AFFIDAVIT

STATE OF TEXAS §
§
COUNTY OF DALLAS §

BEFORE ME, the undersigned authority, on this day personally appeared Wesley R. Speed, who, having been placed under oath by me, did depose as follows:

My name is Wesley R. Speed. I am of legal age and a resident of the State of Texas. The foregoing direct testimony and attached exhibits offered by me are true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true and correct.

Wesley R. Speed

SUBSCRIBED AND SWORN TO BEFORE ME by the said Wesley R. Speed this 19th day of April, 2022.

TERI SMART
Notary Public, State of Texas
Comm. Expires 11-13-2024
Notary ID 514088-5

Notary Public, State of Texas

Services Provided by Oncor's Transmission Organization

Group	Description of Services Provided	Group Manager & Experience
Transmission Engineering	• Plan, organize, direct, and manage engineering design, material and equipment requisition, and construction support for transmission lines, switching stations, and load-serving substations • Create and maintain engineering drawings and documentation for transmission infrastructure • Administer acquisition and management of transmission rights-of-way • Develop generation interconnections and point-of-delivery designs • Support TPMO in creating, tracking, and forecasting capital budgets	Matthew Ponce 18 years in transmission engineering, operations, asset management, program management, and system protection
System Protection	• Establish and implement Oncor's protection and maintenance philosophy for relay protection of transmission facilities, distribution substations, and substation feeders • Develop relaying conceptual designs and protective relay settings • Provide engineering and technical field support, electrical system protection schemes, and other equipment to ensure secure and reliable performance • Develop specifications and conceptual designs • Provide program management, engineering, and technical support for Oncor's SCADA systems	Rafael Garcia 39 years in system protection

Group	Description of Services Provided	Group Manager & Experience
Transmission Operations	• Reliably operate the transmission grid, switching stations, and load-serving substations • Accountable for safe, timely, and reliable construction, operation and maintenance of Oncor's transmission facilities • Provide field operational interface with generating plants and other utilities • Perform maintenance, testing and inspection of electrical facilities • Perform summer preparedness work • Provide first responders for outages to transmission lines and facilities	Alex Machoka 18 years of experience in transmission and distribution operations.
Transmission Program Management Office ("TPMO")	• Plan, execute, and manage Oncor's transmission capital plan • Provide project coordination, scheduling, resource support, budget forecasting, and internal reporting for transmission stakeholders • Lead cross-functional efforts to create and prioritize capital plan and track, manage, and forecast transmission capital budgets	Todd Rosenberger 25 years of experience in engineering, system protection, and project management
Asset Planning	• Distribution and Transmission power system planning to develop new assets and improve existing assets • Improve operation efficiency • Facilitate interconnection of new generation and distributed generation • Ensure facilities meet reliability criteria	Eithar Nashawati 20 years utility experience

Group	Description of Services Provided	Group Manager & Experience
Transmission Grid Operations	• Direct, monitor, and control transmission and substation facilities to meet reliability standards, security and market obligations • Implement ERCOT emergency operations • Coordinate facility outages	Collin Martin 19 years utility experience
Transmission & Distribution Services	• Maintain, test, and enhance software used to monitor and operate the transmission system	Tony Bruton 21 years in transmission engineering, operations management, and network applications
Environmental and NERC Compliance	• Monitor new and revised NERC, TexasRE, and ERCOT reliability and CIP standards • Develop processes or procedures and prepare documentation to ensure and demonstrate compliance with applicable standards • Interface with regulatory agencies for compliance audits and compliance-related agency requests • Develop positions and comments regarding regulatory standards, protocols, and guides	Ray Averitt 39 years in enterprise risk management and compliance program development and oversight
Transmission Services	• Interface with generators, utilities, cooperatives and large retail customers seeking interconnections • Prepare and secure contractual arrangements for interconnections and wholesale transmission service	Robert Holt 33 years of experience

Other Organizations that Provide Services to Transmission Function

Group	Description of Services Provided	Parent Organization
Performance Management	• Provide framework and methodology for setting goals and tracking performance • Help business process owners plan and track effectiveness of organizational processes	Business and Operations Services
Engineering Standards and Maintenance Strategy	• Develop strategies, capabilities and tools to enhance organizational and operational effectiveness • Create, modify, and maintain transmission and substation engineering materials and construction standards • As part of this organization, T&D Maintenance Strategy group develops and supports programs and systems necessary effectively maintain and operate Oncor assets	Business and Operations Services
System Planning	• Review grid and manage activities to address system needs for transmission and distribution • Perform engineering studies to determine present and future system constraints • Propose solutions to alleviate constraints • Study requests for generation interconnections • Work closely with ERCOT to coordinate growth and operational needs	Business and Operations Services
T&D Supply Chain and Strategic Sourcing	• Manage strategic side of Oncor supply chain • Manage purchasing for products and services • Initiate and manage agreements and contracts to	Business and Operations Services

Group	Description of Services Provided	Parent Organization
	optimize material cost, availability and performance of outsourced services • Forecast, schedule, and arrange delivery of major electrical equipment, materials, and supplies • Operate equipment repair and distribution center and materials warehouse	
Technology Group	• Responsible for construction, development, maintenance, use, operation, compliance, and governance of information and communications technology • Analyzes and implements new technologies that will benefit and improve Oncor's productivity • Maintain digital control room • Plan resources and leverage analytics to accommodate system automation and operational methodologies • Improve physical infrastructure, network, and communication capabilities • Expand cyber-security protections and controls	Technology, Measurement & Billing, and Customer Engagement

DOCKET NO. 45414

REVIEW OF THE RATES OF SHARYLAND UTILITIES, L.P.	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY

AND EXHIBITS

OF

RALPH G. GOODLET, JR.

ON BEHALF OF

SHARYLAND UTILITIES, L.P.

April 29, 2016

DOCKET NO. 45414

REVIEW OF THE RATES OF SHARYLAND UTILITIES, L.P.	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

TABLE OF CONTENTS

PAGE

EXHIBITS

standard revenue requirement determination. All of Sharyland's revenues and expenses, including those that were transmission related, were reflected in the deferral calculation. As the Commission found, the deferral mechanism was necessary to allow Sharyland to begin its operations as a start-up utility, which required the construction of both transmission and distribution assets. Although the initial operations were related to serving customers in Sharyland's original service area, Sharyland has since become a major transmission service provider in ERCOT and has developed and constructed a number of major transmission projects in Texas that have improved reliability and provided access to lower-priced supplies of energy to all ERCOT consumers. Without the deferral mechanism, this would not have been possible.

Spreading the deferred costs among all customers who have benefited, including ERCOT consumers who benefit from the ERCOT transmission grid, minimizes the impact of recovery of the deferred costs on any single group of customers and is a practical way to allow Sharyland to recover start-up costs that it is entitled to recover pursuant to the Commission's order in Docket No. 21591 without unduly burdening Sharyland's retail customers.

VII. ACQUISITION ADJUSTMENT RELATED TO CERTAIN TRANSMISSION FACILITIES.

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH THE ACQUISITION OF THE SPS TRANSMISSION FACILITIES ADDRESSED IN DOCKET NO. 41430.

A. In Docket No. 41430, Sharyland sought a determination from the Commission that its purchase of certain facilities from SPS was in the public interest pursuant to PURA § 14.101 and that the certificate of convenience and necessity ("CCN") rights associated with those facilities should be transferred to Sharyland pursuant to PURA § 37.154.[14] In addition, Sharyland sought a Commission ruling on whether it is reasonable and in the public interest to allow Sharyland to include in

[14] *Joint Report and Application of Sharyland Utilities, L.P., Sharyland Distribution & Transmission Services, L.L.C. and Southwestern Public Service Company for Approval of Purchase and Sale of Facilities, for Regulatory Accounting Treatment of Gain on Sale, and for Transfer of Certificate Rights*, Docket 41430, Application (Apr. 29, 2013).

invested capital a greater amount than the net book value of the facilities (*i.e.*, an "acquisition adjustment").

Q DID THE COMMISSION'S FINAL ORDER IN DOCKET NO. 41430 ADDRESS THE ACQUISITION ADJUSTMENT?

A. Yes. Sharyland paid $37 million for the transmission facilities at issue. In its Final Order, the Commission found that the net book value of the purchased facilities as of closing was estimated to be $8,444,775. Therefore, upon closing, SDTS recorded the net book value to the utility plant-in-service account on its books. The difference between the amount Sharyland paid and the net book value was recorded in Federal Energy Regulatory Commission ("FERC") Account 114 on SDTS's books. The Commission also found that Sharyland's proposed journal entries for the transaction were reasonable and that Sharyland would request recovery of the acquisition adjustment in its next rate case,[15] which is this case.

Q. IS SHARYLAND SEEKING TO RECOVER THE ACQUISITION ADJUSTMENT IN THIS PROCEEDING?

A. Yes. The amount recorded in FERC Account 114 pursuant to the Final Order in Docket No. 41430 is $28,970,159. Sharyland is now seeking to include this amount in its transmission plant balance and recover the amount in its transmission cost of service.

Q. WHY IS IT APPROPRIATE FOR SHARYLAND TO RECOVER THE ACQUISITION ADJUSTMENT IN THIS CASE?

A. In Ordering Paragraph 3 in Docket No. 41430, the Commission ordered that "the ratemaking treatment of the acquisition adjustment associated with the purchase of the facilities will be determined in Sharyland's next base rate case." The Commission also found that the purchase price of $37 million was reached in an arm's length negotiation between two unaffiliated parties.[16] It further noted that in considering the price, Sharyland concluded that the price was reasonable in light of estimated avoided transmission cost savings to ERCOT ratepayers of

[15] Docket 41430, Order at 10-11, Finding of Fact Nos. 52-56 (Dec. 20, 2013).

[16] *Id.* at 11, Finding of Fact No. 57.

approximately $135 million in addition to the "reliability, congestion mitigation, and timing benefits of the transaction."[17]

Most importantly, the Commission has already determined that the price paid by Sharyland is reasonable. In Conclusion of Law No. 8, the Commission concluded that:

> Taking into consideration the cost savings associated with the proposed transaction, the improvements to reliability and mitigation of congestion, and the timing benefits of utilizing existing transmission facilities rather than constructing new facilities, the purchase price of $37 million represents a reasonable purchase price for the facilities within the meaning of PURA § 14.101(b)(1).

In light of the Commission's findings of fact and conclusions of law in Docket No. 41430, Sharyland should recover the acquisition adjustment in this case. Ms. Blumenthal and Mr. Meyer also discuss the acquisition adjustment in their testimonies.

VIII. PROPOSED RIDERS

Q. IS SHARYLAND REQUESTING THAT THE COMMISSION APPROVE ANY RIDERS IN THIS PROCEEDING?

A. Yes. As described above, Sharyland is proposing riders to its retail delivery rates as well as its wholesale transmission rate to allow it to recover its deferred costs ("Rider DCRC"). Second, we are proposing two new rate case expense riders ("Rider RCEs"), one applicable to our retail delivery tariff and the other applicable to our wholesale transmission tariff, to recover the reasonable and necessary rate case expenses associated with this proceeding and any other related proceedings. Third, we are proposing a new transition to competition charge rider to recover costs that were necessary for Sharyland to transition to competition ("Rider TTCC-2").

[17] *Id.* at 11, Finding of Fact No. 60.

DOCKET NO. 45414

REVIEW OF THE RATES OF SHARYLAND UTILITIES, L.P.	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

AND EXHIBITS

OF

MARK D. MEYER

ON BEHALF OF

SHARYLAND UTILITIES, L.P.

April 29, 2016

DOCKET NO. 45414

REVIEW OF THE RATES OF SHARYLAND UTILITIES, L.P.	§	**PUBLIC UTILITY COMMISSION**
	§	
	§	**OF TEXAS**

TABLE OF CONTENTS

EXHIBITS

Q. DO THE CCN AND SUBSTATION PROJECTS COMPRISE THE TOTALITY OF ALL OF SHARYLAND'S WEST TEXAS TRANSMISSION CAPITAL INVESTMENT?

A. No. In order to meet its obligation to provide safe and reliable service to its customers and to meet ERCOT standards, Sharyland has made various other investments comprised of routine maintenance and upgrade activities at various substations. The total transmission capital investment for which Sharyland seeks to include in its rates is described in Exhibit MDM-2.

Q. ARE ALL OF THESE PROJECTS USED AND USEFUL IN PROVIDING SERVICE TO THE PUBLIC?

A. Yes, each of these projects has been completed, is in service, and is used and useful in providing service to the public.

Q. WAS THE CAPITAL INVESTMENT RELATED TO CONSTRUCTION IN WEST TEXAS REASONABLE AND NECESSARY?

A. Yes. As described earlier, Sharyland is obligated to provide the necessary transmission facilities for the delivery of electricity to its customers. It has endeavored to carry out its duty to "furnish service, instrumentalities, and facilities that are safe, adequate, efficient, and reasonable" pursuant to PURA § 38.001. Sharyland made its capital investment in west Texas in a reasonable manner to build facilities needed to prevent system problems and provide wholesale customers full access to the generation market.

C. Transmission Facilities Acquired from SPS

Q. PLEASE PROVIDE A BRIEF BACKGROUND REGARDING THE REASONS THAT SHARYLAND PURCHASED TRANSMISSION FACILITIES FROM SPS.

A. In 2010, the Commission approved a transaction in Docket No. 37990 whereby control of Cap Rock was transferred to Sharyland. Prior to that transaction, Sharyland operated transmission and distribution facilities only within ERCOT. As a result of the Cap Rock transaction, Sharyland operated transmission and distribution facilities in the SPP power region. Consistent with the Order in

Docket No. 37990,[10] Sharyland then filed an application in Docket No. 39070 to disconnect Sharyland's facilities in its Stanton division from the SPP and move the facilities and customers to ERCOT. The Commission issued an Order in Docket No. 39070 approving Sharyland's application and ordered Sharyland to implement the move from SPP to ERCOT by January 1, 2014. The disconnection of Sharyland's facilities from SPP and the connection to ERCOT required a significant amount of engineering and transmission investment. However, rather than spending approximately $135 million to build some of the necessary transmission, Sharyland purchased certain transmission facilities from SPS for $37 million.

Q. PLEASE DESCRIBE THE FACILITIES THAT SHARYLAND ACQUIRED FROM SPS.

A. In 2014, Sharyland acquired from SPS approximately 66 miles of transmission facilities, consisting of two transmission lines (the Hobbs to Midland line and the Grassland to Borden line), two substations (the SPS Borden and SPS Midland stations), and associated land rights and facilities. Those lines were operated by SPS at 230 kV but were engineered and built for 345 kV. The purpose of the transaction is also discussed in Mr. Goodlet's direct testimony. Ms. Blumenthal's direct testimony addresses the accounting treatment of the transaction. I support the reasonableness of the SPS acquisition from the perspective of the amount and cost of new transmission facilities that Sharyland would have been required to build if it had not consummated the SPS acquisition.

Q. ARE YOU SUPPORTING THE ACQUISITION ADJUSTMENT THAT SHARYLAND IS PROPOSING TO INCLUDE IN RATE BASE?

A. Yes. Specifically, I provide testimony to support the overall reasonableness of the purchase price of the SPS facilities and the used and useful nature of the facilities. Sharyland witnesses Ms. Blumenthal and Mr. Goodlet provide the specific testimony to address the acquisition adjustment.

[10] Docket No. 37990, Order at 6 (Finding of Fact No. 16).

Q. DID THE COMMISSION REVIEW THIS SALE TRANSACTION WITH SPS?

A. Yes. In Docket No. 41430, the Commission reviewed Sharyland's purchase of the SPS facilities pursuant to PURA § 14.101.[11] Recognizing the benefits discussed above, the Commission found that the purchase was in the public interest and approved the transaction.[12] The Commission stated in its final order that:

> Taking into consideration the cost savings associated with the proposed transaction, the improvements to reliability and mitigation of congestion, and the timing benefits of utilizing existing transmission facilities rather than constructing new facilities, the purchase price of $37 million represents reasonable value for the facilities within the meaning of PURA § 14.101(b)(1).[13]

Q. WAS THE PURCHASE OF THESE FACILITIES FOR $37 MILLION REASONABLE, NECESSARY, AND PRUDENT?

A. Yes. After disconnection from SPP, and because of substantial load growth in west Texas, it would have been necessary to construct additional transmission facilities in ERCOT in order to maintain reliable service to customers in that region. Those new facilities that would have needed to be constructed in lieu of the SPS purchase were calculated to cost approximately $135 million.

That cost included $51.5 million to construct new facilities necessary to assure reliable service to customers in the northernmost portion of Sharyland's system, as addressed in the *Northern Loop Project Study* that was reviewed by the ERCOT Regional Planning Group ("RPG"); approximately $8 million to construct the 10-mile Gardendale to Grady transmission line; and approximately $75 million for the construction of two new 345 kV transmission lines to satisfy reliability and economic needs related to the rapid growth of oil and gas loads in

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[11] *See Joint Report and Application of Sharyland Utilities, L.P., Sharyland Distribution & Transmission Services, LLC, and Southwestern Public Service Company for Approval of Purchase and Sale of Facilities, for Approval of Regulatory Accounting Treatment of Gain on Sale, and for Transfer of Certificate Rights*, Docket 41430, Order (Dec. 20, 2013).

[12] *Id.* at 2, 9-13, 16-19.

[13] *Id.* at Conclusion of Law No. 8.

the area, as addressed in ERCOT's 2013 *West Texas Sensitivity Study*. See Exhibits MDM-7 and MDM-8. Sharyland determined, however, that purchasing the existing Hobbs to Midland and Grassland to Borden lines would address these issues and eliminate the need to construct the new facilities.

Q. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING SHARYLAND'S ACQUISITION OF CERTAIN TRANSMISSION FACILITIES FROM SPS.

In light of the avoided transmission cost, the $37 million paid by Sharyland was reasonable, necessary, and prudent. It avoided approximately $135 million in new transmission construction costs, while also providing reliability, congestion mitigation, and timing benefits.

D. Expansion of the DC Tie

Q. PLEASE DESCRIBE SHARYLAND'S EXPANSION OF THE DC TIE.

A. In October 2007, Sharyland placed into service a 150 MW HVDC interconnection, which provided an asynchronous interconnection between ERCOT and CFE. That facility consisted of a 138 kV transmission line, a 138 kV Tap Station ("Railroad Station"), and a 150 MW HVDC converter station. The HVDC converter station is a bidirectional 150 MW back-to-back station, consisting of a device to convert 138 kV alternating current ("AC") power operating synchronously with the grid from the power that is being exported to direct current ("DC") power, and a separate device to convert the DC power to 138 kV AC power operating synchronously with the grid to which the power is being imported. The 150 MW HVDC interconnection was reviewed by the Commission in Sharyland's last base rate case, Docket No. 41474.

In 2014, Sharyland expanded the DC Tie in order to increase its capacity from 150 to 300 MW. To accomplish the expansion, Sharyland added a second 150 MW HVDC converter.

Q. DID THE EXPANSION OF THE DC TIE REQUIRE THE GRANTING OF A CCN AMENDMENT OR OTHER COMMISSION APPROVAL?

A. No, it did not.

Power Flow Assessment of the Stanton/Midland Northern Loop

Submitted to ERCOT for RPG Review

June 14, 2013

TABLE OF CONTENTS

I. Background

Pursuant to the Public Utility Commission of Texas' (PUCT or Commission) July 8, 2011 final order in Docket No. 39070, Sharyland Utilities, L.P. (Sharyland) will transfer its Southwest Power Pool (SPP) load, and most of its related transmission and distribution facilities, from SPP to Electric Reliability Council of Texas (ERCOT) by January 1, 2014. The parties in Docket No. 39070 considered several transfer options based on a study conducted by Sharyland, using 2014 expected load levels, in order to evaluate the optimal interconnection to ERCOT. The final transfer agreed upon by the parties and approved by the Commission is described in the Docket No. 39070 order and referred to herein as the Agreed Transfer Option (ATO) A one-line schematic of the ATO is shown in Exhibit 1

It is important to note that under the ATO three substations (Grady, Brown, and Koch/Koch-Tap), and their associated loads, would be disconnected from Sharyland's 138 kV transmission loop and would be served via distribution feeds from Oncor Electric Delivery Company, LLC (Oncor). However, since the ATO was evaluated, there have been several significant changes in the expected load levels at these stations and the load-serving capabilities of the upstream Oncor stations that were expected to serve these stations.

First, under the ATO, the Brown Substation load was to be served from distribution points of interconnection (POIs) from Oncor at its Knott and Ackerly metering points. However, Sharyland has experienced voltage quality issues on these metering points as capacity limits have been approached. In addition, since approval of the ATO there has been significant oilfield load growth that was not anticipated in time to include in the original study assumptions. This growth is expected to continue and will further strain the system. Oncor is experiencing similar load growth in its service territory in the same general area, further limiting the ability to serve new loads from the Knott and Ackerly Substations.

