Appendix 1- List of Entergy Proposed Projects

Year Proposed	Entergy Affiliation	Description
2008	EAI	Upgrade to Rison Risers
2008	**ETI**	**Reconductor Newton Bulk****
2009	EAI	Update Colonel Glenn 2012 Loa
2009	EAI	Add Gillett Cap Bank
2009	EGSI-LA	New Jefferson-Neser 69kV
2009	ELL-S	Upgrade S WESCO
2009	EMI	HornLake 230/161kV Xfmr and HornLake-Allen line
2009	EMI	Liberty-Gillsburg Uprate Line To 100MVA
2009	ETI	Beaumont 69kV Improvement Plan
2009	**ETI**	**Close College Station 138kV NO Switch****
2010	EAI	Upgrade SMEPA
2010	EGSI-LA	Upgrade Alchem-Monochem 138kV
2010	EGSI-LA	Upgrade Lawtag-Jennings 69kV
2010	ELL-N	Install Arcadia 36MVAr Cap Bank
2010	ELL-S_SE_LA	SE LA Coastal Improvement Phase 2
2010	ELL-S_SE_LA	SE LA Coastal Improvement Phase 3
2010	EMI	ChurchRd Add New Line and Sub
2010	ETI	Install Johnstown 138kV
2010	**ETI**	**Upgrade Porter Tamina Cedar Hill 138kV****
2011	EAI	Upgrade Cabo
2011	EAI	Update Crawford 2012 Load
2011	EAI_ELL	Sarepta + Additions
2011	EAI	Upgrade Grandview
2011	EAI	Update Hamilton 2012 Load
2011	EAI	Update HWY64 2012 Load
2011	EMI	Upgrade RayBraswell-Byram Line
2011	ETI	Install Merlin 138kV
2012	ELL-S_EGSI-LA	UpgradeColy-Hammond 230kV
2012	EMI	Madison Ridgeland Reliability
2012	EMI	Tillatoba-SouthGrenada Line and Auto
2012	**ETI**	**Western Region Reliability Improvement Phase 3 Final****

**Proposed Projects included in Status Quo Cases and ETI/SPP Integration Cases.

Appendix 2: Topology Map

This document is classified as Critical Energy Infrastructure Information ("CEII") by the Federal Energy Regulatory Commission ("FERC") and will be released upon execution of the appropriate Non-Disclosure Agreement with SPP.

Appendix 3: Market Power Study Report

Market Power Study of Entergy Texas Integration into the Southwest Power Pool

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Potomac Economics, Ltd.

December 2008

CONFIDENTIAL MATERIAL REDACTED

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

Potomac Economics has been engaged to perform an evaluation of market power related to Entergy Texas, Inc. (ETI) joining the Southwest Power Pool (SPP) and to identify mitigation options that would address any market power issues found.

This study is designed to address requirements of the Public Utility Regulatory Act (PURA) as modified by Texas Senate Bill 7.[1] There are two relevant requirements in this case. First, PURA establishes a maximum market share threshold of 20 percent for any area to be defined as a Qualified Power Region (QPR).[2] In other words, a region satisfies this test to be a QPR if no suppliers have a market share greater than 20 percent. Our analysis confirms that this test is satisfied for the combined SPP/ETI Area.[3]

Second, PURA requires that the analysis include an assessment of import capability for QPRs that are not entirely within Texas:

> In determining whether a power region not entirely within the state meets the requirements of this section, the commission shall consider the extent to which the available transmission facilities limit the delivery of electricity from generators located outside the state to areas of the power region within the state.[4]

However, PURA and subsequent Public Utility Commission of Texas (PUCT) precedent do not provide specific guidance or requirements for the analysis necessary to satisfy this section. Hence, we interpret this section as a requirement to evaluate local market power in transmission-constrained areas in the portions of the ETI service area ("the ETI Area"). Because transmission constraints can isolate areas with a relatively small number of potential suppliers, it is the local market power analysis that is most likely to indicate potential competitive concerns that may require some form of market power mitigation.

1 Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §39 (PURA).

2 PURA §39.152(a)(3).

3 Throughout this report the term "ETI Area" is used to describe the area of Texas currently served by Entergy Texas, Inc. (ETI).

4 PURA §39.152(b).

We use a number of market power indicators in this analysis. These indicators include several measures of how concentrated the ownership of supply is in the constrained areas, as well as a determination of whether the largest supplier's resources are needed to meet the demand in the area (i.e., whether the supplier is "pivotal"). Finally, because there are significant transmission constraints that bind into and within the ETI Area, we define two geographic markets for these analyses:

- The entire ETI Area; and
- The Western Subregion within the ETI Area (which is defined as the load and resources west of the Jacinto and Cypress substations).

Our analysis of the local market power issues in the ETI Area indicate limited potential competitive concerns in the ETI Area or Western Subregion. The market concentration results indicate that the market in the ETI Area will support workable competition, although the concentrations are in the highly-concentrated range. Requiring ETI to sell a portion of its capacity in the ETI Area via capacity auctions as described in PURA would substantially reduce the market concentration in the area.

With regard to the pivotal supplier analysis, most scenarios show that ETI will not be pivotal (including all analyses of the Western Subregion). In two cases where we find ETI to be pivotal, we also find that there are a number of factors that significantly ease our competitive concerns. First, ETI has a number of reliability-must-run (RMR) obligations in the area that compel its generation to run to support the reliability of the system. These obligations would prevent ETI from threatening to withhold supply.

Second, the concern in this study is whether ETI could raise prices to retail customers in the region. In scenarios that show ETI as pivotal, it is pivotal over a relatively small portion of the load. Hence, ETI would have to withhold most of its resources to raise prices to a small portion of load. Further, the magnitude of that price increase would be limited by ETI's obligations as a provider-of-last-resort (POLR). Although the specifics of the POLR pricing provisions that would apply to ETI are unknown, it is highly unlikely that they would allow a price increase large enough to make withholding profitable in this case.

Third, in the cases where ETI is pivotal, it is only in a small number of hours. The pivotal supplier analysis uses the load forecast for the annual peak of the year. In general, the load declines sharply from the annual peak hour to other hours, which limits the extent to which ETI is pivotal. In other words, ETI's resources would only be needed to serve a portion of the load when load levels are close to the annual peak.

Finally, as a Regional Transmission Organization (RTO), SPP will have a market monitor and market power mitigation measures necessary to address concerns in the region. Given the vast quantities of withholding that would be necessary to exploit ETI's pivotal supplier status, its conduct would not go unnoticed by the market monitor or the Federal Energy Regulatory Commission (FERC).

Hence, we find that market power mitigation measures are not necessary to address competitive issues in this case. However, if policymakers desire additional assurance that the market will perform competitively, implementing a 15 percent capacity auction as called for in PURA would lower concentration levels and reduce the extent to which ETI is pivotal. Unless additional transmission capacity can be built that produce net benefits to the region, capacity auctions are the most cost-effective form of market power mitigation.

II. MARKET SHARES IN THE COMBINED SPP/ETI REGION

A. Requirements of PURA

As described in the introduction, this study is designed to address the requirements of PURA. There are two relevant requirements in this case. First, PURA establishes a maximum market share threshold for any area to be defined as a Qualified Power Region (QPR):

> QUALIFYING POWER REGIONS. (a) The commission shall certify a power region if:
> (1) a sufficient number of interconnected utilities in the power region fall under the operational control of an independent organization as described by Section 39.151;
> (2) the power region has a generally applicable tariff that guarantees open and nondiscriminatory access for all users to transmission and distribution facilities in the power region as provided by Section 39.203; and
> (3) no person owns and controls more than 20 percent of the installed generation capacity located in or capable of delivering electricity to a power region, as determined according to Section 39.154.[5]

Our market share analysis addresses part (3) of this requirement. Market share analyses offer the simplest, most basic characterization of potential market power. The wholesale market share screen measures whether a seller has a dominant position in the market based on the number of megawatts of installed capacity owned or controlled by the seller as compared to the installed capacity of the entire relevant market.

To calculate the market shares, we use the maximum capacity ratings from the SPP summer 2012 power flow base case. For simplicity, each supplier's total represents a simple "steel in ground" amount.[6] Affiliated companies' generation was aggregated to the parent/holding company. The totals do not reflect contract sales or purchases, transmission limitations, or other complications.[7] The analysis is also conservative because it does not reflect the import

5 PURA §39.152.

6 The one exception to this is the Tenaska Gateway plant. Gateway is switchable between the Eastern Interconnect and ERCOT, but can only deliver 195 MW of its 1,132 MW into SPP.

