Charles River Associates

Prepared For:

The Federal Energy Regulatory Commission

Cost-Benefit Analysis of Entergy and Cleco Power Joining the SPP RTO

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1. EXECUTIVE SUMMARY

On behalf of the Federal Energy Regulatory Commission ("FERC"), Charles River Associates ("CRA") and Resero Consulting[1] have analyzed the costs and benefits of Entergy[2] and Cleco Power[3] joining the Southwest Power Pool ("SPP") [4] regional transmission organization ("RTO"). On June 24, 2009, the FERC and Entergy's retail regulators held a technical conference in Charleston, South Carolina that was attended by Entergy and many of the entities that purchase and/or sell energy in the Entergy region.[5] The FERC agreed to fund a Cost Benefit Analysis ("CBA") to study the costs and benefits of Entergy and Cleco Power joining the SPP as full transmission-owning members with their transmission facilities under SPP operational control.[6]

The CBA was performed over a seven-month period, and included an open and collaborative discussion with stakeholders of the study framework, modeling approach, input assumptions, interim results, and qualitative issues throughout this period. Based on the analysis performed, we conclude that Entergy and Cleco Power joining the SPP RTO will yield

1 Principal study investigators for CRA were Ralph Luciani, Bruce Tsuchida and Pablo Ruiz. Ellen Wolfe of Resero Consulting acted as the lead investigator for the qualitative analysis contained in this study. The findings and conclusions contained in the CBA are solely those of the CRA/Resero Consulting team. The opinions and views expressed in this analysis do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairman or individual Commissioners, or its staff, and are not binding on the Commission.

2 Entergy Arkansas, Inc., Entergy Louisiana, LLC, Entergy Gulf States Louisiana L.L.C., Entergy Mississippi, Inc., Entergy New Orleans, Inc., Entergy Texas, Inc. (collectively, "Entergy"). These utility operating companies serve 2.7 million customers in Arkansas, Louisiana, Mississippi, and Texas.

3 Cleco Power LLC is a regulated electric utility company that serves about 277,000 customers across Louisiana.

4 Southwest Power Pool, Inc. is a group of 57 members in Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas that serve more than five million customers. Membership is comprised of investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, wholesale generators, power marketers, and independent transmission companies. SPP's footprint includes 29 balancing authorities and 50,575 miles of transmission lines. SPP was designated by the FERC as a RTO in 2004. As an RTO, SPP ensures reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity.

5 One outcome of the technical conference was the formation in December 2009 of the Entergy Regional State Committee ("E-RSC"), comprised of participating regulators that regulate the retail rates and services of Entergy: the Arkansas Public Service Commission, the Louisiana Public Service Commission, the Mississippi Public Service Commission, the Public Utility Commission of Texas, and the New Orleans City Council.

6 SPP is a North American Electric Reliability Corp. ("NERC") Regional Entity. Cleco Power is not currently a member of the regional market operated by the SPP, but is a member of the SPP Regional Entity. Entergy is a member of the SERC Regional Entity.

significant economic benefits to the collective SPP/Entergy region.[7] The net benefits to the individual Entergy, SPP and Cleco Power regions is highly dependent on the allocation of regional high voltage transmission expansion costs.[8]

Aside from the allocation of transmission expansion costs, the benefits to the Entergy and SPP regions of joining the SPP RTO are relatively robust across the sensitivity scenarios examined. The benefits to the Cleco Power region are more heavily dependent on the economic conditions that may prevail in the future. A number of important qualitative considerations have been identified as well, with both qualitative benefits and offsetting costs incurred by the Entergy and Cleco Power regions if these regions join the SPP RTO.

Additional addendum studies are contemplated by stakeholders to further assess the costs and benefits of Entergy and/or Cleco Power joining an RTO under alternative assumptions, but otherwise using the models and assumptions developed under this study as the basic framework.

1.1. Study Methodology

Two different cases were analyzed over the 10 year period from 2013 to 2022:

1. Entergy and Cleco Power continue to operate as they do today ("*Status Quo Case*"), and

2. Entergy and Cleco Power join the SPP RTO ("*Join SPP Case*").

In the *Status Quo Case,* SPP is assumed to continue in its capacity as Independent Coordinator of Transmission ("ICT") for the Entergy transmission system. As the SPP RTO is working toward instituting a Day 2 market, a Day 2 market is presumed to be in place in the SPP RTO throughout the 2013-2022 study period.[9] CRA analyzed the impacts on the Entergy, Cleco Power and SPP regions using the General Electric Multi-Area Production Simulation Model ("GE MAPS") model. GE MAPS is a detailed economic dispatch and

7 The "SPP/Entergy region" refers to all load and generation in the current Entergy-SPP-Cleco Power transmission system footprint, including that of merchant generators and cooperative and municipal utilities.

8 The "Entergy region" refers to the area within the Entergy transmission system footprint, and for purposes of this study includes Louisiana Generating and Louisiana Energy and Power Authority. The "Cleco region" refers to the area within the Cleco transmission system footprint as well as the Cleco Power load served by the Entergy transmission system, and for purposes of this study includes the City of Lafayette. The "SPP region" refers to the SPP transmission system footprint that is currently operating within the SPP Energy Imbalance Service market.

9 A Day 2 market refers to a two-settlement (day ahead and real-time) energy market using hourly locational marginal prices and financial transmission rights (FTRs). Day 2 markets are currently in place in PJM, the Midwest ISO, ISO New England and the New York ISO.

production costing model that simulates the operation of the electric power system taking into account transmission topology.

As a general matter, the greater level of coordination and the elimination of wheeling charges between the SPP, Cleco Power and Entergy regions in the *Join SPP Case* will yield system-wide production cost savings through a more efficient system commitment and dispatch. The allocation of these net savings to Entergy, Cleco Power and SPP is assessed by estimating Adjusted Production Costs (i.e., production cost plus purchase costs minus sales revenues) for each of these three regions. In turn, these savings will be offset by additional administrative and other costs incurred if Entergy and Cleco Power join the SPP RTO.

1.2. FINDINGS

1.2.1. Region-wide Net Benefits

The net benefits for the collective SPP/Entergy region if Energy and Cleco Power join the SPP RTO are summarized in Table 1. As shown, the overall net benefit is $1,290 million over the 2013 to 2022 period. In 2010 present value terms, the net benefit is $739 million.[10]

Table 1: 2013-2022 Benefits (Costs) to the SPP/Entergy Region if Cleco Power and Entergy Join the SPP RTO

(in millions of dollars; positive numbers are benefits)

	SPP/Entergy Region			
	Total Dollars		2010 Present Value	
1. Trade Benefits:				
- Decrease in Adjusted Production Costs	1,880		1,073	
- "Lost" Transmission Revenue	(451)		(256)	
Subtotal		**1,428**		**817**
2. Administrative Costs:				
- Additional RTO Administrative Costs net of Avoided ICT Costs	0		0	
- Additional Costs: Internal Staffing/FERC Charges	(138)		(78)	
Subtotal		**(138)**		**(78)**
3. Transmission Cost Allocation		**0**		**0**
Net Benefits (Costs)		**1,290**		**739**

10 A present value rate of 8.0% was applied. An underlying inflation rate of 2.5% was assumed. Benefits and costs over the 2013-2022 period cited in this report are in 2010 present value dollars unless otherwise noted. Figures in the tables throughout this report may not sum due to rounding.

As listed in Table 1, the key cost/benefit measures assessed in this study are: 1. Trade Benefits, 2. Administrative Costs, and 3. Transmission Cost Allocation. Each category is discussed in further detail below.

1. Trade Benefits are comprised of:

- Adjusted Production Costs, the production costs for the generating units in the SPP, Cleco and Entergy regions (fuel, variable O&M and emission costs) plus purchased power costs net of energy sales revenue for each region.[11] The decrease in adjusted production cost in the *Join SPP Case* is $1,073 million for the collective SPP/Entergy region over the 2013-2022 period.

- "Lost" Transmission Revenue. Transmission charges would not be assessed for transactions between SPP, Entergy and Cleco in the *Join SPP Case* yielding reduced or "lost" transmission revenue that would have to be compensated for by increased charges to customers. The "lost" transmission revenue over the 2013-2022 period is estimated to be $256 million, yielding total trade benefits of $817 million.

2. Administrative Costs are comprised of:

- ICT and RTO Administrative Charges. SPP estimates that the additional administrative cost incurred to include Cleco and Entergy in the SPP RTO would be no greater than the costs that would be incurred to operate the Entergy ICT in the *Status Quo Case*. As such, the additional cost to the SPP/Entergy region in the *Join SPP Case* is assumed to be zero.

- Other Additional Costs: Over the 2013 to 2022 period, Entergy and Cleco Power would incur $43 million in costs for additional staffing and equipment to interface with the SPP RTO in the *Join SPP Case*.[12] In addition, Entergy and Cleco Power would incur $34 million of additional FERC charges in the *Join SPP Case.*[13]

3. Transmission Cost Allocation. The total dollars expended on transmission expansion in the SPP/Entergy region (i.e., inclusive of the SPP, Entergy and Cleco Power regions) are projected to be the same whether or not Entergy and Cleco Power join the SPP RTO. Thus

11 Fixed costs that do not change between cases, such as depreciation are not included in this measure.

12 Based on an SPP assessment performed as part of this study, transmission improvements already planned for the Entergy and Cleco transmission systems will be sufficient to allow these systems to integrate into the SPP RTO without further additional transmission improvements.

13 It is CRA's understanding that the allocation of FERC annual charges to jurisdictional entities is under review by the FERC. For purposes of this study, it was assumed that the current policy would continue throughout the study period.

the total cost for transmission expansion to the region as a whole does not change between the Status Quo Case and the Join SPP Case.

In sum, as shown in Table 1, the benefits of increased trade greatly exceed the administrative cost impacts for the collective SPP/Entergy region if Entergy and Cleco Power join the SPP RTO. Moreover, the annual net benefits are projected to be positive for each year of the study period. See Appendix A for more detail.

1.2.2. Allocation of Regional Transmission Expansion Costs

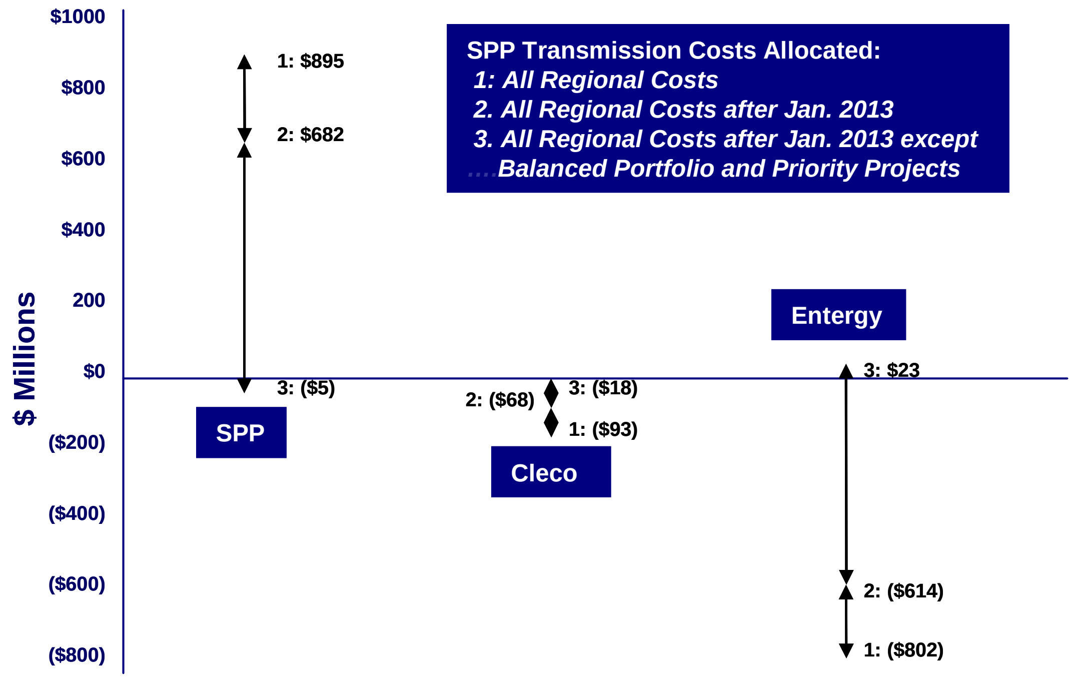
Projected high voltage transmission expansion costs in the SPP, Entergy and Cleco regions would be allocated in the *Join SPP Case* under the "Highway/Byway" allocation mechanism recently approved by the FERC.[14] As part of this study, SPP performed an analysis assuming different types of transmission projects are allocable to Entergy and Cleco Power. The aggregate allocation results over the 2013-2022 period are captured in Figure 1 for the three different transmission cost allocation scenarios assessed by SPP.

In SPP Study 1, the Entergy and Cleco Power regions were assumed to contribute to the regional recovery of SPP upgrades completed after March 2006, coincident with the first regional recovery in SPP. In SPP Study 2, the Entergy and Cleco Power regions were assumed only to contribute to regional recovery of SPP upgrades needed after a "bright line" date of January 1, 2013 (consistent with the start date of the period analyzed in this study). In SPP Study 3, the Entergy and Cleco Power regions were assumed only to contribute to regional recovery of SPP upgrades needed after January 1, 2013, excluding Balanced Portfolio and Priority Projects. The actual allocation would be dependent on a negotiated process between SPP, Entergy and Cleco Power.

14 Under this approach approved by the FERC on June 17, 2010, 100% of the costs of transmission lines of 300 kV and above and 33% of the costs of lines above 100 kV and below 300 kV are recovered on a regional basis.

Figure 1: 2013-2022 Transmission Cost Allocation Benefits (Costs) to the SPP, Entergy and Cleco Power Regions if Cleco Power and Entergy Join the SPP RTO

(in millions of 2010 present value dollars; positive numbers are benefits)



EHV transmission projects (300 kV and above) would be 100% recovered on a regional basis under the Highway/Byway method. The annual revenue requirement for these EHV projects is $691 million for the collective SPP/Entergy region in the *Join SPP Case*. Of these annual EHV costs, the SPP region has $609 million (88%), the Entergy region $82 million (12%), and the Cleco region none. About two-thirds of the SPP region's $609 million annual cost for EHV projects is for the Balanced Portfolio and Priority Projects. As a result, as shown in Figure 1, a significant amount of costs are transferred to the Entergy and Cleco Power regions in SPP Study 1 and SPP Study 2, but not SPP Study 3. The need for additional EHV projects in the Entergy and Cleco Power regions could be the subject of further regional transmission planning analyses. To the extent such projects were approved, the costs would be shared with the SPP region in the *Join SPP Case*.

As shown in Figure 1, the impact to the SPP, Cleco and Entergy regions individually is substantially different across the three SPP transmission cost allocation scenarios. As such, in this study, the benefits and costs for each region are first calculated excluding transmission cost allocation impacts, and then the overall net benefits are captured with a range reflecting the transmission cost allocation figures above.

1.2.3. Net Benefits by Region

Shown in Table 2 are the net benefits individually to the SPP, Entergy and Cleco Power regions. As shown in Table 2, the net benefits to each region are substantially positive prior to allocation of regional transmission expansion costs: $43 million for the Cleco region, $332 million for the SPP region, and $364 million for the Entergy region.

Of the $817 million of SPP/Entergy region trade benefits, the majority, $594 million, accrue to the Entergy region largely because of the greater mix of higher cost gas-fired generation in the Entergy region that is displaced in the *Join SPP Case*. In addition, there are a significant number of Qualifying Facilities ("QFs") in the Entergy region that become firm resources in the *Join SPP Case*. In the *Join SPP Case*, Entergy incurs RTO administrative charges under Schedule 1A of the SPP tariff that exceed the ICT charges incurred in the *Status Quo Case*. In contrast, current SPP members would face lower RTO administrative charges per MWh with Cleco Power and Entergy as members yielding a benefit of $189 million to the SPP region.

Table 2: 2013-2022 Benefits (Costs) to the SPP, Entergy and Cleco Power Regions if Cleco Power and Entergy Join the SPP RTO, excluding Transmission Cost Allocation

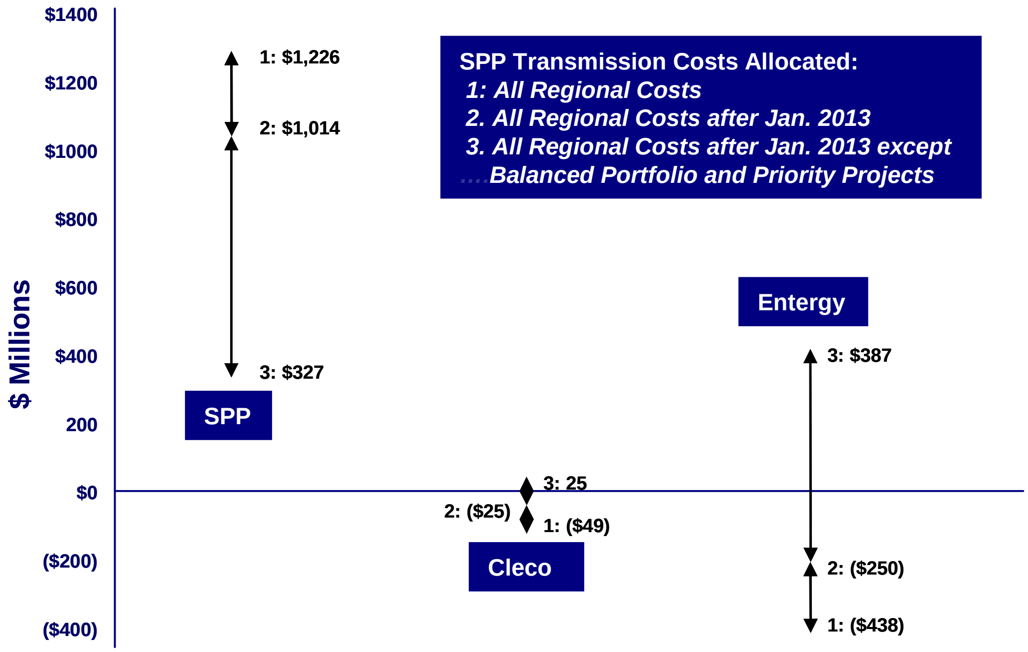
(in millions of 2010 present value dollars; positive numbers are benefits)

	SPP	Cleco	Entergy	Total
Trade Benefits	143	80	594	**817**
Admin Costs: *RTO Administrative Costs net of Avoided ICT Charges*	189	(25)	(164)	**0**
Admin Costs: Internal Staffing/*FERC Charges*	0	(12)	(65)	**(78)**
Subtotal Net Benefits	**332**	**43**	**364**	**739**

Figure 2 shows the net benefits to the SPP, Cleco and Entergy regions including the impact of the potential range of transmission cost allocations. As shown, the net benefits to the SPP region are uniformly positive, while the net benefits to the Cleco region and Entergy region range from positive to negative depending on the transmission cost allocation method applied.

Figure 2: Net Benefits to the SPP, Entergy and Cleco Power Regions if Cleco Power and Entergy Join the SPP RTO including Transmission Cost Allocation

(in millions of 2010 present value dollars; positive numbers are benefits)



No further sub-allocations of regional benefits were performed in this study. Using the detailed GE MAPS results from this study, Entergy is separately performing an assessment of the impact to the Entergy operating companies within the Entergy transmission system footprint.

1.2.4. Sensitivity Analyses

A number of sensitivity analyses were performed including high and low gas prices, high and low regional load growth, and additional wind power construction in SPP. Finally, a “copper sheet” sensitivity was performed in which transmission and reliability must run constraints in the SPP/Entergy region’s transmission system were eliminated (without consideration of the likely prohibitive costs that would be incurred to make such improvements). [15] The change in input assumptions in these sensitivity analyses was applied to both the *Status Quo Case* and *Join SPP* Case. Results are summarized in Table 3.

15 The term “copper sheet” refers to an idealized electrical system in which there are no physical limitations on the flow of electricity from one point on the system to any other point.

Table 3: 2013-2022 Benefits (Costs) to the SPP/Entergy Region if Cleco Power and Entergy Join the SPP RTO

(in millions of 2010 present value dollars, positive numbers are benefits)

Scenario	Total	Change from Base Scenario
Base	**739**	
Sensitivity Scenarios:		
• Low/High Gas Prices	**540 / 858**	*-199 / +119*
• High/Low Load Growth	**713 / 758**	*-26 / +19*
• Increased Wind in SPP	**595**	*-144*
• "Copper Sheet"	**601**	*-138*

As shown, the benefits for the collective SPP/Entergy region remain substantially positive across the sensitivity scenarios examined. The benefits to the SPP region and the Entergy region also remain substantially positive (exclusive of transmission cost allocations) across the sensitivity scenarios. The benefits to the smaller Cleco Power region are impacted more heavily by the changes in assumptions and become negative in three of the six sensitivity scenarios examined.

During the course of the study, other potentially important parameters worthy of additional analysis were identified. Among others, these include Entergy QF treatment, seams charges, and IPP bidding behavior. As noted above, additional addendum studies are contemplated by regional stakeholders to further assess the costs and benefits of Entergy and/or Cleco Power joining an RTO and may include analysis of these and other parameters of interest.

1.2.5. Qualitative Considerations

Resero Consulting, in partnership with CRA, performed a detailed assessment of the likely qualitative impacts of Entergy and Cleco Power joining the SPP RTO. These are impacts not otherwise captured in the quantitative analysis described in this report. For the qualitative assessment, key documents, such as the SPP tariff and the Entergy OATT, as well as information from the WPP and ICT working groups were reviewed. In addition, a number of discussions were held with stakeholders in CBA stakeholder meetings on qualitative issues and concerns and written stakeholder comments also informed the analysis.

The qualitative issues examined included efficiency, competitiveness, transparency and administrative burden costs and risks. The largest qualitative impacts resulting from Entergy and Cleco Power regions joining the SPP RTO were found in the areas of (1) transmission scheduling, dispatch, and congestion management, and (2) transmission planning and interconnection. Substantial qualitative benefits were found to accrue to the Entergy and Cleco Power regions in the *Join SPP Case*, including:

- Improved operational transparency,

- Improved competiveness via resolution of base case overload issues,
- Improved efficiency through resolving various ICT and WPP issues,
- Improved transmission planning and interconnection process, and
- Potentially lower regulation and capacity reserve requirements.

However, additional costs were also found to accrue primarily to the Entergy and Cleco Power regions. These include:

- Risks and costs associated with transmission system access,
- Day 2 market transitional risks, and
- The imposition of SPP's governance structure.

The qualitative analysis also recognizes that some of the impacts associated with the *Join SPP Case* may be achieved by continued actions of the E-RSC without Entergy's formal inclusion in SPP.

2. INTRODUCTION AND BACKGROUND

On June 24, 2009, the FERC and Entergy's retail regulators held a technical conference in Charleston, South Carolina that was attended by Entergy and many of the entities that purchase and/or sell energy in the Entergy region. The FERC agreed to fund a CBA to study the costs and benefits of Entergy and Cleco Power joining the SPP as full transmission-owning members with their transmission facilities under SPP operational control.

This study was performed over a seven-month period, and included open and collaborative discussion with regional stakeholders throughout this period of the study framework, modeling approach, input assumptions, interim results, and qualitative issues. Face-to-face meetings were held with study stakeholders in Baton Rouge, Dallas, and Houston, and conference calls were held on a monthly basis. Relevant study documents were posted on the SPP website, along with CRA's written responses to stakeholder questions.

The CRA team pioneered some of the original RTO Cost Benefit analytical approaches and modeling tools and has applied them in a series of significant regional RTO Cost Benefit Studies, to include:

- 2002 RTO West Study of Pacific Northwest
- 2002 Southeast Regulatory Utility Commissions Conference ("SEARUC") Study of Southeast Region
- 2003 Dominion Virginia Power's PJM Study
- 2003 U.S. Department of Energy's SMD Study
- 2004 ERCOT Stakeholders Cost Benefit Study
- 2005 SPP Cost Benefit Study, led by SPP Regional State Committee
- 2007 Aquila Missouri Cost Benefit Study (Midwest ISO and SPP)
- 2007 AmerenUE Cost Benefit Study (Midwest ISO, SPP, ICT)
- 2010 Big Rivers Cost Benefit Analysis (Midwest ISO)

In addition, the CRA team utilized similar analytical approaches and modeling tools in the conduct of the 2006 U.S. Department of Energy Congestion Study prepared pursuant to the 2005 Energy Policy Act for the purpose of designating National Interest Electric Transmission Corridors.