Second, under the ATO, Sharyland's Koch Substation (used primarily to serve a single pipeline gas compression booster station requiring approximately 940 kW) would be served using a distribution POI at the Ackerly Substation. However, it is not clear whether Oncor's Ackerly Substation will have the available capacity to maintain reliable service to Koch and ultimately the large load at the Koch Substation

Third, in order to serve Sharyland's Grady Substation, the ATO required the installation of a new substation transformer in the West Stanton Substation (near Sharyland's existing Triangle Substation) and the use of a new 25 kV feeder line for approximately 14 miles to the Grady Substation Location. This new feeder line would be tied to the string bus between the low side of the transformer and the low side of the bus structure. This plan had a limitation of approximately 12 MVA before voltage support would become an issue. However, load on the Grady Substation has already exceeded 15.8 MVA with oilfield load west of the substation

continuing to grow rapidly. Due to this load increase, Sharyland considered constructing a new substation needed for load growth in northern Midland and interconnecting that station to Oncor's existing Texaco Mabee transmission line. Feeders constructed out of this new substation could also be used to serve some of the load in the area that is currently being served from the Grady Substation. Two disadvantages to this approach, however, are that the line would provide only radial service, and more importantly, Oncor informed Sharyland in November 2012 that there was no capacity available on that line as oil companies have built substations to serve their load in the area.

Fourth, the ATO would disconnect Sharyland's Vealmoor from both the SPS Borden Substation and the northern portion of Sharyland's loop currently serving Koch, Brown, and Grady. This would result in Sharyland's Vealmoor and Fairview Substations being served radially from Oncor's Salem Substation. The transmission line from Salem is built on older wooden structures and is nearly 30 miles long. There are line breakers at the Vealmoor and Salem Substations. If a wooden pole is lost, line protection would open up at either end and drop the load at both substations. If the failed pole were between Salem and Fairview, the outage to both stations would be absolute until the transmission pole was replaced. Due to the age and condition of the wooden poles, the possibility exists that if a pole fails, it could result in the loss of an adjacent pole. In addition, there are no distribution backup options to shift the lost load on a temporary basis. For the same reasons, the line cannot be taken out of service to perform maintenance activities without causing substation outages. The load at risk would be in excess of 18 MW in 2014

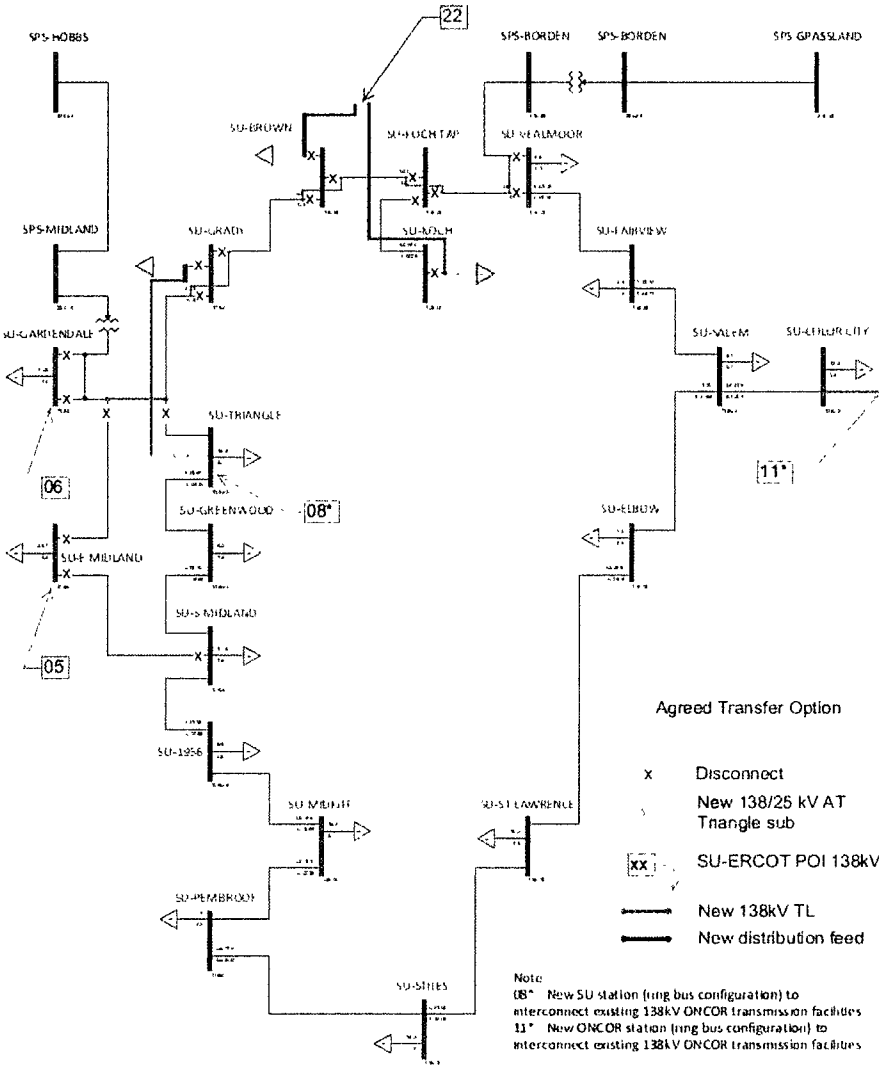


Exhibit 1: One-Line Schematic, Agreed Transfer Option, Sharyland Stanton/Colorado Facilities

2. Stanton/Midland Long-Term Load Growth Perspective

Sharyland has performed an internal evaluation and long-term assessment of its system needs to reliably integrate the loads at Grady, Brown, Koch, Vealmoor, and Fairview into ERCOT. Sharyland performed this assessment using the ERCOT 2017 models, taking into account the updated load forecasts for the region and the upgrades recommended in the Driver Load Integration Project submitted to ERCOT in September 2012

The following options were evaluated and determined to perform adequately from a reliability perspective These solutions would allow Sharyland to serve the expected load growth in the area near the northern portion of the Sharyland loop and integrate the loads served from the Grady, Brown and Koch substations.

- **Option 1** involves the construction of a new 138 kV line connecting the Brown and Koch stations to the Vealmoor station. An additional 138 kV line would connect Oncor's Ackerley Switching station to Brown. Finally a third line would be built between West Stanton and Grady to serve the Grady load. A total of approximately 37 miles of 138 kV lines would have to be built under Option 1 with a total cost of $39.7 million. This option does not eliminate all reliability concerns because it leaves the Grady station served from a single radial 138 kV circuit subject to interruptions under a single contingency.

- **Option 2** involves a new 345/138 kV substation at Brown with a 345 kV line between Brown and a new switching station intersecting WETT's Long Draw - Grelton 345 kV line. Like in Option 1, a new 138 kV line connecting the Brown and Koch stations to the Vealmoor station and a line between West Stanton and Grady would be needed. A total of approximately 30 5 miles of 138 kV and 5.5 miles of 345 kV lines would have to be built under Option 2 with a total cost of $56.5 million. Under this option, Grady would be served from a single radial 138 kV circuit subject to interruptions under a single contingency.

- **Option 3** is the same as Option 2 with the addition of an expanded 345 kV Grady station, a 345/138 kV Autotransformer at Grady and a two mile 345 kV line interconnecting Grady to a second switching station intersecting WETT's Long Draw - Grelton 345 kV line. In addition to the costs of Option 2, two (2) additional miles of 345 kV lines would have to be built under Option 3. With the new line and 345 kV substation expansion at Grady, the total cost of Option 3 is $75.7 million. This option addresses the remaining single contingency risk at Grady

- **Option 4** involves the construction of a new 138 kV line connecting the Vealmoor – Koch – Brown – Grady and W Stanton stations thereby closing the Sharyland loop. A total of approximately 50.87 miles of 138 kV lines would have to be built under Option 4 with a total cost of $51.5 million. This option would result in all loads at the Grady, Brown and Koch stations being served via transmission feeds as opposed to

distribution feeds and would result in none of the loads being radial and hence exposed to a single contingency outage.

- **Option 5** involves the retention of the 138kV loop (in its current state) from Vealmoor-Koch-Brown-Grady-W Stanton in ERCOT while using the existing transmission infrastructure.

Details of the power flow analysis and relative performance of each option have been provided in the ensuing section of the report.

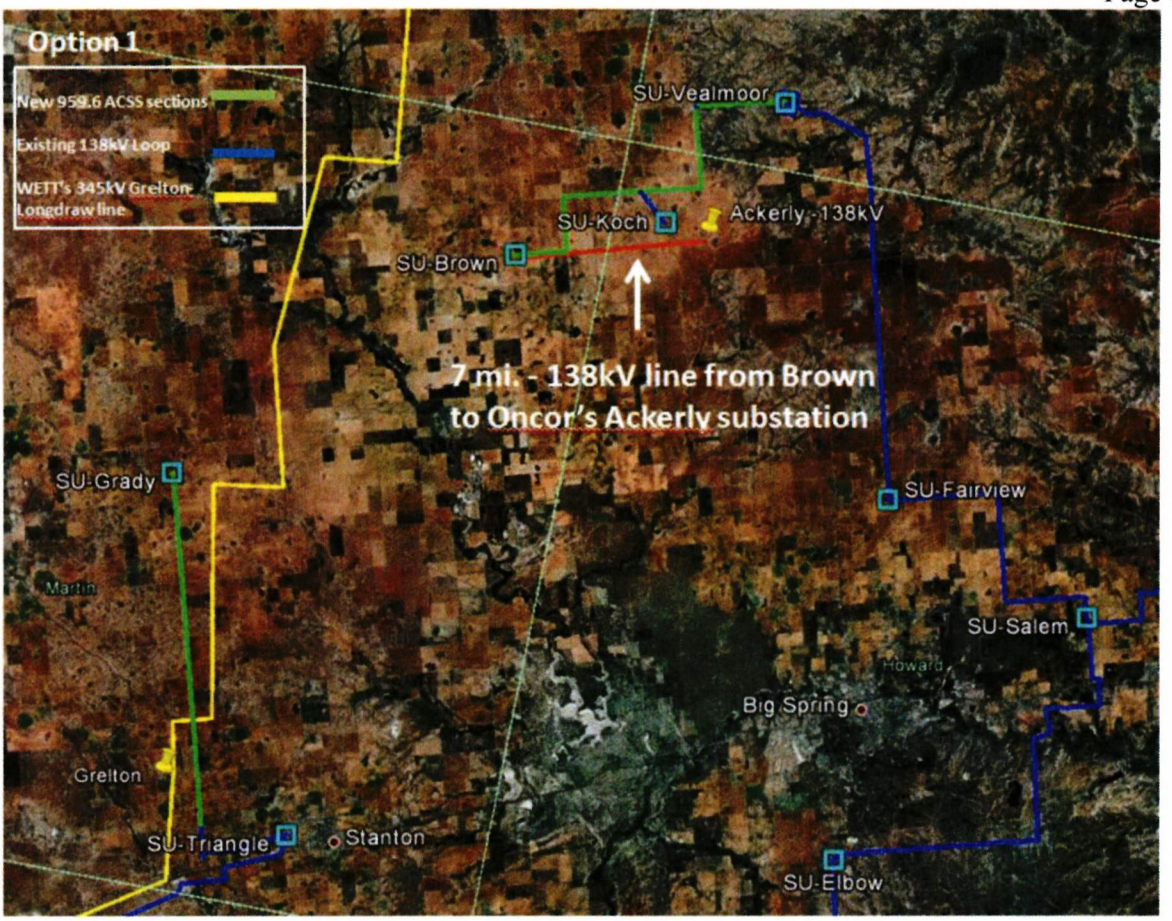


Exhibit 2: Option 1, Schematic

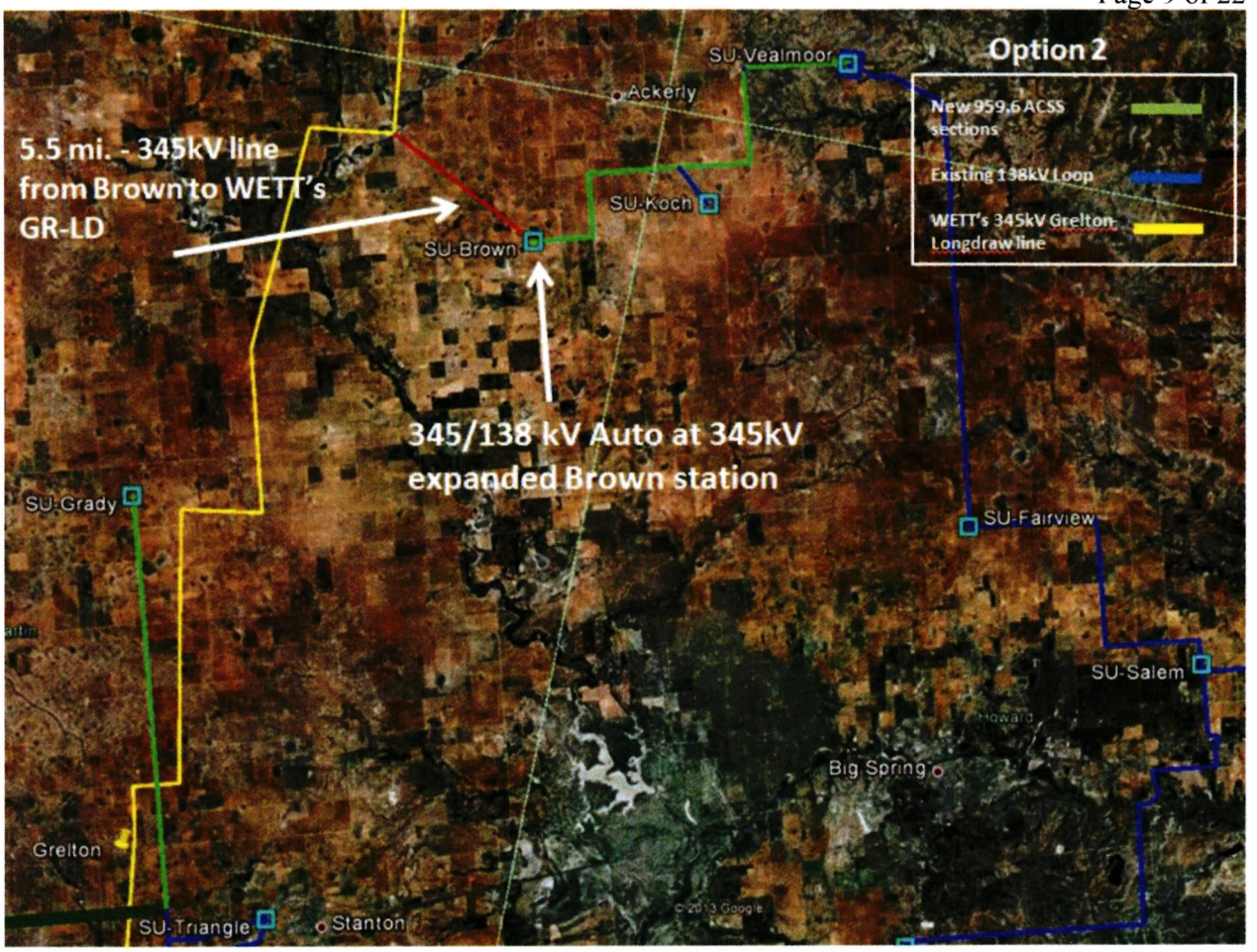


Exhibit 3: Option 2, Schematic

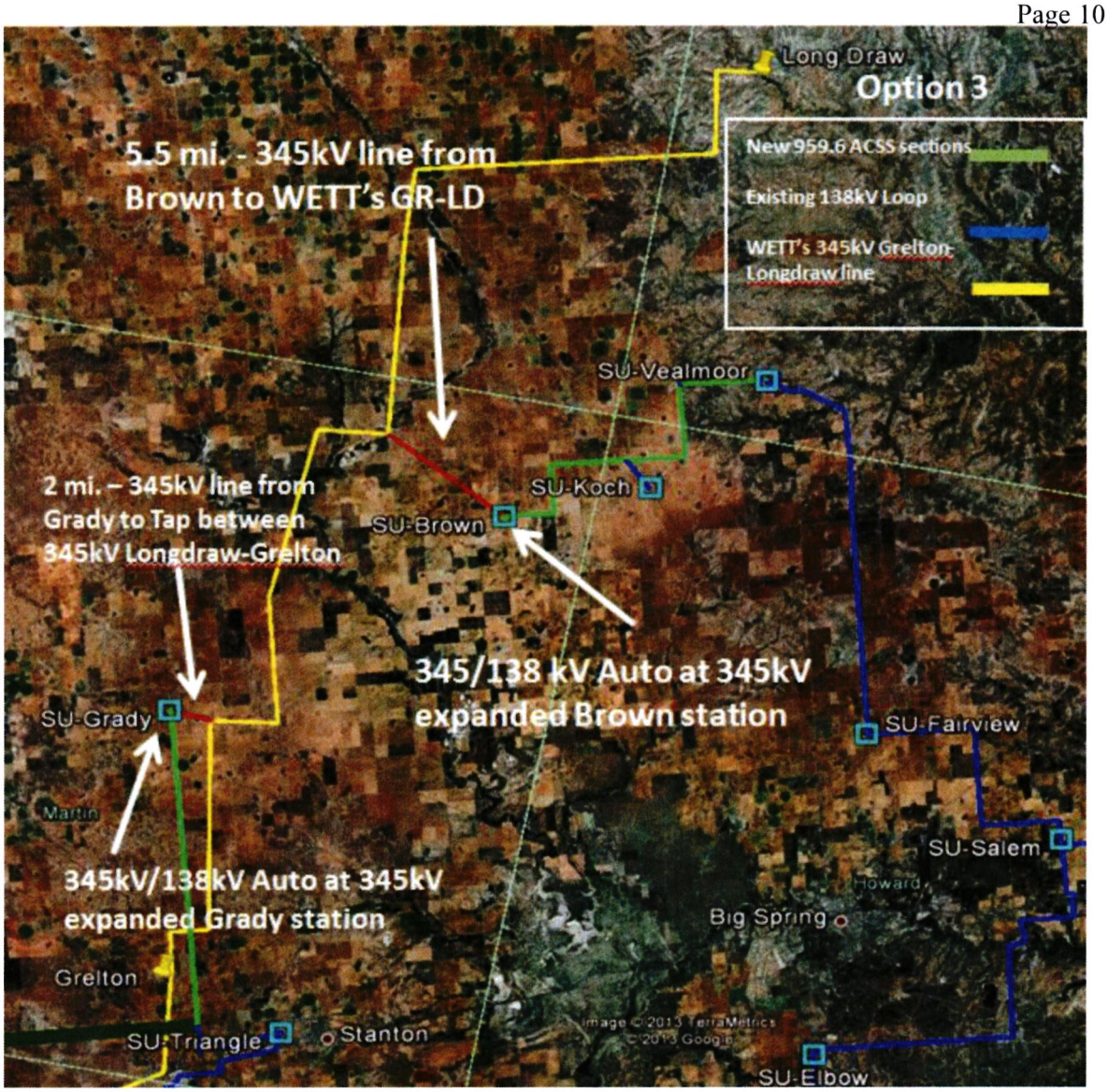


Exhibit 4: Option 3, Schematic

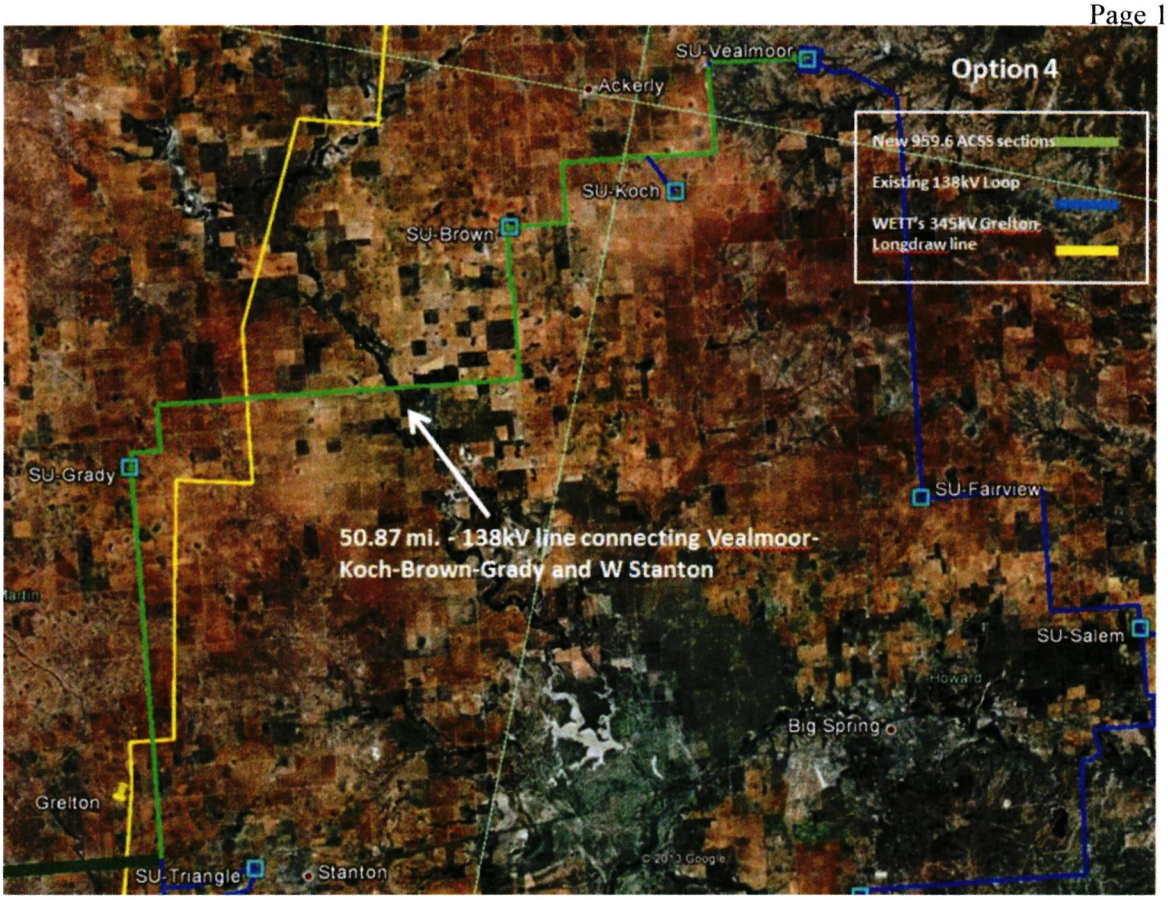


Exhibit 5: Option 4 & 5, Schematic[1]

[1] Note that while the schematic associated with Options 4 and 5 is the same, the transmission parameters comprising the northern section of the loop are different for Options 4 and 5. Option 4 involves the building of a new transmission loop to complete the northern section using 959.6 ACSS/TW Suwanee conductor. Option 5 assumes the retention of the existing northern section of the loop as is in ERCOT.

