DOCKET NO. ________

APPLICATION OF THE CITY OF LUBBOCK THROUGH LUBBOCK POWER AND LIGHT FOR AUTHORITY TO CONNECT A PORTION OF ITS SYSTEM WITH THE ELECTRIC RELIABILITY COUNCIL OF TEXAS	§ § § § § § §	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

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APPLICATION OF THE CITY OF LUBBOCK THROUGH LUBBOCK POWER AND LIGHT FOR AUTHORITY TO CONNECT A PORTION OF ITS SYSTEM WITH THE ELECTRIC RELIABILITY COUNCIL OF TEXAS

TO THE HONORABLE PUBLIC UTILITY COMMISSION OF TEXAS:

The City of Lubbock, through Lubbock Power & Light (LP&L), files this Application for Authority to Connect a Portion of Its System with the Electric Reliability Council of Texas (ERCOT). By this Application and its subsequent direct case, LP&L seeks Commission authority to disconnect a portion of its system from that of the Southwest Power Pool (SPP) and connect to ERCOT, along with related findings that will facilitate LP&L's integration into the ERCOT system, consistent with the public interest. In support thereof, LP&L would show the following.

I. APPLICANT

LP&L is the municipally-owned electric utility of the City of Lubbock. In total, LP&L serves approximately 600 MW of load—consisting of more than 100,000 customers—in and around Lubbock. As detailed in Section III, below, this Application addresses approximately 470 MW of load (the Affected Load) currently served under a wholesale contract with Southwestern Public Service (SPS) that, pursuant to a recent agreement, will expire on May 31, 2021.

II. APPLICANT'S AUTHORIZED REPRESENTATIVES

LP&L's authorized representatives are:

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LP&L requests that all pleadings and other documents filed in this proceeding be served on Lambeth Townsend using the contact information listed above.

III. BACKGROUND

This Application is filed after a period of study, analysis, and discussion by the Commission, ERCOT, SPP, LP&L, and other interested parties that dates to 2015. In the discussion that follows, LP&L recounts the process that led to this filing, and sets forth other factors that provide context for LP&L's Application.

A. LP&L/City-Level Process

This Application addresses a goal of integration with ERCOT that first materialized in 2014. In that year, LP&L issued a Request for Proposal (RFP) for a new wholesale power supply for the Affected Load.[1] This load is currently served under a wholesale power supply

[1] LP&L acquired distribution facilities serving approximately 170 MW in Lubbock from SPS in 2010. LP&L's partial requirements contract with SPS related to that load expires in 2044 and is not addressed by this Application.

contract with SPS that expires on May 31, 2019. LP&L's RFP invited not just SPP-sourced proposals, but those originating from ERCOT as well. After considering the RFP responses—which, notably, did not include a response from SPS—LP&L began evaluating the possibility of a transition to ERCOT for the Affected Load. On October 20, 2015, LP&L's Electric Utility Board and the City of Lubbock's City Council both took formal action to authorize LP&L to seek interconnection of the Affected Load with ERCOT.[2]

To permit more time for ERCOT, SPP, and the Commission to consider the issues implicated by LP&L's request to connect the Affected Load to ERCOT, in late 2016, LP&L began discussions with suppliers regarding a new wholesale "bridge" agreement to extend its SPP-based power supply for two additional years. On March 23, 2017, LP&L and SPS announced the execution of a new contract that provides for LP&L's power supply through May 31, 2021. As a result, LP&L now seeks integration of the Affected Load with the ERCOT system on June 1, 2021.

B. ERCOT/Commission Procedural History

The formal processing of issues related to LP&L's potential integration of the Affected Load into ERCOT began with the submittal of its ERCOT Integration Study to ERCOT's Regional Planning Group (RPG) on December 9, 2015. In its Integration Study, LP&L considered and proposed certain transmission facilities that would result in the integration of the relevant portion of LP&L's own system with that of ERCOT. Interested parties had the opportunity to file comments on that transmission plan at RPG within the ERCOT process, and did so on January 19, 2016. In February 2016, the Commission initiated Project No. 45633,[3] and

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[2] *See* Attachment A for the Electric Utility Board and City Council Resolutions.

[3] *Project to Identify Issues Pertaining to Lubbock Power & Light's Proposal to Become Part of the Electric Reliability Council of Texas*, Project No. 45633.

in March, requested that comments and reply comments from parties on particular questions be filed in April 2016. A workshop was held in Project No. 45633 on May 3, 2016 to consider those comments. In that same timeframe, LP&L completed the required Non-Opt-In-Entity (NOIE) Load Zone Establishment form and submitted it to LP&L's ERCOT Account Manager.[4]

On June 17, 2016, ERCOT filed its own Study of the Integration of the Lubbock Power & Light System into the ERCOT System in Project No. 45633.[5] That study determined that a configuration of transmission projects with three connection points between the ERCOT grid and the LP&L system—designated as Option 4ow—would present the lowest societal costs once capital costs and production cost effects were considered.[6] Later that month, LP&L filed a statement indicating that it would be performing a study to gauge the effect of its integration into ERCOT on customers in ERCOT and SPP, as well as its own system,

At its June 29 Open Meeting, the Commission discussed procedural and substantive issues arising from LP&L's request. On July 19, 2016, Chairman Donna Nelson filed a memorandum memorializing that discussion and setting forth issues to be analyzed by ERCOT and SPP in subsequent, Commission-framed studies.[7] Among other points, Chairman Nelson recounted the Commission's agreement at the June 29 Open Meeting that the question of whether LP&L should be permitted to integrate the Affected Load into ERCOT will be considered separately from the question of whether Certificates of Convenience and Necessity (CCNs) should be issued for the transmission lines required to achieve that integration.[8] The

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[4] *See* Attachment B, LP&L's NOIE Load Zone Establishment Form.

[5] Project No. 45633, Study of the Integration of the Lubbock Power and Light System into the ERCOT System (June 17, 2016).

[6] *Id.* at 5.

[7] Project No. 45633, Letter from Chairman Donna Nelson (July 19, 2016).

[8] *Id.* at 2.

Chairman's memorandum also requested that SPP and ERCOT conduct a study on a list of issues related to the transition.[9]

Through the second half of 2016, ERCOT and SPP worked together to establish joint study assumptions and to develop a study scope that covered most of the Chairman's request. As the two entities conveyed in a letter filed at the Commission on September 15, 2016, they would be unable to provide analysis on two issues requested by the Commission: the cost and reliability impacts by customer class, and the potential for commingling of energy from the two systems.[10] SPP's and ERCOT's work on those studies proceeded through the first half of 2017, and on June 30, 2017, the entities filed their respective analyses in Project No. 45633. A joint Executive Summary, filed by SPP and ERCOT together, followed on July 7.

Throughout the period of the completion of ERCOT and SPP's study, LP&L worked to develop its own study (the LP&L Study) using the same assumptions, where appropriate, and directed at all of the issues requested to be addressed in Commissioner Nelson's memorandum. The LP&L Study is included in this Application as Attachment C.

C. Overview of LP&L Study

As the LP&L Study demonstrates, integration of the Affected Load into ERCOT will bring significant benefits to the SPP and ERCOT systems. Section 7 of the LP&L Study describes the bill impact of the migration of the Affected Load to ERCOT upon customers in both SPP and ERCOT. The remaining residential customers in the Texas portion of SPP will see a decrease in their average monthly bills, while the residential bill impact for ERCOT residential customers will not exceed two-tenths of one percent. Should LP&L's request to integrate the

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[9] *Id.* at 3-4.

[10] Project No. 45633, Letter from Warren Lasher and Lanny Nickel at 2 (Sept. 15, 2016).

Affected Load into ERCOT be denied, LP&L's residential customers will incur monthly bills that are 17% to 19% greater than the monthly bills of LP&L customers if served in ERCOT.

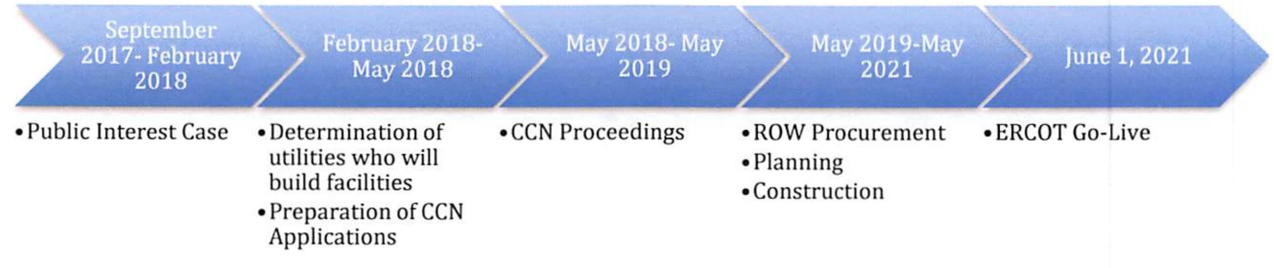
Apart from these bill impacts, the LP&L Study concludes that integration of the Affected Load into ERCOT poses significant other benefits to both the SPP and ERCOT systems. The integration of the Affected Load into ERCOT will eliminate the need for more than $7 million in transmission investment in SPP, and will reduce congestion on the SPP system. SPP will require less spinning and supplemental reserve service, and those procurements will come at a lower cost as demand decreases relative to an unchanged supply. Upon the departure of the Affected Load to ERCOT, SPP will also see improved transmission system outage coordination due to there being fewer congested hours on the transmission ties between SPP and SPS, and the increase in transfer capability between SPP and SPS.

Similarly, within ERCOT, the LP&L Study demonstrates that integration of the Affected Load into ERCOT will increase the export limit that currently constrains wind production in the Panhandle, and will avoid the need for the $39.5 million synchronous condenser at Windmill Station. By providing additional export paths for Panhandle resources, the integration of the Affected Load into ERCOT will result in an improved ability to schedule transmission outages, and will reduce congestion and curtailment of resources when those outages occur. The migration of the Affected Load will substantially reduce the likelihood of instances of sub-synchronous resonance, from approximately 71.7% to 2.6%. This migration will not require ERCOT to procure additional ancillary services and will provide the ERCOT system with additional load to pay for the system's total ancillary services purchases.

IV. REQUEST FOR ESTABLISHMENT OF PROCEDURAL SCHEDULE AND FOR COMMISSION TO HEAR MATTER

As noted in Section III.A. of this Application, LP&L has executed a power supply agreement that will meet its needs for the Affected Load through May 2021. Accordingly, LP&L targets June 1, 2021 for the integration of the Affected Load into ERCOT. While June 1, 2021 might appear to be a distant date, the time needed to complete the necessary activities leading to that date lends urgency to LP&L's request. After the conclusion of the instant proceeding, utilities must develop their applications for CCNs for the necessary transmission lines, and then initiate and complete those proceedings over the one-year timeline established by PURA[11] and Commission rule. Subsequent to that, LP&L and other utilities must procure right-of-way and construct the lines, a process expected to take two years. These considerations lead LP&L to file this Application now and to seek the establishment of a schedule that would complete the Commission's consideration of LP&L's case within six months.

As the following timeline demonstrates, if LP&L's request is approved in this proceeding, preparation for the filing of CCN proceedings must begin soon after the start of 2018.



[11] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-66.016 (West 2007 & Supp. 2016) (PURA).

ERCOT's Coordinated Lubbock Power and Light Integration Impact Analysis, filed in Project No. 45633, underscores this timing constraint. In its analysis, ERCOT noted that the ERCOT protocols establish an auction for Congestion Revenue Rights (CRRs) that occurs three years in advance of the time period addressed by the particular CRRs.[12] As ERCOT frames the concern:

> "Although it is likely that a decision to move forward with LP&L's integration into ERCOT would be made before any affected CRRs would be auctioned (since the farthest CRR auction is 36 months out), ***a decision to move forward with the construction of the necessary Transmission Facilities would need to be made at least 36 months in advance of the interconnection date to avoid impacts on previously auctioned CRRs.***"[13]

Stated differently, the CRR auction process requires that the decision to interconnect LP&L through particular transmission facilities be made by May 31, 2018. The timeline laid out above will accommodate this concern, but with little leeway to add time to the process. And, as noted above, the separate need to develop CCN applications for the interconnection facilities drives a schedule that is yet earlier than the CRR timeline requirements noted by ERCOT.

Furthermore, the policy issues raised by LP&L's request merit the Commission retaining this matter and conducting the hearing itself. While this case does raise factual questions upon which a record should be developed, it also presents questions regarding the expansion of the ERCOT system and the Commission's wholesale market model that are best considered within the policy-making purview of the Commission. LP&L requests that a Commission Administrative Law Judge (ALJ) be assigned to this matter, and that a Prehearing Conference be set, so that a procedural schedule can be developed in accordance with these guidelines.

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[12] Project No. 45633, ERCOT's Coordinated Lubbock Power and Light Integration Impact Analysis at 7 (June 30, 2017).

[13] *Id.* (emphasis added).

V. REQUEST TO DESIGNATE ERCOT AND SPP AS PARTIES, AND TO REQUIRE FILING OF STUDIES IN THIS PROCEEDING

On June 30, 2017, ERCOT and SPP filed their Commission-requested studies in Project No. 45633. On July 7, 2017, the two entities jointly filed an Executive Summary of their studies. In view of the importance of these studies to this Application, LP&L requests that ERCOT and SPP be made parties to this proceeding, and that their studies be filed in this case, so that a complete record can be developed on the issues addressed in their studies.

VI. JURISDICTION

For purposes of the regulatory regime governing transmission service set forth in Chapter 35 of PURA, as a municipally-owned utility, LP&L is categorized as an "electric utility."[14]

The Commission has jurisdiction over this matter pursuant to PURA § 35.004(d), addressing the pricing of transmission service, PURA § 39.151(d), relating to the Commission's authority over the operations of ERCOT, and PURA § 14.001, relating to the Commission's general powers.

VII. AFFECTED PERSONS

LP&L's request would affect the transmission rates and wholesale energy prices paid by Retail Electric Providers (REPs), Electric Cooperatives, and Municipally-Owned Utilities (MOUs) in the ERCOT region. Within the portion of SPP located in Texas, this Application implicates the rates paid by customers of SPS and other MOUs and electric cooperatives within the remaining, Texas-jurisdictional portion of SPP.

VIII. NOTICE

LP&L proposes two forms of notice of this Application:

1. Notice of this filing in the Texas Register; and

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[14] PURA § 35.001 (West 2007 & Supp. 2016).

2. Notice to each party that filed comments and/or reply comments in response to Commission's Staff's questions in Project No. 45633.

IX. REQUEST FOR PROTECTIVE ORDER

LP&L requests the adoption of the Commission's standard protective order, attached as Attachment D, to facilitate discovery and testimony of the parties to the proceeding.

X. RELIEF REQUESTED

LP&L seeks a determination by the Commission that LP&L's proposed interconnection to ERCOT and disconnection from SPP on June 1, 2021, in accordance with the "Option 4ow" endorsed by ERCOT in its June 17, 2016 report, is in the public interest.

LP&L further seeks specific direction from the Commission that:

- It may establish a NOIE Load Zone upon the integration date stated above; and that
- ERCOT and LP&L complete registration and qualification activities to permit integration into ERCOT upon that date.

LP&L further requests any and all other relief to which it is justly entitled.

Respectfully submitted,

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ATTORNEYS FOR THE CITY OF LUBBOCK
D/B/A LUBBOCK POWER & LIGHT

CERTIFICATE OF SERVICE

I hereby certify that on this 1st day of September, 2017, a true and correct copy of the foregoing document has been sent via facsimile, certified mail, return receipt requested, first class mail, or hand-delivered to all parties filing comments or reply comments in Project No. 45633.

LAMBETH TOWNSEND

3693/00/7417024

RESOLUTION

WHEREAS, the City of Lubbock and its municipally owned electric utility, Lubbock Power & Light ("LP&L") are currently served with wholesale power delivered through the Southwest Power Pool Regional Transmission Organization ("SPP");

WHEREAS, the wholesale power contract wherein LP&L acquires its power is to expire May 31, 2019;

WHEREAS, LP&L contracted previously with Southwestern Public Service for the period of time from and after May 31, 2019 to May 31, 2044 for a portion of its power needs (the "SPS" Load");

WHEREAS, LP&L participated in two separate procurement processes regarding power options subsequent to May 31, 2019 (the "Procurement Processes");

WHEREAS, the Procurement Processes did not reveal a complete solution for LP&L's future power needs;

WHEREAS, although the Procurement Processes did not reveal a solution in and of themselves, the evaluation of the responses received, along with independent analyses of Regional Transmission Organizations and wholesale electricity markets (collectively, the "Analysis"), provided a path forward to LP&L;

WHEREAS, the Analysis clearly indicates that the customers of LP&L would be best served by a migration of its load, less and except the SPS Load (the "ERCOT Load"), from SPP to the Electric Reliability Council of Texas Regional Transmission Organization ("ERCOT");

WHEREAS, the migration of the ERCOT Load to ERCOT will require regulatory activities at ERCOT and before the Public Utility Commission of Texas (the "PUC"):

WHEREAS, the Electric Utility Board of the City of Lubbock desires that all regulatory activities be initiated and undertaken in an effort to cause the migration of the ERCOT Load to ERCOT; NOW, THEREFORE:

BE IT RESOLVED BY THE ELECTRIC UTILITY BOARD OF THE CITY OF LUBBOCK:

THAT the Director of Electric Utilities BE and is hereby authorized and directed, for and on behalf of the City of Lubbock, acting by and through LP&L, to execute or cause to be executed, any and all pleadings, reports, studies or other filings (collectively, the "Pleadings") required by, or advisable to be filed with, ERCOT and/or the PUC, and to file or caused to be filed the Pleadings, and to present testimony and otherwise provide support, within and before ERCOT and/or the PUC, in an effort to cause the migration of the ERCOT Load from SPP to ERCOT.

Passed by the Electric Utility Board this 20th day of October, 2015.

Greg Taylor, Chairman

ATTEST:

James Conwright, Board Secretary

APPROVED AS TO CONTENT:

David McCalla, Director of Electric Utilities

APPROVED AS TO FORM:

Richard Casner, LP&L General Counsel

Resolution No. 2015-R0346
Item No. 4.4
October 20, 2015

RESOLUTION

WHEREAS, the City of Lubbock and its municipally owned electric utility, Lubbock Power & Light ("LP&L") are currently served with wholesale power delivered through the Southwest Power Pool Regional Transmission Organization ("SPP");

WHEREAS, the wholesale power contract wherein LP&L acquires its power is to expire May 31, 2019;

WHEREAS, LP&L contracted previously with Southwestern Public Service for the period of time from and after May 31, 2019 to May 31, 2044 for a portion of its power needs (the "SPS" Load");

WHEREAS, LP&L participated in two separate procurement processes regarding power options subsequent to May 31, 2019 (the "Procurement Processes");

WHEREAS, the Procurement Processes did not reveal a complete solution for LP&L's future power needs;

WHEREAS, although the Procurement Processes did not reveal a solution in and of themselves, the evaluation of the responses received, along with independent analyses of Regional Transmission Organizations and wholesale electricity markets (collectively, the "Analysis"), provided a path forward to LP&L;

WHEREAS, the Analysis clearly indicates that the customers of LP&L would be best served by a migration of its load, less and except the SPS Load (the "ERCOT Load"), from SPP to the Electric Reliability Council of Texas Regional Transmission Organization ("ERCOT");

WHEREAS, the migration of the ERCOT Load to ERCOT will require regulatory activities at ERCOT and before the Public Utility Commission of Texas (the "PUC");

WHEREAS, the City Council of the City of Lubbock desires that all regulatory activities be initiated and undertaken in an effort to cause the migration of the ERCOT Load to ERCOT; NOW, THEREFORE:

BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF LUBBOCK:

THAT, to the extent the City Council possesses governance jurisdiction over LP&L, as prescribed by the City Charter and Ordinances of the City of Lubbock, including without limitation, Chapter 1, Article XII, Section 1 of the City Charter and Chapter 2, Article 2.03, Division 12 of the Code of

Ordinances, the Director of Electric Utilities BE and is hereby authorized and directed, for and on behalf of the City of Lubbock, to execute or cause to be executed any and all pleadings, reports, studies or other filings (collectively, the "Pleadings") required by, advisable to be filed with, ERCOT and/or the PUC, and to file or caused to be filed the Pleadings, and to present testimony and otherwise provide support, within and before ERCOT and/or the PUC, in an effort to cause the migration of the ERCOT Load from SPP to ERCOT.

Passed by the City Council this 20th day of October, 2015.

GLEN C. ROBERTSON, Mayor

ATTEST:

Rebecca Garza, City Secretary

APPROVED AS TO CONTENT:

David McCalla, Director of Electric Utilities

APPROVED AS TO FORM:

Richard Casner, LP&L General Counsel

Name(s) of Non-Opt In Entity (NOIE)	Establish NOIE Load Zone (Yes/No)	Name of Substation where Load is Located	Name of Voltage Level where Load is Located	Name of Load
[Name or names (if group) as shown on Standard Form Agreement and CRR Account Holder Application]	[Yes/No]	[Names as per ERCOT model]	[Names as per ERCOT model]	[Names as per ERCOT model]
LPL	Yes	BRANDON	69 kV	LPL Retail Load
LPL	Yes	ERSKINE	69 kV	LPL Retail Load
LPL	Yes	MCCULLOUGH	69 kV	LPL Retail Load
LPL	Yes	VICKSBURG	69 kV	LPL Retail Load
LPL	Yes	CHALKER	115 kV	LPL Retail Load
LPL	Yes	COOP	115 kV	LPL Retail Load
LPL	Yes	MACKENZIE	115 kV	LPL Retail Load
LPL	Yes	MCDONALD	115 kV	LPL Retail Load
LPL	Yes	NORTHEAST	115 kV	LPL Retail Load
LPL	Yes	NORTHWEST	115 kV	LPL Retail Load
LPL	Yes	OLIVER	115 kV	LPL Retail Load
LPL	Yes	SLATON	115 kV	LPL Retail Load
LPL	Yes	SOUTHEAST	115 kV	LPL Retail Load
LPL	Yes	THOMPSON	115 kV	LPL Retail Load
LPL	Yes	WADSWORTH	115 kV	LPL Retail Load

Lubbock Power & Light

Transition to ERCOT Study

PREPARED BY:

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GDS/DNV-GL
LP&L Transition to ERCOT Study

EXECUTIVE SUMMARY

Lubbock Power and Light (LP&L) presents this Executive Summary of its Transition to ERCOT Study (LP&L Study or the Study) conducted jointly by GDS Associates, Inc. and DNV-GL Energy. As the LP&L Study demonstrates, the transition of approximately 470 MW of LP&L load (the Affected Load) from the Southwest Power Pool (SPP) to the Electric Reliability Council of Texas (ERCOT) will produce benefits for both the ERCOT and SPP systems.

I. INTRODUCTION

The LP&L Study is presented in response to Public Utility Commission (Commission) Chairman Donna Nelson's memorandum filed in Project No. 45633 on July 19, 2016 (July 19 Memorandum). In that memorandum, Chairman Nelson memorialized a discussion at the Commission's Open Meeting on June 29, 2016, in which the Commissioners identified issues to be addressed by ERCOT and SPP in their studies of the prospect of LP&L transitioning a portion of its load to ERCOT. The LP&L Study addresses all issues in the Commission's July 19 Memorandum—including the impact of the proposed transition on end-use consumers' bills, an analysis not performed by ERCOT or SPP—and demonstrates that the transition is in the public interest and should be approved.

LP&L is at a turning point regarding its wholesale supply arrangements for the Affected Load. LP&L is not, nor has it ever been, a member of SPP; Southwestern Public Service (SPS), its wholesale supplier, is a member of SPP. LP&L has historically been a full-requirements wholesale customer of SPS for both its power supply and transmission needs; under this arrangement, there was no reason for LP&L to join SPP. While LP&L will continue to receive wholesale power and transmission service from SPS under a contract that expires on May 31, 2021, further extensions of the total-requirements contract will not be possible.

LP&L's geographic position at the southern extremity of SPS's transmission system, and in turn, of SPP's system, creates severe challenges. LP&L sits behind three major constraints that SPP has identified as "Frequently Constrained Areas."[1] Compounding this challenge is SPP's requirement that Load Responsible Entities must meet a Planning Reserve Margin (PRM) requirement with physical generating resources that require a deliverability study be

[1] Frequently Constrained Areas – 2016 Study (Dec. 2016), SPP Market Monitoring Unit.

performed for any new Designated Network Resources (DNRs). SPP conducts an analysis referred to as an Aggregation Study on any new DNRs that must demonstrate that a contemplated DNR can be delivered from the relevant power plants to LP&L's load. In the event that a Load Responsible Entity does not meet this PRM requirement, substantial penalties will be assessed by SPP by multiplying the deficiency by the Cost of New Entry (CONE), by 125%. LP&L's location behind multiple constraints and SPP's PRM and deliverability requirements mean that LP&L does not have access to a true, competitive wholesale market. LP&L is effectively a captive customer of SPS, but there is no guarantee that SPS will have adequate physical generation to supply LP&L in the future.

While a short-term bridge agreement to May 31, 2021 ultimately proved possible, a wholesale power agreement after that date is not assured. The results of a procurement process in 2014, in part, led LP&L to begin consideration of transitioning a portion of its load to ERCOT. As a result of these factors, LP&L's Electric Board and the City of Lubbock's City Council both took formal action on October 20, 2015, directing LP&L to seek interconnection of the Affected Load with ERCOT.

Given this background, LP&L is presented with options in 2021 that do not include the status quo. It cannot expect to simply continue to receive service from SPS on terms that are comparable to its current total-requirements contract. If LP&L is not permitted to join ERCOT, it must pursue membership in SPP, including becoming a Transmission Owner to fully join its native transmission system to the larger SPP grid, and receiving a transmission rate through SPP's Open Access Transmission Tariff (OATT).

The more transparent, Texas-based, and market-focused ERCOT system remains LP&L's selected option. LP&L's intent to join the Affected Load to ERCOT is based on the fundamental characteristics of that market; it is not a short-term tactic designed to capture some temporary advantage. If LP&L is permitted to transition the Affected Load to ERCOT, that Load will remain connected to ERCOT. The analysis performed by GDS and DNV-GL indicate that such a transition for the Affected Load presents certain demonstrable benefits to both the SPP and ERCOT grids, and to all of LP&L's customers, including its largest customer, Texas Tech University.

II. BACKGROUND ON LP&L AND THE INTEGRATION PROCESS

The City of Lubbock (City) is the 11th largest city in Texas, and its municipally-owned electric utility, LP&L, serves approximately 641 MW of load in and around Lubbock, equating to more than 100,000 customers. LP&L seeks to integrate the majority of that load—approximately 470 MW—into ERCOT in 2021. The remainder of LP&L's load is served by a system purchased from SPS in 2010, and is subject to a wholesale power supply contract with SPS that terminates in 2044. That portion of LP&L's load would not move to ERCOT at this time.

LP&L's outreach to ERCOT dates to mid-2015, when LP&L staff met with ERCOT leadership to discuss the prospect of LP&L connecting to the ERCOT system. LP&L followed these discussions with the submittal of its ERCOT Integration Study to ERCOT's Regional Planning Group (RPG) in December 2015 (LP&L's Integration Study). Subsequently, the Commission directed its staff to open Project No. 45633, a project in which issues related to the proposed transition could be vetted. After interested parties commented on the Commission's questions and a workshop was held, the Commission defined the scope of its requested ERCOT and SPP studies in July 2016. Pursuant to the Commission's direction in September 2015, ERCOT filed its Study of the Integration of the Lubbock Power & Light System into the ERCOT System (ERCOT's Study) on June 17, 2016 in Project No. 45633. ERCOT's Study determined that the preferable transmission integration plan was a variation on one previously identified by LP&L, which ERCOT named Option 4ow. LP&L's Integration Study had recommended a lower-cost option, but ERCOT concluded that the additional cost of the investment associated with Option 4ow was justified by the additional production cost savings permitted by that option.

In March 2017, the Chancellor of Texas Tech University filed a letter in Project No. 45633 highlighting the benefits of integrating LP&L with ERCOT for both Texas Tech and the City of Lubbock. Then, on June 30, 2017, both ERCOT and SPP filed their respective studies on the effect of integrating the Affected Load into ERCOT in response to the Commission's July 2016 direction.

Originally, LP&L targeted June 1, 2019 for integration of the Affected Load with ERCOT. To permit ERCOT, SPP, and the Commission to consider the issues raised by LP&L's request to connect to ERCOT, and to prudently provide for its customers and plan for the possibility of a delay in the integration of the Affected Load into ERCOT, in late 2016, LP&L began discussions with suppliers on a wholesale "bridge" agreement to extend its SPP-based power supply for two additional years. On March 23, 2017, LP&L and SPS announced the execution of a new contract that provides for LP&L's power supply through May 31, 2021.

III. STUDY ASSUMPTIONS

The LP&L Study was conducted using the same data, methodologies, and assumptions as those used by ERCOT and SPP, to the extent feasible and appropriate. LP&L engaged GDS and DNV-GL to conduct the Study. As ERCOT noted in a letter to the Commissioners on March 23, 2017, ERCOT agreed to share the input data for its study with LP&L's outside consultants, subject to an appropriate Confidentiality Agreement; the Commission endorsed this arrangement at its March 30, 2017 Open Meeting. ERCOT made its assumptions and inputs available to LP&L's experts, subject to the Confidentiality Agreement, in the subsequent weeks and months. Similarly, SPP executed confidentiality agreements for the sharing of study data with LP&L's consultant team.

LP&L endeavored to conduct its own independent study using the same assumptions and inputs as ERCOT and SPP. In several instances, deviations from those assumptions and inputs were necessary. Those deviations, and the rationale for them, are described below:

a. **The LP&L Study uses a different production cost analysis methodology than that used by ERCOT and SPP.**

A key component of the analyses requested in Chairman Nelson's memorandum and conducted by ERCOT, SPP, and LP&L is the definition of the production cost metric to be used to quantify the benefits associated with the integration of the Affected Load into ERCOT. Definitions of the term "production costs" can vary widely (as described below) but as the term implies, it generally refers to the cost incurred in producing a market's requirement of a good, in this case, electricity. For transmission projects within its traditional footprint, ERCOT applies an annual production cost concept that is not adjusted for energy purchases and sales. The economic merit of a proposed transmission project in ERCOT is evaluated by calculating the annual production cost savings resulting from the proposed project. Note, however, that this approach has traditionally been used by ERCOT in evaluating transmission projects only. The integration of the Affected Load into ERCOT presents a different circumstance since it includes the integration of both transmission *and* load.

SPP's study, on the other hand relies upon a different production cost-based metric, called Adjusted Production Cost (APC). SPP's APC methodology starts with production costs for each generator in the SPP system, but then increases the figure to reflect purchases if the utility is short, with that amount quantified at the utility's load-weighted Locational Marginal Price (LMP). If the utility is long, the surplus over the utility's load is also priced at the utility's load-weighted LMPs. While the production cost analysis methodology traditionally used by SPP and ERCOT are different, both decided to use ERCOT's approach in calculating the net impact of the integration of the Affected Load into ERCOT. As described in their joint Executive Summary, ERCOT and SPP use the production cost impacts from two completely different models for two completely different grids (including SPP, which utilizes an economic model for the entire Eastern Interconnection system), and then simply net them together to present an impact of the integration of the Affected Load into ERCOT.

After a comprehensive review of the industry practice in cost-benefit assessments, LP&L adopted a different variation of this production cost analysis. LP&L's production cost analysis approach evaluates the production cost impacts of the LP&L integration into ERCOT, while considering the costs paid by the entirety of LP&L's Affected Load in ERCOT. This is appropriate because one of the questions at issue in this proceeding is how the migration of the Affected Load, including that Load's payments, will affect customers in both systems. Without such a yardstick, it will be difficult for the Commission to evaluate the true impact of the simultaneous removal of the Affected Load from SPP, and its addition to ERCOT.

Using the methodology described above, the LP&L Study finds that the integration of the Affected Load into ERCOT results in annual savings for the ERCOT market of approximately $6 million in 2020 and $31 million in 2025. The departure of the Affected Load from SPP results in annual savings for the remaining SPP system in Texas of $61 million in 2020 and $74 million in 2025.

b. **LP&L's analysis does not include a third synchronous condenser in the Panhandle, and neither did ERCOT's until its report was presented to the Board.**

In ERCOT's analysis, the "base-case" model of the ERCOT system for the years 2020 and 2025 includes a third synchronous condenser (beyond the two that are already planned, at the Alibates and Tule Canyon stations) that was not part of earlier summaries of the report and received no stakeholder review or comment. As discussed in Section 5.3.3 of the Study and summarized below, this additional 175 MVA synchronous condenser, at Windmill Station (Windmill), will not be economically justified if LP&L is permitted to integrate its proposed load into ERCOT.

On May 16, 2016, ERCOT Staff presented the results of its initial LP&L Integration Impact Analysis to ERCOT's RPG, and projected a production cost increase of $63 million in 2020 and $62 million in 2025. Then, at the Technical Advisory Committee (TAC) meeting on May 25, 2017, ERCOT reported revised production cost increases of $66 million for 2020 and $60 million for 2025. Finally, on June 13, ERCOT Staff presented the results of its study to ERCOT's Board of Directors, and projected significantly different production cost increases of $74 million in 2020 and $77 million in 2025. When asked by a Director why these figures had changed so substantially between the earlier stakeholder meetings and ERCOT Staff's report to the Board, ERCOT responded that, in part, ERCOT's analysis included a third synchronous condenser at Windmill Station in the study's base case. This synchronous condenser was not included in the report given to RPG and TAC. Inclusion of this facility in the base case limits some of the benefit that would come from LP&L's integration into ERCOT.

Apart from the procedural questions surrounding the inclusion of the Windmill synchronous condenser in the base case, the LP&L Study finds that the facility fails the economic criteria specified by ERCOT Protocol 3.11.2 should LP&L be permitted to integrate the

Affected Load into ERCOT. As a result, LP&L's Study does not assume the presence of a third synchronous condenser at Windmill Station in its base case.

IV. IMPACT OF SOUTH PLAINS PROJECT

On October 10, 2016, Sharyland Utilities (Sharyland) submitted a proposal for a new transmission project, called the South Plains Project, to ERCOT's RPG. This project includes three transmission additions—a single circuit, 345 kV line from Abernathy to Grassland, a 345 kV single circuit from Ogallala to Abernathy, and the Windmill synchronous condenser discussed previously. The South Plains Project is proceeding through the RPG process at ERCOT, but has been under study by ERCOT since the fall of 2016. On August 22, 2017, ERCOT reported to the RPG that an additional 328 MW of wind capacity in the Panhandle region has met the relevant Planning Criteria.[2] At this point, however, the project remains under study by ERCOT, and is therefore not included in either ERCOT's or LP&L's modeling base cases.

Nonetheless, the South Plains Project is significant to the potential for the transition of the Affected Load to ERCOT. The South Plains Project does not present the question of *whether* this project will ever become necessary; instead, the question is *when* wind investment in the Panhandle will permit this project to meet ERCOT's economic criteria and justify the construction of the lines. There is significant overlap between the South Plains Project and the Option 4ow transmission integration plan selected by ERCOT; once the South Plains Project meets the relevant planning criteria, the incremental impact of the remaining transmission investment needed to reliably connect the Affected Load to ERCOT equates to an increase to the postage stamp rate of $0.01672 per 4CP kW per month, or 0.3%. While the South Plains Project is not yet approved, it remains a relevant point for consideration as the prospect of integrating the Affected Load into ERCOT is evaluated.

V. IMPACT OF LP&L MIGRATION ON CONSUMERS

In Section 7 of the Study, LP&L responds to the Commission's request that the analysis of LP&L's potential to join ERCOT include consideration of the cost impact by customer class. This bottom-line analysis is inclusive of all components of consumers' electricity bills and is performed for customers in both the ERCOT and SPP markets. The quantitative analysis presented below is followed by a discussion of the qualitative benefits resulting from the integration of the Affected Load into ERCOT.

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[2] ERCOT, RPG meeting, Sharyland Utilities South Plains Transmission Project-ERCOT Independent Review Update (Aug. 22, 2017). http://ercot.com/content/wcm/key_documents_lists/108880/Sharyland_Utilities_South_Plains_Transmission_Project_ERCOT_Update.pdf.

a. Impact on ERCOT Consumers

Within ERCOT, this analysis focuses on customers served by the major investor-owned utilities, as the information necessary to determine the rate impact on customers served by municipal utilities and electric cooperatives was unavailable. The customer bill analysis includes both the regulated utility component of the bill and the energy market component. Power cost data for residential customers were drawn from the Commission's Average Annual Rate Comparison for Residential Electric Service. For commercial customers, power cost figures were obtained from retail electric providers (REPs), conveyed though 12-month indicative offers and pricing matrices that are made available on a daily basis. This market price data was collected in April 2017. The analysis assumes a residential customer usage of 1,000 kWh per month, and for small commercial consumers, the usage assumption is 1,500 kWh per month.

As the following table demonstrates, the residential bill impact of the integration of LP&L's Affected Load into ERCOT does not exceed two-tenths of one percent, and for customers of certain investor-owned utilities, the impact is even less. The tables project the impact of the integration of the Affected Load in 2020. Over time, these small increases will continue to decline, and the benefits of the integration will accrue, as explained in the discussion that follows these tables.

	1,000 kWh per Month Usage		
ERCOT IOU	**LP&L Remains in SPP**	**LP&L Moves to ERCOT**	**Increase/Decrease**
Oncor Electric Delivery Company	$128.45	$128.71	0.20%
CenterPoint Energy Houston Electric, LLC	137.83	138.10	0.20%
AEP Texas Central Company	137.14	137.39	0.18%
AEP Texas North Company	151.72	152.00	0.18%
Texas - New Mexico Power Company	143.74	144.02	0.20%
Sharyland Utilities, L.P.	194.12	194.39	0.14%

Executive Summary Table 1 – Estimated ERCOT IOU Residential Bill Impacts

Integration of the Affected Load into ERCOT will have a similarly small impact on small commercial consumer bills, as follows:

	1,500 kWh per Month Usage		
ERCOT IOU	**LP&L Remains in SPP**	**LP&L Moves to ERCOT**	**Increase/Decrease**
Oncor Electric Delivery Company	$142.31	$142.55	0.16%
CenterPoint Energy Houston Electric, LLC	142.91	143.22	0.22%
AEP Texas Central Company	188.22	188.44	0.11%
AEP Texas North Company	182.64	182.90	0.14%
Texas - New Mexico Power Company	165.64	166.09	0.27%
Sharyland Utilities, L.P.	213.97	214.30	0.15%

Executive Summary Table 2 – Estimated ERCOT IOU Secondary Small Bill Impacts

These end-use customer impacts to ERCOT, small as they are, further lose significance when viewed against the long-term prospect of LP&L being a member of the ERCOT system. LP&L's Analysis includes a Net Present Value (NPV) computation to assess the benefits of the integration of the Affected Load into ERCOT over a forty-year time period. This analysis compares the production cost effect against the payments into the energy market that will be made by the Affected Load, and uses the net benefits of the integration relative to the cost of the transmission investment for Option 4ow. These payments into the energy market will be a tangible benefit to ERCOT's existing load, as they reflect LP&L ratepayers bearing their share of the market's overall energy purchases.

On an NPV basis, the Affected Load will be paying into the ERCOT market more than the production cost increase that will result, with a benefit-cost ratio of 1.39 when viewed over a forty-year time horizon, and considering the relevant discount and inflation rates.

b. Impact on Texas Customers in SPP

The LP&L Study also projects the rate impact of the Affected Load departing SPP on the remaining customers served by SPS. As was the case for ERCOT, rates charged by municipally owned utilities and electric cooperatives were not available and therefore not included in this analysis. Inclusive of all components of SPS's rates, the departure of the Affected Load represents a net savings to residential customers, as demonstrated in the following table. In short, customers served by SPS are benefitted by LP&L's proposed transfer of the Affected Load to ERCOT.