CRA used the General Electric Multi-Area Production Simulation Model ("GE MAPS") to perform the energy modeling in this study. GE MAPS is a detailed economic dispatch and production costing model that simulates the operation of the electric power system taking into account transmission topology. The GE MAPS model determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each element of the transmission system, and the locational marginal price (LMP) for each generator and load area. The GE MAPS model was used by CRA in all of the prior RTO market cost benefit studies it has performed, as well as to support the U.S. Department of Energy in conducting the August 2006 National Electric Transmission Congestion Study.

The following sections describe the study methodology, results and assumptions. In Section 3, the study methodology is described. Section 4 describes the individual cost and benefit measures assessed in this study. Section 5 summarizes the study's quantitative results, and Section 6 discusses qualitative considerations. Appendix A provides additional detail on the study results, and Appendix B provides a detailed discussion of the GE MAPS input assumptions.

3. STUDY METHODOLOGY

3.1. BASIC STUDY METHODOLOGY

This study was performed for the 10-year period from 2013 through 2022, and analyzed two different cases:

1. Entergy and Cleco Power continue to operate independently, as they do today ("*Status Quo Case*"), and

2. Entergy and Cleco Power join the SPP RTO ("*Join SPP Case*").

In the *Status Quo Case,* SPP was assumed to continue in its capacity as the ICT for the Entergy transmission system. As the SPP RTO is working toward instituting a Day 2 market, a Day 2 market was presumed to be in place in the SPP RTO throughout the 2013-2022 study period.

CRA analyzed the impacts on the Entergy, Cleco Power and SPP regions using GE MAPS. In this study, GE MAPS was set up to model the Eastern Interconnection of the United States and Canada. The GE MAPS analysis was performed for the years 2013, 2016, 2019 and 2022, with the results for intervening years interpolated. CRA used its current GE MAPS data base to perform the analysis, supplemented by confidential input data provided by stakeholders with respect to generation unit operating characteristics, and other key inputs. A full listing of the GE MAPS modeling inputs is provided in Appendix B.

In the GE MAPS modeling, there is a commitment (next-day) step and a dispatch (real-time) step. In the commitment process, generating units in a region are turned on or kept on in order for the system to have enough generating capacity available to meet the expected peak load in the region for the next day. GE MAPS then uses the set of committed units to dispatch the system on an hourly real-time basis, whereby committed units throughout the modeled footprint are operated between their minimum and maximum operating points to minimize total production costs.

As a general matter, the greater level of coordination and the elimination of wheeling charges between the SPP, Cleco Power and Entergy regions in the *Join SPP Case* will yield system-wide production cost savings through a more efficient system commitment and dispatch. The allocation of these net savings to Entergy, Cleco Power and SPP is assessed by estimating Adjusted Production Costs (i.e., production cost plus purchase costs minus sales revenues) for each of these three regions. In turn, these savings will be offset by additional administrative and other costs incurred if Entergy and Cleco Power join the SPP RTO.

3.2. SEAMS CHARGES

GE MAPS was used to model different impediments to SPP-Cleco-Entergy trade under the *Status Quo Case* and the *Join SPP Case*. The impediments to trade applied in this study include commitment and dispatch seams charges. Seams charges are applied by CRA in the GE MAPS model at the “seam” or border between regions (e.g., between Entergy and SPP, Entergy and Cleco, SPP and the Midwest ISO, and Entergy and Southern Company). In the absence of seams charges, GE MAPS will optimize the commitment and dispatch of generation across the entire Eastern Interconnect as if it were one balancing authority with traders and operators having perfect information about all load, resources and transmission congestion, and with no transmission wheeling charges payable for regional imports and exports.

In practice, there are impediments to trade that take place on a real-time basis, including wheeling charges and imperfect knowledge regarding flows outside of the control area. For example, trade with a neighboring region is often scheduled in blocks (e.g., eight peak hours) and the price observed by traders can change by the time that transmission service is arranged. In contrast, inside of a Day 2 RTO market, generator bids are accepted in real-time relative to the actual real-time hourly price. During the 2007 CBA stakeholder process in Missouri for the AmerenUE CBA, CRA worked with trading analysts who estimated for CRA the price differential needed across borders before they would actively pursue trades. The cross-seam price differential needed ranged from $3 to $5 per MWh plus the applicable wheeling charge, depending on the nature of the market. An organized Day 2 market was perceived to have lower cross-seam trading friction than a traditional bi-lateral market given the improved transparency that such a market provides, the economic-based congestion management, and the existence of cross-seam agreements.

CRA discussed the seams charges extensively with stakeholders for this study. As a result of those discussions, dispatch seams charges between SPP, Entergy and Cleco Power were set at applicable non-firm off-peak wheeling rates plus a dispatch friction rate of $3/MWh. As shown in Table 4, in the *Join SPP Case*, the dispatch seams charges between SPP, Entergy and Cleco Power were set to zero reflecting the elimination of wheeling rates between these regions and the joint RTO real-time energy market. Outside of the SPP/Entergy region, dispatch seams charges were set at either $3 or $5 per MWh plus the applicable wheeling rate consistent with those developed in the AmerenUE CBA process.

Table 4 : Dispatch Seams Charges Applied in GE MAPS in the SPP/Entergy Region [16]
Dispatch Friction + Wheeling Charge ($/MWh)

	Status Quo Case			Join SPP Case		
	To SPP	To Entergy	To Cleco	To SPP	To Entergy	To Cleco
From SPP	--	3+2	3+2	--	0	0
From Entergy	3+3	--	3+3	0	--	0
From Cleco	3+3	3+3	--	0	0	--

The dispatch seams charges discussed above are applied in GE MAPS to optimize the generation of all units in the modeled footprint that have been already committed to operate in the GE MAPS commitment step. In addition, in deciding which units are most economic to commit to operate, commitment seams charges are also applied in GE MAPS. Commitment seams charges reflect that a control area with responsibility for reliably committing generating units for operation the next day cannot fully rely on units outside of the control area over which the control area has no direct control.

To model the commitment process, CRA defines major “commitment pools” in GE MAPS in which units inside the pool are committed to run to ensure reliable service within the commitment pool without consideration of external non-firm resources. These major commitment pools include, among others, PJM, the Midwest ISO, SPP. Southern Company and TVA. To the extent that the commitment process for regions within a major commitment pool is not jointly optimized, CRA applies a $10 per MWh commitment hurdle between these regions (again, as developed during the AmerenUE CBA stakeholder process). That is, generating units in a commitment pool will not be committed to meet load in another region within the same commitment pool unless there is a least a $10 cost advantage over units that would be available within that region.[17]

In consultation with stakeholders, the SPP/Entergy region was treated as a major commitment pool in this study. In the *Status Quo Case*, commitment seams charges were set at $10/MWh between the SPP RTO and Cleco Power and Entergy. As shown in Table 5, these were set at zero in the *Join SPP Case*, reflecting the joint RTO commitment process

16 Similar seams charges were applied between the City of Lafayette, Louisiana Energy and Power Authority, and Louisiana Generating inside of the SPP/Entergy region. See Appendix B for further detail.

17 Modeling commitment pools, rather than applying commitment seams charges between all balancing regions in the Eastern Interconnect, greatly speeds up the optimization process in GE MAPS.

that would take place. See Appendix B for further detail. Analysis of the 2013 *Status Quo Case* at differing commitment seams charges, as requested by and discussed with study stakeholders, did not appear to materially change the flows between these entities.

Table 5: Commitment Seams Charges ($/MWh) Applied in GE MAPS in the SPP/Entergy Region

	Status Quo Case			Join SPP Case		
	To SPP	To Entergy	To Cleco	To SPP	To Entergy	To Cleco
From SPP	--	10	10	--	0	0
From Entergy	10	--	10	0	--	0
From Cleco	10	10	--	0	0	--

3.3. Modeling Approach for QFs in Entergy

There a number of QFs with contractual rights to "put" or sell energy into the Entergy system at the QFs discretion with respect to timing and amount. QFs serve a host load, and may or may not have energy available at any given time to sell into the market. As part of the study process, Entergy confidentially provided historical QF put sales (MWh) for these QFs to use in CRA's GE MAPS modeling.

Upon joining an SPP Day 2 RTO, FERC may rule, as it has in other Day 2 markets, that the Entergy QF put options no longer apply. If so, the QFs would have to provide prior notice of self scheduled output to the RTO system operator. That is, the QFs would effectively operate as IPPs, albeit with the added limitation of needing to serve their host load.

Status Quo Case**:** To reflect the above, in the *Status Quo Case* in GE MAPS, the Entergy region is committed day-ahead without QF energy considered, and then the system is dispatched in real-time with QF energy included at historical levels. In practice, this means that the system must commit, or turn on, more units than it would if the QFs output were known in advance. This increases system production costs.

- *QF Commitment:* QFs are not included as available for commitment. *(QFs are assumed to be at zero output, so other units must be committed to run).*
- *QF Dispatch:* QFs dispatched at their average historical put levels *(QFs are scheduled at their average historical put levels).*

Join SPP Case**:** CRA identified several potential alternatives for modeling the Entergy QFs with Entergy as part of the SPP RTO.

- *Option 1: Treat QFs identical to Status Quo Case.* This option would eliminate the QF issue as relevant to the Entergy RTO decision, aside from potential qualitative considerations. With QFs treated the same in the *Status Quo Case* and *Join SPP Case*, the QF costs and payments from Entergy would be unchanged between the two cases. Thus, these costs and payments would not need to be considered in the analysis

- *Option 2: Treat QFs as IPPs.* This option would presume that the QF put options will no longer be applied. This option would require obtaining currently unknown plant operating characteristics of each QF, including the host load needs, and would require data gathering from the QFs and would require confidential put payments paid by Entergy to QFs to compare to the revenue paid to the QFs when operating as IPPs.

- *Option 3: Treat QFs as available for commitment at historical put levels.* QFs output at historical put levels would be presumed to be scheduled, and thus available for commitment. This option would reduce the commitment of other generators, and increase market efficiency. This option would not require any additional data from QFs or others. This option assumes that QF output would be identical to historical levels despite the existence of a transparent Day 2 market. With QF output the same in both the Status Quo and Join SPP cases, the QF costs would be unchanged.

After discussions with stakeholders, CRA recommended and implemented the use of Option 3 for this study. It thereby includes in the study the benefit in the *Join SPP Case* of having QF energy available for commitment without the need for uncertain assumptions regarding the operation of these units in a Day 2 market and the supply of confidential QF put payment information. Regardless, the treatment of QFs in the *Join SPP Case* is a potentially important source of benefits. CRA understands that stakeholders are considering addendum study cases in which the treatment of QFs is modeled in alternative ways.

3.3.1. IPP Modeling

Independent Power Producers ("IPPs") in the Entergy and Cleco regions were identified with the assistance of study stakeholders. After discussions with study stakeholders, an additional commitment hurdle was put in place for these IPPs in the *Status Quo Case* of $5/MWh to reflect the impediments to optimal commitment of these IPPs absent a centralized day-ahead market. This IPP commitment hurdle was not included in the *Join SPP Case* which has the Entergy and Cleco Power regions operating under a RTO market. Once committed, IPPs are dispatched in GE MAPS similarly to all other generating units in the region, i.e., based on the operating costs (fuel, emissions, variable O&M) of the units.

The GE MAPS model calculates the amount of market revenues net of operating costs for each modeled generating unit during each of the unit's operating cycles. If a unit's operating costs (fuel and variable O&M) are not recovered during an operating cycle, the shortfall is calculated and aggregated over the year. This measure is sometimes referred to as "uplift" because in a Day 2 RTO each generating unit's operating cycle shortfall is paid to the generator and recovered through an "uplift" charge to all load.

Any unit, IPP or utility-owned, can and will have uplift depending on how it is operated, although uplift tends to be highest for those units that operate at the margins and do not ramp on and off quickly (e.g., combined-cycle units). Even in a Day 2 market, uplift will help IPPs recover their short-term operating costs (e.g., fuel, variable O&M) but not their fixed costs (e.g., return on/of capital, fixed O&M). Thus, IPPs seek means to obtain capacity payments either through contracts with load or through an organized capacity market.

Absent a formal RTO uplift mechanism, IPPs without contracts with load may seek to "bid up" from their marginal operating costs in the real-time market in order to ensure that they recover at least their short-term operating costs. In this study, we do not model a "bid up" for IPPs in the *Status Quo Case*. We essentially assume that over the long-run these IPPs will be under short- or longer-term contracting arrangements with load and will bid in the energy market according to their marginal cost. This assumption and the interplay with the IPP commitment hurdle is another issue that could benefit from further analysis.

4. BENEFITS AND COSTS

4.1. TRADE BENEFITS

The GE MAPS cases analyzed in this study will reflect varying degrees of impediments to trade between SPP, Cleco Power and Entergy (e.g., seams charges, QF and IPP commitment and dispatch). Reductions in the impediments to trading should generally result in production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they are comprised of fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the "trade benefits" referred to in this study.

Increases or decreases in production cost in any particular utility area, by themselves, do not provide an indication of welfare benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions.

For example, a utility that increases its exports would have higher production costs (because it generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered. Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance – an increase in imports or exports – an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area welfare. Increased trading activity provides benefits to both buying parties (purchases at a lower cost than owned-generation cost) and selling parties (sales at a higher price than owned-generation cost). In practice, the benefits of increased trade are divided between buying and selling parties. For example, the "split-savings" rules that govern traditional economy energy transactions between utilities under cost-of-service regulation result in a 50-50 split of trading benefits.[18]

In this study, we quantified trade benefits in two categories: 1) Adjusted Production Costs, and 2) "Lost" Wheeling Revenues. Each is discussed in turn below.

4.1.1. Adjusted Production Costs

Traditional cost-of-service regulation differs from a fully deregulated retail market, in which individual customers and/or load-serving entities buy all their power from unregulated generation providers at prevailing market prices. In such a deregulated market, benefits to load can be ascertained mostly in terms of the impact that changes to prevailing market prices have on power purchase costs. For the SPP/Entergy region, in which cost-of-service rate regulation is in effect, the energy portion of utility rates reflects the production cost for the utility's owned generating units, plus the cost of "off-system" purchased energy, net of revenues from "off-system" energy sales (i.e., Adjusted Production Costs). In turn, utility customers under cost-of-service regulation pay for the fixed costs of owned-generating units through base rates. Deriving trade benefits for SPP and Entergy thus requires an analysis of both the production cost of operating the generating plants and the associated trading activity (purchases and sales).

The production cost of the generating units is derived directly from the MAPS outputs for each case.[19] Note that a simple calculation of regional Adjusted Production Costs using LMPs will miss the economic impact of price differentials between buying and selling regions (i.e., trade benefits). As such, for purposes of deriving the impact of trading with adjoining regions, CRA applies a methodology developed in consultation with Missouri stakeholders during CRA's work in the 2007 RTO cost-benefit studies for Aquila and AmerenUE. In the

18 Consider a simple two-company example. Assume there is a $16 marginal cost to generate in Company A's control area and a $20 marginal cost to generate in Company B's control area and there is no trade. Now assume through a reduction in trade impediments that 1 MW can be traded from A to B over the inter-tie between A and B. Company A will generate 1 MW more at a production cost of $16, while Company B will generate 1 MW less at a production cost savings of $20. Thus, the total saving in production cost is $4 (i.e., $20 – $16). If the trade price is set, for example, at a 50/50 split savings price, Company A will receive $18, for a trade benefit of $2 ($18 – $16), and Company B will pay $18, for a trade benefit of $2 ($20 – $18). The total trade benefit of $4 ($2 + $2) will match the total production cost saving of $4.

19 The production costs for IPPs are included in each region's measure of production costs along with that of utility-owned generating units. Uplift revenues for utility-owned units need not be directly considered in the adjusted production cost calculation as all fuel costs are passed through to ratepayers. The uplift for the IPPs is essentially a transfer payment between load and the IPPs that can impact the share of benefits accruing to IPPs and load.

absence of existing FTRs to help evaluate the value received by trading parties resulting from these price differentials, CRA captures these impacts through a split-savings methodology. Under this methodology, the net hourly GE MAPS tie-line flows into and out of Entergy and SPP are used as a proxy for purchase and sale transactions by Entergy and SPP.

In each hour, the net interchange is derived using Entergy, Cleco Power and SPP tie-line flows to assess whether Entergy, Cleco Power and SPP are net importers (purchasers) or exporters (sellers) of power. If a net purchaser in the hour, the net purchase amount is multiplied by the weighted average split-savings price for tie-lines with flows into the control area. Similarly, if a net exporter (seller) in the hour, the net sale amount is multiplied by the average split-savings price for tie-lines with outgoing flows. We obtained the tie-line prices by defining a "node" in GE MAPS at each end of the tie-line. Similar calculations were performed for trading between the other regions adjoining SPP and Entergy (e.g., the Midwest ISO, TVA, and Southern Company).

4.1.2. "Lost" Transmission Revenue

A simple calculation of regional Adjusted Production Costs using LMPs also will miss the economic impact of the elimination of wheeling rates on regional transmission rates, and thus the net benefits to the Entergy, Cleco Power and SPP regions. Adjusted Production Costs in the *Join SPP Case* will decrease simply as a result of the elimination of inter-SPP/Entergy/Cleco Power wheeling rates (i.e., purchase prices will be lower and sales prices will be higher). However, in turn, these "lost" wheeling revenues will no longer be collected by the SPP, Entergy and Cleco Power transmission providers, and therefore, all else equal, will result in an increase in transmission rates in order for the transmission providers to recover their revenue requirement. As such, in assessing regional benefits, the impact of the lost wheeling revenues are tracked and incorporated into the assessment of the overall costs and benefits.

The tie-line flows in GE MAPS do not lend themselves to a direct calculation of transmission revenues given that the GE MAPS flows in each hour are actual net flows across each tie-line (i.e., including "loop flow"), and transmission revenues are based on scheduled transactions. As such, with assistance from SPP, Entergy and Cleco Power transmission personnel, the annual transmission revenue collected for point-to-point transactions that would have been eliminated or "lost" if there were no Point-to-Point ("PTP") transmission charges between SPP, Entergy and Cleco Power were assessed for the four year period from 2006 to 2009. An annual average was then calculated.

The results are summarized in Table 6. As shown, transmission charges eliminated by Point of Delivery ("POD") and Point of Receipt ("POR") were tracked separately and then averaged (i.e., split 50/50). Consistent with the use of a split-savings methodology to allocate the benefits of purchase/sale transactions in the adjusted production cost calculation discussed above, these avoided transmission charges were allocated 50/50 between the importing

(POR) and exporting (POD) regions. The transmission providers' lost PTP revenue was then charged back to the local load at the bottom of the table.

Table 6 : Point-to-Point Revenue "Eliminated" if Entergy/Cleco Were Members of the SPP RTO during the 2006-2009 Period (in millions of dollars; averaged over the 2006-2009 period)

Transmission Provider	SPP	Entergy	Cleco	Sub Total	Other	Total
	PTP Charges Eliminated by POD					
SPP	0.0	10.9	0.5	11.4	0.0	11.4
Entergy	10.1	0.1	9.4	19.6	1.8	21.4
Cleco	0.9	1.5	0.3	2.7	0.0	2.7
Total	11.0	12.5	10.2	33.8	1.8	35.6
	PTP Charges Eliminated by POR					
SPP	10.9	0.0	0.0	10.9	0.5	11.4
Entergy	2.1	17.2	0.1	19.5	1.9	21.4
Cleco	2.7	0.0	0.0	2.7	0.0	2.7
Total	15.8	17.2	0.1	33.1	2.5	35.6
50/50 POR-POD	13.4	14.9	5.2	33.4	2.1	35.6
Lost PTP Rev	(11.4)	(21.4)	(2.7)	(35.6)		
+Tariff Allocation Impact	(1.4)	(2.1)	3.4	0.0		
Adjusted Lost PTP Rev	(12.8)	(23.5)	0.7	(35.6)		
Net Benefit	0.6	(8.6)	5.9	(2.1)	*<-- if no offsetting trade benefits*	

Based on the analysis, $35.6 million of Cleco, Entergy and SPP wheeling revenue would be "eliminated", and $33.4 million of wheeling charges paid by the load in the Cleco, Entergy and regions would no longer be assessed. Thus, the combined Cleco/Entergy/SPP region would have a $2.1 million negative benefit from the elimination of these charges (assuming no offsetting trade benefits). This is because $2.1 million of "eliminated" wheeling charges are for PODs/PORs external to the Cleco/Entergy/SPP region.

Using 2009 data, SPP subsequently performed an analysis of the allocation of transmission revenue that would take place in the *Join SPP Case* if the transmission revenues collected by the SPP transmission provider were allocated under the terms of the SPP tariff to individual transmission owners (e.g., Entergy and Cleco Power). The allocation is captured in the Tariff Allocation Impact line in Table 6. As shown, the SPP tariff reallocation would provide additional revenues to Cleco ($3.4 million) exactly offset by decreased revenue to SPP and Entergy.

In total, absent offsetting trade benefits, Cleco load would benefit by $5.9 million, SPP load would benefit by $0.6 million and Entergy region load would have additional costs of $8.6 million. The Cleco/SPP/Entergy region would have additional costs of $2.1 million.

The results above were applied in the derivation of trade benefits for the transmission cost and revenue impacts across the SPP/Entergy/Cleco seams. For the impacts of transmission revenues between SPP and Entergy and major neighbors such as TVA where transmission charges would continue to apply in both the *Status Quo Case* and *Join SPP Case*, the MAPS physical wheel charges between SPP/Entergy and other major neighbors were tracked and the change in these wheeling revenues and costs between cases are included in the net benefits calculation.

4.1.3. Trade Benefit Results

Of the $817 of SPP/Entergy region trade benefits, the majority, $594 million, accrue to the Entergy region largely because of the greater mix of higher cost gas-fired generation in the Entergy region that is displaced in the *Join SPP Case*. In addition, there are a significant number of Qualifying Facilities ("QFs") in the Entergy region that become firm resources in the *Join SPP Case*. The lost transmission revenue represents the transmission revenue no longer collected as a result of the elimination of PTP transmission charges between SPP, Entergy and Cleco Power.

Table 7 : 2013-2022 Benefits (Costs) to the SPP, Entergy and Cleco Power Regions if Cleco Power and Entergy Join the SPP RTO

(in millions of 2010 present value dollars; positive numbers are benefits)

	SPP	Entergy	Cleco	Total
Decrease in Adjusted Production Costs	232	765	75	**1,073**
Lost Transmission Revenue	(89)	(172)	5	**(256)**
Total Trade Benefits	**143**	**594**	**80**	**817**

To help illustrate the source of trade benefit savings for the collective SPP/Entergy region, Table 8 shows the change in gas- and coal-fired generation and the increase in net purchases (purchases net of sales) for the region for the example year 2016. The generation from other types of resources with very low dispatch costs, such as nuclear and wind resources, do not change materially between the *Status Quo Case* and the *Join SPP Case*. These types of resources are dispatched whenever available.

Table 8: Increase (Decrease) in 2016 Gas- and Coal-Fired Generation, and Net Purchases for the SPP/Entergy Region in the Join SPP Case

	----SPP/Entergy Region ----		
	TWh	M$	$/MWh
Gas-Fired Generation	(4.1)	(292)	**71**
Coal-Fired Generation	2.5	78	**31**
Purchases net of Sales	1.6	86	**54**
= Net	**0.0**	**(129)**	

As shown, regional gas-fired generation decreases 4.1 TWh and $292 million (2010 dollars) in 2016 (avoiding $71/MWh of cost on average), and is replaced by 2.5 TWh of coal-fired generation at a cost of $78 million ($31/MWh on average) and increased purchases from outside of the region (e.g., MISO, TVA, SOCO) of 1.6 TWh at a cost of $86 million ($54/MWh on average). This yields savings of $129 million (2010 dollars) for the region in 2016 before consideration of avoided transmission cost and lost transmission revenue impacts (which largely offset one-another on a regional basis as discussed in the prior section).[20]

In short, the trade benefit savings appear largely driven by the replacement of gas-fired generation for lower-cost coal-fired generation inside the region and increased imports of lower cost energy from outside the region. This is attributed to the coordinated commitment that takes place in the combined region as well as treating QFs as committable resources in the *Join SPP Case*.[21]

A similar set of results for the SPP, Entergy and Cleco regions individually is provided in Table 9. Here for each region, purchases net of sales include transactions with the other two regions as well as transactions with external regions. As shown, in the Entergy region, avoided gas-fired costs are replaced partially by increased coal-fired generation within the Entergy region, but more substantially by increased imports of relatively low cost power.