7 PUCT Subst. R. §25.401 provides detailed guidance on calculating the installed generation shares. Our analysis does not address four points in the detailed guidelines. Our calculation did not consider: (1) affiliated generators located outside of the region; (2) generators located on the boundary between regions; (3) grandfathered generating capacity located within ozone non-attainment areas; and (4) transmission import capability into the region. The most significant factor in this analysis would be the inclusion of some additional supply owned by ETI's affiliates outside of the SPP/ETI Region. However, ETI's market share would remain

(Footnote is continued on the next page.)

capability from outside the SPP/ETI Area. Hence, capacity shares are understated because imported supply is not included. Table 1 shows our analysis:

Table 1: Market Shares in the SPP/ETI Area

Supplier	Capacity	Share of Combined Regions
American Electric Power Co., Inc.	9,754	18.5%
Westar Energy Inc.	6,568	12.4%
OGE Energy Corp.	5,812	11.0%
Xcel Energy, Inc.	4,195	7.9%
Great Plains Energy Corp.	4,039	7.6%
Tenaska, Inc.	2,348	4.4%
ETI	*2,300*	*4.4%*
Calpine Corp.	1,352	2.6%
Western Farmers Electric Coop	1,292	2.4%
Empire District Electric Co.	1,263	2.4%
Kelson Energy	1,250	2.4%
Bechtel Group, Inc.	1,200	2.3%
All others less than 2%	11,449	21.7%
Total	52,823	100.0%

This analysis shows that ETI has a capacity share of 4.4 percent and that no supplier has a market share greater than 20 percent. Hence, the market share QPR requirement is satisfied for the combined SPP/ETI Area.

well below 20 percent even if this capacity were included (to the extent import capability would allow it to be delivered into the area). Given the total supply in the region, the other factors would also not likely cause the 20 percent market share threshold to be violated.

III. LOCAL MARKET POWER ANALYSIS FOR THE ETI AREA

A. Requirements of PURA and Market Power Metrics

PURA requires that the analysis include an assessment of import capability for QPRs that are not entirely within Texas:

> In determining whether a power region not entirely within the state meets the requirements of this section, the commission shall consider the extent to which the available transmission facilities limit the delivery of electricity from generators located outside the state to areas of the power region within the state.[8]

PURA and subsequent PUCT precedent do not provide specific guidance or requirements for the analysis necessary to satisfy this section. Hence, we interpret this section as a requirement to evaluate local market power in transmission-constrained areas in the ETI Area. To produce a robust evaluation of potential local market power, we analyze two measures of market power in both the ETI Area and the Western Subregion. For each measure, we conduct multiple scenarios that address alternative assumptions regarding obligations to serve load and the participation of a key supplier in the ETI Area. These alternatives are described in the following subsections.

1. Measures of Market Power

To evaluate the competitiveness of the market in both the ETI Area and Western Subregion, we perform the following two analyses.

Market Concentration Analysis: A common measure of market concentration used by economists is the Herfindahl-Hirschman Index (HHI). The HHI is a standard measure of market concentration calculated by summing the square of each supplier's market share. The index ranges from 0 to 10,000, increasing as suppliers' market shares increase and as the number of suppliers serving the market falls. The antitrust agencies generally characterize markets with HHIs greater than 1,800 as highly concentrated.[9] Concentration statistics can indicate the likelihood of coordinated interaction in a market. All else being equal, the higher the HHI, the

8 PURA §39.152(b)

9 The DOJ and FTC evaluate the *change* in HHI as part of standard merger analysis. However, this is only a preliminary analysis that would typically be followed by a more rigorous evaluation of the likely price effects of the merger.

more likely it is that firms would be able to extract excess profits from the market. Due to the prevalence of excess capacity in most hours and other factors that tend to mitigate market power in electricity markets, it is reasonable to conclude that markets with HHIs less than 2,500 are likely to be workably competitive. This is consistent with the range that Mr. Schnitzer established as a market power mitigation target in his prior study of the competitive issues associated with integrating the ETI Area into SPP.[10]

The market share assessment and HHI statistics provide only general indicators of market concentration in electric power markets, not definitive measures of market power.[11] The usefulness of these statistics is limited by the fact that they reflect only the supply-side, and ignore demand-side factors affecting competition. Also, these statistics are relatively static in orientation, which limits their value for characterizing the constantly changing balance of resources and load affecting market power in electric markets. Since electricity cannot be stored economically in large scale, production must match demand on a real-time basis. When demand rises, a larger share of generation is used to satisfy the demand. This means there are fewer alternative resources remaining that could increase output to counteract the actions of a supplier seeking to withhold resources. Hence, markets with higher resource margins tend to be more competitive, but both the market share and HHI statistics neglect this aspect of the market. Pivotal supplier analysis, discussed next, addresses this shortcoming.

Pivotal Supplier Analysis: A more reliable means to evaluate the competitiveness of electricity markets and recognize the dynamic nature of market power in these markets is to identify when one or more suppliers are "pivotal". A supplier is pivotal when the output of some of its resources is needed to meet demand in the market. A pivotal supplier has the ability to unilaterally raise the market prices by withholding its supply. However, a pivotal supplier will only have market power if it has the *incentive* to engage in this conduct. In other words, it must be profitable for the supplier to withhold its supply.

10 Report of Michael Schnitzer, Entergy Gulf States, Inc.'s Transition to Competition Plan at para. 85 (December 29, 2006)

11 For example, see Severin Borenstein, James B. Bushnell, and Christopher R. Knittel, "Market Power in Electricity Markets: Beyond Concentration Measures," *Energy Journal* 20(4), 1999, pp. 65-88.

To determine whether a particular supplier is pivotal, we remove the resources of this supplier from the total available resources and compare this to the total demand for energy and reserves. Total available resources include those located in the market area as well as those that can be supplied to the market through import capability. If internal resources and import capability (excluding those of the supplier in question) are sufficient to satisfy the demand, the supplier is not pivotal. Alternatively, if the internal resources and import capability without the supplier are not sufficient to satisfy the demand, the supplier is pivotal.

2. Data Sources

The data for our analysis comes primarily from the SPP summer 2012 power flow base case. This includes the maximum physical capability of each generating unit as well as the maximum transmission capacity between the ETI Area and the rest of SPP. For jointly-owned units, ownership shares were identified using data provided by Entergy, SPP, and Platts. Data on long-term firm transactions was provided by Entergy.

3. Scenarios

We evaluate a range of concentration and pivotal supplier scenarios in order to reflect two important aspects of the market. First, we incorporate certain assumptions about suppliers' load obligation in our analysis. Second, we consider the uncertain status of the Cottonwood facility owned by Kelson Energy. This facility has initiated a process to disconnect from the Eastern Interconnect and interconnect to ERCOT.

Load Obligations

The obligation to serve load, whether by long-term contract or regulation, has a significant effect on this analysis. Although this study is intended to reflect full retail competition, we recognize that load obligations will likely exist at some level. In most areas where retail competition has been introduced, a limited portion of the native load has switched to alternative suppliers. Additionally, utilities in Texas may be required to serve as the provider-of-last-resort for retail customers in their area. This obligation includes pricing for such service that is regulated by the PUCT.

These load obligations have a significant effect on market power findings because a supplier will not have an incentive to withhold resources it needs to serve its load. Resources that cannot be withheld should be accounted for in the analysis of a firm's market power. The changing load obligations under retail competition complicate assumptions regarding market concentration and pivotal supplier calculations.

We consider three scenarios to reflect alternative assumptions regarding the portion of existing load suppliers will be obligated to serve. We include a zero-percent load obligation case, a 50-percent load obligation case, and 100-percent load obligation case. A zero-percent load obligation case reflects full retail competition with no obligation to serve current retail customers. The *installed capacity* measure described below is used for this case because it includes no offset for load obligations.

When load obligations are non-zero (i.e., in the 50-percent and 100-percent load obligation cases), then the market share and pivotal supplier calculations are based on an *uncommitted capacity* analysis. Uncommitted capacity is calculated based on the installed capacity minus the load obligations of each supplier. This metric better addresses how obligations to serve load at a fixed price affect a supplier's incentives to exercise market power.

The 100-percent load obligation case assumes no retail load switching. The 50-percent load obligation case reflects the load switching experience in ERCOT where we understand that approximately 40 percent of load has switched under the retail access program.

Cottonwood Plant

The second aspect of the market supply that we include in the market concentration and pivotal supplier calculations involves the Cottonwood generating facility owned by Kelson Energy. This facility is currently physically connected to the ETI Area in the Eastern Interconnect, but has initiated a process to disconnect from the Eastern Interconnect and interconnect to ERCOT. Depending on the resolution of that case, the facility will either be connected to ERCOT or it will be connected to the SPP/ETI Area. Therefore, we calculate one set of scenarios assuming Cottonwood is in the SPP/ETI Area and another set assuming it is in ERCOT.

In the next section, we present the results of the concentration analyses. In section C, we present the results of the pivotal supplier analysis.

B. Market Concentration Results: ETI Area

In this section we present the market concentration results for the ETI Area. We provide three separate analyses. In subsection 1, we present the market concentration analysis for the zero-percent load obligation case, which is equivalent to the installed capacity analysis. In addition, we present various mitigation scenarios to illustrate their effect on the market concentration. The second and third analyses involve uncommitted capacity analyses for the 100-percent load obligation case and the 50-percent load obligation case. These two analyses are presented in subsection 2. Because the results of these two analyses indicate no potential competitive concerns, we did not analyze the effects of mitigation.

1. Installed Capacity Results

As discussed above, the installed capacity results are equivalent to a zero-percent load obligation case. In other words, all of the capacity owned by each supplier is included in the market, even if it is needed to satisfy load obligations in reality. Table 1 shows the installed capacity HHI calculation in the ETI Area for the case that assumes the Cottonwood facility remains in the ETI Area.