Usage (kWh)	LP&L Remains in SPP	LP&L Moves to ERCOT	Increase/Decrease
500	$71.25	$70.45	-1.12%
1,000	132.49	130.90	-1.20%
1,500	193.74	191.35	-1.23%
2,000	254.99	251.80	-1.25%
2,500	316.24	312.25	-1.26%
5,000	622.47	614.51	-1.28%

Executive Summary Table 3 – Impact of LP&L Load Transfer to ERCOT on SPS Residential Bills

c. Impact of LP&L Remaining in SPP

If LP&L is not permitted to join its Affected Load with the ERCOT system, that load would bear significantly higher rates. As noted at the outset of this Executive Summary, the circumstances of LP&L's presence in SPP would change substantially. SPS has indicated that it will not be able to offer a wholesale contract to LP&L on a basis similar to what it has done in the past. As the following table demonstrates, residential customers of LP&L will pay higher rates if LP&L is not permitted to integrate into ERCOT. Similar higher rates would be borne by the other LP&L rate classes.

	LP&L Moves to ERCOT	LP&L Remains in SPP	Increase if Ordered to Stay in SPP	
kWh Usage	$	$	$	%
500	56.16	65.75	9.59	17%
1,000	104.63	123.81	19.18	18%
1,500	153.11	181.88	28.77	19%
2,000	201.58	239.94	38.36	19%

Executive Summary Table 4 – Comparison of Monthly LP&L Residential Customer Bills

VI. OTHER BENEFITS

In addition to the pricing impacts summarized above, the integration of the Affected Load into ERCOT will have positive effects on the ERCOT and SPP system. Some of these benefits are quantifiable, and some cannot be quantified, but are nonetheless expected to result from integration of the Affected Load into ERCOT, as follows:

a. Benefits to SPP

i. **Avoided Transmission Projects in SPP. (Sections 5.2.3.2 & 5.2.3.3)** The departure of the Affected Load from SPP results in $7,132,921 in planned transmission investment that can be avoided. No stranded facilities will result from the departure of the Affected Load.

ii. **SPP system congestion is reduced by the transfer of the Affected Load to ERCOT. (Section 5.2.4)** This effect will have a positive impact on operations, and will permit greater flexibility in resolving system issues without increased out-of-merit dispatch.

iii. **There will be a decreased requirement for ancillary services, which will also be procured at a lower price. (Section 5.2.4)** The departure of the Affected Load from SPP reduces the requirements to procure spinning and supplemental reserves. This reduction lowers the likelihood of scarcity pricing of these ancillary services. The transfer of the Affected Load also decreases the cost of those products, as their supply is unchanged while demand will decrease.

iv. **The transfer of the Affected Load to ERCOT will result in improved outage coordination, and an improved ability to take outages. (Section 5.2.4)** This benefit results from there being fewer congested hours on the SPP/SPS ties, and an increase in the available transfer capability between SPP and SPS.

b. Benefits to ERCOT

i. **Integration of the Affected Load avoids the need to construct the Windmill synchronous condenser. (Section 5.3.3)** As a result, integration of the Affected Load will avoid the need for $39.5 million in transmission investment.

ii. **Integration of LP&L through Option 4ow will increase the export limit that currently constrains wind production in the Panhandle. (Section**

5.3.6.3) Integration of the Affected Load increases the Panhandle export limit by 490 MW. Additional increases to the Panhandle export capability can be achieved by converting the LP&L generation units to synchronous condensers, and the contribution of the Affected Load to short-circuit levels in the Panhandle region.

iii. **Integration of the Affected Load into ERCOT will provide ERCOT with additional operational flexibility. (Section 5.3.6.6)** The integration will provide additional export paths for resources in the Panhandle, resulting in an improved ability to take transmission outages, and reducing congestion and curtailment of resources when transmission outages occur. Both of these issues—long-term transmission outages in the Panhandle and the resulting impacts on Panhandle exports—have been issues of significant discussion among ERCOT stakeholders recently.

iv. **Integration of the Affected Load into ERCOT will result in positive impacts from the sub-synchronous resonance perspective. (Section 5.3.6.7)** The proposed integration drastically reduces the likelihood of instances of sub-synchronous resonance in the Panhandle, by decreasing the probability of the concurrent outages posing elevated sub-synchronous resonance risk in the Panhandle from 71.657% to 2.583%.

v. **Integration results in no material additional ancillary services required to be purchased, and will bring 470 MW of LP&L load to bear a portion of the system's ancillary services costs. (Section 5.3.7.1)** Integration of the Affected Load results in no increases in Responsive Reserve and Non-Spinning Reserve service, while the impact of the Affected Load on the total monthly up/down regulation requirements will be less than 0.5%. In sum, upon integration, the Affected Load will provide an additional quantity of load to pay the system's ancillary services requirements, while not materially increasing those requirements.

vi. **The market for Congestion Revenue Rights (CRRs) will not see a material impact resulting from the integration of the Affected Load. (Section 5.3.7.2)** This is because of the location of the LP&L system in the Panhandle and LP&L's intent to establish a Non-Opt-In-Entity Load Zone. The 2021 integration target provides sufficient time for the market to account for the integration of the Affected Load into its CRR procurements.

VII. CONCLUSION

The integration of the Affected Load into ERCOT raises no technical or reliability concerns in either ERCOT or SPP. From the perspective of LP&L, failure to integrate the Affected Load into ERCOT means higher electricity costs for all of LP&L's customers, including its largest customer, Texas Tech University.

For the Texas IOU ratepayers within SPP, the departure of the Affected Load for ERCOT will be a welcome development, in that it decreases rates in excess of 1.12%, eliminates the need for more than $7 million in new transmission investment, and reduces persistent congestion in the southern reaches of SPP that until now has gone unresolved. From an ERCOT perspective, integration of the Affected Load into ERCOT brings significant operational and reliability benefits, including an increase of the Panhandle export limit, a reduction in the likelihood of instances of sub-synchronous resonance, additional operational flexibility from the establishment of more transmission paths in the Panhandle, and avoidance of the need for an additional synchronous condenser. Furthermore, the initial bottom-line impact to customers in ERCOT from the integration of the Affected Load is only two tenths of one percent of a typical monthly bill for residential consumers, with similarly negligible monthly bill impacts for other customer classes. On a long-term, NPV basis, the Affected Load will contribute into the ERCOT wholesale market substantially more than the associated production cost increase, with a benefit-to-cost ratio of 1.39.

1. PURPOSE OF COST-BENEFIT ANALYSIS

Lubbock Power and Light (LP&L) is the wholly-owned municipal electric utility of the City of Lubbock (City), serving residential, commercial, and industrial businesses via its transmission and distribution facilities within its certificated service area. Currently, LP&L is the primary supplier of retail electric service within the municipal limits of the City, maintaining a diversified customer base that includes Texas Tech University as its largest customer. Historically, LP&L has provided retail power service to its customers through its participation in the West Texas Municipal Power Agency (WTMPA), a municipal power agency comprised of the Cities of Lubbock, Brownfield, Floydada, and Tulia, Texas. In June 2004, WTMPA contracted to obtain all energy requirements of its member cities from Southwestern Public Service Company (SPS) through May 31, 2019. By entering into the total requirements power purchase agreement (SPS Power Agreement), WTMPA (and thus LP&L) resolved its long-term power supply issues through May, 2019 and minimized its exposure to fuel price volatility.

On May 26, 2011, SPS gave notice to WTMPA/LP&L that it would not be able to offer total requirements power service under the structure of the SPS Power Agreement beyond the June 30, 2019 expiration date. WTMPA/LP&L's existing contract is structured based on SPS's weighted average embedded power costs as approved by the Federal Energy Regulatory Commission (FERC). SPS stated that it could only offer WTMPA/LP&L full requirements power service beyond June 30, 2019 on a higher, incremental power cost basis.

LP&L has never been a member of SPP, has not transferred functional control of its transmission facilities to SPP, and has not developed an Annual Transmission Revenue Requirement (ATRR) rate for recovery of LP&L's transmission costs. Power delivered to LP&L is served under SPS's Open Access Transmission Tariff (OATT). Acquiring a SPP-based wholesale power supply separate from WTMPA and SPS requires LP&L to request transmission studies from SPP to determine the deliverability of alternative power supply options, and to determine whether LP&L needs to contribute toward any necessary new transmission investments in SPP. LP&L is situated behind three of the eight constraints identified in SPP's December 2016 Frequently Constrained Areas report. These constraints severely limit LP&L's ability to contract with third parties for deliverable capacity.

LP&L began investigating power supply alternatives to serve LP&L's customer power needs beyond June 30, 2019. This included discussions with SPP regarding the availability of transmission capacity to deliver alternative power sources to LP&L customers. In 2014, LP&L issued a request for proposals (RFP) to potential power suppliers in both SPP and ERCOT, subject to transmission studies from both systems. LP&L's 2014 RFP results identified lower cost power supply options in ERCOT than those in SPP.

The results of the LP&L RFP motivated LP&L to investigate and evaluate a move of the majority of the LP&L system and customers to ERCOT. LP&L's Electric Utility Board and the City of Lubbock's City Council both took formal action on October 20th, 2015 directing LP&L to take necessary actions in an effort to cause the migration of load from SPP to ERCOT. LP&L engaged DNV-GL to evaluate LP&L's optimal interconnection alternatives into ERCOT on both a cost and reliability basis. LP&L and DNV-GL presented their optimal interconnection alternatives in ERCOT to the ERCOT Regional Planning Group (RPG) in 2016, and LP&L expressed its interest in joining ERCOT. ERCOT completed its own LP&L interconnection study, and recommended an interconnection plan through an approach that it designated as Option 4ow (a slight variation on DNV-GL's optimal interconnection option) at a $364 million capital cost. The minimum reliable connection to ERCOT, as proposed by LP&L, carried a projected $311.8 million capital cost, but ERCOT recommended the more expensive integration option because the incremental cost met ERCOT's economic criteria and offered additional societal benefits. ERCOT's recommended plan was also consistent with its Panhandle Renewable Energy Zone (PREZ) Study Report (PREZ Report) issued in April 2014.

In the spring of 2016, the Public Utility Commission of Texas (PUCT or Commission) established Project Number 45633 to "Identify Issues Pertaining to Lubbock Power & Light's Proposal to Become Part of the Electric Reliability Council of Texas," invited written comments, and scheduled a workshop to determine the issues necessary to be considered, evaluated, and resolved in considering LP&L's request to move to ERCOT. After comments were filed, the Chairman of the Commission issued a memorandum laying out her view of the major issues to be considered in making such a decision by the Commission; this list of considerations was subsequently endorsed by the full Commission. The Commissioners directed ERCOT and SPP to develop studies in their respective systems and, using their planning criteria, to evaluate both the costs and benefits of an LP&L move to ERCOT from SPP. This would include potential reliability and production cost impacts. Further, the PUCT requested to see the impact of such a potential move on the rates paid by customers.

This report contains the analysis conducted by LP&L and its consultants to quantify the costs and benefits of the transfer of approximately 470 MW of LP&L load and associated transmission and generation facilities from SPP to ERCOT and addresses the issues raised by the Commission in 2016.

2. WHOLESALE MARKET BACKGROUND

To assess the impact of the proposed transfer of a portion of the LP&L load from SPP to ERCOT, it is important to recognize the differences in the two Regional Transmission Organization (RTO) systems, both market-driven and topology-driven, that necessitate the use of unique analysis techniques and tools specific to ERCOT and SPP. These differences impact the types of technical analyses performed, what categories of benefits and costs are included and how those benefits and risks are assigned to customers of the respective RTOs. This report provides a balanced approach that respects the calculations of benefits consistent with the various RTO criteria and that also captures the impact to the LP&L, ERCOT, and SPP load.

2.1. Electric Reliability Council of Texas (ERCOT)

ERCOT represents approximately 90 percent of Texas load, and is a separate interconnection, with several direct current (DC) ties to the U.S. Eastern Interconnect and Mexico. It represents approximately 78,000 MW of firm generation capacity, and about 46,500 miles of transmission lines.[3]

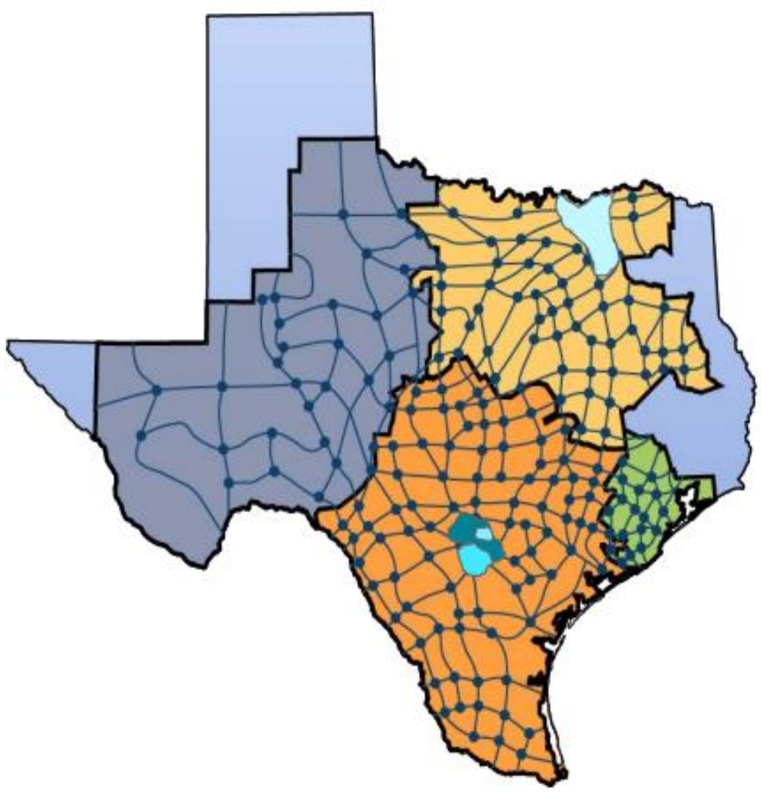

Figure 2.1: ERCOT Nodal Market Map

[3] http://www.ercot.com/content/wcm/lists/114739/ERCOT_Quick_Facts_51517.pdf, p. i.

The ERCOT Nodal Market is configured with three types of settlement points: Resource Nodes, Load Zones and Hubs. Locational Marginal Prices (LMPs) are determined on an hourly basis at the Resource Nodes where generators inject power into the transmission system for the Day Ahead (DA) Market and on a 5-minute basis for Real Time (RT) Operations. Every electrical bus with load is assigned to a Load Zone where settlement point prices are determined hourly on a DA basis and with 15-minute intervals on a RT basis. There are four Competitive Load Zones: North, South, West and Houston; four Non-Opt-In Entity (NOIE) Load Zones: Austin Energy, CPS (City of San Antonio), Lower Colorado River Authority, and Rayburn Country Electric Cooperative; and five DC Tie Load Zones. ERCOT has six Hubs (groups of 345 kV Hub-buses) for liquid wholesale trading: North, South, West, Houston, ERCOT Hub Average, and ERCOT Bus Average.[4] ERCOT also manages wholesale markets for the sale and purchase of Ancillary Services (AS): Regulation Reserves, Responsive Reserves, and Non-Spinning Reserves. Figure 2.1 illustrates the regions covered by the ERCOT Nodal Market.

2.1.1. ERCOT Load

The total peak demand for the ERCOT market footprint in 2016 was 71,110 MW, which occurred on August 11, 2016.[5] This represented an increase of 1.8% over the 2015 system peak.[6] Total energy requirements in ERCOT increased 1.1% to 351.5 TWh.[7] The load-weighted average energy price in ERCOT was $24.62 per MWh in 2016.[8]

The LP&L system sits adjacent to the ERCOT West Zone. For comparison purposes, the Zonal prices in ERCOT are shown below:

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4 http://www.ercot.com/content/wcm/training_courses/109518/Nodal_101.pdf, pp. 45-57.

5 *Id.*, p. i.

6 *Id.*, p. i.

7 https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf, p. xi.

8 http://www.ercot.com/content/wcm/key_documents_lists/103980/11_IMM_Report.pdf, p. 3.

Average Annual Real-Time Energy Market Prices by Zone

	2011	2012	2013	2014	2015	2016
ERCOT	**$53.23**	**$28.33**	**$33.71**	**$40.64**	**$26.77**	**$24.62**
Houston	$52.40	$27.04	$33.63	$39.60	$26.91	$26.33
North	$54.24	$27.57	$32.74	$40.05	$26.36	$23.84
South	$54.32	$27.86	$33.88	$41.52	$27.18	$24.78
West	$46.87	$38.24	$37.99	$43.58	$26.83	$22.05
Natural Gas ($/MMBtu)	$3.94	$2.71	$3.70	$4.32	$2.57	$2.45

Table 2.1: ERCOT Real-Time Energy and Day-Ahead Natural Gas Prices[9]

2.1.2. ERCOT Generation

The ERCOT generation mix in 2016 includes primarily natural gas (45%), coal (27%), wind (15%), and nuclear (13%) resources.[10] Wind generation continues to be the clear majority of generation expansion in the region—totaling approximately 80% of the 5.5 GW of new generation installed in 2016—and has increased its share each year since 2007.[11]

2.1.3. ERCOT Transmission and Congestion

Congestion on the transmission system in ERCOT is included in the pricing differences in the LMPs between the Resource Nodes (Source) and the Load Zones and Hubs (Sink) in the ERCOT Nodal Market. ERCOT manages a Congestion Revenue Rights (CRR) market enabling Market Participants to hedge their congestion cost exposure based on Day Ahead LMPs using a financial instrument. The year 2016 saw a significant increase in real-time congestion costs to $497 million, which represented an increase of 40% from 2015.[12] In 2016, the average annual price in the West Zone was lower than the ERCOT average due to increased congestion caused by high levels of wind output.[13]

9 https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf, p. iii.

10 http://www.ercot.com/content/wcm/lists/114739/ERCOT_Quick_Facts_51517.pdf, p. i.

11 https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf, p. xii.

12 *Id.*, p. i.

13 *Id.*, pp. 4-5.

2.2. Southwest Power Pool (SPP)

In the 2015 State of the Market Report, SPP provided the following overview of its market design:[14]

> The Integrated Marketplace is a full Day-Ahead Market with Transmission Congestion Rights, virtual trading, a Reliability Unit Commitment (RUC) process, a Real-Time Balancing Market (RTBM), and a price-based Operating Reserves market. SPP simultaneously put into operation a single Balancing Authority as part of the implementation of the Integrated Marketplace. The primary benefit of converting to a day-ahead market is to improve the efficiency of daily resource commitments. Another benefit of the new market includes the joint optimization of the available capacity for energy and operating reserves.

2.2.1. SPP Load

The total peak coincident demand for the SPP market footprint in 2016 was 50,622 MW which occurred on July 21, 2016.[15] The total SPP energy requirement for 2016 was 266,442 GWH.[16] In the 2015 SPP Market Monitoring Unit State of the Market report, which was published in August 2016, the SPS system had the third highest energy consumption of SPP market participants at 11.2% of total SPP requirements or 25,590 GWH.[17]

In addition to paying the LMP at their load bus, SPP Load customers pay for Day-Ahead and Real-Time Reliability Unit Commitment Make Whole Payments, Operating Reserves, Reserve Sharing Group costs, and payments to Demand Response Resources. This all-in price in SPP for 2015 was $23.48 per MWh.[18]

The average annual real time energy prices for the SPP North Zone and South Zone trading hubs, based on the hourly real-time prices from the SPP Market Portal, are shown below. Real time data begins with the start of the SPP Integrated Marketplace in March 2014.

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[14] https://www.spp.org/documents/41597/spp_mmu_state_of_the_market_report_2015.pdf, p. 10 (Posted August 2016).

[15] https://www.spp.org/about-us/fast-facts/.

[16] *Id.*

[17] https://www.spp.org/documents/41597/spp_mmu_state_of_the_market_report_2015.pdf, p. 24, Figure 2-16.

[18] *Id.*, p. 15.

Average Annual Real Time Energy Prices (Power)						
	2011	2012	2013	2014 (March – Dec)	2015	2016
SPP North Hub	N/A	N/A	N/A	$24.91	$18.83	$19.30
SPP South Hub	N/A	N/A	N/A	$36.15	$24.83	$25.47
Day Ahead Natural Gas Price ($/MBTu)						
	2011	2012	2013	2014	2015	2016
Henry Hub	$4.00	$2.76	$3.73	$4.37	$2.63	$2.51

Table 2.2: SPP Real-Time Energy and Day-Ahead Natural Gas Prices

2.2.2. SPP Generation

Total installed capacity in SPP at the end of 2015 was 84,943 MW, which was made up of 42% natural gas resources, 34% coal resources, and 15% wind assets.[19] Even though the SPP Annual Planning Capacity Requirement is 12%, the reserve margin at the end of 2015 was over four times the requirement at 49%.[20] Generation additions in the near future are projected to be primarily wind resources.

2.2.3. SPP Transmission and Congestion[21]

Candidate Auction Revenue Rights (ARR) are allocated to the load serving entities that have Network Integration Transmission Service (NITS) to serve their load requirements. Candidate ARR's may be nominated to be converted to ARRs. SPP performs a Simultaneous Feasibility Test (SFT) to determine if nominated ARR's are within the capability of the existing transmission system. If Candidate ARR's are not feasible, the amount awarded is reduced—those paths with the greatest impact on the constraints will have a higher percentage reduction in the award. Based on a recent report that SPP provided to the Market Working Group, approximately 40% of ARR's nominated by NITS holders are feasible and awarded. A significant 22% of NITS holders that nominate ARR's receive no ARR awards. Once ARR's have been awarded, the ARR holder has the opportunity to convert their ARR allocation to a Transmission Congestion Right (TCR). The value of the TCR is based on the LMP differential between the NITS resource point and NITS load settlement point.

The Texas Panhandle is primarily served by 230 kV transmission facilities and continues to be recognized by the SPP Market Monitoring Unit (MMU) as one of the most congested areas in SPP[22] and is the only area that has been consistently identified as such over the last four years.[23]

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19 *Id.*, pp. 18-19.

20 *Id.*, p. 19.

21 *Id.*, Sections 5.3 and 5.3.1.

22 SPP "Frequently Constrained Areas -2016 Study," dated December 2016, p. 8, Figure 1-4.

23 *Id.*, p. 5, Figure 1-1.

3. THE LP&L SYSTEM

The City of Lubbock (City) is the 11th largest city in Texas by population and is projected to grow at an average annual rate of 1.23% between 2016[24] and 2020.[25] The City's growth relies on the vast agriculture industry of the area, education, healthcare, and manufacturing. Texas Tech University is a major economic driver in the City followed by the healthcare industry, which houses the region's largest health systems. The City operates under a council-manager form of government with a City Council comprised of six council members elected from geographic districts and a mayor elected at-large. The City Council appoints a city manager who is the chief administrative officer for the City.

The City's municipally-owned electric utility system, known as LP&L, was established in 1916, and at present is the largest municipal system in the West Texas region and the third largest in the State of Texas. LP&L is governed, with the exception of budget approval, setting of rates, exercising eminent domain power, and issuance of debt, by the Electric Utility Board. The excepted governance responsibilities are maintained by the City Council of the City of Lubbock. The Electric Utility Board is created by Charter of the City of Lubbock, with its powers and authorities prescribed therein and by City of Lubbock Ordinances. The major roles and responsibilities of LP&L (in its capacity as Lubbock's municipal utility), are summarized below:

- LP&L generates and distributes electricity to more than 104,000 customers.
- LP&L operates within certificated areas established by the PUCT, the majority of which is located within the Lubbock city limits.
- In 2010, LP&L purchased the majority of SPS's distribution assets located within the Lubbock city limits making LP&L the electric service provider in the City with the exception of portions of the City of Lubbock that are served by South Plains Electric Cooperative.
- LP&L is a member of WTMPA. Member cities include Lubbock, Brownfield, Floydada, and Tulia. Brownfield, Floydada, and Tulia have announced that they have agreed to terms on a power supply contract for post-2019 that will allow them to remain in SPP.

3.1. LP&L Load

For the purposes of this study, LP&L's load requirements are broken down into two segments: (1) Affected Load and (2) Unaffected Load. "Affected Load" refers to the portion of LP&L load that is subject to the proposed load transfer to ERCOT. "Unaffected Load" refers to

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[24] http://dshs.texas.gov/chs/popdat/ST2016p.shtm.

[25] http://dshs.texas.gov/chs/popdat/st2020.shtm.

the portion of LP&L load remaining in SPP after the load transfer has been effectuated. LP&L provided SPP and ERCOT with the summer peak demand (MW), annual net energy for load (MWh), and monthly allocation factors for peak and energy allocation for their production cost analysis. Table 3.1 shows the total LP&L demand and energy projections for 2020-2025.

Year	**LP&L Total** Peak (MW)	**LP&L Total** Energy (GWh)
2020	647.01	2,807
2021	648.18	2,812
2022	649.37	2,817
2023	650.56	2,822
2024	651.76	2,827
2025	652.97	2,833

Table 3.1: LP&L Total Load Projections

3.1.1. General Description of LP&L Load Characteristics

3.1.1.1. LP&L Unaffected Load

As mentioned above, LP&L acquired distribution assets from SPS in 2010, which are used to serve the Unaffected Load. This acquisition included 19 distribution delivery points that are served off of SPS's transmission system. LP&L acquired only the SPS distribution assets, and SPS retained ownership of its transmission system. The acquired system is electrically isolated from LP&L's legacy transmission and distribution system that serves the Affected Load.

When it acquired the SPS distribution assets, LP&L also entered into a partial requirements contract with SPS that provided for an initial 170 MWs of peak power and associated energy that is intended to meet the electrical requirements of the customer load associated with the acquisition. LP&L intends to honor the terms of the partial requirements contract with SPS associated with the distribution system connected to SPS's transmission system. The Unaffected Load will remain in SPP during the term of the agreement and is not included in the Affected Load that is sought to be interconnected to ERCOT.

3.1.1.1.1. Unaffected Load Summer Peak Demand Forecast

Table 3.2 contains the Summer Peak Demand Forecast for LP&L's Unaffected Load.

LP&L Unaffected Load Year	Peak (MW)
2020	174.19
2021	174.83
2022	175.47
2023	176.11
2024	176.76
2025	177.41

Table 3.2: LP&L Unaffected Load Summer Peak Demand Forecast

3.1.1.1.2. *Unaffected Load Winter Peak Demand Forecast*

Table 3.3 shows the Winter Peak Demand Forecast for the LP&L Unaffected Load. Note that LP&L is a summer peaking entity, and that the winter demand is 68.4% of the summer peak.

LP&L Unaffected Load Year	Peak (MW)
2020	119.08
2021	119.52
2022	119.95
2023	120.39
2024	120.84
2025	121.28

Table 3.3: Unaffected Load Winter Peak Demand Forecast

3.1.1.1.3. *Unaffected Load Net Energy for Load Forecast*

Table 3.4 below shows the Net Energy for Load associated with the LP&L Unaffected Load.

LP&L Unaffected Load Year	Energy (GWh)
2020	608
2021	611
2022	614
2023	616
2024	618
2025	622

Table 3.4: Unaffected Load Net Energy for Load Forecast

3.1.1.2. *Affected Load*

LP&L's Affected Load represents the portion of the total LP&L load requirements that are the subject to the ERCOT load transfer.

3.1.1.2.1. Affected Load Summer Peak Demand Forecast

Table 3.5 contains the Summer Peak Demand Forecast for the LP&L load that is planned to be transferred to ERCOT.

LP&L Affected Load Year	Peak (MW)
2020	472.82
2021	473.36
2022	473.90
2023	474.44
2024	475.00
2025	475.56

Table 3.5: Affected Load Summer Peak Demand Forecast

3.1.1.2.2. Affected Load Winter Peak Demand Forecast

Table 3.6 contains the Winter Peak Demand Forecast for the LP&L load that is planned to be transferred to ERCOT. As previously stated, LP&L is a summer-peaking entity; winter demand is 68.4% of the summer peak.

LP&L Affected Load Year	Peak (MW)
2020	323.23
2021	323.59
2022	323.96
2023	324.34
2024	324.72
2025	325.10

Table 3.6: Affected Load Winter Peak Demand Forecast

3.1.1.2.3. Affected Load Net Energy for Load Forecast

Table 3.7 below shows the Net Energy for Load associated with the portion of the LP&L load that is planned to be transferred to ERCOT.

LP&L Affected Load Year	Peak (MW)
2020	323.23
2021	323.59
2022	323.96
2023	324.34
2024	324.72
2025	325.10

Table 3.7: Net Energy Load Being Transferred to ERCOT

3.2. LP&L Generation and Power Supply

3.2.1. Characteristics of LP&L Owned Generation—Existing and Planned

LP&L owns a mixture of peaking combustion turbine (CT) and intermediate combined cycle (CC) units, totaling approximately 112 MW (111.91 MW), consisting of three CT units at Brandon Station (20.91 MW) and Ty Cooke Generating Station (units 2 and 3 with maximum capacities of 16 MW and 17 MW, respectively). LP&L also owns 58 MW of combined cycle resources at Massengale. Table 3.8 shows the generating characteristics of the LP&L-owned generating resources. Table 3.9 shows the historical capacity factors of the LP&L generating assets.

Name	Category	Maximum Capacity (MW)	Commission Date	Summer Heat Rate (Btu/kWh)
Brandon GT 1	CT Gas	20.91	7/1/1990	10,365
R Massengale CC 6A8	CC	58.00	9/1/2000	10,988
Ty Cooke GT 2	CT Gas	16.00	6/1/1971	11,520
Ty Cooke GT 3	CT Gas	17.00	7/1/1974	15,461

Table 3.8: Characteristics of LP&L Owned Generating Resources

	Annual Capacity Factor (%)	
Unit Name	**2015**	**2016**
Massengale	4.45%	14.16%
Brandon	5.37%	12.83%
Cooke	0.15%	3.26%

Table 3.9: LP&L Historical Capacity Factors for Generating Assets

Two additional gas fired steam electric generating units are located at the Cooke station, which have maximum capabilities of 42 MW and 46 MW. These units have been designated for long-term cold storage. These units can be converted to synchronous condensers to provide support in ERCOT, as needed.

LP&L currently has power supply agreements through WTMPA with SPS to serve the LP&L load. The LP&L-owned generation and Affected Load will move to ERCOT as part of the load transfer. The Unaffected Load will remain in SPP and be served by SPS under a separate power supply agreement and a WTMPA Elk City wind agreement.

This study does not assume that LP&L will be developing any new generation options during the study period, which is consistent with SPP's study.

3.3. LP&L Transmission Facilities

3.3.1. Current LP&L Configuration and Planned Expansion

LP&L has been working with DNV-GL to update the facilities surrounding the City by converting a portion of LP&L's 69 kV transmission to create an outer 115 kV loop that will feed an inner 69 kV loop within the LP&L service territory. The 115 kV facilities are included in a City Council approved Capital Improvements Plan and are currently in the process of engineering design, with construction anticipated to be complete by early 2021. These 115 kV facilities are reflected in this analysis. LP&L provided the revised LP&L system configuration to both SPP and ERCOT to ensure modeling consistency between all three study efforts.

As mentioned in Section 3.1.1.1, LP&L acquired distribution assets from SPS in 2010. This acquisition included 19 distribution delivery points that were served off of SPS's transmission system. LP&L acquired only the SPS distribution assets and SPS retained ownership of its transmission system. The acquired system is electrically isolated from LP&L's transmission and distribution system serving the Affected Load. The load served by the acquired distribution assets, the Unaffected Load, will remain in SPP during the term of the agreement and is not included in the load that will be interconnected to ERCOT.

3.3.1.1. Interconnection Points with SPS

LP&L's Affected Load is presently served by four 230 kV interconnections with SPS. The interconnection at the Holly station is a 230/69 kV interconnection, while the remaining three 230 kV interconnection points at Wadsworth, McDonald, and Southeast are ties to the planned LP&L 115 kV loop. Figure 3.1 below shows the LP&L topology as modeled for the current interconnection with SPP.

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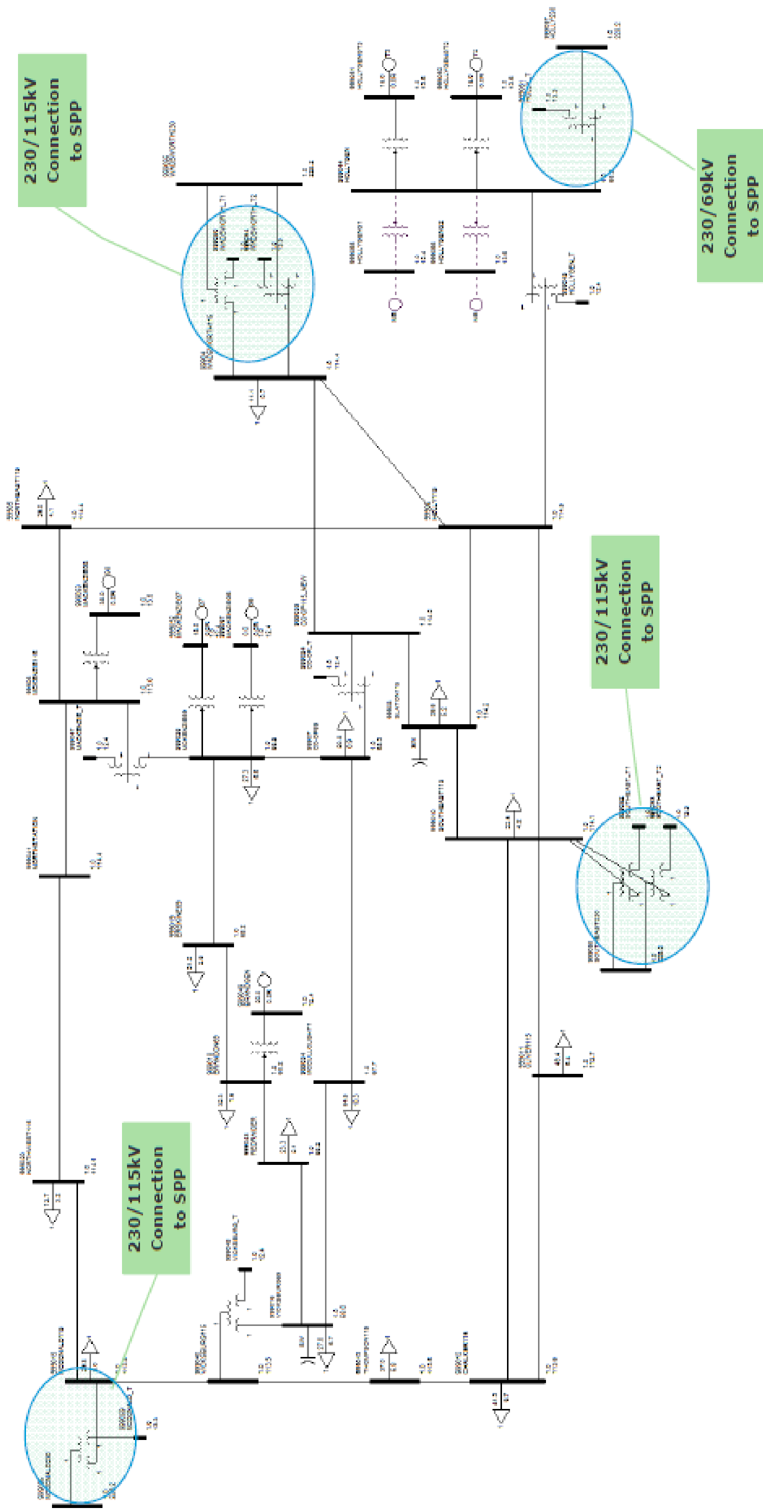

Figure 3.1: LP&L System Configuration in SPP

3.3.2. LP&L Transmission Facilities Associated with the Unaffected Load

The Unaffected Load is served from SPS transmission facilities through LP&L's acquired distribution facilities. No LP&L transmission facilities will remain in SPP upon completion of the ERCOT load transfer.

3.3.3. LP&L Transmission Facilities Affiliated with Affected Load

Given the unique nature of the service to the Unaffected Load through the 2010 acquisition, all LP&L facilities shown in Figure 3.1 above are affiliated with the transfer of the Affected Load to ERCOT.

3.3.4. Incremental Facilities Required to Transition LP&L Affected Load to ERCOT

The final configuration agreed upon between ERCOT and LP&L for the analysis assumes that the four 230 kV interconnections with SPS are eliminated and replaced with three 345 kV interconnection points within the ERCOT system. The Wadsworth interconnection will be converted to a 345/115 kV interconnection, and the station will be fed from the Ogallala–Abernathy–Wadsworth–Oliver–Long Draw 345kV line. The interconnection at McDonald will be eliminated and replaced by a 345/115 kV interconnection at a proposed LP&L North 115 kV station. This interconnection will be fed from the Ogallala–Abernathy–North 345 kV line. To the south, the LP&L system will no longer be fed from the Southeast station. Instead, two new 115 kV lines will be sourced from the new Oliver 345 kV station and will feed the LP&L Chalker and LP&L Oliver stations. Figure 3.2 illustrates the revised LP&L interconnection with ERCOT as supplied to ERCOT for its study.

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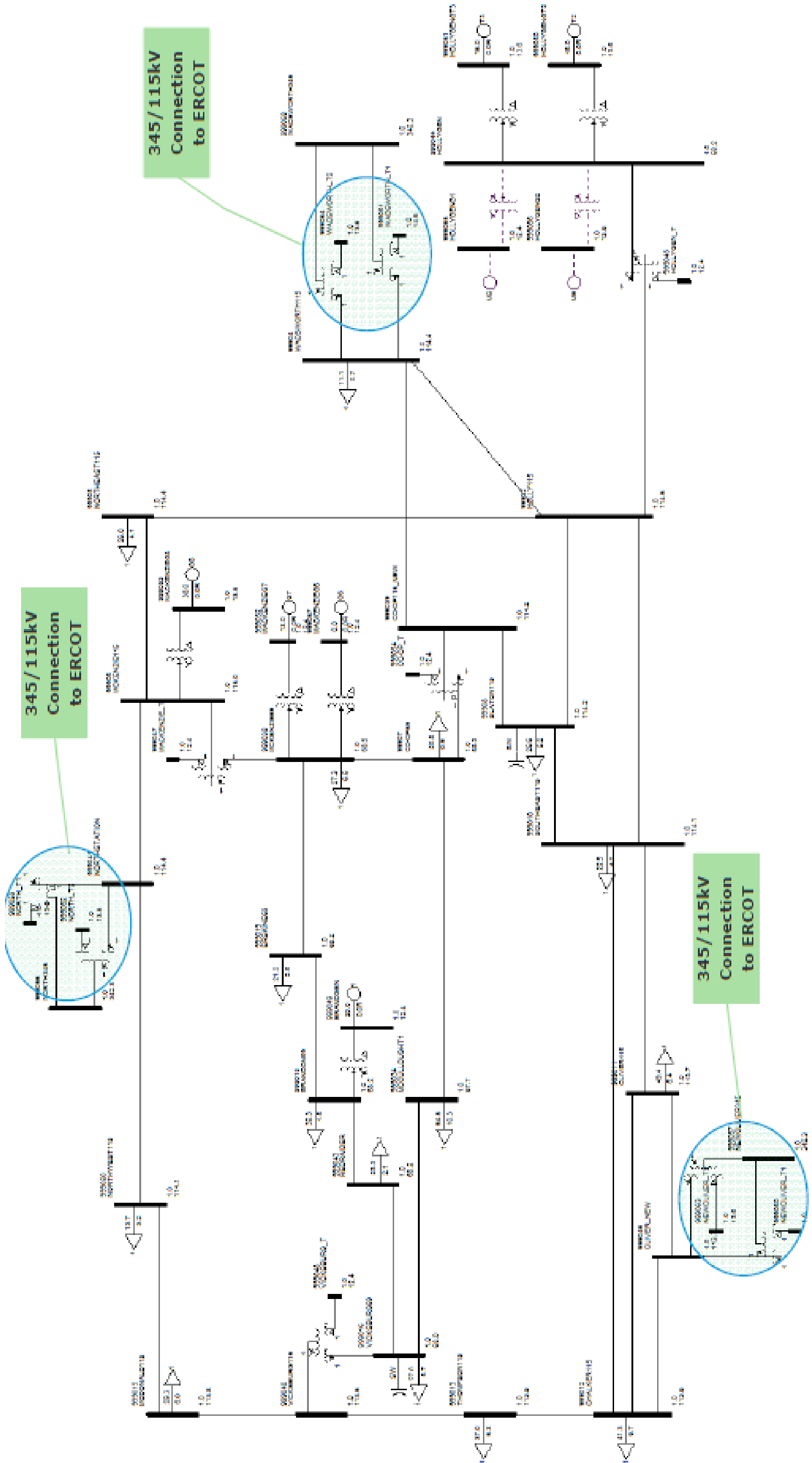

Figure 3.2: LP&L System Configuration in ERCOT

A significant portion of the facilities that have been proposed to integrate the LP&L Affected Load into ERCOT have been on the ERCOT drawing board since at least April 2014. ERCOT published the April 2014 Panhandle Renewable Energy Zone (PREZ) Report that identified two sets of upgrades to increase the Panhandle export capability as wind generation was expected to increase in the Panhandle.[26] The Stage 1 upgrades included the addition of two synchronous condensers and a second Alibates to Tule Canyon 345 kV loop.[27] The Stage 2 improvements referenced additional synchronous condensers and a new Ogallala to Long Draw 345 kV line. Figure 3.3 illustrates the original plan for the Stage 2 upgrade.