SPP provides coal-fired generation to replace the Entergy gas-fired generation and thus increases its exports. The increase in SPP's sales revenue more than compensates for the cost of the additional coal fired generation.

Table 9 : Increase (Decrease) in 2016 Gas- and Coal-Fired Generation, and Net Purchases for the SPP, Entergy and Cleco Power Region in the Join SPP Case

	-------- SPP --------			-------- Entergy --------			-------- Cleco --------		
	TWh	M$	$/MWh	TWh	M$	$/MWh	TWh	M$	$/MWh
Gas-Fired Gen	(0.2)	(14)	72	(6.5)	(402)	62	2.6	125	48
Coal-Fired Gen	1.2	33	28	0.5	17	33	0.8	28	33
Purch net of Sales	(1.1)	(45)	42	6.1	285	46	(3.5)	(153)	44
= Net	**0.0**	**(27)**		**0.0**	**(101)**		**0.0**	**(1)**	

20 The use of overall $/MWh average can mask a number of underlying impacts all of which are tracked in the GE MAPS modeling and results herein, but can be helpful in understanding overall impacts at a high level. Additional opportunity sales from Entergy QFs (i.e., other than puts) are treated as gas-fired and small impacts from other types of generating resources are ignored for purposes of this discussion.

21 The potential institution of a cost for CO_2 emissions through federal climate legislation would make the cost difference between coal and gas-fired generation smaller and likely would decrease the benefits of the *Join SPP Case* from that of this Base scenario. Note that the "low gas" sensitivity analysis also decreases the coal-to-gas cost difference and results in lower, but still substantially positive benefits for the *Join SPP Case*.

Cleco Power has a significant increase in gas-fired generation as the reduction in the seams charges surrounding Cleco Power in the *Join SPP Case* allow its combined-cycle resources to generate more to export to other regions. However, the increased gas-fired generation does not increase Cleco trade benefits as the sales prices are not substantially different from the generation costs for these facilities.

Cleco Power, as a smaller region with extensive transmission interties with the Entergy regions, "swings" more on a percentage basis through the analyses conducted herein. Including jointly owned units, the Cleco Power region has over 1,800 MW of coal-fired generation physically located in the region while the peak load for 2013 is slightly less than 2,100 MW. As a result, the combined-cycle units in the Cleco region are not often called on to operate in the *Status Quo Case* given that the seams charges between Cleco Power and Entergy in the *Status Quo Case* make the plants less able to be dispatched ahead of the combined-cycle facilities in the Entergy region. In the *Join SPP Case,* these generating plants are running at a significantly higher capacity factor because these seams charges are eliminated.

4.2. Administrative Costs

A number of costs must be analyzed in addition to those directly addressed in GE MAPS. These include RTO administrative costs, ICT costs, FERC charges and implementation costs. The specific categories of costs addressed in this study are discussed in detail below.

4.2.1. ICT Costs and RTO Administrative Charges

In the *Status Quo Case*, Entergy would continue to incur costs payable to SPP for SPP to operate as its Independent Coordinator of Transmission. SPP provided a projection of these costs which total to $136 million (2010 present value) over the 2013-2022 study period.

The SPP RTO incurs significant capital and operating costs to operate its markets, and these costs are recovered through administrative charges under SPP Schedule 1A. These charges would be payable by Entergy and Cleco Power if they were to become RTO members. SPP estimates that the additional administrative cost incurred to include Cleco and Entergy in the SPP RTO would be no greater than the costs that would be incurred to operate the Entergy ICT in the *Status Quo Case*. As such, the additional cost to the collective SPP/Entergy region in the *Join SPP Case* is zero. That is, the total of ICT Charges and RTO Administrative Charges for the collective SPP/Entergy region in the *Status Quo Case* is projected by SPP to be the same as the total RTO Administrative Charges for the region in the *Join SPP Case.*

However, there are individual region impacts. In the *Join SPP Case*, Entergy incurs $300 million of RTO administrative charges under Schedule 1A of the SPP tariff over the 2013-2022 period which exceeds the $136 million of ICT charges incurred in the *Status Quo Case.* This leads to a net additional cost to Entergy of $164 million (2010 present values). Cleco

Power, which does not incur ICT charges in the *Status Quo Case*, incurs RTO administrative charges of $25 million (2010 present value) in the *Join SPP Case*. In contrast, current SPP members would face lower RTO administrative charges per MWh in the *Join SPP Case* with Entergy and Cleco Power as members, yielding a benefit of $189 million (2010 present value) to the SPP region. See Appendix A for further detail.

4.2.2. FERC Charges

All load-serving investor-owned utilities must pay annual FERC charges in order for FERC to recover its administrative costs. Historically, these FERC charges have been assessed to individual investor-owned utilities based only on the quantity of the utility's wholesale transactions (i.e., those related to interstate commerce). However, the annual FERC charges for RTO member load-serving utilities are assessed directly to the RTO, and then in turn assessed by the RTO to member companies. Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load. FERC charges for RTO members are therefore higher than those for non-RTO members.

As more of the country's utilities join an RTO, the FERC per-unit charges for energy transmitted in interstate commerce are likely to decrease. Nevertheless, as long as only wholesale transactions are assessed the FERC charge under a non-RTO (Status Quo) basis, there will be higher FERC charges to RTO members than non-RTO members, all else being equal.

For purposes of this study, the FERC charges in the *Join SPP Case* were projected by multiplying the FERC charges estimated by the SPP RTO (on a dollars per load served basis) in 2010 by the load in the Entergy and Cleco regions. For the *Status Quo Case*, the average inflation-adjusted FERC charges paid by Entergy and Cleco Power in the 2006-2009 period was derived. It was assumed that non-FERC jurisdictional cooperatives and municipalities would not incur FERC charges of this type in the *Status Quo Case*. The difference in these figures was then escalated at inflation and discounted over the 10-year study period. Using this approach, the increase in FERC fees was projected to be $32 million (2010 present value) for the Entergy region and $3 million (2010 present value) for the Cleco region. See Appendix A for further detail.

4.2.3. Internal Staffing and Equipment Costs

RTO market participants will incur expenditures to participate in an RTO market over and above the RTO administrative charges. This will include additional staffing, new computer equipment and other items. As part of this study, Entergy and Cleco provided a projection of the additional costs they would likely incur to participate in the SPP RTO. CRA assumed that other entities in the Entergy and Cleco regions would incur similar charges on a per MWh of load basis. Over the 10 year period, the expected cost is projected to be $34 million (2010 present value) for the Entergy region and $9 million (2010 present value) for the Cleco Power region. See Appendix A for further detail.

4.3. TRANSMISSION EXPANSION COST ALLOCATION

Projected high voltage transmission expansion costs in the SPP, Entergy and Cleco regions would be allocated in the *Join SPP Case* under the "Highway/Byway" allocation mechanism recently approved by the FERC. Under this approach approved by the FERC on June 17, 2010, 100% of the costs of transmission lines of 300 kV and above and 33% of the costs of lines above 100 kV and below 300 kV are recovered on a regional basis.

As part of this study, SPP performed an analysis assuming different types of transmission projects are subject to allocation to Entergy and Cleco Power in the *Join SPP Case*. The actual allocation would be dependent on a negotiated process between SPP, Entergy and Cleco Power. The aggregate allocation results over the 2013-2022 period are captured below for the three different transmission cost allocation studies assessed by SPP.

Table 10 : 2013-2022 Transmission Cost Allocation Benefits (Costs) to the SPP, Entergy and Cleco Power Regions if Cleco Power and Entergy Join the SPP RTO

(in millions of 2010 present value dollars; positive numbers are benefits)

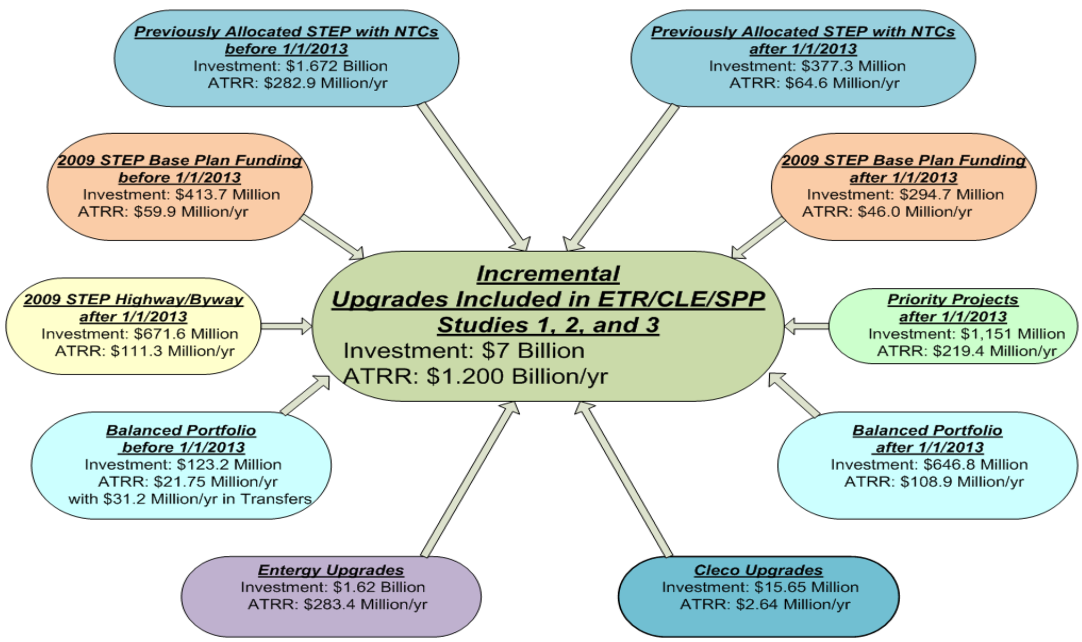
	SPP RTO Transmission Costs Allocated	SPP	Cleco	Entergy	Total
1	All Regional Costs	895	(93)	(802)	**0**
2	Regional Costs beginning Jan. 2013	682	(68)	(614)	**0**
3	Regional Costs beginning Jan. 2013 excluding Balanced Portfolio and Priority Projects	(5)	(18)	23	**0**

In SPP Study 1, the Entergy and Cleco Power regions were assumed to contribute to the regional recovery of SPP upgrades completed after March 2006, coincident with the first regional recovery in SPP. In SPP Study 2, the Entergy and Cleco Power regions were assumed only to contribute to regional recovery of SPP upgrades needed after a "bright line" date of January 1, 2013 (consistent with the start date of the study period analyzed in this study). In SPP Study 3, the Entergy and Cleco Power regions were assumed only to contribute to regional recovery of SPP upgrades needed after January 1, 2013, excluding Balanced Portfolio[22] and Priority Projects[23].

22 The SPP Balanced Portfolio, as approved by SPP in April 2009, includes five new 345 kV transmission lines, a 345 kV transformer, and a new connection between two existing 345 kV lines. The 250 mile "Woodward-Tuco" line between Hale County, Texas (north of Abernathy) and Woodward, Oklahoma will cost $229 million. The 215 mile "Spearville-Knoll-Axtell" line between Spearville, Kansas (east of Dodge City); Hays County, Kansas; and Axtell, Nebraska will cost $237 million. The 100 mile "Seminole-Muskogee" line between Seminole County and Muskogee, Oklahoma will cost $131 million. The 36 mile "Sooner-Cleveland" line between Sooner Lake in Noble County, Oklahoma and Cleveland, Oklahoma will cost $34 million. The 30 mile "Iatan-Nashua" line between Iatan and Nashua, Missouri (north of Kansas City) will cost $54 million. The Anadarko Transformer in Anadarko, Oklahoma will cost $8 million. The Swissvale-Stilwell Tap near Gardner, Kansas will cost $2 million. The total cost is currently projected to be $770 million.

Figure 3 shows the total cost and the associated Annual Transmission Revenue Requirement ("ATRR") for the various categories of transmission projects subject to allocation in the *Join SPP Case*. As shown, there is $7 billion of transmission expansion cost subject to allocation for the SPP/Entergy region, of which $5.4 billion (77%) is located in the SPP region, $1.6 billion (22%) in the Entergy region and $15.6 million (<1%) in the Cleco region.

Figure 3: Transmission Expansion Costs Potentially Allocable to SPP, Entergy and Cleco Regions in the Join SPP Case



All of the categories in Figure 3 are included in the SPP Study 1 results. SPP Transmission Expansion Plan ("STEP") projects with Notification to Construct ("NTC") dates before January 1, 2013 and 2009 STEP Base Plan Funding before January 1, 2013 are excluded from the cost allocation in both SPP Study 2 and SPP Study 3. Balanced Portfolio and Priority Projects are excluded in SPP Study 3. The resulting transmission costs subject to allocation

23 The Priority Projects, as approved by SPP in April 2010, are as follows: A double-circuit 345-kV line from Spearville, Kansas; to Comanche County, Kansas; to Medicine Lodge, Kansas; to Wichita, Kansas projected to cost $356 million. A double-circuit 345-kV line from Comanche County, Kansas, to Woodward, Oklahoma projected to cost $108 million. A double-circuit 345-kV line from Woodward, Oklahoma to Hitchland, Texas projected to cost $247 million. A 345-kV line from Nebraska City, Nebraska; to Maryville, Missouri; to Sibley, Missouri projected to cost $301 million. A 345-kV line from Valliant, Oklahoma to Texarkana, Texas projected to cost $131 million, and new equipment in Tulsa County, Oklahoma projected to cost $840,000. The total cost to engineer and construct these projects is estimated to be $1.15 billion.

in the SPP, Entergy and Cleco Power regions in SPP Study 1, 2 and 3 are summarized in Table 11.

Table 11 : Total Cost of Transmission Projects Subject to Allocation in the Join SPP Case ***(in billions of dollars)***

	Study 1	Study 2	Study 3
SPP Region	5.35	3.14	1.34
Entergy Region	1.62	1.62	1.62
Cleco Region	0.02	0.02	0.02
Total SPP RTO	6.99	4.78	2.98

The projects included in Table 11 have varying amounts of regional sharing under the SPP tariff. Of these, EHV transmission projects (300 kV and above) would be 100% recovered on a regional basis under the Highway/Byway method. The annual revenue requirement for these EHV projects is $691 million for the collective SPP/Entergy region in the *Join SPP Case*. Of these annual EHV costs, the SPP region would have $609 million (88%), the Entergy region $82 million (12%), and the Cleco region none. About two-thirds of the SPP region's $609 million annual cost is for the Balanced Portfolio and Priority Projects. As a result, as shown in Table 10, a significant amount of costs are transferred to the Entergy and Cleco Power regions in SPP Study 1 and SPP Study 2, but not SPP Study 3. The need for additional EHV projects in the Entergy and Cleco Power regions could be the subject of further regional transmission planning analyses. To the extent such projects were approved, the costs would be shared with the SPP region in the *Join SPP Case*.

As shown in Table 10, the impact to the SPP, Cleco and Entergy regions individually is substantially different across the three SPP transmission cost allocation scenarios. As such, in this study, the benefits and costs for each region are first calculated excluding transmission cost allocation impacts, and then the overall net benefits are captured with a range reflecting the allocation costs above.

5. OVERALL COST-BENEFIT RESULTS

Shown in Table 12 are the overall net benefits, between the Join SPP case and the Status Quo case, using the components discussed above. As shown, the overall net benefit for the SPP/Entergy region is $739 million *(2010 present value)* over the 2013 to 2022 period.

Table 12: 2013-2022 Benefits (Costs) to the SPP, Entergy and Cleco Power Regions if Cleco Power and Entergy Join the SPP RTO

(in millions of 2010 present value dollars; positive numbers are benefits)

	SPP	Cleco	Entergy	Total
Trade Benefits	143	80	594	**817**
Admin Costs: *RTO Administrative Costs net of Avoided ICT Charges*	189	(25)	(164)	**0**
Admin Costs: *FERC & Capital/Labor Costs*	0	(12)	(65)	**(78)**
SubTotal Net Benefits	**332**	**43**	**364**	**739**
Transmission Expansion Cost Allocation	(5) to 895	(93) to (18)	(802) to 23	**0**
Total Net Benefits (Costs)	**327 to 1,226**	**(49) to 25**	**(438) to 387**	**739**

As shown in Table 12, the net benefits to the SPP, Entergy and Cleco Power regions individually are substantially positive prior to allocation of regional transmission expansion costs: $43 million for the Cleco Power region, $332 million for the SPP region, and $364 for the Entergy region. However, after consideration of the allocation of transmission expansion costs, the range of net benefits to the Cleco and Entergy region is partially in the negative range.

No further sub-allocations of regional benefits were performed in this study. Using the detailed GE MAPS results from this study, Entergy is separately performing an assessment of the impact to individual entities within the Entergy transmission system footprint.

5.1.1. Sensitivity Analyses

A number of sensitivity analyses were performed including high and low gas prices, high and low load growth, additional wind power construction in SPP, and finally a “copper sheet” sensitivity in which transmission and reliability must run constraints in the SPP/Entergy region’s electrical system were relaxed.

Results are summarized in Table 3. For ease of comparison, the sensitivity scenario increase or decrease to benefits is compared to base scenario results which exclude the transmission cost allocation impact.

Table 13 : 2013-2022 Benefits (Costs) to the SPP/Entergy Region if Cleco Power and Entergy Join the SPP RTO

(in millions of 2010 present value dollars; positive numbers are benefits)

	SPP	Cleco	Entergy	Total
Base Benefits (excl. transmission cost)	**332**	**43**	**364**	**739**
Increase (Decrease) in Benefits with:				
• - Low / High Gas Prices	-13 / +24	-65 / +20	-121 / +75	**-199 / +119**
• - High/Low Load Growth	-20 / +9	-21 / +30	+15 / -20	**-26 / +19**
• - Increased Wind in SPP	-67	-73	-3	**-144**
• - "Copper Sheet"	+208	-354	+8	**-138**

As shown, the benefits for the collective SPP/Entergy region remain substantially positive across the sensitivity scenarios examined. The relative impact on the SPP and Entergy regions of the sensitivity scenarios is generally larger, but does not materially eliminate the positive benefits (absent transmission cost allocation) for these regions. The smaller Cleco Power region is impacted more heavily by the changes in assumptions.

Low/High Gas Prices: In this sensitivity, natural gas prices were increased/decreased in accordance with the difference between the base and high/low natural gas forecasts prepared by the U.S. Energy Information Administration ("US EIA").[24] Lower gas prices decrease the cost difference between coal and gas-fired plants and thus tend to decrease the benefits of the more efficient dispatch that takes place in an RTO. The opposite effect takes place with high gas prices. As shown, the benefits for the overall region, SPP and Entergy remain substantially positive over the gas price range examined. However the overall benefits to Cleco Power with low gas prices are negative.

Low/High Load Growth: In this sensitivity, the SPP/Entergy region load was increased/decreased by +/-0.75% per year for each year after 2010. By 2022, this yields load increases/decreases of roughly +/- 10%. All else equal, increased load growth that does not precipitate new capacity construction tends to decrease the benefits of combining the dispatch of multiple regions as existing lower-cost resources operate more often and have less "room" to dispatch more. The impacts are relatively small on an overall SPP/Entergy regional basis and for the SPP and Entergy regions as well. The changes are again more material for the smaller Cleco Power region.

Increased Wind in SPP: In this sensitivity, additional wind power was included in the GE MAPS model in western SPP in both the *Status Quo Case* and the *Join SPP Case*. CRA increased the amount of wind power located in SPP by 1 GW (from 4 GW to 5 GW) in 2013

24 Because the US EIA high gas forecast has lower prices in 2022 than the US EIA base forecast, for purposes of this study the difference between the 2019 high and base US EIA forecasts was maintained in 2022.

and 2016, and by 7 GW (from 7 GW to 14 GW) by 2022.[25] To perform this study, SPP resolved the 2022 load flow analysis to include additional EHV ("extra-high voltage") transmission expansion. CRA located new wind power at EHV backbone sites in western SPP, as the wind collector system was not included in the load flow.

The increased amount of wind power in the SPP region and the associated EHV expansion was assumed to be constructed in both the *Status Quo Case* and the *Join SPP Case*. No additional wind power was assumed to be constructed in the Entergy and Cleco regions. By 2022, the 14 GW of wind in the SPP region supplies approximately 18% of the energy for load in the SPP region and 11% of the energy for load in the collective SPP/Entergy region in both the *Status Quo Case* and the *Join SPP Case*. Generation from the wind power in SPP does not change between the *Status Quo Case* and the *Join SPP Case*, as the amount of wind in place is unchanged between the cases. The wind power always generates whenever available and was not subject to curtailment in GE MAPS given the supporting transmission assumed to be constructed.

As shown, the benefits to the SPP/Entergy region in the *Join SPP Case* decrease if additional wind power is constructed in SPP. We attribute this to the fact that additional wind generation displaces significant amounts of gas-fired generation. Thus, there is less high-cost gas-fired generation available to be displaced through the integrated regional dispatch in the *Join SPP Case,* yielding a decline in benefits.

In addition to the results noted above, an illustrative estimate was made of the potential allocation of the SPP wind EHV expansion to Entergy/Cleco in the *Join SPP Case*. If the SPP Wind EHV expansion costs $2.0 billion and would be constructed regardless of whether Entergy and Cleco were part of the SPP RTO, then in the *Join SPP Case*, roughly $630 million of the costs of this expansion would be shared by the Entergy ($580 million) and Cleco Power ($50 million) regions. Thus, this scenario would result in negative economic benefits in the *Join SPP Case* to both the Entergy and Cleco Power regions under such a transmission cost sharing approach (again, assuming that the SPP Wind EHV expansion would take place regardless of whether Entergy and Cleco were part of the SPP RTO).

Such a result presumes that the Entergy and Cleco regions can continue to trade with SPP as usual in *the Status Quo Case* in the "Increased Wind in SPP" scenario without SPP increasing the export transmission charges paid to SPP by entities that import power from SPP. However, under SPP's tariff, the SPP export transmission charge includes an adder for SPP regional transmission costs. That is, increasing the SPP export charge is one potential way for SPP to fund the EHV expansion associated with new wind power. Note that the

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25 A similar increase in the amount of wind power in the "wind-rich" upper Midwest ISO/MAPP area was also included in the GE MAPS model in this scenario to avoid an unrealistic scenario in which only SPP would construct additional wind power in the central U.S. and would export it to other "wind-rich" areas.

Entergy and Cleco Power regions pay the SPP export charge for imports from SPP only in the *Status Quo Case*.

In the *Status Quo Case*, the Adjusted Production Costs for Entergy in 2022 in the “Increased Wind in SPP” scenario decrease by more than $350 million (2010 dollars) in comparison to the Base scenario. This indicates that the Entergy region benefits from the increased wind in SPP whether or not it is a member of the SPP RTO. However, this result is based on the modeled assumption that SPP export transmission charges to Entergy and Cleco would not increase to fund the SPP EHV expansion needed for new wind power. Incorporating an increase to the SPP export charge would increase the export charges to Entergy and Cleco Power in the *Status Quo Case*, and thereby increase the benefits of Entergy and Cleco Power joining the SPP in this scenario.

Copper Sheet. Finally, a “copper sheet” sensitivity was performed in which transmission and reliability must-run constraints in the SPP/Entergy region’s transmission system were eliminated (without consideration of the likely prohibitive costs that would be incurred to make such improvements). As a general matter, benefits of integration tend to decrease as constraints are eliminated. For the SPP/Entergy region, benefits are more than 10% lower, but are still substantially positive. The Entergy region is roughly unchanged, while the Cleco Power region’s benefits are decreased markedly and the SPP region’s benefits increase.

Upon review, we attribute the Cleco Power impacts to the elimination of significant transmission and Entergy RMR constraints near Cleco’s border causing its coal plants which export power to have to compete against somewhat lower cost SPP coal plants located far away. In the *Join SPP Case* with inter-SPP/Cleco/Entergy seams charges eliminated, the resulting Cleco exports are significantly reduced causing benefits to decrease. Based on this sensitivity, the coal fuel prices used for the Cleco and SPP units are likely worthy of further review to see if the cost differences between SPP and Cleco coal-fired units are material.