The table shows each supplier's physical capacity within the ETI Area as well as capacity imports. There are 960 MW of capacity purchases with 839 MW from sources outside the ETI Area. Most of the outside imports are from Entergy units in Louisiana serving ETI load, although some imports serve municipal entities. We assume Cottonwood is available at 600 MW and that Tenaska's Frontier unit is limited to 300 MW due to limits on the firm transmission available for these resources. Available transfer capability (ATC) indicates the unused capacity on the interfaces into the ETI Area. We assume the unused ATC cannot be withheld, so we attribute a market share of zero to the ATC in the HHI calculation.

Table 1: Market Concentration in ETI Area: Installed Capacity
Cottonwood Included

Supplier	Owned capacity	Capacity Purchases/ Imports	Capacity Sales	Net Capacity	Share
ArcLight Capital Prtrs/Reliant Energy	115	-	-	115	1.7%
ConocoPhillips/NRG Energy	555	-	-	555	8.0%
Dupont	75	-	-	75	1.1%
East Texas Electric Coop, Inc.	340	239	-	579	8.3%
ETI	*2,300*	*643*	-	*2,943*	*42.3%*
Exxon Mobil Corp.	495	-	-	495	7.1%
Kelson Energy	600			600	8.6%
SRMPA	-	77	-	77	1.1%
Sabine River Authority of Louisiana	91	-	91	-	0.0%
Southwestern Power Administration	52	-	52	-	0.0%
Tenaska, Inc.	300	-	-	300	4.3%
ATC				1,224	0.0%
Total	4,923	960	143	6,964	
				HHI:	**2,068**

Note: Withholding of ATC is assumed to be impossible so market share is assumed to be zero. Reliability investments have no effect on ATC. Cottonwood (Kelson Energy) limited to 600 MW, Frontier (Tenaska) limited to 300 MW. Jointly-owned plants operated jointly.

Table 1 shows that ETI has a market share of 42.3 percent. The HHI in the ETI Area is 2,068. Due to the potential that Cottonwood may disconnect from the Eastern Interconnect we made the same calculations, but with Cottonwood's capacity removed. However, removing Cottonwood caused an increase in ATC of 131 MW, partially offsetting the capacity loss. The HHI in this alternative case (not shown) rose to 2,292.

The HHI for both cases is within the range that should support a workably competitive market. Additionally, HHI values must be evaluated in light of other factors. In this case, these factors include load obligations, excess capacity, reliability-must-run (RMR) obligations, and other factors that may increase or decrease the competitiveness of the market. As discussed in the next section, these factors tend to mitigate potential competitive concerns. Considering the HHI values and these other factors, we conclude that these results do not raise significant competitive concerns.

Nonetheless, we performed sensitivity analyses presented below that show how the market concentration in the ETI Area would be affected by two types of mitigation measures. The first is the expansion of the transmission capacity into the ETI Area to raise ATC values and allow increased competition from external suppliers. The second is capacity sales by ETI that would reduce ETI's market share.

For capacity sales we use 500 MW because it is approximately 15 percent of ETI's capacity in the area. Fifteen percent is the divestiture floor value in PURA. Table 2 shows the results of the mitigation analyses.

Table 2: Summary of HHI Impact of Mitigation Measures

Case	ATC Mitigation (MW)	Cap Sale Mitigation (MW)	ETI Share	Total Capacity (MW)	HHI
Cases with Cottonwood @ 600 MW					
No Mitigation	0	0	42.3%	6,964	2,068
500 MW ATC Mitigation	500	0	39.4%	7,464	1,810
500 MW Capacity Sale (~15% Sale)	0	500	34.8%	6,963	1,544
Cases with Cottonwood @ 0 MW					
No Mitigation	0	0	45.3%	6,495	2,292
500 MW ATC Mitigation	500	0	42.1%	6,995	1,976
500 MW Capacity Sale (~15% Sale)	0	500	37.6%	6,495	1,712

The table shows that both mitigation approaches are effective at reducing the HHI to less than 2,000. Capacity sales are generally more effective because they reduce the market share of the largest supplier (ETI) more directly. With Cottonwood out of the market, a 500 MW capacity sale mitigation reduces the HHI to 1,713 while the same amount of new transmission reduces it to 1,976.

The installed capacity analysis ignores the effects of load obligations, excess capacity, and RMR obligations. These are better captured in the uncommitted capacity and pivotal supplier analyses discussed below.

2. Uncommitted Capacity Results

The next analysis of uncommitted capacity shares accounts for load obligations by subtracting the peak load obligation from the suppliers' total resources. It is a variation on the installed capacity market analysis which implicitly assumes a zero percent load obligation.

The uncommitted capacity measure is typically a more accurate indicator of market power because it reflects the mitigation effects of load obligations (i.e. there is no incentive to withhold resources needed to serve load). We calculated the uncommitted capacity values for a 100-percent load obligation case and a 50-percent load obligation case. Table 3 shows the analysis for the 50-percent load obligation case with Cottonwood included.

Table 3: Market Concentration Analysis ETI Area: Uncommitted Analysis
50-Percent Load Obligation Case; Cottonwood Included

Supplier	Owned Capacity	Firm Purchases /Imports	Firm Sales	Net Capacity	Load Obligation	Uncommitted Capacity	Share of Uncommitted Capacity
ETI	2300	643	0	2943	2066	877	20.3%
Kelson Energy	600	0	0	600	0	600	13.9%
Tenaska, Inc.	300	0	0	300	0	300	6.9%
East Texas Electric Coop, Inc.	340	189	0	529	479	50	1.2%
Exxon Mobil Corp.	495	0	0	495	0	495	11.4%
ConocoPhillips/NRG Energy	555	0	0	555	0	555	12.8%
SRMPA	0	127	0	127	89	38	0.9%
Dupont	75	0	0	75	0	75	1.7%
ArcLight Capital Partners/Reliant Energy	115	0	0	115	0	115	2.7%
Sabine River Authority of Louisiana	91	0	91	0	0	0	0.0%
Southwestern Power Administration	52	0	52	0	0	0	0.0%
ATC	1224	0	0	1224	0	1224	0.0%
Total	4923	960	143	5740	2634	4329	
						HHI	**958**

Note: Cottonwood (Kelson Energy) limited to 600 MW and Frontier (Tenaska) limited to 300. Withholding of ATC assumed to be impossible so market share is 0. Jointly-owned plants assumed to be operated jointly.

The table shows the owned physical capacity located in the ETI Area, as well as the capacity that is imported or exported over the interconnections into the ETI Area. Uncommitted capacity is defined as the net capacity less the load obligation. The uncommitted capacity value is the basis for the market shares and the HHI. The resulting HHI is 958, which indicates that the market is not concentrated.

Table 4 shows the 100-percent load obligation case. Uncommitted Capacity is reported as zero when load obligation is greater than net capacity. The table shows that the HHI in this case is also low at 861.

Table 4: Market Concentration Analysis ETI Area: Uncommitted Analysis
100-Percent Load Obligation Case; Cottonwood Included

Supplier	Owned Capacity	Firm Purchases /Imports	Firm Sales	Net Capacity	Load Obligation	Uncommitted Capacity	Share of Uncommitted Capacity
ETI	2300	643	0	2943	4131	0	0.0%
Kelson Energy	600	0	0	600	0	600	17.4%
Tenaska, Inc.	300	0	0	300	0	300	8.7%
East Texas Electric Coop, Inc.	340	189	0	529	479	50	1.4%
Exxon Mobil Corp.	495	0	0	495	0	495	14.3%
ConocoPhillips	555	0	0	555	0	555	16.1%
NRG Energy, Inc.	0	0	0	0	0	0	0.0%
SRMPA	0	127	0	127	89	38	1.1%
Dupont	75	0	0	75	0	75	2.2%
ArcLight Capital Partners, LLC	115	0	0	115	0	115	3.3%
Reliant Energy	0	0	0	0	0	0	0.0%
Sabine River Authority of Louisiana	91	0	91	0	0	0	0.0%
Southwestern Power Administration	52	0	52	0	0	0	0.0%
ATC	1224	0	0	1224	0	1224	0.0%
Total	4923	960	143	5740	4700	3452	
						HHI	**861**

Note: Cottonwood (Kelson Energy) limited to 600 MW and Frontier (Tenaska) limited to 300. Withholding of ATC assumed to be impossible so market share is 0. Jointly-owned plants assumed to be operated jointly.

The results of both of the uncommitted capacity cases indicate that there are no competitive concerns. These low levels of market concentration can be explained by the fact that the load obligations substantially reduce ETI's available supply to service others. In fact, in the 100 percent case, ETI is a net buyer.[12] Because these results raise no competitive concerns, there is no need to show the effects of potential mitigation measures on the uncommitted capacity market concentration.

12 In the case with Cottonwood removed the HHIs are slightly lower. Hence, those case also do not reveal competitive concerns.

C. Pivotal Supplier Results: ETI Area

Our next analysis seeks to determine if any suppliers may be "pivotal" in the ETI Area under peak demand conditions. A supplier is pivotal if its resources are necessary to satisfy the load and reserves within the area (in this case, the ETI Area). Pivotal supplier analyses provide a more reliable indicator of market power than HHI analyses in electricity markets because they capture the effects of excess capacity and other factors that affect the competitiveness of the market.