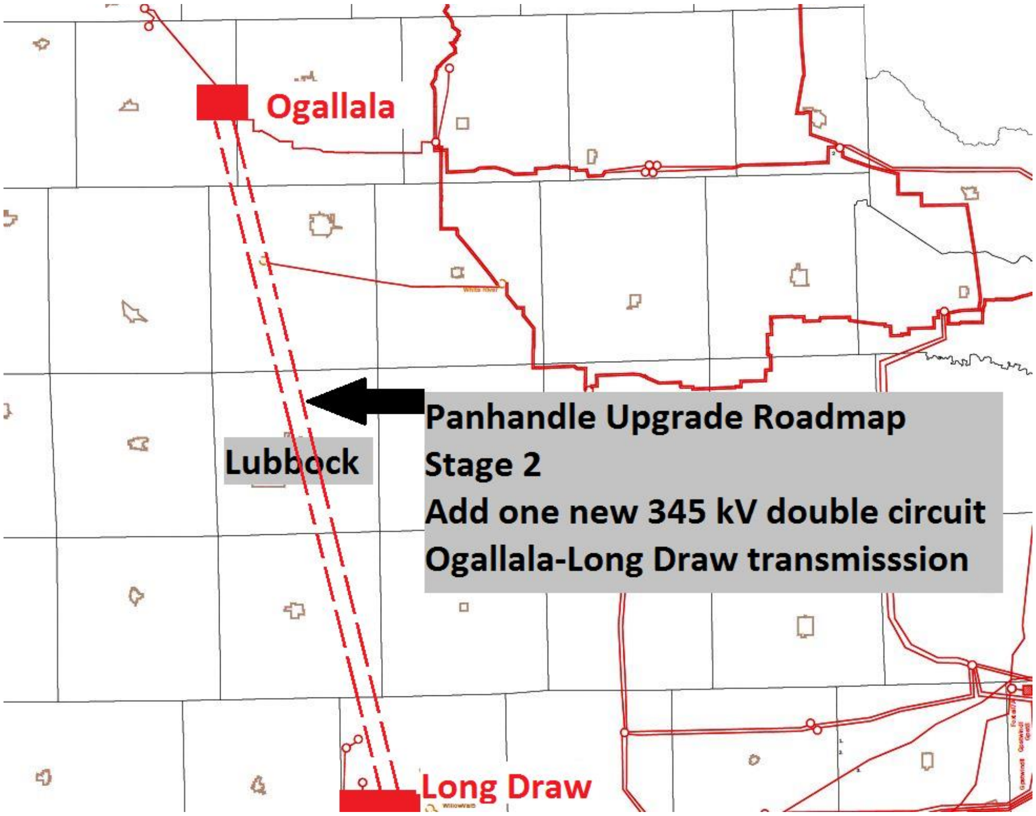

Figure 3.3: Ogallala to Long Draw Proposal[28]

On September 24, 2015, the Commission requested that ERCOT develop a report outlining the transmission facilities that would be needed to integrate the LP&L system into ERCOT. ERCOT published its findings on June 9, 2016 as the "Study of the Integration of the Lubbock Power & Light System into the ERCOT System (Version 1.0)," referred to in this

26 "Study of the Integration of the Lubbock Power & Light System into the ERCOT System (Version 1.0)", published June 9, 2016, Section 5.1.

27 Sharyland Utilities received CCN approval in 2016; the project is under construction with an expected in-service date of March-April 2018.

28 "Study of the Integration of the Lubbock Power & Light System into the ERCOT System (Version 1.0)", published June 9, 2016, Section 5.1.

document as the "June 2016 ERCOT LP&L Integration Study," which is discussed in the next section.

3.3.4.1. Alternatives Examined by ERCOT RPG

The study scope and approach for the June 2016 ERCOT LP&L Integration Study was presented to the Regional Planning Group (RPG) in December 2015. In developing the list of options to be evaluated, ERCOT relied on previous analyses conducted by both LP&L[29] and Sharyland, along with other studies performed by ERCOT.[30]

ERCOT selected nine LP&L options and two Sharyland Utilities' options for their evaluation. Table 3.10 shows the list of selected options and estimated capital costs.[31] Figures 3.4 and 3.5 show the schematic of eight of the nine LP&L options, with Option 12C excluded.[32]

Case	Capital Cost Estimate
LPL Option 1	$311,818,800
LPL Option 4	$344,443,600
LPL Option 4ow	$364,081,400
LPL Option 8A	$426,107,200
LPL Option 8B	$338,096,000
LPL Option 11	$492,368,200
LPL Option 12	$397,751,918
LPL Option 12C	$391,751,918
LPL Option 20	$466,552,338
SHY Option 1-2a	$383,800,200
SHY Option 1-2b	$365,076,200

Table 3.10: ERCOT Studied Options and Cost Estimates

29 "Lubbock Power & Light ERCOT Integration Study," December 9, 2015.

30 "Study of the Integration of the Lubbock Power & Light System into the ERCOT System (Version 1.0)," published June 9, 2016., Section 2.

31 *Id.*, Table 4.3.

32 "Lubbock Power & Light ERCOT Integration Study," December 9, 2015, Appendix B.

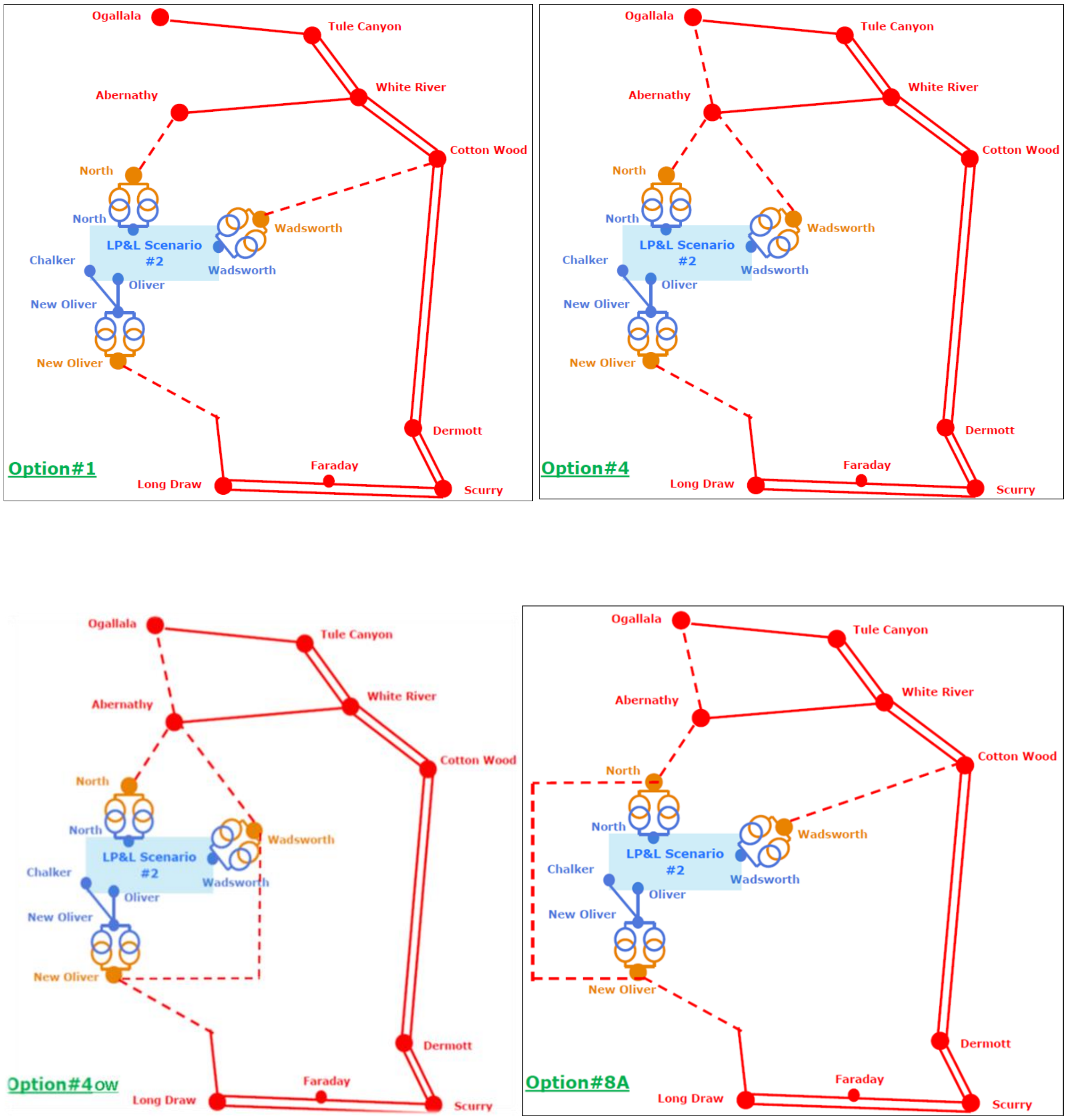

Figure 3.4: Interconnection Options Evaluated by ERCOT – Part 1

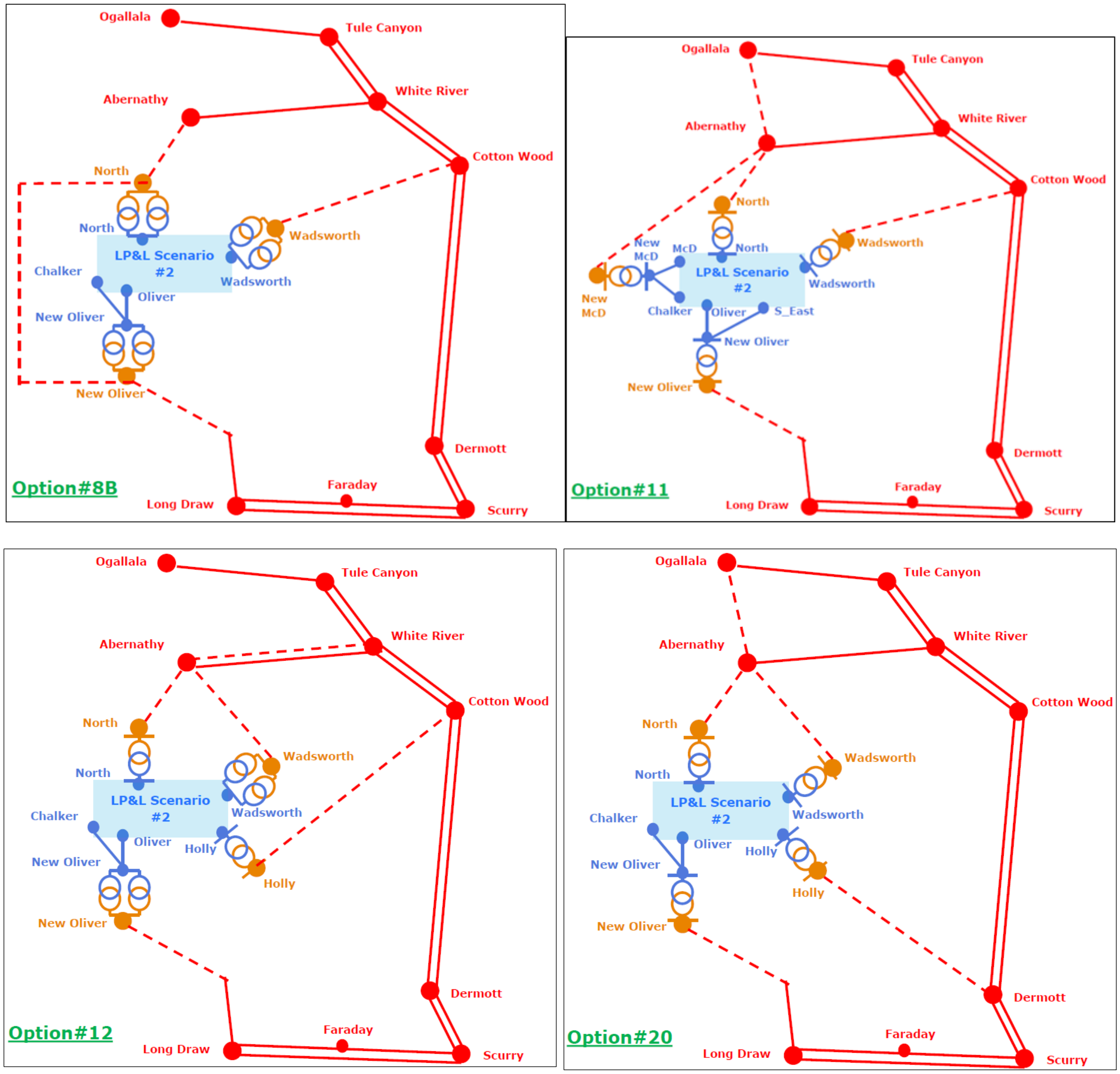

Figure 3.5: Interconnection Options Evaluated by ERCOT – Part 2

In the June 2016 ERCOT LP&L Integration Study, the evaluation of the various options included several factors[33] to identify a preferred option. This list of evaluation criteria[34] includes:

- Steady-state evaluation: Does the recommended option reliably integrate LP&L into ERCOT while meeting regional reliability criteria?[35]
- Weighted Short-Circuit Ratio (WSCR): What is the relative performance of various options (and specifically the recommended option) in terms of improving the system strength and the related Panhandle export capability?[36]
- Panhandle export limits: What is the effect of the project on Panhandle wind export capability?[37]
- Economic assessment: How do the various options compare in terms of relative economic merits quantified in terms of production cost impacts?[38]
- Load deliverability: Can the project handle the long-term LP&L load projection?[39]

The June 2016 ERCOT LP&L Integration Study results indicated that of all the options, two options clearly distinguished themselves throughout the analysis—LP&L Option 4ow and LP&L Option 8B. LP&L Option 8B had the best performance on the WSCR[40] and Panhandle Export[41] criteria, but was only slightly better than the LP&L Option 4ow project. With respect to the economic assessment,[42] LP&L Option 4ow had the second highest relative annual production cost benefit at $11.3 million when compared to the option with the lowest capital cost, LP&L Option 1, while LP&L Option 8B had a $5.2 million incremental benefit. The two

[33] "Study of the Integration of the Lubbock Power & Light System into the ERCOT System (Version 1.0)", published June 9, 2016, Section 4.

[34] The evaluation of the impact of the LP&L load transfer to ERCOT in both the ERCOT study and this LP&L Assessment continue to consider those same factors to maintain consistency in study methodology and provide the ability to assess how various factors have changed over the study processes.

[35] "Study of the Integration of the Lubbock Power & Light System into the ERCOT System (Version 1.0)", published June 9, 2016, Section 3.2.1.

[36] *Id.*, Section 3.1.3.

[37] *Id.*, Section 4.3.

[38] *Id.*, Section 4.4.

[39] *Id.*, Section 4.5.

[40] *Id.*, Table 4.1.

[41] *Id.*, Table 4.2.

[42] *Id.*, Table 4.3.

preferred options were virtually identical when assessing load deliverability. The same limiting element / limiting contingency pair restricted both results, but LP&L Option 4ow had a 3 MW higher load deliverability factor.[43]

3.3.4.2. The Preferred Option: The "4ow" Plan

ERCOT concluded that the Option 4ow plan would be well aligned with the 2014 Panhandle Roadmap Stage 2 upgrade from Ogallala to Long Draw[44] and that it would integrate LP&L load into ERCOT while meeting applicable reliability criteria, would have the lowest societal cost when considering capital cost and production costs, would provide for the largest Panhandle export increase, and would provide greater opportunities for expansion.[45]

The decision to prefer the LP&L Option 4ow plan does result in an incremental capital cost increase of $52.3 million over the base case, but ERCOT also recognized that the incremental facilities result in $11 million decrease to ERCOT annual production costs, which justifies the capital cost increase of the Option 4ow plan.

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43 *Id.*, Table 4.4.

44 *Id.*, Section 5.1.

45 *Id.*, Section 5.3.

4. GENERAL ASSUMPTIONS

4.1. Production Cost Definitions

LP&L, ERCOT, and SPP all provide different variations of production cost analysis in response to the July 19 Memorandum from Chairman Nelson. Each RTO and LP&L have taken the components of their respective analyses to compute production cost impacts, but it should be noted that the production cost calculation varies between studies. The definitions below are designed to assist the reader in understanding the production cost calculation methodology used by LP&L in this Study and how it compares and/or contrasts with that used in the joint ERCOT-SPP study.

4.1.1. LP&L Adjusted Production Cost (LP&L APC)

In the pre-RTO construct, the LP&L customer base was responsible for paying the total annual revenue requirement related to the cost of producing and delivering energy and capacity to meet the total LP&L load requirements. The components of the consumer bill primarily consisted of generation, transmission, and local distribution charges. Under the RTO market design, the cost of load and the cost of operating generation are bifurcated and the LMP defines the cost to serve the load at that point on the electric grid. LP&L's generation is dispatched to meet total RTO load requirements and is not tied to the LP&L load serving obligation. The generation resources effectively operate as a separate entity. The difference between operating LP&L generation and the revenue collected from the RTO based on the LMP at the generator bus lower the cost to LP&L consumers and is reflected in the LP&L APC benefits metric.

In summary, the LP&L APC is defined as:

$$\text{LP\&L APC} = (\text{Load Cost}_{\text{Affected Load}} + \text{Load Cost}_{\text{Unaffected Load}}) - \text{LP\&L Generator Margins},$$

where LP&L Generator Margins = (Revenue from LP&L Generation - Production Cost for LP&L Generation)

The LP&L APC calculation is the same whether the Affected Load moves to ERCOT or remains in SPP.

4.1.2. ERCOT Adjusted Production Cost (ERCOT APC)

ERCOT uses an annual production cost, unadjusted for purchases and sales, for economic evaluations of transmission projects within the ERCOT footprint. The annual production cost is an effective metric that captures the decrease in generation production costs due to new transmission projects or transmission upgrades that relieve the congestion on the bulk electric system within ERCOT. However, when calculating the economic benefits before and after the addition of a transmission project, the annual production cost metric does not take into account any other factor except for the change in generation production costs. ERCOT's annual production cost metric is, therefore, not an effective metric when calculating the benefits and costs associated with the integration studies in which the proposed projects consist of transmission lines and loads.

Under such circumstances, multiple RTO/ISOs in the United States, including Midcontinent ISO (MISO), SPP, and PJM, use variations of this metric, known as the Adjusted Production Costs metric. When integrating load into ERCOT, the production cost in ERCOT is bound to increase due to serving the additional consumers. Such increase in production cost is expected to be offset by the payments made by the additional consumers. The ERCOT APC metric used in this study intends to capture the changes in load by adjusting the annual production cost for the payments made by the additional load integrating into the ERCOT footprint.

The formula below demonstrates the calculation of ERCOT Hourly Adjusted Production Costs.

$$\begin{aligned} &Hourly\ Adj.Production\ Cost\ benefit\ (\Delta\ Adj.PC) \\ &= [\,Hourly\ Production\ Costs\ (PC)_{w\ LP\&L} \quad - Production\ Costs_{Base\ Case}] \\ &\qquad\qquad - \sum_{node\ i} (Load_i * LMP_i) \end{aligned}$$

I: LP&L nodes
LMP_i: Locational Marginal Price at Node i
$Load_i$: Load (MW) at node i

4.1.3. SPP Adjusted Production Cost (SPP APC)

Benefits for SPP are calculated using both the LP&L APC and the SPP Adjusted Production Cost (SPP APC) as referenced in the SPP APC Calculation white paper associated with the 2017 ITP10 Study, dated February 29, 2016. In short, SPP relies on a formula of:

Adjusted Production Cost $ = Production Cost $ + Purchase $ - Sales $

To expand upon the definition, in each hour, SPP captures all of the generator production costs for each company within the footprint. The company generation is measured against the company load to determine if the company is long or short on generation in the hour. If short, the company is assumed to be purchasing, and this deficit is priced at the load weighted LMP for the company. Conversely, if the company is long on generation, the company is assumed to be selling, and this surplus is priced at the company generation weighted LMP. In the SPP APC there is no treatment of load costs, only production costs, purchases, and sales.

4.1.4. Summary of APC Calculations for LP&L, ERCOT, and SPP

Table 4.1 provides a side-by-side comparison of the LP&L APC, ERCOT APC, and SPP APC calculations as defined above. The only common component between the methodologies is the generator production cost. The LP&L APC is the preferred method for assessing the impact to the LP&L consumers because it is the only method that captures the real costs borne by the customer, which includes the cost to serve the load, the cost to operate LP&L generation, and any revenues that provide an offset to the generator production costs and load payments. The ERCOT APC as defined below includes the effect of the increased load payments that ERCOT receives as a result of additional load being brought to the system. The SPP APC only focuses on the generator side of the equation consistent with their approved methodology. It should also be noted that PJM, which is one of the most mature energy markets in the US, includes the effect of load payments in its evaluation of transmission.[46] There is also stakeholder discussion within MISO to consider the use of load payments as a component of its evaluation of Market Efficiency Projects.

APC Component	LP&L APC	ERCOT APC	SPP APC
Load Cost	Yes	Yes, only includes LP&L incremental load	No
Generator Production Cost	Yes	Yes	Yes
Generator Revenue	Yes	No	No
Purchases/Sales	No	No	Yes

Table 4.1: Comparison of Adjusted Production Cost Calculations

4.2. Economic Models and Assumptions

To conduct an economic evaluation of the impact of the LP&L load transfer on both the ERCOT and SPP systems, the effects of the load change in each region on resource dispatch, cost of generation, and the cost of load must be considered. The proper tool to reflect these factors is an hourly Security Constrained Economic Dispatch (SCED)-based production cost simulation. Such a simulation can assess the economic performance of each RTO under different system conditions.

The bases for the SPP production cost analysis are the 2020 and 2025 SPP Integrated Transmission Plan–Ten Year (ITP 10) models with adjustments made for the LP&L study. The ERCOT 2016 Regional Transmission Planning (RTP) 2019 economic dataset and assumptions are used as the basis for the development of the 2020 study year model. Further, the ERCOT 2016

[46] http://www.pjm.com/-/media/documents/manuals/m14b.ashx, pp. 43-44.

Long-Term System Assessment (LTSA) 2025 economic dataset and assumptions are used as a basis for the 2025 study year model. This is done to align with the ERCOT–SPP coordinated study scope to the extent possible. Details associated with economic modeling assumptions are provided in the subsequent sections of this report.

The results of the economic analysis have been used to address the following facets of Chairman Nelson's Memorandum regarding the impact of the LP&L integration on both the ERCOT and SPP grids:

- Impact on Energy Production Costs—The results of the economic analysis are used to derive the annual energy production cost impacts on both the ERCOT and the SPP grids. Due to the unique nature of this transition (LP&L transition from SPP to ERCOT includes transmission and load facilities), several variations of the annual production cost (adjusted for relevant load payments) are used to quantify the total production cost impact. Definitions of these variations in production cost are provided earlier in this Section.

- Cost impacts on all customer classes—While Section 7 in this report provides a comprehensive evaluation of the cost impacts on all customer classes in ERCOT and SPP, the LMPs resulting from the economic analysis are used to provide a sense of the cost impact on serving future load in both ERCOT and SPP following the integration of LP&L into ERCOT.

- Analysis of avoided or new projects—The results of the economic analysis are used to identify any avoided projects by virtue of the LP&L integration into ERCOT.

- System Loss impacts—While not explicitly outlined in Chairman Nelson's Memorandum, the impact of LP&L integration into ERCOT on system losses has been quantified. The economics associated with system loss impacts have been expressed in terms of potentially avoided (or additionally required) Cost Of New Entry (CONE).

In addition to the above, qualitative analysis and commentary around the impact of LP&L integration into ERCOT regarding the following aspects is provided:

- Ancillary Service Benefits

- Financial Transmission Rights (FTRs) or Congestion Revenue Rights (CRRs)

To the greatest extent possible, the LP&L study uses the same basic input assumptions as the ERCOT and SPP studies. Where the LP&L analysis uses different assumptions, these are pointed out along with the reasons for using different assumptions.

4.2.1.1. Generation

LP&L provided both SPP and ERCOT with dispatch parameters for the LP&L generating resources. The associated parameters are included in Table 3.8 above.

No changes were made to the SPP production cost cases regarding generation expansion.

All the generation units modeled in the ERCOT 2016 RTP for 2019 study and 2016 LTSA for 2025 (current trends scenario) economic models have been included in the ERCOT study. The Generation Interconnection Status (GIS) Report dated February 2017 is used to identify and incrementally add any generation units that meet Section 6.9 requirements of the ERCOT Planning Guide but were not modeled in the study models.

The list of incremental generation units added to create the ERCOT study models for 2020 and 2025 are depicted in Table 4.2.

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Generations near Study Region - Feb 2017 GIS					
GINR Reference Number	Project Name	County	Projected Date	Fuel	MW For Grid
15INR0061	SolaireHolman 1	Brewster	3/1/2017	SOLAR	50
14INR0023b	Longhorn South	Briscoe	12/1/2017	WIND	160
13INR0005c	Grandview W 3	Carson	12/1/2017	WIND	188
15INR0085	Tyler Bluff Wind	Cooke	4/1/2017	WIND	126
16INR0023	BNB Lamesa Solar (Phase I)	Dawson	3/1/2017	SOLAR	102
15INR0074	Falvez Astra W	Deaf Smith	5/1/2017	WIND	163
16INR0037b	Old Settler Wind	Floyd	2/1/2017	WIND	150
16INR0037	Cotton Plains Wind	Floyd	3/1/2017	WIND	50
16INR0037c	Pumpkin Farm Wind	Floyd	1/1/2019	WIND	280
15INR0064	BearKat Wind A	Glasscock	9/1/2017	WIND	197
15INR0064b	BearKat Wind B	Glasscock	4/1/2018	WIND	163
14INR0062	Salt Fork 1 Wind	Gray	4/1/2017	WIND	174
14INR0060b	Willow Springs Wind	Haskell	10/1/2017	WIND	230
16INR0087	RTS Wind	McCulloch	10/1/2017	WIND	160
13INR0010b	Mariah Del Norte	Parmer	2/1/2017	WIND	230
13INR0010a	Mariah Del Este	Parmer	6/1/2018	WIND	139
13INR0010c	Mariah Del Sur	Parmer	6/1/2018	WIND	230
12INR0059b	Barilla Solar 1B	Pecos	2/1/2017	SOLAR	7
15INR0070_1	West Texas Solar	Pecos	3/1/2017	SOLAR	110
16INR0073	East Pecos Solar	Pecos	3/1/2017	SOLAR	120
15INR0070_1b	Pearl Solar	Pecos	4/1/2017	SOLAR	50
15INR0045	Riggins Solar	Pecos	12/1/2017	SOLAR	150
17INR0020a	RE Maplewood 2a Solar	Pecos	12/1/2018	SOLAR	100
17INR0020b	RE Maplewood 2b Solar	Pecos	12/1/2019	SOLAR	100
17INR0020c	RE Maplewood 2c Solar	Pecos	12/1/2019	SOLAR	100
17INR0020d	RE Maplewood 2d Solar	Pecos	12/1/2020	SOLAR	100
17INR0020e	RE Maplewood 2e Solar	Pecos	12/1/2020	SOLAR	100
16INR0091	Santa Rita Wind	Reagan	12/1/2017	WIND	300
14INR0044	West of Pecos Solar	Reeves	12/1/2017	SOLAR	100
17INR0027	Dermott Wind 1	Scurry	9/1/2017	WIND	250
13INR0056	Fluvanna Renewable 1	Scurry	10/1/2017	WIND	155
17INR0027b	Coyote Wind	Scurry	9/1/2018	WIND	250
13INR0038	Swisher Wind	Swisher	12/1/2017	WIND	300
16INR0065b	SP-TX-12-Phase B	Upton	8/1/2017	SOLAR	120
16INR0114	Upton Solar	Upton	12/1/2018	SOLAR	102
16INR0065	Castle Gap Solar	Upton	1/1/2019	SOLAR	150
16INR0065a	Castle Gap Solar 2	Upton	1/1/2020	SOLAR	30
11INR0082a	Val Verde Wind	Val Verde	8/1/2017	WIND	149
16INR0062b	Lockett Wind Farm	Wilbarger	10/1/2017	WIND	184

Table 4.2: List of Incremental Generation Units Added to Create Study Models

ERCOT-provided wind (AWS True Wind profile) and PV-SAT solar profiles (also provided by ERCOT) were used to derive the hourly production profiles for all the wind and solar units. As explained below, specific focus was placed on the modeling and treatment of the Golden Spread Electric Cooperative (GSEC) Antelope Station and Elk Station generation units. Detailed information associated with the pattern and duration of commitment combined with accurate incremental heat rate curves was used to model these generation resources in the economic model.

One unique consideration in the analysis involves the dispatch commitment of the GSEC Antelope and Elk units because they have the capability to participate in either the SPP or ERCOT markets. GSEC agreed to release its confidential operational parameters and commitment patterns under a Non-Disclosure Agreement (NDA) to ensure that imports and exports to SPP and ERCOT are consistently modeled in all scenarios.

4.2.1.2. Load Modeling

LP&L provided both ERCOT and SPP a revised load forecast of the LP&L Affected Load and Unaffected Load to be used in the production cost analysis. The load information provided to ERCOT and SPP is discussed in Section 3.1.

No changes are made to any load profiles in SPP other than the removal of the Affected Load.

Demand peak and energy values used for ERCOT zones follow ERCOT's assumptions for load in the 2016 ERCOT 2019 RTP model adjusted for the 2020 study year and 2016 LTSA 2025 model for the 2025 study year. Table 4.3 and Table 4.4 depict the ERCOT wide annual demand peak and energy trend used for the economic assessment. These assumptions for load forecast are used to update the hourly load profiles for the study models.

Demand Peak (MW)	2020	2025
ERCOT Houston Zone	22,254	21,747
ERCOT North Zone	29,459	29,373
ERCOT South Zone	20,110	20,507
ERCOT West Zone	5,454	5,950
Total ERCOT CP	74,429	76,553

Table 4.3: ERCOT Peak Demand Forecast

Annual - Energy (TWh)	2020	2025
ERCOT Houston Zone	129	128
ERCOT North Zone	134	137
ERCOT South Zone	108	112
ERCOT West Zone	34	38
Total ERCOT	406	415

Table 4.4: ERCOT Annual Energy Forecast

4.2.1.3. Fuel Price Forecast

ERCOT and SPP agreed to use an EIA natural gas forecast that was consistently applied in all production cost models. The LP&L analysis relies on this natural gas forecast for its production cost runs. In line with the ERCOT 2016 RTP Study Assumptions, Natural Gas prices as shown in Table 4.5 are used by LP&L for its economic assessments.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	5.08	5.03	4.97	4.73	4.75	4.76	4.79	4.83	4.83	4.86	4.98	5.18
2025	6.50	6.44	6.36	6.05	6.07	6.10	6.14	6.18	6.18	6.22	6.38	6.63

Table 4.5: Natural Gas Commodity Price Forecast (Henry Hub)

Table 4.6 shows the coal price range employed by LP&L.

Fuel Forecast	2020	2025
Coal	2.32 - 3.29	2.8 - 4.03

Table 4.6: Coal Price Forecasts

4.2.1.4. Transmission Additions

As stated in Section 3, a revised LP&L transmission system topology, including new transmission lines internal to the LP&L System, revised facility ratings, and updated impedance data, was provided to both ERCOT and SPP to ensure conformity in the study process.

Upon review of the SPP power flow cases, no changes to the SPP transmission system topology were made with the exception of the removal of the LP&L transmission system associated with the Affected Load transfer.

The 2016 RTP 2019 and 2016 LTSA 2025 power flow cases for the study years 2020 and 2025 are used to model the base transmission topology in ERCOT. Additionally, the ERCOT Transmission Project and Information Tracking (TPIT) report from February 2017 was used to incrementally add any new transmission projects that have been approved but not modeled in the base topology.

In the vicinity of the LP&L system, the following Panhandle region upgrades were included in the study models:

- Addition of a 2nd circuit along the Alibates–AJ Swope–Windmill–Ogallala–Tule Canyon 345 kV loop
- Addition of two (2) 175 MVA Synchronous Condensers at Tule Canyon and Alibates stations.

The following Panhandle region additions are NOT included in the study models:

- Third 175 MVA Synchronous Condenser at Windmill Station—This upgrade was deemed economic per ERCOT 2016 RTP assessment. However, this was not included in the study models by virtue of the results of avoided project analysis. The issue is more completely addressed in Section 5.3.3.
- 345 kV South Plains project—This project was still under ERCOT-independent review at the time of this assessment and hence was not included in the study models.

4.2.1.5. LP&L System Modeling

The LP&L system is modeled with a 115 kV outer loop encircling a 69 kV inner loop as described in Section 3. All generation facilities within LP&L (Massengale, Brandon, and Cooke) are modeled with a total peak capacity of approximately 112 MW. The LP&L load is used for economic modeling purposes and is shown in Table 4.7. The LP&L 8,760 hourly load profiles, as provided by LP&L, were used for the assessment.

Year	Peak (MW)	Energy (GWh)
2020	472.8	2,199
2021	473.4	2,201
2022	473.9	2,203
2023	474.4	2,206
2024	475.0	2,209
2025	475.6	2,211

Table 4.7: LP&L BAU Load Used for Economic Modeling Purposes

ERCOT's recommended transmission Option 4ow was used to integrate LP&L network into the ERCOT grid. An economic assessment was conducted for all the three study scenarios as defined in Section 4.3.2 for study years of 2020 and 2025.

4.2.1.6. ERCOT Panhandle Interface Definition

Per the Panhandle Transfer Capability Analysis report issued by ERCOT on September 8, 2015, the Panhandle Interface is defined to comprise the following 345 kV lines:

- Tesla–Riley/Jim Treece (double circuit line)
- Tesla–Edith Clarke (double circuit line)
- Cottonwood–Edith Clarke (double circuit line)
- Cottonwood–Dermott (double circuit line)

Figure 4.1 shows a contour map outlining the existing Panhandle Interface definition. Existing Panhandle Interface definitions comprises of all the dashed transmission lines. However, the addition of the LP&L network and the interconnection option changes the definition of the Panhandle Interface. Figure 4.2 shows a contour map outlining the Panhandle Interface definition defined by ERCOT with the recommended Option 4ow.

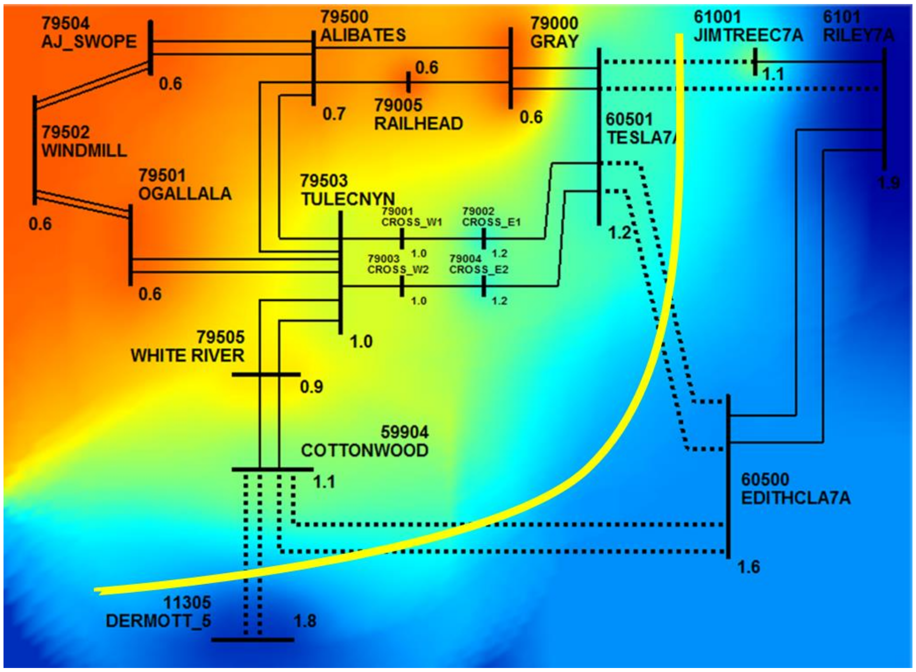

Figure 4.1: Panhandle Interface Definition Without LP&L[47]

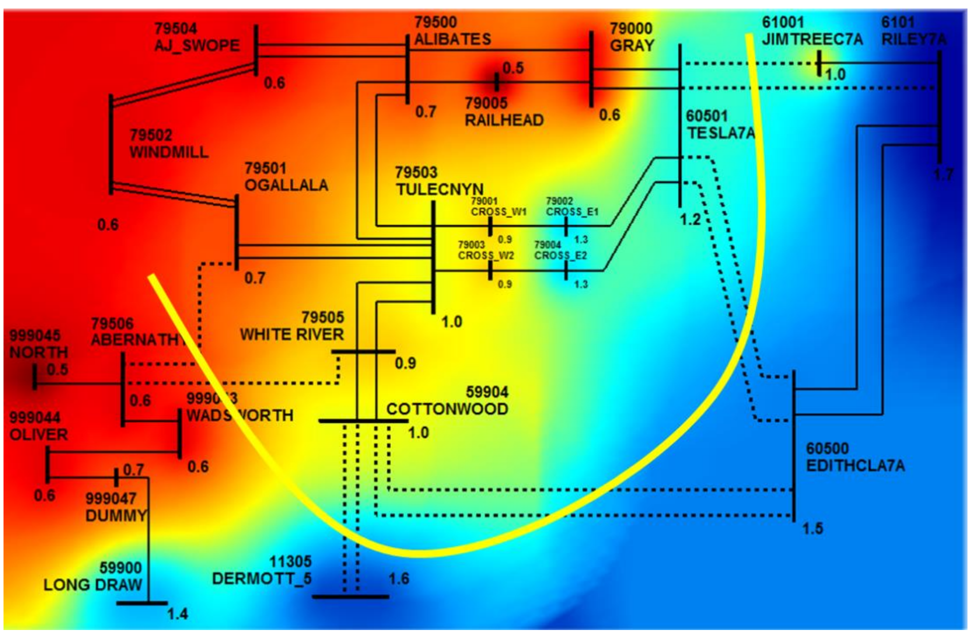

Figure 4.2: Panhandle Interface Definition with LP&L Integration Option 4ow[48]

To account for the operational margin, 90% of the planning-level Panhandle Interface limit as obtained in Section 5.3.3 was used as the operational Panhandle Interface limit for the economic assessment.

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[47] "Panhandle Transfer Capability Analysis" Report – ERCOT – September 8, 2015 (emphasis added).

[48] "LP&L Study Status Update for Regional Planning Group" at Appendix Y – ERCOT – March 22, 2016 (emphasis added).