During the course of the study, other potentially important parameters worthy of additional analysis were identified. Among others, these include Entergy QF treatment, seams charges, and IPP bidding behavior. For example, to the extent that IPPs would be assumed to sell power solely on the short-term spot market, the IPPs may seek to increase their bids in the Status Quo Case to ensure recovery of costs (i.e., in the absence of uplift revenue recovery). This could serve to increase prices generally in the *Status Quo* case, potentially leading to greater benefits to load in the *Join SPP Case*.

As noted above, additional addendum studies are contemplated by regional stakeholders to further assess the costs and benefits of Entergy and/or Cleco Power joining an RTO and may include analysis of these and other parameters of interest.

6. QUALITATIVE CONSIDERATIONS

6.1. Background and Approach to the Qualitative Assessment

The Qualitative Assessment element of the CBA examined the impacts of Entergy joining SPP relative to the *Status Quo Case,* in which SPP and Entergy[26] continue to operate as they do now. For example, in the *Status Quo Case* Entergy coordinates with SPP through the Independent Coordinator of Transmission (ICT) and the Weekly Procurement Process (WPP) but is not a member SPP.[27] The objective of the Qualitative Assessment is to assess market and operational differences that were not analyzed quantitatively in the balance of the study. The analysis herein is primarily qualitative, although in limited instances quantitative data was used to explore qualitative impacts. Similarly the relative level of impacts is explored, albeit to a limited extent. Ultimately the findings of this section are qualitative in nature.

Documents reviewed in the course of this analysis included the SPP tariff and the Entergy OATT. Information from the WPP and ICT working groups was reviewed.[28] Discussions with stakeholders in CBA stakeholder meetings also informed the analysis.

The qualitative analysis considered market, operational and administrative impacts in a number of areas including the following.

- Transmission scheduling, dispatch, and congestion management
- Transmission planning and interconnection
- Ancillary services and capacity reserves
- Outage management
- Governance

The following states were assumed for the *Status Quo Case* and *Join SPP Case*.

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26 In this Section, unless otherwise indicated "Entergy" is used generally to represent the set of Entergy Operating Companies and to also generally refer to Entergy Corporation to the extent that benefits or disbenefits initially experienced by the operating companies ultimately accrue to Entergy Corporation.

27 Note that the qualitative assessment focused on Entergy and SPP operating differences. It is recognized that the CBA also addresses the possibility that Cleco Power may join SPP. It is assumed that many of the impacts applicable to Entergy's operations separate to SPP may also be relevant for Cleco Power and that the Entergy-related discussions may therefore apply by extension.

28 Note that the work underlying the papers and consultant reports reviewed for this report was not recreated or independently verified in the course of conducting this Cost Benefit Analysis. Instead those work products were assumed to be credible by virtue of the processes under which they were conducted. It is recognized, however, that alternative positions to those found in such work papers and reports may have been previously expressed and that this study also does not recreate that record.

- *Status Quo Case*: Entergy is assumed to coordinate with SPP operations under ICT and WPP arrangements. SPP is assumed to be operating a Day 2 market. SPP and the ICT perform transmission planning and coordinate to some extent, but separate market models are maintained, as are separate SPP and Entergy/ICT processes (e.g., for the WPP and for transmission planning).

- *Join SPP Case*: Entergy is assumed to be fully integrated with SPP, and SPP is assumed to be operating a Day 2 market. Entergy and SPP are assumed to continue to operate as a single Balancing Area Authority (BAA). Transmission planning is assumed to be centralized.

Assumptions for the two cases are described in more detail under the respective topical areas.

The expected changes were reviewed against a set of potential areas of impact, including the ability of institutional arrangements under both the *Status Quo* and *Join SPP* Cases to accomplish the following:

- Facilitate development of competitive markets
- Minimize discriminatory environment
- Increase efficiency of production
- Promote efficient resource expansion
- Promote efficient grid expansion
- Reduce opportunities to exercise market power
- Enhance grid reliability
- Facilitate the ability to conduct business
- Minimize costs and administrative burdens

Table 14 describes these impact areas. Note that for each area of operational difference only a subset of the impact areas may be relevant.

Table 14: Commercial, Operational and Administrative Impacts

Impact Area	Illustrative Description
1. [Facilitate Development of] **Competitive Markets**	Does the operating difference facilitate or hinder competition or market penetration (the ability of new retailers to compete for load[29] or the ability for independent generation to serve load)—for example, through changes in complexity, price volatility and/or the way in which costs are allocated?
2. [Minimize] **Discriminatory Environment**	Does the operating difference reduce perceived or actual barriers that unduly discriminate against small/large players, non-incumbents, etc.?
3. [Increase] **Efficiency of Production**	Does the operating difference encourage the efficient use (dispatch, commitment) of existing facilities and/or promote economically efficient consumption of electricity? (This considers microeconomic principles and incorporates maximization of social welfare—the sum of consumer and producer surplus.)[30]
4. [Promote] **Efficient Resource Expansion**	Does the operating difference provide proper incentives for resource investment (including Distributed Generation and Demand-Side Management)? This includes the need for site-specific pricing and resource siting signals, and changes in risk and/or uncertainty associated with nodal pricing.
5. [Promote] **Efficient Grid Expansion**	Does the operating difference encourage or discourage investment in the grid by various entities? Will those investments be directed to the right locations? Will it encourage proper trade-offs between wires and resources/Demand Side Management alternatives?
6. [Reduce] **Opportunities to Exercise Market Power**	Does the operating difference increase or decrease the need for mechanisms to mitigate potential exercise of market power?
7. [Enhance] **Grid Reliability**	Does the operating difference recognize the physical realities of the grid, reduce burdens on grid operators, and reduce the potential for involuntary firm load curtailments?
8. [Facilitate] **Ability to Conduct Business**	Does the operating difference make it easier for entities to participate in the Entergy and SPP markets?

The balance of the Qualitative Assessment provides an analysis for each of the operational differences associated with the *Status Quo* and *Join SPP* cases.

29 Given that there is no retail access in Entergy's service area currently, the ability for other retail providers to serve load is not relevant at this time.

30 Note that this metric reflects social welfare generally. However, various impacts tend to affect producer surplus and consumer surplus differently. Since the impacts are perceived differently by each stakeholder group, the discussions within the text identify, where possible, how each impact is viewed by different groups.

6.2. Limitations of the Qualitative Assessment

By its nature the Qualitative Assessment addresses issues that are not easily measurable. As a result characterizing the impacts - especially relative to one another - requires judgment. However, the more valuable benefit of this analysis is the collection, organization and articulation of a number of types of benefits such that stakeholders with varying views can judge for themselves the relative impacts.

Contemporary and historical issues with Entergy and SPP operations are mostly known, but issues that may arise as policies and economic conditions change are not specifically knowable. Certain aspects of SPP's Day 2 operation, and, perhaps more importantly, Entergy's operations assuming it does not join SPP, are not specifically knowable. It is therefore not possible to compare the *Status Quo Case* to the *Join SPP Case* on an apples-to-apples basis. Nevertheless, the Qualitative Assessment attempts to compare a snapshot of the current state of separate operations with a snapshot of the expected state of combined Day 2 operations. It should be noted that if Entergy does not join SPP, some of its practices may very well evolve over time to more closely match those of SPP.

6.3. Findings of the Qualitative Assessment

This section presents the findings of relevant areas of impact, organized by the areas of operational differences described in Section 6.1:

1. Transmission scheduling, dispatch, and congestion management
2. Transmission planning and interconnection
3. Ancillary services
4. Outage management
5. Governance

Each narrative includes a brief description of those aspects of the operational differences that are pertinent to the qualitative analysis and discusses the significant impacts identified in each area of impact. The *Status Quo* and *Join Entergy* case distinctions are discussed in more detail in each of the topical areas.

Note that while this report identifies benefits and costs of "disbenefits", such impacts are in the context of the comparison of the *Status Quo Case* and the *Join SPP Case*. Identification of any disbenefits, for example, is not intended to suggest that any current Entergy or ICT FERC-approved provisions are deficient.[31] Instead, the purpose of this report is to explore the extent to which certain market design features can be improved upon and any collateral impacts that may result in the case that Entergy joins SPP.

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31 For example, the FERC has determined that the ICT meets the FERC RTO standards with respect to calculating available transfer capability and total transmission capability.

6.3.1. Transmission Scheduling, Energy Dispatching and Congestion Management Impacts

This section addresses the differences between the Entergy and SPP short-term transmission scheduling, dispatch and congestion management practices and the likely costs and benefits associated with these areas if Entergy joins SPP.

In the *Status Quo Case*, participants within Entergy request transmission service, and they schedule transmission service in accordance with the amounts Entergy sells them, consistent with the Entergy OATT. No formal, organized (e.g., RTO-like) day-ahead or real-time energy market exists in the *Status Quo Case*. The WPP is operated by the ICT, matching weekly on- and off-peak offers with Entergy's energy needs. Transmission Loading Relief (TLR) procedures are used in real-time if congestion occurs. In the *Join SPP Case*, SPP's Day 2 market transmission reservations will be converted to financial rights. In the day-ahead time frame, the Day 2 market will optimize submitted schedules and bids. In real time the SPP Energy Imbalance Service (EIS) market is used to balance the system and resolve real-time congestion. TLRs are used to manage any congestion that cannot be economically resolved.

Under the *Join SPP Case* assumptions, the SPP mechanisms would be extended to cover Entergy's system. Self-scheduled energy reservations will continue to be cleared through the Day 2 market in conjunction with redispatching units based on economic bids. The EIS market would be extended to include Entergy's system, and TLRs would continue to be applied to any congestion that could not otherwise be resolved through the EIS.

Although the Quantitative Assessment is intended to capture the economic impacts of the efficiency of the inclusion of Entergy in the Day 2 market, there are several other areas of impacts associated with the *Status Quo* and *Join SPP* cases: transparency, transmission system and energy market access, and commercial risks.

Transparency

Currently Entergy's transmission models are available to market participants, but SPP's market models are protected in ways that restrict market participants' access. Market participants may therefore experience a lack of transparency with respect to the network model used to grant transmission service and redispatch the system. Their ability to analyze the transmission system and market outcomes will therefore be more limited if Entergy joins SPP.[32]

[32] Note that SPP has expressed the belief that it can more effectively plan and manage the transmission system with the network models protections in place, given that participating transmission owners and neighboring utility systems provide to SPP more information for inclusion in the model than they would if the models were widely available to the public.

Conversely, there are concerns about transparency associated with the ICT relevant to the *Status Quo Case*. In fact, ESPY Energy Solutions, LLC, a consulting firm, identified a number of areas in which there were transparency concerns.[33] In addition, errors in Entergy's ATC and AFC calculations have been identified. For example, ESPY concluded that Entergy's ATC and AFC calculations should be examined in more depth.[34] Such errors adversely affect how market participants perceive Entergy's processes for selling transmission service and operating the grid, and they may substantially impact market access if the errors are big enough. At the same time, however there is inconsistent data across Entergy and SPP. In fact, Entergy's *reporting of errors* is more transparent than that of SPP because SPP does not report ATC errors at all. Since it is not possible to make a quantitative comparison of ATC calculation errors, any potential lack of ATC and AFC transparency in Entergy may simply be a perception on the part of Entergy's transmission customers[35].

The WPP process is also viewed as being opaque,[36] since only dispatch and price information are available from the process.

Note that while the ESPY Report was prepared by a consultant acting independently on behalf of the E-RSC, ESPY's findings have been disputed in subsequently filed public comments as being overly dependent on stakeholder views, without critical analysis, and contradicting findings from related FERC proceedings.[37] FERC is also conducting an audit, evalu-

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33 ESPY's "Review of the ICT Independence and Authority – Findings and Recommendations" dated June 29, 2010. (www.spp.org/publications/Review%20and%20Recommendations.doc). See also "ESPY's Review of the ICT Independence and Authority – Findings and Recommendations", dated September 9, 2010.

34 "ESPY's Review of the ICT Independence and Authority – Findings and Recommendations", dated September 9, 2010.

35 Unless otherwise indicated Entergy's "transmission customers" refers to customers who take transmission service under Entergy's Open Access Transmission Tariff.

36 See for example June 2010 ICT Quarterly Performance Report, p. 34, indicating that: "stakeholders have expressed frustration about the lack of detailed information about the WPP results." It continues that: "Due to the strictures of Attachment V, however, the results of the WPP are considered confidential. Therefore, SPP cannot disclose any details about the WPP results that are not publicly available under the Tariff." See also for example the ICT June 30, 2010 Quarterly Report Attachment 5 communications indicating that details associated with Network Resource Designation errors that were not provided in Entergy's filing.

37 See Entergy Services, Inc.'s Comments on ESPY's Review of the ICT Independence and Authority – Findings and Recommendations, June 30, 2010, pp. 2-3 for example. (http://www.spp.org/publications/responses%20to%20ESPY%20ICT%20Report.zip.)

ating Entergy's planning and operations practices and OATT compliance.[38] The results of the audit have not yet been released.

Transmission System and Energy Market Access

Status Quo Case impacts include continued concerns about restricted access to Entergy's transmission system and its energy market.[39] The ICT uses transmission models that include a 3-year look-ahead, which includes only those Entergy upgrades planned to be completed within the next three years. Use of the 3-year model results in transmission customers being denied access or allocated costs of upgrades even though Entergy's 10-year planning processes may already assume that Entergy will fund necessary transmission upgrades.[40] The E-RSC has recommended that Entergy adopt a 5-year planning horizon. Such convergence of the planning processes would tend to reduce the disbenefit of continued ICT control relative to the *Join SPP Case*.

The ICT and WPP processes are also believed to have constraints and limitations that result in suboptimal outcomes. For example, ICT limitations include inconsistent load flow models, lack of synchronism between study and reservation procedures, issues identifying generation dispatch alternatives, and/or unnecessary transmission customer and WPP participant

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38 The audit is being conducted by the FERC Division of Audits (DA) in the Office of Enforcement and the Division of Compliance (DC) in the Office of Electric Reliability of the Federal Energy Regulatory Commission are jointly commencing an audit of Entergy Services, Inc. (Entergy). The audit will evaluate Entergy's: (1) practices related to Bulk Electric System planning and operations; (2) compliance with the requirements contained within its Open Access Transmission Tariff; and (3) other obligations and responsibilities as approved by the Commission.

39 As indicated previously, the FERC has found historically that the Entergy and ICT operations meet FERC requirements, and the discussion herein is not intended to imply otherwise.

40 See for example Recommendation by Long-Term Transmission Issues Working Group to "Eliminate the Negative Impact of Base Case Overloads on Transmission and Generation Interconnection Service Customers" dated July 11, 2007 (included in June 2010 ICT Quarterly Report as Attachment E.). See also comments filed in conjunction with the June 24, 2009 Technical Conference (e.g., "An LSE Perspective on the Results of the ICT Experiment", Presented to FERC/State Commission Technical Conference, by Lafayette Utilities System" filed in Docket ER05-1065-000). See also, for example, Union Power Partners, L.P. Comments of February 21, 2008, filed in Docket ER05-1065-000 (e.g., pp. 14 - 24). Comments on page 21 of this text suggest that the Entergy OATT Base Plan upgrades that would not be initiated in the forthcoming three years resulted in Supplemental Upgrades being charged directly to transmission customers that requested transmission service.

transaction costs.[41] Also the WPP does not provide information that allows bidders to understand why their bids were not accepted. The WPP – at a minimum – lacks transparency and stakeholder confidence that it produces optimal results, and in the worst case it has actual deficiencies that cause suboptimal outcomes. Participants, for example, are otherwise constrained in the bilateral market while their bids are into the WPP for consideration, yet their experience is that a small fraction of offers are actually struck in the WPP.[42]

Lastly, while the WPP offers merchants an opportunity to provide energy to serve Entergy's load, the procurement process is limited compared with the SPP Day 2 market. For example, the WPP provides for only weekly procurement and only of peak energy products.[43]

Note that while there has been some discussion about the volume of TLRs as evidence of inefficiencies of the Entergy system, and at times discussions alluding to the high volume of TLRs on the SPP system, the TLR data does not support a conclusion that either SPP has had a particularly high number of real-time transmission curtailments compared with Entergy or that Entergy has had particularly more TLRs than SPP. In fact, TLRs affecting firm service are similar in number between the Entergy and SPP systems. Further, whereas SPP data indicate a high number of Type 3 TLRs – those that do not affect firm service – SPP indicates that it has been a recognized and endorsed operating practice for SPP to report such TLRs in order to provide market participants with more insights about system conditions. (These events have led to an insignificant number of actual curtailments, and SPP is modifying its

41 See for example Operational Efficiency Task Force meeting notes from March 16, 2010 stating that at the Entergy/SPP seam there are potential inefficiencies due to inconsistent load flow models, lack of synchronism between study and reservation procedures, issues related to identifying generation dispatch alternatives, and/or unnecessary transmission and WPP customer transaction costs. Also see the June 30, 2010 ICT Quarterly Report referencing several efforts to improve efficiency for customers, including the Transmission Request Advocacy Assistance and Coordination Function ("TRAAC") described in Attachment 3, and the Customer Assistance Process described in Attachment 4. Note that the reasonableness of the WPP and its outcomes were not independently verified for this analysis and that the "success" of bidders' participation in the WPP is also directly dependent upon the prices and flexibility offered by those bidders. Further, as indicated previously, these characterizations do not suggest that WPP fails to meet the Commission's standards. Instead, they simply indicate certain disadvantages of the WPP compared with the expectations for SPP's Day 2 market. In fact the WPP may offer a higher level of transparency than other utility procurement processes, and it is simply the comparison of the WPP with the structured RTO-like Day 2 market that elicits the disadvantages of the WPP relative to what is expected for the Day 2 market.

42 See for example the "Weekly Procurement Process (WPP) Overview" presentation by SPP to the E-RSC, September 9, 2010, slide 6 reflecting the bids struck relative to the bids offered.

43 Conversely, if Entergy were to join SPP the Day 2 market would not offer a weekly procurement. However, it is expected that other bilateral market processes would continue to exist in the *Join SPP Case* to provide for long-term and mid-term bilateral procurement.

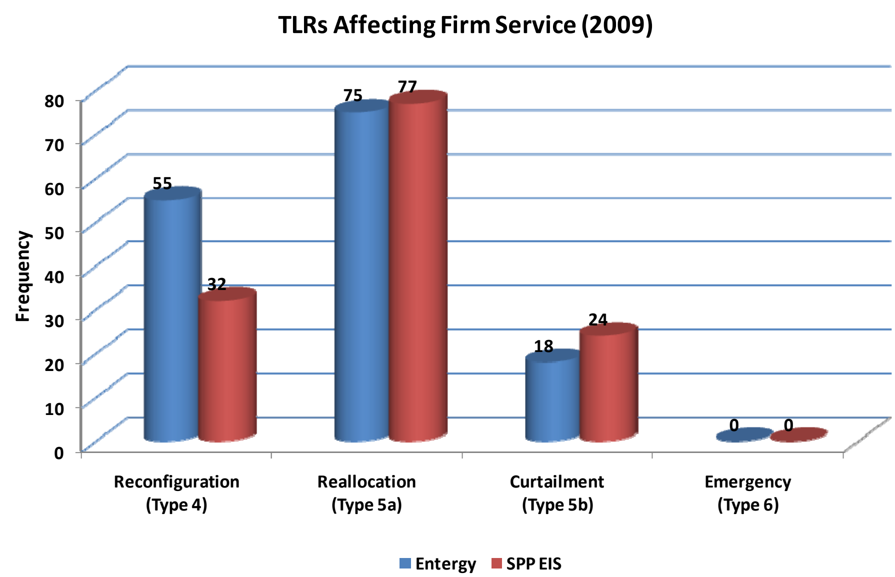
practice to provide visibility to congestion events through an alternative mechanism that does not report them as TLRs.) Figure 4 displays the TLR data.[44]

Also note that Entergy applies Local Area Procedures (LAPs) to manage congestion on internal constraints, whereas SPP does not rely significantly on LAPs. Conversely, in SPP's integrated markets network constraints are essentially all reflected in the integrated market model, significantly minimizing the need for local operating procedures.

Figure 5 reflects that there is substantive impact in Entergy's systems from LAPs. Should these LAP curtailments be eliminated under the *Join SPP Case*, this would be an additional benefit.

44 Data from NERC Transmission Loading Relief (TLR) Monthly Summaries for 2009. (http://www.nerc.com/filez/Logs/monthlysummaries.htm). Note that TLR data does not reflect Entergy actions for the management of Local Area Procedures (LAPs). The Entergy-ICT working group is continuing to address needs currently managed through LAPs.

Figure 4: TLR Comparison between Entergy and SPP Systems



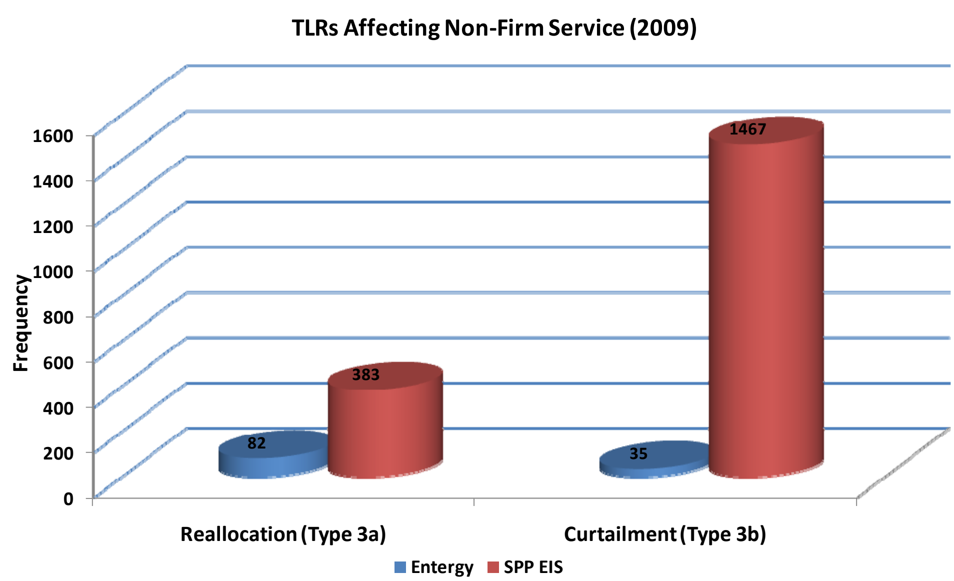
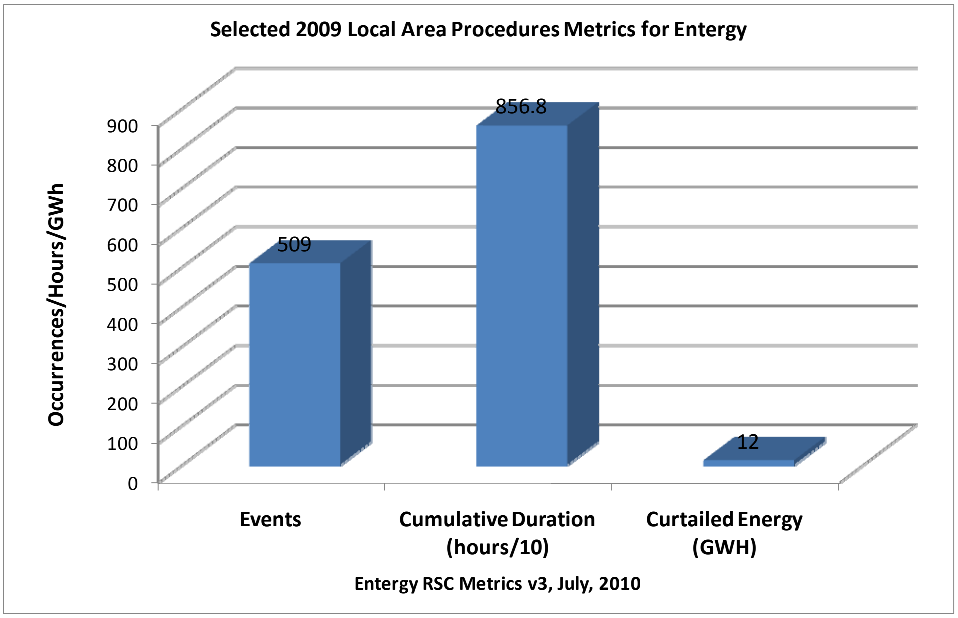


Figure 5: Local Area Procures invoked by Entergy



Commercial Risks

Transitioning to an RTO environment creates business risks generally, and Entergy and those of its transmission customers that are not yet members of SPP will face business risks if Entergy joins SPP. Because the Day 2 market is not yet operational, these risks are difficult to quantify.