We determine whether a supplier is pivotal by comparing the demand in the area to the total supplies in the area, less uncommitted resources owned by the supplier in question. If the demand cannot be satisfied with these supplies, the supplier is pivotal. Only uncommitted resources of the supplier are removed from the total supply because only uncommitted capacity can be profitably withheld by the supplier.

We examine six cases in Table 5. We determine whether ETI is pivotal in cases assuming a load obligation of 100 percent, 50 percent, and 0 percent. These three cases are examined both with and without the Cottonwood facility.

Table 5: Pivotal Supplier Analysis in the ETI Area

	ETI Net Supply	ETI Load Obligation	Uncommit. ETI Supply	ETI Area Supply	ETI Area Supply w/o ETI	ETI Area Load + Reserves	Pivotal
Cases with Cottonwood at 600 MW							
100% Load Obligation	2943	4131	0	6964	6964	4841	*No*
50% Load Obligation	2943	2066	877	6964	6086	4841	*No*
0% Load Obligation	2300	0	2300	6964	4664	4841	*Yes*
Cases with Cottonwood Removed							
100% Load Obligation	2943	4131	0	6495	6495	4841	*No*
50% Load Obligation	2943	2066	877	6495	5617	4841	*No*
0% Load Obligation	2300	0	2300	6495	4195	4841	*Yes*

All values in MW. ETI net supply decreases in no-load obligation case because ETI is assumed to no longer control firm transmission into ETI.

The table shows the ETI net supply, which includes its internal generating resources and the import capability ETI can control by designating external resources to be imported to serve the load. In the zero-percent load obligation case, ETI's net capacity declines because we assume that ETI will not have the ability to hold the firm transmission into the ETI Area. This assumption is based on the fact that firm transmission is acquired by designating network resources outside the ETI Area to serve load within the area. If a supplier has no load to serve, it will not have the ability to designate network resources and occupy the firm transmission into the ETI Area. Accordingly, ETI is no longer entitled to the 643 MW of network transmission rights reflected in the 100-percent and 50-percent load obligation cases.

The pivotal supplier calculation is performed on the right-hand side of the table where the total ETI Area supply (including import capability) is reduced by ETI's uncommitted capacity, and compared to the total demand in the area (i.e., load plus reserve requirements).[13] ETI is pivotal if the supply in the area not controlled by ETI does not exceed the total demand in the area. The results of our analysis show that ETI is only pivotal in the 0 percent load case, both with and without Cottonwood. With Cottonwood included, only roughly 180 MW of demand could not be served without ETI's resources. Without Cottonwood, the unsatisfied demand could climb to approximately 650 MW. Because ETI has 2300 MW of supply, it would therefore have to withhold roughly 1650 MW in the case without Cottonwood to raise prices to the residual 650 MW of peak load in the ETI Area.

The indication that ETI is pivotal in these cases raises potential competitive concerns. However, this does not mean that it actually has market power. In order to have market power, ETI must have the ability to withhold the resources necessary to raise prices and profit by doing so. Based on our review of the relevant factors that bear on ETI's ability and incentives to withhold resources, we find that market power mitigation should not be necessary to achieve a workably competitive market in the ETI Area. This finding is based, in part, on the following factors:

First, a significant portion of ETI's capacity is reliability-must-run, which means that they must be operated to support the transmission system. Because RMR resources cannot be withheld by the supplier, they should not be included in the pivotal supplier test. ETI is not pivotal if it cannot withhold such capacity.

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13 Reserves are assumed to be three percent of load.

Second, ETI will likely continue to be obligated to serve load as a provider-of-last-resort. POLR prices in ERCOT are capped relative to prevailing wholesale prices. It is unclear what "price-to-beat" or POLR provisions would be applied in the ETI Area. However, because ETI would have to withhold the majority of its resources in order to receive the price-to-beat or POLR price from the remaining retail customers, such a strategy would only be economic if the PUCT allowed extremely high POLR pricing. We believe that this is unlikely and withholding of this magnitude, therefore, is unlikely to be economic.

Third, in the cases where ETI is pivotal, it is only pivotal in a small number of hours. The pivotal supplier analysis uses the load forecast for the annual peak of the year. In general, the load declines sharply from the annual peak hour to other hours, which limits the extent to which ETI is pivotal. In other words, ETI's resources would only be needed to serve a portion of the load when load levels are close to the annual peak.

Finally, as an RTO, SPP will have a market monitor and market power mitigation measures necessary to address market power in the region. Given the vast quantities of withholding that would be necessary exploit ETI's pivotal supplier status, its conduct would not go unnoticed by the market monitor or FERC.

IV. Analysis of Local Market Power in Western Subregion of ETI Area

In this section of the report, we review the market concentration and the pivotal supplier analyses for the Western Subregion of the ETI Area. The Western Subregion is defined as the load and resources in the ETI Area west of the Jacinto and Cypress substations. We analyze it separately because transmission constraints limit the extent to which load in the area can be served by resources outside of the Western Subregion. Section A below contains the market concentration analysis of the Western Subregion while Section B contains the pivotal supplier analysis.

Based on information from ETI, we assume a transfer capability into the Western Subregion from the rest of ETI of [redacted]. Like the analyses for the entire ETI Area, we produce results for three scenarios with varying load obligation assumptions. Cottonwood is not located in the Western Subregion so we do not model the alternative Cottonwood scenarios. Tenaska's Frontier unit is located in the Western Subregion and we do continue to limit that unit to 300 MW in each of the analyses.

A. Market Concentration Results: Western Subregion

As with the broader ETI Area, we produce market concentration results for three scenarios. One scenario for installed capacity (zero-percent load obligation case) and two for the uncommitted capacity case (50-percent load obligation case, and 100-percent load obligation case).

Like the previous analyses, we assume the rights to the transfer capability (which can be used to serve a large share of the load in the area) can only be held by entities serving load in the area. Because the installed capacity analysis assumes no load obligation, the [redacted] of transfer capability is open to all market participants. In the 50-percent and 100-percent cases, we assume that ETI controls the portion of the interface capability into the Western Subregion that corresponds to the load that they serve in the area. In other words, we assume that they can serve their load with resources outside of the Western Subregion, effectively preventing competing suppliers from using this capability.

We assume any transfer capability not held by suppliers within the Western Subregion is available on a competitive basis with no single firm having a significant market share (or the ability to prevent others from using the import capability). These assumptions are bolstered by the fact that the SPP will operate a real-time market that will fully use the transmission capability into the area. This real-time market will provide a supplemental source of supply for competitive retail suppliers. For purposes of these analyses, the assumption that transmission capability will be competitively available is reflected by attributing a market share of zero for the transfer capability.

Table 6: Market Concentration in Western Subregion: Installed Capacity

Redacted

The market concentration analysis for the Installed Capacity case is shown above in Table 6. The HHI in this case is well below the 1,000 level. This indicates that the market is unconcentrated and raises no significant competitive concerns.

The analysis of uncommitted capacity under a 50-perent-load-obligation scenario is shown in Table 7.

Table 7: Concentration of Uncommitted Capacity Western Subregion
50-Percent-Load-Obligation

Redacted

ETI's net capacity in the Western Subregion grows from 456 MW in the Installed Capacity case to [redacted] in this case because we assume that it will have the ability to control [redacted] of the [redacted] of total transfer capability. Likewise, East Texas Electric Cooperative is assumed to control firm import capacity needed to serve its 50-percent load obligation. The smaller quantity of remaining rights is released to the market. These changes increase the market share of ETI and the overall market concentration. As the table shows, the HHI in this case is 1,560. It remains well below levels that would raise competitive concerns.

The analysis of uncommitted capacity in the 100-perent-load-obligation scenario results in a very high HHI. However, all load serving entities have sufficient capacity to serve their own load so competitive concerns are limited.

In summary, the three market concentration analyses in this subsection do not raise significant market power concerns in the Western Subregion.

B. Pivotal Supplier Results: Western Subregion

In this section, we present our pivotal supplier analysis for the Western Subregion. Like the concentration analysis, we consider three load-obligation scenarios (0 percent, 50 percent, and 100 percent). ETI's net supply in the 100 percent load obligation case is equal to its load obligation. This occurs because ETI's load obligation is greater than its physical generating capacity in the Western Subregion. Therefore, ETI uses the transfer capability to serve the balance of its load.

In the 50-percent load obligation case, ETI is able to retain transfer rights up to its assumed load obligation (50 percent of its current load). Hence, the ETI net supply in that case is the ETI load obligation plus ETI's physical generation capacity in the subregion (456 MW). In the zero-percent load obligation case, ETI net supply is equal to its physical capacity because it cannot retain network transmission rights without load obligations.

A summary of the pivotal supplier analysis of the Western Subregion is shown in Table 8. The pivotal supplier calculations are shown on the right-hand side of the table. The total ETI area supply is reduced by ETI uncommitted capacity and compared to the Western Subregion load plus reserves. Reserves are assumed to be three percent of load.

Table 8: Pivotal Supplier Analysis – Western Subegion

Redacted

In summary, the table shows that ETI is not pivotal in any of the cases. Even if they were, however, market power concerns would be substantially mitigated by the fact [redacted].

