation as part of IRP	Hydroelectric is a site specific resource that has limited development opportunities in Louisiana. As a result, it is not appropriate to assess conventional hydroelectric resources (or any other specific resource) in the context of the IRP. Such analysis would be conducted as part of the evaluation of responses to a Request for Proposals ("RFP") or of an unsolicited offer for a particular resource.
Sierra Club – Entergy should include hydroelectric projects.	

APPENDIX D Entergy Long Term Transmission Plan (ELL and EGSL Projects)

Report Date: January 19, 2015

Entergy Project ID	MTEP Project ID	MTEP Designation	Project Driver	Project Name	Operating Company	Proposed ISD (Planning)	Project Funding Status	Project Status	Project Status Comments	Current Projected ISD	Actual ISD	Mitigation Plan if required	Included in Model? (Yes/No)
11-EGL-007	4602	Appendix B	Transmission Reliability - Meeting Planning Criteria	Moril to Delcambre 138 kV line: Upgrade station equipment	EGSL	Summer 2016	Proposed & In Target	Scoping	Scoping to begin 3rd Quarter 2014	Summer 2016		N/A	
11-EGL-016-02	N/A	Pre-Planned	Transmission Reliability - Meeting Planning Criteria	Mossville to Canal - Phase 2: Upgrade 69 kV Line	EGSL	Winter 2014	Approved	Construction	Construction started 12/15/14. Outages have been approved	2/14/15		N/A	
11-EGL-017	4608	Appendix B	Transmission Reliability - Meeting Planning Criteria	Five Points to Line 281 Tap to Line 247 Tap- Upgrade 69 kV line	EGSL	Summer 2019	Proposed & In Target	Scoping		Summer 2019		N/A	
11-EGL-018	4630	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Francis to Marydale: Upgrade 69 kV line	EGSL	Summer 2017	Proposed & In Target	Scoping	Accelerated Need By Date from 2023 to Summer 2017	Summer 2017		N/A	
12-EGL-004	4603	Appendix B	Transmission Reliability - Meeting Planning Criteria	McManus to Brady Heights - Upgrade 69 kV line	EGSL	Winter 2023	Conceptual	Conceptual	Conceptual Moved out from 2016 to 2023	Winter 2023		N/A	
12-EGL-010	N/A	Pre-Planned	Transmission Reliability - Meeting Planning Criteria	Kirk Substation: Construct new 138-69 kV substation near St. Martinville (Formerly New Iberia: Add 138-69 kV substation)	EGSL	Summer 2015	Proposed & In Target	Scoping	PEP is under review to evaluate a proposed change in the station configuration.	Spring 2016		NCLL	
14-EGL-002	4611	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Construct new Waddill 230-69 kV Substation (formerly referred to as Flannery Area Project) Also reconfigure 69 kV lines 340 and 749	EGSL	Summer 2017	Proposed & In Target	Scoping	Accelerated Need By Date from 2020 to 2017	Summer 2017		N/A	
14-EGL-003	N/A	Pre-Planned	Transmission Reliability - Meeting Planning Criteria	Willow Glenn: Upgrade 500-230 kV single phase transformer bank with 1200 MVA single phase bank	EGSL	Summer 2016	Approved	Design/Construction	Autotransformer and breakers have been ordered and are scheduled to be delivered to support EGSL Construction; January 2016 (Auto) and March 2015 (breakers).	Summer 2016		Planned NCLL until project completed	
14-EGL-004	4606	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Fancy Point: Add 2nd 500-230 kV, 1200 MVA transformer	EGSL	Summer 2017	Proposed & In Target	Scoping	Detailed scoping to begin 3rd Quarter 2014	Summer 2017		Planned NCLL until project completed	
14-EGL-005	4625	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	Nelson: Upgrade 500-230 kV single phase transformer bank with 1200 MVA transformer bank	EGSL	Winter 2015	Approved	Design	Autotransformer has been ordered. Design complete	Spring 2015		N/A	
14-EGL-006	N/A	Pre-Planned	Transmission Reliability - Meeting Planning Criteria	LeBlanc - New Cap Bank #1	EGSL	Summer 2015	Proposed & In Target	Construction	Permanent and Temporary Servitudes are being finalized	Summer 2015		N/A	
14-EGL-007	4610	Appendix B	Transmission Reliability - Meeting Planning Criteria	Chlomal to Lacassine - Upgrade Line	EGSL	Winter 2023	Conceptual	Conceptual	Conceptual Moved out from 2019 to 2023	Winter 2023		N/A	
14-EGL-008	4609	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Krotz Springs - New Cap Bank	EGSL	Summer 2016	Proposed & In Target	Scoping	Alternative locations for the capacitor bank are being evaluated based on constructability issues.	Summer 2016		N/A	
14-EGL-010	4626	Appendix B	Transmission Reliability - Meeting Planning Criteria	Meaux to Abbeville - Upgrade Meaux Line bay bus	EGSL	Summer 2024	Conceptual	Conceptual	Conceptual Project need date moved out from 2020 to 2024	Summer 2024		N/A	
14-EGL-012	4628	Appendix B	Transmission Reliability - Meeting Planning Criteria	LeBlanc - New Cap Bank #2	EGSL	Summer 2021	Conceptual	Conceptual	Conceptual Accelerated one year from 2022 to 2021	Summer 2021		N/A	