In the absence of actual Day 2 market data, without all the rules fully developed, and without results from market simulations that might identify important issues, there is uncertainty about how the Day 2 system dispatch will work, including for example the effects of and on qualifying facilities and reliability must-run units. While SPP now envisions a must-offer requirement or resource-showing, market participants may view the energy markets as unacceptably risky and prefer instead to self-schedule and self-commit some portion of their resources.

The Day 2 market timelines impact some market participants because their energy schedules are uncertain until the afternoon before the energy flows. This creates the risk of added costs to manage gas imbalances.

For Entergy itself, joining SPP creates a new category of risk associated with transmission access and the cost of that access. Entergy – like other participants – can obtain financial transmission rights under SPP's Day 2 market, but the certainty of the hedge[45], especially on a long-term basis, is not nearly the same as the access they currently have as a bundled utility.

At the same time, in the *Status Quo Case*, Entergy's transmission customers have no hedge products with which to manage the uncertainty of transmission access costs, and as explained above in the discussion of Transmission System and Energy Market Access, Entergy's transmission customers are at risk for costs that are sometimes significant.[46]

There are some additional potential risks related to Qualifying Facilities (QFs) located in Entergy's service area. Since the treatment of QF energy has not yet been resolved, it is unclear if Entergy would be relieved of its obligation to take the QF energy in the *Join SPP Case*. In addition, the price treatment in this case is uncertain; it is unclear whether Entergy would be obligated to absorb any difference between Day 2 market prices and QF contract prices or whether the QFs would be required to accept market prices and be exposed to market risk. While the availability of the Day 2 market may enable more efficient use of the QF energy, the *Join SPP Case* creates price risk and uncertainty for one or more parties depending on the outcome of regulatory proceedings at the federal and state levels.

In summary, Entergy and its transmission customers – especially those not used to doing business with the SPP – will face added commercial risks and added costs of doing business if Entergy joins SPP. Whereas the energy cost impacts of doing business with SPP under the *Join SPP Case* have been quantified in the balance of this cost-benefit analysis, the impact of the commercial risks are not easily quantifiable. As with any new market transition, commercial risks and the costs of managing those risks are greatest prior to the market start up and then decline as experience is gained with business and operating practices and with market outcomes.

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45 In the *Status Quo* case, transmission service is purchased at cost-based rates. The SPP Day 2 market will charge for transmission service based on the cost of any redispatch that is required in order to deliver scheduled amounts, but amounts will vary from hour-to-hour and day-to-day based on transmission congestion. Parties can purchase a financial instrument known as a Financial Transmission Right (FTR) that allows them to largely control what they pay (hedge the cost) for transmission service from one point to another. They can purchase a set of these rights to hedge the cost of network service. However under some circumstances, parties may be unable to obtain the hedges or the purchased hedges may not fully cover the transmission costs and be exposed to additional unanticipated payments.

46 For example, if Entergy is unable to obtain the FTRs needed to hedge congestion costs, Entergy and its retail customers could be exposed to new congestion management costs for the delivery of energy to customers and bilateral trading partners.

6.3.2. Transmission Planning and Interconnection Impacts

Entergy and SPP have somewhat different transmission planning processes and fundamentally different interconnection processes. Entergy participates in regional transmission planning initiatives, and in accordance with FERC Order 890, Entergy conducts transmission planning that includes regional and inter-regional planning with neighboring transmission providers. Per Attachment K to the Entergy OATT, the ICT coordinates regional planning between Entergy, SPP, and SPP's respective members through the Entergy-SPP RTO Regional Planning Process ("ESRPP"). Entergy and the ICT also participate in the Southeast Inter-Regional Participation Process ("SIRPP"), which includes coordination with transmission owners in the Southeast. Over time, current initiatives by FERC are likely to further expand regional coordination.

SPP has the added opportunity to coordinate with its members given that it has visibility into each transmission system and information provided by neighboring regions – information that SPP suggests is more detailed because of the protection SPP places on its network model information. Additionally, SPP has the authority to plan economically driven high-voltage (EHV) upgrades that cross member transmission systems, thus benefiting the SPP region.

With respect to assessing interconnection requests, Entergy and SPP use fundamentally different evaluation processes. Entergy uses a queuing process for interconnection studies and SPP uses a batch process with an open season.

Under the *Status Quo Case* it is assumed that the current processes would continue, whereas under the *Join SPP Case* it is assumed that SPP's current processes would be extended to include Entergy as a member of SPP.

These differences may create grid and resource expansion efficiency, competitiveness, transparency and administrative impacts should Entergy join SPP.

Grid and Resource Expansion Efficiency

If Entergy joins SPP, the single transmission planning process that covers both Entergy and the existing SPP members should operate more efficiently and it should produce more economically efficient plans. These benefits are derived from drivers such as information that is not currently shared but that will be shared in the *Join SPP Case* and from regional objectives that cannot be addressed optimally by SPP or Entergy alone. For example, the SPP transmission planning process would be expanded to Entergy's service area under the *Join SPP Case*.

The SPP planning process includes regional initiatives like the EHV overlay that are not part of the Entergy planning process. These additional initiatives will require Entergy and its transmission customers to incur costs they might not incur in the *Status Quo Case*, either directly or via cost allocation policies that are under development. These added costs are captured in the quantitative analysis. Entergy and its transmission customers should also receive the benefits from these processes and from any future transmission projects that reach Entergy's footprint or immediately surrounding areas, and if the SPP planning process is both robust and properly executed, benefits should outweigh the costs.

Competitiveness of Markets

Entergy uses its 3-year upgrade plan in the network model that provides the basis for assessing interconnection requests. As a result, the models used to assess a transmission customer's interconnection costs do not reflect upgrades that Entergy may be planning in its long-term transmission plan (i.e., Entergy-planned upgrades with in-service dates in years 4 through 10). Entergy's interpretation of the NERC non-consequential firm load provisions and the resulting use of the 3-year planned upgrades historically have been seen as a significant disadvantage when parties consider interconnecting to Entergy's system[47] because transmission upgrade costs are thereby shifted from Entergy to interconnecting customers, and this can be seen as a competitiveness issue. The *Join SPP Case* offers the benefit of eliminating this condition.[48] As suggested previously, any comparison to the *Status Quo Case* is somewhat artificial in this regard, especially given Entergy's transmission planning processes are expected to change as a result of the E-RSC's activities. To the extent Entergy implements a 5-year planning case or otherwise resolves the model discrepancy, the benefits described herein will be recognized regardless of whether Entergy ultimately joins SPP.

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47 These issues, called Note B type Base Case overload impacts", have been widely documented elsewhere. See for example Recommendation by Long-Term Transmission Issues Working Group to "Eliminate the Negative Impact of Base Case Overloads on Transmission and Generation Interconnection Service Customers" dated July 11, 2007. (included in June 2010 ICT Quarterly Report as Attachment E.) See also comments filed in conjunction with the June 24, 2009 Technical Conference (i.e., "An LSE Perspective on the Results of the ICT Experiment", Presented to FERC/State Commission Technical Conference, by Lafayette Utilities System" filed in Docket ER05-1065-000). See also, for example, Union Power Partners, L.P. Comments of February 21, 2008, filed in Docket ER05-1065-000 (e.g., pp. 14 - 24). For example on page 21 the comments reflect that the Entergy OATT Base Plan upgrades that would not be initiated in the forthcoming three years resulted in Supplemental Upgrades charged directly to customers requesting transmission service. Entergy explains the alternative application of the NERC requirements with respect to limited interruptions of non-consequential load and identifies the fact that the ICT does not include such contingencies in their Base transmission planning process, whereas Entergy does consider these in their construction planning process. See Entergy's Comments in response to the June 24, 2009 Technical Conference, dated July 20, 2009, filed in Docket ER05-1065-000, pp. 7-9.

48 Note that there was significant stakeholder discussion during the conduct of this cost-benefit analysis about the fact that this condition may improve or resolve itself without Entergy joining SPP through activities at the Regional State Committee level and through the Commission. This study has not attempted to characterize the relatively likelihood of successful resolution with Entergy in SPP as compared to future E-RSC activity although it recognizes that the E-RSC has been provided with authority to propose changes that are supported unanimously.

Transparency

As indicated in Section 6.3.1, Entergy and its transmission customers may experience the disbenefits of the lack of transparency associated with SPP's network model in the *Join SPP Case*.

Some stakeholders have suggested that SPP's transmission planning process better enables public participation than does the transmission planning process administered by the ICT. However, the ICT transmission planning process does provide for stakeholder input.[49] Further, although SPP has an explicit process to generally conduct its transmission planning process and present the results, market participants are not always clearly able to understand the bases for the outcomes – especially given the size of the SPP model and the size of SPP's footprint. In fact, SPP's complex process is sometimes characterized by participants as a "black box." This condition may persist or even worsen if SPP includes the Entergy system in its system transmission plan. Thus any potential transmission process benefits offered in the *Join SPP Case* may likely be tempered by the opaqueness of the outcomes that will likely grow as the SPP footprint grows.

Cost, Risks and Administrative Burdens

There are a number of impacts in the areas of participant costs, risks and other administrative burdens that are not reflected in the quantitative analyses.

Since Entergy currently uses a queuing process, parties wishing to have interconnection requests processed probably see a faster processing time under Entergy's current process than they would through SPP's batch process.

The EHV planning process that applies certain sets of assumptions may create cost risks given the limited nature of those assumption sets (e.g., if wind development assumptions do not come to fruition, the EHV process could lead to construction of transmission lines that are significantly underutilized).

There are concerns that SPP's staff is already having difficulty addressing identified transmission planning issues and that adding in Entergy's large service area may overtax them. To the extent that ICT efforts and the balance of SPP staff efforts in transmission planning can be consolidated under the *Join SPP Case,* any impact of this type would be expected to diminish over the first year or two of combined operations.

Reliability/Costs of Ensuring Reliability

There are no indications that either the Entergy System or SPP operate unreliably at this time, nor are there concerns about operating reliably under the *Join SPP Case*. However,

49 Entergy OATT, Schedule K, Section 9.

while SPP's transmission system assessment found that Entergy would not have to make system upgrades to meet SPP standards beyond those identified in Entergy's 10-year plan, SPP did note that some of Entergy's planned projects will not be completed by the time they are needed. Additionally, stakeholder processes have identified possible loss-of-load risks due to persistent transmission system constraints in Entergy's service area. While it is expected that measures will be taken to ensure that the systems are operated reliably, there will likely be costs associated with managing these measures and/or costs to end users if firm loads are curtailed. To the extent that Entergy's joining SPP either causes these upgrades to occur sooner or reduces the likelihood of delays in future upgrades, these additional costs and risks may be reduced.

Summary of Transmission Planning Qualitative Impacts

Entergy's inclusion in SPP's transmission planning process would provide a more public process for transmission planning and greater planning efficiencies due to increased coordination and information sharing. Issues associated with the Entergy's use of the 3-year network model for assessing interconnection costs would also be resolved. The disbenefits are expected to be outweighed by the benefits; they include the lack of transparency resulting from the application of SPP's network model and potential risks that the centralized transmission planning process applied to Entergy may not result in cost-effective projects for Entergy. Inclusion of Entergy would also likely create increased demands on SPP staff in the short run.

6.3.3. Ancillary Services and Capacity Reserve Impacts

The quantitative analysis of this report captures the larger system benefits of coordinated economic dispatch and reserve scheduling if Entergy joins SPP Since Entergy and SPP currently participate in an operating reserve sharing group, it is not expected that there will be a significant shift in the way contingency reserves are procured and deployed, nor will the reserve cost burden change if Entergy joins SPP.

Currently, market participants can purchase or self-provide ancillary services in both Entergy and SPP. Market participants will still be able to self-provide under the *Join SPP Case* unless they find that SPP's markets offer a less expensive source of ancillary services, so no new risks should be created for Entergy's transmission customers, for example, from participating in the Day 2 market.

The Day 2 markets include provisions for the designation of zones within which reserves will be procured and related costs allocated. This structure should protect against the possibility that participants may be allocated costs for integrating remote wind resources even though they may not benefit from the inexpensive energy produced by those resources. At the same time, the Day 2 market will allow some level of transfers between zones such that Entergy may be able to sell excess reserve and regulation capacity to higher-value areas within SPP.

SPP's wind integration study showed that wind development in SPP may increase regulation requirements in SPP.[50] Regulation requirements, which are driven by the coincident variability of renewable generation and load, are expected to increase as the amount of wind in SPP increases. The *Join SPP Case* may provide an opportunity to reduce the amount of regulation that is procured due to a combination of increased operational coordination and a reduction in the aggregate variability of load and renewable resources that is inherent in a larger, more diverse system. Since this outcome was not modeled in the quantitative analysis, any such reductions would provide an added benefit of the *Join SPP Case*.

With respect to the sharing of regulation costs, it is not yet known at this time if Entergy will join the SPP reliability coordinator or continue to act as its own reliability coordinator. To the extent Entergy joins the SPP reliability coordinator the possibility of, and extent of, cost shifts between Entergy and SPP will depend on the designation of regulation zones, if any.

Entergy and SPP may be able to reduce their installed capacity reserve margins in the *Join SPP Case*. This benefit was also not captured in the quantitative analysis.

In summary, outside of the dispatch efficiency captured by the quantitative analysis, the *Join SPP Case* may offer a more efficient mechanism for procuring and managing reserves. Direct benefits due to lower regulating requirements and capacity reserve requirements may also be realized that were not assumed in the quantitative analysis, although it is unclear how regulation costs will be allocated to SPP members. No net adverse impacts of the *Join SPP Case* in the area of Ancillary Services have been identified.

6.3.4. Outage Management Impacts

No substantial benefits or disbenefits have been identified in the area of outage management. Existing seams agreements provide for transmission outage coordination, the ICT is already coordinating outages for Entergy's system, and outages are posted on OASIS. No significant changes in practices are expected if Entergy joins SPP.

50 SPP WITF Wind Integration Study, Charles River Associates, January 4, 2010. (http://www.spp.org/publications/2010.zip), Section 5.2.1.

6.3.5. Governance Impacts

The ICT's governance has been judged to not be strong enough to overcome pre-existing transparency, competitive and market challenges.[51] Further, there have been ongoing concerns regarding the independent role of the ICT, and an impression that ICT sides with Entergy[52], and significant efforts by the E-RSC and its consultants have identified a number of possible areas of improvement even if Entergy does not join SPP.[53]

From the perspective of business practices and how they are developed and modified, if Entergy joins SPP, SPP's business practices and the rules by which SPP modifies and develops business practices would apply. Consequently, neither Entergy nor the ICT would be responsible for the length of time required to address stakeholder concerns about existing business practices, new business practices, and issues related to data, market and process transparency. In addition, under the *Join SPP Case*, SPP's External Market Monitor would provide the kind of independent market monitoring and oversight that does not currently exist for Entergy's markets.

Historically there has been a perception that if Entergy joins SPP, users of Entergy's system will be able to exert more influence over a variety of planning, interconnection and resource decisions than they can today. However, given SPP's governance structure, users are unlikely to have more representation in the *Join SPP Case* than they have in the *Status Quo Case*. Rather, if Entergy were to join SPP, small users may continue to feel under-represented. At the same time, if it joined SPP, Entergy would likely have significantly less influence than it does today.

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51 See for example comments filed in conjunction with the June 24, 2009 Technical Conference (e.g., "An LSE Perspective on the Results of the ICT Experiment", Presented to FERC/State Commission Technical Conference, by Lafayette Utilities System" filed in Docket ER05-1065-000). Comments indicated that ICT lacked the authority to require grid improvements and modify the tariff, that the ICT was out resourced by Entergy, and that the ICT-Entergy contractual relationship inhibits ICT from being "too aggressive". Comments of others support these independence issues (e.g., Union Power Partners, L.P. Comments of February 21, 2008). Entergy in its comments following the technical conference acknowledged that the ICT currently does not have the authority to require Entergy to build transmission, and that this was an explicitly functional division acknowledged by FERC. Entergy nonetheless raises the possibility of modifying this division of authority in the future. Entergy post conference comments filed in Docket ER05-1065-000, July 20, 2009, pp. 52-54)

52 "ESPY's Review of the ICT Independence and Authority – Findings and Recommendations" dated June 29, 2010, 5th page. See also "ESPY's Review of the ICT Independence and Authority – Findings and Recommendations", dated September 9, 2010.

53 See for example recommendations to the E-RSC from ESPY Energy Solutions, LLC, in memo: "ESPY's Review of the ICT Independence and Authority – Findings and Recommendations" dated June 29, 2010. Recommendations include shifting authority to the ICT for AFC/ATC calculations, the WPP, and expanding dispute resolution to address SPP/Entergy disputes.

Beyond business process efficiencies and market monitoring, it is not clear that there would be significant direct governance benefits in the areas of competitiveness – for example – for Entergy transmission customers, in the *Join SPP Case*. Rather, in SPP final decision-making authority shifts away from Entergy to the more diverse SPP decision-making structure, which means Entergy users may not ultimately have more leverage with Entergy under SPP.

From a governance perspective, the most important consideration is the extent to which the E-RSC activities are expected to be successful. This is, however, not within the strict boundaries of the *Status Quo* vs. *Join SPP* cases because it represents another path by which Entergy transmission customers and stakeholders could realize some of the benefits they would enjoy in the *Join SPP Case* without Entergy having to join SPP.[54]

6.3.6. Qualitative Conclusions

The Qualitative Assessment examined the non-quantified potential impacts of Entergy joining SPP in energy scheduling, dispatching and congestion management, transmission planning and interconnection, ancillary services, outage management and governance. Various impacts were identified including effects on competitiveness, efficiency, discrimination, and administrative burden. This section detailed the impacts in each area. Table 15 summarizes the more significant impacts.

54 The influence of the E-RSC is seen as productive and thereby relevant to the ultimate policy choice, and for that reason it is noted herein.

Table 15: Summary of Qualitative Impacts

Impact	Section of Report With Explanation
1. Disbenefits of the inaccessibility of SPP's model, given that it would be applied to the Entergy system.	6.3.1 Transmission Scheduling, Energy Dispatching and Congestion Management Impacts - Transparency and 6.3.2 - Transmission Planning and Interconnection Impacts – Transparency
2. Operational transparency benefits with SPP conducting the scheduling and dispatching process.	6.3.1 Transmission Scheduling, Energy Dispatching and Congestion Management Impacts - Transparency
3. Competitiveness benefits by resolving the Base Case overload issue associated with Entergy's using the 3-year network model for assessing transmission access and interconnection.	6.3.1 Transmission Scheduling, Energy Dispatching and Congestion Management Impacts - Transparency and 6.3.2 - Transmission Planning and Interconnection Impacts – Competitiveness of Markets
4. Efficiency benefits stemming from resolving current inconsistent load flow models, lack of synchronism between study and reservation procedures, issues related to identifying generation dispatch alternatives, and/or unnecessary transmission customer and WPP participant transaction costs.	6.3.1 Transmission Scheduling, Energy Dispatching and Congestion Management Impacts – Transmission System and Energy Market Access
5. Benefits of the more comprehensive Day 2 energy procurement process rather than the weekly on-peak WPP.	6.3.1 Transmission Scheduling, Energy Dispatching and Congestion Management Impacts - Transmission System and Energy Market Access
6. Disbenefits to Entergy and its transmission customers of the risks associated with transitioning to SPP and the Day 2 market (direct transition costs were captured in the quantitative analysis) – expected to be transitional.	6.3.1 Transmission Scheduling, Energy Dispatching and Congestion Management Impacts – Commercial Risks
7. Disbenefits to Entergy and its transmission customers of later market closing under the Day 2 market than with Entergy's bilateral practices.	6.3.1 Transmission Scheduling, Energy Dispatching and Congestion Management Impacts – Commercial Risks
8. Disbenefits to Entergy in the area of risk of access/cost of access to its transmission system with the shift from operating its own system to being an SPP member.	6.3.1 Transmission Scheduling, Energy Dispatching and Congestion Management Impacts – Commercial Risks
9. Benefits of more efficient and optimal transmission planning and interconnection process.	6.3.2 - Transmission Planning and Interconnection Impacts- Grid and Resource Expansion Efficiency
10. Transitional disbenefits of further taxing SPP's staff to integrate Entergy planning into the balance of SPP planning.	6.3.2 - Transmission Planning and Interconnection Impacts - Costs, Risks and Administrative Burdens
11. Potential benefits of lower regulation requirements and capacity reserve margins with the combined SPP and Entergy footprint.	6.3.3 – Ancillary Services and Capacity Reserve Impacts
12. Benefits of the SPP governance structure that is explicit and viewed as stronger than that of the ICT, limited by the voting structure of the SPP governance system which may offer little or no additional representation to smaller Entergy transmission customers. Also potentially achievable through E-RSC actions, independent of Entergy joining SPP.	6.3.5 - Governance
13. Disbenefits to Entergy of diminished influence in the SPP governance process.	6.3.5 - Governance

Note that both benefits and disbenefits of the *Join SPP Case* have been identified, and that the different impacts may affect different stakeholders. Table 16 shows the Table 15 numbered impacts, as organized by benefit or disbenefits and whether the impact affects Entergy or other stakeholders (Entergy transmission customers or other SPP members).

Table 16: Summary of Benefits and Disbenefits by Entergy vs. Non-Entergy Impacts

	Entergy	Entergy Transmission Customer/Other SPP member
Benefits		2. Operational transparency
		3. Improved competitiveness via resolution of base case overload issues
		4. Improved efficiency through resolving various issues.
		5. More comprehensible features of Day 2 market vs. weekly, on-peak only WPP
		9. More optimal transmission planning and interconnection process.
	11. Potentially lower regulation and capacity reserve requirements	11. Potentially lower regulation and capacity reserve requirements
		12. Explicit SPP governance
Disbenefits	1. Inaccessibility of SPP's model	1. Inaccessibility of SPP's model
	6. Day 2 market transitional risks	6. Day 2 market transitional risks
	7. Late Day 2 market close	
	8. Perceived risky transmission system access	
	10. Transitional burden on SPP staff	10. Transitional burden on SPP staff
	13. To Entergy of SPP governance	

Table 16 suggests that there will be benefits for most parties other than Entergy if Entergy joins SPP. The disbenefits include the lack of transparency with respect to the network model – a disbenefit that is probably small compared with other transparency benefits offered if Entergy joins SPP – and other transitional disbenefits that are likely to be limited to one or two years. The majority of the disbenefits, however, accrue to Entergy – an outcome that is not unexpected.

Thus, the Qualitative Assessment indicates that the inclusion of Entergy into SPP would produce qualitative benefits for parties other than Entergy that will likely outweigh the costs those parties would incur. Not included in the above summary tables, but relevant for policymakers, is the fact that some of the benefits of the *Join SPP Case* could be captured even if Entergy does not join SPP if the E-RSC continues to be successful in effecting further changes to the Entergy and ICT structure.

7. CONCLUSION

Based on the analysis performed, we conclude that Entergy and Cleco Power joining the SPP RTO will yield significant economic benefits to the collective SPP/Entergy region. The net benefits to the individual Entergy, SPP and Cleco Power regions is highly dependent on the allocation of regional high voltage transmission expansion costs.

Aside from the allocation of transmission expansion costs, the benefits to the Entergy and SPP regions are relatively robust across the sensitivity scenarios examined. The benefits to the Cleco Power region are more heavily dependent on the economic conditions that may prevail in the future. A number of important qualitative considerations have been identified as well, with both qualitative benefits and offsetting costs incurred by the Entergy and Cleco Power regions in the *Join SPP Case*.

Additional addendum studies are contemplated by stakeholders to further assess the costs and benefits of Entergy and/or Cleco Power joining an RTO under alternative assumptions using the models and assumptions developed under this study as the basic framework.

APPENDIX A: FURTHER QUANTITATIVE RESULT DETAILS

The net benefit to each region including the impact of transmission cost allocation is captured in Table 17.