4.3. Reliability Models and Base Assumptions

The ERCOT and SPP economic assessments referenced in Section 4.1 only tell a portion of the story regarding the LP&L load transfer scenario. In addition to changes in the cost of production and cost of load service, flows on the respective transmission systems of ERCOT, SPP, and LP&L are affected. These changes in the network topology may result in impacts to the transmission system, such as thermal loading and voltage issues, stability concerns, and short circuit impacts. Steady state power flow analysis forms the primary basis for the evaluation of reliability impacts under NERC and ERCOT criteria for transmission planning. In addition to the traditional contingency assessments conducted by both SPP and ERCOT, the ERCOT analysis also evaluates weighted short-circuit ratio (WSCR), stability effects, Panhandle export limit impacts, sub-synchronous resonance impact, and operational flexibility issues.

4.3.1. SPP Reliability Modeling Assumptions

The bases for the SPP Power flow analysis are the 2021 light load and summer peak Integrated Transmission Plan–Near Term (ITPNT) base cases L0, L5, S0, and S5 scenarios as provided by SPP. The “L” series are light load cases and the “S” series refers to summer peak cases. The “0” and “5” designations capture a range of transmission changes from no new transmission service added (“0”) to all new transmission service and associated upgrades added (“5”). SPP developed and further supplied a series of thirty-two (32) power flow study cases for the purpose of the LP&L study. All SPP power flow models are adjusted to reflect the changed assumptions identified in Section 3, such as the revised LP&L system topology and LP&L load forecast.

Another change made as part of the LP&L reliability assessment includes the redispatch of the regional generation in response to the projected load transfer. While the SPP models include dispatch commitments for all LP&L generating assets, a review of the historical data and the production cost runs from the Economic Assessment indicated that it was unlikely that LP&L generation would be committed. As such, GDS modified the SPP study models to allocate the original LP&L generation commitments to other resources in SPS.

Each power flow model is evaluated under different operating scenarios with all facilities in service and NERC contingency conditions consistent with the ITPNT contingency files provided by SPP. Transmission facilities that exceed 100% of their rating and buses with a voltage of greater than 1.05 per unit or less than 0.95 per unit are flagged as potential reliability issues for the “all facilities in service” analysis. The same criteria are employed for the contingency analysis, with the exception of the low-voltage criteria, which is reduced to 0.90 per unit. Results are compared across all cases and between similar cases with all LP&L load in SPP and with the transfer of LP&L Affected Load to ERCOT in effect.

The SPP power flow analysis is performed with the Siemens PTI PSS/E power flow product along with the PowerGEM TARA tool. PSS/E is primarily used for the development of the transmission system models of the SPP and ERCOT systems. TARA is used in the contingency analysis to identify any transmission system limitations and to evaluate the effectiveness of mitigation plans to alleviate any potential transmission facility loading or voltage issues.

4.3.2. ERCOT Reliability Modeling Assumptions

ERCOT finalized its LP&L integration study and recommended the preferred integration Option 4ow in May 2016. The reliability component of the Study was performed to address the following aspects outlined in Chairman Nelson's Memorandum:

- Evaluation of the cost and **reliability** impacts on all customer classes in ERCOT and SPP
- Analysis of avoided projects or new projects as a result of moving the LP&L Load to ERCOT and the estimated costs of those projects
- Evaluation of the impacts on operations, both from a cost and reliability perspective, on the ERCOT and SPP systems.

The reliability impact assessment associated with the LP&L integration into ERCOT includes more than just a steady state assessment. To adequately address all aspects of the reliability impacts of LP&L integration on the ERCOT system as outlined in Chairman Nelson's Memorandum, the following evaluations are performed:

- Steady State impact assessment
- Transient Stability impact assessment
- Panhandle export limit assessment
  - System strength perspective
  - Transient stability perspective
- Operational flexibility impact assessment
- Sub-synchronous resonance impact assessment

All of these assessments (and the economic assessment) have been evaluated for the following scenarios on the ERCOT system:

- **Base Scenario**: This scenario reflects the existing ERCOT grid modified to reflect the year 2020 conditions, including the latest load forecast, financially committed generation additions, and approved transmission projects in the North, West, and Far West ERCOT Weather zones (Study Region) expected to be in service by 2020. The Base Scenario is used as the reference for comparison purposes.

- **Change Scenario**: This scenario is developed by adding the LP&L network, LP&L generation, and the Affected Load to the ERCOT grid as modeled in the Base Scenario.

- **Sensitivity Scenario**: Based on the information provided by LP&L, two LP&L generation units (Cooke Unit #1 and Cooke Unit #2) may be converted to Synchronous Condensers should the LP&L network integrate to ERCOT. To that effect, a sensitivity scenario was developed to evaluate the impact of those Synchronous Condensers on the performance of the overall system and to take into consideration the short circuit contributions from LP&L's motor load.

4.3.2.1. Modeling Assumptions—Steady State Impact Assessment

The ERCOT 2016 RTP 2021 West/Far West (WFW) Summer Peak case is used as the base case for developing Base and Change scenarios for the steady state assessment. The latest GIS report from February 2017 was reviewed to assess any generation units in the Study Region that meet Section 6.9 requirements of the ERCOT Planning Guide but were not modeled in the RTP case. All the generation resources in the Study Region that meet the Section 6.9 requirements of the ERCOT Planning Guide are incrementally added to the study case. Per ERCOT's RTP model development methodology, all wind generation resources in the Study Region are dispatched at 3%. The load in the North weather zone is scaled to the higher of the SSWG load forecast and ERCOT's 90/10 Economic load forecast. The Antelope and Elk generation units connecting to Sharyland's 345 kV Abernathy station are turned offline and the loads outside of the Study Region are scaled to maintain the generation/load balance. Ratings associated with approved Synchronous Condensers at 345 kV Alibates and Tule Canyon stations are updated to +175/-125 MVArs.

In addition to the relevant NERC Planning event categories (P1 through P7) and in-line with ERCOT's Planning Guide (Table 4.8), the following system conditions are also considered as part of the steady state contingency analysis:

- Prior outage of LP&L Massengale generating units G7 & G8 (combined cycle train) followed by manual system adjustments and P1/P7 event (including ERCOT_1 contingencies).

- Prior outage of a single 345/115 kV transformer followed by manual system adjustments and P1/P7 event (including ERCOT_1 contingencies). Prior outage of the following 345/115 kV transformers in the Study Region are evaluated:
    - New Oliver 345/115 kV auto outage as X-1
    - North station 345/115 kV auto outage as X-1
    - Wadsworth 345/115 kV auto outage as X-1

- Prior outage of a single transmission element (rated 100 kV or above) followed by manual system adjustments and P1 event. All relevant combinations of N-1-1 events in this Study Region are evaluated.

Initial Condition		Event	Facilities within Applicable Ratings and System Stable with No Cascading or Uncontrolled Outages	Non-consequential Load Loss Allowed
1	Normal System	Loss of Single BES element and Common tower outage (NERC P1 & P7 events)	Yes	No
2	Unavailability of a generating unit, followed by Manual System Adjustments	Common tower outage (NERC P3 events)	Yes	No
3	Unavailability of a 345/138 kV (in this case 345/115 kV) transformer, followed by Manual System Adjustments	Common tower outage; or Contingency loss of one of the following: 1. Generating unit; 2. Transmission circuit; 3. Transformer; 4. Shunt device; or 5. FACTS device	Yes	No

Table 4.8: ERCOT Planning Guide Event Categories

The following performance criteria are used to assess the impact of LP&L integration into ERCOT from the steady state standpoint:

- Per the ERCOT Planning Guide Section 4.1.1.2, for the studied system conditions, all facilities shall be within their applicable ratings, the ERCOT system shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss.

<u>Thermal Overloads</u>

- Rate A (Continuous) for normal operating conditions & Rate B (2-Hr Emergency) for all other events
    - Loading levels above 95% of Rate B were considered as violations to maintain 5% margin

<u>Steady State Voltage Magnitude Violations</u>

- 0.95-1.05 p.u. for Normal Operating Conditions
- 0.90-1.05 p.u. for all other events

<u>Steady State Pre & Post-Contingency Voltage Deviation Violations</u>

- +/- 0.07 p.u. for NERC P1-P7 planning events

The same assumptions as those outlined above are also used for the steady state voltage stability (P-V) analysis performed to evaluate the operational flexibility impacts of LP&L integration into ERCOT.

4.3.2.2. Modeling Assumptions—System Strength Impact Assessment

The ERCOT 2016 RTP 2021 WFW case is used to create the three study scenarios described above. Synchronous Condensers at the 345 kV Alibates and Tule Canyon stations are updated with a capacity of 175 MVA.[49] Each synchronous condenser is modeled to produce a fault current of 1606A for a bolted 3-phase fault at the 345 kV terminals. Gas generation units in West Texas are kept offline (including the Antelope/Elk generation units at the 345 kV Abernathy substation). All the generation resources in the study region that meet the Section 6.9 requirements of ERCOT Planning Guide are incrementally added to the study case. All renewable resources in the Panhandle region are included for the WSCR computation. Table 4.9 depicts the renewable generation capacity at each Panhandle station that is included for the WSCR assessment. The system short circuit MVA at each Panhandle station (S_{SCMVAi}) is calculated without considering the short-circuit contribution of the renewable generation in the Panhandle region.

POI	MW
AJ Swope	355
Alibates	749
Cottonwood	257
Gray	463
Ogallala	300
Railhead	408
Tule Canyon	510
Windmill	1262
White River	901
Sum	5205

Table 4.9: ERCOT Panhandle Renewable Generation Capacity[50]

4.3.2.3. Modeling Assumptions—Transient Stability Impact Assessment

The ERCOT Dynamics Working Group (DWG) Future Year (FY) 2020 High Wind Light Load (HWLL) and 2021 Summer Peak (SP) dynamic datasets are used as the starting datasets for the transient stability assessment. The following incremental changes are made to the aforementioned datasets prior to simulating any dynamic contingency:

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49 SU Panhandle Project Update, August 2016 Regional Planning Group Meeting.

50 Note that the 345 kV Tesla station is not depicted in Table 4.9 despite being part of Panhandle region per ERCOT's latest definition of the Panhandle interface. This is so since there is no generation capacity at the Tesla station meeting Section 6.9 requirements of the ERCOT Planning Guide.

- All renewable resources in the Study Region meeting Section 6.9 requirements of the ERCOT Planning Guide, that were not already modeled in the datasets, are incrementally modeled. Table 4.10 depicts the dispatch levels used to incrementally model any new renewable resource.

	HWLL condition	SP Condition
Solar Units	47%	78%
Wind	85%	33%

Table 4.10: Dispatch Level for Incremental Generation Units in the Study Region

- For the HWLL condition, the total Panhandle generation is limited to the Panhandle export limit of 4548 MW as obtained through the system strength assessment (Section 5.3.5.4.1).

- Except for the self-serve gas units, all other gas units in the non-study region are scaled down to maintain the load and generation balance.

- Minimum load and high growth forecasts associated with LP&L load are used to model the same in the 2020 HWLL and 2021 SP datasets, respectively.

- The LP&L generation units were assumed as offline for the HWLL conditions and are assumed at full dispatch levels for the Summer Peak condition.

- Antelope and Elk generation units are assumed as offline for the HWLL condition and assumed as fully dispatched for the Summer Peak condition.

The transient stability assessment is performed by simulating the planning level contingencies as defined by the NERC TPL-001-04 standard (P1 through P7) and the ERCOT Planning Guide. The dynamic contingencies are developed and simulated for all the LP&L facilities that are expected to move to ERCOT and for all the facilities inside the ERCOT Panhandle region, as well as facilities in the close vicinity of the ERCOT-LP&L interconnection points.

In accordance with NERC TPL-001-04 Section R4.1 and ERCOT Planning Guide section 4.1.1, the following performance criteria are used to assess the impact of LP&L's integration into ERCOT from a transient stability standpoint:

- <u>For planning event P1:</u> No generating unit shall pull out of synchronism. A generator being disconnected from the system by a fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

- For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

- Voltage at BES elements in the study region should exhibit transient stability and acceptable transient voltage recovery
    - P1 events–Voltage should recover to 0.9 p.u. within 5 seconds after clearing the fault.
    - P2-P7 events–Voltage should recover to 0.9 p.u. within 10 seconds after clearing the fault.

- For P1-P7 events, power oscillation within the range of 0.2 Hz to 2 Hz shall decay with a minimum of a 3% damping ratio.

Although the modeling assumptions associated with the system strength and transient stability impacts are classified under the reliability impact, it is important to note that the same assumptions are used to derive the Panhandle export limit that is utilized in the economic assessment.

4.4. Transmission Facilities Cost Allocation Models and Base Assumptions

LP&L has never been a member of SPP, has not transferred functional control of its transmission facilities to SPP, and has not developed an Annual Transmission Revenue Requirement (ATRR) rate for recovery of LP&L's transmission costs. LP&L is a wholesale customer through WTMPA of SPS, a wholly owned subsidiary of Xcel Energy, Inc. SPS is a Transmission Owning Member of SPP, and all SPS Transmission Facilities are under the functional control of SPP. Transmission Services provided using the SPS transmission network are governed by the SPP Tariff as the Transmission Provider.

The Transmission Service used to serve LP&L's load is pursuant to its contractual arrangement with SPS and is governed by the NITS Agreement between SPS and SPP. The LP&L load served under the SPS NITS Agreement is identified as a delivery point in the NITS Agreement between SPS and SPP. If the LP&L Affected Load remains in SPP, LP&L must acquire third party deliverable capacity service equal to LP&L's peak load to qualify for firm transmission service necessary to serve the LP&L load.

Under the current load serving arrangement, the LP&L transmission system is connected to SPP via delivery points owned and operated by SPS; SPS's facilities are under the functional control of SPP. LP&L and SPS have a contractual arrangement for the delivery of energy at the delivery points. The LP&L transmission system beyond the delivery point is operated and maintained by LP&L and is not under SPP functional control.

LP&L has considered its resource options to serve its Affected Load. Any option must consider the availability to deliver those resources to LP&L. Given the location of LP&L's operating area, it is uniquely positioned to acquire the necessary Transmission Service from either SPP or ERCOT. While there are other resource considerations that are more fully analyzed in this report, this phase of the analysis is limited to the LP&L total Transmission Service cost to serve its load absent any consideration of the merits or disadvantages of varying resources options.

To realize the benefits of the RTO structure, LP&L would be required to join either SPP or ERCOT as a Transmission Owning Member; integrate its existing and proposed Transmission Facilities into the respective RTO pursuant to the applicable RTO Membership Agreement and Bylaws; and relinquish functional control of its facilities and make available LP&L's Transmission Facilities pursuant to the SPP Tariff or the ERCOT Protocols. As such, LP&L would be entitled to recover its costs to own and maintain the Transmission Facilities.

LP&L conducted an analysis of the net impact on transmission costs to serve its load post RTO integration. This included an analysis of the LP&L transmission network to identify LP&L Transmission Facilities that qualify under the RTO guidelines. LP&L performed a Transmission Cost of Service (TCOS) study to determine its costs to own and operate the Transmission Facilities proposed to be integrated and placed under the functional control of the RTO. In SPP, LP&L's ATRR will be recovered by the RTO from Transmission Customers (TCs) in the Transmission Pricing Zone (TPZ) pursuant to the SPP Tariff. In ERCOT, LP&L's ATRR will be recovered from the wholesale transmission customers pursuant to LP&L's Wholesale Transmission Tariff.

As a Load Serving Entity (LSE), LP&L will purchase Transmission Service independent of its capacity as a Transmission Owner (TO). LP&L performed an assessment to estimate the cost of NITS to serve its load in SPP and TCOS in ERCOT. LP&L netted the revenue it would receive as the TO with the costs it would pay as a TC to determine net cost to deliver the needed resources to serve its load.

LP&L's TCOS study uses a forward-looking test year based on projected 2021 costs, which is the projected year of RTO integration. The TCOS study yields an ATRR of approximately $19.1 million for the facilities under SPP functional control and approximately $29.8 million in ERCOT. The variance in ATRR is attributable to the additional Transmission Facilities required to integrate LP&L's Transmission System into ERCOT that are not needed in SPP.

LP&L conducted an analysis of the costs it would incur as a TC in the respective RTO. While there are multiple TPZs in the SPP footprint, there is only one in ERCOT. SPP has unilateral discretion in which TPZ to integrate a TO's facilities. Practical consideration of LP&L's network configuration and topology suggest that LP&L is most suited to the SPS TPZ (Zone 11) in SPP. Therefore, the analysis is predicated upon SPP transmission costs in Zone 11.

In SPP, Transmission Service cost is a function of the total ATRR for all TO Transmission Facilities in the TPZ. SPP will sum the total ATRR applicable to the TPZ. The ATRR is recovered from all TCs in the TPZ based on the TC's load proportionate to percentage of the total load in the zone or Load Ratio Share (LRS). Because there are multiple TPZs in the SPP footprint, certain Transmission Facilities benefit all zones. The ATRR associated with those transmission projects are allocated across all TPZs in the SPP footprint—referred to as regional charges.

In ERCOT, LP&L will pay for transmission service based on its LRS of the ERCOT 4 Coincident Peak. In ERCOT, LP&L's TCOS is estimated to be $29.8 million and LP&L is projected to pay $24.0 million for transmission service.[51]

LP&L analyzed the current Transmission Service charges in the respective RTOs. The analysis added the LP&L ATRR to the existing cost structure in the respective RTO TPZ. The analysis also added the LP&L load to the zone to estimate the TPZ total load. Applying the LP&L's LRS to the total ATRR for the zone (including the SPP regional charges as applicable), LP&L can reasonably estimate the NITS charges it would incur as a TC in the respective RTO TPZ. LP&L also factored in other charges such as RTO administrative costs, applicable FERC fees, and load dispatch charges to determine the Transmission Service cost LP&L would expect to pay.

The final step in the analysis was to net LP&L's ATRR against its Transmission Service cost to determine LP&L's cost of transmission to serve its load. In SPP, LP&L has a projected ATRR of approximately $19.1 million. Incorporating this ATRR into Zone 11 and calculating LP&L's share of Zone 11's zonal and regional ATRR and other applicable schedules, the total projected SPP Transmission Service cost in 2021 is approximately $37.6 million. LP&L projects its net transmission expense in SPP to be $18.5 million.

[51] Projected cost of LP&L transmission service in ERCOT is projected to be approximately $27.4 million in 2025.

5. IMPACT EVALUATION METHODOLOGY AND RESULTS

5.1. Overall Impact to LP&L

Each regional transmission system calculates the benefits and costs of particular transmission projects through the use of some form of production cost method, as described in Section 4.1. Given the fact that ERCOT and SPP rely on different methodologies to assess benefits and costs under their respective production cost methods, this study focuses on the impacts to the LP&L customers based on having load in each of the two RTOs. Unlike the SPP APC and the ERCOT APC, the impact on LP&L must include the cost to serve load, the value of its generation assets, the value of any congestion rights associated with its power supply alternatives, and any additional benefits or costs that may be associated with the LP&L load transfer not captured in the production cost analysis and power flow analysis.

5.1.1. LP&L Load Cost Impacts

Load cost impacts are calculated as the total cost to serve the hourly load based upon the locational marginal price (LMP) at the bus where the load occurs. In SPP, the LMP is made up of three components: (1) the marginal energy component (MEC), (2) the marginal congestion component (MCC), and (3) the marginal loss component (MLC). In ERCOT, the LMP does not include the MLC.

The load cost impact is usually not considered in the RTO evaluation of production cost, but this cost is vital to understanding what the proposed load transfer means to the LP&L customers. Within the SPP footprint, it is likely that LP&L customers will pay a SPS load zone price, which includes all SPS buses and LP&L buses in the SPP footprint. Within ERCOT, LP&L would join as a Non-Opt In Entity (NOIE) with its own NOIE load zone. LP&L would therefore not pay the ERCOT West Zone price but a LP&L load bus specific price. To maintain consistency for the LP&L System, an LP&L load price is calculated to assess the actual load LMP differences between the two RTOs being evaluated. The LP&L load price is the load weighted LMP of all LP&L buses within the respective RTO footprint.

Table 5.1 below shows the load cost for the LP&L system in 2020 and 2025.

2020 Study Year			
Load Cost	**LP&L Remain in SPP**	**LP&L Move to ERCOT**	**(Benefit)/Cost**
LP&L Affected Load (subject to transfer)	$98,980,479	$69,166,152	($29,814,327)
LP&L Unaffected Load (Stay in SPP)	$27,712,398	$26,731,637	($980,761)
Total LP&L Load Cost	$126,692,877	$95,897,789	($30,795,088)
2025 Study Year			
Load Cost	**LP&L Remain in SPP**	**LP&L Move to ERCOT**	**(Benefit)/Cost**
LP&L Affected Load (subject to transfer)	$121,438,853	$94,590,212	($26,848,641)
LP&L Unaffected Load (Stay in SPP)	$34,543,925	$33,665,387	($878,538)
Total LP&L Load Cost	$155,982,778	$128,255,599	($27,727,179)

Table 5.1: LP&L Load Cost Impacts

5.1.1.1. Impacts on Locational Prices

Figure 5.1 shows the differences in LMP between the Affected Load staying in SPP and the effect of that load moving to ERCOT. In addition, the load cost for the Unaffected Load that is staying in SPP is also provided, as it is expected that the Unaffected Load price will change given the reduction in congestion associated with removing the LP&L Affected Load from the SPS system.

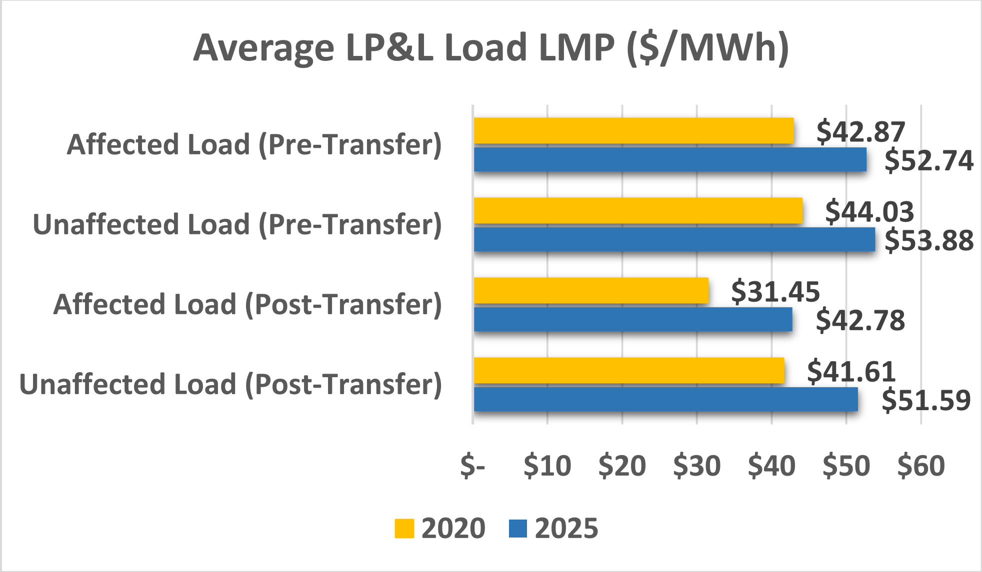

Figure 5.1: LP&L Load LMP Comparison

The Unaffected Load sees a reduction in the average LMP once the Affected Load is removed. This is primarily due to the decrease in the Marginal Congestion Cost (MCC) resulting from less frequently binding constraints in the SPS system near the Unaffected Load.

5.1.2. LP&L Generation and Power Supply Impacts

It is assumed that LP&L generation is dispatched as part of the entire RTO pool wide dispatch. Currently, LP&L load requirements are served through WTMPA with a full requirements contract from SPS. After LP&L becomes a member of an RTO, LP&L generation is committed based upon its bid price; therefore, generation will only run when it is economic to do so. The difference between cost and generation and the LMP at the generator bus are generator margins, which can be used by LP&L to offset the load price.

5.1.2.1. Changes in LP&L Production Costs

The results of the production cost analysis in both 2020 and 2025 as shown in Table 5.2 indicate a minimal impact from the LP&L generator perspective. In 2020, LP&L generation under a LP&L remains in SPP case and a LP&L Affected Load transfer to ERCOT case both result in uneconomic dispatch of LP&L resources. However, the net effect is less than $66,000. By 2025, there is a net benefit in the LP&L load in ERCOT case, but it is only $85,000. This highlights why an adjusted production cost metric alone, without further analysis or context, is ineffective for proper evaluation of the economic impact of the LP&L load transfer.

	2020 Study Year			2025 Study Year		
Generation and Power Supply	LP&L Remain in SPP	LP&L Move to ERCOT	(Benefit)/Cost	LP&L Remain in SPP	LP&L Move to ERCOT	(Benefit)/Cost
LP&L Production Cost	$181,373	$362,097	$180,724	$140,782	$1,748,276	$1,607,494
LP&L Generator Revenues	$170,616	$296,452	$125,836	$92,767	$1,832,744	$1,739,977
Net LP&L Generation Impact (Cost Less Revenue)	$10,757	$65,645	$54,888	$48,015	$(84,468)	$(132,483)

Table 5.2: LP&L Production Cost Comparison

5.1.2.2. Changes in Need and Timing of Planned Generation Expansion

Any changes in the need and timing of planned generation expansion for LP&L are driven by changes in the RTO reserve margin criteria. The minimum reserve margin requirement in SPP is 12.0% as compared to a 13.75% target capacity reserve margin in ERCOT. In SPP, load serving entities are required to own or contract with third parties for dependable, deliverable generating capacity in sufficient quantity to cover load. Reserves must be obtained but do not have to meet deliverability requirements. Substantial penalties have been proposed for LSEs that are short of required capacity. SPP does not have a managed capacity exchange; all capacity transactions in SPP are bilateral. In ERCOT, high market price caps require LSEs to hedge exposure to high energy market prices through firm transactions or with financial options. The value of capacity in each market can be expected to remain unchanged. It is not anticipated over the short term that the need or timing for any generation expansion of LP&L generating resource fleet would change.

5.1.3. LP&L Transmission Impacts

The assessment of the transmission impacts on LP&L for the load transfer to ERCOT focuses primarily on changes to the SPS/SPP System due to the removal of the Affected Load (approximately 470 MW) and associated generation and transmission facilities. For the reliability assessment, the contingency analysis examining transmission overloads and voltage issues with and without the load transfer assesses whether additional transmission upgrades may be required to alleviate reliability violations, or possibly identify planned transmission facilities that are no longer needed due to the load transfer. The analysis of the SPP cases that assume the removal of all notice to construct (NTC) projects assesses if there is any benefit to delay or removal of potential NTCs, and would result in additional benefits to LP&L were the transmission revenue requirement reduced by the delayed or deferred projects.

5.1.3.1. Additional Facilities Required to Meet RTO Reliability Criteria

The first step in the reliability analysis is to determine if any transmission facilities violate the SPP planning criteria due to the transfer of LP&L's Affected Load from the SPP footprint. This exercise only identifies transmission system elements that are not overloaded in the Base Case with all LP&L load in SPP but are overloaded if the Affected Load is transferred. The identification of overloads does not necessarily mean that additional transmission facilities will need to be built. It is probable that in the context of the RTO operation, the identified transmission overloads would be alleviated with redispatching generation, hence alleviating the need to construct new transmission facilities.

If LP&L is unsuccessful with the ERCOT load transfer, the redesign of the following facilities internal to the LP&L system may need to be addressed in the unlikely event that market redispatch would not be effective in addressing the potential loading conditions:

- Southeast Transformer 230/115 kV and McDonald Transformer 230/115 kV

In addition to the internal LP&L transformer loading issues identified above, two additional facilities external to LP&L were also noted. If LP&L is successful in the ERCOT load transfer, the following overloaded elements external to the LP&L system may need to be addressed in the unlikely event that market redispatch would not be effective in not resolving the potential loading issues:

- Allen–LP&L South–LP&L East 115 kV line and Sundown Transformer 230/115 kV
- Texas County–Hitchland 230 kV

5.1.3.2. Avoided Transmission Expenses

There are no avoided LP&L projects in the SPP system as a result of the proposed load transfer to ERCOT.

5.2. Impact to SPP

This study quantifies the impact on the remaining members of SPP upon implementation of the LP&L load transfer. GDS evaluated the SPP System impacts based upon the SPP APC methodology. In addition, other metrics such as load cost and impacts to transmission expansion are also included to ensure that a robust picture of the impact of the LP&L load transfer is included.

Similar to the LP&L impact analysis, both a production cost analysis using PROMOD and a power flow analysis using PSS/E is employed.

5.2.1. Load Cost

SPP does not consider load cost as part of the adjusted production cost analysis. The load cost for the SPP region is calculated in this analysis to show how the actual costs paid by LSEs with the load transfer are impacted, without regard to the generator margins associated with any transactions.

5.2.1.1. Impact on Load Costs in SPP and TX

Figure 5.2 shows the change in annual load costs for 2020 and 2025 for the LP&L (Affected and Unaffected), SPP, and TX regions.

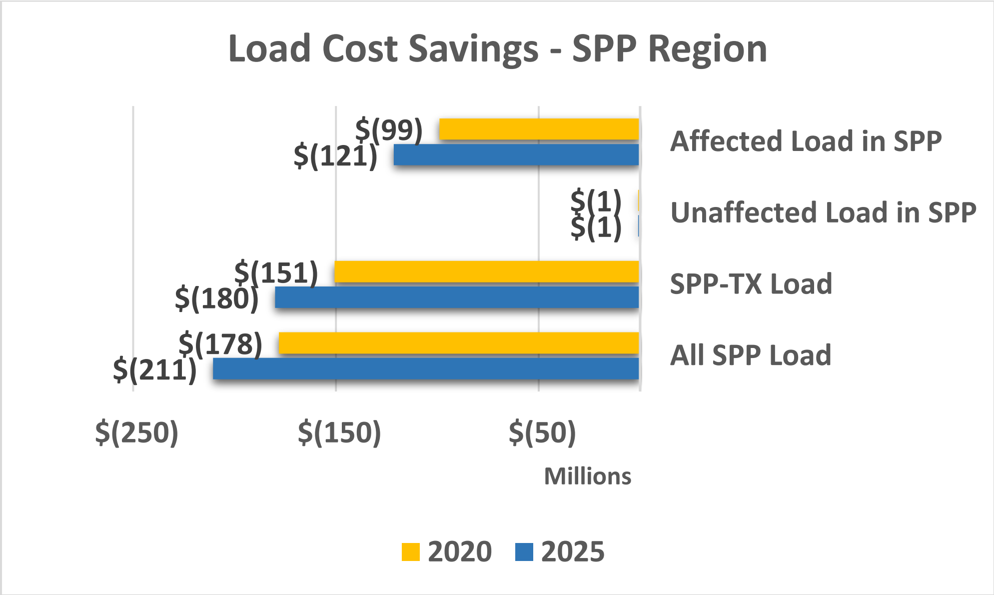

Figure 5.2: Load Cost Savings in SPP

As mentioned in Section 2.2.3, the Texas Panhandle area of SPP is one of the most congested areas of SPP. Any removal of load in the congested region reduces the use of the transmission system, and lowers the overall costs to customers through lower production costs and lower congestion.

In 2020, SPP is expected to receive $99 million less in load payments from the LP&L Affected Load. In addition, the removal of the LP&L load provides additional savings to the balance of the SPP footprint. In 2020, SPP would realize a savings of $79 million ($178 million minus $99 million). In 2025, SPP would receive $121 million less in load payments from the LP&L Affected Load, and realize additional savings of $90 million.

In the Texas portion of SPP, which includes portions of SPS, AEP West, and Western Farmers Electric Cooperative, the savings are $52 million ($151 million minus $99 million) in 2020, and $59 million ($180 million minus $121 million) in 2025.

5.2.2. Generation and Power Supply Costs

Figure 5.3 identifies the total production costs for the SPP and Texas regions with and without the LP&L Affected Load included in SPP. As expected, by removing the Affected Load from SPP, which reduces congestion primarily in the SPS footprint, production costs in SPP decrease by $84 million in 2020. Of the $84 million production cost decrease, approximately $61 million is due to production cost changes in the Texas portion of SPP. Similar numbers for 2025 are also shown in Figure 5.3.

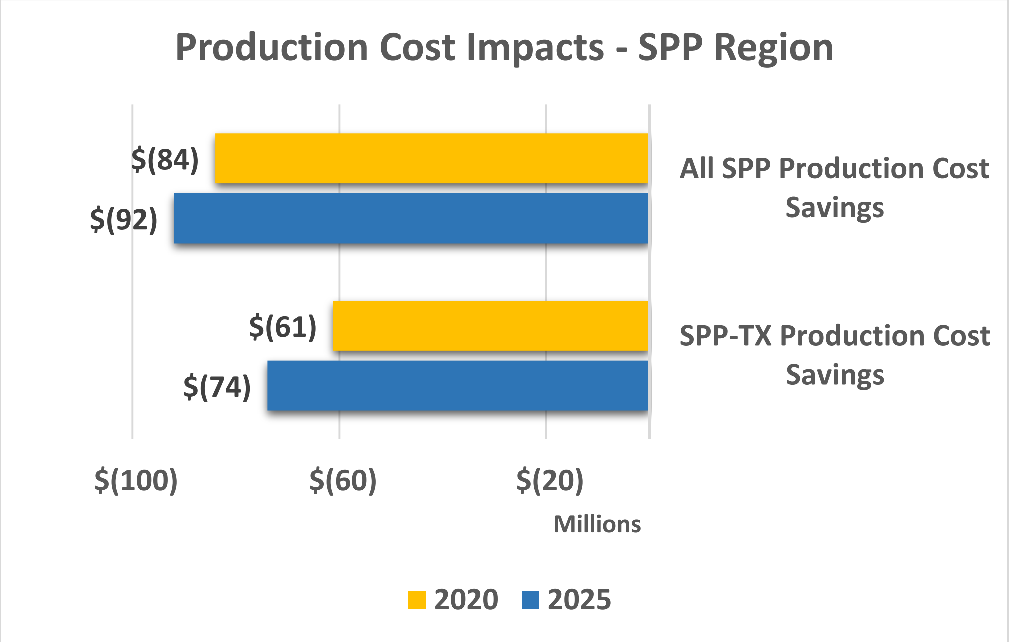

Figure 5.3: Production Cost Savings – SPP

5.2.2.1. Changes in Adjusted Production Costs

The APC calculation for Figure 5.3 is calibrated to replicate the SPP methodology from the February 29, 2016 white paper. As stated previously, the SPP APC includes sales and purchases but does not reflect any load cost changes. The removal of the affected load properly corresponds with a reduction in the cost of production in both the SPP and Texas regions.

5.2.2.2. Changes in Need and Timing of Planned Generation Expansion

Consistent with the LP&L perspective on generator additions, any changes in the need and timing of a planned generation expansion for SPP are driven by changes in the RTO reserve margin criteria as described in more detail in Section 5.1.2.2.

5.2.3. Transmission Impacts (Highway/Byway)

5.2.3.1. Additional Facilities Required to Meet RTO Reliability Criteria

The facilities identified and conclusions reached in Section 5.1.3.1 are also applicable with respect to the SPP system.

5.2.3.2. Avoided Transmission Expenses

Avoided transmission expenses are those expenses that can be reduced due to either the elimination or deferral of planned transmission projects within SPP. SPP staff provided power flow cases with and without NTC projects. The initial analysis identified those facilities that are needed, assuming all projects with NTC are constructed, versus a case where no projects with NTCs are constructed. Additional sensitivity analysis on individual NTCs was also performed.

The following transmission facilities are identified as being overloaded with the LP&L system remaining in SPP but are not overloaded with the ERCOT load transfer in effect:

- Caprock–Norton 115 kV
- East Plant–Pierce Tap 115 kV
- Tuco–Stanton West–Indiana–Erskine 115 kV
- Plant X–Sundown 230 kV
- Potter–Harrington 230 kV
- East Plant Interchange 230 kV 3-winding transformer

These facilities being no longer overloaded means that the transfer of the Affected Load to ERCOT eliminates the need for these potential transmission upgrades in SPP.

The following individual transmission projects with NTC are identified as causing minimal impact with the overload of just a few existing transmission facilities when the planned upgrades are removed, but are not showing any violations when being removed in conjunction with the LP&L Affected Load transfer:

- Tuco 230/115 kV Ckt 1 Transformer
- Yoakum County Interchange 345/230 kV Transformer

In assessing the net effect of the few upgrades that will be potentially needed to address local reliability issues and the elimination of the existing projects with NTC that are identified as no longer needed with the ERCOT load transfer in effect, it is determined that the remaining issues that result from the elimination of the Tuco and Yoakum County projects would result in significant savings due to the relatively low cost of the required mitigation strategies.

The following upgrades would need to be addressed in lieu of the Tuco project with the LP&L Affected Load transfer:

- Carlisle Interchange 115 kV–Lubbock Power & Light–Doud Substation 115 kV line—SPP has noted in its submittal in this proceeding that the mitigation to resolve this overload is to reset the current transformer at a cost of $50,000.[52]

- Lubbock South Interchange 115 kV–Lubbock East Interchange 115 kV line—SPP has noted in their submittal in this proceeding that the mitigation to resolve this overload is to reset the current transformer at a cost of $50,000.

The following upgrade would need to be addressed in lieu of the Yoakum project:

- Sundown 230/115/13.8 kV transformer—SPP has noted in its submittal in Project No. 45633 that because this overload only appears in the Scenario 5 summer peak case, no mitigation is recommended.[53]

SPP has cost estimates for the Tuco and Yoakum projects as part of its Project Tracking system. As of June 15, 2017, the expected costs of the two NTC projects are:

- Tuco: $3,800,415
- Yoakum: $3,432,506

Because the total cost of the Tuco and Yoakum projects ($7,232,921) is much greater than the total cost of remedying the overload ($100,000), both projects can be avoided by the LP&L Affected Load transfer. Therefore, $7,132,921 of transmission costs in SPP can be avoided by LP&L integrating into ERCOT.

5.2.3.3. Potential for Stranded Transmission Facilities and Associated Expenses

Stranded investment from a LP&L perspective would relate to those facilities in the SPP footprint that are committed specifically to accommodate load serving obligations of SPS. The results of the analyses of individual transmission projects with NTC show similar reliability performance in the case with planned upgrades being removed, and the case when being removed in conjunction with the ERCOT load transfer in effect. As such, the LP&L transfer to ERCOT results in no stranded facilities.

5.2.4. Other Impacts

Aside from the production cost and power flow impacts, the transfer of the Affected Load from SPP to ERCOT provides benefits to the remaining SPP system in other areas, such as:

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[52] PUCT Project No. 45633, "LP&L Exit Study Report", filed June 30, 2017.

[53] *Id.*

operational impacts, ancillary service requirements and costs, transmission congestion rights valuation, reduction in the shadow prices across regional flowgates, and changes in import/export capability across the SPP/SPS interface.

The evaluation of the level of congestion across binding constraints as determined by the shadow prices provides insight into the impact on system reliability from the load transfer. The shadow price indicates the redispatch cost needed to relieve the congestion across a particular flowgate by 1 MW. In the PROMOD analysis, 590 flowgates are modeled. Figure 5.4 shows the number of impacted flowgates by changes in shadow prices and the magnitude of the changes for both increased and reduced congestion with the LP&L Affected Load transfer.