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Entergy Project ID	MTEP Project ID	MTEP Designation	Project Driver	Project Name	Operating Company	Proposed ISD (Planning)	Project Funding Status	Project Status	Project Status Comments	Current Projected ISD	Actual ISD	Mitigation Plan if required	Included in Model? (Yes/No)
14-EGL-016	4604	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Port Hudson to Zachary REA 69 kV Line Reconductor	EGSL	Summer 2016	Proposed & In Target	Scoping	Accelerated Need By Date to Summer 2016	Summer 2016		N/A	
14-EGL-017	4605	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	Horseshoe Substation (Crown Zellerbach Area): Construct new 230-138 kV substation on the Fancy Point to Enjay 230 kV line	EGSL	Summer 2017	Proposed & In Target	Scoping	Changed name to reflect new substation name and line connection in title	Summer 2017		N/A	
14-EGL-019	N/A	Pre-Planned	Transmission Reliability - Meeting Planning Criteria	Mud Lake 230 kV Substation: Loop Sabine to Big 3 230 kV Line into new Mud Lake 230 kV substation and add (2) 230 kV capacitor banks at Mud Lake	EGSL	Fall 2016	Approved	Scoping	Detailed scoping in progress. Currently projected to be complete in the Summer 2016.	Summer 2016		N/A	
14-EGL-020	4719	A in MTEP14	Transmission Service	PPG to Rosebluff 230 kV Line: Upgrade line to increase capacity	EGSL	Summer 2015	Approved	Design	Scoping complete. Design has begun. Current project schedule is targeting a 7/1/15 ISD.	7/1/15		N/A	
14-EGL-022-1	4761	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	EGSL SPOF Projects: Modify relaying at Willow Glen 500 kV	EGSL	Summer 2015	Proposed & In Target	Scoping	Definition Phase underway. Site visits completed. Review and updating of drawings by PCS will be completed by March 2015. PEP will also be completed by the end of February 2015. Due to the need to change 21 panels, add new relay room, replacement of transformer under another capital project, etc. and uncertainty in availability of outages, ISD would likely be by December 2016 or beyond this date. After PEP and outage planning is done, a schedule will be developed and ISD identified.	12/31/2016		N/A	N/A
14-EGL-022-2	4762	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	EGSL SPOF Projects: Modify relaying at Fancy Point 500kV	EGSL	Summer 2015	Proposed & In Target	Scoping	Scope to be determined	Summer 2015		N/A	N/A
14-EGL-023	4720	A in MTEP14	Customer Driven	Michigan 230 kV substation: Construct new Michigan 230 kV substation and cut in to the Nelson to Verdine 230 kV line	EGSL	Summer 2015	Approved	Design	Design complete. Material has been ordered. Awaiting customer to prep the site. Expected mobilization is 01/05/2015.	Fall 2015		N/A	
14-EGL-024-1	4763	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	EGSL Underrated Breaker Project: Jaguar 69 kV 20940-CO	EGSL	Winter 2016	Proposed & In Target	Scoping	Under Review	Winter 2016		N/A	N/A
14-EGL-024-2	4764	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	EGSL Underrated Breaker Project: Jaguar 69 kV 20905-CO	EGSL	Winter 2016	Proposed & In Target	Scoping	Under Review	Winter 2016		N/A	N/A
14-EGL-024-3	4765	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	EGSL Underrated Breaker Project: Blount 69 kV 14105-TC	EGSL	Winter 2016	Proposed & In Target	Scoping	Under Review	Winter 2016		N/A	N/A
14-EGL-024-4	4766	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	EGSL Underrated Breaker Project: Coly 230 kV 21825-C	EGSL	Winter 2016	Proposed & In Target	Scoping	Under Review	Winter 2016		N/A	N/A
14-EGL-024-5	4767	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	EGSL Underrated Breaker Project: Coly 230 kV 21830-C	EGSL	Winter 2016	Proposed & In Target	Scoping	Under Review	Winter 2016		N/A	N/A
14-EGL-026	8284	A in MTEP14	Economic	LETP: Coly - Add 2nd 500-230 kV, 1200 MVA Autotransformer	EGSL	Summer 2018	Approved	Scoping	New project (Economic MTEP 14)	Summer 2018		N/A	N/A