Table 17: Net Benefit to Entergy, Cleco and SPP Regions of Join SPP Case

In Millions of Nominal As-spent Dollars Inflation 2.5%
Benefits are shown as positive figures, costs as negative figures Discount Rate 8.0%

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2010 PrValue
ENTERGY REGION IN SPP RTO											
Trade Benefits	115	112	109	105	100	96	90	93	97	100	594
Administrative Costs	(36)	(39)	(39)	(39)	(39)	(40)	(41)	(43)	(44)	(45)	(230)
SubTotal	79	73	70	66	62	56	49	50	52	55	364
+ Transmission Cost Allocation											
Study 1	(68)	(84)	(160)	(155)	(173)	(168)	(160)	(157)	(161)	(165)	(802)
Study 2	(26)	(44)	(128)	(123)	(143)	(139)	(132)	(130)	(133)	(136)	(614)
Study 3	(5)	(4)	12	16	(4)	(0)	7	8	8	8	23
Net Benefits											
w/Study 1	**11**	**(11)**	**(90)**	**(90)**	**(111)**	**(113)**	**(111)**	**(107)**	**(109)**	**(110)**	**(438)**
w/Study 2	**53**	**29**	**(58)**	**(58)**	**(81)**	**(84)**	**(83)**	**(79)**	**(80)**	**(82)**	**(250)**
w/Study 3	**74**	**69**	**82**	**81**	**58**	**56**	**56**	**58**	**61**	**63**	**387**
CLECO REGION IN SPP RTO											
Trade Benefits	(2)	1	4	8	14	21	28	29	31	33	80
Administrative Costs	(6)	(6)	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(8)	(37)
SubTotal	(8)	(5)	(1)	2	8	14	21	22	23	25	43
+ Transmission Cost Allocation											
Study 1	(6)	(8)	(18)	(17)	(19)	(20)	(20)	(20)	(21)	(21)	(93)
Study 2	(2)	(4)	(13)	(13)	(15)	(15)	(16)	(16)	(16)	(17)	(68)
Study 3	(1)	(1)	(2)	(2)	(4)	(5)	(5)	(5)	(5)	(5)	(18)
Net Benefits											
w/Study 1	**(14)**	**(13)**	**(19)**	**(15)**	**(11)**	**(6)**	**1**	**2**	**3**	**4**	**(49)**
w/Study 2	**(10)**	**(9)**	**(15)**	**(11)**	**(7)**	**(1)**	**5**	**6**	**7**	**8**	**(25)**
w/Study 3	**(8)**	**(6)**	**(4)**	**0**	**4**	**10**	**16**	**17**	**18**	**19**	**25**
IMPACT ON EXISTING SPP											
Trade Benefits	24	26	28	30	27	24	21	21	22	22	143
Administrative Costs	30	33	32	32	31	32	34	35	36	37	189
SubTotal	53	59	60	63	58	56	55	56	58	59	332
+ Transmission Cost Allocation											
Study 1	75	92	178	172	192	188	180	177	182	186	895
Study 2	29	49	141	136	158	155	148	145	149	153	682
Study 3	6	5	(10)	(14)	7	5	(2)	(3)	(3)	(3)	(5)
Net Benefits											
w/Study 1	**128**	**151**	**238**	**235**	**251**	**245**	**235**	**234**	**239**	**245**	**1,226**
w/Study 2	**82**	**107**	**201**	**199**	**216**	**211**	**202**	**202**	**207**	**212**	**1,014**
w/Study 3	**59**	**64**	**50**	**49**	**66**	**61**	**53**	**54**	**55**	**56**	**327**
SPP-ENTERGY-CLECO Net Benefits											
Trade Benefits	137	139	141	143	142	140	139	144	149	154	817
Administrative Costs	(12)	(12)	(13)	(13)	(14)	(14)	(15)	(15)	(15)	(16)	(78)
Net Benefits	**125**	**127**	**128**	**130**	**128**	**126**	**124**	**129**	**134**	**138**	**739**
Inflation Factor	*1.077*	*1.104*	*1.131*	*1.160*	*1.189*	*1.218*	*1.249*	*1.280*	*1.312*	*1.345*	

Note: The "Entergy region" refers to the areas within the Entergy transmission system footprint, and for purposes of this study includes Louisiana Generating and Louisiana Energy and Power Authority. The "Cleco region" refers to the areas within the Cleco transmission system footprint as well as the Cleco Power load served by the Entergy transmission system, and for purposes of this study includes the City of Lafayette. The "Existing SPP region" refers to the SPP transmission system footprint that is currently operating within the SPP Energy Imbalance Service market.

Further detail regarding the net benefits to each of the regions prior to consideration of transmission cost allocation is captured in Table 18.

Table 18: Net Benefit Detail, excluding Transmission Cost Allocation

In Millions of Nominal As-spent Dollars Inflation 2.5%
Benefits are shown as positive figures, costs as negative figures Discount Rate 8.0%

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2010 PrValue
ENTERGY REGION IN SPP RTO											
Trade Benefits											
+ Decrease in Adjusted Prod Costs	142	140	137	134	130	126	122	126	129	133	765
+ Lost T&O Trans Revenue	(27)	(28)	(28)	(29)	(30)	(31)	(32)	(32)	(33)	(33)	(172)
= *Subtotal Trade Benefits*	115	112	109	105	100	96	90	93	97	100	594
Administrative Costs											
+ Avoided ICT Charges	20	21	22	23	24	25	26	27	27	28	136
+ RTO Administrative Charges	(46)	(50)	(50)	(51)	(51)	(53)	(55)	(57)	(59)	(60)	(300)
+ FERC Charges	(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(32)
+ Internal Capital/Labor	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(34)
= *Subtotal Admin/Capital*	(36)	(39)	(39)	(39)	(39)	(40)	(41)	(43)	(44)	(45)	(230)
SubTotal	79	73	70	66	62	56	49	50	52	55	364
CLECO REGION IN SPP RTO											
Trade Benefits											
+ Decrease in Adjusted Prod Costs	(3)	0	4	7	13	20	27	28	30	32	75
+ Lost T&O Trans Revenue	1	1	1	1	1	1	1	1	1	1	5
= *Subtotal Trade Benefits*	(2)	1	4	8	14	21	28	29	31	33	80
Administrative Costs											
+ RTO Administrative Charges	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(5)	(5)	(5)	(25)
+ FERC Charges	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(3)
+ Internal Capital/Labor	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)	(9)
= *Subtotal Admin/Capital*	(6)	(6)	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(8)	(37)
SubTotal	(8)	(5)	(1)	2	8	14	21	22	23	25	43
IMPACT ON EXISTING SPP											
Trade Benefits											
+ Decrease in Adjusted Prod Costs	38	40	43	45	43	40	37	38	39	39	232
+ Lost T&O Trans Revenue	(14)	(14)	(15)	(15)	(16)	(16)	(16)	(17)	(17)	(17)	(89)
= *Subtotal Trade Benefits*	24	26	28	30	27	24	21	21	22	22	143
Administrative Costs											
+ RTO Administrative Charges	30	33	32	32	31	32	34	35	36	37	189
SubTotal	53	59	60	63	58	56	55	56	58	59	332
SPP-ENTERGY-CLECO Net Benefits											
Trade Benefits											
+ Decrease in Adjusted Prod Costs	177	180	183	187	186	186	186	192	198	204	1,073
+ Lost T&O Trans Revenue	(41)	(42)	(42)	(43)	(44)	(46)	(47)	(48)	(49)	(50)	(256)
= *Subtotal Trade Benefits*	137	139	141	143	142	140	139	144	149	154	817
Administrative Costs											
+ Avoided ICT Charges	20	21	22	23	24	25	26	27	27	28	136
+ RTO Administrative Charges	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(27)	(28)	(136)
+ FERC Charges	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(7)	(7)	(34)
+ Internal Capital/Labor	(6)	(6)	(7)	(7)	(8)	(8)	(8)	(9)	(9)	(9)	(43)
= *Subtotal Admin/Capital*	(12)	(12)	(13)	(13)	(14)	(14)	(15)	(15)	(15)	(16)	(78)
Net Benefits	**125**	**127**	**128**	**130**	**128**	**126**	**124**	**129**	**134**	**138**	**739**
Inflation Factor	*1.077*	*1.104*	*1.131*	*1.160*	*1.189*	*1.218*	*1.249*	*1.280*	*1.312*	*1.345*	

Note: The "Entergy region" refers to the areas within the Entergy transmission system footprint, and for purposes of this study includes Louisiana Generating and Louisiana Energy and Power Authority. The "Cleco region" refers to the areas within the Cleco transmission system footprint as well as the Cleco Power load served by the Entergy transmission system, and for purposes of this study includes the City of Lafayette. The "Existing SPP region" refers to the SPP transmission system footprint that is currently operating within the SPP Energy Imbalance Service market.

Further detail regarding the annual trade benefits of each sensitivity case is captured in Table 19.

Table 19: Annual Trade Benefits for Sensitivity Cases (millions of as spent nominal dollars)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2010 PrVal	PV Costs	PV Net(a) Benefits	Increase from Base Scenario
Discount Rate 8%														
Inflation Factor	1.077	1.104	1.131	1.160	1.189	1.218	1.249	1.280	1.312	1.345				
Overall Trade Benefits														
Base Scenario	**137**	**139**	**141**	**143**	**142**	**140**	**139**	**144**	**149**	**154**	**817**	(78)	739	
Low Gas	105	105	106	106	107	108	109	110	111	113	618	(78)	540	(199)
High Gas	155	156	157	158	161	164	166	170	175	179	935	(78)	858	119
Low Demand	134	140	146	152	148	144	139	146	153	160	836	(78)	758	19
High Demand	143	143	143	143	139	134	130	129	128	128	791	(78)	713	(26)
Increased Wind in SPP	111	120	130	140	128	114	100	102	104	105	673	(78)	595	(144)
No Trans Congestion	114	115	117	118	118	118	118	120	123	126	679	(78)	601	(138)
Entergy Trade Benefits														
Base Scenario	**115**	**112**	**109**	**105**	**100**	**96**	**90**	**93**	**97**	**100**	**594**	(230)	364	
Low Gas	92	92	92	92	84	75	65	67	69	71	473	(230)	243	(121)
High Gas	122	121	119	116	114	112	110	112	114	116	669	(230)	439	75
Low Demand	110	111	112	113	103	93	81	82	82	82	574	(230)	344	(20)
High Demand	113	113	113	113	107	100	94	95	97	99	608	(230)	378	15
Increased Wind in SPP	104	104	104	104	101	98	95	99	104	109	590	(230)	360	(3)
No Trans Congestion	111	114	116	119	107	95	81	88	94	101	601	(230)	371	8
Cleco Trade Benefits														
Base Scenario	**(2)**	**1**	**4**	**8**	**14**	**21**	**28**	**29**	**31**	**33**	**80**	(37)	43	
Low Gas	(10)	(9)	(8)	(7)	1	10	19	19	19	19	15	(37)	(21)	(65)
High Gas	2	5	7	10	17	24	31	33	36	38	100	(37)	64	20
Low Demand	3	7	10	14	19	25	31	33	36	39	110	(37)	73	30
High Demand	0	2	4	6	11	16	21	21	20	19	59	(37)	23	(21)
Increased Wind in SPP	(2)	2	5	8	4	(0)	(5)	(3)	(1)	1	7	(37)	(30)	(73)
No Trans Congestion	(50)	(51)	(52)	(53)	(49)	(44)	(39)	(41)	(44)	(46)	(274)	(37)	(311)	(354)
SPP Trade Benefits														
Base Scenario	**24**	**26**	**28**	**30**	**27**	**24**	**21**	**21**	**22**	**22**	**143**	189	332	
Low Gas	22	22	22	22	23	23	24	24	23	23	130	189	319	(13)
High Gas	31	31	32	32	30	28	25	25	25	26	167	189	355	24
Low Demand	21	22	23	25	26	27	28	31	35	39	152	189	340	9
High Demand	30	28	27	24	21	18	15	13	12	10	123	189	312	(20)
Increased Wind in SPP	8	14	21	28	22	16	10	5	0	(5)	76	189	265	(67)
No Trans Congestion	52	52	52	52	60	67	75	74	72	71	351	189	540	208

(a) - Excluding transmission expansion cost impacts

APPENDIX B: GE MAPS MODELING ASSUMPTIONS

B.1 OVERVIEW

This appendix summarizes the key inputs to the GE MAPS locational price forecasting model. GE MAPS is a detailed economic dispatch and production-costing model for electricity networks. It was originally developed by General Electric (GE) and is currently used by over twenty major utilities and RTOs in the U.S. CRA has worked closely with GE to ensure that the model's data structures and functionality accurately reflect the competitive market.

GE MAPS determines the least-cost security constrained dispatch of generating units to satisfy a given demand, on the assumption that the units are dispatched according to their variable costs. The major advantage of GE MAPS is its ability to simulate the hourly operation of generating units and transmission systems (e.g. transformers, lines, phase shifters, busses) in significant detail. For example, it accurately represents capacity constraints, minimum up time limitations, and thermal constraints on the transfer capability of transmission lines, line and unit contingencies and scheduling limitations of hydro-plants. As such, GE MAPS provides a highly accurate, detailed simulation of the hourly operation of the individual generating units and transmission systems that constitute the wholesale market.

Among the key outputs of the GE MAPS model is a set of Locational Marginal Prices (LMPs), computed for each bus in each hour, and the hourly dispatch of all generators in each relevant geographic market.

The model's geographic footprint encompasses the U.S. portion of the Eastern Interconnection with a focus on the Southwest Power Pool (SPP) and Entergy footprints and surrounding regions. The four years of GE MAPS simulation are 2013 (the analysis start year), 2016, 2019, and 2022 (the analysis end year). Results for years not simulated are interpolated.

B.2 DATA SOURCES

Primary data sources for CRA's GE MAPS model include the Eastern Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG), the General Electric generation and transmission databases for the Eastern Interconnect, the NERC Electricity Supply and Demand (ES&D) database, the NERC regions and Independent System Operators/Regional Transmission Organizations, the FERC submissions by generation and transmission owners, and CRA analysis of plant operations and market data. Major data components are listed in the sections following.

All financial assumptions specified in this appendix are expressed in real 2009 US dollars, unless otherwise noted.

B.3 TRANSMISSION

The CRA model used two sets of power flow cases provided by SPP. These power flow cases encompass the entire Eastern Interconnection system, including lines, transformers, phase shifters, and DC ties. Monitored constraints originate in the following sources:

- The list of flowgates provided by SPP for SPP and surrounding areas
- The NERC Book of Flowgates provided by SPP
- The list of flowgates provided by Entergy for Entergy and surrounding areas

For constraints monitored for their thermal limit violations, limits are updated with respect to the power flow to reflect transmission upgrades. For constraints enforced for stability purposes, CRA uses the limits obtained from the sources above. Furthermore, flows on all lines with a nominal rating of 345kV and above within the SPP and Entergy footprint are monitored.

B.4 LOAD INPUTS

For each load-serving entity, GE MAPS requires an annual forecast of peak load and total energy, and an hourly load profile.

For peak load and energy forecasts, CRA uses the latest FERC-714 load forecast data available (2007/2008) for each company where available. Ontario data is drawn from the 10-Year Outlook: Ontario Demand Report published by the Independent Electricity Market Operator of Ontario. For SPP, the load forecast is derived from the SPP EIA 411 (2009) and historical data. As most forecasts only project load through 2018 or so, CRA uses the average growth rate by forecast area to extrapolate the peak load and energy forecast through 2022.

For non-SPP areas, load shapes are drawn from hourly actual demand for 2006, as published in FERC Form 714 submissions and on the websites of various Independent System Operators (ISOs) and NERC reliability regions.[55] These hourly load shapes, combined with forecasts for peak load and annual energy for each company, are used by GE MAPS to develop a complete load shape for each company for each forecast year

Entergy has provided 2006 load data by operating company. Given the impact of hurricane Katrina on the 2006 New Orleans load, CRA is using 2008 load shapes for Entergy New

55 It is important that all hourly load profiles use the same year for all areas. It is also important that the hourly load profiles and hourly wind profiles are time-synchronized, especially for high wind potential areas such as SPP. This is because both load and wind are heavily correlated to weather patterns. Therefore, CRA plans to use 2006 data for both hourly load profiles and wind profiles.

Orleans (with slight adjustments). Entergy also provided the list of the 12 BAs under Entergy TR system and identification of loads where multiple loads exist on a single bus.

For SPP areas, CRA is using the historical hourly load shapes (and corresponding wind profiles) for 2006 provided by SPP and used for the Wind Integration Study.[56] The 2006 SPP load data is scaled using the 2009 SPP EIA 411 load and energy forecast. SPP provided the load and energy forecast data for the SPP Nebraska regions, as they were not included in the 2009 EIA 411.

B.5 Thermal Unit Characteristics

GE MAPS includes a detailed model of thermal generation in order to accurately simulate operational characteristics and project realistic hourly dispatch and prices. Modeled characteristics include unit type, unit fuel type, heat rate values and shape (based on unit technology type), summer and winter capacities, fixed and variable non-fuel operation and maintenance costs, startup fuel usage, forced and planned outage rates, minimum up and down times, and quick start and spinning reserve capabilities.[57]

The CRA generation database reflects unit-specific data for each unit based on a wide variety of sources. In cases where unit-specific data is not available, representative values based on unit type, fuel, and size are used. Table-B1 shows these generic assumptions.

56 SPP WITF Wind Integration Study, available at http://www.spp.org/publications/2010.zip

57 Note that certain data types are specified on a plant-specific basis in CRA's database and therefore do not require corresponding generic data. These include but are not limited to summer/winter capacity, full load heat rates and emissions data.

Table-B1: Generic Characteristics for Thermal Units

Unit Type and Size	Variable O&M ($/MWh)	Fixed O&M ($/kW-year)	Forced Outage Rate (%)	Planned Outage Rate (%)	Typical Forced Outage Length (Days)	Heat Rate Shape
Combined Cycle	$ 2.50	$ 21.00	1.75%	7.78%	2	4 blocks: 50% capacity at 113% FLHR, 67% capacity @ 75% FLHR, 83% capacity @ 86% FLHR, and 100% capacity @ 100% FLHR
Combustion Turbine (<50MW) *1	$ 10.00	$ 10.00	2.46%	4.92%	1	Single block, 100% capacity at 100% FLHR
Combustion Turbine (50MW<) *1			2.49%	6.66%	1	
Steam Turbine Coal (<100MW)	$ 5.00	$ 35.00	3.32%	8.73%	7	3 blocks: 50% capacity at 106% FLHR, 75% capacity @ 90% FLHR, and 100% capacity @ 100% FLHR
Steam Turbine Coal (100MW<200MW)	$ 4.00		3.93%	8.26%	7	
Steam Turbine Coal (200MW<600MW)	$ 3.00		4.36%	9.20%	7	
Steam Turbine Coal (600MW<) *2 *3	$ 2.00		4.36%	9.20%	7	
Steam Turbine Gas/Oil (<100MW)	$ 6.00		2.35%	6.78%	2	4 blocks: 30% capacity at 110% FLHR, 50% capacity @ 90% FLHR, 75% capacity @ 96% FLHR,and 100% capacity @ 100% FLHR
Steam Turbine Gas/Oil (100MW<200MW)	$ 5.00		3.14%	11.96%	2	
Steam Turbine Gas/Oil (200MW<600MW)	$ 4.00		3.05%	13.01%	2	
Steam Turbine Gas/Oil (600MW<) *4	$ 3.00		3.03%	14.97%	2	

*1 Includes start up cost
*2 Min Up / Min Down will be 16/8 for newer sliding pressure super critical units.
*3 Heat rate shapes will be 4 blocks: 30% capacity at 110% FLHR, 50% capacity @ 93% FLHR, 75% capacity @ 95% FLHR, and 100% capacity @ 100% FLHR
*4 Heat rate shapes will be 4 blocks: 20% capacity at 110% FLHR, 50% capacity @ 95% FLHR, 75% capacity @ 98% FLHR, and 100% capacity @ 100% FLHR

The primary data source for generation units and characteristics is the 2006 NERC Electricity, Supply and Demand (ES&D) database, which contains unit type, fuel type (primary and secondary), and capacity data for existing units. Heat rate data is drawn from prior ES&D databases where available. For newer plants, heat rates are based on industry averages for the technology of the unit. The 2003 NERC Generation Availability Data System (GADS) database, released in January 2005, is the source for forced and planned outage rates, based on plant type, size, and vintage. Fixed and variable operation and maintenance costs are estimates based on plant size, technology, and age. These estimates are supplemented by FERC Form 1 submissions where available. The Fixed O&M values include an estimate of $1.50/kW-yr for insurance and 10% of base Fixed O&M (before insurance) for capital improvements.

Plants that are known to be cogeneration facilities are either modeled with a low heat rate (6000 Btu/kWh), or set as must-run units in the dispatch, to reflect the fact that steam demand requires operation of the plant even when uneconomical in the electricity market. Entergy provided the list of RMR units, interfaces for the load pockets that require these RMR units, and the trigger points as a level of load for these RMR units.

CRA received individual unit data from a number of study participants under NDAs. Entergy and SPP provided data on their must-run units. Entergy provided historical hourly output data on its QFs.

B.6 Nuclear Units

CRA assumes that nuclear plants run when available and that they have minimum up and down times of one week. Forced outage rates for each unit are drawn from the Energy Central database of unit outages. Nuclear plants do not contribute to quick-start or spinning reserves. The model includes refueling and maintenance outages for each nuclear plant. In the near future, outages posted on the NRC website or announced in the trade press are included. For later years, refueling outages are projected on the basis of the refueling cycle, typical outage length, and last known outage dates of each plant. Since these facilities are treated as must run units, CRA does not specifically model their cost structure. For this specific study, no nuclear retirements are anticipated. CRA is using nuclear outage data from Entergy and SPP. No nuclear units in the US are anticipated to retire by 2022. Watts Bar 2 is assumed to come online by 2013.

B.7 Hydro Units

GE MAPS has special provisions for modeling hydro units, and requires specification of a monthly pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. Plant capacity data is drawn from the NERC ES&D database. Plant monthly energy data is drawn from an average of Form EIA-860 submissions for 1992-1998. CRA assumes that hydro plants are able to provide spinning reserves of up to 50% of plant capacity

B.8 Renewable Resources

Individual wind resources are modeled either as low-cost ($1/MWh) dispatchable energy resources with a fixed annual capacity factor of 30% or with a fixed wind shape taken from NREL data. All SPP wind units are assigned fixed wind shapes from the NREL sites they are mapped to on a unit-by-unit basis. All non-SPP wind units in areas surrounding SPP (WAPA, MISO, TVA, Entergy, and AECI) are also assigned fixed wind shapes (but on a region-by-region aggregate mapping to NREL sites for the corresponding region). All non-SPP wind units in areas further from SPP (Ontario, PJM, New York, New England, VACAR, Southern, and Florida) are modeled with a fixed 30% capacity factor.

B.9 Capacity Additions and Retirements

CRA adds new generation based on projects in development or advanced stages of permitting, as indicated by trade press announcements, trade publications, environmental permit applications, and internal knowledge. CRA also adds generic capacity where economically justified, or as required to maintain resource adequacy per installed capacity reserve margins published by various NERC regions. CRA tracks planned and announced retirements from power pool publications and trade press announcements and retires units accordingly with the exception of nuclear units. For the Entergy and SPP regions:

AECI Chocteau County 2 CC unit is assumed to be on-line mid-2011. SWEPCO's Turk coal-fired plant is assumed to be on-line by 2013. Teche 4 (38 MW peaking) is assumed to be on-line by 2012. Teche 2 is assumed to be retired in 2010. Plum Point 2 (pre-air permit) and Washington Parish CC are not included as the development stage is too early. Based on input provided by SPP, it is assumed that there will be 4 GW of windpower in place in SPP in 2013, increasing to a total of 7 GW by 2022 in both the *Status Quo* and *Join SPP Cases*.

Target reserve margins of 13.6% for SPP and 14% for Entergy were applied in the NEEM modeling in both the Status Quo and Join SPP cases. While there is the possibility that reserve margin requirements could decrease in the Entergy region in the *Join SPP Case*, these reserve margins are not binding in the 2013 to 2022 study period.