These results confirm the conclusions from the market concentration analyses that there are not significant competitive concerns associated with satisfying the demand in the Western Subregion.

V. Conclusion

The results of our analyses of the ETI Area and the Western Subregion in ETI do not raise substantial competitive concerns. Hence, we find that market power mitigation measures are not necessary to address competitive issues in this case.

However, a subset of the market power measures we present in this report do indicate potential concerns. In particular, the market concentration levels both with and without Cottonwood are at the high end of levels that we would consider workably competitive. Additionally, ETI is pivotal in cases where it has no load obligations. However, there are a number of factors that mitigate any potential competitive concerns raised by these results. These factors include:

- ETI has a number of RMR obligations that compel its generation to run to support the reliability of the system, which would prevent it from withholding its supply.
- It is unlikely to be profitable for ETI to exercise market power as ETI would have to withhold most of its resources to raise prices to a small portion of load. Further, the magnitude of that price increase would be limited by ETI's potential POLR obligations.
- ETI is pivotal in only a small number of hours when load is near the annual peak.
- SPP will have a market monitor and market power mitigation necessary to address market power in the region.

Nonetheless, if policymakers desire additional assurance that the market will perform competitively, implementing a capacity auction for 15 percent or more of ETI's capacity as called for in PURA would lower concentration levels and reduce the extent to which ETI is pivotal. Unless additional transmission capacity can be built that produces net benefits to the region, the capacity auctions are likely the most cost-effective form of market power mitigation.

Appendix 4: Energy Construction Plan

Posted at

http://oasis.e-terrasolutions.com/documents/EES/2009-11%20ETR%20Construction%20Plan%20(April%2017%202008%20Rev%20-%20Final).pdf

Appendix 5: STEP Plan

Posted at

http://www.spp.org/publications/2007%20SPP%20Transmission%20Expansion%20Plan%2020080131_BOD_Public.pdf

Appendix 6: SPP-Entergy SPP_ETI Integration Summary Stability Report

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The SPP-Entergy Stability Study to Evaluate the Proposed SPP/Entergy Texas System Integration

Project 18554-21-00
Summary Report # 18554-21-00-3

December 02, 2008

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Contents

List of Tables

Page

1 Introduction

Currently, Entergy owns and operates a portion of the electric grid in the eastern part of Texas, which is known as Entergy Texas, Inc. (ETI). As part of ETI's transition to competition proposal, one of the options being considered by ETI is to move its service territory into the Southwest Power Pool (SPP). In order to determine how to integrate ETI into SPP reliably, Entergy and SPP have embarked on a joint study divided into two phases, namely, steady state analysis and stability analysis.

As part of the steady state analysis, a minimum set of reliability and economic projects required to meet the minimum transfer requirements into ETI, as well as the North-American Electric Reliability Corporation (NERC) and SPP reliability criteria, is identified. In the proposed stability study, the initial set of projects that have been agreed upon by SPP and Entergy will be included in the model and extensive stability analysis will be performed in the Eastern Interconnect (EI) portion of Entergy and SPP to meet NERC reliability criteria. If stability problems are identified, additional reinforcements will be added until all NERC and Entergy/SPP criteria are addressed.

Powertech Labs, Inc. (PLI) has been contracted to conduct this phase of the study, which is concerned with voltage security, transient security, and small-signal stability issues. Voltage security will include voltage stability/collapse, bus voltage magnitude decline/rise, and branch overload issues, which are also collectively referred to as static studies. Dynamic studies, on the other hand, will contain those related to transient security and small signal stability, namely, transient stability/separation, transient voltage dips, and damping issues.

Note that this report is concerned with the results of a high level study to address the above issues, in which the scope is reduced to a handful of specified contingencies. The full study concerning a thorough contingency screening is due to be performed in near future.

2 Model Development

2.1 Simulation Tools

The studies were based on computer simulations using the following programs of PLI's DSA*Tools*™ software (http://www.dsatools.com):

- Power-flow and Short-circuit Analysis Tool (PSAT).
- Voltage Security Assessment Tool (VSAT).
- Transient Security Assessment Tool (TSAT).

These programs automatically convert the power flow and dynamic data from PSS/E format. Special (non-convertible) models were set up through the User-Defined Model (UDM) capability of the software. The following features of these programs were also used for sanity checking of data:

- Power flow data checking capability of PSAT and VSAT.
- Dynamic data checking capability of TSAT.
- Visual checks using various data tabulations.

2.2 Base Power Flows

In this study, Entergy and SPP initially supplied three base power flow cases representing the whole EI system. These cases are as follows:

1. 2012 Summer Peak Loading Condition with Cottonwood Generation and without Series Compensation of Mt. Olive – Hartburg 500 kV line (12S+CW-SC).
2. 2012 Summer Peak Loading Condition without Cottonwood Generation and with 30% Series Compensation of Mt. Olive – Hartburg 500 kV line (12S-CW+SC).
3. 2012 Summer Peak Loading Condition without Cottonwood Generation and without Series Compensation of Mt. Olive – Hartburg 500 kV line (12S-CW-SC).

The summaries of the base cases are shown in Table 2-1.

Table 2-1: Base Power Flow Summaries.

Base Case	Generation MW / MVAR		Load MW / MVAR	
	EI	ETI	EI	ETI
12S+CW-SC	729852 / 160003	3087 / 893	711449 / 199657	4688 / 1489
12S-CW+SC	729865 / 160161	2985 / 907	711441 / 199657	4684 / 1489
12S-CW-SC	729869 / 160172	2984 / 942	711441 / 199657	4684 / 1489

2.3 Dynamic Data

Entergy-SPP provided the dynamic data of the EI system, including the ETI area, matching the base power flows. PLI added the controls data for the existing HVDC links in the EI system. Data issues were insignificant and mostly remote to Entergy and SPP.

2.4 Load Models

Throughout the EI system, constant power load was used in static studies for both active and reactive components. In dynamic studies, constant impedance, constant current, and constant power (ZIP) load models were implemented based on the conversion percentages for various areas and buses provided by Entergy and SPP.

2.5 Study Regions

The focus of this project was to examine the integrated system within ETI and relevant parts of the Entergy and SPP systems around it. The corresponding regions were defined as follows:

- ETI region (considered as part of Entergy but monitored in both Entergy and SPP evaluations): Area 551 (ETI).
- Nearby Entergy region: Areas 331 (BCA), 332 (LAGN), 334 (WESTMEMP), 335 (CONWAY), 336 (BUBA), 337 (PUPP), 338 (DERS), 339 (DENL), and 351 (EES).
- Nearby SPP region: Areas 502 (CELE), 503 (LAFA), 504 (LEPA), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), and 526 (SPS).

All buses at 115 kV and higher, as well as all 100 MVA or larger generating units, were monitored in the corresponding regions for bus voltage, branch current, and other criteria violations, in both static and dynamic studies.

2.6 Applied Criteria

For the Entergy and SPP, as well as the ETI grid (assessed by Entergy criteria), the applied criteria is as follows:

- Voltage decline: 0.92 pu for all 115 kV and higher buses, in the study region.
- Branch overload: 100% of rating "A" for 115 kV and higher in the study region of Entergy, and 100% of rating "B" for 115 kV and higher in the study region of SPP.
- Transient stability: all units remaining in synchronism.
- Dynamic voltage: 115 kV and higher buses having no more than 20% dips, lasting no more than 20 cycles for single contingencies, and 40 cycles for double contingencies, in the study region.
- Damping: 5%.

The above criteria were applied to pre-contingency conditions of the three base cases, as well as when subjected to contingencies described in the next subsection.

2.7 Applied Contingencies

Entergy and SPP provided specific lists of N-2 contingencies each consisting of a single branch, either transmission line or transformer, and a generating unit. Table 2-2 through Table 2-5 show these contingencies for both static and dynamic studies. Note that in the cases without Cottonwood, Nelson unit 6 (G6) is used instead of Cottonwood steam and gas unit pair (G5). Furthermore, L1 and L3 were used in three sensitivity scenarios described in Section 3.3.

Table 2-2: Entergy Contingencies for Static Studies.

Cont. # & Name		Branch					Generator		
		From Bus # & Name		To Bus # & Name		ID	Bus # &Name		ID
1	G1+L1	334204	6CHINA 230.	334200	6PORTER 230.	1	334070	G1LEWIS 22.0	1
2	G2+L2	334206	6JACINTO230.	334204	6CHINA 230.	1	334758	JAC U1 13.8	1
3	G3+L3	334325	8HARTBRG500.	334320	8CYPRESS500.	1	334298	CYPR U1 13.8	1
4	G4+L4	334204	6CHINA 230.	334434	6SABINE 230.	1	334440	G4SABIN 24.0	1
5	G5+L5	337368	8MTOLIV 500.	334325	8HARTBRG500.	1	303027 303026	1S4INTHB13.8 1G4INTHB18.0	1
6	G6+L6	334325	8HARTBRG500.	335192	8NELSON 500.	1	335206	G6NELSON20.0	1

Table 2-3: SPP Contingencies for Static Studies.