3. Power Flow Analysis

Sharyland performed a comprehensive power flow analysis to quantify the relative merits and/or limitations associated with options one through four vis-à-vis the retention of the existing northern section of the loop in ERCOT (represented by Option five). Additionally, the ability of each option to serve the northern Stanton/Midland loop load and the impact of each option on the reliability performance of the entire loop has also been assessed.

Based on ERCOT's independent evaluation of Sharyland's Regional Planning Group (RPG) submittal, the following option has been recommended by ERCOT to serve the long term load growth needs of the southern portion of the Stanton/Midland loop:

- Build a new 345kV/138kV station (Einstein) on the SU-Elland – SU-St. Lawrence 138kV line near the WETT 345kV Bearkat substation and install a 345/138 kV autotransformer at this station such that the emergency rating is at least 600 MVA.
- Build a new 345kV line from the Einstein station to WETT's Bearkat station (0.92 miles).
- Upgrade the SU-Eisl Tap – Su-St Lawrence 138 kV line (approximately 5.5 miles) such that the circuit emergency rating is at least 326 MVA.
- Install 19.6 Mvar capacitor banks at both Driver and SU-Midkiff 138 kV substations
- Install a 26 Mvar capacitor bank at SU - Greenwood 138 kV substation.
- Upgrade the Big Spring – Big Spring West 138 kV line (approximately 2 miles) so that the circuit emergency rating is at least 394 MVA.

Note that in addition to the aforementioned recommendation, the following additional connection with Oncor was included as part of the base transmission model in the ERCOT independent evaluation given Oncor's executed Interconnection Agreement (IA) with Sharyland for this connection:

- Loop CRMWD – Forsan Tap 138 kV line into SU-Elland (Sharyland recently signed an Interconnect Agreement (IA) with Oncor).

This interconnection is expected to be effective by October 2013. This is determined to be a neutral project by ERCOT. It should be noted that the Pembrook –Stiles 138 kV line and Skywest – SU-1956 138 kV line should remain open until the completion of the neutral project.

The study was performed considering all of ERCOT's recommendations in their independent review of the project as well as the following assumptions:

- The ERCOT SSWG 13DSB 2017 Summer Peak case was utilized as the base transmission model for the study.
- The following transmission improvements and/or additions were incrementally incorporated to develop the study case.

  - Upgrade the Stanton East – SU-West Stanton – SU-East Midland 138 kV line (approximately 4.1 miles) so that the circuit Rate B is 394 MVA (Tier 4 project – 14TPIT0052).
- Exhibit 6 depicts the updated load levels associated with the Stanton/Midland facilities as utilized for the reliability assessment. ERCOT Gas and/or load in remote regions was scaled in order to maintain the load generation balance.
- Power flow analysis has been performed under normal operating and contingency conditions.

i. Normal Operating Conditions

Exhibit 7-a depicts the results associated with thermal overloads under normal operating conditions. As is evident from Exhibit 7-a, none of the options studied result in any incremental thermal overloads when compared to the base case under normal operating conditions. No exacerbation of previously existing thermal overloads, attributable to any of the options, were witnessed under normal operating conditions. Additionally, none of the thermal overloads observed under normal operating conditions were in the region under study

Exhibit 7-b depicts the results associated with voltage magnitude violations under normal operating conditions. As is evident from Exhibit 7-b, there are no incremental voltage magnitude violations associated with any of the options under study when compared to the base case under normal operating conditions.

ii. Contingency Conditions

Exhibit 8-a depicts the results associated with thermal overloads under contingency conditions. The following key observations can be made from the results presented in Exhibit 8-a:

- All the options involving only 138kV connections to integrate the loads on Brown, Koch and Grady stations to the remaining Stanton/Midland loop performing comparably i.e. Options 1, 4 and 5.
- Options 2 and 3, involving additional 345kV connections when integrating the Brown, Koch and Grady stations to the remaining Stanton/Midland loop, performing relatively better from a reliability standpoint. In terms of incremental alleviations, Options 2 and 3 result in the following overload alleviations vis-à-vis the base case conditions:
  - 138kV Morgan Creek – Barber Lake for the outage of either circuit (alleviation is common to both Options 2 and 3)
  - 138kV Odessa – Liquid Air segment (additional alleviation only for Option 3)

SUBSTATION NAME	BUS NUMBER	LOAD FORECAST (MW)
SU_WSTANTON	79549	38
SU_VEALMOOR	79600	14.03
SU_FAIRVIEW	79603	9.44
SU_SALEM	79604	10.01
SU_COLORCTY	79605	19.01
SU_ELBOW	79608	14.76
SU_TRIANGLE	79627	0
SU_GRENWOOD	79610	25.33
SU_MIDKIFF	79611	40
SU_PEMBROOK	79612	18.38
SU_1956	79613	8.35
SU_STILES	79614	51.83
SU_S_MIDLND	79615	32.02
SU_E_MIDLND	79616	31.33
SU_STLAWREN	79617	33.93
SU_GARNDALE	79618	30.75
SU_EILAND	79620	23.93
SU_E_STILES	79623	20.92
SU_DRIVERSUB	79624	48.62
SU_EISLTAP	79625	0
SU_GRADY	79550	18.78
SU_BROWN	79551	10.89
SU_KOCH	79552	0.92
TOTAL		**501.23**

Exhibit 6: Stanton-Colorado City 2017 Load Forecast

From Bus No	From Bus Name	From Bus kV	To Bus No	To Bus Name	To Bus kV	Ckt ID	Rating (MVA)	Worst Overload Base Case	Worst Overload OP1	Worst Overload OP2	Worst Overload OP3	Worst Overload OP4	Worst Overload OP5
1694	TENASKA_8	138	140053	TNSKA_STG	13.8	1	90	103	103	103	103	103	103
3268	ASPNPOI_8	138	120121	LFBIO_UNIT1	13.8	1	60	100.7	100.7	100.7	100.7	100.7	100.7
11482	WFCOGEN2_8	138	140042	WFCOGE_UNIT2	13.2	1	45	105.3	105.3	105.3	105.3	105.3	105.3
180441	KINDERMG_1G	13.8	180444	KMCCS_1_8	138	1	21	120.1	120.1	120.2	120.2	120.1	120.1
180442	KINDERMG_2G	13.8	180444	KMCCS_1_8	138	1	39	118.5	118.5	118.6	118.7	118.5	118.5
180443	KINDERMG_3G	13.8	180444	KMCCS_1_8	138	1	39	118.5	118.5	118.6	118.7	118.5	118.5

Exhibit 7-a: Thermal Overload Comparative Analysis, Normal Operations

Bus No.	Bus Name	kV	Base Case		OP1		OP2		OP3		OP4		OP5	
			V(p.u.)	V(kV)	V(p.u.)	V(kV)	V(p.u.)	V(kV)	V(p.u.)	V(kV)	V(p.u.)	V(kV)	V(p.u.)	V(kV)
1514	SHPFIELD1_9	69	0.9413	64.946	0.9413	64.947	0.9412	64.946	0.9412	64.943	0.9413	64.947	0.9413	64.947
1517	BURKBURN_9	69	0.946	65.274	0.946	65.274	0.946	65.273	0.9459	65.271	0.946	65.274	0.946	65.274
1537	KMA_9	69	0.9475	65.378	0.9475	65.378	0.9475	65.377	0.9475	65.376	0.9475	65.378	0.9475	65.378
1806	ENLOE_T9	69	0.9471	65.351	0.9471	65.351	0.9471	65.351	0.9471	65.351	0.9471	65.351	0.9471	65.351
2204	CRESSON1_9	69	0.9472	65.355	0.9472	65.355	0.9472	65.355	0.9472	65.355	0.9472	65.355	0.9472	65.355
3188	WILLSPNT_9	69	0.9464	65.304	0.9464	65.304	0.9464	65.304	0.9464	65.304	0.9464	65.304	0.9464	65.304
3255	FRANKSTN_9	69	0.9477	65.392	0.9477	65.392	0.9477	65.392	0.9477	65.392	0.9477	65.392	0.9477	65.392
3270	CAROLSPG_9	69	0.9477	65.39	0.9477	65.39	0.9477	65.39	0.9477	65.39	0.9477	65.39	0.9477	65.39
3464	EQUIPIPE1_9	69	0.9434	65.093	0.9434	65.093	0.9434	65.093	0.9434	65.093	0.9434	65.093	0.9434	65.093
3470	BLOOMGRV1_9	69	0.95	65.548	0.95	65.548	0.95	65.549	0.95	65.548	0.95	65.548	0.95	65.548

Exhibit 7-b: Voltage Magnitude Violations Comparative Analysis, Normal Operations

- In case of Option 2, the reliability concern associated with Grady station (and load) being radial still persists. This concern is further exacerbated given the length of the radial line from W Stanton to Grady which is expected to increase the likelihood of such an outage. Finally, it is important to note that the Grady station load represents a region that is expected to witness significant load growth in the future years and hence the need to address the reliability concern around the Grady station load is significant.
- In case of Option 3, while it does address the reliability concern at Grady station, it is important to note that the marginal reliability benefits associated with this option are not commensurate with the significant incremental cost associated with the option vis-à-vis the remaining options

Exhibit 8-b depicts the results associated with the voltage magnitude violations under contingency conditions No major steady state voltage security concerns are observed in the region based on results presented in Exhibit 8-b. A majority of the voltage magnitude violations are over-voltage issues that are observed to be alleviated following adjustment of switched shunts (capacitor banks) in the region. The only significant low voltage issue is observed on the 138kV Gardendale station which is observed to be unaffected across all options evaluated.

From Bus No	From Bus Name	From Bus kV	To Bus No	To Bus Name	To Bus kV	Ckt ID	Rating (MVA)	Worst Overload %						Worst Contingency Label					
								Base Case	OP1	OP2	OP3	OP4	OP5	Base Case	OP1	OP2	OP3	OP4	OP5
1010	PERMIANB_8	138	1074	4 WINKSS_8	138	1	186	113.6	113.2	113.3	113	113.3	113.3	SINGLE 5	SINGLE 5	SINGLE 5	SINGLE 5	SINGLE 5	SINGLE 5
1010	PERMIANB_8	138	1087	WRDGLFTA_8	138	1	249	100						SINGLE 3					
1023	MIDLNDE_8	138	1116	WINDWOOD_8	138	1	162	155.5	155.6	155.8	162.2	156.1	156.1	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45
1027	ODESEHV_8	138	1128	LIQDAIR_8	138	1	326	103.9	103.9	103.1		103.6	103.6	SINGLE 46	SINGLE 46	SINGLE 46		SINGLE 46	SINGLE 46
1032	MRGNCRK_8	138	1189	BARBER_LK1	138	1	186	101.8	103.4			104.3	104.3	SINGLE 59	SINGLE 59			SINGLE 59	SINGLE 59
1032	MRGNCRK_8	138	1189	BARBER_LK1	138	2	186		100.4			101.2	101.2		SINGLE 58			SINGLE 58	SINGLE 58
1059	MIDESSA_8	138	1138	TEXASINS_8	138	1	186	112.1	111.9	111.7	103.6	111.3	111.4	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45
1095	SCRWBEAN_T	138	1096	BLACKRVR_8	138	1	94	121.7	121.7	121.7	121.7	121.7	121.7	SINGLE 95	SINGLE 95	SINGLE 95	SINGLE 95	SINGLE 95	SINGLE 95
1116	WINDWOOD_8	138	1117	MIDLANDW_8	138	1	162	114	114	114.2	120.8	114.5	114.5	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45
1118	CRMWD8TA_8	138	1120	MIDLAIRP_8	138	1	162	117.4	117.4	117.4	116.3	117.3	117.3	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45
1118	CRMWD8TA_8	138	1121	GLENHAVN_8	138	1	162	116.9	116.9	116.8	115.8	116.8	116.8	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45
1122	ODESSANO_8	138	1130	AMOSFOST_8	138	1	211	120.8	120.3	120.4	120.5	120.5	120.5	SINGLE 44	SINGLE 44	SINGLE 44	SINGLE 44	SINGLE 44	SINGLE 44
1127	ODESSA1_8	138	1128	LIQDAIR_8	138	1	326	101.9	101.9	101.1		101.6	101.6	SINGLE 46	SINGLE 46	SINGLE 46		SINGLE 46	SINGLE 46
1129	WESTOVER_8	138	1130	AMOSFOST_8	138	1	211	123.9	123.4	123.5	123.6	123.6	123.6	SINGLE 44	SINGLE 44	SINGLE 44	SINGLE 44	SINGLE 44	SINGLE 44
1137	TEXINSTA_8	138	1138	TEXASINS_8	138	1	186	128.2	128.1	127.8	119.6	127.5	127.5	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45	SINGLE 45
1142	2 HOLTSS_9	69	1262	EMMATAP_9	69	1	62	108.7	106.7	107.6	107.4	107.7	107.7	SINGLE 131	SINGLE 131	SINGLE 131	SINGLE 131	SINGLE 131	SINGLE 131
1274	FULERTON_9	69	1275	EXXONFUL_9	69	1	28	100.9	100.6	100.7	100.6	100.7	100.7	SINGLE 136	SINGLE 136	SINGLE 136	SINGLE 136	SINGLE 136	SINGLE 136

Exhibit 8-a: Thermal Overload Comparative Analysis, Contingency Conditions

Bus no	Bus Name	kV	Worst Voltage Limit	Base Case		OP1		OP2		OP3		OP4		OP5	
				Initial Voltage	Worst Voltage	Initial Voltage	Worst Voltage	Initial Voltage	Worst Voltage	Initial Voltage	Worst Voltage	Initial Voltage	Worst Voltage	Initial Voltage	Worst Voltage
59903	BEARKAT	345	1.05	1.04525	1.05156	1.0451	1.05164					1.04523	1.05164	1.04523	1.05164
79545	EINSTEIN	138	1.05	1.0446	1.05355	1.04438	1.05364					1.04459	1.05365	1.04459	1.05364
79546	345EINSTEIN	345	1.05	1.04516	1.05155	1.04501	1.05163					1.04514	1.05163	1.04514	1.05163
79611	SU-MIDKIFF	138	1.05	1.0372	1.09747	1.03729	1.09705					1.03756	1.09731	1.03752	1.09731
79612	SU-PEMBROOK	138	1.05	1.03517	1.08666	1.03522	1.08626					1.0355	1.08651	1.03547	1.08651
79614	SU-STILES	138	1.05	1.03903	1.0725	1.03896	1.07212					1.03923	1.07235	1.03921	1.07236
79617	SU-STLAWREN	138	1.05	1.04532	1.05537	1.04512	1.05505					1.04535	1.05525	1.04534	1.05525
79618	SU-GARNDALE	138	0.92	0.98496	0.88393	0.98521	0.88417	0.9853	0.88414	0.98936	0.88508	0.98533	0.88411	0.9853	0.8841
79622	SU-DRIVERT1	138	1.05	1.02701	1.05184	1.02714	1.05131	1.02749	1.05279	1.03234	1.05277	1.02739	1.0517	1.02735	1.05169
79623	SU-E STILES	138	1.05	1.03847	1.0656	1.03838	1.06523	1.03893	1.06614	1.04151	1.06616	1.03864	1.06546	1.03862	1.06546
79624	SU-DRIVERSUB	138	1.05	1.03095	1.0518	1.03107	1.05128	1.03143	1.05276	1.03622	1.05273	1.03132	1.05166	1.03128	1.05166
79625	SU-EISLTAP	138	1.05	1.04164	1.05358	1.04131	1.05366	1.04222	1.05359	1.04308	1.05427	1.04159	1.05367	1.04159	1.05367
79626	SU-DRIVERT2	138	1.05	1.03452	1.09749	1.03462	1.09707	1.035	1.0981	1.03971	1.09812	1.03489	1.09733	1.03485	1.09734

Exhibit 8-b: Steady State Voltage Security Assessment Results, Contingency Conditions

iii. Recommendations

Based on the results obtained for normal operations and contingency conditions and key observations derived thereof, Sharyland recommends the following in terms of integration the loads on the Grady, Brown & Koch station along the northern section of the Stanton/Midland loop:

- Option 5 is recommended as the preferred option due to the following:
  - Option 5 presents the ability to serve Grady, Koch and Brown from transmission feeders and to close the loop thereby providing reliable loop service to Fairview, Vealmoor, Grady, Koch and Brown substations.
  - Option 5 does not present any incremental reliability concerns to the regional transmission system based on the results of the reliability assessment.
  - Option 5 entails no additional costs to ratepayers as the facilities are already in place, but it is subject to the PUCT's approval of the $37M purchase of SPS lines pending in Docket #41430.
  - Finally, Option 5 presents flexibility of adding a 345kV connection to this part of the loop in the future to support load growth thereby making it comparable to Option 3.
- Sharyland recommends Option 4 as the second preferred option due to the following key characteristics:
  - The benefits associated with Option 4 are similar to that for Option 5 except for cost.
  - In comparison to Option 3, Option 4 could result in anywhere between $17-$20M cost savings while providing the flexibility for a 345kV connection in the future.

4. Budgetary Cost Estimates

Based on the descriptions provided above, Sharyland has prepared budgetary planning level estimates associated with Options 1 through 4. Exhibits 9a through 9e depict the total estimated cost for options 1 through 5. Exhibit 9a summarizes the cost of all 5 options

	OP1	OP2	OP3	OP4	OP5
Total Cost	$ 39,700,000.00	$ 56,520,000.00	$ 75,740,000.00	$ 51,500,000.00	0[2]

Exhibit 9-a: Budgetary Cost Estimates, Option 1-5

[2] Subject to the approval of the $37 million dollar purchase of the SPS transmission lines under the SPM Docket #41430.