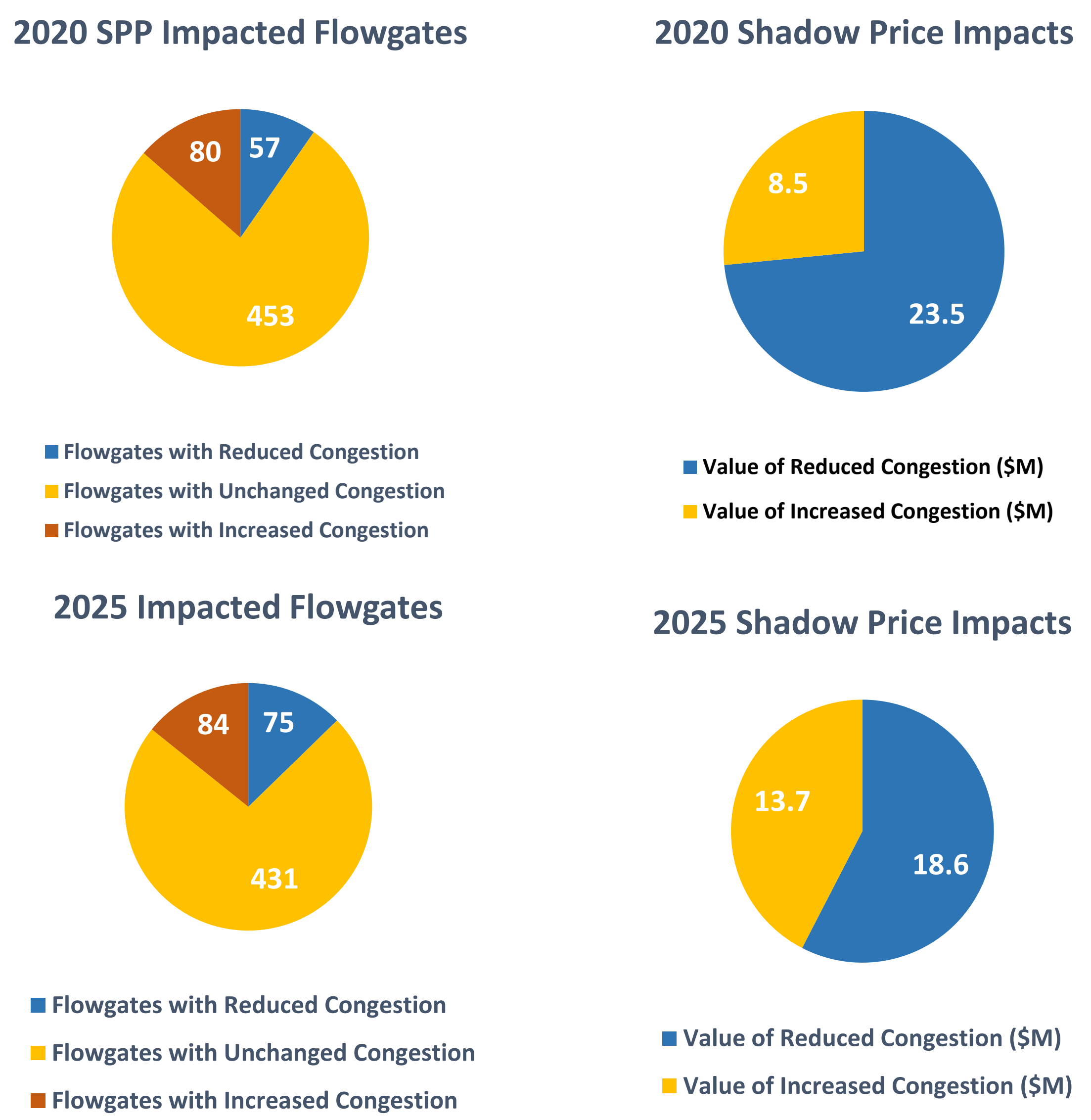

Figure 5.4: Congestion Analysis – Shadow Prices (2020/2025)

Although more flowgates show increased shadow prices than those that show decreased shadow prices, the overall trend indicates that system congestion is reduced by the load transfer to ERCOT. This reduced congestion impact would have a net positive impact on operations. Also, it points to increased flexibility to resolve system issues without higher levels of out-of-merit generation.

The ancillary services most impacted by the LP&L load transfer are those related to spinning (Schedule 5) and supplemental (Schedule 6) reserve products. The removal of the LP&L Affected Load creates two benefits to the remaining SPP members. First, the requirements for reserves are reduced with the load removal, which reduces the likelihood of scarcity pricing for Schedules 5 and 6. Second, the cost of those services will decrease as the supply is unchanged but the demand is reduced.

LP&L-owned generation in the SPS region is primarily made up of combined cycle and peaking generation. In particular, peaking generation can provide ancillary services such as regulation and supplemental reserves. The historical dispatch of LP&L generation has been extremely low, implying that the costs of these resources are not economic when considered against the total dispatch requirements of the region. Moving these assets into the ERCOT footprint will not adversely affect the cost of the ancillary services in the SPP system because these resources are making sales in the SPP IM at a low level. Also, with the load transfer in place, requirements for regulation and reserves are decreased and the ability of resources external to the SPS footprint are increased based upon increased import capability into a formerly constrained area.

SPP bases transmission congestion rights, or TCRs, between designated Network Resources and network load. For the first year of the transition, it is possible that the value of TCRs within the SPP footprint could decrease; however, the ARR holders will have sufficient time to reevaluate their portfolios prior to making their annual commitments. This is a temporary condition, as the TCR auction takes place each year. It is expected that entities who hold transmission rights will allocate their ARRs to maximize the value of the ARR, once the impact of the LP&L load transfer is determined. Even if the value of a TCR decreases, since it is based upon the difference in locational price between designated network resource and network load, any reduction in the value of the TCR is driven by a reduction in the load price for the network load, which is a benefit that has accrued to the load aside from the TCR valuation. The existing NITS customers will benefit from LP&L's withdrawal because it should increase the quantity of ARR's awarded compared to those requested, which should allow for greater ability to hedge congestion.

Improved outage coordination and the ability to take outages on the SPS System should be reflected in a reduction in congested hours on the SPP/SPS ties flowgate and also in an increase in available transfer capability between SPP and SPS. Although the congestion hours and available transmission capability (ATC) increase can be quantified, it is not possible to determine the dollar value of improved coordination on outages or cost reductions due to improved flexibility and maintenance scheduling.

5.3. Impact to ERCOT

5.3.1. Load Cost and Locational Price Impacts

5.3.1.1. Customer and Locational Price Impacts

The load cost impacts associated with LP&L integration into ERCOT are evaluated from two different perspectives—the load cost impact on ERCOT as the result of LP&L integration and the load payments made by LP&L after integration of the Affected Load into ERCOT. Table 5.3 provides the load weighted annual average ERCOT LMPs before and after the integration of LP&L into ERCOT for 2020 and 2025 respectively for each of the three study scenarios described in Section 4.3.2. As evident from the results in Table 5.3, the integration of LP&L into ERCOT is expected to have a minimal increase (approximately \$0.02 per MWh for 2020 and \$0.07 per MWh for 2025) on the load weighted annual average ERCOT LMPs. While the absolute LMP values differ from those documented in the SPP-ERCOT Coordinated Lubbock Power and Light Integration Impact Analysis (ERCOT Integration Report) for a variety of reasons, it is noteworthy that the incremental impact of LP&L integration in terms of the LMPs aligns very closely with the ERCOT's results. The locational benefits of LP&L significantly reduce the extent of the load cost impact to ERCOT in comparison to a similar load being added to any other part of the ERCOT system. For instance, the addition of a 300-400 MW spot load in the Houston region due to a liquefied natural gas-related load addition would result in a much higher production cost increase. This is because the addition of such a load in Houston would not be accompanied by the production cost benefits accrued by the LP&L load in terms of the increased Panhandle export capability.

Scenario	2020 (\$/MWH)	2025 (\$/MWH)
Base	31.37	43.68
Change	31.39	43.75
Sensitivity	31.38	43.70

Table 5.3: ERCOT System-wide Annual Load Weighted Average LMPs

The results presented in Table 5.3 assumes LP&L to comprise its own NOIE load zone.

Additionally, the load payments expected to be made by LP&L post-integration into ERCOT are also estimated in the economic study. Table 5.4 provides a summary of annual load payments by LP&L for the scenarios studied for 2020 and 2025.

Scenario	2020 ($ million)	2025 ($ million)
Change	69.2	94.6
Sensitivity	69.1	94.3

Table 5.4: LP&L Load Payments in ERCOT

5.3.2. Production Cost Impacts

Detailed hourly production cost simulations are performed for all the study scenarios to evaluate the production cost impacts of LP&L integration into ERCOT. The lesser of the WSCR and the stability Panhandle export limit is used with the 10% operational margin for the purposes of production cost simulations. Tables 5.5 and 5.6 provide the summary results associated with the production cost impacts of LP&L integration into ERCOT.

Scenario	LP&L Included?	Panhandle Interface Limit (MW)			Production Cost Savings ($M)
		WSCR Limit	Stability Limit	PH Interface limit	
Base	No	4059	>4059	3,653	NA
Change	Yes	4548	>4548	4,093	(63.2)
Sensitivity	Yes	4684	>4684	4,216	(60.9)

Table 5.5: Annual Production Cost Saving for 2020 Study Year

Scenario	LP&L Included?	Panhandle Interface Limit (MW)			Production Cost Savings ($M)
		WSCR Limit	Stability Limit	PH Interface limit	
Base	No	4059	>4059	3,653	NA
Change	Yes	4548	>4548	4,093	(63.1)
Sensitivity	Yes	4684	>4684	4,216	(55.3)

Table 5.6: Annual Production Cost Saving for 2025 Study Year

As evident from the results depicted in Tables 5.5 and 5.6, the LP&L integration into ERCOT results in an annual production cost increase of approximately $63 million. This increase is observed to be consistent across both the study years of 2020 and 2025. The sensitivity scenario is observed to result in a lower production cost increase in comparison to the Change Scenario. This is because of the additional Panhandle export limit benefits observed for the sensitivity scenario by virtue of the additional short circuit contribution from the LP&L's loads and refurbished synchronous condensers. While ERCOT has deemed the synchronous condenser conversion as uneconomic in the near future, the combined benefits of the LP&L loads and unit conversions may be warranted based on the results depicted in Tables 5.5 and 5.6.

It is important to note that the annual production cost increase associated with integrating a similar amount of load elsewhere on the ERCOT system is expected to be much higher. This underlines the locational benefits of the LP&L load and transmission facilities required to integrate the same. The production cost savings obtained from the Panhandle export benefits associated with the LP&L integration reduces the overall production cost impacts.

While straight annual production cost savings are traditionally used by ERCOT to evaluate the economic merits of transmission projects, the same methodology cannot be used to quantify the true cost-benefit impacts of LP&L integration into ERCOT. This is because the LP&L integration is comprised of load in addition to the transmission facilities. Various RTO/ISOs in the United States, including Midcontinent ISO (MISO), SPP, and PJM, use different versions of the adjusted production cost metric to evaluate the economic merit of similar projects. The ERCOT APC metric, as defined earlier in the report and used by LP&L for this Study, is used to obtain a true reflection of the cost-benefit impacts of LP&L integration into ERCOT. Details associated with the cost-benefit assessment are provided in subsequent sections of this report.

5.3.3. Avoided Transmission Projects/Expenses

The analysis associated with the identification of avoided transmission projects in ERCOT (if any) by virtue of the LP&L integration focuses on projects that are deemed needed and justified from economic or reliability perspective. The only transmission project that is identified as being economic per 2016 ERCOT RTP assessment is the addition of one 175 MVA synchronous condenser at 345 kV Windmill Station. ERCOT concludes that the addition of the synchronous condenser meets the economic criteria in 2019. However, the assumption that the project meeting economic criteria in 2019 automatically implies the physical installation by January 2019 is fundamentally flawed. Historical evidence suggests a two and a half (2.5) year timeline from the approval of the project to installation of the synchronous condensers. The synchronous condensers at 345 kV Tule Canyon and Alibates stations were approved toward the end of 2015 and are expected to be in-service by Summer of 2018. Based on a similar timeline, it is reasonable to assume that the additional synchronous condenser at 345 kV Windmill Station will not be in-service prior to the end of 2019 (assuming an immediate approval of this project).

Production cost simulations are performed to evaluate the incremental benefits associated with the additional synchronous condenser at 345 kV Windmill Station. The following key observations are made from the results of the assessment:

- Annual production cost savings for one (1) Synchronous Condenser at Windmill Station **without** LP&L: $12.1 million

- Annual production cost savings for one (1) Synchronous Condenser at Windmill Station **with** LP&L: $4.6 million

Based on the ERCOT economic criteria of using 15% of the capital cost of the project, which in this case is $5.925 million (15% of 39.5 million estimated cost for the synchronous condenser), as the first-year annual revenue requirement, the third synchronous condenser does not meet the economic criteria with LP&L added to ERCOT. It is important to note that ERCOT reiterated its commitment to using the same criteria for the economic review of transmission projects at the May 2017 RPG meeting update, in which ERCOT stated, *"Based on the review, ERCOT Economic studies will continue to use 15% of the capital cost of the project as the 1st year annual revenue requirement to determine societal benefit until next annual review."*

The above analysis notwithstanding, LP&L also evaluated the economic performance of synchronous condensers over a 6-year period assuming that the Affected Load integrates into the ERCOT grid in mid-2021. Table 5.7 provides the annual production savings expected to result from the installation of the additional synchronous condensers at 345 kV Windmill Station assuming that the Affected Load is integrated into ERCOT by mid-2021. It is important to note that the annual production cost savings associated with the synchronous condensers at 345 kV Windmill Station in the presence of LP&L are used for subsequent years. No assumptions around the linear increase in the annual production cost savings from 2020 to 2025 (the study year containing generation additions that do not meet section 6.9 requirement of ERCOT Planning Guide) are made.

Year	2020	2021	2022	2023	2024	2025
Annual Production Cost Savings ($M)	12.1	8.35	4.6	4.6	4.6	4.6

Table 5.7: Economic Assessment of Additional Synchronous Condenser at 345 kV Windmill Station

Based on the results depicted above and in Table 5.7 and ERCOT-provided cost estimates for the synchronous condensers at $39.5 million, the additional Synchronous Condenser at 345 kV Windmill Station is not justified based on ERCOT's economic criteria as outlined in ERCOT Protocol Section 3.11.2. Based on the above analysis, the additional Synchronous Condenser at 345 kV Windmill Station is identified as an avoided project due to the integration of the Affected Load at the time of this assessment.

5.3.4. Cost-Benefit Assessment

As mentioned earlier, the ERCOT APC savings metric is used to capture the true impact of the LP&L integration into ERCOT. The ERCOT APC savings for each study scenario are determined by adjusting the annual production cost savings for that scenario with the expected LP&L load payments. The ERCOT APC savings are determined for 2020 and 2025. The ERCOT

APC savings for 2020 and 2025 are used to perform a Net Present Value (NPV) assessment of the benefits of the LP&L integration over a 40-year horizon. Similarly, an NPV assessment of the cost associated with LP&L integration ($364M associated with Option 4ow) is performed over a 40-year horizon. A discount rate of 8% and an inflation rate of 2.5% is used for the NPV assessment. The assumptions associated with the duration, discount rate, and inflation rate used in the NPV assessment are consistent with those used by SPP and ERCOT in the ERCOT-SPP coordinated study. Note that a $39.5M avoided cost associated with the additional synchronous condenser at 345 kV Windmill Station is accounted for.

Table 5.8 provides summary results associated with the cost-benefit assessment.

Scenario	2020			2025			NPV Benefit ($M)	NPV Cost ($M)	Benefit/Cost Ratio
	Production Cost Savings ($M)	LP&L Load Payments ($M)	ERCOT APC Savings ($M)	Production Cost Savings ($M)	LP&L Load Payments ($M)	ERCOT APC Savings ($M)			
Base	NA	NA	NA	NA	NA	NA	NA	NA	NA
Change	(63.2)	69.2	6.0	(63.1)	94.6	31.5	582	419	1.39
Sensitivity	(60.9)	69 .1	8.2	(55.3)	94.3	39.0	712	436	1.63

Table 5.8: Cost-Benefit Assessment Results

The following key observations can be made from the summary results depicted in Table 5.8:

- The LP&L integration into ERCOT is observed to provide net benefits to ERCOT in 2020 when taking into account the LP&L load payments. These net benefits accrued to ERCOT are observed to significantly increase in 2025 primarily due to the increase in the LP&L load payments.
- The results of the NPV assessments demonstrate that the benefits associated with the LP&L integration into ERCOT far outweigh the cost in the long term. This is underlined by a benefit-to-cost ratio of 1.39 associated with the LP&L integration into ERCOT. A benefit-to-cost ratio of 1.0 to 1.25 or above is the widely-used threshold for economic justification criteria.
- The cost-benefit assessment is also repeated with the same inputs except those associated with the avoided cost of the additional synchronous condenser at Windmill Station. Even with the additional synchronous condenser at Windmill Station assumed to not be avoided by LP&L, the benefit-to-cost ratio is observed to be as high as 1.24.

- It is important to note that the sensitivity scenario results in an even higher benefit-to-cost ratio (1.63). This is primarily due to the additional Panhandle export limit benefits not accounted for in the ERCOT Integration Report.

5.3.5. Capacity Cost Savings

A system loss impact assessment associated with the LP&L integration into ERCOT has also been performed. A net loss savings of 8.3 MW is observed in 2020 by virtue of the LP&L integration into ERCOT. The net loss savings observed are primarily due to the presence of a local load (LP&L load) in the vicinity of the remotely located Panhandle generation. The potential annual capacity cost savings for 8.3 MW of loss savings is estimated to be approximately $788,000. The capacity cost savings estimate assumes an annualized Cost of New Entry (CONE) of $95 per kW-year and a capacity reserve margin target of 12%. The benefit-to-cost ratio associated to LP&L integration is expected to be even higher if the capacity cost saving is taken into account.

5.3.6. Reliability Impact Assessment

As noted previously, ERCOT finalized its LP&L integration study and recommended the preferred integration Option 4ow in May 2016. As part of the Study, a comprehensive reliability impact assessment was conducted to identify any reliability concerns in the study region as the result of LP&L integration into ERCOT. This independent reliability impact analysis was performed to address the following aspects outlined in Chairman Nelson's Memorandum:

- Evaluation of the cost and **reliability** impacts on all customer classes in ERCOT and SPP
- Analysis of avoided projects or new projects as a result of moving the LP&L Load to ERCOT and the estimated costs of those projects
- Evaluation of the impacts on operations, both from a cost and reliability perspective, on the ERCOT and SPP systems

As noted before, the reliability impact assessment on the ERCOT side is comprised of the following evaluations:

- Steady State Impact assessment
- Transient Stability impact assessment
- Panhandle export limit assessment
  - System strength perspective
  - Transient stability perspective
- Operational flexibility impact assessment
- Sub-synchronous resonance impact assessment

5.3.6.1. Steady State Impact Assessment Results

The intent of the steady state impact assessment was to corroborate the ability of ERCOT's proposed Option 4ow to reliably integrate LP&L into the ERCOT grid. Additionally, in line with Chairman Nelson's Memorandum, the steady state impact assessment was also aimed at identifying any additional transmission projects and/or reliability impacts associated with LP&L's integration into ERCOT. The Steady State assessment was performed under normal operating and contingency conditions. The Base and Change scenarios are both evaluated from thermal overload and voltage perspectives vis-à-vis ERCOT's Planning Guide and NERC Standard TPL-001-04.

Based on the study assumptions and methodology described in the previous section, it was observed that integration of LP&L loads and facilities into the ERCOT grid do not pose any incremental reliability concerns in terms of steady state voltage and thermal overloads in either LP&L network or ERCOT grid. Based on the results of the steady state assessment, no additional transmission projects and/or upgrades (incremental to ERCOT recommended Option 4ow) are identified as needed for the LP&L integration.

5.3.6.2. Transient Stability Impact Assessment Results

Based on the study assumptions and methodology described in the previous Section, it was observed that the proposed integration of LP&L loads and facilities into ERCOT grid do not pose any incremental reliability concerns or performance violations in terms of transient voltage and angle stability standpoints for all the dynamic contingencies simulated. The ERCOT's proposed Option 4ow is deemed sufficient to reliably integrate LP&L into ERCOT from transient stability standpoint.

It is important to note that the LP&L integration into ERCOT has significant benefits in terms of the Panhandle export capability from transient stability standpoint. These benefits are discussed in the subsequent subsections.

5.3.6.3. Panhandle Export Capability Assessment Results

According to various planning and operational studies performed by ERCOT and utilities in the Panhandle region, there are well-documented limits to the amount of power that can be exported from the generation-rich Panhandle region of ERCOT, i.e., Panhandle export limit. Historically, the Panhandle export limit has been observed to be the function of system strength, voltage stability (P-V characteristics), and transient stability of the Panhandle region. The integration of LP&L into ERCOT is expected to result in significant benefits to the Panhandle export limit both in terms of system strength and transient stability. This section aims to evaluate the impact of LP&L integration into ERCOT on Panhandle export limit from system strength and transient stability standpoints. While this assessment is presented in the reliability impact assessment, the results of this assessment are used in the economic assessment. This is important because an increase in the Panhandle export limit by virtue of the LP&L integration into ERCOT is expected to result in greater access to low cost renewable resources for energy consumers across the state of Texas.

5.3.6.4. System Strength Impact Assessment Results

ERCOT quantified the Panhandle system strength in terms of a Weighted Short-Circuit Ratio (WSCR). A WSCR based Panhandle export limit can then be derived using a target WSCR equal to 1.5. The analytical expression for WSCR is given below[54]:

$$WSCR = \frac{\sum_{i=1}^{N} S_{SCMVAi} \times P_{MWi}}{\left(\sum_{i=1}^{N} P_{MWi}\right)^2}$$

S_{SCMVAi} = Short-circuit MVA at the i^{th} ERCOT Panhandle station
P_{MWi} = Total WGR capacity interconnection at the i^{th} station

As outlined earlier in the report, apart from the Base and Change Scenarios, a Sensitivity Scenario was specifically designed to evaluate the incremental benefits associated with the following aspects of LP&L integration:

- Conversion of LP&L's Cooke G1 and G2 generation units to synchronous condensers.
- Inclusion of the short circuit contribution of the dynamic loads within the LP&L system – Given the location of the LP&L load, it is prudent to evaluate the short circuit benefits that the LP&L motor loads may provide to the overall Panhandle system strength. To consider the short circuit contribution of the LP&L dynamic loads, the amount of motor load within LP&L network is estimated using the load class and load mix of the LP&L system. Motor load is assumed to provide a short circuit contribution up to four (4) p.u. of the rated motor current.[55] It is important to note that all the analyses performed by ERCOT to date do not take this factor into account when evaluating the impact of LP&L integration on the Panhandle export limit. It is important to note that the System Strength study scope presented by ERCOT at the August 2017 RPG meeting makes note of the fact that the impact of the load on system strength needs to be evaluated.

The WSCR based Panhandle export limits as calculated for the three (3) study scenarios are outlined and depicted in Table 5.9.

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[54] Panhandle Renewable Energy Zone (PREZ) Study Report, April 2014, ERCOT System Planning.

[55] Understanding Short Circuit Motor Contribution, August 2010, D. Broussard P.E., GE Industrial Solutions.

Case	Panhandle Export Limit for WSCR = 1.5 (MW)
Base	4058
Change	4548
Sensitivity	4684

Table 5.9: System Strength Assessment Results

The key findings associated with the system strength impact assessment are as follows:

- Integration of LP&L network to ERCOT results in an increase in WSCR based Panhandle export limit by 490 MW. Based on the study results, a clear benefit is obtained by virtue of LP&L integration to ERCOT from a system strength perspective. The results associated with the incremental benefit of LP&L integration into ERCOT from a system strength perspective aligns very closely with the ERCOT results published in the ERCOT Integration Report.

- By considering the potential short circuit contribution from future LP&L synchronous condensers and LP&L motor loads the WSCR based Panhandle export limit will further increase from 4548 MW to 4684 MW, a further increase of 136 MW.

5.3.6.5. *Transient Stability Impact Assessment Results*

Table 5.10 provides a summary of the results of the transient stability assessment as used to determine the transient stability based Panhandle Export limit. As seen from this Table, for all the scenarios studied, the transient stability-based Panhandle Export limit is more than the WSCR based limit, hence the system strength-based limit is observed to be binding. In addition, the integration of the LP&L network to the ERCOT grid is observed to increase the Panhandle export limit from a transient stability standpoint. It is important to note that while additional synchronous condensers in the Panhandle may demonstrate system strength benefits, these benefits are expected to be significantly undermined due to stability limitations in the absence of a new transmission path out of the Panhandle. The unique nature of the LP&L integration into ERCOT lies in its ability to provide system strength and stability in equal measure. Finally, the benefits of future synchronous condensers in the Panhandle will also be amplified in the presence of LP&L system in ERCOT.

Study Scenario	Transient Stability based PH Export Capability	WSCR Based PH Export Capability	Planning-level Panhandle Interface Limit
BASE	>4059	4059	4059
CHANGE	>4548	4548	4548
SENSITIVITY	>4684	4684	4684

Table 5.10: Panhandle Export Limit Impact Assessment Results

Following a determination of the WSCR based Panhandle export limit and transient stability based limit, the lesser of the two is used as the Planning-level Panhandle Export limit for the economic assessment as depicted in Table 5.10.

5.3.6.6. Operational Flexibility Impact Assessment Results

The Panhandle export limit results presented in the previous subsection take into account the ERCOT Planning Methodology when determining such limits. The planning methodology does not necessarily take into account aspects such as operational flexibility in terms of prior outage conditions in real time operations. The "Texas Panhandle Stability Study" Report, issued by ERCOT Operations Support staff on May 4, 2016, concluded that, in real time, the voltage stability based Panhandle export limit could be more limiting than the WSCR-based limit when taking into account prior transmission system outages. The results of this analysis were used to define a "Generic Transmission Limit" (GTL) for the Panhandle region to be enforced in real time operations. The resulting GTL, currently applied to the Panhandle region, has been at times observed to be lower than what has been planned by virtue of WSCR criteria hence further limiting the ERCOT consumers' access to the renewable resources available in the Panhandle region.

Because integration of the LP&L network into the ERCOT grid results in additional export paths for the renewable resources available in the Panhandle region, the LP&L integration will provide increased operational flexibility specifically in terms of the Panhandle transmission system without significantly compromising access to the Panhandle renewable resources.

The presence of LP&L in the ERCOT system offers increased operational flexibility in terms of reduced impact of prior outages on the Panhandle export limit. To quantify the extent of the increased operational flexibility in the Panhandle region, a comprehensive steady state voltage stability (P-V analysis) similar to that performed by ERCOT operation staff was conducted. Relevant prior outage conditions in the Panhandle region pre- and post-LP&L integration are taken into account.

For the P-V analysis, wind generation resources in the Panhandle are used as the source while loads outside the Study Region are used as the sink. Specifically, for the operational flexibility impact assessment, the following prior outage conditions are studied:

- Prior outage of 345 kV Cottonwood–White River double circuit
- Prior outage of 345 kV Tesla–Tule Canyon double circuit
- Prior outage of 345 kV Tesla–Riley/Jim Treece double circuit
- Prior outage of 345 kV Abernathy–Ogallala single circuit (only applicable to Change scenario)

- Prior outage of 345 kV Grassland–Longdraw single circuit (only applicable to Change scenario)

For both Base and Change scenarios, all the P1 and P7 category contingencies around the facilities in the Panhandle region, LP&L network and interconnecting facilities are simulated against the above-mentioned prior outages to determine the maximum feasible power transfer from the source to sink without any voltage instability (non-convergence) issues.

The Panhandle export limit as obtained by the voltage stability assessment are provided in Table 5.11. For both study scenarios, i.e., with and without integration of the LP&L network, the prior outage of Cottonwood to White River Double Circuit line followed by loss of Tule Canyon to Tesla Double circuit line was observed to result in the least Panhandle export capability from a voltage stability standpoint. However, as shown in Table 5.11, integration of LP&L to the ERCOT grid was observed to result in an increase in voltage stability based Panhandle export capability by about 2,500 MW.

Scenarios	Most limiting Conditions		Panhandle Export Limit (MW)
	Prior Outage	Contingency	
BASE	Cottonwood - White River DKT	Tule Canyon - Tesla DKT	2757.9
CHANGE			5308.5

Table 5.11: Steady State Voltage Stability Assessment Results

Per the report issued by ERCOT in May 2016, the lesser of the WSCR-based Panhandle export limit and the voltage stability based limit will be used by ERCOT Operation Support staff as the Panhandle real-time GTL. While the real-time GTL will be calculated based on the real-time transmission topology and committed generation, the integration of LP&L network into ERCOT grid significantly increases both WSCR based limit. Thus, it can be concluded that the integration of LP&L network to ERCOT grid could significantly increase the real-time GTL, hence more renewable energy resources from the panhandle region will be available to energy consumers across of the state of Texas. The results depicted in Table 5.11 also underline the increased operational flexibility afforded to the Panhandle region in ERCOT post-LP&L integration without significantly compromising the Panhandle export limit.

It is important to note that the analysis presented in this section is representative of the benefits of LP&L integration on the real-time Panhandle GTL.

5.3.6.7. Sub-synchronous Resonance Impact Assessment

Given the location of the LP&L system relative to some of the series compensated lines on the ERCOT system, it is prudent to evaluate the sub-synchronous resonance (SSR) risk impacts on the ERCOT grid following the integration of the LP&L network. This section provides a brief overview of the SSR phenomenon and various manifestations of the same. Further, it reviews the methodology that is currently being used by ERCOT for SSR risk assessment. The assessment evaluates the impact of LP&L integration on the potential for SSR risk only for generation resources within ERCOT.

SSR is an interaction between series compensated transmission lines and turbine generator units in the power system. This phenomenon occurs at sub-synchronous (<60 Hz) frequencies. It is typically observed when a generation resource is radially connected to one (1) or more series compensated transmission lines. A radial connection implies that the only path for the generator power output to flow is via the series compensated line. Although a radial connection is expected to lead to SSR risk in most of the cases, it should be noted that generators may exhibit potential for SSR under non-radial connections. There are different manifestations of SSR for conventional turbine-generator units and wind generation resources (WGRs).

In case of conventional generators, SSR has three (3) manifestations as described below.

- Torsional Interaction
  - Turbine-generators typically have one (1) or more torsional oscillation modes at sub-synchronous frequencies.
  - Presence of series capacitors in the transmission system in the vicinity of the turbine-generator may lead to negative electrical damping at the torsional oscillation frequencies.
  - If the generator torsional modes are excited during a power system event, there will be oscillations in the shaft torque at sub-synchronous frequency. If the damping at the torsional mode is negative (taking into account the inherently positive mechanical damping and the potentially negative electrical damping), these oscillations will continue to grow, thereby causing shaft fatigue and, in some cases, extensive shaft damage.
- Induction Generator Effect
  - Presence of series capacitors on the transmission system creates a series resonant condition at sub-synchronous frequencies.
  - Due to the induction generator effect, a synchronous machine may exhibit negative resistance in the sub-synchronous frequency range. In effect, such a machine will offer negative damping to sub-synchronous frequency oscillations.
  - Sub-synchronous frequency oscillations may be triggered in the power system during events such as faults and transmission line outages.

  - Depending upon the level of negative damping being offered by the synchronous machine vis-à-vis the positive damping offered by other elements in the power system, the oscillation magnitude will continue to increase thereby causing damage.

- Torsional Amplification
  - Presence of series capacitors may cause amplification of torsional oscillations during power system events such as faults.

In case of WGRs, SSR manifests in the form of negatively damped oscillations in generator output when radial connection to series compensated lines is established. There is potential for damage to turbine power electronic converters as well as series capacitors if oscillations magnitude is not limited.

ERCOT Nodal Protocol Revision Request (NPRR) 562 discusses the approach and methodology to address SSR risk. NPRR 562 was approved by ERCOT's Board of Directors on June 13, 2017.

Per the June 2017 approved version of NPRR 562:

- Any generation resource which is radially connected to series compensated lines for 14[56] or fewer concurrent outages may be considered vulnerable to SSR risk
  - Frequency scan assessment needs to be conducted for all such generators to capture potential for SSR risk. If the frequency scan indicates potential SSR vulnerability, a detailed SSR analysis must be performed.

- If SSR risk is confirmed under 4 or fewer concurrent outages, SSR mitigation must to be implemented
  - May involve addition of equipment such as relays/filters at the generation as well as transmission system level

- If risk is observed for 5 or 6 concurrent outages, procedural mitigation (for example, outage coordination) can be implemented
  - ERCOT will implement SSR monitoring to prevent specific outage combination

Guidelines provided in the now approved ERCOT NPRR 562 are used to conduct the SSR risk evaluation for the generation resources in ERCOT for the Base and Change Study Scenarios (i.e., with and without integration of the LP&L network). The intent of the SSR impact assessment was to quantify the impact of LP&L integration on the risk for SSR for generation

56 The number of outages may be reviewed by ERCOT in consultation with the TSPs.

units (existing and/or meeting ERCOT planning guide section 6.9 requirements) in ERCOT. The transmission lines in the proximity of the LP&L network that are equipped with series capacitors are as follows (refer Figure 5.5):

- 345 kV Tule Canyon–Tesla line
- 345 kV Dermott–Clear Crossing line
- 345 kV Edith Clarke–Clear Crossing line

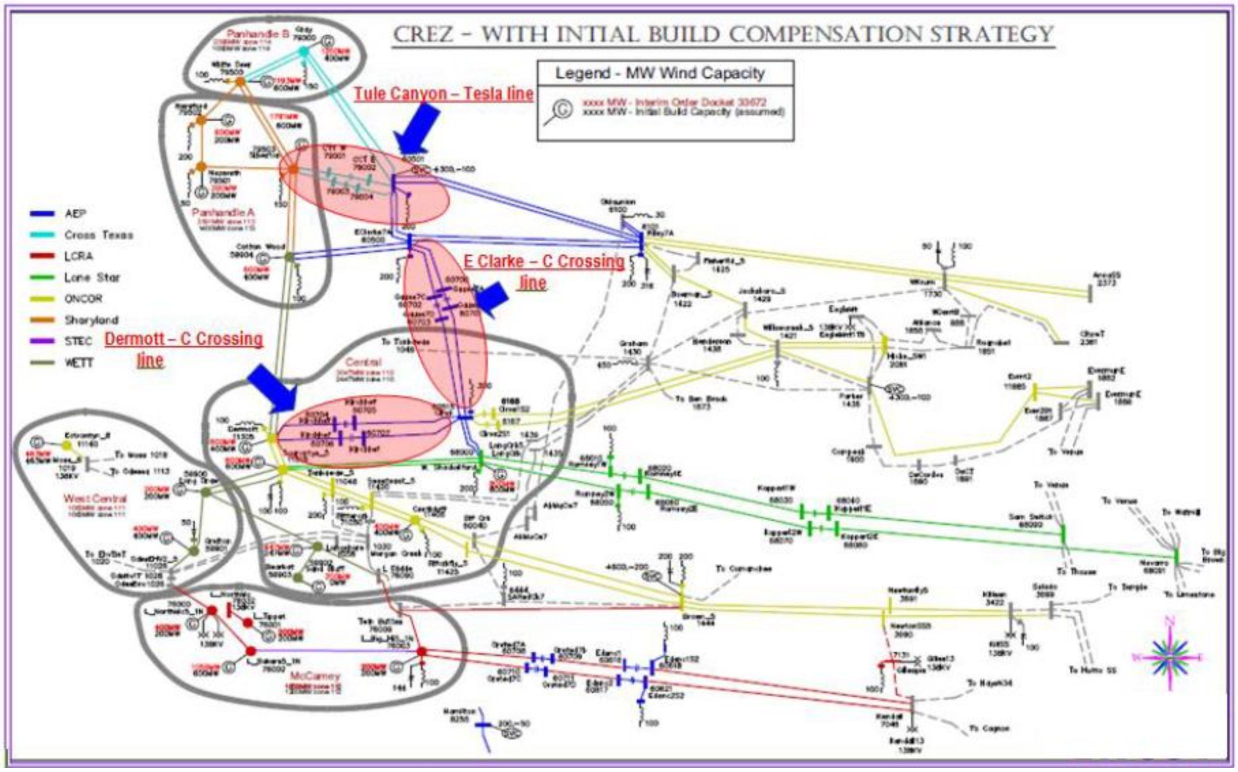

Figure 5.5: Series Compensated Transmission Lines Included for SSR Risk Assessment

Keeping the objective of this study in mind, only outages that result in radial connection between series compensated lines and Panhandle generation resources have been evaluated. For the base study scenario, it is observed that four outages (N-4) are required to establish the radial connection between the Tesla–Tule Canyon series compensated line and the generation units in Panhandle region. Per requirements outlined in ERCOT NPRR 562, this outage count requires the resource entity to provide SSR mitigation. Following the integration of the LP&L network into the ERCOT grid (Change Scenario), the outage count required to establish the radial connection between the series compensated line and the generation units in Panhandle region will increase from 4 to 5 concurrent outages. This increase in outage count is caused by the additional transmission paths that are required to integrate the LP&L network to the ERCOT grid.

Table 5.12 illustrates the historical probability of the occurrence of single circuit and double circuit outages in the ERCOT grid.[57] As depicted in the Table 5.12 the maximum likelihood of having a N-4 condition in ERCOT grid is 71.657%, which is associated with two (2) double circuit outages. However, the maximum likelihood of having a N-5 condition in the ERCOT grid is 2.584%, which is associated with two (2) double circuit outages and one (1) single circuit outage. Considering the above observations from Table 5.12 and the impact of LP&L's integration in increasing the outage counts, integration of LP&L into ERCOT results in the reduction of the likelihood of SSR risk in the Panhandle region from 71.657% to 2.584%. Based on the data provided in Table 5.12, a similar conclusion can be made when considering other combinations of single and double circuit outages, which result in N-4 condition. Moreover, the increase in the number of outages that result in radial connection with series compensated lines is expected to provide more flexibility to grid operators from the SSR risk standpoint when planning and/or coordinating long-term outages.

		Single Circuit Outages						
		0	**1**	**2**	**3**	**4**	**5**	**6**
Double Circuit Outages	0	100.000%	100.000%	100.000%	90.439%	4.804%	0.101%	0.002%
	1	100.000%	99.999%	21.956%	0.519%	0.011%	0.000%	
	2	71.657%	2.584%	0.055%	0.001%	0.000%		
	3	0.302%	0.006%	0.000%	0.000%			
	4	0.001%	0.000%	0.000%				
	5	0.000%						

Green	N-4 or less
Yellow	N-5
Orange	N-6

Table 5.12: Historical "N-X" Outage Probability Within ERCOT

It is important to note that the historical outage probability data utilized in Table 5.12 is based on historical outage statistics presented by ERCOT at their December 2015 SSR workshop. It is also noteworthy that ERCOT planning staff used the aforementioned outage statistics to justify and build consensus around the outage counts associated with SSR mitigation and protection as documented in the now approved NPRR 562.

5.3.7. Other Impacts

5.3.7.1. Ancillary Service Impacts

In response to Chairman Nelson's Memorandum, the potential impact of the LP&L transfer on the ERCOT ancillary services market was studied. The study approach and methodology as documented in the "ERCOT Methodologies for Determining Minimum Ancillary Service Requirements" (approved by ERCOT Board on 12/13/2016) was used to conduct the

[57] ERCOT Sub-Synchronous Resonance (SSR) Workshop, [presentation by ERCOT Staff] December 4, 2015.

analysis. Given the amount of load and its size of generation, LP&L's integration into ERCOT is not expected to result in any material changes to ERCOT's Responsive Reserve Service (RRS) and Non-Spinning Reserve service procurement. Consequently, the impact of LP&L integration into ERCOT on ancillary services focuses on the potential change in requirement of Regulation Up/Down services.

The following data, as provided by ERCOT, was used for this assessment:

- Historical Regulation Service Deployment Data on a 5-minute interval basis
- Historical Net Load Data on a 5-minute interval basis (Year 2015 & 2016)
- Control Performance Standard Data (CPS1)

In addition, the historical 1-minute load data for LP&L load for the years 2015 and 2016 was also used. The 95th percentile of net load variance in conjunction with the historical regulation service deployment was utilized to determine the hourly Regulation Up/Down service requirements for each month in 2017. As specified in the ERCOT Ancillary Service guidelines, further adjustments are incorporated based on the increase in wind generation capacity as well as the ERCOT CPS1 data. The process was performed with and without the LP&L load included in ERCOT system in order to capture the impact of the LP&L integration into ERCOT.