Cont. # & Name		Branch					Generator		
		From Bus # & Name		To Bus # & Name		ID	Bus # &Name		ID
1	G1+X1	500250	DOLHILL7345.	500260	DOLHILL6230.	1	501813	G3RODEMR22.0	1
2	G1+X4	500470	LEESV 6 230.	500480	LEESV 4 138.	1	501813	G3RODEMR22.0	1
3	G1+L2	500250	DOLHILL7345.	507760	SW SHV7 345.	1	501813	G3RODEMR22.0	1
4	G1+L5	500280	ELEESV6 230.	500770	RODEMR 6230.	1	501813	G3RODEMR22.0	1
5	G2+L1	508572	LEBROCK7345.	508585	TENRUSK7345.	1	509403	PIRKEY1 23.4	1
6	G2+L6	508298	LYDIA 7 345.	510911	VALIANT7345.	1	509403	PIRKEY1 23.4	1
7	G2+L7	510907	PITSB-7 345.	515136	SUNNYSD7345.	1	509403	PIRKEY1 23.4	1
8	G5+L1	508572	LEBROCK7345.	508585	TENRUSK7345.	1	515225	MUSKOG5G18.0	1
9	G5+L6	508298	LYDIA 7 345.	510911	VALIANT7345.	1	515225	MUSKOG5G18.0	1
10	G5+L7	510907	PITSB-7 345.	515136	SUNNYSD7345.	1	515225	MUSKOG5G18.0	1

Table 2-4: Entergy Contingencies for Dynamic Studies.

Cont. # & Name		Branch					Generator		
		From Bus # & Name		To Bus # & Name		ID	Bus # &Name		ID
1	G1+B1	334067	6LEWISCR230.	334072	4LEWIS 138.	1	334070	G1LEWIS 22.0	1
2	G1+B2	334072	4LEWIS 138.	334090	4ALDEN 138.	1	334070	G1LEWIS 22.0	1
3	G2+B3	334206	6JACINTO230.	334208 334207	4JACINTO138. 1JACINTO13.8	1	334758	JAC_U1 13.8	1
4	G3+B4	334320	8CYPRESS500.	334326	6CYPRESS230.	1	334298	CYPR U1 13.8	1
5	G3+B5	334206	6JACINTO230.	334326	6CYPRESS230.	1	334298	CYPR U1 13.8	1
6	G4+B6	334204	6CHINA 230.	334434	6SABINE 230.	1	334440	G4SABIN 24.0	1

7	G4+B7	334434	6SABINE 230.	335070	6CARLYSS230.	1	334440	G4SABIN 24.0	1
8	G5+B8	334325	8HARTBRG500.	335192	8NELSON 500.	1	303027 303026	1S4INTHB13.8 1G4INTHB18.0	1
9	G5+B9	334325	8HARTBRG500.	334320	8CYPRESS500.	1	303027 303026	1S4INTHB13.8 1G4INTHB18.0	1
10	G6+B10	335192	8NELSON 500.	335190	6NLSON 230.	1	335206	G6NELSON20.0	1

Table 2-5: SPP Contingencies for Dynamic Studies.

Cont. # & Name		Branch					Generator		
		From Bus # & Name		To Bus # & Name		ID	Bus # &Name		ID
1	G1+X1	500250	DOLHILL7345.	500260	DOLHILL6230.	1	501813	G3RODEMR22.0	1
2	G1+X4	500470	LEESV 6 230.	500480	LEESV 4 138.	1	501813	G3RODEMR22.0	1
3	G1+L2	500250	DOLHILL7345.	507760	SW SHV7 345.	1	501813	G3RODEMR22.0	1
4	G1+L5	500280	ELEESV6 230.	500770	RODEMR 6230.	1	501813	G3RODEMR22.0	1
5	G2+L1	508572	LEBROCK7345.	508585	TENRUSK7345.	1	509403	PIRKEY1 23.4	1
6	G2+L6	508298	LYDIA 7 345.	510911	VALIANT7345.	1	509403	PIRKEY1 23.4	1
7	G5+L7	500250	DOLHILL7345.	500260	DOLHILL6230.	1	501801	G1DOLHIL24.0	1
8	G5+L1	500470	LEESV 6 230.	500480	LEESV 4 138.	1	501801	G1DOLHIL24.0	1
9	G5+L6	500250	DOLHILL7345.	507760	SW SHV7 345.	1	501801	G1DOLHIL24.0	1
10	G5+L7	500280	ELEESV6 230.	500770	RODEMR 6230.	1	501801	G1DOLHIL24.0	1

For transient simulations the single branch outages were first simulated with a 3-phase fault at either end to identify the more significant end. The N-2 contingencies were then simulated with the 3-phase fault at this end. The applied fault durations are presented in Table 2-6. Unsymmetrical faults were not considered in this project, as the zero sequence data corresponding to the new configuration was not available.

Table 2-6: Applied Durations for the 3-Phase Faults.

Voltage Level	Fault Duration (Cycles)
500 kV	4
345 kV	5
230 kV	6
161 kV	6
138 kV	6
115 kV	6

Multiple contingencies, where two or more branches are tripped simultaneously, were also supplied as follows:

- 9 multiple contingencies in Entergy system, which were identified as contingencies 800, 801, 802, 803, 806, 807, 809, 810, and 811.
- 46 multiple contingencies in SPP system, which were identified as DOLHILL6, RICHARD, RAPIDES6, AEPW-01, AEPW-02, AEPW-04, AEPW-05, AEPW-06, AEPW-07, AEPW-08, AEPW-09, AEPW-10, AEPW-11, AEPW-12, AEPW-14, AEPW-

15, AEPW-17, AEPW-18, AEPW-19, AEPW-20, AEPW-21, AEPW-22, AEPW-23a, AEPW-23b, AEPW-24, AEPW-25, AEPW-26, AEPW-27, AEPW-28, CELE-01, CELE-02, CELE-03, GRDA-01, KCPL-01, KCPL-02, OKGE-01, SWPA-01, SWPA-02, SWPA-03, SWPA-04, SWPA-05, SWPA-06, SWPA-07, SWPA-08, SWPA-09, SWPA-10.

These contingencies were also applied in both static and dynamic simulations, where a 3-phase fault at the first bus (with appropriate duration) is assumed for the latter.

2.8 Applied Transfers

For both static and dynamic studies the following transfer was considered for stressing the system:

- **Source:** Generation increase, 50% in areas 515, 520, 523, and 524 (i.e., SPP) and 50% in area 351 (i.e., Entergy).
- **Sink:** Load increase, 100% in area 551 (i.e., ETI).

Furthermore, three sensitivity scenarios (described in Section 3.3) were studied with a transfer having the same source as above, but with generation decrease of G1LEWIS, G2LEWIS, G1SABIN, G2SABIN, G3SABIN, G4SABIN, and G5SABIN as the sink.

3 Voltage Security Studies

In voltage security studies Under-Load Tap Changer (ULTC) and switched shunt controls were enabled for both pre- and post-contingency analyses. Moreover, typical governor action (i.e., 4% droop) of the Entergy and SPP areas was also considered in post-contingency situations.

3.1 Voltage Security Findings in the Entergy System

Before applying the transfer, there was one bus voltage violation at 335385 (4LEROY 138.) and one branch overload of 337678 (3BISMRK 115.) – 3377685 (3HSEHVW 115.) – '1'. The former was fixed through an IDEV file supplied by Entergy and the latter was ignored (far from focus region). The Voltage Stability (VS) limits of the three base cases after applying the transfer are summarized in Table 3-1.

Table 3-1: Voltage Stability Limits for Entergy Contingencies.

Base Case	VS Limit (MW)	Limiting Contingency
12S+CW-SC	600	G1+L1
12S-CW+SC	450	G1+L1
12S-CW-SC	450	G1+L1

The bus voltage violations and branch overloads at the VS limits are summarized in Table 3-2 and Table 3-3, respectively, which are not very severe. The decline column in Table 3-2 is the amount of voltage that goes below the criterion of 0.92 pu (e.g., 0.02 pu decline would indicate 0.90 pu bus voltage).

Table 3-2: Top 10 Bus Voltage Violations at VS Limit for Entergy Contingencies.

Base Case	Bus # & Name		Decline (PU)	Critical Contingency
12S+CW-SC	334059	4WYNTEX 138.	0.0245	G1+L1
	334057	4HUNTSVL138.	0.0242	G1+L1
	334058	L558T485138.	0.0229	G1+L1
	334056	L558TP91138.	0.0210	G1+L1
	334052	4CEDAR 138.	0.0198	G1+L1
	334060	4MT.ZION138.	0.0196	G1+L1
	334051	4BISHOP 138.	0.0193	G1+L1
	334053	4CINCINT138.	0.0189	G1+L1
	334043	4TUBULAR138.	0.0184	G1+L1
	334050	4PEE DEE138.	0.0183	G1+L1
12S-CW+SC	334059	4WYNTEX 138.	0.0274	G1+L1
	334057	4HUNTSVL138.	0.0264	G1+L1
	334058	L558T485138.	0.0247	G1+L1
	334056	L558TP91138.	0.0239	G1+L1
	334052	4CEDAR 138.	0.0224	G1+L1

	334053	4CINCINT138.	0.0224	G1+L1
	334054	4WALKER 138.	0.0214	G1+L1
	334051	4BISHOP 138.	0.0212	G1+L1
	334060	4MT.ZION138.	0.0206	G1+L1
	334050	4PEE DEE138.	0.0195	G1+L1
12S-CW-SC	334059	4WYNTEX 138.	0.0338	G1+L1
	334057	4HUNTSVL138.	0.0328	G1+L1
	334058	L558T485138.	0.0313	G1+L1
	334056	L558TP91138.	0.0304	G1+L1
	334052	4CEDAR 138.	0.0290	G1+L1
	334053	4CINCINT138.	0.0289	G1+L1
	334054	4WALKER 138.	0.0279	G1+L1
	334051	4BISHOP 138.	0.0279	G1+L1
	334060	4MT.ZION138.	0.0273	G1+L1
	334050	4PEE DEE138.	0.0263	G1+L1

Table 3-3: Branch Loading Violations at VS Limit for Entergy Contingencies.