Transmission Addition/Upgrade Description	Required Equipment & Quantity							
	345/138 Auto 477MVA	345 GCB	345kV Disconnects	Property/acreage	138 GCB	138kV Disconnects		Estimated Cost
Additional breaker and half bay at Oncor 138kV Ackerly Switching Station								$ 1,700,000.00
6.75 miles of 138kV line from Oncor's Ackerly Switching station to SU-Brown (959.6 ACSS Suwannee)								$ 7,000,000.00
5.73 miles of 138kV line from SU-Brown to Su-Kochtap (959.6 ACSS Suwannee)								$ 6,000,000.00
2 miles of 138kV line from SU-Kochtap to Su-Koch (959.6 ACSS Suwannee)								$ 2,000,000.00
8.37 miles of 138kV line from SU-Kochtap to Su-Vealmoor (959.6 ACSS Suwannee)								$ 8,500,000.00
14.27 miles of 138kV line from W Stanton to Su-Grady (959.6 ACSS Suwannee)								$ 14,500,000.00
Total Cost Estimate for Northern Loop Integration								**$ 39,700,000**

Exhibit 9-b: Budgetary Cost Estimates, Option 1

Transmission Addition/Upgrade Description	Required Equipment & Quantity						
	345/138 Auto 477MVA	345 GCB	345kV Disconnects	Property/ acreage	138 GCB	138kV Disconnects	Estimated Cost
Brown 345/138 Auto/Switchyard	1	3	9	10			$ 11,620,000
Breaker and half 345kV Switching station between LD-GR							$ 4,000,000.00
5.5 miles of 345kV line from 345/138kV Brown Switchyard to 345kV Switching station between WETT LD-GR							$ 9,900,000.00
5.73 miles of 138kV line from SU-Brown to Su-Kochtap (959.6 ACSS Suwannee)							$ 6,000,000.00
2 miles of 138kV line from SU-Kochtap to Su-Koch (959.6 ACSS Suwannee)							$ 2,000,000.00
8.37 miles of 138kV line from SU-Kochtap to Su-Vealmoor (959.6 ACSS Suwannee)							$ 8,500,000.00
14.27 miles of 138kV line from W Stanton to Su-Grady (959.6 ACSS Suwannee)							$ 14,500,000.00
Total Cost Estimate for Northern Loop Integration							**$ 56,520,000**

Exhibit 9-c: Budgetary Cost Estimates, Option 2

Transmission Addition/Upgrade Description	Required Equipment & Quantity						
	345/138 Auto 477MVA	345 GCB	345kV Disconnects	Property /acreage	138 GCB	138kV Disconnects	Estimated Cost
Brown 345/138 Auto/Switchyard	1	3	9	10			$ 11,620,000
Breaker and half 345kV Switching station between LD-GR							$ 4,000,000.00
Grady 345/138 Auto/Switchyard							$ 11,620,000
Breaker and half 345kV Second Switching station between LD-GR							$ 4,000,000.00
2 miles of 345kV line from 345/138kV Grady Switchyard to 345kV Second Switching station between WETT LD-GR							$ 3,600,000.00
5.5 miles of 345kV line from 345/138kV Brown Switchyard to 345kV Switching station between WETT LD-GR							$ 9,900,000.00
5.73 miles of 138kV line from SU-Brown to Su-Kochtap (959.6 ACSS Suwannee)							$ 6,000,000.00
2 miles of 138kV line from SU-Kochtap to Su-Koch (959.6 ACSS Suwannee)							$ 2,000,000.00
8.37 miles of 138kV line from SU-Kochtap to Su-Vealmoor (959.6 ACSS Suwannee)							$ 8,500,000.00
14.27 miles of 138kV line from W Stanton to Su-Grady (959.6 ACSS Suwannee)							$ 14,500,000.00
Total Cost Estimate for Northern Loop Integration							**$ 75,740,000**

Exhibit 9-d: Budgetary Cost Estimates, Option 3

Transmission Addition/Upgrade Description	Required Equipment & Quantity							
	345/138 Auto 477MVA	345 GCB	345kV Disconnects	Property /acreage	138 GCB	138kV Disconnects		Estimated Cost
5.73 miles of 138kV line from SU-Brown to Su-Kochtap (959.6 ACSS Suwannee)								$ 6,000,000.00
2 miles of 138kV line from SU-Kochtap to Su-Koch (959.6 ACSS Suwannee)								$ 2,000,000.00
8.37 miles of 138kV line from SU-Kochtap to Su-Vealmoor (959.6 ACSS Suwannee)								$ 8,500,000.00
14.27 miles of 138kV line from W Stanton to Su-Grady (959.6 ACSS Suwannee)								$ 14,500,000.00
20.5 miles of 138kV line from Grady to Brown (959.6 ACSS Suwannee)								$ 20,500,000.00
Total Cost Estimate for Northern Loop Integration								**$ 51,500,000**

Exhibit 9-e: Budgetary Cost Estimates, Option 4

ERCOT System Planning:

2012 West Texas Sensitivity Study Report

September 17, 2013

Document Revisions

Date	Version	Description	Author(s)
09/17/2013	2 0	Final **Corrections:** On page 36: The facilities connecting West Stanton to Vealmoor are already in place and currently owned by ~~Xcel SPS~~ Sharyland Utilities Upon the PUCT's approval of the Docket #41430, the facilities will be ~~owned by Sharyland Utilities and be~~ transferred to ERCOT from SPP	Sun Wook Kang, Audrey Zhou, Naga Kota

TABLE OF CONTENTS

I. Executive Summary

The West Texas Sensitivity Study is the result of a coordinated planning process, performed by ERCOT Staff with extensive review and input by NERC registered Transmission Planners (TPs), Transmission Owners (TOs) and other stakeholders, which addresses reliability and economic transmission needs to meet the growing electric demand being driven by the oil and natural gas industry and the associated economic expansion in supporting residential, commercial and supporting industries in the ERCOT West and Far West weather zones.

The transmission improvements identified in the West Texas Sensitivity Study include several 69 kV and 138 kV line upgrades, and several 138/69 kV autotransformer upgrades, six new 345/138 kV autotransformers, three new 138 kV lines and a new 69 kV line. Table 1 summarizes the reliability and economic driven projects identified in the 2012 West Texas Sensitivity Study that are in addition to the 2012 Five-Year Transmission projects previously identified by ERCOT.

The project completion years stated in this West Texas Sensitivity Study were chosen to timely address reliability and economic needs. The TOs will attempt to meet these project completion dates, but lead times necessary to implement projects based on factors such as availability of construction clearances, time required to receive necessary regulatory or governmental approvals, time required to design the projects, equipment and land acquisition and resource constraints which may result in different project completion dates. It should be noted that the scope of the projects identified in this report with sufficient implementation lead time may change if further analysis by ERCOT and/or the TOs/TPs results in better alternatives or a need for modifying the projects due to a change in demand or generation assumptions in the West Texas study area is identified. Projects requiring Regional Planning Group (RPG) approval will be reviewed in future assessments (also where sufficient lead time exists), such as future ERCOT Regional Transmission Plans to make sure the identified system facilities are still needed. Conversely, projects may also need to be accelerated if system conditions require earlier in-service dates.

The TOs designated to complete these projects will provide ERCOT additional details on project scope, project cost, and an implementation schedule with completion date(s). This information from the TOs may be provided through further RPG review and/or Transmission Project Information Tracking (TPIT) updates in accordance with ERCOT Planning Guide Section 6.4.1.

Table 1: Reliability Driven Projects and Year Needed

Project Area	#	Project Name	2015	2017
Midland, Ector and Andrews Counties	R1	Construct a new 345/138 kV substation at or near the existing Gardendale substation	✓	✓
	R2	Loop the existing Moss-Midland East 345 kV line into the new 345/138 kV substation at or near the Gardendale substation	✓	✓
	R3	Install a new 500 MVA 345/138 kV transformer at the new 345/138 kV substation at or near Gardendale substation	✓	✓
	R4	Loop the existing double circuit 138 kV line (Grandview-Mockingbird and Texaco Tap-Ector Hillmont)	✓	✓
	R5	Construct a new 138 kV line from new 345/138 kV substation at or near Gardendale to Midessa (~7.2 miles)	✓	✓
	R6	Construct a new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line in Andrews County	✓	✓
	R7	Connect a 345 kV line from the new 345/138 kV substation near Gardendale to the new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line	✓	✓
	R8	Loop the existing Amoco-Arena 138 kV line into the new 345/138 kV substation	✓	✓
	R9	Install a new 500 MVA 345/138 kV transformer at the new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line	✓	✓
	R10	Upgrade Midland East-Windwood 138 kV line	✓	✓
	R11	Upgrade Westover-Amoco South Foster 138 kV line	✓	✓
	R12	Upgrade Odessa North-Amoco South Foster 138 kV line	✓	✓
	R13	Upgrade Fullerton-Exxon Fullerton 69 kV line	✓	✓
	R14	Upgrade CRMWD 8 Tap-Glenhaven 138 kV line	✓	✓
	R15	Upgrade CRMWD 8 Tap-Midland Airport 138 kV line	✓	✓
	R16	Upgrade Odessa EHV Switch-Odessa 138 kV line	✓	✓
	R17	Install 36.8 Mvar capacitor bank at North Andrew 138 kV substation	✓	✓
Reagan and Crockett Counties	R18	Close the normally-open Powell Field-Powell Field Junction 69 kV line	✓	✓
	R19	Close the normally-open Illinois #4-Pandale 69 kV line	✓	✓
	R20	Maintain neutral or appropriate narrow bandwidth for the phase shifter at Big Lake during certain system conditions	✓	✓

	R21	Expand the existing Humble Tap (Powell Field Tap) 69 kV substation to accommodate new 138/69 kV facilities	✓	✓
	R22	Loop the existing Big Lake-North McCamey 138 kV line into the expanded Humble Tap substation	✓	✓
	R23	Install a new 138/69 kV transformer at the expanded Humble Tap substation	✓	✓
	R24	Upgrade the existing Big Lake-Kemper Exxon Tap 69 kV line	✓	✓
	R25	Upgrade the existing Kemper Exxon Tap-Humble Tap 69 kV line	✓	✓
	R26	Upgrade the existing Shell Powell Tap-Powell Field 69 kV line	✓	✓
Reeves, Winkler and Ward Counties	**R27**	Construct a new 138 kV substation adjacent to the existing Barilla-Musquiz 138 kV line	✓	✓
	R28	Loop the existing Barilla-Musquiz 138 kV line into the new 138 kV substation	✓	✓
	R29	Expand the existing Flat Top 69 kV substation to accommodate new 138/69 kV facilities	✓	✓
	R30	Install a new 138/69 kV transformer at Flat Top	✓	✓
	R31	Construct a new 138 kV line from the new 138 kV substation to Flat Top (~8.7 miles)	✓	✓
	R32	Upgrade the existing Barilla Draw Field Tap-Flat Top 69 kV line		✓
Crane County	**R33**	Upgrade the existing 138/69 kV transformer at Crane	✓	✓
	R34	Upgrade the existing 69 kV bus tie at Crane	✓	✓
Tom Green and Irion Counties	**R35**	Accelerate the construction of a new 138 kV line from Yucca to RingTail	✓	✓
	R36	Convert the existing 69 kV line from Barnhart Phillips Tap to Yucca 138 kV to 138 kV	✓	✓
	R37	Install a new 138/69 kV transformer at Barnhart Phillips Tap	✓	✓
	R38	Upgrade the existing 345/138 kV transformer at Twin Buttes		✓
	R39	Install a second new 345/138 kV transformer at Twin Buttes	✓	✓
	R40	Construct a new 138 kV line from Twin Buttes to Bluffs (~7.8 miles)	✓	✓
	R41	Upgrade the existing Bluffs-College Hills 138 kV line	✓	✓
	R42	Upgrade the existing 138/69 kV transformer at San Angelo North	✓	✓
	R43	Upgrade the existing 138/69 kV transformer at College Hill		✓
Menard and Mason Counties	**R44**	Expand the existing North Brady 69 kV substation	✓	✓
	R45	Construct a new 69 kV line from Mason Switch to North Brady (~25 miles)	✓	✓

Mitchell County	**R46**	Upgrade the existing Morgan Creek 138/69 kV transformer	✓	✓
	R47	Upgrade the two existing Morgan Creek-Barber Lake 138 kV lines		✓
Uvalde and Bandera Counties	**R48**	Upgrade the Utopia-Tarplery 69 kV line (Terminal Equipment)	✓	✓
	R49	Upgrade the existing Montell-Uvalde 69 kV line		✓
Llano County	**R50**	Upgrade Ferguson-Sandy Creek 138 kV line	✓	✓
Coke County	**R51**	Upgrade Cedar Hill 138/69 kV transformer	✓	✓
	R52	Install 12 Mvar capacitor bank at Spade Ranch 69 kV bus	✓	✓
	R53	Install 12 Mvar capacitor bank at Sterling City 69 kV bus	✓	✓
	R54	Add 12 Mvar capacitor bank to the existing capacitor bank at Cedar Hill 69 kV substation	✓	✓
Taylor County	**R55**	Upgrade Abilene South-Abilene West Texas Gulf 69 kV line	✓	✓
Borden, Howard and Mitchell Counties (N-1 & G-1 projects)	**R56**	Expand the existing Vealmoor 138 kV substation to accommodate 345/138 kV facilities		✓
	R57	Install a new 450 MVA 345/138 kV transformer at Vealmoor		✓
	R58	Connect 345 kV line from Vealmoor to Long Draw		✓
	R59	Connect W Stanton to Vealmoor (Northern Loop Project) *		✓
Reagan, Upton, Irion and Tom Green Counties (N-1 & G-1 projects)	**R60**	Construct a new 345/138 kV substation at the junction where the Bakers-Big Hill 345 kV line (CREZ line) and the Ringtail-Big Lake 138 kV line cross (50% of the Bakers-Big Hill 345 kV line, ~5 miles north of Ringtail 138 kV bus)		✓
	R61	Loop the Bakers-Big Hill 345 kV line into the new substation		✓
	R62	Loop the Big Lake-Ringtail 138 kV line into the new substation		✓
	R63	Install a new 345/138 kV transformer at the new substation		✓
	R64	Upgrade the existing 138 kV line from Ringtail to the new substation (~5 miles)		✓

* The West Stanton to Vealmoor project was submitted for RPG review and comments in June 2013. Upon completion of the RPG review, the project was classified as a Tier 4 project

Table 2: Economic Driven Projects and Year Needed

Project Area	#	Project Name	2015	2017
Andrews County	E1	Upgrade the existing 138/69 kV transformer # 1 at Andrews North		✓

II. Assumptions and Process

This report documents the West Texas Sensitivity Study performed by ERCOT System Planning in accordance with the ERCOT Planning Guide Section 3.

The West Texas Sensitivity Study is an addendum to the 2012 Five-Year Transmission Plan which addresses the project needs in the West and Far West weather zones to meet the projected load growth related to the oil and natural gas industry and the associated economic growth in residential, commercial and supporting industries. The West Texas Sensitivity Study analyzed the reliability and efficiency of the transmission system for the years 2015 and 2017 according to the NERC Reliability Standards and the ERCOT Planning Criteria. Upgrades identified for the years 2015 and 2017 need to be further reviewed by the appropriate TPs to determine the need for an earlier in-service year (2014 or 2016, respectively).

The scope for the West Texas Sensitivity Study was presented to the RPG. Study updates were given to and comments received by stakeholders during RPG monthly meetings in December 2012, May 2013, June 2013 and August 2013.

A. Tools

ERCOT utilized the following software tools while performing the 2012 Five-Year Transmission Plan:

- PSS/E version 32 was used to develop the conditioned cases and the AC reliability cases
- PowerWorld version 16 with SCOPF was used to create a security-constrained AC reliability case
- UPLAN version 8.12.0.9073 was used to perform security-constrained economic analysis

B. Assumptions

1. Demand

Demand for Reliability Analysis:

The 2012 Five-Year Transmission Plan final power flow cases for 2015 and 2017 (North, North Central, West and Far West were used as the start case for the West Texas Sensitivity reliability studies. The 2012 Five-Year Transmission Plan compared the ERCOT econometric 90/10 load

forecast versus the SSWG forecast and utilized the higher of the two demand forecasts for each weather zone for the reliability analysis. The load forecast used in the 2012 Five-Year Transmission Plan cases for years 2015 and 2017 are shown in Figure 1.

Weather Zone	SSWG Forecast		ERCOT Econometric 90/10 Forecast	
	2015	2017	2015	2017
NORTH	1683	1708	1851	1968
NORTH_CENTRAL	25215	26010	27605	29151
EAST	2632	2664	3245	3443
FAR_WEST	1843	1876	2079	2191
WEST	2090	2144	2274	2362
SOUTH_CENTRAL	13169	13810	12617	13659
COAST	24808	25347	23904	24697
SOUTH	6212	6474	6380	6715
ERCOT	77652	80033	79955	84186

Total using Highest Forecast	81411	84987

Figure 1: 2012 Five-Year Transmission Plan Demand Forecasts (MW)

Using the highest load forecast for each weather zone resulted in a simultaneous system demand greater than the amount of generation available to serve the load plus reserves for all of the base cases. For all study years the analysis of the system was split into two load variation regions, defined by weather zones: 1. North, North Central, West and Far West; 2. South, South Central, East and Coast. For each region studied, the corresponding weather zone demand was set to the higher of the two demand forecast highlighted in Figure 1. For the weather zones outside the study area the demand was set to the SSWG forecast. This was done to achieve a balance of load plus reserves and generation.

For the West Texas Sensitivity Study reliability cases, the load forecasts in the West and Far West weather zones were revised based on the latest normal load forecast provided by NERC registered Transmission Planners (TPs), Transmission Owners (TOs) and other stakeholders to account for revised load forecasts for the developments in the oil and natural gas industry and the associated residential, commercial and industrial expansion as of February 2013. The loads in the other weather zones remained at same level as the 2012 Five-Year Transmission Plan reliability cases.

Because the loads in this area have been rapidly increasing for this area ERCOT also requested that the TPs and TOs provide a forecast with additional load growth above the normal forecast to test the robustness of planned transmission improvements. The West Texas Sensitivity Study and

the 2012 Five-Year Transmission Plan (2012 5YTP) load forecasts for the West and Far West weather zones are shown in Figure 2.

	2015			2017		
	2012 5YTP	West Texas Sensitivity (Normal)	West Texas Sensitivity (High)	2017 (2012 5YP)	West Texas Sensitivity (Normal)	West Texas Sensitivity (High)
West	2273	2434	2551	2362	2585	2696
FAR West	2079	3227	3616	2192	3569	3944

Figure 2: West Texas Sensitivity Demand Forecasts (MW)

Demand for Economic Analysis:

The final 2015 and 2017 cases used for the economic analysis of the 2012 Five-Year Transmission Plan served as the start cases for the West Texas Sensitivity Study economic analysis. The 2012 Five-Year Transmission Plan used the ERCOT econometric 50/50 demand forecast for all weather zones. The ERCOT econometric 50/50 load forecast consists of an hourly demand profile for each year for each of eight weather zones representing the different climate-related weather patterns observed in the ERCOT Region. These eight hourly forecasts are summed by hour to produce the ERCOT forecast. The ERCOT econometric forecast is based on a "normalized" weather profile and economic predictions.

For the West Texas economic cases, the load forecasts in the West and Far West weather zones were revised based on the normal load forecast provided by the TPs and TOs and other stakeholders to account for revised load forecasts for the developments in the oil and natural gas industry and the associated residential, commercial and industrial expansion (shown in Figure 2). The loads in the other weather zones remained at same level as the 2012 Five-Year Transmission Plan economic cases.

2. Generation

The base cases used in the West Texas Sensitivity Study include all existing generation facilities and planned generation facilities modeled in the 2012 Five-Year Transmission Plan. These generating facilities were included in the 2012 Five-Year Transmission Plan cases to meet the Five-Year Transmission Plan study criteria:

- Stephens-Borlynn Wind Project, 360 MW, Borden County
- RRE Austin Solar, 80 MW, Travis County
- Panda Sherman Natural Gas Combined Cycle, 743 MW, Grayson County
- Panda Temple Natural Gas Combined Cycle, 1485 MW, Bell County

Hydro-electric power plants were also kept offline throughout the analysis since the future year availability of water was not known.

Mothballed generation units were placed in-service in the reliability analysis per the SSWG Procedure Manual Section 4.3.3.1. Because the analysis was divided into regions, the mothballed plants in a given region were not placed in-service when that region was being analyzed.

The generation output for all wind plants within the North and West region was set at zero and the Coastal region was dispatched at 10% for the reliability analysis.

3. Transmission Model

The 2012 Five-Year Transmission Plan final cases for 2015 and 2017 summer peak base cases posted in December 2012 were used as the starting point models for the transmission topology. These cases contain all 2012 Five-Year Transmission reliability and economic projects for all weather zones. The cases were updated to incorporate input from TOs and recently approved RPG projects. The key updates include the Atlas Load Integration Project (2015 and 2017 cases), the 138 kV line from Permian Basin to Culberson (modeled in 2017 case), the radial 138 kV line from Ringtail to Yucca (Tier 4 modeled in the 2017 case), and the ratings of several TNMP 69 kV facilities located in Reeves and Ward Counties (2015 and 2017 cases). More details can be found in Appendix E.

III. Reliability Driven Projects

The project completion years stated in this West Texas Sensitivity Study were chosen to timely address reliability and economic needs. The TOs will attempt to meet these project completion dates, but lead times necessary to implement projects based on factors such as availability of construction clearances, time required to receive required regulatory or governmental approvals, equipment availability, land acquisition and resource constraints may result in different project completion dates. It should be noted that the scope of the projects identified in this report may change if further analysis by ERCOT or the TOs and TPs finds better alternatives or a need for modifying the projects due to a change in demand or generation assumptions is identified. Projects requiring Regional Planning Group (RPG) approval will be reviewed in future assessments (where sufficient lead time exists), such as future ERCOT Regional Transmission Plans to make sure the identified system facilities are still needed.