Figures 5.6 and 5.7 reflect the percentage change for ERCOT's hourly Regulation Up/Down requirements because of the Affected Load's integration into the ERCOT system. As evident from Figures 5.6 and 5.7, the integration of LP&L load into ERCOT would result in a maximum change of 2.54% in terms of the hourly regulation up procurement requirements and a maximum change of 3.64% in terms of the hourly regulation down procurement requirements. Conversely, Figures 5.8 and 5.9 depict the average percentage change for ERCOT's monthly Regulation Up/Down requirements in presence of the LP&L system. The impact of the Affected Load's integration on the total monthly regulation up/down procurement requirements are observed to be less than 0.5%. As expected, LP&L load integration would result in a slight increase in load variance regarding the net load calculation. However, the total amount of LP&L load in comparison to ERCOT produces minimal change in procurement requirements and is expected to have a negligible impact on ancillary services.

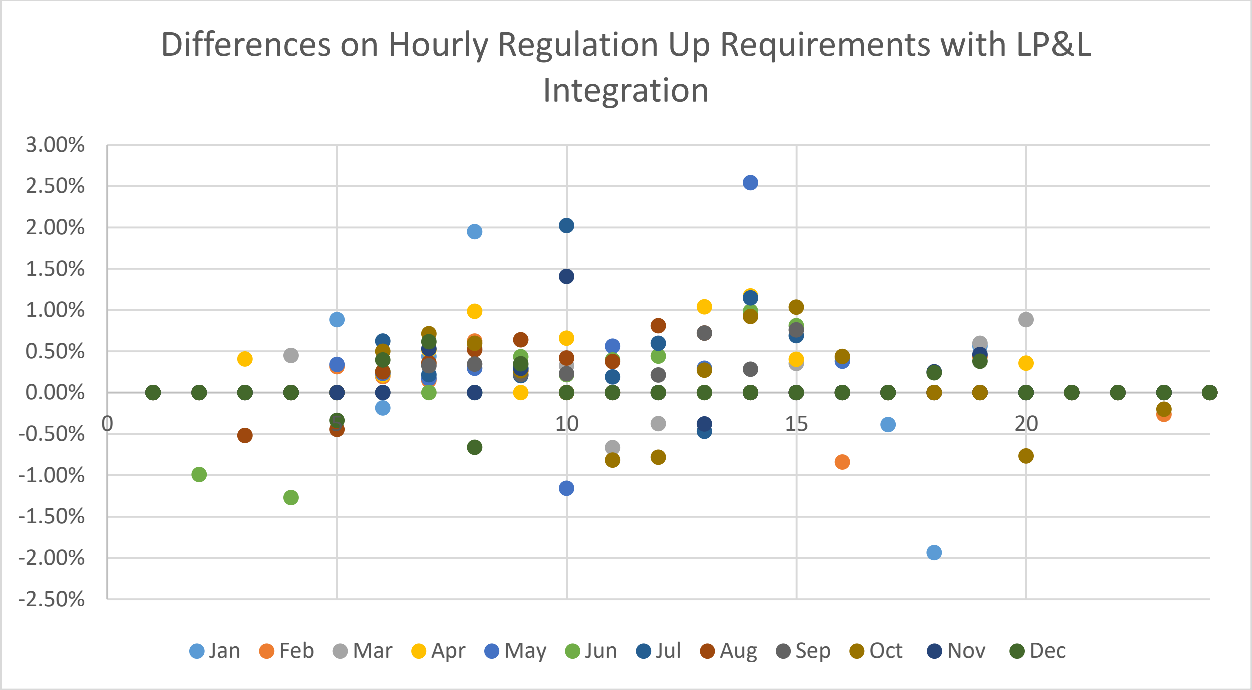

Figure 5.6: Differences on Hourly Regulation Up Requirements with LP&L Integration

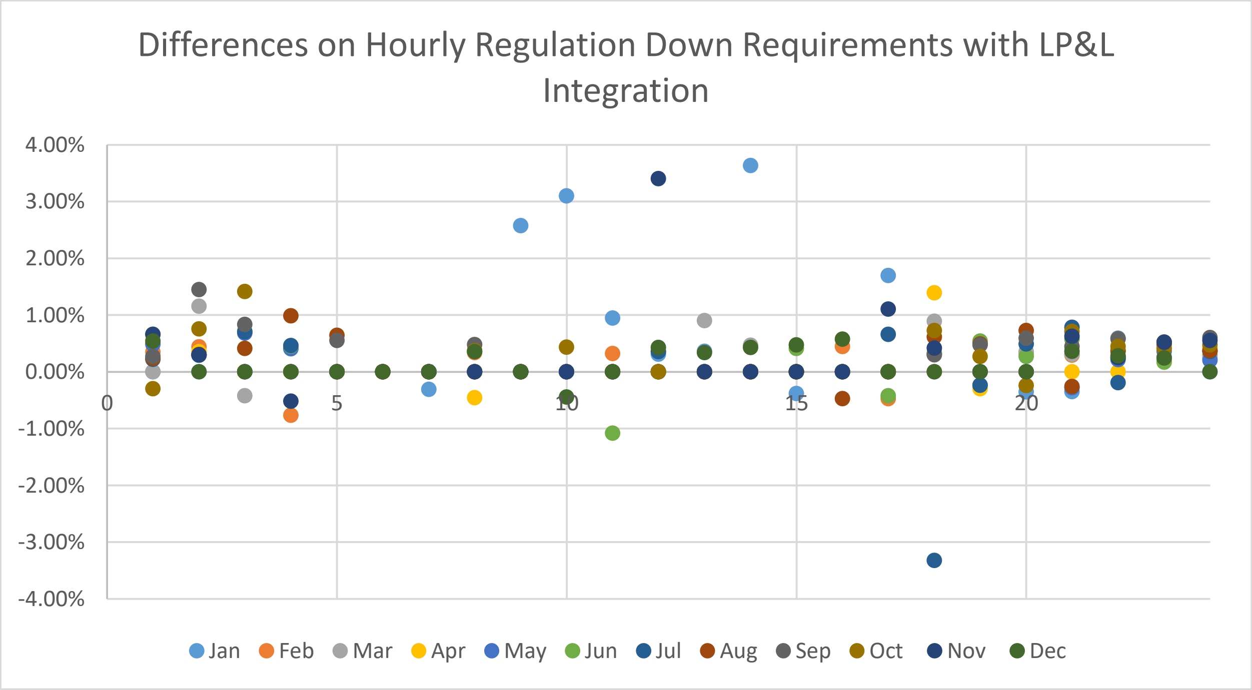

Figure 5.7: Differences on Hourly Regulation Down Requirements with LP&L Integration

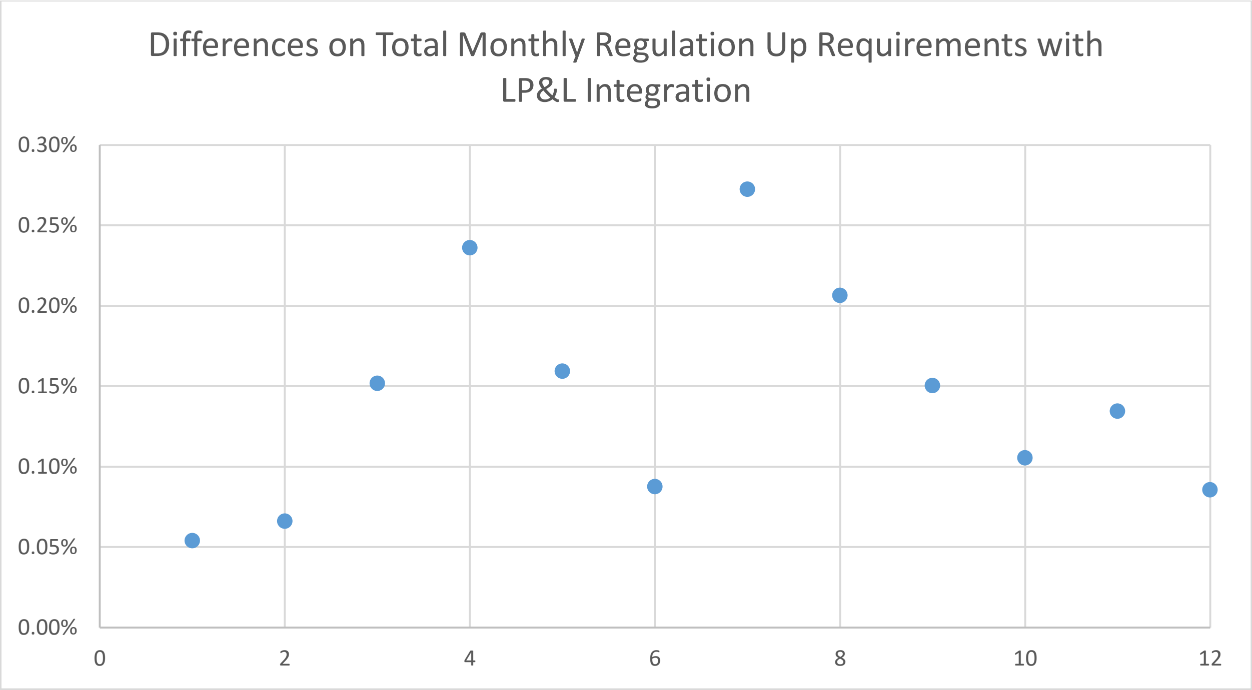

Figure 5.8: Differences on Monthly Regulation Up Requirements with LP&L Integration

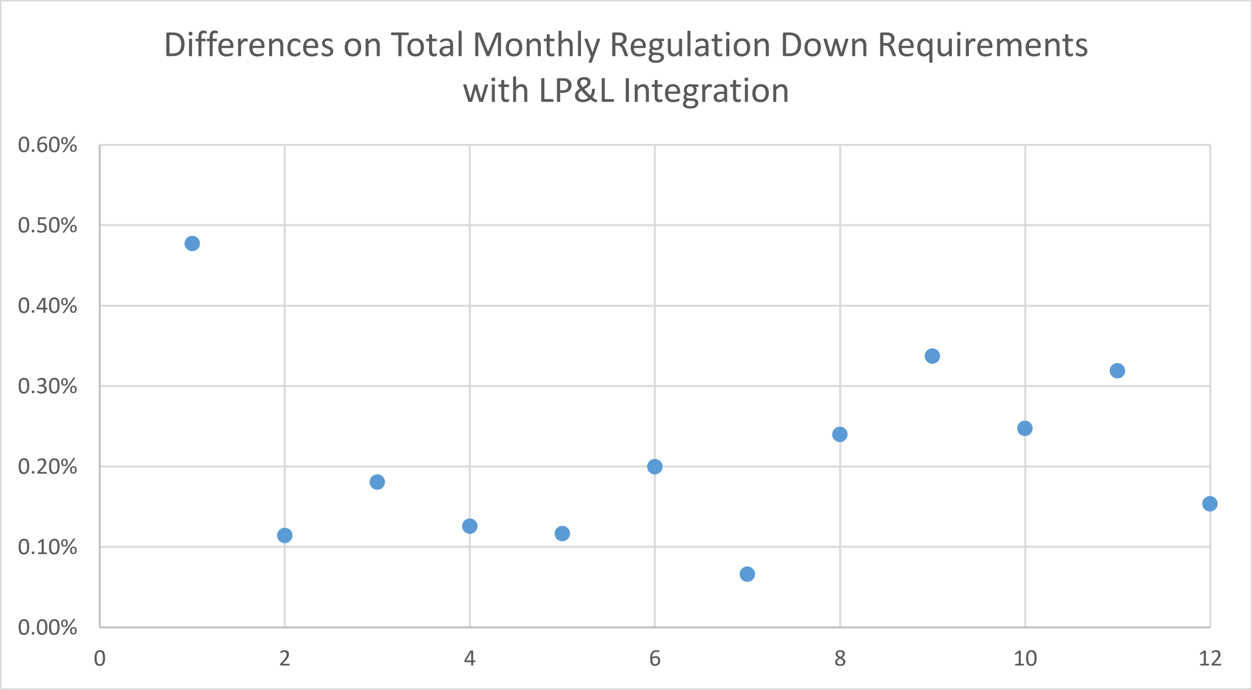

Figure 5.9: Differences on Monthly Regulation Down Requirements with LP&L Integration

5.3.7.2. Congestion Revenue Rights Impacts

Congestion Revenue Rights (CRRs) in ERCOT are financial hedging instruments used by the market participants to hedge against congestion, and hence price volatility, in the ERCOT nodal market. Congestion can have a significant effect on LMPs by driving higher cost generation to be dispatched during the congested periods. During these periods, cheaper generation must either be curtailed (as in the case of renewables) or not be dispatched at the level it otherwise would be (as in the case of conventional units). CRRs in ERCOT are acquired either semi-annually or through monthly auctions. Considering the location of the LP&L network in relation to the ERCOT grid, the time frame of this integration and LP&L's preference in joining ERCOT Market as a NOIE load zone, LP&L's integration will have a very negligible impact on existing or future CRRs.

More importantly, like any other major transmission and/or load addition to the system, the LP&L integration into ERCOT and its timeline provides the market and the stakeholders ample time to account for the same from a CRR perspective with minimal impacts.

6. WHOLESALE TRANSMISSION RATE IMPACTS

This section of the report addresses the rate impacts to the wholesale customers of any affected utility in ERCOT and in the Texas portions of SPP. More specifically, this report section discusses and summarizes the analysis performed to determine the impacts on wholesale transmission service rates in ERCOT and in the Texas portions of SPP. While Sections 5.2 and 5.3 discuss overall SPP and ERCOT impacts on wholesale power costs, the information needed to determine the wholesale power cost impacts on all individual utilities in SPP and ERCOT is not readily available. Similarly, the report primarily addresses the wholesale transmission rate impacts on the total of all wholesale transmission customers in ERCOT and the Texas portion of SPP.

6.1. LP&L Wholesale Transmission Cost of Service

LP&L's Transmission Cost of Service (TCOS) is based on projected 2021 data from LP&L budget forecast, including both direct and indirect O&M and a debt service coverage ratio of 1.5 for current and required facilities.

As discussed previously, the preferred Option 4ow requires additional facilities to be built for LP&L to connect to the ERCOT power grid, resulting in higher transmission cost in ERCOT than in SPP. The annual cost of the LP&L-owned and operated transmission assets to the SPP and ERCOT markets is projected to be $19 million and $30 million respectively; the difference is primarily due to LP&L's portion, estimated to cost $105 million, of the needed transmission facilities required to interconnect to the ERCOT grid under the Option 4ow plan.

6.2. ERCOT Impacts

Transmission service providers (TSPs) in ERCOT recover their PUCT approved TCOS through an access charge applied to all LSEs. The TCOS includes the cost of facilities rated above 60 kilovolts, including transmission-related facilities in distribution substations. The sum of all TSPs' approved access charges is the ERCOT-wide postage stamp access charge. The access charges are applied to the LSE's average four coincident peak (4CP) demand at the time of ERCOT's four summer month peaks in the prior year. The 4CP billing determinants are set annually by the PUCT.

If LP&L's move to ERCOT is approved by the PUCT, the ERCOT wholesale transmission rates will be impacted by the following changes:

- An increase in the total ERCOT TCOS related to LP&L's TCOS for its transmission facilities, including any ERCOT interconnection facilities to be constructed by LP&L.

- A decrease in the ERCOT postage stamp access charge resulting from the additional LP&L load, or 4CP, to be transferred to ERCOT[58]

- An increase in the total ERCOT TCOS related to the additional TCOS for the construction of the LP&L interconnection facilities to be constructed by other TSPs.

- A potential decrease in the total ERCOT TCOS related to planned ERCOT transmission system additions that will be avoided if LP&L moves to ERCOT.

For purposes of estimating the above impacts to the ERCOT wholesale transmission rate, the current approved total ERCOT TCOS and 4CP are projected to 2021. The projections are based on the following assumptions:

- The total ERCOT 2021 TCOS prior to any LP&L transfer is based on the approved 2017 ERCOT TCOS plus an average annual TCOS increase amount of approximately $139 million per-year. The annual average TCOS increase is based on the average annual increase from 2006 to 2017, excluding the CREZ affected years of 2013, 2014, and 2015.

- The projected LP&L TCOS is based on current LP&L transmission facilities, planned upgrades to those current facilities, and the 345 kV substations and tie line facilities included in ERCOT's 4ow plan (approximately $105 million.) The forecast 2021 LP&L ERCOT TCOS amount is $29.8 million.

- The ERCOT 2021 4CP prior to any LP&L transfer is based on the same methodology laid out in Section 4.3 above in the bullet entitled "LP&L Wholesale Transmission Access Fee Assumptions." The forecasted ERCOT Total 4CP for 2021 is 70,436 MW.

- The projected 2021 LP&L ERCOT 4CP is based on LP&L's load forecast for the NCP portion of their Affected Load. This projected non-coincident peak amount was then adjusted to an ERCOT 4CP amount based on a historic coincidence factor. The estimated LP&L 2021 ERCOT 4CP amount is 395.8 MW.

- The 2021 TCOS for the ERCOT 4ow plan interconnection facilities not built by LP&L is based on the average carrying charge of the major TSPs in ERCOT that may construct these remaining transmission facilities (approximately $259 million). This additional estimated 2021 TCOS amount is $42.2 million.

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[58] This decrease in the ERCOT postage stamp access charge will not occur immediately but rather over multiple years. As TSPs file full or interim TCOS applications with PUCT, their approved access charges will be based on the new ERCOT 4CP that includes the additional LP&L load. For purposes of determining the ERCOT wholesale transmission rate impacts in this study, it is assumed that the access charge decrease due to LP&L's additional load will occur in 2021.

- The forecasted 2021 ERCOT total TCOS and 4CP, prior to a move by LP&L, are $4,011,336,791 and 70,436 MW, respectively. Based on these amounts, the forecasted 2021 ERCOT annual access fee is estimated to be $56.95 per 4CP kW.

After making the forecasted adjustment for the four LP&L impacts described above, the adjusted 2021 ERCOT total TCOS is $4,105,734,227 and the total ERCOT 4CP is 70,834 MW. The resulting adjusted 2021 forecasted ERCOT annual access charge is $57.65 per 4CP kW. Therefore, the net impact of LP&L's move to ERCOT on the ERCOT wholesale transmission rate is a slight net increase of $0.70 per 4CP kW per year, or $0.058 per 4CP kW per month. The impact on the 2021 forecasted ERCOT access charge for each of the four impacts is:

Description of Impact	Impact of LP&L	Impact Including Avoided Costs*
LP&L Transmission Cost of Service	$0.03502 per 4CP kW	$0.03502 per 4CP kW
Addition of LP&L Load (4CP)	-0.02652 per 4CP kW	-0.02652 per 4CP kW
Interconnection Facilities TCOS	0.04967 per 4CP kW	0.00822 per 4CP kW
Total Net Impact	**$0.05817 per 4CP kW**	**$0.01672 per 4CP kW**

* LP&L Interconnection facilities avoid approximately $0.04145 per monthly 4CP kW related to a portion of the proposed South Plains Project.

Table 6.1: Impact of LP&L ERCOT Integration on Monthly Access Charge

As shown in Table 6.1, if the LP&L interconnection is considered from the perspective of eliminating the eventual need for other transmission investment in the ERCOT system, namely the South Plains project as discussed previously, the total additional costs to the ERCOT system beyond proposed projects is only $0.016 per kW per month.

6.3. SPP Impacts

Network Integration Transmission Service (NITS) charges in SPP are determined in accordance with the agreement between SPP and transmission entities.[59] The cost of owning and operating assets (Annual Transmission Revenue Requirement or ATRR, equivalent to TCOS in ERCOT) that are incurred by Transmission Owners (TOs). Certain Transmission Facility costs are directly allocated to a Transmission Pricing Zone (TPZ) and are recovered 100% from the Transmission Customers (TCs) within that TPZ (i.e., Zonal ATRR). Other Transmission Facilities are recovered from all TPZs (Regional ATRR) pursuant to the RTO Tariff.

As explained in Section 2, LP&L is currently a wholesale customer of SPS, and is not a SPP TO. If LP&L were to become a Transmission Owning Member of SPP, SPP has unilateral discretion on which TPZ LP&L's facilities will be integrated.[60] Practical consideration of LP&L's network configuration and topology suggest that LP&L is most suited to the SPS TPZ (Zone 11) in SPP. Therefore, this analysis is predicated upon SPP transmission costs in Zone 11 based on SPP costs as projected in its ten-year forecast.

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[59] Transmission entities are referred to as Transmission Customers (TCs) in SPP.

[60] LP&L has not decided whether it will request that SPP will create a separate load zone or remain part of SPS' load zone.

The transfer of the LP&L Affected Load from a SPS wholesale customer to a SPP Transmission Customer would increase zonal ATRR to SPP transmission customers due to transmission facilities owned by LP&L.

LP&L's ATRR in SPP is projected to be approximately $19.1 million, which includes its cost to own and operate its current and proposed qualifying transmission facilities in SPP. Incorporating LP&L's ATRR in Zone 11 results in approximately a 16% increase to the projected 2021 Zone 11 ATRR (excluding LP&L) of $122.5 million.

LP&L performed an analysis comparing Transmission Service charges under varying SPP load scenarios to assess the impact on SPP Transmission Customers in the Zone 11. The base scenario used a 2021 rate year and assumed LP&L is a fully integrated TO member of SPP. LP&L projects that it would pay total SPP NITS charges of approximately $37.6 million.

This base scenario was compared to similar Transmission Service charges if LP&L transferred the Affected Load to ERCOT. In this case the remaining SPP load would result in SPP NITS charges to LP&L of approximately $10.1 million—a difference of $27.5 million in LP&L charges paid to SPP.

The decrease in SPP revenue is partially offset by the exclusion of LP&L's $19.1 million ATRR included in the Base Scenario. The shifts in Load Ratio Share and changes in administrative fee paid by LP&L as a result of the load transfer is projected to increase the costs allocated to other SPP customers by $8.4 million that would have otherwise been paid by LP&L.

It is estimated that the SPP-Texas portion of the total SPP net amount of $8.4 million is approximately $3.9 million. Similarly, this is $4.6 million less than the SPP-Texas impact if LP&L remains in SPP. This increase is more than offset by reduced load payments described in Section 5.2.1.1 as demonstrated in reduced retail rates for SPS customers.

If LP&L's Affected Load remains in SPP and if LP&L continues to receive Network Integration Service (NITS), new Designated Network Resources (DNR) will be required because LP&L's contract with SPS that serves the Affected Load will terminate. The DNR contracted by LPL to serve its load and meet SPP's Planning Reserve Margin (PRM) requirement will be identified in a Transmission Service Request to SPP and included in a subsequent SPP Aggregate Study. As provided for in Attachment J of the SPP Tariff, transmission upgrade costs associated with NITS may be recovered as a Base Plan Upgrade and subject to zonal and regional allocation. The SPP Tariff limits the maximum Base Plan recovery of transmission upgrades per Transmission Service Request to $180,000 per MW times the requested capacity—referred to as the Safe Harbor Limit. Costs above the Safe Harbor Limit are directly assigned to the Transmission Customer. Upgrade costs at or below the Safe Harbor Limit are recovered from all SPP zonal and/or regional NITS customers. For example, if LP&L requests 400 MW of transmission capacity for a given DNR, the Safe Harbor Limit would be 400 times $180,000, which equals $72 million. The additional $72 million in Base Plan costs would be allocated to the SPP footprint. Based on the average carrying charge of 17% identified in the SPP 10 year forecast, the ATRR for $72 million in transmission upgrades is approximately $12.2 million per year. This annual cost is a potential avoided cost to SPP customers if LP&L's Affected Load transfers to ERCOT.

7. RETAIL RATE IMPACTS

As previously mentioned, one of the issues in Chairman Nelson's Memorandum is to determine the impacts to the "retail customers of any affected utility, including the rates, the quality of service, and any other costs or benefits." The information necessary to determine the rate impacts on the retail customers of electric cooperatives and municipally-owned electric utilities (other than for LP&L) are not readily available. Therefore, this section of the report will only address the estimated rate impacts on the retail rates in the territories of the major investor owned utilities (IOUs) in ERCOT, of SPS, and of LP&L. In addition, the retail rate impact analysis focuses on the impacts on typical customers in the main customer classes of each of these utilities.

7.1. IOU Customers—ERCOT

The ERCOT IOUs for which retail rate impacts have been developed include:

- Oncor Electric Delivery Company,
- CenterPoint Energy Houston Electric,
- AEP-Texas Central Company,
- AEP-Texas North Company,
- Texas-New Mexico Power Company, and
- Sharyland Utilities, L.P.

These IOUs only provide energy delivery service and their customers are retail electric providers (REPs) rather than end-use customers. The REPs are responsible for the energy supply to their end-use, retail customers. For purposes of this report, we have developed retail rate impacts for typical end-use customers in the IOUs major customer classes (all of the ERCOT IOUs have similar major customer classes).

Two retail rate impacts are developed for these retail customers: (1) power supply cost impacts on the REP's energy prices to retail customers, and (2) wholesale transmission delivery cost impacts on the IOU's retail transmission rates to end-use customers. A summary of the total impact on the typical customer bills is also provided.[61]

7.1.1. Power Cost Impacts

The impacts on the IOU's 2021 power costs are based on the following assumptions:

- For residential customers, power cost baselines are established by compiling rates from the PUCT's Average Annual Rate Comparison for Residential Electric Service. The power costs are unbundled from this PUCT data by subtracting the customer's delivery charges

[61] The IOU rate impacts are based on their current rates.

from the total bill. The customer's delivery charges are calculated using the current rates from the PUCT's March 2017 Generic Transmission and Distribution Rates report.

- For commercial customers, power cost baselines are developed from the REP's 12-month term indicative offers and pricing matrices that are published or distributed daily. While these rates reflect market prices available in April 2017, it should be noted that every REP has different rates due to the nature of the competitive market.
- To determine the estimated ERCOT power cost impacts, the 2017 rates are adjusted to reflect forecasted energy costs for 2021. The 2017 to 2021 adjustment factors represent the increase in power costs from the ERCOT West Zone 2016 LMPs to the forecasted ERCOT 2020 LMPs before and after LP&L's move to ERCOT.

Based on these assumptions there is a power cost increase of approximately $0.0014/kwh, or 1%, to ERCOT IOU customers.

7.1.2. Transmission Cost Impacts

As discussed in Section 7.1 above, the 2021 wholesale transmission access charge in ERCOT was determined for both the status quo scenario and the LP&L transfer to ERCOT scenario. By applying these access charges to the LSE's forecasted 2020 4CP demands, increased wholesale transmission costs for the six IOUs in ERCOT are determined. These cost increases will be recovered from their end-use retail customers through their transmission cost recovery factor (TCRF).

The impacts on the IOU's 2021 TCRF factors are based on the following assumptions:

- The class allocation factors contained in the IOU's current TCRF clauses will be representative of class allocation factors in 2021.
- Customer class billing determinants for calculating the 2021 TCRF factors are escalated by applying the average annual ERCOT growth rate of 1.01% to the billing determinants used by the IOUs in their most recent PUCT TCRF filings.

Based on these assumptions, the IOU's 2021 TCRF factors are calculated by first allocating their estimated total 2021 ERCOT wholesale transmission costs by their current TCRF customer class allocation factors. The allocated amount to each class was then divided by the class' estimated 2021 billing determinants to determine the class TCRF factors. The TCRF calculations are performed for both the status quo scenario and the LP&L transfer to ERCOT scenario. The 2021 residential TCRF factor increases attributable to the LP&L Affected Load transfer are provided below:

LSE Name	Residential TCRF Increase
Oncor Electric Delivery Company	$0.000189 per kWh
CenterPoint Energy Houston Electric, LLC	$0.000191 per kWh
AEP Texas Central Company	$0.000169 per kWh
AEP Texas North Company	$0.000201 per kWh
Texas - New Mexico Power Company	$0.000201 per kWh
Sharyland Utilities, L.P.	$0.000188 per kWh

Table 7.1: Impact of LP&L ERCOT Integration on IOU Residential TCRF Rate

7.1.3. Summary

The quantifiable retail rate impacts for the end-use customers of the IOUs in ERCOT are the power supply cost and transmission delivery cost impacts described above. These impacts on customers' total monthly bills have been calculated using the current retail rates of the IOUs.[62]

For a residential customer using 1,000 kWh per month, the bill impacts resulting from the LP&L transfer are summarized below:

	1,000 kWh per Month Usage		
ERCOT IOU	LP&L Remains in SPP	LP&L Moves to ERCOT	Increase/Decrease
Oncor Electric Delivery Company	$128.45	$128.71	0.20%
CenterPoint Energy Houston Electric, LLC	137.83	138.10	0.20%
AEP Texas Central Company	137.14	137.39	0.18%
AEP Texas North Company	151.72	152.00	0.18%
Texas - New Mexico Power Company	143.74	144.02	0.20%
Sharyland Utilities, L.P.	194.12	194.39	0.14%

Table 7.2: Estimated ERCOT IOU Residential Bill Impacts

As shown, the impacts on typical residential bills do not exceed two-tenths of one percent, and for customers of certain IOUs, the impact is even less.

For a small commercial customer using 1,500 kWh per month, the bill impacts resulting from the LP&L transfer are summarized below:

[62] Information needed to reasonably forecast the IOU's current base rates to 2021 is not publicly available. Projecting retail rates to 2021 is not necessary to adequately address the retail rate impact issue included in Chairman Nelson's July 19, 2016 Memorandum.

ERCOT IOU	1,500 kWh per Month Usage LP&L Remains in SPP	LP&L Moves to ERCOT	Increase/Decrease
Oncor Electric Delivery Company	$142.31	$142.55	0.16%
CenterPoint Energy Houston Electric, LLC	142.91	143.22	0.22%
AEP Texas Central Company	188.22	188.44	0.11%
AEP Texas North Company	182.64	182.90	0.14%
Texas - New Mexico Power Company	165.64	166.09	0.27%
Sharyland Utilities, L.P.	213.97	214.30	0.15%

Table 7.3: Estimated ERCOT IOU Secondary Small Bill Impacts

Like the impacts on residential customers, the impacts on the small commercial customer using 1,500 kWh per month are similarly small.

These monthly bill impacts, as well as bill impacts for additional customer sizes and types, are provided in the Appendix.

7.2. IOU CUSTOMERS—SPP

The only SPP IOU in Texas for which retail rate impacts have been developed is SPS. The only other Texas IOU that is a member of SPP is Southwestern Electric Power Company (SWEPCO). Because the impacts of an LP&L load transfer to ERCOT will have a minimal impact on SWEPCO, retail rate impacts on SWEPCO's retail customers are not critical and, therefore, have not been developed.

Similar to the ERCOT IOU rate impacts, retail rate impacts for SPS's customers are related to power cost impacts and transmission cost impacts. SPS's retail rates primarily include base rates, a fuel cost recovery factor (FCRF) and a TCRF.[63] SPS's tariff includes rate schedules for numerous rate classes and special contract customers. The retail rate impacts developed for this report are for SPS' major rate classes, which include:

- Residential Service;
- Small General Service;
- Secondary General Service;
- Primary General Service; and
- Sub-Transmission.

7.2.1. Power Cost Impacts

For the power cost impacts to SPS's Texas retail customers, forecasts are made to determine what SPS's power costs would be if (1) LP&L remained in the SPP SPS zone in 2021 and (2) if LP&L transferred their Affected Load to ERCOT. The analysis is based on the overall SPP power cost change and its impact on SPS' FCRF. The 2021 FCRF factors, assuming LP&L remains in SPP, are based on the following assumptions:

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63 Other less significant riders and adjustment factors also apply to SPS retail customers.

- For all customer classes, 2017 power cost baselines are established by compiling rates from SPS's most recent base rate filing and fuel factor filing in PUCT Dockets 45524 and 46760, respectively,

- The 2017 FCRFs are then adjusted to reflect forecasted power costs for 2021 based on the increase in LMPs from the 2016 SPP South LMPs to the 2020 SPP LMPs, as developed in the production costs modeling discussed in Section 5.2, and

- The 2017 to 2021 FCRF adjustment factor of 1.72 is applied if LP&L remains in SPP, and 1.63 if LP&L moves to ERCOT.

Assuming LP&L transfers the Affected Load to ERCOT, SPS's FCRF is reduced by $0.001526 per kwh, or 4%.

7.2.2. Transmission Cost Impacts

Section 6.2 of the report discusses the impacts on SPP wholesale transmission charges in the SPS zone. The SPS zone of SPP includes all SPS wholesale and retail loads in Texas and New Mexico. Therefore, a portion of the wholesale transmission cost increase on the SPS zone of SPP due to adding LP&L's transmission revenue requirement will need to be assigned or allocated to SPS' Texas retail jurisdiction. The latest available SPS jurisdictional allocation is from SPS last rate case, PUCT Docket No. 45524. Based on that information, the jurisdictional 12CP transmission demand allocation factor allocated 46.27% to SPS's Texas retail jurisdiction prior to any LP&L load transfer to ERCOT. Using this allocation factor, the SPS Texas retail jurisdiction would pay approximately $17 million of the LP&L ATRR if LP&L remains in SPP. Assuming LP&L's proposed load transfer to ERCOT is approved, there will be two partially offsetting impacts on SPS's Texas retail jurisdiction transmission costs. First, those customers will not need to pay the $17 million discussed above for LP&L's ATRR. Second, they will pay a larger portion of the SPS zone transmission costs of SPP. After the LP&L Affected Load transfer to ERCOT, the SPS Texas retail jurisdiction allocation factor decreases to 41.76%.

The amount the SPS Texas retail jurisdiction pays annually in SPS zone transmission costs increases from approximately $138.9 million to approximately $143 million, or an annual net increase of $4.1 million. However, this increased amount is partially offset by the avoided or delayed new SPP transmission upgrades caused by the LP&L load transfer.

The next step in estimating the transmission cost impacts on SPS retail customers is to allocate the total Texas retail jurisdiction amounts discussed in the preceding paragraph to the SPS customer classes. For this purpose, the SPS Texas retail customer class demand allocation factor from SPS's TCRF filing was used. The amounts allocated to each major customer class are then divided by the projected customer class TCRF billing determinates. The result is the average SPS transmission-related costs by major customer class. The average SPS transmission cost by customer class is calculated for both the status quo and LP&L transfer to ERCOT scenarios. For the status quo scenario (which includes LP&L joining SPS as a TO) the average transmission cost impacts per billing unit by major SPS customer class are provided below:

Customer Class	LP&L Remains in SPP	LP&L Moves to ERCOT
Residential	$0.00102 per kWh	$0.00109 per kWh
Small General	$0.00083 per kWh	$0.00090 per kWh
Secondary General	$0.25095 per kWh	$0.26947 per kWh
Primary General	$0.22095 per kWh	$0.23725 per kWh
Large General Service - Transmission 69 kV	$0.23166 per kWh	$0.24876 per kWh

Table 7.4: Estimated Impact of LP&L RTO Transfer on SPS Retail Customer TCRF

7.2.3. Summary

The quantifiable retail rate impacts for typical Texas customers of SPS are the power supply cost and transmission cost impacts described in Sections 7.2.1 and 7.2.2, above. These impacts on SPS Texas customers' total monthly bills have been calculated using the current retail rates of SPS.

The cumulative effect of the power and transmission cost impacts of the Affected Load portion of LP&L load not remaining in the SPP RTO decreases rates for SPS's Texas customers. As shown below, a residential customer of SPS using 1,000 kWh a month would have a bill approximately 1.2% lower if LP&L joined ERCOT as opposed to SPP. Other rate classes would see similar impacts, as detailed in the Appendix. This analysis shows that an increase in transmission costs is more than offset by a decrease in power costs resulting in overall lower costs for SPP's Texas customers if LP&L transfers to ERCOT.

Usage (kWh)	LP&L Remains in SPP	LP&L Moves to ERCOT	Increase/Decrease
500	$71.25	$70.45	-1.12%
1,000	132.49	130.90	-1.20%
1,500	193.74	191.35	-1.23%
2,000	254.99	251.80	-1.25%
2,500	316.24	312.25	-1.26%
5,000	622.47	614.51	-1.28%

Table 7.5: Estimated Impact of LP&L Load Transfer to ERCOT on SPS Residential Bills

7.3. LP&L CUSTOMERS

LP&L's current retail rates went into effect on October 1, 2016. For purposes of estimating the transmission cost and power cost impacts on customer bills, the current base rates are used. These base rates are then adjusted to exclude transmission related costs that will be recovered in LP&L's wholesale TCOS in SPP or in ERCOT. In addition, the Power Cost Recovery Factor (PCRF) charge under LP&L's current power supply situation is revised to reflect 2021 wholesale transmission service charges and LP&L power supply costs in ERCOT and in SPP.

Based on these estimated changes in LP&L transmission and power supply costs, monthly bill impacts are prepared for typical customers in LP&L's major customer classes. The major customer classes include the following:

- Residential Service;
- Residential with Electric Heating;
- Small General Service;
- Secondary General Service; and
- Primary General Service.

7.3.1. Power Cost Impacts

LP&L's projected power costs are developed using LP&L's most recent financial forecast for 2020/21 with adjustments based on production cost studies produced by DNV-GL and GDS for LP&L moving to ERCOT and staying in SPP, respectively.

7.3.1.1. LP&L Remains in SPP

LP&L's forecast capacity costs to remain in SPP are projected based on capacity costs included in LP&L's long-term partial requirements agreement with SPS for the 170 MW LP&L customer load remaining in SPP. The LP&L 2021/22 generation fuel costs are extrapolated from 2020 and 2025 production cost studies produced by GDS for LP&L staying in SPP. LP&L's total projected power costs in 2020/21 is $174.3 million for LP&L staying in SPP.

7.3.1.2. LP&L Transfers Load to ERCOT

LP&L's 2021/22 capacity and energy costs for the Affected Load that moves to ERCOT are projected based on an estimated hedge cost and ERCOT wholesale market ancillary and energy costs. LP&L's 2021/22 generation fuel costs are extracted from production cost studies produced by DNV-GL for LP&L moving to ERCOT. LP&L's total projected power costs in 2020/21 are $139.2 million for the LP&L move to ERCOT scenario and includes the power costs for LP&L customer load remaining long-term in SPP. This is approximately a $35.1 million projected power cost reduction for LP&L customers as a result of moving most of its customer load to ERCOT in 2020/21.

7.3.2. Transmission Cost Impacts

7.3.2.1. LP&L Remains in SPP

Should LP&L be directed to keep all of its load in SPP, several transmission related costs impacts, both positive and negative, will occur on LP&L's retail customers as compared to LP&L's current transmission costs. Currently, as a member of WTMPA, LP&L pays SPS for all SPP transmission costs related to transmission service to LP&L wholesale points of delivery (PODs). In addition, LP&L's retail customers pay for the cost of LP&L owned transmission facilities. The total transmission-related costs currently recovered in LP&L's retail rates is approximately $29 million. After SPS' wholesale power supply agreement (PSA) with WTMPA expires in 2019,[64] LP&L would then become a member of SPP and submit an application for recovery of all qualifying LP&L transmission related costs, including a portion of LP&L's more general expenses such as A&G expense and payments in lieu of taxes, through the SPP OATT. The revenues LP&L would receive from SPP would be used to offset LP&L's retail rates.[65]

To calculate a reasonable estimate of transmission service cost incurred as a Transmission Customer independent of its capacity as a TO, LP&L performed an analysis to estimate the costs of NITS (i.e., Transmission Service) in SPP, including zonal and regional charges, RTO administrative costs, applicable FERC fees and load dispatch charges. Based on this analysis, GDS projects LP&L's 2021 total payment to SPP would be approximately $37.6 million.

7.3.2.2. LP&L Transfers Load to ERCOT

The obvious transmission cost impact on any load LP&L transfers from SPP to ERCOT is that the transferred load will pay the ERCOT transmission access charge for wholesale transmission service rather than charges under the SPP OATT. Based on the proposed LP&L Affected Load[66] transfer, the difference in 2021 wholesale transmission charges for the Affected Load are:

Total Transmission Charges in SPP	$27,483,053
Total Transmission Charges in ERCOT	24,036,324
ERCOT Savings	3,446,729

Table 7.6: Estimated Annual Wholesale Transmission Charges to LP&L for Affected Load

The ERCOT amount shown above is based on adjustments to the current ERCOT access charge. First, both the total ERCOT TCOS and ERCOT system 4CP demand have been forecasted to 2021. Next, the ERCOT 4CP was increased for the LP&L load and the total ERCOT TCOS was increased for (1) LP&L's TCOS and (2) the TCOS for the LP&L interconnection facilities that will be constructed by other TSPs.