APPENDIX D Entergy Long Term Transmission Plan (ELL and EGSL Projects)

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Entergy Project ID	MTEP Project ID	MTEP Designation	Project Driver	Project Name	Operating Company	Proposed ISD (Planning)	Project Funding Status	Project Status	Project Status Comments	Current Projected ISD	Actual ISD	Mitigation Plan if required	Included in Model? (Yes/No)
15-EGL-001	7917	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Gillis 230 kV Substation: Add 61 MVAR capacitor bank	EGSL	Summer 2016	Proposed & In Target	Scoping	New Project	Summer 2016			
15-EGL-002	7919	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Pecan Grove 230 kV Substation: Add 61 MVAR capacitor bank	EGSL	Summer 2016	Proposed & In Target	Scoping	New Project	Summer 2016			
15-EGL-003	7920	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Carlyss to Boudoin 230 kV Line: Upgrade station equipment at Carlyss	EGSL	Summer 2016	Proposed & In Target	Scoping	New Project	Summer 2016			
15-EGL-004	7921	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Nelson to Michigan 230 kV line: Upgrade line to minimum of 2000A	EGSL	Summer 2016	Proposed & In Target	Scoping	New Project	Summer 2016			
15-EGL-005	7923	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Lake Charles Bulk to Chlomal 69 kV Line: Reconductor line	EGSL	Summer 2017	Proposed & In Target	Scoping	New Project	Summer 2017			
15-EGL-006	7924	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Goosport Substation: Install 138-69 kV autotransformer	EGSL	Summer 2017	Proposed & In Target	Scoping	New Project	Summer 2017			
15-EGL-008	7929	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Solac: Upgrade 69 kV switch on Autotransformer	EGSL	Summer 2016	Proposed & In Target	Scoping	New Project	Summer 2016			
15-EGL-009	7948	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Scott to Carencro 69 kV line: Reconductor Line	EGSL	Summer 2017	Proposed & In Target	Scoping	New Project	Summer 2017			
15-EGL-010	7949	Appendix B	Transmission Reliability - Meeting Planning Criteria	Solac: Add 3rd Autotransformer	EGSL	Summer 2023	Conceptual	Conceptual	New Project	Summer 2023			
15-EGL-011	7950	Appendix B	Transmission Reliability - Meeting Planning Criteria	East Broad to Ford 69 kV line: Reconductor line	EGSL	Summer 2020	Proposed & In Target	Scoping	New Project	Summer 2020			
15-EGL-012	7952	Appendix B	Transmission Reliability - Meeting Planning Criteria	Contraband to Solac 69 kV line: Reconductor line	EGSL	Summer 2023	Conceptual	Conceptual	New Project	Summer 2023			
15-EGL-013	7954	Appendix B	Transmission Reliability - Meeting Planning Criteria	Mossville to Alfol 69 kV line: Reconductor line	EGSL	Summer 2023	Conceptual	Conceptual	New Project	Summer 2023			
15-EGL-014	7960	Appendix B	Transmission Reliability - Meeting Planning Criteria	Chlomal to Iowa 69 kV line: Reconductor line	EGSL	Summer 2024	Conceptual	Conceptual	New Project	Summer 2024			
15-EGL-015	7965	Appendix B	Transmission Reliability - Meeting Planning Criteria	Lake Charles Bulk to L673 TP 69 kV line: Reconductor line	EGSL	Summer 2025	Conceptual	Conceptual	New Project	Summer 2025			
15-EGL-016	8585	Target Appendix A in MTEP15 (OOC)	Transmission Reliability - Meeting Planning Criteria	LCTP: Construct new Sulphur Lane 500 kV switching station	EGSL	Summer 2018	Approved	Scoping	New Project to address reliability needs in the Lake Charles area due to projected growth. Being submitted to MISO as out of cycle	Summer 2018			
15-EGL-017-01	8586	Target Appendix A in MTEP15 (OOC)	Transmission Reliability - Meeting Planning Criteria	LCTP: Construct new 500-230 kV Bulk Substation west of Carlyss. Install new 500-230 kV, 1200 MVA autotransformer composed of three single phase units.	EGSL	Summer 2018	Approved	Scoping	New Project to address reliability needs in the Lake Charles area due to projected growth. Being submitted to MISO as out of cycle	Summer 2018			

APPENDIX D Entergy Long Term Transmission Plan (ELL and EGSL Projects)