1. Midland, Ector and Andrews County Reliability Project

The load in Midland and Ector Counties is served mainly by the 345/138 kV transformers at the Moss, Odessa EHV and Midland East substations through the 138 kV lines running between the transformers, while the load in Andrews County is supported mainly by the 138 kV and 69 kV lines from the Holt substation (Ector County), and the two long 138 kV lines from Lamesa (Dawson County) and Wink (Winkler County) substations.

Compared to the 2017 case built for the 2012 Five-Year Transmission Plan, the 2017 normal load case built for the West Texas Sensitivity Study has nearly 670 MW of additional load modeled in Midland, Ector and Andrews Counties. Primarily driven by the oil and gas business development and supporting commercial, industrial and residential development in the region, the significant load increase will cause wide spread overloads and low voltages under system intact and contingency conditions. The study result of the 2017 normal load case indicates the overload of roughly 83 miles of 138 kV lines, 11 miles of 69 kV lines and two existing 345/138 kV transformers at Moss and Midland East. In addition to the overload issues, 37 low voltage buses (100 kV and above) are found under either system intact or contingency conditions. The low voltage issues extend to some of the buses in Dawson County. These unacceptable system issues in the region precipitate the need for transmission reinforcement. Figure 3.1 illustrates the system issues in Midland, Andrews and Ector Counties.

Several options were tested to resolve the thermal and voltage issues identified in Figure 3.1, including the ones listed below:

- Option A: Major new 345 kV and 138 kV lines on new rights of way:
  - Construct a new 345 kV line from Midland East to Andrews North (~52 miles)
  - Expand the existing Andrews North 138 kV substation to accommodate new 345/138 kV facilities
  - Install a new 345/138 kV transformer at the Andrews North station
  - Construct a new 345/138 kV substation adjacent to the Quail-Longshore 345 kV line and install a new 345/138 kV transformer
  - Construct a new 138 kV line (~15 miles) from the new substation to Midessa

  - Construct a new 138 kV line from Midessa to Gardendale (bus number # 1183, ~7.2 miles)
- Option B: Switch existing line (from SPP) into ERCOT, convert from 230 kV operation to 138 kV operation, and construct a new 138 kV line on new right of way:
  - Tap the existing Midland East-Moss 345 kV line (~ 50% from each end) to construct a new 345/138 kV substation and install a new 345/138 kV transformer at the new substation
  - Connect the new 345/138 kV substation to Gardendale (bus number # 1183) at 138 kV
  - Construct a new 138 kV line from Midessa to Gardendale (~7.2 miles)
  - Tap the existing Amoco Three Bar tap-Arena 138 kV line and construct a new 138 kV substation,
  - Disconnect an existing 230 kV line that is currently connected to the Southwest Power Pool (SPP) System and connect it to the ERCOT System at 138 kV operation. Connect the new 138 kV substation in Andrews Counties and the new 345/138 kV substation near Gardendale through the Amoco Midland Farm Tap 138 kV substation (~ 40.2 miles) using this line.
- Option C: Switch existing line (from SPP) into ERCOT, convert from 230 kV operation to 345 kV operation, and construct a new 138 kV line on new right of way:
  - Construct a new 345/138 kV substation at or near the existing Gardendale substation
  - Loop the existing Moss-Midland East 345 kV line into the new 345/138 kV substation
  - Install a new 500 MVA 345/138 kV transformer at the new 345/138 kV substation at or near Gardendale
  - Loop the existing Grandview-Mockingbird and Texaco Tap-Ector Hillmont double circuit 138 kV line into the new 345/138 kV substation
  - Construct a new 138 kV line from the new substation at or near Gardendale to Midessa (~7.2 miles)
  - Construct a new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line
  - Disconnect an existing 230 kV line that is currently connected to the SPP System and connect it to the ERCOT System at 345 kV operation. Connect the 345 kV line from the new 345/138 kV substation at or near Gardendale to the new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line in Andrews County
  - Loop the existing Amoco-Arena 138 kV line into the new 345/138 kV substation
  - Install a new 500 MVA 345/138 kV transformer at the new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line

Option A addresses most of the system issues and provides better system loss reduction than Option C. However, Option A requires significant new rights of way for the new 345 kV (~52 miles) and 138 kV (~22 miles) lines. Estimated by ERCOT, the capital cost of Option A is likely to be more than $200 million. Option B addresses most of the system issues, but it does not provide better system performance and system loss reduction compared to Option C. Therefore,

Option A and Option B were not selected based on system performance, system losses, public impact and construction cost.

Based on the evaluation of different options, Option C is selected as the preferred solution to address most of the system issues in the three counties:

#1 Construct a new 345/138 kV substation at or near the existing Gardendale substation
#2 Loop the existing Moss-Midland 345 kV line into the new 345/138 kV substation
#3 Install a new 500 MVA 345/138 kV transformer at the new 345/138 kV substation near Gardendale
#4 Loop the existing Grandview-Mockingbird and Texaco Tap-Ector Hillmont double circuit 138 kV lines into the new 345/138 kV substation
#5 Construct a new 138 kV line from the new substation near at or near Gardendale to Midessa (~7.2 miles). Minimum emergency rating applied for the new line is 394 MVA
#6 Construct a new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line
#7 Disconnect an existing 230 kV line that is currently connected to the SPP System and connect it to the ERCOT System at 345 kV operation Connect the 345 kV line from the new 345/138 kV substation near Gardendale to the new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line in Andrews County. Connect the 345 kV line from the new 345/138 kV substation near Gardendale to the new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line in Andrews County. Minimum emergency rating applied for the line is 717 MVA per information provided by Sharyland Utilities
#8 Loop the existing Amoco-Arena 138 kV line into the new 345/138 kV substation
#9 Install a new 500 MVA 345/138 kV transformer at the new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line

Option C addresses a number of overload issues, improves voltage in the region, provides operational flexibility during maintenance and construction, and reduces transmission losses significantly. A high-level loss analysis indicates roughly 34 MW of transmission loss reduction with the preferred project modeled in the 2017 West Texas base case.

Part of the project involves connecting the new 345/138 kV substation at or near Gardendale and the new 345/138 kV substation adjacent to the existing Amoco-Arena 138 kV line. The two new substations will be connected by an existing 230 kV transmission line that is currently connected in the SPP system. The line will be disconnected from the SPP system, connected to the ERCOT system, and converted from 230 kV to 345 kV operation. Recently, Xcel SPS and Sharyland Utilities have signed a purchase agreement so that Sharyland Utilities can acquire this existing 230 kV transmission line. The acquisition plan is subject to regulatory approval by the PUCT. The existing 230 kV line was originally constructed for up to 345 kV operation. Thus, relatively minimal effort is expected for the voltage conversion. If the Xcel SPS line is not acquired and integrated into ERCOT, transmission upgrades similar to those described in Option A may be necessary.

In addition to the line conversion, the project includes construction of a new 138 kV line from the new substation at or near Gardendale to Midessa (7.2 miles) to relieve the loadings on the 138 kV lines between Moss, Odessa EHV, and Midland East.

The project described above resolves most of the system issues in the region, but some local overload and low voltage issues remain. The remaining issues needs to be addressed by the following transmission reinforcements:

#1 Upgrade the Midland East-Windwood 138 kV line (3.3 miles, Minimum emergency rating assumed: 326 MVA)
#2 Upgrade the Westover-Amoco South Foster 138 kV line (0.6 mile, Minimum emergency rating assumed: 326 MVA)
#3 Upgrade the Odessa North-Amoco South Foster 138 kV line (4.3 miles, Minimum emergency rating assumed: 326 MVA)
#4 Upgrade the Fullerton-Exxon Fullerton 69 kV line (0.01 miles, Minimum emergency rating assumed: 109 MVA)
#5 Upgrade the CRMWD 8 Tap-Glenhaven 138 kV line (4.8 miles, Minimum emergency rating assumed: 326 MVA)
#6 Upgrade the CRMWD 8 Tap-Midland Airport 138 kV line (0.7 miles, Minimum emergency rating assumed: 326 MVA)
#7 Upgrade the Odessa EHV Switch-Odessa 138 kV line (2.3 miles, Minimum emergency rating assumed: 394 MVA, if 394 MVA is not achievable without rebuilding or reconductoring the line, the minimum target emergency rating of 652 MVA is recommended since the line is already rated at 326 MVA emergency in the 2017 West Texas base case)
#8 Install 36.8 Mvar capacitor bank at the Andrews North 138 kV substation

Both the aforementioned project and the local transmission upgrades are needed in order to meet the reliability criteria in the 2015 case.

Some of the projects above exist in the June-2013 TPIT report and are scheduled for completion in 2013, 2014 or 2015. The upgrade of the Fullerton-Exxon Fullerton 69 kV line was completed on 7/25/2013. The upgrade of the Odessa EHV-Odessa 138 kV line is scheduled for completion in December 2014. The upgrade of the Midland Airport-CRMWD 8 Tap-Glenhaven 138 kV line is scheduled for completion in May 2015. The projected completion date of the upgrade of the Westover-Amoco South Foster 138 kV line, and the Odessa North-Amoco South Foster 138 kV line is currently December 2015. Mitigation plan(s) will need to be developed if the projects cannot be completed before summer 2015.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.1 Thermal overload issues in Midland, Ector and Andrews Counties

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
Amoco South Foster - Odessa North 138 kV	Odessa EHV - Odessa 138 kV	125 22	142 02

Crmwd 8 Tap - Midland Airport 138 kV	Midland East 345/138 kV Xfmr	101 73	123 94
Fullerton - Exxon Fullerton 69 kV	Holt Switch - Emma Tap 69 kV	104 80	125.77
Glenhaven - Crmwd 8 Tap 138 kV	Midland East 345/138 kV Xfmr	102 32	124 54
Holt Switch - Emma Tap 69 kV	Holt Switch - Amoco Midland Farms Tap 138 kV	105 77	119 39
Midland East – Windwood 138 kV	Odessa EHV - Liquid Air 138 kV	137 74	156.81
Moss Switch 345/138 kV Xfmr	Midland East 345/138kV Xfmr	117 54	102 64
Odessa EHV - Odessa 138 kV	Moss Switch 345/138 kV Xfmr	100 93	115 85
Texas Junction Tap – Odessa Texas Instruments 138 kV	Odessa EHV - Liquid Air 138 kV	107 30	127 40
Westover - Amoco South Foster 138 kV	Odessa EHV - Odessa 138 kV	128 21	145 15
Permian Basin To Wink Switch 138 kV*	Permian Basin - Ward Gulf Tap 138 kV	113 24	114 02
Permian Basin - Ward Gulf Tap 138 kV*	Permian Basin To Wink Switch 138 kV	N/A	101 24
Midland East 345/138kV Xfmr	Odessa EHV – Liquid Air 138 kV	N/A	112 41
Odessa EHV- Liquid Air 138 kV	Midland East 345/138kV Xfmr	N/A	114 95
Midessa - Midland West 138 kV	Midland East 345/138kV Xfmr	N/A	107 95
Odessa Texas Instruments - Midessa 138 kV	Odessa EHV - Liquid Air 138 kV	N/A	111 25
Windwood - Midland West 138 kV	Odessa EHV - Liquid Air 138 kV	N/A	115 69
Odessa - Glen Haven 138 kV	Midland East 345/138kV Xfmr	N/A	110 18
Liquid Air - Odessa 138 kV	Midland East 345/138kV Xfmr	N/A	112 88
Holt Switch - Amoco Midland Farms Tap 138 kV	Lamesa - West Dawson 138 kV	N/A	102 92
Andrews North - Bakke Tap 69 kV	Holt Switch - Emma Tap 69 kV	N/A	102 24
Ector Hillmont - 1183 138 kV	Midland East - Goddard 138 kV	N/A	114 58
Moss – Ector Hillmont 138 kV	Midland East - Goddard 138 kV	N/A	129 99
Midland East - Goddard 138 kV	Moss – Ector Hillmont 138 kV	N/A	107 52

* Permian Basin-Wink and Permian Basin-Ward Gulf Tap 138 kV lines are located in Ward and Winkler Counties. However, these issues are noted in this section because the major project addresses the line overloads.

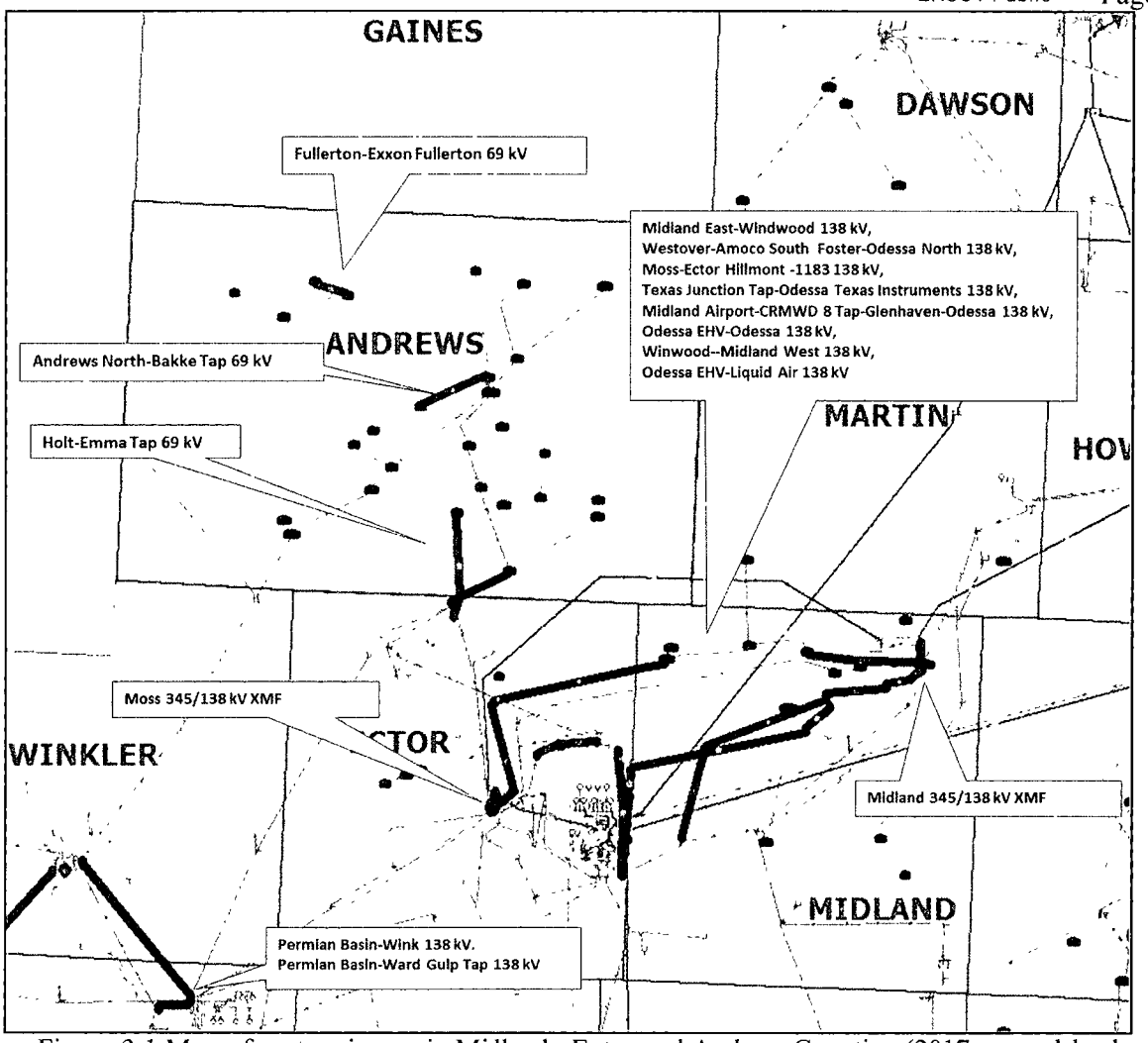


Figure 3.1 Map of system issues in Midland, Ector and Andrew Counties (2017 normal load condition)

2. Reagan and Crockett County Reliability Project

A significant increase in load is expected in Reagan and Crockett Counties. Compared to the 2017 case built for the 2012 Five-Year Transmission Plan, the 2017 normal load case has nearly 200 MW of additional load modeled in the counties.

The load in the area is currently served by the 138/69 kV transformers at Big Lake and Friend Ranch and through the 138 kV and 69 kV lines between the 138/69 kV substations. Due to the load increase, the existing transmission system in Reagan and Crockett Counties needs transmission reinforcement to address a number of overloads and low voltages under system intact and contingency conditions. The study result of the 2017 normal load case indicates the

overload of roughly 65 miles of 69 kV lines, 47 miles of 138 kV lines and two 138/69 kV transformers. In addition to the thermal issues, seven low voltage buses (100 kV and above) were found under system intact and contingency conditions.

Among the overloaded 69 kV lines, the power flows on the Big Lake-Kemper Exxon Tap-Powell Field Tap 69 kV lines and the Shell Powell Tap-Powell Field 69 kV line exceed the line ratings under system intact condition. The two long 138 kV lines to Big Lake from North McCamey and from Twin Buttes are either overloaded or experience heavy flow under contingency conditions. The existing 138/69 kV transformers at Big Lake are also susceptible to overload under contingency conditions. Figure 3.2 illustrates the system issues of the region.

Several options were tested to resolve the thermal and voltage issues, including the ones listed below:

- Option A
  - Close the normally-open Powell Field-Powell Field Junction 69 kV line
  - Close the normally-open Illinois #4-Pandale 69 kV line
  - Maintain neutral or appropriate narrow bandwidth for the phase shifter at Big Lake during certain system conditions
  - Expand the existing Humble Tap (Powell Field Tap) 69 kV substation to accommodate new 138/69 kV facilities
  - Loop the existing Big Lake-North McCamey 138 kV line into the expanded Humble Tap substation
  - Install a new 138/69 kV transformer at the expanded Humble Tap substation
  - Upgrade the existing Big Lake-Kemper Exxon Tap 69 kV line (5.6 miles)
  - Upgrade the existing Kemper Exxon Tap-Humble Tap (Powell field Tap) 69 kV line (0.3 mile)
  - Upgrade the existing Shell Powell Tap-Powell Field 69 kV line (5 miles)
- Option B:
  - Close the normally-open Powell Field-Powell Field Junction 69 kV line
  - Close the normally-open Illinois #4-Pandale 69 kV line
  - Maintain neutral or appropriate narrow bandwidth for the phase shifter at Big Lake during certain system conditions
  - Upgrade the two existing 138/69 kV transformers at Big Lake
  - Upgrade the existing Big Lake-Kemper Exxon Tap 69 kV line (5.6 miles)
  - Upgrade the existing Kemper Exxon Tap-Humble Tap (Powell field Tap) 69 kV line (0.3 mile)
  - Upgrade the existing Shell Powell Tap-Powell Field 69 kV line (5 miles)

Although Option B addresses most of system issues, there are still remaining low voltage and overload issues under contingency conditions such as the loss of the 69 kV lines from Big Lake toward Kemper Exxon Tap. Thus, Option B is not selected as the potential solution.

Based on the evaluation of different options, Option A is selected as the preferred solution to address the system issues:

#1 Close the normally-open Powell Field-Powell Field Junction 69 kV line
#2 Close the normally-open Illinois #4-Pandale 69 kV line

#3 Maintain neutral or appropriate narrow bandwidth for the phase shifter at Big Lake during certain system conditions
#4 Expand the existing Humble Tap (Powell Field Tap) 69 kV substation to accommodate new 138/69 kV facilities
#5 Loop the existing Big Lake-North McCamey 138 kV line into the expanded Humble Tap substation
#6 Install a new 138/69 kV transformer at the expanded Humble Tap substation (Minimum emergency rating assumed: 143 MVA)
#7 Upgrade the existing Big Lake-Kemper Exxon Tap 69 kV line (5.6 miles, Minimum emergency rating assumed: 109 MVA)
#8 Upgrade the existing Kemper Exxon Tap-Humble Tap (Powell field Tap) 69 kV line (0.3 mile, Minimum emergency rating assumed: 109 MVA)
#9 Upgrade the existing Shell Powell Tap-Powell Field 69 kV line (5 miles, Minimum emergency rating assumed: 109 MVA)

All of the projects selected above are needed in order to meet the reliability criteria in the 2015 case.

Part of the projects involves appropriately operating the existing phase shifter at Big Lake. The angle of the phase shifter will need to be maintained at neutral or a very narrow bandwidth to avoid potential overload or heavy flow on the transformers at Big Lake or the 138 kV line toward the new 345/138 kV substation (new substation driven by G-1+N-1) near Ringtail in anticipation of a contingency under peak load condition.

Originally, several new capacitor banks were considered as part of the potential project set to obtain acceptable voltage levels. However, they were removed due to voltage support provided by the new 345/138 kV project near Ringtail proposed for the G-1+ N-1 system issue (Ref: Section for G-1-N-1 Reliability Project for Reagan, Upton, Irion and Tom Green Counties).