Base Case	From Bus # & Name		To Bus # & Name		ID	% Load	Critical Contingency
12S+CW-SC	335368	8WELLS 500.	335500	8WEBRE 500.	1	115.7	G6+L6
	334067	6LEWISCR230.	334072	4LEWIS 138.	1	109.4	G6+L5
	334281	4FORK CK138.	334282	4RAYBURN138.	1	107.9	G6+L5
	334334	4LEACH 138.	334335	4TOLEDO 138.	1	106.0	G3+L3
	334333	4NEWTONB138.	334334	4LEACH 138.	1	104.1	G1+L1
	334327	6AMELIA 230.	334360	6HELBIG 230.	1	101.5	G3+L3
	334391	4CARROLS138.	334396	47NECHES138.	2	117.3	810
	334438	6HANKS 230.	334445	6GULFWAY230.	1	106.3	807
12S-CW+SC	334334	4LEACH 138.	334335	4TOLEDO 138.	1	110.1	G6+L5
	335192	8NELSON 500.	335190	6NLSON 230.	1	108.3	G6+L6
	334333	4NEWTONB138.	334334	4LEACH 138.	1	108.3	G6+L5
	334281	4FORK CK138.	334282	4RAYBURN138.	1	106.9	G3+L3
	334067	6LEWISCR230.	334072	4LEWIS 138.	1	105.9	G1+L1
	334391	4CARROLS138.	334396	47NECHES138.	2	112.9	810
	334438	6HANKS 230.	334445	6GULFWAY230.	1	103.8	807
12S-CW-SC	335192	8NELSON 500.	335190	6NLSON 230.	1	117.1	G6+L5
	334334	4LEACH 138.	334335	4TOLEDO 138.	1	110.4	G6+L6
	334333	4NEWTONB138.	334334	4LEACH 138.	1	108.6	G6+L5
	334281	4FORK CK138.	334282	4RAYBURN138.	1	108.3	G3+L3
	334067	6LEWISCR230.	334072	4LEWIS 138.	1	105.6	G1+L1
	334391	4CARROLS138.	334396	47NECHES138.	2	112.7	810
	334438	6HANKS 230.	334445	6GULFWAY230.	1	104.3	807

3.2 Voltage Security Findings in the SPP System

Before applying the transfer, there were six bus voltage violations at 500010 (ABBEVL 4138.), 503306 (ABBVILL4138.), 502404 (BONIN 4138.), 500380 (GUIDRY 4138.), 500720 (PLAISAN4138.), and 505588 (STIGLER5138.), and two branch overloads of 502403

(BONIN 6230.) – 502404 (BONIN 4138.) – '1' and 502404 (BONIN 4138.) – 335379 (4SCOTT1 138.) – '1'. The first three voltage violations and the two branch overloads were fixed through an IDEV file supplied by SPP and the three remaining voltage violations were ignored. The Voltage Stability (VS) limits of the three base cases after applying the transfer are summarized in Table 3-4.

Table 3-4: Voltage Stability Limits for SPP Contingencies.

Base Case	VS Limit (MW)	Limiting Contingency
12S+CW-SC	950	G2+L1 or G5+L1
12S-CW+SC	800	G2+L1 or G5+L1
12S-CW-SC	750	G2+L1 or G5+L1

These limits are much higher than those of Entergy contingencies. As a result, for SPP contingencies there were no bus voltage or branch loading violations at the minimum limits reported in Table 3-1.

3.3 Voltage Security Findings of Sensitivity Scenarios

Three sensitivity scenarios were studied for all three base power flows as described in Table 3-5. Their Voltage Stability (VS) limits after applying the corresponding transfer (i.e., generation increase in EI against generation decrease in ETI) are summarized in Table 3-6.

Table 3-5: Sensitivity Scenarios for Each of The Three Base Cases.

Scenario #	Additional Unit Outage at Pre-contingency	Contingency
1	–	G2LEWIS Unit + Porter – China 230 kV Line
2	G1LEWIS	G2LEWIS Unit + Porter – China 230 kV Line
3	G5SABIN	G4SABIN Unit + Cypress – Hartburg 500 kV Line

Table 3-6: Voltage Stability Limits for Sensitivity Scenarios.

Base Case	VS Limit (MW)		
	Scenario 1	Scenario 2	Scenario 3
12S+CW-SC	>1000	>1000	650
12S-CW+SC	>1000	350	400
12S-CW-SC	>1000	100	350

The bus voltage violations and branch overloads at the limits of Table 3-5 are summarized in Table 3-7 and Table 3-8, respectively.

Table 3-7: Top 10 Bus Voltage Violations at VS Limit for Sensitivity Scenarios.

Base Case	Bus # & Name		Decline (PU)	Scenario #
12S+CW-SC	None (up to 1000 MW Transfer)			1
	334057	4HUNTSVL138.	0.0330	2
	334028	7GRIMES 345.	0.0327	2
	334029	7FRONTR 345.	0.0327	2
	334058	L558T485138.	0.0323	2
	334059	4WYNTEX 138.	0.0309	2
	334060	4MT.ZION138.	0.0305	2
	334043	4TUBULAR138.	0.0301	2
	334044	4DOBBIN 138.	0.0300	2
	334023	4NAVSOTA138.	0.0297	2
	334024	4SOTA 1138.	0.0279	2
	334028	7GRIMES 345.	0.0423	3
	334029	7FRONTR 345.	0.0423	3
	334442	6KEITHLA230.	0.0391	3
	334443	6SOSIDE 230.	0.0383	3
	334444	6SLTGRAS230.	0.0382	3
	334436	6P AC BK230.	0.0370	3
	334435	6MID CO 230.	0.0334	3
	334437	6KOLBS 230.	0.0297	3
	334438	6HANKS 230.	0.0272	3
	334445	6GULFWAY230.	0.0187	3
12S-CW+SC	None (up to 1000 MW Transfer)			1
	334057	4HUNTSVL138.	0.0352	2
	334059	4WYNTEX 138.	0.0347	2
	334058	L558T485138.	0.0333	2
	334056	L558TP91138.	0.0315	2
	334044	4DOBBIN 138.	0.0290	2
	334060	4MT.ZION138.	0.0285	2
	334053	4CINCINT138.	0.0271	2
	334054	4WALKER 138.	0.0264	2
	334066	4GEORGIA138.	0.0263	2
	334052	4CEDAR 138.	0.0262	2
	334442	6KEITHLA230.	0.0500	3
	334443	6SOSIDE 230.	0.0492	3
	334444	6SLTGRAS230.	0.0491	3
	334436	6P AC BK230.	0.0479	3
	334435	6MID CO 230.	0.0443	3
	334437	6KOLBS 230.	0.0404	3
	334438	6HANKS 230.	0.0380	3
	334028	7GRIMES 345.	0.0336	3
	334029	7FRONTR 345.	0.0336	3
	334445	6GULFWAY230.	0.0297	3
12S-CW-SC	None (up to 1000 MW Transfer)			1
	334057	4HUNTSVL138.	0.0343	2
	334059	4WYNTEX 138.	0.0342	2
	334058	L558T485138.	0.0322	2
	334056	L558TP91138.	0.0310	2
	334044	4DOBBIN 138.	0.0275	2
	334053	4CINCINT138.	0.0269	2

	334060	4MT.ZION138.	0.0268	2
	334054	4WALKER 138.	0.0263	2
	334066	4GEORGIA138.	0.0261	2
	334052	4CEDAR 138.	0.0257	2
	334442	6KEITHLA230.	0.0518	3
	334443	6SOSIDE 230.	0.0509	3
	334444	6SLTGRAS230.	0.0508	3
	334436	6P AC BK230.	0.0496	3
	334435	6MID CO 230.	0.0462	3
	334437	6KOLBS 230.	0.0420	3
	334438	6HANKS 230.	0.0397	3
	334028	7GRIMES 345.	0.0387	3
	334029	7FRONTR 345.	0.0387	3
	334445	6GULFWAY230.	0.0316	3

Table 3-8: Branch Loading Violations at VS Limit for Sensitivity Scenarios.