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Entergy Project ID	MTEP Project ID	MTEP Designation	Project Driver	Project Name	Operating Company	Proposed ISD (Planning)	Project Funding Status	Project Status	Project Status Comments	Current Projected ISD	Actual ISD	Mitigation Plan if required	Included in Model? (Yes/No)
15-EGL-017-02	8587	Target Appendix A in MTEP15 (OOC)	Transmission Reliability - Meeting Planning Criteria	LCTP: Construct new 500 kV transmission line from Sulphur Lane to new 500/230 kV Bulk Substation west of Carlyss	EGSL	Summer 2018	Approved	Scoping	New Project to address reliability needs in the Lake Charles area due to projected growth. Being submitted to MISO as out of cycle	Summer 2018			
15-EGL-017-03	8588	Target Appendix A in MTEP15 (OOC)	Transmission Reliability - Meeting Planning Criteria	LCTP: Construct new 230 kV line from new Bulk Substation to Carlyss 230 kV substation	EGSL	Summer 2018	Approved	Scoping	New Project to address reliability needs in the Lake Charles area due to projected growth. Being submitted to MISO as out of cycle	Summer 2018			
15-EGL-018	8589	Target Appendix A in MTEP15 (OOC)	Transmission Reliability - Meeting Planning Criteria	LCTP: Reconfigure Carlyss 230 kV substation into a breaker and a half configuration	EGSL	Summer 2018	Approved	Scoping	New Project to address reliability needs in the Lake Charles area due to projected growth. Being submitted to MISO as out of cycle	Summer 2018			
15-EGL-019	8590	Target Appendix A in MTEP15 (OOC)	Transmission Reliability - Meeting Planning Criteria	LCTP: Construct new 12 mile 230 kV line from Carlyss to new 230 kV substation adjacent to Graywood.	EGSL	Summer 2018	Approved	Scoping	New Project to address reliability needs in the Lake Charles area due to projected growth. Being submitted to MISO as out of cycle	Summer 2018			
15-EGL-020	TBD	Target Appendix A in MTEP15 (OOC)	Customer Driven	Intracoastal 69 kV Substation: Install 150 MVA, 230-69 kV autotransformer at Intracoastal and connect to Mud Lake 230 kV substation	EGSL	Summer 2016	Approved	Scoping	New customer requested project to provide an additional source into the Intracoastal 69 kV substation	Summer 2016		N/A	
15-EGL-021	TBD	Target Appendix A in MTEP15 (OOC)	Transmission Reliability - Meeting Planning Criteria	Carlyss to Sweet Crude Tap (L-238): Reconductor 69 kV line (0.94 miles) to a minimum of 1200A.	EGSL	Summer 2016	Approved	Scoping	New customer requested project to provide an additional source into the Intracoastal 69 kV substation	Summer 2016		N/A	
14-EGL-027	8284	A in MTEP14	Economic	LETP: Richardson to Iberville - Construct new Richardson 230 kV substation new Dow Meter and construct new 230 kV line from Richardson to Iberville 230 kV substation. (EGSL Portion of project)	EGSL/ELL	Winter 2018	Approved	Scoping	New project (Economic MTEP 14)	Winter 2018		N/A	N/A
14-ELL-019	8284	A in MTEP14	Economic	LETP - Richardson to Iberville - Construct new Richardson 230 kV substation new Dow Meter and construct new 230 kV line from Richardson to Iberville 230 kV substation. (ELL Portion of project)	EGSL/ELL	Winter 2018	Approved	Scoping	New project (Economic MTEP 14)	Winter 2018		N/A	N/A