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.2 Thermal overload issues in Reagan and Crockett Counties

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
Big Lake - Big Lake Philips Tap 69 kV	Friend Ranch 138/69 kV Xfmr	156 26	165 3
Big Lake 138/69 kV Xfmr	Big Lake 138/69 kV2Xfmr	134 35	131 82
Big Lake 138/69 kV Xfmr	Big Lake 138/69 kV Xfmr	135 13	132 61
Cactus - Iraan 69 kV	West Yates - Air Products Tap 69 kV	N/A	101 07
Friend Ranch - Ozona 69 kV	Temprank4A - North McCamey 138 kV (2017) Twin Buttes - Schkade & Big Lake 138 kV (2015)	108 53	119 02
Humble Tap- Atlantic Best Tap 69 kV	Friend Ranch 138/69 kV Xfmr	N/A	107.62

438

Temprank4A - North McCamey 138 kV	Twin Buttes - Schkade & Big Lake 138 kV	N/A	102 7
Midway Lane - Ozona 69 kV	Friend Ranch 138/69 kV Xfmr	133 74	137 01
Big Lake Philips Tap - Strauss Rea 69 kV	Friend Ranch 138/69 kV Xfmr	155 56	164 52
Powell Field Tap - Midway Lane 69 kV	Strauss Rea - Powell Field Tap 69 kV	150 62	159 03
Big Lake - Temprank4A 138 kV	Twin Buttes - Schkade & Big Lake 138 kV	N/A	102 84
Midway Lane - Ozona 69 kV	Friend Ranch 138/69 kV Xfmr	133 74	N/A
Powell Field Tap - Strauss Rea 69 kV	Friend Ranch 138/69 kV Xfmr	150 49	N/A
Strauss Rea - Powell Field Tap 69 kV	Friend Ranch 138/69 kV Xfmr	150 49	N/A

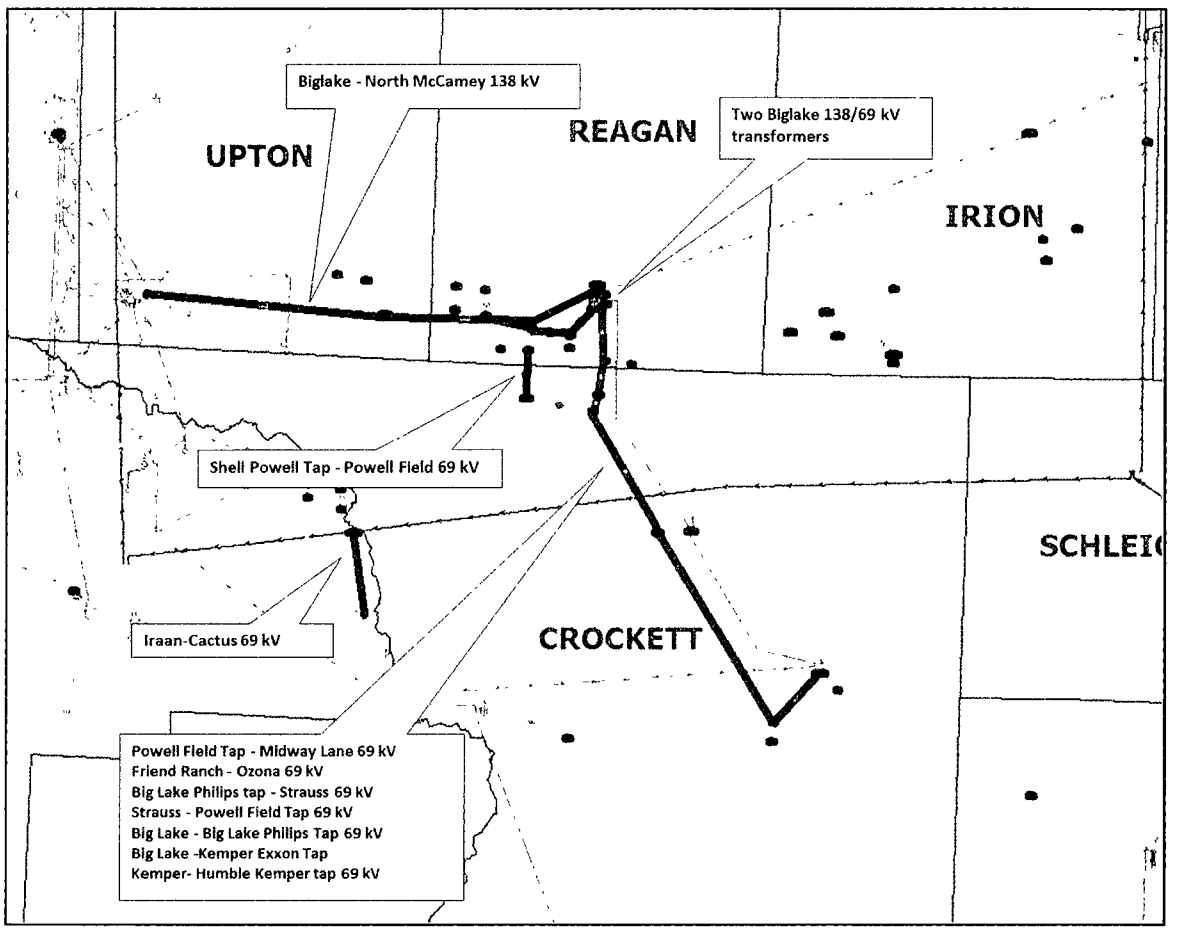


Figure 3.2 Map of system issues in Reagan and Crockett Counties (2017 normal load condition)

3. Reeves, Winkler and Ward County Reliability Project

The load in Reeves, Winkler and Ward Counties is served mainly through the lengthy 69 kV lines out of the Wink and TNP Wink 138/69 kV substations. Approximately 41 MW of additional load is expected in the counties by 2017, compared to the 2017 case built for the 2012 Five-Year Transmission Plan.

The study result of the 2017 normal load case indicates the overload of roughly 15 miles of 69 kV lines, including the Wink-TNP Wink 69 kV line and the TNP Wink-AA Pipeline-TNP Lonestar Tap 69 kV lines under contingency conditions.

The options listed below were tested to resolve the thermal issues identified in Figure 3.3.

- Option A:
  - Construct a new 138 kV line from a tap off of the existing Barilla-Musquiz 138 kV line to Pecos (27.7 miles)
  - Install a new 138/69 kV transformer at Pecos
- Option B: Rebuilding the TNMP Wink-Lone Star Tap-Barstow Tap-Pecos 69 kV lines (33 miles)
- Option C:
  - Construct a new 138 kV substation adjacent to the existing Barilla-Musquiz 138 kV line
  - Loop the existing Barilla-Musquiz 138 kV line into the new 138 kV substation
  - Expand the existing Flat Top 69 kV substation to accommodate new 138/69 kV facilities
  - Install a new 138/69 kV transformer at Flat Top
  - Construct a new 138 kV line from the new substation (#1) to Flat Top (~8.7 miles)
  - Upgrade the existing Barilla Draw Field Tap-Flat Top 69 kV line (5.7 miles)

Although Option A addresses the system issues, it requires 28 miles of new right of way for a new 138 kV line while it leaves 18 miles of existing 69 kV line from IH-20 toward Flat Top as a radial line serving the load at Barilla Draw Field Tap and Flat Top. Option B addresses the system issues except the overload of the Wink-Wink TNP 69 kV line. Provided by TNMP, the estimated capital costs of Option A and Option B are roughly $25 million and $15 million, respectively. Option C addresses the system issues, provides a network service to Flat Top and Barilla Draw Tap, and is expected to cause relatively less public impact because the new 138 kV line will use 8.7 miles of existing unused 69 kV line right of way. The estimated capital cost of Option C is about $16.5 million. Based on the cost, public impact and system performance, Option C is the best option.

Based on the evaluation of different options, the following potential project, Option C, is needed for the area to resolve the overload issues in Figure 3.3:

#1 Construct a new 138 kV substation adjacent to the existing Barilla-Musquiz 138 kV line
#2 Loop the existing Barilla-Musquiz 138 kV line into the new 138 kV substation
#3 Expand the existing Flat Top 69 kV substation to accommodate new 138/69 kV facilities
#4 Install a new 138/69 kV transformer at Flat Top

#5 Construct a new 138 kV line from the new substation (#1) to Flat Top (~8.7 miles, Minimum emergency rating assumed: 326 MVA)
#6 Upgrade the existing Barilla Draw Field Tap-Flat Top 69 kV line (5.7 miles, Minimum emergency rating assumed: 109 MVA)

The potential project addresses the overload issues, provides a network service to the radially-served Flat Top and Barilla Draw Field Tap 69 kV substations, and provides operational flexibility during maintenance or construction.

Except upgrading the Barilla Draw Field Tap-Flat Top 69 kV line, the projects listed above are needed in order to meet the reliability criteria in the 2015 case. The existing Barilla Draw Field Tap-Flat Top 69 kV line is slightly overloaded in 2017 due to the new 138 kV injection into the Flat Top station under contingency condition. Thus, upgrading the Flat Top-Barilla Draw Field Tap 69 kV line is needed by 2017.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.3 Thermal overload issues in Reeves, Winkler and Ward Counties

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
AA Pipeline TNP - Lonestar Tap TNP 69 kV	Wink TNP - Bonesprings Tap 69 kV	N/A	107 62
Wink TNP - AA Pipeline TNP 69 kV	Wink TNP – Bonesprings Tap 69 kV	N/A	107 67
Wink Sub - Wink TNP 69 kV	Wink Sub - Wink TNP 138 kV	117 42	125.14

Note that the Permian Basin-Wink and Permian Basin-Ward Gulf Tap 138 kV line overload issues were already listed in the table in Section 1 (Midland, Ector, Andrews Counties) since the line overloads were relieved by the new 345/138 kV project in the section.

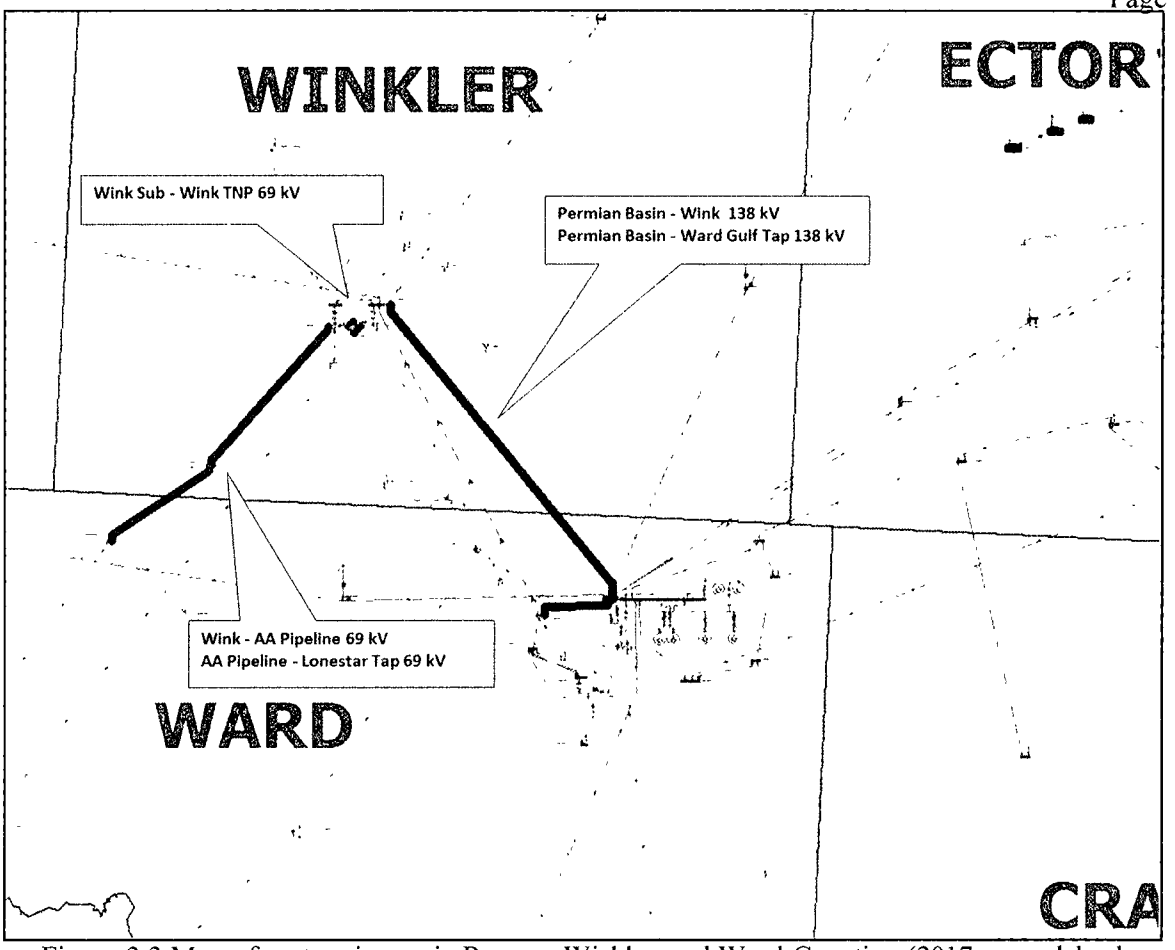


Figure 3.3 Map of system issues in Reeves, Winkler and Ward Counties (2017 normal load condition)

4. Crane County Reliability Project

Approximately 40 MW of additional load is expected in Crane County by 2017, compared to the 2017 case built for the 2012 Five-Year Transmission Plan. The load in the area is mainly served by the two existing 138/69 kV transformers at Crane. One transformer is rated at 143 MVA (AEP) and the other is rated at 84 MVA (ONCOR). The study result indicates the overload of the 84 MVA transformer and the Crane 69 kV bus tie for the loss of the 143 MVA transformer.

The potential projects to address the overload issues identified in Figure 3.4 are

#1 Upgrade the existing smaller 138/69 kV transformer at Crane (Minimum emergency rating assumed: 143 MVA)

#2 Upgrade the existing 69 kV bus tie at Crane (Minimum emergency rating assumed: 124 MVA)

The projects are needed in order to meet the reliability criteria in the 2015 case. **442**

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.4 Thermal overload issues in Crane County

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
Crane 69 kV bus tie	Crane 138/69 kV Xfmr (AEP)	144 41	150 27
Crane 138/69 kV Xfmr (ONCOR)	Crane 138/69 kV Xfmr (AEP)	110 55	116 71

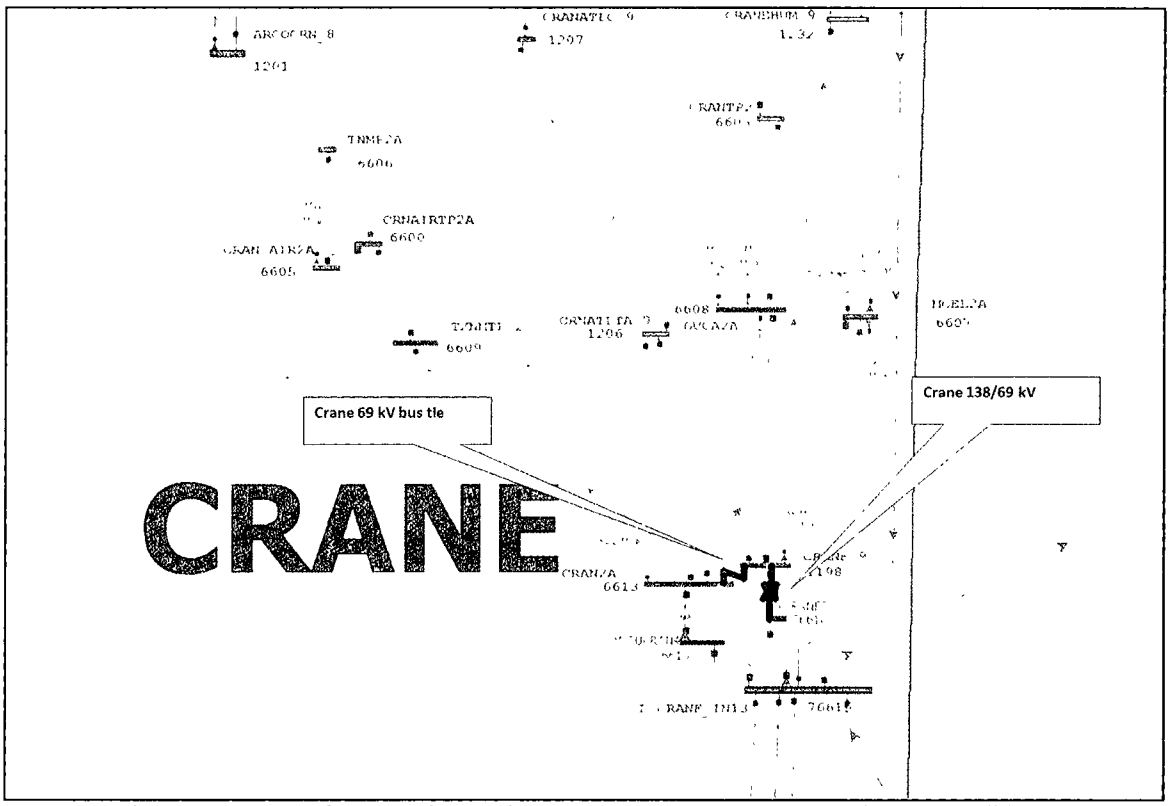


Figure 3.4 Map of system issues in Crane County (2017 normal load condition)

5. Tom Green and Irion County Reliability Project

Compared to the 2017 case built for the 2012 Five-Year Transmission Plan, approximately 132 MW of additional load is modeled in Tom Green and Irion Counties for the 2017 normal load case. Approximately half of the area load is served through the 138 kV lines running between the 345/138 kV transformers at Red Creek and Twin Buttes. The rest of the load is served by the 69 kV lines connecting the 138/69 kV transformers located at San Angelo Concho, San Angelo North, San Angelo College Hills and San Angelo Power Station.

Due to the load increase in the area, the study result of the 2017 normal case indicates the overloads of multiple transmission facilities:

- One of the two existing 345/138 kV transformers at San Angelo Red Creek
- Roughly 16 miles of 138 kV lines from San Angelo Red Creek to Highland Street and from San Red Creek to Paul Ann
- Roughly 10.3 miles of a 69 kV line from San Angelo Concho to Mathis Field
- Existing 138/69 kV transformer at San Angelo North

Based on the inputs from AEP, several options were developed and tested to resolve the system issues identified in Figure 3.5:

- Option A:
  - Construct a new Little Hill Station on the San Angelo Power Station (SAPS) to Eldorado Live Oak 138 kV line
  - Install a new 345/138 kV autotransformer at Little Hill
  - Construct a 345 kV line between Big Hill and Little Hill (~0.7 miles)
  - Loop the Santiago-Live Oak 138 kV line into Little Hill
  - Upgrade the SAPS to Little Hill 138 kV line (~26 miles)
  - Upgrade the Eldorado Live Oak to Little Hill 138 kV line (~12 miles)
  - Rebuild the Red Creek to Concho 138 kV line (~9.7 miles)
  - Construct a new 138 kV line from Ringtail to Yucca (13.5 miles, Note: this line is already modeled in the 2017 West Texas base case as a radial line serving Yucca from Ringtail, but not in the 2015 West Texas base case)
  - Convert the existing 69 kV line from Barnhart Phillips Tap to Yucca 138 kV to 138 kV (~12 miles)
  - Install a new 138/69 kV transformer at Barnhart Phillips Tap
- Option B:
  - Upgrade the existing Twin Buttes 345/138 kV transformer
  - Install a second 345/138 kV transformer at Twin Buttes
  - Construct a Grape Creek Tap 138 kV bus
  - Removes the College Hills to Grape Creek Tap 69 kV line
  - Construct a new Grape Creek Tap to Twin Buttes 138 kV line (~9.7 miles)
  - Construct a new Bluffs to Twin Buttes 138 kV line (~7.8 miles)
  - Upgrade the Bluffs -College Hills 138 kV line (~0.7 mile)
  - Install a new 138/69 kV transformer at Grape Creek Tap
  - Construct a new 138 kV line from Ringtail to Yucca (13.5 miles, Note: this line is already modeled in the 2017 West Texas base case as a radial line serving Yucca from Ringtail, but not in the 2015 West Texas base case)
  - Convert the existing 69 kV line from Barnhart Phillips Tap to Yucca 138 kV to 138 kV (~12 miles)
  - Install a new 138/69 kV transformer at Barnhart Phillips Tap
- Option C:
  - Upgrade the existing 345/138 kV transformer at Twin Buttes
  - Install a second new 345/138 kV transformer at Twin Buttes
  - Construct a new 138 kV line from Twin Buttes to Bluffs (~7.8 miles)
  - Upgrade the existing Bluffs-College Hills 138 kV line (~0.7 mile)

- Upgrade the existing 138/69 kV transformer at San Angelo North
- Upgrade the existing 138/69 kV transformer at College Hill
- Construct a new 138 kV line from Ringtail to Yucca (13.5 miles, Note: this line is already modeled in the 2017 West Texas base case as a radial line serving Yucca from Ringtail, but not in the 2015 West Texas base case)
- Convert the existing 69 kV line from Barnhart Phillips Tap to Yucca 138 kV to 138 kV (~12 miles)
- Install a new 138/69 kV transformer at Barnhart Phillips Tap

Both Option A and Option B cause other thermal issues calling for additional transmission upgrades in the region. The capital costs of Option A and Option B without the common element associated with Ringtail, Yucca and Barnhart are roughly $42 million and $56 million, respectively. Option C addresses the system issues and the capital cost of Option C without the common element associated with Ringtail, Yucca and Barnhart is roughly $28 million. Based on the system performance and the cost, Option A and Option B were not selected as the preferred solution for the region.