B.10 Environmental Regulations

For thermal generating units, variable operating and maintenance costs associated with installed scrubbers (SO_2 reduction) or with Selective Catalytic Reduction (SCR) processes for NO_x reduction are included in the marginal production cost and the unit energy bids. No fixed or capital costs of these emission control technologies are included in the calculation of marginal cost. CRA tracks industry announcements of units that are planning to install NO_x or SO_2 abatement technologies in the near future and models the resulting changes in emission rates and the variable and fixed costs associated with the new installations.

To account for SO_2 trading under EPA's Acid Rain Program, the model incorporates the opportunity cost of SO_2 tradable permits into the marginal cost bids, based on unit emission rates and forecast allowance trading prices for the time period of the simulation. NO_x emission rates are drawn from the CEMS data filed with the US Environmental Protection Agency. Emission allowance prices for CO_2, NO_x, and SO_2 are based on NEEM simulation results.[58] CRA modeled NO_x and SO_2 allowances based on the Clean Air Interstate Rule (CAIR)[59] and CO_2 allowances based on the Regional Greenhouse Gas Initiative (RGGI) for northeastern states only. Given that there are no existing regulations, no mercury emissions or national carbon policies are modeled. Figure-B1 shows the CAIR regions. Table-B2 shows the allowance prices.

58 NEEM uses the same fuel forecast as MAPS and therefore the assumptions used for emission allowance data are consistent.

59 CAIR requires participating states to submit two allowances per ton of SO_2 emission starting in 2010 and 2.86 allowances per ton starting in 2015, rather than one allowance as per the Title IV Acid Rain Program. Thus the introduction of CAIR impacts the allowance price markets substantially. CAIR states are most states east of MN, IA, MO, AR, LA and TX.

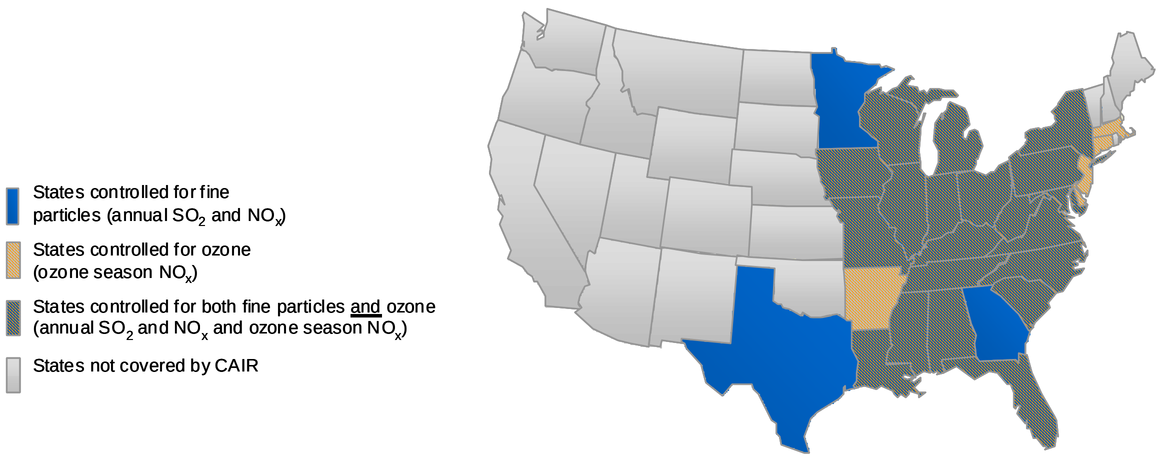

Figure-B1: CAIR Regions

Table-B2: Allowance Prices ($ / short ton)

	CO_2	NO_x	SO_2
2013	2.42	1,347	323
2016	2.81	1,560	262
2019	3.24	1,806	303
2022	3.09	1,770	351

Note: CO_2 allowances based on the Regional Greenhouse Gas Initiative (RGGI) for northeastern states only

B.11 External Region Supply

CRA explicitly models the US portion of the Eastern Interconnect and the Canadian provinces of Ontario, Manitoba and Saskatchewan. Regions outside this study area are modeled as either supply profiles or scheduled interchanges. CRA uses historical flows, combined with expectations of future conditions in these areas to project quantities and prices of power exchanged with the model footprint. In this analysis, flows from New Brunswick to New England, and from Hydro Quebec to New England, New York, and Ontario are modeled as scheduled flows, based on 12 months of historical data.

The DC ties with the WECC and ERCOT interconnections are modeled as fixed flows, based on the flows in the power flow models provided by SPP.[60]

B.12 Dispatchable Demand (Interruptible Load)

The presence of demand response is important to energy and installed capacity prices. The value of energy to interruptible loads caps the energy prices, and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value. CRA uses values for interruptible load, and demand side management reduction in peak from the NERC ES&D database. This interruptible load is spread among load areas based on their load share of the total system load. The dispatchable demand is implemented as generators with a dispatch price of $600/MWh for the first block (50% of area dispatchable demand) and $800/MWh for the second block. These units rarely run, as the high prices they require indicate a supply shortfall and prompt economic new entry. Thus they play an insignificant role in the energy market, but can play an important role in the capacity market. If these loads can be interrupted during peak hours, they will be paid the capacity market-clearing price. Thus they have strong incentives to make themselves available during peak hours. When interruptible demand is included in the calculation of the required reserve margin, it reduces the requirement of installed capacity and thus reduces new entry and helps increase energy prices, consistent with market behavior.

B.13 Market Model Assumptions

B.13.1 Marginal Cost Bidding

All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel Variable O&M plus opportunity cost of tradable emissions permits). To the extent that markets are not perfectly competitive, the modeling results will reflect the lower bound on prices expected in the actual markets.

B.13.2 Operating Reserve Requirement (spinning and standby)

Operating reserves are based on requirements instituted by each reliability region. These requirements are typically based on the loss of the largest single generator, or the largest single generator and half the second largest generator, or a percentage of peak demand, depending on the pool. The spinning reserves market affects energy prices, since units that spin cannot

60 Typically CRA would model these as price sensitive supply curves derived from historical electricity prices and gas prices near these DC ties to calculate market heat rates for on-peak and off-peak periods, and for summer and winter. For this study CRA freezes the flows on the DC ties to eliminate any external noise that a price sensitive supply curve may create.

produce electricity under normal conditions. Energy prices are higher when reserves markets are modeled.

For the SPP reserve sharing group, which includes Entergy and AECI, requirements for spinning plus regulation and quick start reserves are treated separately as two types of constraints that need to be met simultaneously with the requirement to balance generation and loads. GE MAPS is used to co-optimize commitment and dispatch for meeting spinning plus regulation requirements and quick start requirements.

The SPP reserve sharing group requirements for operating reserves are 100% of the first largest contingency (largest committed unit) plus 50% of the second largest contingency (second largest committed unit), where 50% or more of this needs to be supplied by spinning reserves. For the current SPP reserve sharing group, this requirement is set at 1876 MW carried by reserve sharing group members pro-rated by their load.[61] Out of this required 1876 MW of operating reserves, 938 MW is provided by spinning reserves. The balance could be provided by quick starts. CRA assumes that this operating reserve requirement does not change between the two cases.

In modeling supply for operating reserves within the area of interest, the spinning and quick start capabilities of generating units are specified on a unit-type basis. For spinning reserves, the maximum level of spinning reserve capability of a thermal unit is set to be the lesser of the unit's ramp rate (in MW/min) times 10 and its capacity above minimum block. This is because spinning reserves are typically needed to meet the requirements within 10 minutes. Assumed ramp rates are: 10 MW/min for combine cycle units, 6 MW/min for gas and oil steam units, and 3 MW/min for coal units. For hydro plants, spinning reserve capability is set on a monthly basis at 50% of the difference between plant's capacity in that month and its average for that month's hourly output. No spinning capability is assigned to nuclear generators. Entergy provided additional unit ramping rates for its coal units. SPP data included ramping rates.

B.13.3 Transmission Losses

Transmission losses are modeled at marginal rates over the entire Eastern Interconnection. The reference bus is fixed.

B.14 Seams Charges and Wheeling Rates

Seam charges are "per MWh" charges for moving energy from one control area to another in an electric system. In MAPS, seams charges are applied to net interregional power flows and

61 For this study, the share of this 938 MW of spinning reserve is AECI 47.5 MW, LaGen 30 MW, Cleco 15 MW, LEPA 1 MW, LAFA 1 MW, SMEPA 19 MW, Entergy 270.5 MW, SPP 492.5 MW, and WAPA 61.5 MW.

are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Seams charges are considered for both commitment and dispatch of generating units; however, the charges between any two areas may be different for commitment than for dispatch. For the current analysis, commitment is done on a pool by pool basis, and dispatch is done by the system as a whole, subject to seams charges. The seams charges modeled for dispatch include both the actual wheeling rates defined in transmission tariffs, and a second value, which is referred to as friction, representing the hurdles caused by market inefficiencies. The wheeling rates are based on the non-firm hourly rates.

Table-B3 gives an overview of the seams charges used for dispatch between SPP, Entergy, and other neighboring control areas. The SPP, Entergy and AECI regions are treated as one commitment pool with a $10/MWh commitment hurdle between SPP and Entergy (and others) in the *Status Quo Case*.

Table-B3: Seams Charges

Seams Charges for Entergy CBA Study ($/MWh)

	From Commitment Pool	To Commitment Pool	Dispatch Seams Charge Wheel	Friction	Total
	Day 2:				
1	MISO	PJM	0	2	2
	MISO	All Other	5	3	8
2	PJM	MISO	0	2	2
	PJM	All Other	3	3	6
3	SPP/Entergy	All		*See below*	
4	NE	NY	0	3	3
	NE	All but NY	7	3	10
5	NY	NE	0	3	3
	NY	HQ	2	3	5
	NY	OH	4	3	7
	NY	PJM	5	3	8
	Non-Day 2:				
6	VACAR-Duke/CPL	All	2	5	7
7	FRCC	All	3	5	8
8	KY	All	2	5	7
9	SOCO	All	5	5	10
10	TVA	All	3	5	8
11	OH	All	1	5	6
12	HQ	All	8	5	13
13	NB/Maritimes	All	3	5	8

From	To	Dispatch Seams Charge Wheel	Friction	Total	Commit Seams Charge	
Entergy/SPP Region Seams Charges (Base Case) (a)(b)						
Cleco	*SPP, Entergy, LEPA and LAFA*	3	3	6	10	
Cleco	*LaGen*	0	3	3	10	
Entergy	*LaGen*	0	3	3	10	
Entergy	*Cleco, SPP, AECI, LEPA, LAFA, SMEPA*	3	3	6	10	
Entergy	*All Other*	3	5	8	(c)	
SPP	*Cleco, Entergy, AECI, LEPA, LAFA, LaGen*	2	3	5	10	*SWPA wheel rate*
SPP	*All Other (b)*	2	3	5	(c)	*Day 2 planned*
LEPA	*Entergy and Cleco*	3	3	6	10	
LAFA	*Entergy and Cleco*	3	3	6	10	
LaGen	*Entergy and Cleco*	0	3	3	10	
LaGen	*SOCO*	3	5	8	(c)	*Ent-SOCO charge applied*
Entergy IPPs w/o LTC	*Entergy*	0	0	0	5	
AECI and SMEPA	*SPP and Entergy*	3	3	6	10	
AECI and SMEPA	*All Other*	3	5	8	(c)	
Entergy/SPP Region Seams Charges (Change Case)						
SPP	*AECI and SMEPA*	2	3	5	10	
SPP	*All Other (b)*	2	3	5	(c)	*Day 2 planned*
AECI and SMEPA	*SPP*	3	3	6	10	
AECI and SMEPA	*All Other*	3	5	8	(c)	
Other Intra-Commitment Pool Seams Charges						
Intra-FRCC	*Intra-FRCC*	3	5	8	10	
Duke/CPL/SCG	*Duke/CPL/SCG*	2	5	7	10	
NWE	*MISO/WAPA*	4	5	9	10	
WAPA	*MISO/NWE '*	4	5	9	10	
MISO	*NWE/WAPA*	5	3	8	10	
MISO	*SASK*	5	3	8	10	
SASK	*MISO*	6	5	11	10	
Intra-Maritimes	*Intra-Maritimes*	3	5	8	10	

Notes: *$3 dispatch friction hurdle for flows out of active managed markets*
Non-market areas not expected to be as efficient hence higher dispatch friction of $5
Average of on- and off-peak non-firm hourly wheeling rate used in addition to friction
PJM to/from MISO friction set at $2 given extensive seams management process
(a) $3 friction for Cleco-Entergy-SPP-LAFA-LEPA-LaGen-AECI-SMEPA Base Case transactions
(b) Entergy, Cleco, LEPA, LAFA and LaGen become part of SPP in Change Case
(c) Separate commitment pools

To reflect the likely dispatch of IPP units in the Entergy region, an additional commitment hurdle rate of $5/MWh was included in the *Status Quo Case* for IPPs in the Entergy and Cleco regions without long-term (through at least 2016) firm transmission service in place. Those IPPs in the Entergy and Cleco region without long-term firm transmission service are shown in Table-B4 below.

Table-B4: IPPs in Entergy and Cleco regions

Entergy

- Carville Cogeneration Energy
- Cottonwood CC 1 & 2 (Intergen)
- Duke-Hinds
- Duke Hot Springs 1
- Hot Springs (Tractabel)
- Robert Ritchie 2
- Union Power - Panda Energy
- Cogentrix Batesville (MS) (a)

Cleco

- Cleco Evangeline

(a) Located outside of the Entergy area in the power flow case, and thus accounted for in Entergy imports.

B.15 Fuel Prices

GE MAPS uses monthly fuel prices for each thermal unit. The fundamental assumption of behavior in competitive markets is that generators will bid their marginal cost into the energy market. The marginal cost for a gas plant is the opportunity cost of fuel purchased (in addition to non-fuel variable O&M and environmental adders), or the spot price of gas at the location closest to the plant. CRA therefore uses forecasts of spot prices at regional hubs and refines these on the basis of historical differentials between price points and their associated hubs. For fuel oil, CRA estimates the price as delivered to generators on a regional basis.

The remainder of this section discusses the fuel price forecast methodology. The tables and figures that appear in this section show the methodology and results of the methodology used. The fuel forecasts for gas and oil are based on NYMEX forwards from April 2, 2010 and the EIA's Annual Energy Outlook (AEO) long term forecasts in its 2010 Early Release. The forecasted gas and oil prices are used in NEEM to derive the coal prices.

Specific oil and gas price used in this study are provided in the following sections.

B.16 Natural Gas and Fuel Oil Price Forecasts

B.16.1 Natural Gas Forecast

Principal Drivers

The principal drivers are the projected prices for natural gas at Henry Hub.

Base Case Forecast

In the near term, the Base Scenario forecast is set equal to NYMEX futures prices for natural gas at Henry Hub as of April 2, 2010. For later years, the forecast follows the AEO long term trend. Figure-B2 shows the CRA Base Scenario forecast for natural gas prices at Henry Hub. Note that this figure shows values in 2009 dollars.

Regional Prices

CRA forecasts natural gas prices on a regional basis following major traded pricing points along pipelines. Regional forecasts are derived by adding the basis differential by region and a local delivery charge by state to the Henry Hub gas price.

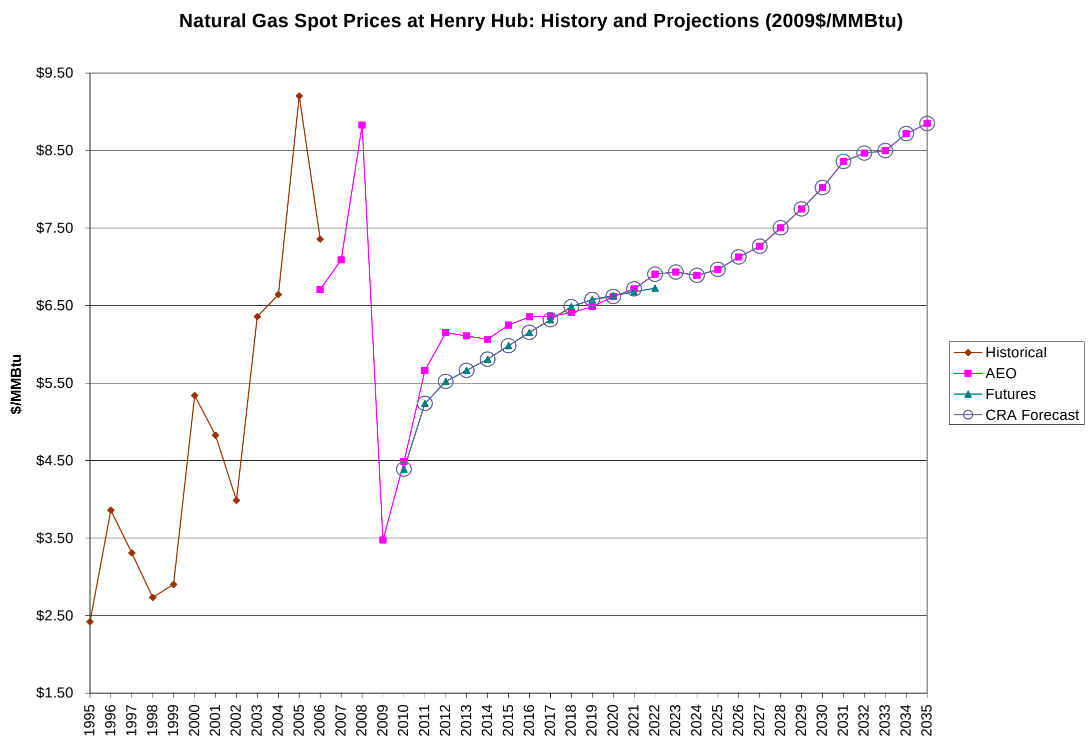

Figure-B2: Henry Hub Prices: History and Projection (in Real 2009 $/MMBtu)

Basis Differentials by Region

CRA recognizes multiple pricing points within each census region, all of which are actual pipeline trading points surveyed and reported by Platt's Gas Daily. Some of these pricing points coincide with the NYMEX Clearport hubs, which include Henry Hub. For the other points, CRA uses a regression model to one or more NYMEX Clearport hubs, calibrated with historical data, to derive a forecast. The NYMEX Clearport hub futures settlement data are only available for a short period, typically between 12 and 24 months. Within this timeframe, CRA derives monthly differentials to these hubs using NYMEX data. Beyond this period, CRA scales the basis differentials in proportion to the Henry Hub forecast. Forecast prices at each hub are derived using the Henry Hub forecast and the scaled basis differential for that hub. The pricing points used and their relation to the NYMEX Clearport futures are shown in Table-B5.

Table-B5: Pricing Points and NYMEX Hubs

Region	States	Natural Gas Pricing Point	Weights	Deriving Source - Summer (NYMEX Clearport hubs)
Eastern New York	NY (East)	Transco Zone 6 (NYC)	1	Direct NYMEX Clearport Hub
Western New York	NY (West)	Dominion (Appalachia)	0.5	Direct NYMEX Clearport Hub
		Iroquois	0.5	Regressed to Michigan and Transco Zone 6 NYC
PJM	DC, DE, MD, NJ, PA (East)	Texas Eastern Zone M-3	0.5	Direct NYMEX Clearport Hub
		Transco Zone 6 (non-NYC)	0.5	Regressed to Texas Eastern Zone M 3 and Transco Zone 6 NYC
Appalachia	KY, OH, PA (West), WV	Columbia Gas Appalachia	0.25	Direct NYMEX Clearport Hub
		Leidy Hub	0.25	Regressed to Transco Zone 6 NYC
		Dominion (Appalachia)	0.5	Direct NYMEX Clearport Hub
Southern New England	CT, MA, RI	Algonquin City Gates	1	Regressed to Transco Zone 6 NYC
Northern New England	ME, NH, VT	Tennessee Zone 6	0.5	Regressed to Texas Eastern Zone M 3 and Transco Zone 6 NYC
		Dracut	0.5	Regressed to Dominion (Appalachia)
Iowa-Missouri-Nebraska	IA, MO, NE	Ventura	1	Direct NYMEX Clearport Hub
Florida	FL	Florida CityGate	1	Direct NYMEX Clearport Hub
Mid-Continent	KS, OK	NGPL Mid-Continent Basis	1	Direct NYMEX Clearport Hub
Midwest	IL, IN, MI, MN, ND, SD, WI	Chicago Basis	0.5	Direct NYMEX Clearport Hub
		Michigan Basis	0.5	Direct NYMEX Clearport Hub
Ontario-East	ON (East)	Niagara	1	Regressed to Dominion (Appalachia) and Michigan Basis
Ontario-West	ON (West)	Dawn, Ontario	1	Regressed to Michigan Basis
South Atlantic East Region 1	VA	Texas Eastern Zone M-3	0.8	Direct NYMEX Clearport Hub
		Florida Gas, Mobile Bay	0.2	Regressed to Transco Zone 3
South Atlantic East Region 2	NC	Texas Eastern Zone M-3	0.5	Direct NYMEX Clearport Hub
		Florida Gas, Mobile Bay	0.5	Regressed to Transco Zone 3
South Atlantic East Region 3	SC	Texas Eastern Zone M-3	0.3	Direct NYMEX Clearport Hub
		Florida Gas, Mobile Bay	0.7	Regressed to Transco Zone 3
South Atlantic East Region 4	GA	Texas Eastern Zone M-3	0.1	Direct NYMEX Clearport Hub
		Florida Gas, Mobile Bay	0.9	Regressed to Transco Zone 3
South Atlantic East Region 5	AL, MS	Transco Zone 4	0.5	Regressed to Transco Zone 3
		Florida Gas, Mobile Bay	0.5	Regressed to Transco Zone 3
South Atlantic East Region 6	AR, TN	Texas Eastern Zone M-1	0.5	Regressed to East LA Basis
		Henry Hub	0.5	Direct NYMEX Clearport Hub
South Atlantic South	LA	Henry Hub	1	Direct NYMEX Clearport Hub

Local Delivery Charges

Burner tip prices for natural gas are the sum of the basis differentials by region as derived above and a local component that captures pipeline lateral charges and/or charges to local distribution companies (LDC). CRA estimates this local component at $0.07/MMBtu for all units. For older units, CRA estimates extra LDC charges derived from AGA statistics.

Gas units within the Entergy footprint do not pay LDC charges. A 6% tax is applied to gas units in Arkansas. Natural gas prices are varied seasonally based on NYMEX futures data in the near term. In the long term, the seasonal pattern for the last available year is repeated for each year.

Gas Price Forecast Summary

Table-B6 contains monthly gas price forecasts for several states within the SPP and Entergy footprint for the years to be modeled. All prices are in real 2009 dollars.