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10-ELL-008	N/A	Pre-Planned	Transmission Reliability - Meeting Planning Criteria	Southeast LA Coastal Improvement Plan: Phase 3 Construct Oakville to Alliance 230kV Line Add 230 - 115 kV Autotransformer at Alliance Substation	ELL	Summer 2013	Approved	Scoping	Oakville Substation expansion placed into service 9/3/12. Alliance Substation expansion and 230/115kV Auto placed into service 1/16/14. T-Line routing challenges continue to delay start of ROW acquisition. Projected ISD delayed from 6/1/15 to 6/1/18. Awaiting conditional permit approval from LADOTD to construct line within their ROW for Hwy 23. Identifying location of two Parish water lines along west side of Hwy, continue discussions on	6/1/18		Planned NCLL until project completed	
11-ELL-001	N/A	Pre-Planned	Enhanced Transmission Reliability	Golden Meadow to Leeville 115 kV - Rebuild/relocate 115 kV transmission line	ELL	Spring 2014	Approved	Construction	T-Line ROW acquisition completed Dec-2013. The DNR-OCM permit was received in Nov-2013, and the USACE permit was received in Feb-2014. Construction of driveway pads needed for the T-Line structures completed Oct-2014. T-Line construction is in	3/31/15		N/A	
11-ELL-004	N/A	Pre-Planned	Transmission Reliability - Meeting Planning Criteria	Northeast LA Improvement Project Phase 3 Upgrade Sterlington to Oakridge to Dunn 115 kV Line	ELL	Summer 2015	Approved	Construction	Pre-Construction meeting held on 1/09/15. Construction to start 1/15/2015	12/30/15		Planned NCLL until project completed	
11-ELL-012	N/A	Pre-Planned	Transmission Reliability - Meeting Planning Criteria	Valentine to Clovelly 115 kV upgrade	ELL	Summer 2015	Approved	Construction	Design, material procurement, permitting, and ROW access improvements complete. T-Line	5/1/15		Planned NCLL until project completed	
12-ELL-004	4769	A in MTEP14	Load Growth	Schriever: Construct new 230 kV substation	ELL	2017	Proposed & In Target	Scoping	Under Review	3/31/17		N/A	
13-ELL-004	N/A	Pre-Planned	Transmission Reliability - Meeting Planning Criteria	Minden Improvement Project Ph. 1-Place cap bank at Minden REA	ELL	Summer 2015	Proposed & In Target	Scoping	Will require co-ordination with Lagen on final design and operation	Summer 2015		N/A	
13-ELL-006	4634	Appendix B	Transmission Reliability - Meeting Planning Criteria	Ninemile to Westwego 115 kV: Reconductor Line	ELL	Summer 2020	Conceptual	Conceptual	Conceptual	Summer 2020		N/A	
14-ELL-002	4635	Appendix B	Transmission Reliability - Meeting Planning Criteria	Sterlington 115 kV Substation: Upgrade jumpers on the Sterlington to Walnut Grove 115 kV line (line 107)	ELL	Summer 2024	Conceptual	Conceptual	Conceptual	Summer 2024		N/A	
14-ELL-006	4639	Appendix B	Transmission Reliability - Meeting Planning Criteria	Ninemile to Harvey2 115 kV: Reconductor line and change station limiting elements	ELL	Summer 2025	Conceptual	Conceptual	Conceptual Moved ISD back to from 2022 to 2025	Summer 2025		N/A	
14-ELL-008-1	4770	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	ELL Underrated Breaker Project: Waterford 230 kV S7145-CO	ELL	Winter 2016	Proposed & In Target	Scoping	Under Review	Winter 2016		N/A	N/A
14-ELL-008-2	4771	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	ELL Underrated Breaker Project: Waterford 230 kV S7154-CO	ELL	Winter 2016	Proposed & In Target	Scoping	Under Review	Winter 2016		N/A	N/A
14-ELL-009-1	4773	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	ELL SPOF Projects: Modify relaying at Ninemile 230 kV	ELL	Summer 2015	Proposed & In Target	Design	Project is in Design Phase - Kickoff meeting to commence project has been held and schedule developed. Currently scheduled to be completed by Summer 2016 barring availability of outages.	Summer 2016		N/A	N/A

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14-ELL-009-2	4774	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	ELL SPOF Projects: Modify relaying at Southport 230 kV	ELL	Summer 2015	Proposed & In Target	Design	Project is in Design Phase - Kickoff meeting to commence project has been held and schedule developed. Currently scheduled to be completed by Summer 2016 barring availability of outages.	Summer 2016		N/A	N/A
14-ELL-009-3	4775	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	ELL SPOF Projects: Modify relaying at Labarre 230 kV	ELL	Summer 2015	Proposed & In Target	Design	Project is in Design Phase - Kickoff meeting to commence project has been held and schedule developed. Currently scheduled to be completed by Summer 2016 barring availability of outages.	Summer 2016		N/A	N/A
14-ELL-009-4	4776	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	ELL SPOF Projects: Modify relaying at Harahan 230 kV	ELL	Summer 2015	Proposed & In Target	Design	Project is in Design Phase - Kickoff meeting to commence project has been held and schedule developed. Currently scheduled to be completed by Summer 2016 barring availability of outages.	Summer 2016		N/A	N/A
14-ELL-009-5	4777	A in MTEP14	Transmission Reliability - Meeting Planning Criteria	ELL SPOF Projects: Modify relaying at Paris 230 kV	ELL	Summer 2015	Proposed & In Target	Design	Project is in Design Phase - Kickoff meeting to commence project has been held and schedule developed. Currently scheduled to be completed by Summer 2016 barring availability of outages.	Summer 2016		N/A	N/A
14-ELL-016	4783	A in MTEP14	Customer Driven	Haute 115 kV Substation: Construct new substation and cut into existing Lutcher to Belle Point 115 kV line	ELL	Summer 2014	Approved	Construction	The Haute Substation is complete. Project team has accelerate schedule to complete by 12/18/14 . Energization pending legal transfer of ownership.	4/1/2015		N/A	N/A
14-ELL-018	7841	A in MTEP14	Customer Driven	Reese Substation: Construct new 115 kV substations	ELL	Spring 2015	Approved	Complete	In-Service	Spring 2015	12/17/14	N/A	Yes
14-ELL-020	8284	A in MTEP14	Economic	LETP: Panama Substation: Cut-in Bagatelle to Sorrento 230 kV line	ELL	Winter 2018	Approved	Scoping	New project (Economic MTEP 14)	Winter 2018		N/A	N/A
14-ELL-021	8284	A in MTEP14	Economic	LETP: Romeville Substation: Upgrade line bay bus.	ELL	Winter 2017	Approved	Scoping	New project (Economic MTEP 14)	Winter 2017		N/A	N/A
15-ELL-001	7988	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Terrebonne to Gibson: Construct new 230 kV line and operate at 115 kV	ELL	Summer 2018	Proposed & In Target	Scoping	New Project	Summer 2018			
15-ELL-002	7970	Appendix B	Transmission Reliability - Meeting Planning Criteria	Minden Area Improvement Ph. 2: Construct new 115 kV substation east of Minden REA and cut-in Minden REA to Arcadia 115 kV line and construct new 115 kV lines to cut the Minden to Sailes 115 kV line in and out of the new substation	ELL	Summer 2020	Proposed & In Target	Scoping	New Project	Summer 2020			