Based on the evaluation of different options, the following project, Option C, is selected as the preferred solution to address the system issues in these counties:

#1 Convert the existing 69 kV line from Barnhart Phillips Tap to Yucca 138 kV to 138 kV (Minimum emergency rating assumed: 345 MVA)
#2 Install a new 138/69 kV transformer at Barnhart Phillips Tap (Minimum emergency rating assumed: 99 MVA)
#3 Upgrade the existing 345/138 kV transformer at Twin Buttes (Minimum emergency rating assumed: 852 MVA)
#4 Install a second new 345/138 kV transformer at Twin Buttes (Minimum emergency rating assumed: 852 MVA)
#5 Construct a new 138 kV line from Twin Buttes to Bluffs (~7.8 miles, Minimum emergency rating assumed: 966 MVA)
#6 Upgrade the existing Bluffs-College Hills 138 kV line (~0.7 mile, Minimum emergency rating assumed: 966 MVA)
#7 Upgrade the existing 138/69 kV transformer at San Angelo North (Minimum emergency rating assumed: 143 MVA)
#8 Upgrade the existing 138/69 kV transformer at College Hill (Minimum emergency rating assumed: 143 MVA)
#9 Construct a new 138 kV line from Ringtail to Yucca (13.5 miles, Minimum emergency rating assumed: 345 MVA, Note: this line is already modeled in the 2017 West Texas base case as a radial line serving Yucca from Ringtail, but not in the 2015 West Texas base case. This is included as part of the project since it needs to be accelerated to meet the reliability criteria in the 2015 case)

The projects are needed in order to meet the reliability criteria in the 2015 case, except upgrading the existing 345/138 kV transformer at Twin Buttes and upgrading the existing 138/69 kV transformer at College Hill, These two items are needed to meet the reliability criteria in the 2017 case.

As noted in the project description, the new 138 kV line from Ringtail to Yucca is already modeled in the 2017 West Texas Sensitivity Study base case, serving the load at Yucca radially from Ringtail (March-12-2013-TPIT, 16TPIT0031, 16TPIT0032, and in-service year of 2016 as Tier 4). The study result of the 2015 base case indicates the overload of the 69 kV lines in Irion County under contingency conditions. Therefore, the projected in-service year of the new 138 kV line from Ringtail to Yucca should be accelerated to 2015. Upon completion of the conversion of the existing 69 kV line from Barnhart Phillips Tap to Yucca to 138 kV, the new 138 kV line from Ringtail to Yucca will become one of the key outlets of a new 345/138 kV injection proposed for the G-1+N-1 issue in the region. More details of the new 345/138 kV injection can be found in the section of the G-1+N-1 Reliability Project for Reagan, Upton, Irion and Tom Green Counties. These projects will provide a network service to Yucca and Barnhart and improves the voltages at the 69 kV buses in Irion County.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.5 Thermal overload issues in Tom Green and Irion County

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
Big Lake - Barnhart Tap 69 kV	San Angelo Concho - San Angelo Mathis Field 69 kV	116 89	N/A
Mertzon - Barnhart Philips Tap 69 kV	Big Lake - Barnhart Tap 69 kV	106 94	N/A
Mertzon - Mertzon Tap 69 kV	Big Lake - Barnhart Tap 69 kV	113 23	N/A
San Angelo Mathis Field – Tankersley 69 kV	Big Lake - Barnhart Tap 69 kV	137 38	N/A
Tankersley – Mertzon 69 kV	Big Lake - Barnhart Tap 69 kV	129 03	N/A
San Angelo Concho - San Angelo Mathis Field 69 kV	Big Lake - Barnhart Tap 69 kV	145 18	103 88
San Angelo North 138/69 kV Xfmr	San Angelo Concho 138/69 kV Xfmr	104 29	105 37
San Angelo Coke Street - Sa Highland Street 138 kV	Twin Buttes 345/138 kV Xfmr	105 23	107 16
San Angelo Red Creek - San Angelo Coke Street 138 kV	Twin Buttes 345/138 kV Xfmr	113 51	116 67
San Angelo Red Creek 345/138 kV Xfmr #1	San Angelo Red Creek 345/138 kV Xfmr #2	107 57	115 37
San Angelo Red Creek – Paul Ann 138 kV	San Angelo Red Creek – San Angelo Coke Street 138 kV	N/A	101 93

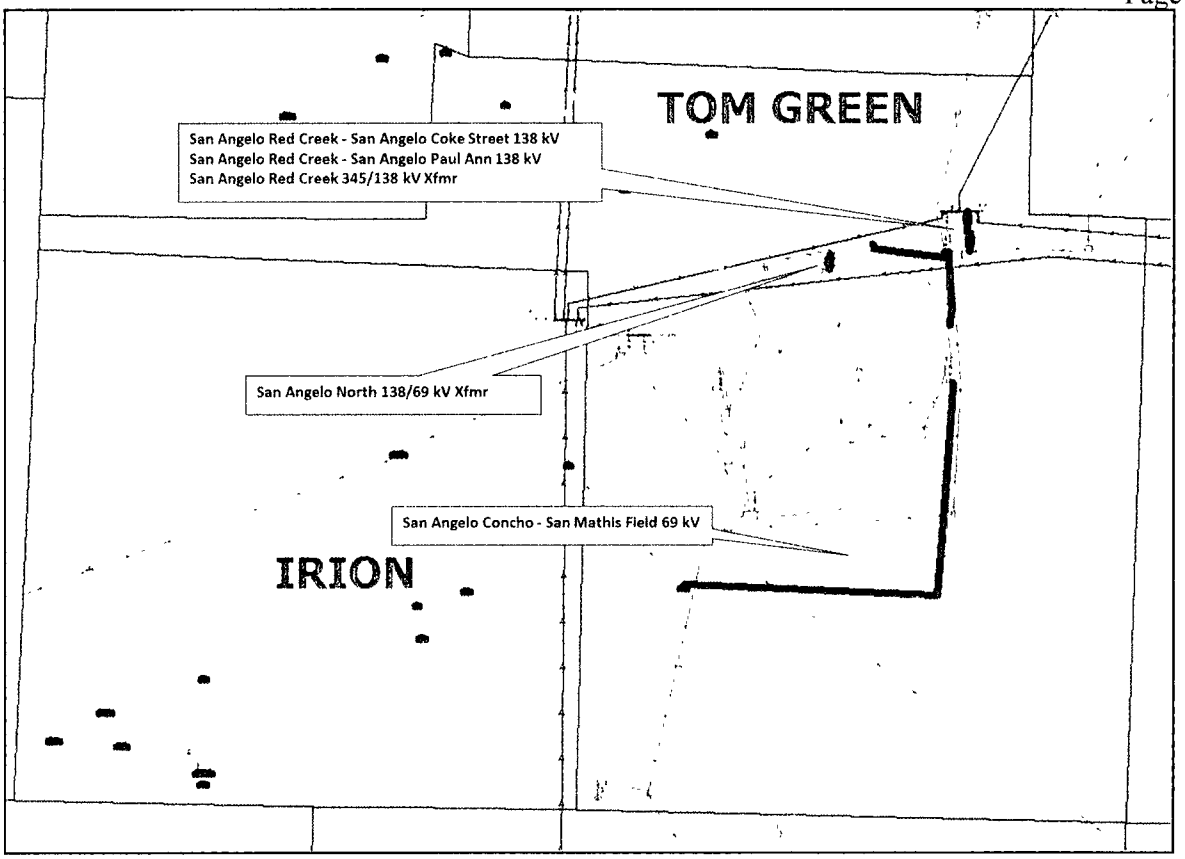


Figure 3.5 Map of system issues in Tom Green and Irion Counties (2017 normal load condition)

6. Menard and Mason County Reliability Project

The loads in McCulloch and the south of Concho Counties are being served by 69 kV lines from Yellow Jacket in Menard County and TNC Mason in Mason County. Compared to the 2017 case built for the 2012 Five-Year Transmission Plan, the 2017 normal load case has roughly 18 MW of additional load modeled in the region.

The study result of the 2017 normal load case indicates the overload of the TNC Mason-Katemcy 69 kV line (16.8 miles) for the loss of the Yellow Jacket-Eden 69 kV line, and the overload of the Yellow Jacket-Eden-Eden Rea Tap 69 kV lines (24.5 miles) for the loss of the TNC Mason-Katemcy 69 kV line.

Based on the inputs from AEP, several options were developed and tested to resolve the system issues identified in Figure 3.6:

- Option A:
  - Expand the existing North Brady 69 kV substation
  - Construct a new 69 kV line between North Brady and Mason Switching Station (~25 miles)

- Option B:
  - Construct a new Katemcy Station on the Mason to North Brady 69 kV line
  - Upgrade the Yellow Jacket-Eden 69 kV line (~20 miles)
  - Upgrade the Katemcy-Mason 69 kV line (~17 miles)
  - Install two 7.2 Mvar capacitor banks at Eden
- Option C:
  - Construct a new 69 kV line between Yellow Jacket and North Brady (~35 miles)

All these options address the system issues. It is also expected that Option A and Option C would provide operational flexibility for maintenance outage conditions on the existing system in the area due to the new 69 kV line on a new right of way required under both options. The capital cost of each option is $32 million for Option A, $39 million for Option B and $41 million for Option C. Thus, Option A is the best option as the least cost project.

Based on the evaluation of different options, the following project, Option A, is selected as the preferred solution to address the overload issues and to provide better operational flexibility to the system:

#1 Expand the existing North Brady 69 kV substation
#2 Construct a new 69 kV line from Mason Switch to North Brady (~25 miles, Minimum emergency rating assumed: 242 MVA)

The projects are needed in order to meet the reliability criteria in the 2015 case.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.6 Thermal overload issues in Menard and Mason Counties

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
TNC Mason Sub - Katemcy 69 kV	Yellow Jacket - Eden 69kV	NA	104 83
Yellow Jacket – Eden 69kV	TNC Mason Sub – Katemcy 69 kV	101 97	109 77
Eden-Mcec Tap 69 kV	TNC Mason Sub – Katemcy 69 kV	N/A	103 21

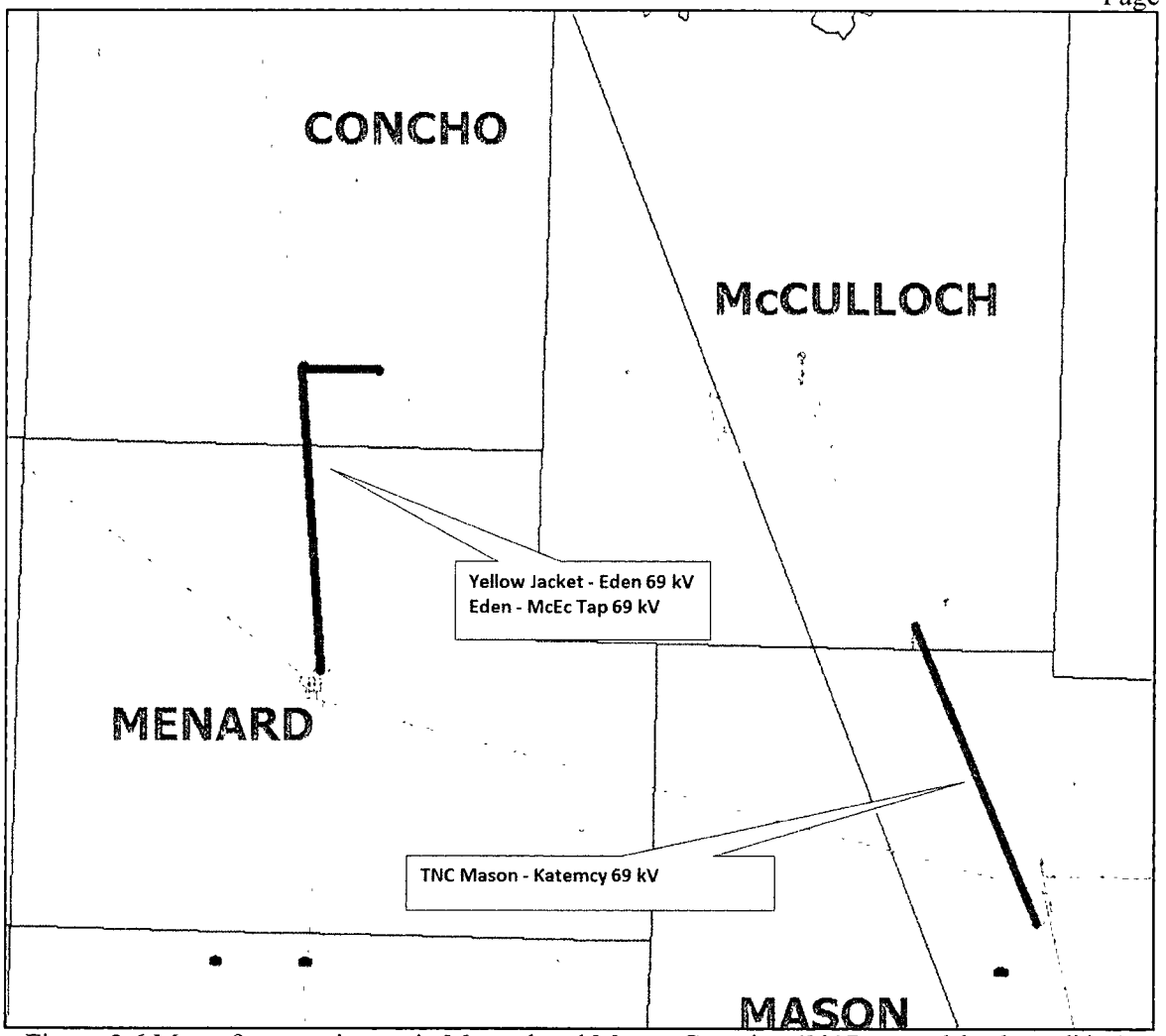


Figure 3.6 Map of system issues in Menard and Mason Counties (2017 normal load condition)

7. Mitchell County Reliability Project

The transmission system around Morgan Creek in Mitchell County is electrically close to the system in the neighboring counties such as Scurry, Howard and Nolan. For these counties, approximately 117 MW of additional load is modeled in the 2017 case compared to the 2017 case built for the 2012 Five-Year Transmission Plan.

Under various contingency conditions, the Morgan Creek 138/69 kV transformer is overloaded. The worst contingency causing the transformer overload is the loss of the 345 kV line from Scurry County South to Long Draw. There are two 138 kV lines out of Morgan Creek running toward Barber Lake. The loss of any one of the two 138 kV lines causes the overload of the remaining 138 kV line.

The following potential projects address the overload of the 138 kV lines and the 138/69 kV transformer at Morgan Creek identified in Figure 3.7:

#1 Upgrade the two existing Morgan Creek-Barber Lake 138 kV lines (6.3 miles, Minimum emergency rating assumed: 326 MVA)
#2 Upgrade the existing Morgan Creek 138/69 kV transformer (Minimum emergency rating assumed: 125 MVA)

The upgrade of the existing Morgan Creek 138/69 kV transformer is needed in order to meet the reliability criteria in the 2015 case, and the upgrades of the two 138 kV lines are needed in order to meet the reliability criteria in the 2017 case.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.7 Thermal overload issues in Mitchell County

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
Morgan Creek Unit 138/69 kV Xfmr	Eskota 138/69 kV Xfmr (2015) Scurry County - Long Draw & Faraday 345 kV (2017)	108 63	113 58
Morgan Creek – Barber Lake 138 kV #2	Morgan Creek – Barber Lake 138 kV #1	NA	113 61
Morgan Creek – Barber Lake 138 kV #1	Morgan Creek – Barber Lake 138 kV #2	NA	113 61

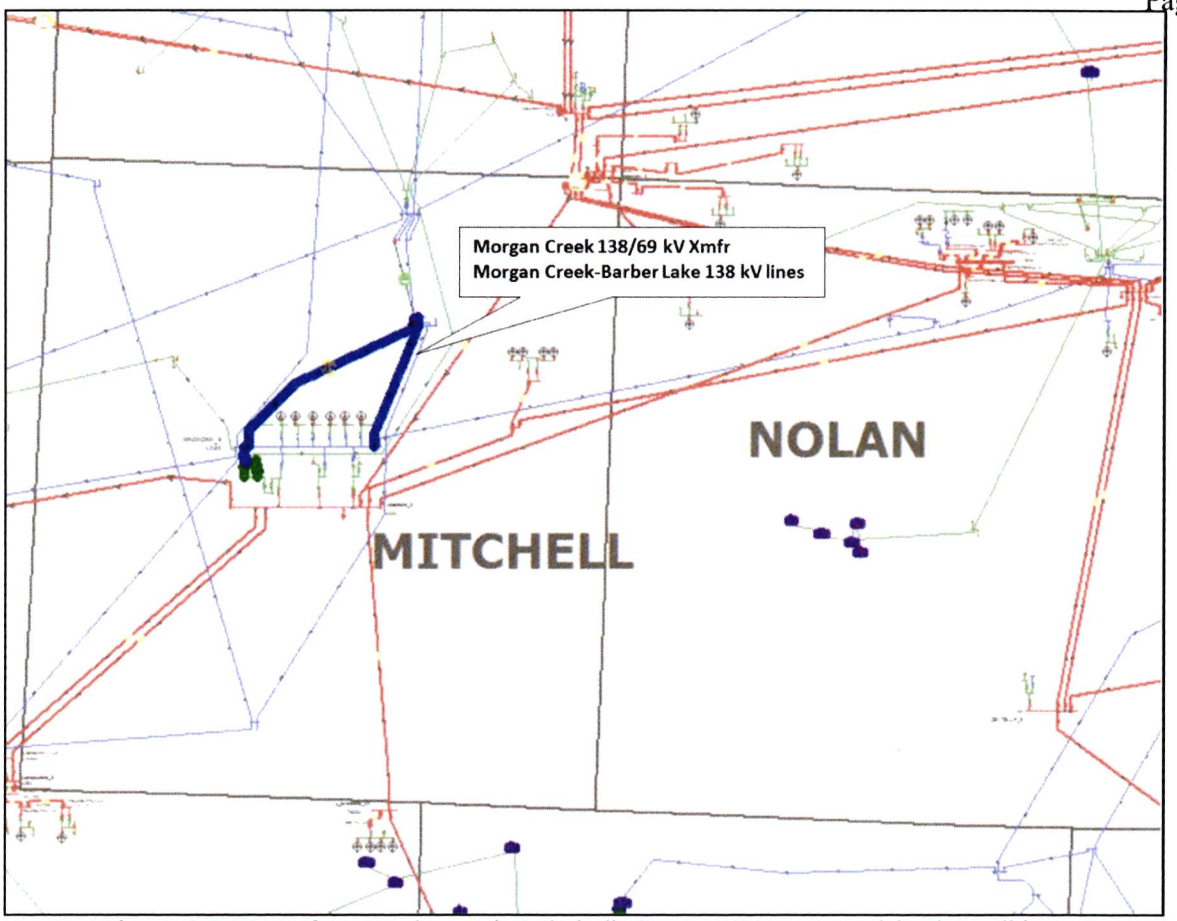


Figure 3.7 Map of system issues in Mitchell County (2017 normal load condition)

8. Uvalde and Bandera County Reliability Project

The load in Real, Uvalde and Bandera Counties is served by the lengthy and lossy 69 kV lines connecting the 138/69 kV transformers at the Bandera and Uvalde substations. Compared to the 2017 case built for the 2012 Five-Year Transmission Plan, an additional seven MW of load is modeled in the 2017 normal load case.

The study result of the 2017 normal load case indicates the overload of 56 miles of 69 kV lines under contingency conditions. The Uvalde-Montell-Campwood 69 kV line is overloaded for the loss of the Leakey-Utopia-Tarpley-Bandera 69 kV line. The Utopia-Tarpley 69 kV line is overloaded for the loss of the Montell-Uvalde 69 kV line. The Hondo-Hondo Creek 69 kV line is slightly overloaded for the loss of Moore-Downie 69 kV line.