Base Case	From Bus # & Name		To Bus # & Name		ID	% Load	Scenario #
12S+CW-SC	335368	8WELLS 500.	335500	8WEBRE 500.	1	103.5	1
	334067	6LEWISCR230.	334072	4LEWIS 138.	1	111.5	2
	335368	8WELLS 500.	335500	8WEBRE 500.	1	110.0	2
	334334	4LEACH 138.	334335	4TOLEDO 138.	1	125.2	3
	334362	6INLAND 230.	334363	6HARTBRG230.	1	123.9	3
	334333	4NEWTONB138.	334334	4LEACH 138.	1	123.5	3
	334281	4FORK CK138.	334282	4RAYBURN138.	1	121.0	3
	334361	6MCLEWIS230.	334362	6INLAND 230.	1	119.4	3
	334361	6MCLEWIS230.	334368	6NEW OC 230.	1	118.8	3
	334363	6HARTBRG230.	334325	8HARTBRG500.	2	117.7	3
	334363	6HARTBRG230.	334325	8HARTBRG500.	1	117.7	3
	335368	8WELLS 500.	335500	8WEBRE 500.	1	113.9	3
	334280	4DOUCETT138.	334281	4FORK CK138.	1	113.5	3
	335088	4MRSHAL 138.	335125	4MOSSVL 138.	1	111.7	3
	335125	4MOSSVL 138.	335200	4NELSON 138.	1	105.6	3
	335089	4HOLYWOD138.	335200	4NELSON 138.	1	104.1	3
12S-CW+SC	None (up to 1000 MW Transfer)						1
	334067	6LEWISCR230.	334072	4LEWIS 138.	1	115.4	2
	334334	4LEACH 138.	334335	4TOLEDO 138.	1	122.8	3
	334333	4NEWTONB138.	334334	4LEACH 138.	1	121.2	3
	334281	4FORK CK138.	334282	4RAYBURN138.	1	120.8	3
	334280	4DOUCETT138.	334281	4FORK CK138.	1	113.3	3
	334362	6INLAND 230.	334363	6HARTBRG230.	1	112.0	3
	335088	4MRSHAL 138.	335125	4MOSSVL 138.	1	110.1	3
	334363	6HARTBRG230.	334325	8HARTBRG500.	2	108.2	3
	334363	6HARTBRG230.	334325	8HARTBRG500.	1	108.2	3
	334361	6MCLEWIS230.	334362	6INLAND 230.	1	107.7	3
	334361	6MCLEWIS230.	334368	6NEW OC 230.	1	107.0	3
	335125	4MOSSVL 138.	335200	4NELSON 138.	1	106.7	3
	335089	4HOLYWOD138.	335200	4NELSON 138.	1	103.1	3
12S-CW-SC	None (up to 1000 MW Transfer)						1
	334067	6LEWISCR230.	334072	4LEWIS 138.	1	116.3	2

	334334	4LEACH 138.	334335	4TOLEDO 138.	1	125.2	3
	334333	4NEWTONB138.	334334	4LEACH 138.	1	123.5	3
	334281	4FORK CK138.	334282	4RAYBURN138.	1	121.6	3
	334280	4DOUCETT138.	334281	4FORK CK138.	1	114.1	3
	335088	4MRSHAL 138.	335125	4MOSSVL 138.	1	109.4	3
	334362	6INLAND 230.	334363	6HARTBRG230.	1	109.4	3
	335125	4MOSSVL 138.	335200	4NELSON 138.	1	106.6	3
	334363	6HARTBRG230.	334325	8HARTBRG500.	2	105.9	3
	334363	6HARTBRG230.	334325	8HARTBRG500.	1	105.9	3
	334361	6MCLEWIS230.	334362	6INLAND 230.	1	105.0	3
	334361	6MCLEWIS230.	334368	6NEW OC 230.	1	104.3	3
	335089	4HOLYWOD138.	335200	4NELSON 138.	1	102.5	3

4 Transient Security Studies

The transient simulations included the application of the specified Entergy and SPP contingencies both before and after the transfer. Damping was checked by Prony analysis of the time domain results. All simulations were stable and there were no criteria violations in any of the three base cases both before and after 1000 MW of transfer. The three sensitivity scenarios (described in Section 3.3) were also simulated, which showed no violations up to 1000 MW of their corresponding transfer.

The worst scenario was the tripping of 500250 (DOLHILL7345.) – 507760 (SW SHV7 345.) – circuit '1', along with 501813 (G3RODEMR22.0) unit '1', after a 5-cycle 3-phase fault at the first side (i.e., SPP N-2 contingency G1+L2). The worst transient voltage dip occurred at 500206 (DOLHILL6230.) with about 14 cycles duration, both before and after 1000 MW of transfer. This situation remained virtually the same for the three base cases.

5 Conclusions

Integration of the Entergy Texas, Inc. (ETI) grid into the SPP system was studied from voltage and transient security points of view. Three base cases representing 2012 summer peak conditions were considered, namely, with and without Cottonwood units, as well as adding 30% series compensation to Mt. Olive – Hartburg 500 kV line of the case without Cottonwood.

In this study a number of specific N-1 (consisting of one branch, either line or transformer), N-2 (consisting of one branch and one generating unit), and multiple contingencies (consisting of two or more branches) were considered. In dynamic simulations, 3-phase faults with appropriate fault durations were applied. The system was stressed through a transfer of generation from specific Entergy and SPP areas (i.e., increasing generation) to ETI (i.e., increasing load). The areas corresponding to the ETI grid and its surrounding regions in the Entergy and SPP systems were monitored for violations based on the Entergy and SPP criteria, whichever applicable.

With Cottonwood, voltage security analysis showed that 600 MW could be transferred against load increase in ETI before any voltage collapse. Without Cottonwood this limit was reduced to 450 MW, which remained virtually the same with or without series compensation of Mt. Olive – Hartburg 500 kV line. The limiting contingency was the combination of Lewis Creek unit '1' and China – Porter 230 kV line. The simulations showed no voltage security issues before the transfer. However, some moderate branch loading and bus voltage decline violations were observed as the transfer approached the corresponding voltage stability limits.

Sensitivity studies revealed that without Cottonwood the voltage stability limit could reduce to 100 MW of transfer against generation reduction in ETI if Lewis Creek unit 1 was out of service. This limit increased to 350 MW as a result of Mt. Olive – Hartburg 500 kV line series compensation. Similarly, if Sabine unit 5 was out of service these limits were 350 MW and 400 MW, respectively.

Transient security analysis revealed no criteria violation (i.e., transient stability, transient voltage dip, and damping) for any of the simulated contingencies, both before and after 1000 MW of transfer.

Appendix 7: ROA Functionality Chart

SOUTHWEST POWER POOL

Results by Functional Area

ROA Activity	ERCOT	SPP
Customer Registration	• Initial Company/Profile data set up	• Initial Company/Profile data set up
Scheduling	• None	• All REPS will be treated as TCs and be required to follow TC processes and procedures
Wholesale Settlements	• Initial set-up and load profiling	• New process for receiving data from ETI – SCR727 • New process for Data validation • New process for Load profiling
Invoicing	• None	• Non-ERCOT REP fee will need to be reviewed. Any associated administration fees will be allocated to REPs through SPP Settlements • SPP will invoice TCs (or their agents) for balancing energy and associated fees

SPP.ORG 4

Appendix 8: ERCOT High Level Impact Analysis

Impact Analysis Date	October 14, 2008
Scope of Request	**Southwest Power Pool / Entergy Texas Inc. / Retail Open Access** • ERCOT to assist Entergy Texas, Inc. (ETI) and affiliate Retail Electric Provider (REP) to complete the Retail Market Testing • ERCOT to assist ETI working with Profiling Working Group for Weather Zone and Profile Tree approvals • ERCOT to assist ETI with Profile ID assignments • ERCOT to assist ETI with Load Research Sampling • ERCOT to assist ETI to submit appropriate transactions to Load ~ 425,000 Electric Service Identifiers (ESI IDs) into ERCOT's registration database • ERCOT to assist ETI affiliated REP to submit appropriate transactions to move-in ~ 425,000 ESI IDs • ERCOT to assist ETI to submit appropriate initial meter reads for the ESI IDs • ERCOT to produce ESI ID Service History and Usage Extract (aka SCR727 extract) – full – for ETI to give to Southwest Power Pool (SPP) o No new data elements are currently requested to be added to extract for SPP needs • ERCOT to support the retail activities in the ETI territory of Texas. • ERCOT to produce ongoing ESI ID Service History and Usage Extract daily for ETI to give to SPP
Cost/Budgetary Impact	Estimated cost: $250,000 – 500,000 ERCOT's system cost estimated to be $250,000 ERCOT's labor cost estimated to be $186,030

	Breakdown of labor costs - ERCOT's labor cost for supporting retail TDSP qualification is estimated to be $134,550. • Retail Client Relations ongoing support and Market Participant registration (includes agreements, setup, communications and digital certificates) – $19,370. • Load Profiling ongoing support and work with Profiling Working Group - $47,450. • Retail Customer Choice ESI ID registration and monitoring - $27,560 • Market Operations Testing support for certification – $10,920 • Data Integrity and Analysis ongoing support for ESI ID account registration, extracts, and training - $29,250 ERCOT's labor cost for supporting ETI's LSE preparedness and qualification is estimated to be $51,480. • Retail Client Relations ongoing support and Market Participant registration (includes agreements, setup, communications and digital certificates) – $19,370 • Retail Customer Choice ESI ID registration and monitoring - $11,440.