APPENDIX D Entergy Long Term Transmission Plan (ELL and EGSL Projects)

Report Date: **January 19, 2015**

Entergy Project ID	MTEP Project ID	MTEP Designation	Project Driver	Project Name	Operating Company	Proposed ISD (Planning)	Project Funding Status	Project Status	Project Status Comments	Current Projected ISD	Actual ISD	Mitigation Plan if required	Included in Model? (Yes/No)
15-ELL-003	7990	Appendix B	Load Growth	Luna: Construct new 115 kV substation	ELL	Winter 2017	Proposed & In Target	Scoping	New Project	Winter 2017			
14-ELL-012	4779	A in MTEP15 (OOC)	Transmission Reliability - Meeting Planning Criteria	Ninemile to Derbigny: Upgrade 230 kV line	ELL/ENOI	Summer 2016	Proposed & In Target	Scoping	Project currently accelerated and targeted for June 1, 2016 ISD. Lattice structure inspections to take place Spring 2015. Team meeting with conductor vendor, 3M, on 01.14.15 to determine installation logistics. Project may require funding out of process to support ISD.	6/1/2016		N/A	
14-ELL-013	4780	Appendix B	Transmission Reliability - Meeting Planning Criteria	Ninemile to Napoleon: Upgrade 230 kV line	ELL/ENOI	Summer 2017	Proposed & In Target	Scoping	New Project. Project currently accelerated for targeted for June 1, 2017 ISD. Lattice structure inspections to take place Spring 2015. Team meeting with conductor vendor, 3M, on 01.14.15 to determine installation logistics.	6/1/2017		N/A	
15-EMI-003	7904	Target Appendix A in MTEP15	Transmission Reliability - Meeting Planning Criteria	Natchez SES - Redgum: Rebuild 115 kV line	EMI/ELL	Summer 2018	Proposed & In Target	Scoping	Under Review	Summer 2018		N/A	

APPENDIX E: 1ST STAKEHOLDER MEETING CHARTS[1]

Table 1: Scenario Storylines

	Scenario 2: Industrial Renaissance	Scenario 3: Distributed Disruption	Scenario 4: Resource 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.

[1] As requested by Staff in their comments on the Draft IRP Report, the following three charts from the first IRP stakeholder meeting held January 22, 2014, have been provided. Since these charts were produced the Scenario names have been modified. "Scenario One" was renamed to "Industrial Renaissance" in the November 2014 filing. The "Industrial Renaissance" scenario from the May 2014 filing (Scenario Two) was renamed to "Business Boom."

Table 2: 20 Year Market Modeling Inputs (2015-2034)

	Scenario 1	Industrial Renaissance	Distributed Disruption	Resource Shift
Electricity CAGR (Energy GWh)	~0.8%	~TBD%	~TBD%	~TBD%
Peak Load Growth CAGR	~0.8%	~TBD%	~TBD%	~TBD%
Henry Hub Natural Gas Prices ($/MMBtu)	$4.89 levelized 2013$	Low Case $3.84 levelized 2013$	Same as Reference Case ($4.89 levelized 2013$)	High Case ($8.18 levelized 2013$)
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	CAIR & MATS	CAIR & MATS	CAIR & MATS	CAIR & MATS
Delivered Coal Prices – Entergy Owned Plants (Plant Specific Includes Current Contracts) $/MMBtu	Reference Case (Vol. Weighted Avg. $2.69 levelized 2013$)	Low Case (Vol. Weighted Avg. $TBD levelized 2013$)	Same as Reference Case (Vol. Weighted Avg. $2.69 levelized 2013$)	High Case (Vol. Weighted Avg. $TBD levelized 2013$)
Delivered Coal Prices – Non Entergy Plants In Entergy Region	Mapped to similar Entergy Plant	Mapped to Similar Entergy Plant	Mapped to Similar Entergy Plant	Mapped to Similar Entergy Plant
Delivered Coal Prices – Non Entergy Regions	Reference Case - Varies By Region	Low Case - Varies By Region	Same As Reference Case – Varies By Region	High Case – Varies By Region
Coal Retirements Capacity (GW)*	TBD	TBD	TBD	TBD
New Nuclear Capacity (GW)*	TBD	TBD	TBD	TBD
New Biomass (GW)*	TBD	TBD	TBD	TBD
New Wind Capacity (GW)*	TBD	TBD	TBD	TBD
New Solar Capacity (GW)*	TBD	TBD	TBD	TBD