Table-B6: Gas Price Forecast Summary ($/MMBtu)

Year	Month	Kansas		Louisiana		Nebraska		Oklahoma	
		No LDC	With LDC	No LDC	With LDC	No LDC	With LDC	No LDC	With LDC
2013	1	$ 5.98	$ 6.27	$ 6.21	$ 6.30	$ 6.22	$ 6.34	$ 5.98	$ 6.20
	2	$ 5.94	$ 6.23	$ 6.17	$ 6.25	$ 6.18	$ 6.30	$ 5.94	$ 6.16
	3	$ 5.73	$ 6.02	$ 5.96	$ 6.05	$ 5.97	$ 6.09	$ 5.73	$ 5.95
	4	$ 5.17	$ 5.46	$ 5.50	$ 5.59	$ 5.44	$ 5.56	$ 5.17	$ 5.40
	5	$ 5.13	$ 5.42	$ 5.46	$ 5.54	$ 5.39	$ 5.52	$ 5.13	$ 5.36
	6	$ 5.17	$ 5.46	$ 5.49	$ 5.58	$ 5.43	$ 5.55	$ 5.17	$ 5.39
	7	$ 5.22	$ 5.51	$ 5.55	$ 5.63	$ 5.48	$ 5.61	$ 5.22	$ 5.45
	8	$ 5.27	$ 5.56	$ 5.59	$ 5.68	$ 5.53	$ 5.65	$ 5.27	$ 5.49
	9	$ 5.29	$ 5.58	$ 5.62	$ 5.70	$ 5.55	$ 5.67	$ 5.29	$ 5.51
	10	$ 5.38	$ 5.67	$ 5.70	$ 5.79	$ 5.64	$ 5.76	$ 5.38	$ 5.60
	11	$ 5.57	$ 5.86	$ 5.92	$ 6.01	$ 5.92	$ 6.04	$ 5.57	$ 5.80
	12	$ 5.82	$ 6.10	$ 6.16	$ 6.25	$ 6.16	$ 6.28	$ 5.82	$ 6.04
2016	1	$ 6.30	$ 6.57	$ 6.66	$ 6.74	$ 6.67	$ 6.79	$ 6.30	$ 6.51
	2	$ 6.26	$ 6.53	$ 6.62	$ 6.70	$ 6.63	$ 6.75	$ 6.26	$ 6.47
	3	$ 6.07	$ 6.34	$ 6.43	$ 6.51	$ 6.44	$ 6.56	$ 6.07	$ 6.28
	4	$ 5.66	$ 5.93	$ 6.00	$ 6.08	$ 5.93	$ 6.04	$ 5.66	$ 5.87
	5	$ 5.61	$ 5.88	$ 5.95	$ 6.03	$ 5.88	$ 5.99	$ 5.61	$ 5.82
	6	$ 5.66	$ 5.93	$ 6.00	$ 6.08	$ 5.93	$ 6.04	$ 5.66	$ 5.87
	7	$ 5.72	$ 5.99	$ 6.06	$ 6.14	$ 5.99	$ 6.10	$ 5.72	$ 5.93
	8	$ 5.77	$ 6.04	$ 6.11	$ 6.19	$ 6.04	$ 6.15	$ 5.77	$ 5.98
	9	$ 5.79	$ 6.06	$ 6.13	$ 6.21	$ 6.06	$ 6.17	$ 5.79	$ 6.00
	10	$ 5.87	$ 6.14	$ 6.20	$ 6.28	$ 6.13	$ 6.25	$ 5.87	$ 6.08
	11	$ 6.06	$ 6.33	$ 6.42	$ 6.50	$ 6.41	$ 6.53	$ 6.06	$ 6.27
	12	$ 6.29	$ 6.56	$ 6.65	$ 6.73	$ 6.64	$ 6.76	$ 6.29	$ 6.50
2019	1	$ 6.75	$ 7.01	$ 7.15	$ 7.22	$ 7.16	$ 7.26	$ 6.75	$ 6.96
	2	$ 6.71	$ 6.97	$ 7.11	$ 7.18	$ 7.12	$ 7.22	$ 6.71	$ 6.92
	3	$ 6.54	$ 6.80	$ 6.93	$ 7.00	$ 6.94	$ 7.05	$ 6.54	$ 6.74
	4	$ 6.03	$ 6.29	$ 6.40	$ 6.47	$ 6.32	$ 6.43	$ 6.03	$ 6.23
	5	$ 5.99	$ 6.25	$ 6.35	$ 6.43	$ 6.28	$ 6.39	$ 5.99	$ 6.19
	6	$ 6.05	$ 6.31	$ 6.41	$ 6.49	$ 6.33	$ 6.44	$ 6.05	$ 6.25
	7	$ 6.11	$ 6.37	$ 6.48	$ 6.55	$ 6.40	$ 6.51	$ 6.11	$ 6.31
	8	$ 6.16	$ 6.41	$ 6.52	$ 6.59	$ 6.44	$ 6.55	$ 6.16	$ 6.36
	9	$ 6.17	$ 6.42	$ 6.53	$ 6.60	$ 6.45	$ 6.56	$ 6.17	$ 6.37
	10	$ 6.23	$ 6.49	$ 6.59	$ 6.67	$ 6.52	$ 6.63	$ 6.23	$ 6.43
	11	$ 6.43	$ 6.68	$ 6.81	$ 6.89	$ 6.81	$ 6.92	$ 6.43	$ 6.63
	12	$ 6.67	$ 6.93	$ 7.06	$ 7.13	$ 7.05	$ 7.16	$ 6.67	$ 6.87
2022	1	$ 7.08	$ 7.33	$ 7.50	$ 7.57	$ 7.50	$ 7.61	$ 7.08	$ 7.27
	2	$ 7.04	$ 7.29	$ 7.45	$ 7.52	$ 7.46	$ 7.56	$ 7.04	$ 7.23
	3	$ 6.85	$ 7.10	$ 7.26	$ 7.34	$ 7.27	$ 7.38	$ 6.85	$ 7.04
	4	$ 6.33	$ 6.57	$ 6.71	$ 6.78	$ 6.63	$ 6.73	$ 6.33	$ 6.52
	5	$ 6.28	$ 6.53	$ 6.66	$ 6.73	$ 6.58	$ 6.69	$ 6.28	$ 6.47
	6	$ 6.34	$ 6.59	$ 6.72	$ 6.79	$ 6.64	$ 6.74	$ 6.34	$ 6.53
	7	$ 6.41	$ 6.65	$ 6.79	$ 6.86	$ 6.71	$ 6.81	$ 6.41	$ 6.60
	8	$ 6.46	$ 6.70	$ 6.84	$ 6.91	$ 6.76	$ 6.86	$ 6.46	$ 6.64
	9	$ 6.47	$ 6.71	$ 6.85	$ 6.92	$ 6.77	$ 6.87	$ 6.47	$ 6.66
	10	$ 6.54	$ 6.78	$ 6.91	$ 6.98	$ 6.83	$ 6.94	$ 6.54	$ 6.72
	11	$ 6.74	$ 6.98	$ 7.15	$ 7.22	$ 7.14	$ 7.24	$ 6.74	$ 6.93
	12	$ 7.00	$ 7.24	$ 7.40	$ 7.47	$ 7.40	$ 7.50	$ 7.00	$ 7.19

B.16.2 Fuel Oil Price Forecast

Principal Drivers

The principal drivers underlying this forecast are the projected price for light sweet crude oil at Cushing, Oklahoma.

Base Case Forecast

In the near term, the Base Scenario forecast is set equal to NYMEX futures prices for light sweet crude oil at Cushing, Oklahoma as of April 2, 2010. For later years, the forecast follows the AEO long term trend. Figure-B3 shows the CRA Base Scenario forecast for light sweet crude oil at Cushing, Oklahoma. Note that this figure shows values in 2009 dollars.

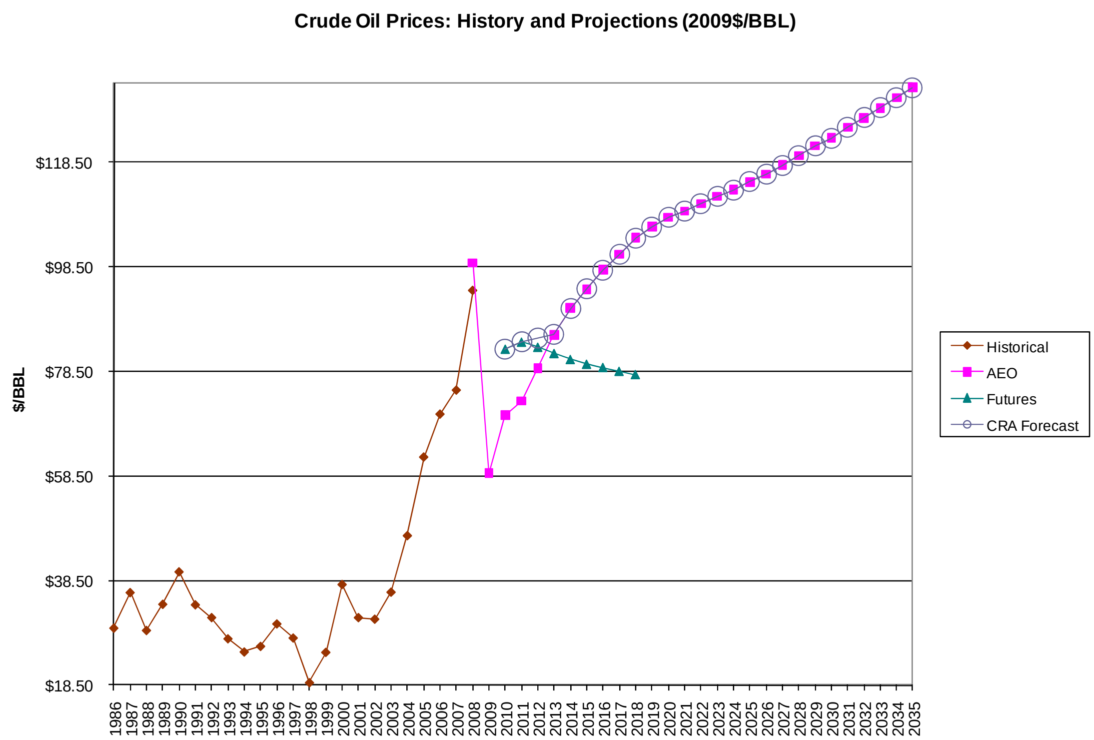

Figure-B3: Crude Oil Prices: History and Projection (in Real 2009 $/BBL)

Regional Prices

CRA forecasts prices for fuel oil #2 and #6 (1% sulfur) by US census region. This forecast is prepared in two steps. First, CRA uses a regression model calibrated to historical data to derive prices for fuel oil #2 and #6 at New York Harbor from the forecast of crude oil prices. Second, historical basis multipliers for each of the census regions are applied to the mid-Atlantic Census region (which includes New York Harbor). Both fuel oil #2 and fuel oil #6 prices are varied monthly based on NYMEX futures data in the near term and based on historical monthly patterns in the longer term.

Oil Price Forecast Summary

Table-B7 contains monthly oil price forecasts for several states within the SPP and Entergy footprint for the years to be modeled. All prices are in real 2009 dollars.

Table-B7: Oil Price Forecast Summary ($/MMBtu)

Year	Month	Kansas FO2	Kansas FO6	Louisiana FO2	Louisiana FO6	Nebraska FO2	Nebraska FO6	Oklahoma FO2	Oklahoma FO6
2013	1	$19.25	$ 8.18	$18.95	$10.41	$19.25	$ 8.18	$18.95	$10.41
	2	$19.24	$ 8.19	$18.95	$10.42	$19.24	$ 8.19	$18.95	$10.42
	3	$18.40	$ 8.19	$18.11	$10.42	$18.40	$ 8.19	$18.11	$10.42
	4	$18.29	$ 8.19	$18.01	$10.43	$18.29	$ 8.19	$18.01	$10.43
	5	$17.46	$ 8.20	$17.19	$10.43	$17.46	$ 8.20	$17.19	$10.43
	6	$17.25	$ 8.20	$16.99	$10.44	$17.25	$ 8.20	$16.99	$10.44
	7	$17.29	$ 8.21	$17.03	$10.44	$17.29	$ 8.21	$17.03	$10.44
	8	$17.60	$ 8.21	$17.33	$10.45	$17.60	$ 8.21	$17.33	$10.45
	9	$18.09	$ 8.22	$17.81	$10.45	$18.09	$ 8.22	$17.81	$10.45
	10	$18.31	$ 8.22	$18.03	$10.46	$18.31	$ 8.22	$18.03	$10.46
	11	$18.51	$ 8.22	$18.23	$10.46	$18.51	$ 8.22	$18.23	$10.46
	12	$18.80	$ 8.23	$18.51	$10.47	$18.80	$ 8.23	$18.51	$10.47
2016	1	$22.18	$ 9.47	$21.84	$12.05	$22.18	$ 9.47	$21.84	$12.05
	2	$22.18	$ 9.48	$21.84	$12.06	$22.18	$ 9.48	$21.84	$12.06
	3	$21.21	$ 9.48	$20.88	$12.07	$21.21	$ 9.48	$20.88	$12.07
	4	$21.09	$ 9.49	$20.76	$12.07	$21.09	$ 9.49	$20.76	$12.07
	5	$20.14	$ 9.49	$19.83	$12.08	$20.14	$ 9.49	$19.83	$12.08
	6	$19.90	$ 9.50	$19.59	$12.08	$19.90	$ 9.50	$19.59	$12.08
	7	$19.94	$ 9.50	$19.64	$12.09	$19.94	$ 9.50	$19.64	$12.09
	8	$20.29	$ 9.50	$19.98	$12.09	$20.29	$ 9.50	$19.98	$12.09
	9	$20.86	$ 9.51	$20.54	$12.10	$20.86	$ 9.51	$20.54	$12.10
	10	$21.11	$ 9.51	$20.78	$12.11	$21.11	$ 9.51	$20.78	$12.11
	11	$21.34	$ 9.52	$21.01	$12.11	$21.34	$ 9.52	$21.01	$12.11
	12	$21.67	$ 9.52	$21.33	$12.12	$21.67	$ 9.52	$21.33	$12.12
2019	1	$24.13	$10.33	$23.76	$13.15	$24.13	$10.33	$23.76	$13.15
	2	$24.13	$10.34	$23.75	$13.15	$24.13	$10.34	$23.75	$13.15
	3	$23.07	$10.34	$22.72	$13.16	$23.07	$10.34	$22.72	$13.16
	4	$22.94	$10.35	$22.59	$13.16	$22.94	$10.35	$22.59	$13.16
	5	$21.91	$10.35	$21.57	$13.17	$21.91	$10.35	$21.57	$13.17
	6	$21.65	$10.36	$21.32	$13.18	$21.65	$10.36	$21.32	$13.18
	7	$21.70	$10.36	$21.37	$13.18	$21.70	$10.36	$21.37	$13.18
	8	$22.08	$10.36	$21.74	$13.19	$22.08	$10.36	$21.74	$13.19
	9	$22.69	$10.37	$22.34	$13.19	$22.69	$10.37	$22.34	$13.19
	10	$22.96	$10.37	$22.61	$13.20	$22.96	$10.37	$22.61	$13.20
	11	$23.21	$10.38	$22.85	$13.21	$23.21	$10.38	$22.85	$13.21
	12	$23.57	$10.38	$23.21	$13.21	$23.57	$10.38	$23.21	$13.21
2022	1	$25.19	$10.81	$24.81	$13.75	$25.19	$10.81	$24.81	$13.75
	2	$25.19	$10.81	$24.80	$13.76	$25.19	$10.81	$24.80	$13.76
	3	$24.09	$10.82	$23.72	$13.76	$24.09	$10.82	$23.72	$13.76
	4	$23.96	$10.82	$23.59	$13.77	$23.96	$10.82	$23.59	$13.77
	5	$22.88	$10.83	$22.53	$13.77	$22.88	$10.83	$22.53	$13.77
	6	$22.62	$10.83	$22.27	$13.78	$22.62	$10.83	$22.27	$13.78
	7	$22.67	$10.84	$22.32	$13.79	$22.67	$10.84	$22.32	$13.79
	8	$23.06	$10.84	$22.70	$13.79	$23.06	$10.84	$22.70	$13.79
	9	$23.70	$10.84	$23.33	$13.80	$23.70	$10.84	$23.33	$13.80
	10	$23.98	$10.85	$23.61	$13.81	$23.98	$10.85	$23.61	$13.81
	11	$24.24	$10.85	$23.86	$13.81	$24.24	$10.85	$23.86	$13.81
	12	$24.61	$10.86	$24.23	$13.82	$24.61	$10.86	$24.23	$13.82

B.17 OTHER FUEL PRICE FORECASTS

Coal price forecasts are developed by the CRA NEEM model as described in above. Table-B8 shows the forecasted coal prices for major coal plants in SPP.

Table-B8: Coal Prices ($/MMBtu)

Plant	Capacity	State	2013	2016	2019	2022
AES Shady Point 1 & 2	320	OK	1.85	1.87	1.92	1.84
Dolet Hills	650	LA	2.00	2.06	2.19	2.09
Flint Creek	528	AR	2.18	2.20	2.24	2.14
Gentleman 1 & 2	1295	NE	1.26	1.30	1.33	1.26
GRDA 1	490	OK	2.27	2.29	2.33	2.24
GRDA 2	520	OK	2.27	2.29	2.33	2.24
Harrington 1 - 3	1021	TX	2.19	2.22	2.26	2.19
Hawthorn 5	545	MO	1.70	1.72	1.76	1.69
Holcomb	362	KS	1.94	1.97	2.00	1.91
Hugo	440	OK	2.04	2.07	2.11	2.01
Iatan 1 & 2	1556	MO	1.94	1.98	2.01	1.94
Independence 1 & 2	1678	AR	2.67	2.70	2.74	2.67
Jeffrey EC 1 - 3	2164	KS	1.81	1.85	1.87	1.79
Lacygne 2	682	KS	1.71	1.73	1.77	1.67
Lawrence EC 5	373	KS	2.06	2.08	2.13	2.05
Montrose 1 - 3	505	MO	1.69	1.72	1.76	1.69
Muskogee 4 - 6	1496	OK	2.25	2.28	2.32	2.25
Nearman Creek	200	KS	1.98	2.00	2.04	1.94
Nebraska City 1 & 2	1316	NE	1.49	1.51	1.54	1.45
North Omaha 2 - 5	478	NE	1.45	1.47	1.51	1.42
Pirkey	675	TX	2.00	2.06	2.19	2.09
Plum Point	665	AR	2.67	2.70	2.74	2.67
Rodemacher 2	512	LA	2.79	2.80	2.78	2.71
Rodemacher 3	660	LA	0.73	0.73	0.73	0.73
Roy L. Nelson 6	550	LA	2.55	2.59	2.62	2.55
Sheldon 1 & 2	225	NE	1.45	1.47	1.51	1.42
Sikeston	235	MO	2.04	2.06	2.11	2.02
Sooner 1 & 2	1046	OK	2.43	2.46	2.50	2.42
Southwest Power St. 2	275	MO	2.11	2.13	2.18	2.09
Tolk 1 & 2	1060	TX	2.02	2.06	2.09	2.02
Welsh 1 - 3	1584	TX	2.43	2.47	2.49	2.41
White 1 & 2	1640	AR	2.68	2.70	2.74	2.64

Nuclear plants are assumed to run whenever available, so nuclear fuel prices do not impact commitment and dispatch decisions in the market simulation model. CRA therefore does not do a detailed analysis of nuclear fuel prices.

Wind and hydro plants do not have fuel prices. CRA assumes that the marginal cost is $1/MWh.

B.18 NEEM FORECAST

The NEEM model is a long-term planning model that optimizes fuel and environmental compliance decisions based on the environmental scenario considered. NEEM is a linear program that minimizes total electrical system costs over a long time-horizon subject to meeting demand, reserve margin, and environmental/renewable targets. Output from CRA's North American Electricity and Environment Model (NEEM) is used to populate the MAPS model with plant-specific coal price inputs. Given that coal-fired generation is the target of many existing, pending and proposed environmental policies, the future coal selection at generating stations and the quantity of coal consumed nationally is heavily dependent upon the scenario modeled and the resultant retrofit decisions, generation levels, and new capacity additions.

NEEM contains a detailed treatment of coal supply, with 23 supply curves representing domestic production areas, imports, and different coal qualities (sulfur and Btu). These curves are built up from mine level data on production costs and annual production capability.

Coal units in the model choose coals based on the various coal options' characteristics and the plant-specific delivered price for each. The delivered prices are the sum of the mine-mouth prices and plant-specific transport costs. Each of the supply curves is divided into tranches of tonnages (typically 4 to 15 tranches). As demand rises, exhausting the annual supplies available at a given tranche, the market price for that coal rises accordingly. Mine-mouth prices for each coal type are determined by North American supply and demand. In addition, there are mine lifetime supply constraints applied to each cost tranche of each coal production area, simulating depletion. Mine depletion is of greatest relevance for the Central Appalachian production area where the total available resources are relatively small relative to annual consumption.

The individual coal supply curves have been constructed using mine level cost and available tonnage information from some 1000 mines. Costs include labor costs, permitting, and other factors. Table-B9 includes the quality parameters associated with each of the 23 coals included in the NEEM model.

Table-B9: Coal Quality Parameters

Coal	Rank	SO2 (lbs/MMBtu)	Hg (lbs/TBtu)	Btu per lb
Arizona Bituminous	Bituminous	0.93	4.2	10,915
Central Applachian, compliance	Bituminous	1.12	5.9	12,507
Central Applachian, high-sulfur	Bituminous	2.00	8.2	12,325
Central	Bituminous	4.92	12.7	12,174
Gulf Lignite	Lignite	3.37	10.8	6,840
Illinois Basin, low-sulfur	Bituminous	2.50	4.5	12,091
Illinois Basin, medium-sulfur	Bituminous	3.50	6.5	11,502
Illinois Basin, high-sulfur	Bituminous	5.00	6.3	11,665
Imports	Bituminous	1.00	5.5	12,000
Northern Appalachian, high-Btu / high-sulfur	Bituminous	4.07	12.5	12,938
Northern Appalachian, high-Btu / low-sulfur	Bituminous	2.44	12.3	12,840
Northern Appalachian, low-Btu / high-sulfur	Bituminous	3.77	20.9	11,516
Northern Appalachian, low-Btu / low-sulfur	Bituminous	1.76	16	12,098
New Mexico Bituminous	Bituminous	1.55	4.2	9,393
Plains Lignite	Lignite	2.30	10.8	6,585
PRB, Montana	Subbituminous	1.18	5.2	9,052
PRB, North	Subbituminous	0.83	7.1	8,400
PRB, South	Subbituminous	0.71	5.8	8,800
Colorado Bituminous	WesternBit	0.98	3.7	11,218
Utah Bituminous	WesternBit	1.28	4.1	11,790
Southern Appalachian	Bituminous	2.52	8.7	11,747
Wyoming Sub-bituminous	Subbituminous	1.14	3.7	9,185
Saskatchewan Lignite	Lignite	[redacted]		10,000

Not all plants are allowed to select from the full range of coals available in the model. Limitations on coal selection are a function of coal rank (bituminous, subbituminous, lignite) – NEEM requires a capital cost to change from bituminous to subbituminous, if a particular plant is not already able to burn subbituminous. Transportation access of various coals by each plant (e.g., rail access) also limits the selections. Coal selection is regulated within the model through a plant-specific coal transportation cost matrix that matches plants to coals (and the cost of transport). The matrix represents the cheapest transportation option for each coal/plant pairing (rail, truck, or barge). The plant/coal-type transport cost entries are populated based on a proprietary forecast of the $/ton-mile cost of long-haul shipments and data about the types of coal burned at each plant.

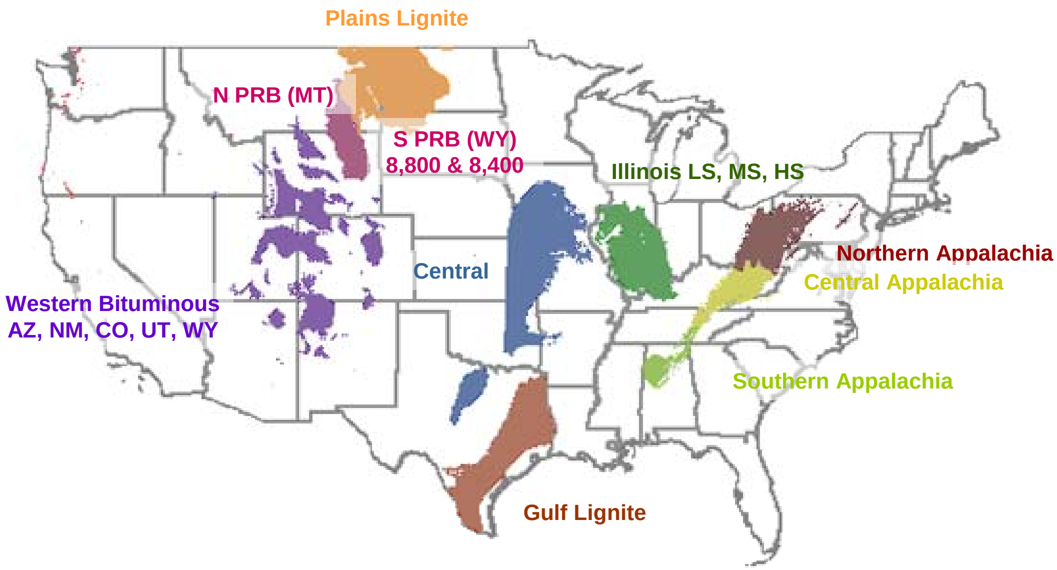

Figure-B4: Key Coal-Producing Regions in the United States

Note: Imports and Saskatchewan lignite not depicted.

The relevant coal-related output from the NEEM model is a set of coal choices by the plants in the model, a plant-specific delivered coal price for each NEEM unit by year (for each coal burned), a schedule of pollution control retrofit decisions by unit, and also emissions allowance prices.