7.3.3. Other Impacts

In addition to the transmission and power supply cost impacts discussed above, there are other potential impacts or benefits if LP&L transfers load to ERCOT. Some of these additional, non-quantifiable benefits are mentioned in prior sections of this report. Additional other benefits include the following:

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[64] The LP&L-specific PSA with SPS related to the 170 MW load acquired from SPS will remain in effect.

[65] Note that LP&L's retail customers will receive a similar benefit if LP&L transfers load and its transmission facilities to ERCOT.

[66] The estimated LP&L ERCOT 4CP in 2021 is 438 MW.

- LP&L will have the option to opt-in to retail competition in ERCOT. This option is not currently available in SPP.
- ERCOT has a more robust competitive wholesale power market than SPP. This will likely result in lower power supply costs for LP&L's retail customers.
- LP&L will avoid FERC regulation and FERC fees for the ERCOT load.

7.3.4. Summary

When discussing some of the costs and benefits of transferring load to ERCOT there is an occasional reference to staying in SPP as the status quo for LP&L. But that is not the case. SPS has notified WTMPA and its members that it will not extend their current PSA, which expires on May 31, 2019.[67] Therefore, LP&L's current power supply and transmission service arrangements, which would be the status quo, are no longer an option to LP&L. The only options available to LP&L are to either remain in SPP or move to ERCOT. Under either option, LP&L will have a new power supply and transmission service arrangement.

Comparing retail rates for the move-to-ERCOT option and the stay-in-SPP option is the comparison that matters. Accordingly, the LP&L typical customer bill comparisons that have been prepared show bundled typical customer bill amounts under the move to ERCOT rate levels and the stay in SPP rate levels.

Residential service is available for domestic purposes and makes up over half of LP&L's customer base. As shown on Table 7.7 below, for a residential customer that uses 1,000 kWh per month, their monthly bill will be $19.18 higher if LP&L is ordered to stay in SPP.[68]

	LP&L Moves to ERCOT	LP&L Remains in SPP	Increase if Ordered to Stay in SPP	
kWh Usage	$	$	$	%
500	56.16	65.75	9.59	17%
1,000	104.63	123.81	19.18	18%
1,500	153.11	181.88	28.77	19%
2,000	201.58	239.94	38.36	19%

Table 7.7: Comparison of Monthly LP&L Residential Customer Bills

The Small General Service rate is available to customers taking secondary service for loads under 10 kW and make up approximately 7% of LP&L's customer base. As shown on Table 7.8 below, for a Small General Service Customer that uses 1,500 kWh would have a monthly bill that is $22.34 higher if LP&L is ordered to stay in SPP.

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[67] SPS and LP&L have agreed to a separate two-year PSA that will expire in June 2021.

[68] LP&L bills shown in comparisons do not include the portion of the bills that recover franchise fees and taxes, which are applied as a percentage of the total bill. Part of these costs will be recovered through LP&L transmission revenue requirement, resulting in slightly lower bills than shown.

kWh Usage	LP&L Moves to ERCOT $	LP&L Remains in SPP $	Increase if Ordered to Stay in SPP $	%
500	52.21	59.65	7.45	14%
1,000	91.51	106.40	14.89	16%
1,500	130.82	153.15	22.34	17%
2,000	170.12	199.90	29.78	18%

Table 7.8: Comparison of Monthly LP&L Small General Service Customer Bills

Table 7.9 below shows bill impacts for the Secondary General Service Customer rate class, which is available to commercial customers whose load exceeds 10 kW. A Secondary General Service customer that uses 5,000 kWh per month with a monthly demand of 14 kW, would have a monthly bill that is $80.25 higher if LP&L is ordered to stay in SPP.

kWh Usage	NCP kW Demand	LP&L Moves to ERCOT $	LP&L Remains in SPP $	Increase if Ordered to Stay in SPP $	%
5,000	14	499.13	579.38	80.25	16%
7,500	11	595.90	694.27	98.38	17%
7,500	21	735.10	855.47	120.38	16%
10,000	27	957.14	1,115.44	158.30	17%

Table 7.9: Comparison of Monthly LP&L Secondary General Service Customer Bills

The Primary General Service Rate Class is made up of all commercial and industrial customers that take service at primary voltage. As shown in Table 7.10 below, a Primary General Service customer that uses 1,250,000 kWh per month with a monthly demand of 2,238 kW, would have a monthly bill that is $16,570 higher if LP&L is ordered to stay in SPP.

kWh Usage	NCP kW Demand	LP&L Moves to ERCOT $	LP&L Remains in SPP $	Increase if Ordered to Stay in SPP $	%
1,000,000	1,442	73,882.24	86,177.24	12,295.00	17%
1,250,000	2,283	99,721.83	116,291.83	16,570.00	17%
1,750,000	4,795	164,257.71	191,452.71	27,195.00	17%
2,250,000	4,110	179,272.06	209,099.56	29,827.50	17%

Table 7.10: Comparison of Monthly LP&L Primary General Service Customer Bills

Impacts for additional usage and demand levels as well as other LP&L rate classes are included in the Appendix.

It is expected that LP&L customers in the other rate classes, including the State University class (i.e., Texas Tech University), will also have to pay substantially more if LP&L is ordered to stay in SPP.

8. CONCLUSIONS AND RECOMMENDATIONS

In its Study, LP&L presents detailed analyses regarding each of the issues raised by Chairman Nelson in her memorandum filed in Project No. 45633 on July 19, 2016. A brief summary of the LP&L Study's response to those issues is stated below.

1. A production cost analysis for ERCOT and SPP.

On an Adjusted Production Cost basis that takes LP&L load payments in ERCOT into account, integration of the Affected Load will be a savings to ERCOT of $6 million in 2020 and $31 million in 2025. In the portion of SPP that is within Texas, removal of the Affected Load will result in a reduction in Adjusted Production Costs of $61 million in 2020 and $74 million in 2025.

On a long-term, net present value basis, the Affected Load will contribute into the ERCOT wholesale market substantially more than the associated production cost increase, with a benefit-to-cost ratio of 1.39.

2. An analysis of the impacts on the transmission system that includes an evaluation of the estimated economic impacts of the proposed integration. For SPP, this should also include evaluation of costs necessary to disconnect a portion of the LP&L system from SPP.

The LP&L transmission integration plan selected by ERCOT, Option 4ow, has a capital cost of $364 million. Inclusive of the adjusted annual production cost benefit described above, the economic impact of the proposed integration on a typical residential customer is less than two-tenths of one percent of a 1,000 kWh monthly bill. No costs are associated with the disconnection of the Affected Load from SPP.

The South Plains Project was submitted to ERCOT by Sharyland in October 2016. The project is currently undergoing ERCOT review through the Regional Planning Group (RPG) process, and would require three transmission additions—a single circuit, 345kv line from Abernathy to Grassland, a 345kv single circuit from Ogallala to Abernathy, and the Windmill Synchronous Condenser. As ERCOT has not yet completed its independent review of the South Plains project, LP&L has not included it in the base case for the modeling performed by LP&L's consultants. However, once that project is found necessary—a conclusion which is likely only a matter of time, as wind development in the Panhandle continues—the incremental impact of the remaining portions of Option 4ow is minimal. If the South Plains Project is approved, LP&L's Study concludes that the incremental impact of integration of the Affected Load would be only $0.01672 per 4CP kW per month, or 0.3%.

The integration of the Affected Load into ERCOT produces a net benefit to transmission customers in SPP. No incremental transmission expansion costs are associated with disconnecting the Affected Load from the SPP system.

3. Analysis of avoided projects or new projects as a result of moving the LP&L load to ERCOT and the estimated costs of those projects.

Within SPP, the departure of the Affected Load from that system would avoid more than $7 million in planned transmission projects.

The integration of the Affected Load will avoid the need for the third synchronous condenser in the Panhandle, at Windmill Station. This equates to an avoided transmission investment of $39.5 million.

4. An evaluation of the impacts on operations, both from a cost and reliability perspective, on the ERCOT and SPP systems.

Integration of the Affected Load into ERCOT will provide operational and reliability benefits to the ERCOT system. This integration will increase the Panhandle export limit and provide ERCOT additional export paths for resources in the Panhandle, resulting in an improved ability to schedule transmission outages. Even during those outages, the integration of the Affected Load will result in a higher operational Panhandle export limit, thereby providing greater operational flexibility. Furthermore, integrating the Affected Load into ERCOT drastically reduces the likelihood of sub-synchronous resonance in the Panhandle, by reducing the probability of concurrent outages posing elevated subsynchronous resonance risk from 71.657% to 2.584%. These reliability impacts are benefits to the ERCOT system, not costs. The cost impacts of the migration of the Affected Load into ERCOT are specified in response to Issue No. 7, below.

Similarly, SPP sees reliability benefits from the departure of the Affected Load. In addition to the more than $7 million in avoided transmission projects referred to in the response to Issue No. 3, the departure of the Affected Load reduces congestion in SPP and reduces the system's ancillary services requirements. The exit of the Affected Load also improves outage coordination in SPP, in that it results in fewer congested hours on the SPP/SPS ties, and increases the available transfer capability between SPP and SPS.

5. An evaluation of the impacts on ancillary services-both from a cost and reliability perspective.

The Affected Load joining the ERCOT system will have no appreciable impact on the quantity of responsive reserve, non-spinning reserve, and reg-up/down services required to be purchased in ERCOT. No decrease in reliability is expected. However, that Load will be available to pay its share of the system's overall ancillary services procurement, reducing the ancillary services cost borne by loads in ERCOT generally.

The Affected Load leaving SPP will reduce the system's spinning and supplemental reserve requirements; this reduction lowers the likelihood of scarcity pricing for these ancillary services. The transfer of the Affected Load will decrease the cost of these products to market participants because the supply will be unaffected and the demand will decrease.

6. An evaluation of the impacts on congestion rights.

Because of LP&L's location in the Panhandle, its intent to establish a Non-Opt-In Entity Load Zone, and the lead time in advance of its targeted 2021 ERCOT integration date, the integration of the Affected Load will have no appreciable effect on ERCOT's Congestion Revenue Rights (CRR) market. However, the 36-month lead time required by the CRR market could not be met unless the decision to integrate LP&L into ERCOT through Option 4ow is made by May 31, 2018.

The departure of the Affected Load from SPP will have little impact on the market for SPP's Transmission Congestion Rights (TCRs) because the market for TCRs will have sufficient time to account for the reduced load in the Lubbock area.

7. An evaluation of the cost and reliability impacts on all customer classes in ERCOT and SPP.

Of the reliability impacts identified in response to Issue No. 4, above, the LP&L Study identified no effects that were specific to particular customer classes in either SPP or ERCOT. The LP&L Study provides an end-use customer impact analysis by customer class that considers both the transmission investment required by Option 4ow and the adjusted production cost impacts described above. For a residential customer in ERCOT using 1,000 kWh per month, the bill impact of integrating the Affected Load varies depending on the transmission and distribution utility that serves the customer, but, in any event, does not exceed two tenths of one percent. A similar result holds for a 1,500 kWh per month small commercial consumer, with the highest bill impact at 0.27%.

The departure of the Affected Load from SPP will be a benefit to SPS consumers in Texas. A 1,000 kWh residential customer will see a 1.20% decrease in the monthly bill upon integration of the Affected Load into ERCOT.

8. Any other potential reliability impacts on both the ERCOT and SPP systems.

Other than those reliability benefits already mentioned in response to other issues, the LP&L Study identifies no other potential reliability impacts resulting from the integration of the Affected Load into ERCOT.

The integration of a significant load in the Panhandle brings a number of reliability benefits, including voltage stability, system strength, improved system damping, and other operational benefits in the long term.

9. A study of sub-synchronous resonance impacts and any attendant cost implications, including potential cost savings.

The integration of the Affected Load into ERCOT will result in positive impacts from a sub-synchronous resonance perspective. Integrating the Affected Load into ERCOT drastically reduces the likelihood of sub-synchronous resonance in the Panhandle, by reducing the probability of concurrent outages posing elevated SSR risk from 71.657% to 2.584%.

The departure of the Affected Load from SPP will have no effect on sub-synchronous resonance in that system.

10. An evaluation of power flow and system contingency for both the ERCOT and SPP systems.

The LP&L Study includes power flow and system contingency analyses to consider the reliability implications of integration of the Affected Load and other points addressed elsewhere in this section, including whether any transmission projects can be avoided due to the migration of the Affected Load in ERCOT. These analyses raise no issues not already addressed in response to other issues.

11. An evaluation of LP&L's proposal to use some of its existing generation as synchronous condensers.

LP&L recognizes that ERCOT concludes that the conversion of the existing LP&L generating fleet into synchronous condensers is not economically justified at this time. However, the LP&L Study includes a "sensitivity case" run with the assumption that those units would be converted into synchronous condensers. This analysis suggests that the benefits (including increases in the stability limit in the Panhandle, and an improved weighted short circuit ratio limit) along with the Adjusted Production Cost effect justifies the proposal in the long term.

12. An evaluation of LP&L's ability to ensure that comingling of the SPP and ERCOT systems will not occur.

The Affected Load is physically separated from the system that delivers electricity to the remainder of its load, which is under a wholesale power contract with SPS that will be in effect from 2019 until 2044. That load is served by a system purchased from SPS in 2010; the systems that serve both the Affected Load and the Unaffected Load were never integrated. If approved to proceed with integrating the Affected Load into ERCOT, the physical connections of that load to the surrounding SPS system will be terminated. There will be no commingling of electricity between the SPP and ERCOT systems.

GLOSSARY OF ACRONYMS

APC	Adjusted Production Cost
ARR	Auction Revenue Rights
AS	Ancillary Services
ATC	Available Transmission Capability
ATRR	Annual Transmission Revenue Requirement
BES	Bulk Electric System
CC	Combined Cycle
CONE	Cost of New Entry
CP	Coincident Peak
CPS1	Control Performance Standard Data
CRR	Congestion Revenue Rights
CT	Combustion Turbine
DA	Day Ahead
DC	Direct Current
DNR	Designated Network Resource
DWG	Dynamic Working Group
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FCRF	Fuel Cost Recovery Factor
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
FY	Future Year
GIS	Generation Interconnection Status
GSEC	Golden Spread Electric Cooperative
GTL	Generic Transmission Limit
HWLL	High Wind Light Load
IOU	Investor Owned Utility
ITP 10	Integrated Transmission Plan-10 Year
ITPNT	Integrated Transmission Plan- Near Term
LMP	Locational Marginal Price

LP&L	Lubbock Power and Light
LRS	Load Ratio Share
LSE	Load Serving Entity
LTSA	Long-Term System Assessment
MCC	Marginal Congestion Component/Marginal Congestion Cost
MEC	Marginal Energy Component
MISO	Midcontinent ISO
MLC	Marginal Loss Component
MMU	Market Monitoring Unit
NDA	Non-Disclosure Agreement
NERC	North American Electric Reliability Corporation
NITS	Network Integration Transmission Service
NOIE	Non-Opt-In Entity
NPRR	Nodal Protocol Revision Request
NPV	Net Present Value
NTC	Notice to Construct
OATT	Open Access Transmission Tariff
POD	Point of Delivery
PREZ	Panhandle Renewable Energy Zone
PRM	Planning Reserve Margin
PSA	Power Supply Agreement
PUCT	Public Utility Commission of Texas
REP	Retail Electric Provider
RFP	Request for Proposal
RPG	Regional Planning Group
RRS	Responsive Reserve Service
RT	Real Time
RTBM	Real-Time Balancing Market
RTO	Regional Transmission Organization
RTP	Regional Transmission Plan
RUC	Reliability Unit Commitment

SCED	Security Constrained Economic Dispatch
SP	Summer Peak
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company
SSR	Sub-Synchronous Resonance
SSWG	Steady State Working Group
SWEPCO	Southwestern Electric Power Company
TARA	Transmission Adequacy & Reliability Assessment
TC	Transmission Customer
TCOS	Transmission Cost of Service
TCR	Transmission Congestion Rights
TCRF	Transmission Cost Recovery Factor
TO	Transmission Owner
TPIT	Transmission Project and Information Tracking
TPZ	Transmission Pricing Zone
TSP	Transmission Service Provider
WFW	West/Far West
WGR	Wind Generation Resource
WSCR	Weighted Short-Circuit Ratio
WTMPA	West Texas Municipal Power Agency

LIST OF APPENDICES

Impact of LP&L Load Transfer to ERCOT on ERCOT Retail Rates - CenterPoint Energy Houston Electric

		Demand/Usage			2021 Estimated Monthly Bill			
Line No.	Rate Class	kWh	NCP kVA	4CP kVA	Status Quo	If LP&L Joins ERCOT	Increase - $	Increase - %
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	500	-	-	$ 71.65	$ 71.79	$ 0.13	0.19%
2		1,000	-	-	137.83	138.10	0.27	0.20%
3		1,500	-	-	204.02	204.42	0.40	0.20%
4		2,000	-	-	270.20	270.74	0.54	0.20%
5		2,500	-	-	336.38	337.05	0.67	0.20%
6		5,000	-	-	667.29	668.64	1.35	0.20%
7	Secondary Service Less Than or Equal to 10 kVA	500	-	-	51.65	51.75	0.10	0.20%
8		1,000	-	-	97.28	97.49	0.21	0.21%
9		1,500	-	-	142.91	143.22	0.31	0.22%
10		2,000	-	-	188.54	188.95	0.41	0.22%
11		2,500	-	-	234.17	234.68	0.52	0.22%
12		5,000	-	-	462.32	463.35	1.03	0.22%
13	Secondary Service Greater Than 10 kVA Non-IDR	5,000	11	-	428.42	429.06	0.65	0.15%
14		5,000	14	-	449.36	450.12	0.75	0.17%
15		10,000	15	-	786.87	787.92	1.04	0.13%
16		10,000	18	-	807.82	808.97	1.15	0.14%
17		15,000	23	-	1,173.26	1,174.84	1.58	0.13%
18		15,000	27	-	1,201.19	1,202.92	1.73	0.14%
19		20,000	30	-	1,552.66	1,554.75	2.09	0.13%
20		20,000	37	-	1,601.54	1,603.88	2.34	0.15%
21	Secondary Service Greater Than 10 kVA IDR	5,000	11	7	519.57	520.24	0.67	0.13%
22		5,000	14	8	535.97	536.75	0.78	0.15%
23		10,000	15	14	891.84	893.25	1.40	0.16%
24		10,000	18	14	902.00	903.41	1.41	0.16%
25		15,000	23	22	1,276.71	1,278.85	2.13	0.17%
26		15,000	27	22	1,288.55	1,290.67	2.12	0.16%
27		20,000	30	29	1,654.79	1,657.59	2.81	0.17%
28		20,000	37	30	1,681.33	1,684.20	2.87	0.17%
29	Primary Service Non-IDR	25,000	38	-	1,669.13	1,671.78	2.66	0.16%
30		25,000	46	-	1,718.28	1,721.29	3.01	0.18%
31		50,000	76	-	3,153.32	3,158.64	5.31	0.17%
32		50,000	91	-	3,245.48	3,251.46	5.98	0.18%
33		100,000	152	-	6,121.72	6,132.34	10.62	0.17%
34		100,000	183	-	6,312.17	6,324.18	12.01	0.19%
35		250,000	381	-	15,033.04	15,059.65	26.61	0.18%
36		250,000	457	-	15,499.95	15,529.95	30.00	0.19%
37	Primary Service IDR	25,000	38	36	1,678.59	1,681.64	3.05	0.18%
38		25,000	46	37	1,697.68	1,700.77	3.09	0.18%
39		50,000	76	72	3,142.05	3,148.14	6.09	0.19%
40		50,000	91	73	3,175.19	3,181.32	6.13	0.19%
41		100,000	152	144	6,068.97	6,081.15	12.19	0.20%
42		100,000	183	146	6,140.29	6,152.59	12.30	0.20%
43		250,000	381	362	14,855.33	14,885.84	30.52	0.21%
44		250,000	457	366	15,025.50	15,056.23	30.73	0.20%
45	Transmission (Does not include EECRF)	250,000	381	362	15,737.17	15,770.02	32.85	0.21%
46		250,000	457	366	15,755.82	15,788.91	33.08	0.21%
47		500,000	761	723	29,865.22	29,930.86	65.63	0.22%
48		500,000	913	730	29,903.30	29,969.41	66.11	0.22%
49		750,000	1,142	1,085	43,998.13	44,096.61	98.48	0.22%
50		750,000	1,370	1,096	44,054.87	44,154.06	99.19	0.23%
51		1,000,000	1,522	1,446	58,126.19	58,257.45	131.27	0.23%
52		1,000,000	1,826	1,461	58,202.34	58,334.56	132.22	0.23%

Impact of LP&L Load Transfer to ERCOT on ERCOT Retail Rates - Oncor Delivery Company

Line No.	Rate Class	Demand/Usage kWh	NCP kW	4CP kW	2021 Estimated Monthly Bill Status Quo	If LP&L Joins ERCOT	Increase - $	Increase - %
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	500	-	-	$ 65.75	$ 65.88	$ 0.13	0.20%
2		1,000	-	-	128.45	128.71	0.26	0.20%
3		1,500	-	-	191.14	191.53	0.39	0.20%
4		2,000	-	-	253.84	254.36	0.52	0.21%
5		2,500	-	-	316.53	317.18	0.65	0.21%
6		5,000	-	-	630.01	631.31	1.30	0.21%
7	Secondary Less Than or Equal to 10 kW	500	-	-	52.04	52.12	0.08	0.15%
8		1,000	-	-	97.18	97.33	0.16	0.16%
9		1,500	-	-	142.31	142.55	0.23	0.16%
10		2,000	-	-	187.45	187.76	0.31	0.17%
11		2,500	-	-	232.59	232.98	0.39	0.17%
12		5,000	-	-	458.28	459.06	0.78	0.17%
13	Secondary Greater Than 10 kW Non-IDR	5,000	11	-	420.19	420.96	0.77	0.18%
14		5,000	14	-	445.37	446.28	0.92	0.21%
15		10,000	15	-	752.70	753.90	1.20	0.16%
16		10,000	18	-	777.88	779.22	1.35	0.17%
17		15,000	23	-	1,118.78	1,120.60	1.82	0.16%
18		15,000	27	-	1,152.34	1,154.36	2.02	0.18%
19		20,000	30	-	1,476.46	1,478.86	2.40	0.16%
20		20,000	37	-	1,535.20	1,537.95	2.74	0.18%
21	Secondary Greater Than 10 kW IDR	5,000	11	7	405.67	406.26	0.59	0.14%
22		5,000	14	8	426.89	427.57	0.68	0.16%
23		10,000	15	14	756.46	757.69	1.23	0.16%
24		10,000	18	14	770.27	771.51	1.24	0.16%
25		15,000	23	22	1,124.54	1,126.41	1.87	0.17%
26		15,000	27	22	1,140.94	1,142.79	1.85	0.16%
27		20,000	30	29	1,483.98	1,486.43	2.46	0.17%
28		20,000	37	30	1,519.57	1,522.09	2.52	0.17%
29	Primary Service Non-IDR	25,000	38	-	1,419.59	1,422.06	2.47	0.17%
30		25,000	46	-	1,474.26	1,477.07	2.81	0.19%
31		50,000	76	-	2,799.53	2,804.48	4.95	0.18%
32		50,000	91	-	2,902.04	2,907.62	5.58	0.19%
33		100,000	152	-	5,559.42	5,569.31	9.89	0.18%
34		100,000	183	-	5,771.28	5,782.48	11.20	0.19%
35		250,000	381	-	13,845.92	13,870.70	24.78	0.18%
36		250,000	457	-	14,365.32	14,393.31	27.98	0.19%
37	Primary Service IDR	25,000	38	36	1,448.00	1,450.75	2.75	0.19%
38		25,000	46	37	1,478.06	1,480.85	2.79	0.19%
39		50,000	76	72	2,856.36	2,861.86	5.50	0.19%
40		50,000	91	73	2,909.57	2,915.10	5.53	0.19%
41		100,000	152	144	5,673.08	5,684.08	11.00	0.19%
42		100,000	183	146	5,786.42	5,797.52	11.11	0.19%
43		250,000	381	362	14,130.82	14,158.38	27.55	0.19%
44		250,000	457	366	14,403.13	14,430.87	27.74	0.19%
45	Transmission (Does not include EECRF)	250,000	381	362	13,073.20	13,098.82	25.62	0.20%
46		250,000	457	366	13,131.10	13,156.90	25.79	0.20%
47		500,000	761	723	25,788.41	25,839.61	51.20	0.20%
48		500,000	913	730	25,904.80	25,956.34	51.55	0.20%
49		750,000	1,142	1,085	38,507.81	38,584.63	76.82	0.20%
50		750,000	1,370	1,096	38,682.10	38,759.44	77.34	0.20%
51		1,000,000	1,522	1,446	51,223.03	51,325.42	102.40	0.20%
52		1,000,000	1,826	1,461	51,455.79	51,558.89	103.09	0.20%

Impact of LP&L Load Transfer to ERCOT on ERCOT Retail Rates - AEP Texas Central Company

Line No.	Rate Class	Demand/Usage kWh	NCP kW	4CP kW	2021 Estimated Monthly Bill Status Quo	If LP&L Joins ERCOT	Increase - $	Increase - %
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	500	-	-	$ 71.94	$ 72.06	$ 0.12	0.17%
2		1,000	-	-	137.14	137.39	0.25	0.18%
3		1,500	-	-	202.34	202.71	0.37	0.18%
4		2,000	-	-	267.54	268.04	0.50	0.19%
5		2,500	-	-	332.74	333.36	0.62	0.19%
6		5,000	-	-	658.74	659.98	1.24	0.19%
7	Secondary Less Than or Equal to 10 kW	500	-	-	69.87	69.95	0.07	0.10%
8		1,000	-	-	129.05	129.19	0.14	0.11%
9		1,500	-	-	188.22	188.44	0.21	0.11%
10		2,000	-	-	247.40	247.68	0.28	0.11%
11		2,500	-	-	306.57	306.93	0.36	0.12%
12		5,000	-	-	602.44	603.15	0.71	0.12%
13	Secondary Greater Than 10 kW Non-IDR	5,000	11	-	432.61	433.35	0.74	0.17%
14		5,000	14	-	454.76	455.63	0.87	0.19%
15		10,000	15	-	791.58	792.75	1.17	0.15%
16		10,000	18	-	813.74	815.04	1.30	0.16%
17		15,000	23	-	1,180.10	1,181.87	1.77	0.15%
18		15,000	27	-	1,209.64	1,211.59	1.95	0.16%
19		20,000	30	-	1,561.23	1,563.56	2.34	0.15%
20		20,000	37	-	1,612.92	1,615.56	2.64	0.16%
21	Secondary Greater Than 10 kW IDR	5,000	11	7	459.04	459.59	0.54	0.12%
22		5,000	14	8	477.61	478.24	0.62	0.13%
23		10,000	15	14	834.19	835.33	1.14	0.14%
24		10,000	18	14	846.18	847.32	1.14	0.14%
25		15,000	23	22	1,224.32	1,226.04	1.72	0.14%
26		15,000	27	22	1,238.50	1,240.22	1.71	0.14%
27		20,000	30	29	1,606.86	1,609.13	2.27	0.14%
28		20,000	37	30	1,637.82	1,640.14	2.32	0.14%
29	Primary Service Non-IDR	25,000	38	-	1,706.78	1,710.80	4.02	0.24%
30		25,000	46	-	1,774.13	1,778.80	4.67	0.26%
31		50,000	76	-	3,258.01	3,266.05	8.04	0.25%
32		50,000	91	-	3,384.29	3,393.54	9.25	0.27%
33		100,000	152	-	6,360.46	6,376.55	16.09	0.25%
34		100,000	183	-	6,621.45	6,640.04	18.58	0.28%
35		250,000	381	-	15,676.25	15,716.54	40.29	0.26%
36		250,000	457	-	16,316.10	16,362.52	46.42	0.28%
37	Primary Service IDR	25,000	38	36	2,099.66	2,103.52	3.86	0.18%
38		25,000	46	37	2,131.46	2,135.37	3.91	0.18%
39		50,000	76	72	4,002.27	4,009.99	7.72	0.19%
40		50,000	91	73	4,056.99	4,064.76	7.77	0.19%
41		100,000	152	144	7,807.47	7,822.92	15.45	0.20%
42		100,000	183	146	7,925.79	7,941.38	15.59	0.20%
43		250,000	381	362	19,232.99	19,271.67	38.68	0.20%
44		250,000	457	366	19,514.45	19,553.40	38.95	0.20%
45	Transmission (Does not include EECRF)	250,000	381	362	5,386.03	5,408.23	22.19	0.41%
46		250,000	457	366	5,417.73	5,440.12	22.40	0.41%
47		500,000	761	723	9,878.88	9,923.22	44.34	0.45%
48		500,000	913	730	9,942.92	9,987.67	44.75	0.45%
49		750,000	1,142	1,085	14,376.07	14,442.60	66.53	0.46%
50		750,000	1,370	1,096	14,471.81	14,538.95	67.14	0.46%
51		1,000,000	1,522	1,446	18,868.92	18,957.60	88.67	0.47%
52		1,000,000	1,826	1,461	18,997.00	19,086.50	89.50	0.47%

Impact of LP&L Load Transfer to ERCOT on ERCOT Retail Rates - AEP Texas North Company

		Demand/Usage			2021 Estimated Monthly Bill			
Line No.	Rate Class	kWh	NCP kW	4CP kW	Status Quo	If LP&L Joins ERCOT	Increase - $	Increase - %
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	500	-	-	$ 79.95	$ 80.09	$ 0.14	0.17%
2		1,000	-	-	151.72	152.00	0.28	0.18%
3		1,500	-	-	223.50	223.92	0.42	0.19%
4		2,000	-	-	295.27	295.83	0.56	0.19%
5		2,500	-	-	367.04	367.74	0.70	0.19%
6		5,000	-	-	725.90	727.30	1.39	0.19%
7	Secondary Less Than or Equal to 10 kW	500	-	-	68.71	68.80	0.09	0.12%
8		1,000	-	-	125.68	125.85	0.17	0.14%
9		1,500	-	-	182.64	182.90	0.26	0.14%
10		2,000	-	-	239.61	239.95	0.34	0.14%
11		2,500	-	-	296.57	297.00	0.43	0.14%
12		5,000	-	-	581.39	582.25	0.85	0.15%
13	Secondary Greater Than 10 kW Non-IDR	5,000	11	-	428.95	429.67	0.72	0.17%
14		5,000	14	-	458.18	459.04	0.86	0.19%
15		10,000	15	-	766.76	767.90	1.13	0.15%
16		10,000	18	-	796.00	797.26	1.27	0.16%
17		15,000	23	-	1,143.55	1,145.27	1.72	0.15%
18		15,000	27	-	1,182.53	1,184.43	1.90	0.16%
19		20,000	30	-	1,510.60	1,512.86	2.26	0.15%
20		20,000	37	-	1,578.81	1,581.38	2.58	0.16%
21	Secondary Greater Than 10 kW IDR	5,000	11	7	442.20	442.86	0.66	0.15%
22		5,000	14	8	464.67	465.44	0.77	0.17%
23		10,000	15	14	804.08	805.46	1.38	0.17%
24		10,000	18	14	816.14	817.53	1.39	0.17%
25		15,000	23	22	1,180.46	1,182.56	2.10	0.18%
26		15,000	27	22	1,193.71	1,195.80	2.09	0.17%
27		20,000	30	29	1,547.15	1,549.92	2.76	0.18%
28		20,000	37	30	1,580.03	1,582.86	2.83	0.18%
29	Primary Service Non-IDR	25,000	38	-	1,510.56	1,512.50	1.95	0.13%
30		25,000	46	-	1,560.91	1,563.09	2.17	0.14%
31		50,000	76	-	2,865.12	2,869.01	3.89	0.14%
32		50,000	91	-	2,959.53	2,963.85	4.32	0.15%
33		100,000	152	-	5,574.23	5,582.02	7.78	0.14%
34		100,000	183	-	5,769.36	5,778.02	8.66	0.15%
35		250,000	381	-	13,707.88	13,727.36	19.49	0.14%
36		250,000	457	-	14,186.25	14,207.89	21.64	0.15%
37	Primary Service IDR	25,000	38	36	1,531.89	1,534.22	2.33	0.15%
38		25,000	46	37	1,550.01	1,552.36	2.36	0.15%
39		50,000	76	72	2,869.12	2,873.79	4.66	0.16%
40		50,000	91	73	2,900.14	2,904.83	4.69	0.16%
41		100,000	152	144	5,543.60	5,552.92	9.33	0.17%
42		100,000	183	146	5,610.85	5,620.26	9.41	0.17%
43		250,000	381	362	13,572.85	13,596.20	23.35	0.17%
44		250,000	457	366	13,732.55	13,756.05	23.50	0.17%
45	Transmission (Does not include EECRF)	250,000	381	362	13,996.19	14,014.20	18.01	0.13%
46		250,000	457	366	14,019.17	14,037.27	18.10	0.13%
47		500,000	761	723	27,112.34	27,148.33	35.99	0.13%
48		500,000	913	730	27,159.12	27,195.30	36.18	0.13%
49		750,000	1,142	1,085	40,233.73	40,287.73	54.00	0.13%
50		750,000	1,370	1,096	40,303.48	40,357.77	54.29	0.13%
51		1,000,000	1,522	1,446	53,349.88	53,421.87	71.98	0.13%
52		1,000,000	1,826	1,461	53,443.44	53,515.80	72.37	0.14%

Impact of LP&L Load Transfer to ERCOT on ERCOT Retail Rates - Texas-New Mexico Power Company

Line No.	Rate Class	Demand/Usage kWh	NCP kW	4CP kW	2021 Estimated Monthly Bill Status Quo	If LP&L Joins ERCOT	Increase - $	Increase - %
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	500	-	-	$ 74.49	$ 74.64	$ 0.14	0.19%
2		1,000	-	-	143.74	144.02	0.28	0.20%
3		1,500	-	-	212.98	213.41	0.43	0.20%
4		2,000	-	-	282.22	282.79	0.57	0.20%
5		2,500	-	-	351.46	352.18	0.71	0.20%
6		5,000	-	-	697.68	699.10	1.42	0.20%
7	Secondary Service Less than 5 KW	500	-	-	58.35	58.50	0.15	0.26%
8		1,000	-	-	111.99	112.29	0.30	0.27%
9		1,500	-	-	165.64	166.09	0.45	0.27%
10		2,000	-	-	219.29	219.89	0.60	0.27%
11		2,500	-	-	272.93	273.69	0.75	0.28%
12		5,000	-	-	541.17	542.67	1.50	0.28%
13	Secondary Service Greater Than 5 kW Non-IDR	5,000	11	-	420.93	421.65	0.71	0.17%
14		5,000	14	-	449.45	450.29	0.85	0.19%
15		10,000	15	-	762.03	763.16	1.12	0.15%
16		10,000	18	-	790.55	791.80	1.25	0.16%
17		15,000	23	-	1,141.15	1,142.86	1.70	0.15%
18		15,000	27	-	1,179.17	1,181.05	1.88	0.16%
19		20,000	30	-	1,510.77	1,513.01	2.24	0.15%
20		20,000	37	-	1,577.30	1,579.85	2.55	0.16%
21	Secondary Service Greater Than 5 kW IDR	5,000	11	7	410.92	411.59	0.67	0.16%
22		5,000	14	8	436.70	437.49	0.79	0.18%
23		10,000	15	14	777.38	778.79	1.41	0.18%
24		10,000	18	14	794.05	795.47	1.42	0.18%
25		15,000	23	22	1,164.68	1,166.83	2.15	0.18%
26		15,000	27	22	1,184.42	1,186.55	2.13	0.18%
27		20,000	30	29	1,541.46	1,544.28	2.82	0.18%
28		20,000	37	30	1,584.49	1,587.39	2.89	0.18%
29	Primary Service Non-IDR	25,000	38	-	2,068.47	2,070.61	2.15	0.10%
30		25,000	46	-	2,121.62	2,123.96	2.35	0.11%
31		50,000	76	-	3,897.45	3,901.74	4.29	0.11%
32		50,000	91	-	3,997.11	4,001.78	4.67	0.12%
33		100,000	152	-	7,555.42	7,564.01	8.59	0.11%
34		100,000	183	-	7,761.39	7,770.75	9.36	0.12%
35		250,000	381	-	18,535.98	18,557.47	21.50	0.12%
36		250,000	457	-	19,040.94	19,064.32	23.38	0.12%
37	Primary Service IDR	25,000	38	36	1,725.58	1,728.26	2.68	0.16%
38		25,000	46	37	1,769.47	1,772.19	2.71	0.15%
39		50,000	76	72	3,212.18	3,217.54	5.36	0.17%
40		50,000	91	73	3,291.58	3,296.97	5.39	0.16%
41		100,000	152	144	6,185.38	6,196.10	10.72	0.17%
42		100,000	183	146	6,352.57	6,363.38	10.82	0.17%
43		250,000	381	362	15,113.99	15,140.83	26.84	0.18%
44		250,000	457	366	15,518.75	15,545.77	27.02	0.17%
45	Transmission (Does not include EECRF)	250,000	381	362	14,404.97	14,430.87	25.90	0.18%
46		250,000	457	366	14,418.20	14,444.27	26.08	0.18%
47		500,000	761	723	26,840.32	26,892.07	51.76	0.19%
48		500,000	913	730	26,867.31	26,919.42	52.11	0.19%
49		750,000	1,142	1,085	39,279.10	39,356.77	77.66	0.20%
50		750,000	1,370	1,096	39,319.33	39,397.52	78.19	0.20%
51		1,000,000	1,522	1,446	51,714.45	51,817.97	103.52	0.20%
52		1,000,000	1,826	1,461	51,768.44	51,872.67	104.23	0.20%

Impact of LP&L Load Transfer to ERCOT on ERCOT Retail Rates - Sharyland Utilities, L.P.