Table 3: Proposed Sensitivities for the LA IRP

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

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

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

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

*EGSL/ELL use MISO capacity market purchases/sales to ensure appropriate resource adequacy

APPENDIX F: AURORA DSM PORTFOLIOS BY SCENARIO

AURORA DSM Portfolios by Scenario			
Industrial Renaissance	**Business Boom**	**Distributed Disruption**	**Generation Shift**
DSM1 – Residential Lighting & Appliances	DSM1 – Residential Lighting & Appliances	DSM1 – Residential Lighting & Appliances	DSM1 – Residential Lighting & Appliances
DSM3 – ENERGY STAR Air Conditioning	DSM3 – ENERGY STAR Air Conditioning	DSM3 – ENERGY STAR Air Conditioning	DSM3 – ENERGY STAR Air Conditioning
DSM4 – Appliance Recycling		DSM4 – Appliance Recycling	DSM4 – Appliance Recycling
DSM5 – Home Energy Use Benchmarking		DSM5 – Home Energy Use Benchmarking	DSM5 – Home Energy Use Benchmarking
DSM8 – Multifamily	DSM8 – Multifamily	DSM8 – Multifamily	DSM8 – Multifamily
			DSM9 – Water Heating
			DSM10 – Pool Pump
DSM12 – Dynamic Pricing	DSM12 – Dynamic Pricing		DSM12 – Dynamic Pricing
DSM13 – Commercial Prescriptive & Custom	DSM13 – Commercial Prescriptive & Custom	DSM13 – Commercial Prescriptive & Custom	DSM13 – Commercial Prescriptive & Custom
DSM14 – Small Business Solutions	DSM14 – Small Business Solutions	DSM14 – Small Business Solutions	DSM14 – Small Business Solutions
DSM15 – Non-Residential Dynamic Pricing	DSM15 – Non-Residential Dynamic Pricing	DSM15 – Non-Residential Dynamic Pricing	DSM15 – Non-Residential Dynamic Pricing
DSM16 – Retro Commissioning		DSM16 – Retro Commissioning	DSM16 – Retro Commissioning
DSM17 – Commercial New Construction	DSM17 – Commercial New Construction	DSM17 – Commercial New Construction	DSM17 – Commercial New Construction
DSM18 – Data Center		DSM18 – Data Center	DSM18 – Data Center
DSM19 – Machine Drive	DSM19 – Machine Drive	DSM19 – Machine Drive	DSM19 – Machine Drive
DSM20 – Process Heating	DSM20 – Process Heating	DSM20 – Process Heating	DSM20 – Process Heating
DSM21 – Process Cooling and Refrigeration	DSM21 – Process Cooling and Refrigeration	DSM21 – Process Cooling and Refrigeration	DSM21 – Process Cooling and Refrigeration
DSM22 – Facility HVAC	DSM22 – Facility HVAC	DSM22 – Facility HVAC	DSM22 – Facility HVAC
DSM23 – Facility Lighting	DSM23 – Facility Lighting	DSM23 – Facility Lighting	DSM23 – Facility Lighting
DSM24 – Other Process/Non-Process Use	DSM24 – Other Process/Non-Process Use	DSM24 – Other Process/Non-Process Use	DSM24 – Other Process/Non-Process Use

APPENDIX G: WIND MODELING ASSUMPTIONS

In response to stakeholder comments regarding the assumptions used to evaluate wind resources in the IRP, the Companies have prepared this Appendix.

For purposes of the 2015 ELL/EGSL IRP, the delivered cost of energy from a wind resource developed in or near ELL or EGSL's service area ("local") is judged to be comparable to the cost of energy from a remote[1] wind resource ("remote"). While the capacity factors of remote resources are generally higher, the additional costs associated with transmission service and the differences in Locational Marginal Prices ("LMPs") combine to generally equalize energy prices between local and remote resources. Additionally, all remote resources located outside of MISO carry an increased risk of unavailability compared to resources located in MISO due to MISO's emergency curtailment procedures of external systems. Risk associated with potential changes in rules, transmission, and market structures are inherently greater for a remote resource relative to a local resource based on intervening entities that would be involved in conjunction with the long-term nature of these resources.

For some factors, it is reasonable to apply the same assumptions for local and remote wind resources because they are not expected to be materially different. For instance, the installed cost is assumed to be the same. In addition, the non-dispatchable, intermittent nature is expected to be similar and is expected to result in similar capacity credit awarded by MISO. The transmission interconnection cost to connect the resource to a nearby substation is unknown and would be dependent on the specific location regardless of whether the wind resource is local or remote; therefore, it is reasonable to ignore that cost because it is unknown, but expected to be comparable.

Other factors are expected to be different for local as compared with remote wind resources. Key differences include capacity factor, transmission service cost, and LMPs. Assessment of each of these factors is discussed in turn.

Wind quality and speed in the mid-west is expected to yield higher capacity factors as compared to local wind resources. Based on a National Renewable Energy Laboratory ("NREL") cost and performance study published in 2010[2], the capacity factor for a wind resource in the mid-west is assumed to be 50%; whereas, based on the same study, a local wind resource is only expected to be 34%. Thus, remote wind resources have an advantage over local wind resources with respect to energy production potential.

It is important to draw a distinction between transmission interconnection costs as described above and the transmission service cost necessary to make the wind resource deliverable to the Companies' load. A local resource is not expected to require additional transmission service

[1] For example, a wind resource located in Kansas or Oklahoma or other mid-west location.

[2] http://www.nrel.gov/docs/fy11osti/48595.pdf (Figure 96)

charges to make it deliverable. However, a remote wind resource may require SPP point-to-point transmission service to the MISO border and MISO point-to-point transmission service to ELL / EGSL's load. Based on current MISO and SPP tariff rates, the combined cost of transmission service could be approximately $$5/MWh for off-peak hours[4], $10/MWh for on-peak hours[4], or when adjusted to a wind generation profile, a weighted average of $7.11/MWh. This transmission service cost and risk is not incurred by a local wind resource.

Wind generation is paid the hourly LMP at the generator bus while customers pay for energy based on the hourly load-weighted average LMP for the load zone. The difference between the load LMP and generator LMP is an estimate of the risk that customers are exposed to by having a remote resource as opposed to a local resource. To estimate the potential LMP differential risk, three representative SPP wind resources[3] for 2014 were assessed, assuming a generic SPP wind profile. The LMP differentials in 2014 between these three nodes and ELL / EGSL's load (load-weighted average of EES.ELILD and EES.EGILD) are $12.92/MWh, $13.84/MWh, and $17.07/MWh respectively, or approximately $14.60/MWh on average. A local wind resource is not subject to this potential LMP differential risk.

In summary, the table below shows a comparison of the cost of electricity of a local wind resource with a remote resource taking the differences in capacity factor, transmission cost, and LMP into consideration. In this example, the capacity factor advantage of a remote wind resource is almost completely offset by additional transmission service costs and LMP differential risk, which results in similar Levelized Cost of Electricity ("LCOE") estimates for both remote and local wind resources.

Location	Installed Cost ($/kW)	Fixed Charge Rate (%)	Capacity Factor (%)	Transmission Cost ($/MWh)	LMP Differential ($/MWh)	LCOE ($/MWh)
Local	$2000	10.5%	34%	$0	$0	$70.51
Remote	$2000	10.5%	50%	$7.11	$14.60	$69.65
	= [A]	= [B]	= [C]	= [D]	= [E]	= [F]

[F] = [A] x [B] x (1/([C] x 8760)) x 1000 (kW/MW) + [D] + [E]

From this assessment, the expected cost difference is approximately 1% between modeling potential wind resources with local assumptions as compared with remote assumptions. If inflation in the transmission service cost and LMP differential were taken into consideration, the local wind resource would have a lower LCOE as compared to the remote wind resource.

[3] Keenan Wind Farm (Oklahoma Gas & Electric, OKGEWDWRDEHVUNKEENAN_WIND_RA), Centennial Wind Farm (Oklahoma Gas & Electric, OKGECENTWINDUNCENTWIND_RA), Spearville Wind Farm (Kansas City Power & Light, KCPLSPEARVILUNWINDFARM_RA). Historical LMPs by location obtained from SPP Integrated Marketplace (https://marketplace.spp.org/web/guest/lmp-by-location).
[4] MISO transmission cost estimates calculated based on MISO OATT Schedule 7 year 2015 rates, as of July 2015. SPP transmission cost estimates calculated based on SPP OATT Schedule 7 Attachment T, as of July 2015.