Line No.	Rate Class	Demand/Usage kWh	NCP kW	4CP kW	2021 Estimated Monthly Bill Status Quo	If LP&L Joins ERCOT	Increase - $	Increase - %
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	500	-	-	$ 102.06	$ 102.20	$ 0.13	0.13%
2		1,000	-	-	194.12	194.39	0.27	0.14%
3		1,500	-	-	286.18	286.59	0.40	0.14%
4		2,000	-	-	378.25	378.78	0.54	0.14%
5		2,500	-	-	470.31	470.98	0.67	0.14%
6		5,000	-	-	930.62	931.96	1.34	0.14%
7	Secondary Less Than or Equal to 10 kW	500	-	-	86.46	86.57	0.11	0.13%
8		1,000	-	-	150.21	150.43	0.22	0.15%
9		1,500	-	-	213.97	214.30	0.33	0.15%
10		2,000	-	-	277.72	278.16	0.44	0.16%
11		2,500	-	-	341.48	342.03	0.55	0.16%
12		5,000	-	-	660.26	661.35	1.09	0.17%
13	Secondary Greater Than 10 kW Non-IDR	5,000	11	-	528.86	529.39	0.54	0.10%
14		5,000	14	-	580.69	581.31	0.62	0.11%
15		10,000	15	-	895.52	896.40	0.88	0.10%
16		10,000	18	-	947.36	948.32	0.96	0.10%
17		15,000	23	-	1,331.30	1,332.63	1.33	0.10%
18		15,000	27	-	1,400.42	1,401.86	1.44	0.10%
19		20,000	30	-	1,749.80	1,751.56	1.76	0.10%
20		20,000	37	-	1,870.75	1,872.70	1.95	0.10%
21	Secondary Greater Than 10 kW IDR	5,000	11	7	495.91	496.75	0.84	0.17%
22		5,000	14	8	538.76	539.77	1.00	0.19%
23		10,000	15	14	868.05	869.81	1.77	0.20%
24		10,000	18	14	905.41	907.20	1.78	0.20%
25		15,000	23	22	1,289.17	1,291.87	2.69	0.21%
26		15,000	27	22	1,337.50	1,340.17	2.67	0.20%
27		20,000	30	29	1,694.85	1,698.39	3.54	0.21%
28		20,000	37	30	1,784.54	1,788.17	3.64	0.20%
29	Primary Service Non-IDR	25,000	38	-	1,667.33	1,671.49	4.16	0.25%
30		25,000	46	-	1,777.59	1,782.44	4.85	0.27%
31		50,000	76	-	3,305.74	3,314.05	8.32	0.25%
32		50,000	91	-	3,512.46	3,522.08	9.61	0.27%
33		100,000	152	-	6,582.54	6,599.17	16.63	0.25%
34		100,000	183	-	7,009.78	7,029.09	19.31	0.28%
35		250,000	381	-	16,426.74	16,468.41	41.67	0.25%
36		250,000	457	-	17,474.16	17,522.40	48.24	0.28%
37	Primary Service IDR	25,000	38	36	1,643.36	1,647.41	4.05	0.25%
38		25,000	46	37	1,716.24	1,720.35	4.11	0.24%
39		50,000	76	72	3,257.79	3,265.88	8.09	0.25%
40		50,000	91	73	3,391.10	3,399.25	8.15	0.24%
41		100,000	152	144	6,486.65	6,502.84	16.19	0.25%
42		100,000	183	146	6,765.72	6,782.08	16.36	0.24%
43		250,000	381	362	16,186.38	16,226.93	40.56	0.25%
44		250,000	457	366	16,864.68	16,905.56	40.88	0.24%
45	Transmission (Does not include EECRF)	250,000	381	362	13,035.57	13,074.92	39.35	0.30%
46		250,000	457	366	13,058.94	13,098.60	39.66	0.30%
47		500,000	761	723	25,903.35	25,981.96	78.61	0.30%
48		500,000	913	730	25,950.80	26,030.04	79.25	0.31%
49		750,000	1,142	1,085	38,775.70	38,893.66	117.96	0.30%
50		750,000	1,370	1,096	38,846.52	38,965.43	118.90	0.31%
51		1,000,000	1,522	1,446	51,643.47	51,800.70	157.23	0.30%
52		1,000,000	1,826	1,461	51,738.38	51,896.87	158.49	0.31%

Impact of LP&L Load Transfer to ERCOT or SPP RTOs on SPS Retail Rates

Line No.	Rate Class	Demand/Usage kWh	NCP kW	4CP kW	2021 Estimated Monthly Bill LPL Stays in SPP	LPL Moves to ERCOT	Decrease if LP&L Joins ERCOT Amount	Percent
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential Standard Service	500	-	-	$ 71.25	$ 70.45	$ (0.80)	-1.12%
2		1,000	-	-	132.49	130.90	(1.59)	-1.20%
3		1,500	-	-	193.74	191.35	(2.39)	-1.23%
4		2,000	-	-	254.99	251.80	(3.19)	-1.25%
5		2,500	-	-	316.24	312.25	(3.98)	-1.26%
6		5,000	-	-	622.47	614.51	(7.97)	-1.28%
7	Small General Service	500	-	-	64.32	63.51	(0.80)	-1.25%
8		1,000	-	-	117.39	115.78	(1.61)	-1.37%
9		1,500	-	-	170.45	168.04	(2.41)	-1.41%
10		2,000	-	-	223.52	220.31	(3.21)	-1.44%
11		2,500	-	-	276.59	272.57	(4.02)	-1.45%
12		5,000	-	-	541.93	533.89	(8.04)	-1.48%
13	Secondary General Service	5,000	14	-	503.92	495.84	(8.08)	-1.60%
14		7,500	11	-	598.48	586.17	(12.31)	-2.06%
15		7,500	21	-	743.08	730.96	(12.13)	-1.63%
16		10,000	27	-	967.78	951.60	(16.19)	-1.67%
17		15,000	23	-	1,185.82	1,161.21	(24.60)	-2.07%
18		15,000	27	-	1,243.66	1,219.13	(24.53)	-1.97%
19		20,000	30	-	1,562.91	1,530.10	(32.82)	-2.10%
20		20,000	37	-	1,664.14	1,631.45	(32.69)	-1.96%
21	Primary General Service	250,000	685	-	21,520.30	21,122.10	(398.21)	-1.85%
22		250,000	1,142	-	27,096.75	26,705.99	(390.75)	-1.44%
23		500,000	1,370	-	42,982.10	42,185.69	(796.41)	-1.85%
24		750,000	3,425	-	81,161.03	79,988.76	(1,172.28)	-1.44%
25		1,000,000	1,442	-	70,067.15	68,453.16	(1,613.98)	-2.30%
26		1,250,000	2,283	-	93,432.50	91,422.86	(2,009.65)	-2.15%
27		1,750,000	4,795	-	150,291.12	147,503.68	(2,787.44)	-1.85%
28		2,250,000	4,110	-	168,139.03	164,521.68	(3,617.35)	-2.15%
29	69 kV Large General Serv. Transmission	250,000	381		16,441.35	16,063.19	(378.15)	-2.30%
30		250,000	457		17,199.29	16,822.44	(376.85)	-2.19%
31		500,000	761		32,162.72	31,406.40	(756.32)	-2.35%
32		500,000	913		33,678.61	32,924.89	(753.72)	-2.24%
33		750,000	1,142		47,894.06	46,759.59	(1,134.47)	-2.37%
34		750,000	1,370		50,167.91	49,037.33	(1,130.57)	-2.25%
35		1,000,000	1,522		63,615.43	62,102.80	(1,512.64)	-2.38%
36		1,000,000	1,826		66,647.23	65,139.78	(1,507.44)	-2.26%

Impact of LP&L Load Transfer to ERCOT or SPP RTOs on LP&L Retail Rates

Line No.	Rate Class	Demand/Usage kWh	NCP kW	4CP kW	2021 Estimated Monthly Bill LPL Moves to ERCOT	LPL Stays in SPP	Increase if Ordered to Stay in SPP Amount	Percent
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential Standard Service	500	-	-	$ 56.16	$ 65.75	$ 9.59	17.08%
2		1,000	-	-	104.63	123.81	19.18	18.33%
3		1,500	-	-	153.11	181.88	28.77	18.79%
4		2,000	-	-	201.58	239.94	38.36	19.03%
5		2,500	-	-	250.05	298.00	47.95	19.18%
6		5,000	-	-	492.41	588.31	95.90	19.48%
7	Residential Electric Space Heating	500	-	-	54.28	63.76	9.49	17.48%
8		1,000	-	-	100.86	119.83	18.97	18.81%
9		1,500	-	-	147.45	175.90	28.46	19.30%
10		2,000	-	-	194.03	231.97	37.94	19.55%
11		2,500	-	-	240.62	288.04	47.43	19.71%
12		5,000	-	-	473.54	568.39	94.85	20.03%
13	Small General Service	500	-	-	52.21	59.65	7.45	14.26%
14		1,000	-	-	91.51	106.40	14.89	16.27%
15		1,500	-	-	130.82	153.15	22.34	17.07%
16		2,000	-	-	170.12	199.90	29.78	17.51%
17		2,500	-	-	209.43	246.65	37.23	17.77%
18		5,000	-	-	405.95	480.40	74.45	18.34%
19	Large School Service	20,000	55	-	1,858.10	2,169.05	310.95	16.73%
20		20,000	91	-	2,294.06	2,667.29	373.23	16.27%
21		25,000	68	-	2,304.08	2,691.47	387.39	16.81%
22		25,000	114	-	2,861.14	3,328.11	466.97	16.32%
23		30,000	82	-	2,762.17	3,227.73	465.56	16.85%
24		30,000	137	-	3,428.22	3,988.93	560.71	16.36%
25		50,000	137	-	4,582.42	5,358.93	776.51	16.95%
26		50,000	228	-	5,684.43	6,618.37	933.94	16.43%
27	Secondary General Service	5,000	14	-	499.13	579.38	80.25	16.08%
28		7,500	11	-	595.90	694.27	98.38	16.51%
29		7,500	21	-	735.10	855.47	120.38	16.38%
30		10,000	27	-	957.14	1,115.44	158.30	16.54%
31		15,000	23	-	1,178.51	1,377.46	198.95	16.88%
32		15,000	27	-	1,234.19	1,441.94	207.75	16.83%
33		20,000	30	-	1,553.00	1,816.80	263.80	16.99%
34		20,000	37	-	1,650.44	1,929.64	279.20	16.92%
35	Primary General Service	250,000	685	-	23,718.81	27,603.81	3,885.00	16.38%
36		250,000	1,142	-	30,797.74	35,825.24	5,027.50	16.32%
37		500,000	1,370	-	47,141.96	54,911.96	7,770.00	16.48%
38		750,000	3,425	-	91,786.41	106,866.41	15,080.00	16.43%
39		1,000,000	1,442	-	73,882.24	86,177.24	12,295.00	16.64%
40		1,250,000	2,283	-	99,721.83	116,291.83	16,570.00	16.62%
41		1,750,000	4,795	-	164,257.71	191,452.71	27,195.00	16.56%
42		2,250,000	4,110	-	179,272.06	209,099.56	29,827.50	16.64%
43	Large Municipal Service	25,000	38	-	1,910.86	2,223.53	312.67	16.36%
44		25,000	46	-	2,019.82	2,349.21	329.39	16.31%
45		50,000	76	-	3,774.42	4,399.76	625.34	16.57%
46		50,000	91	-	3,978.72	4,635.41	656.69	16.51%
47		100,000	152	-	7,501.54	8,752.22	1,250.68	16.67%
48		100,000	183	-	7,923.76	9,239.23	1,315.47	16.60%
49		250,000	381	-	18,696.52	21,825.31	3,128.79	16.73%
50		250,000	457	-	19,731.64	23,019.27	3,287.63	16.66%
51	Small School Service	500	-	-	51.83	59.27	7.44	14.34%
52		1,000	-	-	91.30	106.17	14.87	16.29%
53		1,500	-	-	130.77	153.08	22.31	17.06%
54		2,000	-	-	170.24	199.98	29.74	17.47%
55		2,500	-	-	209.71	246.89	37.18	17.73%
56		5,000	-	-	407.06	481.41	74.35	18.27%
57	Small Municipal Service	500	-	-	51.83	59.27	7.44	14.34%
58		1,000	-	-	91.30	106.17	14.87	16.29%
59		1,500	-	-	130.77	153.08	22.31	17.06%
60		2,000	-	-	170.24	199.98	29.74	17.47%
61		2,500	-	-	209.71	246.89	37.18	17.73%
62		5,000	-	-	407.06	481.41	74.35	18.27%

DOCKET NO. ______

APPLICATION OF THE CITY OF LUBBOCK THROUGH LUBBOCK POWER AND LIGHT FOR AUTHORITY TO CONNECT A PORTION OF ITS SYSTEM WITH THE ELECTRIC RELIABILITY COUNCIL OF TEXAS	**§ § § § § §**	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

PROTECTIVE ORDER

This Protective Order shall govern the use of all information deemed confidential (Protected Materials) or highly confidential (Highly Sensitive Protected Materials), including information whose confidentiality is currently under dispute, by a party providing information to the Public Utility Commission of Texas (Commission) or to any other party to this proceeding.

It is ORDERED that:

1. **Designation of Protected Materials**. Upon producing or filing a document, including, but not limited to, records on a computer disk or other similar electronic storage medium in this proceeding, the producing party may designate that document, or any portion of it, as confidential pursuant to this Protective Order by typing or stamping on its face "PROTECTED PURSUANT TO PROTECTIVE ORDER ISSUED IN DOCKET NO. _______" (or words to this effect) and consecutively Bates Stamping each page. Protected Materials and Highly Sensitive Protected Materials include the documents so designated, as well as the substance of the information contained in the documents and any description, report, summary, or statement about the substance of the information contained in the documents.

2. **Materials Excluded from Protected Materials Designation**. Protected Materials shall not include any information or document contained in the public files of the Commission or any other federal or state agency, court, or local governmental authority subject to the Public Information Act.[1] Protected Materials also shall not include documents or information which at the time of, or prior to disclosure in, a proceeding is or was public

[1] TEX. GOV'T CODE ANN. §§ 552.001-552.353 (Vernon 2012 and Supp. 2016).

knowledge, or which becomes public knowledge other than through disclosure in violation of this Protective Order.

3. **Reviewing Party**. For the purposes of this Protective Order, a "Reviewing Party" is any party to this docket.

4. **Procedures for Designation of Protected Materials**. On or before the date the Protected Materials or Highly Sensitive Protected Materials are provided to the Commission, the producing party shall file with the Commission and deliver to each party to the proceeding a written statement, which may be in the form of an objection, indicating: (a) any exemptions to the Public Information Act claimed to apply to the alleged Protected Materials; (b) the reasons supporting the producing party's claim that the responsive information is exempt from public disclosure under the Public Information Act and subject to treatment as protected materials; and (c) that counsel for the producing party has reviewed the information sufficiently to state in good faith that the information is exempt from public disclosure under the Public Information Act and merits the Protected Materials designation.

5. **Persons Permitted Access to Protected Materials**. Except as otherwise provided in this Protective Order, a Reviewing Party may access Protected Materials only through its "Reviewing Representatives" who have signed the Protective Order Certification Form (see Attachment A). Reviewing Representatives of a Reviewing Party include its counsel of record in this proceeding and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by the Reviewing Party and directly engaged in this proceeding. At the request of the PUC Commissioners, copies of Protected Materials may be produced by Commission Staff. The Commissioners and their staff shall be informed of the existence and coverage of this Protective Order and shall observe the restrictions of the Protective Order.

6. **Highly Sensitive Protected Material Described**. The term "Highly Sensitive Protected Materials" is a subset of Protected Materials and refers to documents or information that a producing party claims is of such a highly sensitive nature that making copies of such documents or information or providing access to such documents to employees of the Reviewing Party (except as specified herein) would expose a producing party to

unreasonable risk of harm. Highly Sensitive Protected Materials include but are not limited to: (a) customer-specific information protected by § 32.101(c) of the Public Utility Regulatory Act;[2] (b) contractual information pertaining to contracts that specify that their terms are confidential or that are confidential pursuant to an order entered in litigation to which the producing party is a party; (c) market-sensitive fuel price forecasts, wholesale transactions information and/or market-sensitive marketing plans; or (d) business operations or financial information that is commercially sensitive. Documents or information so classified by a producing party shall bear the designation "HIGHLY SENSITIVE PROTECTED MATERIALS PROVIDED PURSUANT TO PROTECTIVE ORDER ISSUED IN DOCKET NO. _______" (or words to this effect) and shall be consecutively Bates Stamped. The provisions of this Protective Order pertaining to Protected Materials also apply to Highly Sensitive Protected Materials, except where this Protective Order provides for additional protections for Highly Sensitive Protected Materials. In particular, the procedures herein for challenging the producing party's designation of information as Protected Materials also apply to information that a producing party designates as Highly Sensitive Protected Materials.

7. **Restrictions on Copying and Inspection of Highly Sensitive Protected Material**. Except as expressly provided herein, only one copy may be made of any Highly Sensitive Protected Materials except that additional copies may be made to have sufficient copies for introduction of the material into the evidentiary record if the material is to be offered for admission into the record. The Reviewing Party shall maintain a record of all copies made of Highly Sensitive Protected Material and shall send a duplicate of the record to the producing party when the copy or copies are made. The record shall specify the location and the person possessing the copy. Highly Sensitive Protected Material shall be made available for inspection only at the location or locations provided by the producing party, except as specified by Paragraph 9. Limited notes may be made of Highly Sensitive Protected Materials, and such notes shall themselves be treated as Highly Sensitive Protected Materials unless such notes are limited to a description of the

[2] Public Utility Regulatory Act, TEX. UTIL. CODE ANN., § 32.101(c) (West 2007 & Supp. 2016) (PURA).

document and a general characterization of its subject matter in a manner that does not state any substantive information contained in the document.

8. **Restricting Persons Who May Have Access to Highly Sensitive Protected Material**. With the exception of Commission Staff, The Office of the Attorney General (OAG), and the Office of Public Utility Counsel (OPC), and except as provided herein, the Reviewing Representatives for the purpose of access to Highly Sensitive Protected Materials may be persons who are (a) outside counsel for the Reviewing Party, (b) outside consultants for the Reviewing Party working under the direction of Reviewing Party's counsel or, (c) employees of the Reviewing Party working with and under the direction of Reviewing Party's counsel who have been authorized by the presiding officer to review Highly Sensitive Protected Materials. The Reviewing Party shall limit the number of Reviewing Representatives that review Highly Sensitive Protected Materials to the minimum number of persons necessary. The Reviewing Party is under a good faith obligation to limit access to each portion of any Highly Sensitive Protected Materials to two Reviewing Representatives whenever possible. Reviewing Representatives for Commission Staff and OPC, for the purpose of access to Highly Sensitive Protected Materials, shall consist of their respective counsel of record in this proceeding and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by them and directly engaged in these proceedings.

9. **Copies Provided of Highly Sensitive Protected Material**. A producing party shall provide one copy of Highly Sensitive Protected Materials specifically requested by the Reviewing Party to the person designated by the Reviewing Party who must be a person authorized to review Highly Sensitive Protected Material under Paragraph 8, and must be either outside counsel or an outside consultant. Other representatives of the Reviewing Party who are authorized to view Highly Sensitive Protected Material may review the copy of Highly Sensitive Protected Materials at the office of the Reviewing Party's representative designated to receive the information. Each Reviewing Party may make two additional copies of Highly Sensitive documents for outside consultants whose business offices are located outside of Travis County. All restrictions on Highly Sensitive documents in this order shall apply to the additional copies maintained in the outside consultants' offices. Any Highly Sensitive Protected Materials provided to a

Reviewing Party may not be copied except as provided in Paragraph 7 and shall be returned along with any copies made pursuant to paragraph 7 to the producing party within two weeks after the close of the evidence in this proceeding. The restrictions contained herein do not apply to Commission Staff, OPC, and the OAG when the OAG is a representing a party to the proceeding.

10. **Procedures in Paragraphs 10-14 Apply to Commission Staff, OPC, and the OAG and Control in the Event of Conflict**. The procedures in Paragraphs 10 through 14 apply to responses to requests for documents or information that the producing party designates as Highly Sensitive Protected Materials and provides to Commission Staff, OPC, and the OAG in recognition of their purely public functions. To the extent the requirements of Paragraphs 10 through 14 conflict with any requirements contained in other paragraphs of this Protective Order, the requirements of these Paragraphs shall control.

11. **Copy of Highly Sensitive Protected Material to be Provided to Commission Staff, OPC and the OAG**. When, in response to a request for information by a Reviewing Party, the producing party makes available for review documents or information claimed to be Highly Sensitive Protected Materials, the producing party shall also deliver one copy of the Highly Sensitive Protected Materials to the Commission Staff, OPC, and the OAG (if the OAG is representing a party) in Austin, Texas. Provided however, that in the event such Highly Sensitive Protected Materials are voluminous, the materials will be made available for review by Commission Staff, OPC, and the OAG (if the OAG is representing a party) at the designated office in Austin, Texas. The Commission Staff, OPC and the OAG (if the OAG is representing a party) may request such copies as are necessary of such voluminous material under the copying procedures specified herein.

12. **Delivery of the Copy of Highly Sensitive Protected Material to Commission Staff and Outside Consultants**. The Commission Staff, OPC, and the OAG (if the OAG is representing a party) may deliver the copy of Highly Sensitive Protected Materials received by them to the appropriate members of their staff for review, provided such staff members first sign the certification specified by Paragraph 15. After obtaining the agreement of the producing party, Commission Staff, OPC, and the OAG (if the OAG is

representing a party) may deliver the copy of Highly Sensitive Protected Materials received by it to the agreed, appropriate members of their outside consultants for review, provided such outside consultants first sign the certification in Attachment A.

13. **Restriction on Copying by Commission Staff, OPC and the OAG**. Except as allowed by Paragraph 7, Commission Staff, OPC and the OAG may not make additional copies of the Highly Sensitive Protected Materials furnished to them unless the producing party agrees in writing otherwise, or, upon a showing of good cause, the presiding officer directs otherwise. Commission Staff, OPC, and the OAG may make limited notes of Highly Sensitive Protected Materials furnished to them, and all such handwritten notes will be treated as Highly Sensitive Protected Materials as are the materials from which the notes are taken.

14. **Public Information Requests**. In the event of a request for any of the Highly Sensitive Protected Materials under the Public Information Act, an authorized representative of the Commission, OPC, or the OAG may furnish a copy of the requested Highly Sensitive Protected Materials to the Open Records Division at the OAG together with a copy of this Protective Order after notifying the producing party that such documents are being furnished to the OAG. Such notification may be provided simultaneously with the delivery of the Highly Sensitive Protected Materials to the OAG.

15. **Required Certification**. Each person who inspects the Protected Materials shall, before such inspection, agree in writing to the following certification found in Attachment A to this Protective Order:

> I certify my understanding that the Protected Materials are provided to me pursuant to the terms and restrictions of the Protective Order in this docket, and that I have been given a copy of it and have read the Protective Order and agree to be bound by it. I understand that the contents of the Protected Materials, any notes, memoranda, or any other form of information regarding or derived from the Protected Materials shall not be disclosed to anyone other than in accordance with the Protective Order and unless I am an employee of the Commission or OPC shall be used only for the purpose of the proceeding in Docket No. ______. I acknowledge that the obligations imposed by this certification are pursuant to such Protective Order. Provided, however, if the information contained in the Protected Materials is obtained from

> independent public sources, the understanding stated herein shall not apply.

In addition, Reviewing Representatives who are permitted access to Highly Sensitive Protected Material under the terms of this Protective Order shall, before inspection of such material, agree in writing to the following certification found in Attachment A to this Protective Order:

> I certify that I am eligible to have access to Highly Sensitive Protected Material under the terms of the Protective Order in this docket.

The Reviewing Party shall provide a copy of each signed certification to Counsel for the producing party and serve a copy upon all parties of record.

16. **Disclosures between Reviewing Representatives and Continuation of Disclosure Restrictions after a Person is no Longer Engaged in the Proceeding**. Any Reviewing Representative may disclose Protected Materials, other than Highly Sensitive Protected Materials, to any other person who is a Reviewing Representative provided that, if the person to whom disclosure is to be made has not executed and provided for delivery of a signed certification to the party asserting confidentiality, that certification shall be executed prior to any disclosure. A Reviewing Representative may disclose Highly Sensitive Protected Material to other Reviewing Representatives who are permitted access to such material and have executed the additional certification required for persons who receive access to Highly Sensitive Protected Material. In the event that any Reviewing Representative to whom Protected Materials are disclosed ceases to be engaged in these proceedings, access to Protected Materials by that person shall be terminated and all notes, memoranda, or other information derived from the protected material shall either be destroyed or given to another Reviewing Representative of that party who is authorized pursuant to this Protective Order to receive the protected materials. Any person who has agreed to the foregoing certification shall continue to be bound by the provisions of this Protective Order so long as it is in effect, even if no longer engaged in these proceedings.

17. **Producing Party to Provide One Copy of Certain Protected Material and Procedures for Making Additional Copies of Such Materials**. Except for Highly Sensitive Protected Materials, which shall be provided to the Reviewing Parties pursuant

to Paragraphs 9, and voluminous Protected Materials, the producing party shall provide a Reviewing Party one copy of the Protected Materials upon receipt of the signed certification described in Paragraph 15. Except for Highly Sensitive Protected Materials, a Reviewing Party may make further copies of Protected Materials for use in this proceeding pursuant to this Protective Order, but a record shall be maintained as to the documents reproduced and the number of copies made, and upon request the Reviewing Party shall provide the party asserting confidentiality with a copy of that record.

18. **Procedures Regarding Voluminous Protected Materials**. P.U.C. PROC. R. 22.144(h) will govern production of voluminous Protected Materials. Voluminous Protected Materials will be made available in the producing party's voluminous room, in Austin, Texas, or at a mutually agreed upon location, Monday through Friday, 9:00 a.m. to 5:00 p.m. (except on state or Federal holidays), and at other mutually convenient times upon reasonable request.

19. **Reviewing Period Defined**. The Protected Materials may be reviewed only during the Reviewing Period, which shall commence upon entry of this Protective Order and continue until the expiration of the Commission's plenary jurisdiction. The Reviewing Period shall reopen if the Commission regains jurisdiction due to a remand as provided by law. Protected materials that are admitted into the evidentiary record or accompanying the evidentiary record as offers of proof may be reviewed throughout the pendency of this proceeding and any appeals.

20. **Procedures for Making Copies of Voluminous Protected Materials**. Other than Highly Sensitive Protected Materials, Reviewing Parties may take notes regarding the information contained in voluminous Protected Materials made available for inspection or they may make photographic, mechanical or electronic copies of the Protected Materials, subject to the conditions in this Protective Order; provided, however, that before photographic, mechanical or electronic copies may be made, the Reviewing Party seeking photographic, mechanical or electronic copies must provide written confirmation of the receipt of copies listed on Attachment B of this Protective Order identifying each piece of Protected Materials or portions thereof the Reviewing Party will need.

21. **Protected Materials to be Used Solely for the Purposes of These Proceedings**. All Protected Materials shall be made available to the Reviewing Parties and their Reviewing Representatives solely for the purposes of these proceedings. Access to the Protected Materials may not be used in the furtherance of any other purpose, including, without limitation: (a) any other pending or potential proceeding involving any claim, complaint, or other grievance of whatever nature, except appellate review proceedings that may arise from or be subject to these proceedings; or (b) any business or competitive endeavor of whatever nature. Because of their statutory regulatory obligations, these restrictions do not apply to Commission Staff or OPC.

22. **Procedures for Confidential Treatment of Protected Materials and Information Derived from Those Materials**. Protected Materials, as well as a Reviewing Party's notes, memoranda, or other information regarding or derived from the Protected Materials are to be treated confidentially by the Reviewing Party and shall not be disclosed or used by the Reviewing Party except as permitted and provided in this Protective Order. Information derived from or describing the Protected Materials shall be maintained in a secure place and shall not be placed in the public or general files of the Reviewing Party except in accordance with the provisions of this Protective Order. A Reviewing Party must take all reasonable precautions to insure that the Protected Materials including notes and analyses made from Protected Materials that disclose Protected Materials are not viewed or taken by any person other than a Reviewing Representative of a Reviewing Party.

23. **Procedures for Submission of Protected Materials**. If a Reviewing Party tenders for filing any Protected Materials, including Highly Sensitive Protected Materials, or any written testimony, exhibit, brief, motion or other type of pleading or other submission at the Commission or before any other judicial body that quotes from Protected Materials or discloses the content of Protected Materials, the confidential portion of such submission shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they contain Protected Material or Highly Sensitive Protected Material and are sealed pursuant to this Protective Order. If filed at the Commission, such documents shall be marked "PROTECTED MATERIAL" and shall be filed under seal with the presiding officer and served under seal to the counsel of record for the Reviewing Parties.

The presiding officer may subsequently, on his/her own motion or on motion of a party, issue a ruling respecting whether or not the inclusion, incorporation or reference to Protected Materials is such that such submission should remain under seal. If filing before a judicial body, the filing party: (a) shall notify the party which provided the information within sufficient time so that the producing party may seek a temporary sealing order; and (b) shall otherwise follow the procedures in Rule 76a, Texas Rules of Civil Procedure.

24. **Maintenance of Protected Status of Materials during Pendency of Appeal of Order Holding Materials are not Protected Materials**. In the event that the presiding officer at any time in the course of this proceeding finds that all or part of the Protected Materials are not confidential or proprietary, by finding, for example, that such materials have entered the public domain or materials claimed to be Highly Sensitive Protected Materials are only Protected Materials, those materials shall nevertheless be subject to the protection afforded by this Protective Order for three (3) full working days, unless otherwise ordered, from the date the party asserting confidentiality receives notice of the presiding officer's order. Such notification will be by written communication. This provision establishes a deadline for appeal of a presiding officer's order to the Commission. In the event an appeal to the Commissioners is filed within those three (3) working days from notice, the Protected Materials shall be afforded the confidential treatment and status provided in this Protective Order during the pendency of such appeal. Neither the party asserting confidentiality nor any Reviewing Party waives its right to seek additional administrative or judicial remedies after the Commission's denial of any appeal.

25. **Notice of Intent to Use Protected Materials or Change Materials Designation**. Parties intending to use Protected Materials shall notify the other parties prior to offering them into evidence or otherwise disclosing such information into the record of the proceeding. During the pendency of Docket No. ______ at the Commission, in the event that a Reviewing Party wishes to disclose Protected Materials to any person to whom disclosure is not authorized by this Protective Order, or wishes to have changed the designation of certain information or material as Protected Materials by alleging, for example, that such information or material has entered the public domain, such

Reviewing Party shall first file and serve on all parties written notice of such proposed disclosure or request for change in designation, identifying with particularity each of such Protected Materials. A Reviewing Party shall at any time be able to file a written motion to challenge the designation of information as Protected Materials.

26. **Procedures to Contest Disclosure or Change in Designation**. In the event that the party asserting confidentiality wishes to contest a proposed disclosure or request for change in designation, the party asserting confidentiality shall file with the appropriate presiding officer its objection to a proposal, with supporting affidavits, if any, within five (5) working days after receiving such notice of proposed disclosure or change in designation. Failure of the party asserting confidentiality to file such an objection within this period shall be deemed a waiver of objection to the proposed disclosure or request for change in designation. Within five (5) working days after the party asserting confidentiality files its objection and supporting materials, the party challenging confidentiality may respond. Any such response shall include a statement by counsel for the party challenging such confidentiality that he or she has reviewed all portions of the materials in dispute and, without disclosing the Protected Materials, a statement as to why the Protected Materials should not be held to be confidential under current legal standards, or that the party asserting confidentiality for some reason did not allow such counsel to review such materials. If either party wishes to submit the material in question for in camera inspection, it shall do so no later than five (5) working days after the party challenging confidentiality has made its written filing.

27. **Procedures for Presiding Officer Determination Regarding Proposed Disclosure or Change in Designation**. If the party asserting confidentiality files an objection, the appropriate presiding officer will determine whether the proposed disclosure or change in designation is appropriate. Upon the request of either the producing or Reviewing Party or upon the presiding officer's own initiative, the presiding officer may conduct a prehearing conference. The burden is on the party asserting confidentiality to show that such proposed disclosure or change in designation should not be made. If the presiding officer determines that such proposed disclosure or change in designation should be made, disclosure shall not take place earlier than three (3) full working days after such

determination unless otherwise ordered. No party waives any right to seek additional administrative or judicial remedies concerning such presiding officer's ruling.

28. **<u>Maintenance of Protected Status during Periods Specified for Challenging Various Orders</u>**. Any party electing to challenge, in the courts of this state, a Commission or presiding officer determination allowing disclosure or a change in designation shall have a period of ten (10) days from: (a) the date of an unfavorable Commission order; or (b) if the Commission does not rule on an appeal of an interim order, the date an appeal of an interim order to the Commission is overruled by operation of law, to obtain a favorable ruling in state district court. Any party challenging a state district court determination allowing disclosure or a change in designation shall have an additional period of ten (10) days from the date of the order to obtain a favorable ruling from a state appeals court. Finally, any party challenging a determination of a state appeals court allowing disclosure or a change in designation shall have an additional period of ten (10) days from the date of the order to obtain a favorable ruling from the state supreme court, or other appellate court. All Protected Materials shall be afforded the confidential treatment and status provided for in this Protective Order during the periods for challenging the various orders referenced in this paragraph. For purposes of this paragraph, a favorable ruling of a state district court, state appeals court, Supreme Court or other appellate court includes any order extending the deadlines in this paragraph.

29. **<u>Other Grounds for Objection to Use of Protected Materials Remain Applicable</u>**. Nothing in this Protective Order shall be construed as precluding any party from objecting to the use of Protected Materials on grounds other than confidentiality, including the lack of required relevance. Nothing in this Protective Order constitutes a waiver of the right to argue for more disclosure, provided, however, that unless the Commission or a court orders such additional disclosure, all parties will abide by the restrictions imposed by the Protective Order.

30. **<u>Protection of Materials from Unauthorized Disclosure</u>**. All notices, applications, responses or other correspondence shall be made in a manner which protects Protected Materials from unauthorized disclosure.

31. **<u>Return of Copies of Protected Materials and Destruction of Information Derived from Protected Materials</u>**. Following the conclusion of these proceedings, each Reviewing Party must, no later than thirty (30) days following receipt of the notice described below, return to the party asserting confidentiality all copies of the Protected Materials provided by that party pursuant to this Protective Order and all copies reproduced by a Reviewing Party, and counsel for each Reviewing Party must provide to the party asserting confidentiality a letter by counsel that, to the best of his or her knowledge, information, and belief, all copies of notes, memoranda, and other documents regarding or derived from the Protected Materials (including copies of Protected Materials) that have not been so returned, if any, have been destroyed, other than notes, memoranda, or other documents which contain information in a form which, if made public, would not cause disclosure of the substance of Protected Materials. As used in this Protective Order, "conclusion of these proceedings" refers to the exhaustion of available appeals, or the running of the time for the making of such appeals, as provided by applicable law. If, following any appeal, the Commission conducts a remand proceeding, then the "conclusion of these proceedings" is extended by the remand to the exhaustion of available appeals of the remand, or the running of the time for making such appeals of the remand, as provided by applicable law. Promptly following the conclusion of these proceedings, counsel for the party asserting confidentiality will send a written notice to all other parties, reminding them of their obligations under this Paragraph. Nothing in this Paragraph shall prohibit counsel for each Reviewing Party from retaining two (2) copies of any filed testimony, brief, application for rehearing, hearing exhibit or other pleading which refers to Protected Materials provided that any such Protected Materials retained by counsel shall remain subject to the provisions of this Protective Order.

32. **<u>Applicability of Other Law</u>**. This Protective Order is subject to the requirements of the Public Information Act, the Open Meetings Act,[3] the Texas Securities Act[4] and any other applicable law, provided that parties subject to those acts will notify the party asserting

[3] TEX. GOV'T CODE ANN. § 551.001-551.146 (Vernon 2012 & Supp. 2016).

[4] TEX. REV. CIV. STAT. ANN. arts. 581-1 to 581-43 (Vernon 2010 & Supp. 2016).

confidentiality, if possible under those acts, prior to disclosure pursuant to those acts. Such notice shall not be required where the Protected Materials are sought by governmental officials authorized to conduct a criminal or civil investigation that relates to or involves the Protected Materials, and those governmental officials aver in writing that such notice could compromise the investigation and that the governmental entity involved will maintain the confidentiality of the Protected Materials.

33. **Procedures for Release of Information under Order**. If required by order of a governmental or judicial body, the Reviewing Party may release to such body the confidential information required by such order; provided, however, that: (a) the Reviewing Party shall notify the producing party of the order requiring the release of such information within five (5) calendar days of the date the Reviewing Party has notice of the order; (b) the Reviewing Party shall notify the producing party at least five (5) calendar days in advance of the release of the information to allow the producing party to contest any release of the confidential information; and (c) the Reviewing Party shall use its best efforts to prevent such materials from being disclosed to the public. The terms of this Protective Order do not preclude the Reviewing Party from complying with any valid and enforceable order of a state or federal court with competent jurisdiction specifically requiring disclosure of Protected Materials earlier than contemplated herein. The notice specified in this section shall not be required where the Protected Materials are sought by governmental officials authorized to conduct a criminal or civil investigation that relates to or involves the Protected Materials, and those governmental officials aver in writing that such notice could compromise the investigation and that the governmental entity involved will maintain the confidentiality of the Protected Materials.

34. **Best Efforts Defined**. The term “best efforts” as used in the preceding paragraph requires that the Reviewing Party attempt to ensure that disclosure is not made unless such disclosure is pursuant to a final order of a Texas governmental or Texas judicial body, the written opinion of the Texas Attorney General sought in compliance with the Public Information Act, or the request of governmental officials authorized to conduct a criminal or civil investigation that relates to or involves the Protected Materials. The Reviewing Party is not required to delay compliance with a lawful order to disclose such information but is simply required to timely notify the party asserting confidentiality, or

its counsel, that it has received a challenge to the confidentiality of the information and that the Reviewing Party will either proceed under the provisions of §552.301 of the Public Information Act, or intends to comply with the final governmental or court order. Provided, however, that no notice is required where the Protected Materials are sought by governmental officials authorized to conduct a criminal or civil investigation that relates to or involves the Protected Materials, and those governmental officials aver in writing that such notice could compromise the investigation and that the governmental entity involved will maintain the confidentiality of the Protected Materials.

35. **Notify Defined**. "Notify" for purposes of Paragraphs 32, 33 and 34 means written notice to the party asserting confidentiality at least five (5) calendar days prior to release; including when a Reviewing Party receives a request under the Public Information Act. However, the Commission or OPC may provide a copy of Protected Materials to the Open Records Division of the OAG as provided herein.

36. **Requests for Non-Disclosure**. If the producing party asserts that the requested information should not be disclosed at all, or should not be disclosed to certain parties under the protection afforded by this Protective Order, the producing party shall tender the information for in camera review to the presiding officer within ten (10) calendar days of the request. At the same time, the producing party shall file and serve on all parties its argument, including any supporting affidavits, in support of its position of non-disclosure. The burden is on the producing party to establish that the material should not be disclosed. The producing party shall serve a copy of the information under the classification of Highly Sensitive Protected Material to all parties requesting the information that the producing party has not alleged should be prohibited from reviewing the information.

Parties wishing to respond to the producing party's argument for non-disclosure shall do so within five working days. Responding parties should explain why the information should be disclosed to them, including why disclosure is necessary for a fair adjudication of the case if the material is determined to constitute a trade secret. If the presiding officer finds that the information should be disclosed as Protected Material under the terms of this Protective Order, the presiding officer shall stay the order of disclosure for such period of time as the presiding officer deems necessary to allow the producing party to appeal the ruling to the Commission.

37. **Sanctions Available for Abuse of Designation**. If the presiding officer finds that a producing party unreasonably designated material as Protected Material or as Highly Sensitive Protected Material, or unreasonably attempted to prevent disclosure pursuant to Paragraph 36, the presiding officer may sanction the producing party pursuant to P.U.C. PROC. R. 22.161.

38. **Modification of Protective Order**. Each party shall have the right to seek changes in this Protective Order as appropriate from the presiding officer.

39. **Breach of Protective Order**. In the event of a breach of the provisions of this Protective Order, the producing party, if it sustains its burden of proof required to establish the right to injunctive relief, shall be entitled to an injunction against such breach without any requirements to post bond as a condition of such relief. The producing party shall not be relieved of proof of any element required to establish the right to injunctive relief. In addition to injunctive relief, the producing party shall be entitled to pursue any other form of relief to which it is entitled.

ATTACHMENT A

Protective Order Certification

I certify my understanding that the Protected Materials are provided to me pursuant to the terms and restrictions of the Protective Order in this docket and that I have received a copy of it and have read the Protective Order and agree to be bound by it. I understand that the contents of the Protected Materials, any notes, memoranda, or any other form of information regarding or derived from the Protected Materials shall not be disclosed to anyone other than in accordance with the Protective Order and unless I am an employee of the Commission or OPC shall be used only for the purpose of the proceeding in Docket No. _____. I acknowledge that the obligations imposed by this certification are pursuant to such Protective Order. Provided, however, if the information contained in the Protected Materials is obtained from independent public sources, the understanding stated here shall not apply.

Signature	Party Represented
Printed Name	Date

I certify that I am eligible to have access to Highly Sensitive Protected Material under the terms of the Protective Order in this docket.

Signature	Party Represented
Printed Name	Date

ATTACHMENT B

I request to view/copy the following documents:

Document Requested	# of Copies	Non-Confidential	Protected Materials and/or Highly Sensitive Protected Materials

Signature

Party Represented

Printed Name

Date