To address the overload issues identified in Figure 3.8, the following potential projects need to be done:

#1 Upgrade the existing Montell-Uvalde 69 kV line (25.8 miles, Minimum emergency rating assumed: 109 MVA)

#2 Upgrade the Utopia-Tarplery 69 kV line (Terminal Equipment, 16 miles, Minimum emergency rating assumed: 64 MVA)

The Utopia-Tarplery 69 kV line upgrade is needed in order to meet the reliability criteria in the 2015 case, and the Montell-Uvalde 69 kV line upgrade is needed in order to meet the reliability criteria in the 2017 case.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.8 Thermal overload issues in Uvalde and Bandera Counties

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
Tarpley - Utopia 69 kV	Utopia 138/69 kV Xfmr (2015) Montell - Uvalde 69 kV (2017)	100 00	102 11
Hondo Creek - Hondo Sub 69 kV	Moore Sub - Downies Sub 138 kV	NA	100 43
Montell - Campwood 69 kV	Bandera - Tarpley - Utopia - Leakey 69 kV	NA	111 45
Uvalde - Montell 69 kV	Bandera - Tarpley - Utopia - Leakey 69 kV	NA	119 33

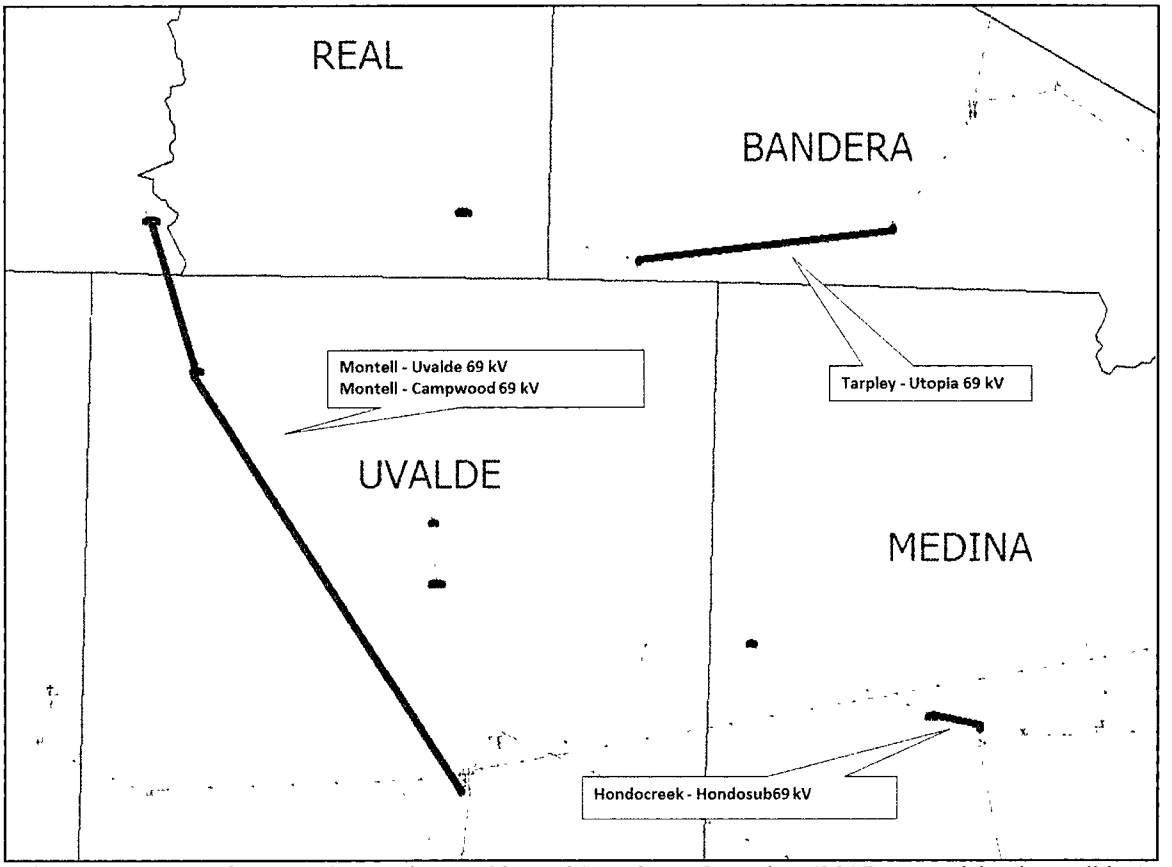


Figure 3.8 Map of system issues in Uvalde and Bandera Counties (2017 normal load condition)

9. Llano County Reliability Project

No additional load was modeled in the 2017 normal case for Llano County which is located at the far eastern edge of the study area. The study result indicates the overload of the Ferguson-Sandy Creek 138 kV line under various contingency conditions. The worst critical contingency causing the line overload is the loss of the Ferguson-Horseshoe Bay and Ferguson-Gillespie 138 kV lines.

To address the system issue identified in Figure 3.9, the following potential project needs to be done:

#1 Upgrade Ferguson-Sandy Creek 138 kV line (9 miles, Minimum emergency rating assumed: 326 MVA)

The upgrade is needed in order to meet the reliability criteria in the 2015 case.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

453

Table 3.9 Thermal overload issues in Llano County

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
Ferguson - Sandy Creek Switchyard 138 kV	Ferguson - Gillespie & Ferguson - Horseshoe Bay 138 kV	108 97	107 67

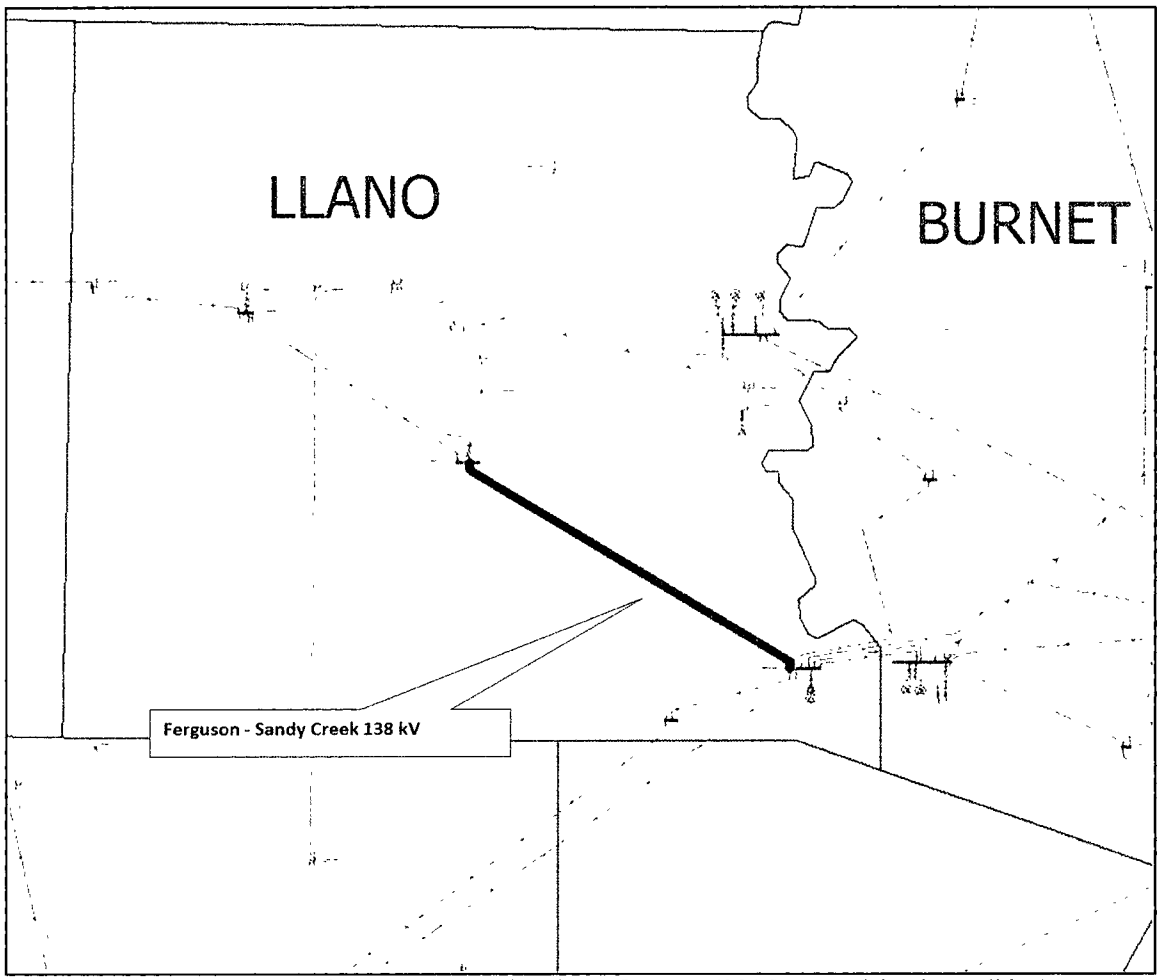


Figure 3.9 Map of system issues in Llano County (2017 normal load condition)

10. Coke County Reliability Project

Much of the load in Coke and Sterling Counties is being served by the 138/69 kV transformer at Cedar Hill through the long 69 kV lines running toward Sterling and Runnels Counties. Compared to the 2017 case built for the 2012 Five-Year Transmission Plan, roughly 42 MW of additional load is modeled for the area in the 2017 normal load case.

The study result of the 2017 normal load case indicates the overload of the Cedar Hill 138/69 kV transformer under system intact and contingency conditions, and a low voltage issue at the Cedar Hill 138 kV bus for the loss of the Cedar Hill-Oak Creek 138 kV line.

To address the thermal and voltage issues identified in Figure 3.10, the following potential projects need to be done:

#1 Upgrade Cedar Hill 138/69 kV transformer (Minimum emergency rating assumed: 143 MVA)
#2 Install 12 Mvar capacitor bank at Spade Ranch 69 kV bus
#3 Install 12 Mvar capacitor bank at Sterling City 69 kV bus
#4 Add 12 Mvar capacitor bank to the existing capacitor bank at Cedar Hill 69 kV substation

The projects are needed in order to meet the reliability criteria in the 2015 case.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.10 Thermal overload issues in Coke County

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
Cedar Hill 138/69 kV Xfmr	Base Case	N/A	107 8
Cedar Hill 138/69 kV Xfmr	Big Spring - Big Spring Gulf Tap 69 kV	104 53	112 73

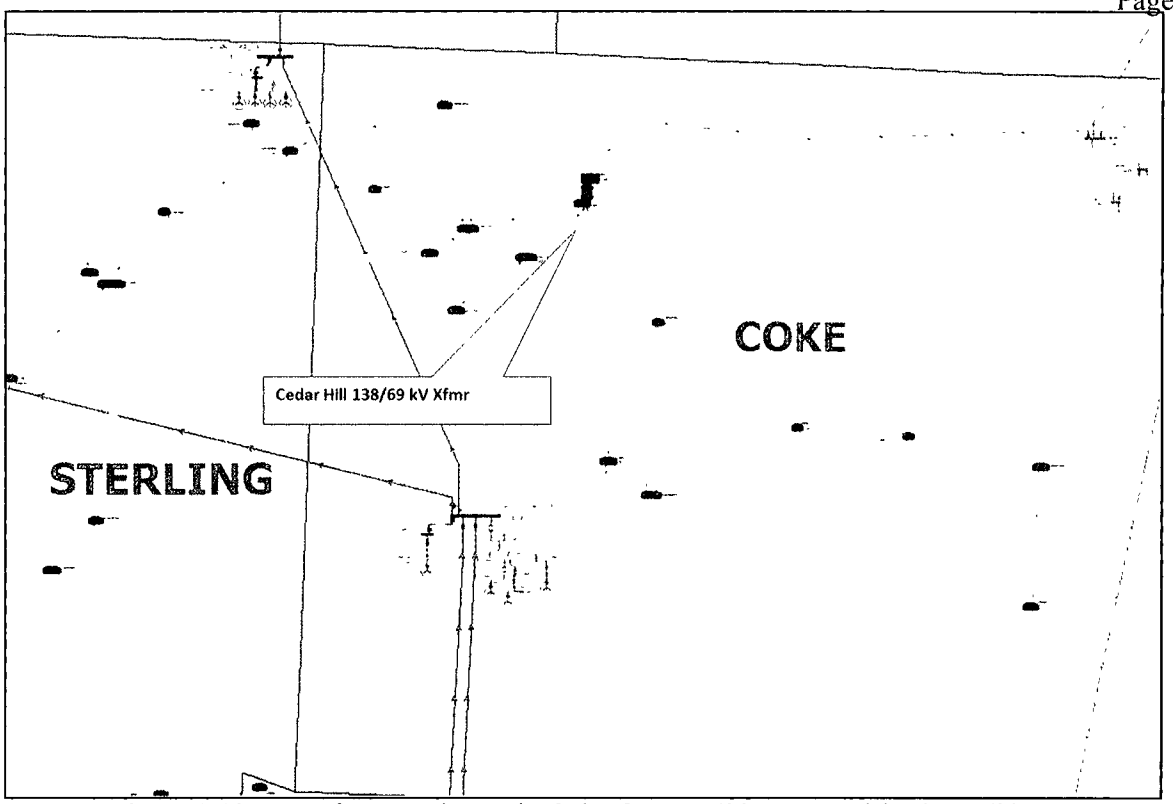


Figure 3.10 Map of system issues in Coke County (2017 normal load condition)

11. Taylor County Reliability Project

Approximately 111 MW of additional load is modeled for Taylor County in the 2017 normal load case compared to the 2017 case built for the 2012 Five-Year Transmission Plan. The area load is served by the 138/69 kV transformers located at Abilene South, Abilene East, Abilene North West and Abilene Elm Creek through the 69 kV lines in the region. The study result of the 2017 normal load case indicates the overload of the Abilene South-Abilene West Texas Gulf 69 kV line under various contingency conditions. The worst contingency causing the overload is the loss of the Abilene East-Abilene Plant 69 kV line.

To address the thermal issue identified in Figure 3.11, the following project needs to be done:

#1 Upgrade Abilene South-Abilene West Texas Gulf 69 kV line (2.2 miles, Minimum emergency rating assumed: 109 MVA)

The project is needed in order to meet the reliability criteria in the 2015 case.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.11 Thermal overload issues in Taylor County

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
Abilene South - Abilene West Texas Gulf Tap 69 kV	Abilene East - Abilene Plant 69 kV	102 67	112 36

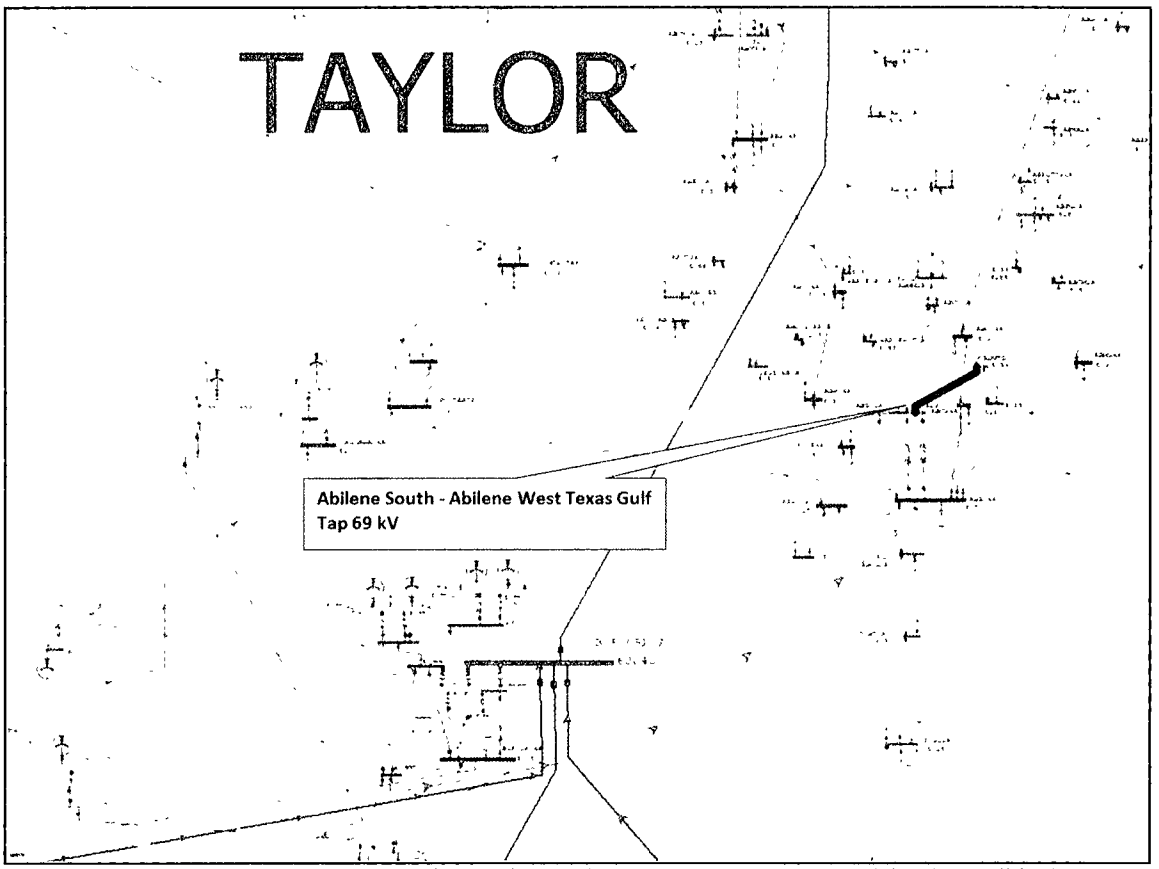


Figure 3.11 Map of system issues in Taylor County (2017 normal load condition)

12. G-1+N-1 Reliability Project for Borden, Howard and Mitchell Counties

With the entire set of preferred projects identified in Section 3.1 through 3.11 modeled in the base cases, a reliability analysis was performed under the prior outage of generation.

The study result indicates that the Barber Lake-China Grove 138 kV lines and the Morgan Creek-Cosden 138 kV line are overloaded if certain contingencies occur when a combined cycle unit (498 MW) at Odessa is out of service. The following potential projects need to be done to resolve the thermal issues identified in Figure 3.12:

#1 Expand the existing Vealmoor 138 kV substation to accommodate 345/138 kV facilities

#2 Install a new 345/138 kV transformer at Vealmoor (Minimum emergency rating assumed: 450 MVA)
#3 Connect 345 kV line from Vealmoor to Long Draw (18 miles, Minimum emergency rating assumed: 1084 MVA), which requires voltage conversion of an existing 230 kV line to 345 kV.
#4 Connect Vealmoor to West Stanton (Sharyland Northern Loop Project)
   a. Vealmoor-Koch Tap (8.37 miles, Minimum emergency rating assumed: 176 MVA)
   b. Koch Tap-Koch (2 miles, Minimum emergency rating assumed: 271 MVA)
   c. Koch Tap-Brown (5.73 miles, Minimum emergency rating assumed: 176 MVA)
   d. Brown-Grady (20.18 miles, Minimum emergency rating assumed: 271 MVA)
   e. Grady- West Stanton (14.27 miles, Minimum emergency rating assumed: 176 MVA)

The projects are needed in order to meet the reliability criteria in the 2017 case.

Part of the projects involves connecting Vealmoor to Long Draw (~18 miles). Similar to the 230 kV line discussed in Section 3.1, the transmission line is already in place and connected to the SPP system. The line needs conversion from 230 kV to 345 kV operation and to be switched from the SPP system to the ERCOT system. The existing 230 kV line was originally constructed for up to 345 kV operation. Thus, relatively minimal effort is expected for the voltage conversion. This line is also part of the acquisition plan between Sharyland Utilities and Xcel SPS, which is subject to regulatory approval by the PUCT. If the Xcel SPS line is not acquired and integrated into ERCOT, other transmission upgrade alternatives will need to be evaluated.

To address the transmission system issues, part of the project also connects West Stanton to Vealmoor at 138 kV. This 138 kV line connection is one of the options in the report submitted by Sharyland Utilities to RPG to resolve their distribution system issues:

- The existing distribution system in the area does not provide a reliable service at the Grady, Koch and Brown substations which have experienced significant load growth due to the oil and gas business development.
- An extended power outage of the Vealmoor and Fairview stations is likely to occur if there is a fault on the 30-mile circuit supported by aging wood poles between Vealmoor and Salem.

The facilities connecting West Stanton to Vealmoor are already in place and currently owned by Sharyland Utilities. Upon the PUCT's approval of the Docket #41430, the facilities will be transferred to ERCOT from SPP. The West Stanton to Vealmoor project was submitted for RPG review and comments in June 2013. Upon completion of the RPG review, the project was classified as a Tier 4 project.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.12 Thermal overload issues (G-1-N-1, Borden, Howard and Mitchell Counties)

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
Barber Lake- China Grove 138 kV	Willow Valley - Faraday 345 kV	NA	110.80
China Grove - China Grove 138 kV	Willow Valley - Faraday 345 kV	NA	110.74
Morgan Creek - Cosden 138 kV	DCKT Odessa EHV - Quail Switch & Long Shore Switch 345 kV	NA	100.88

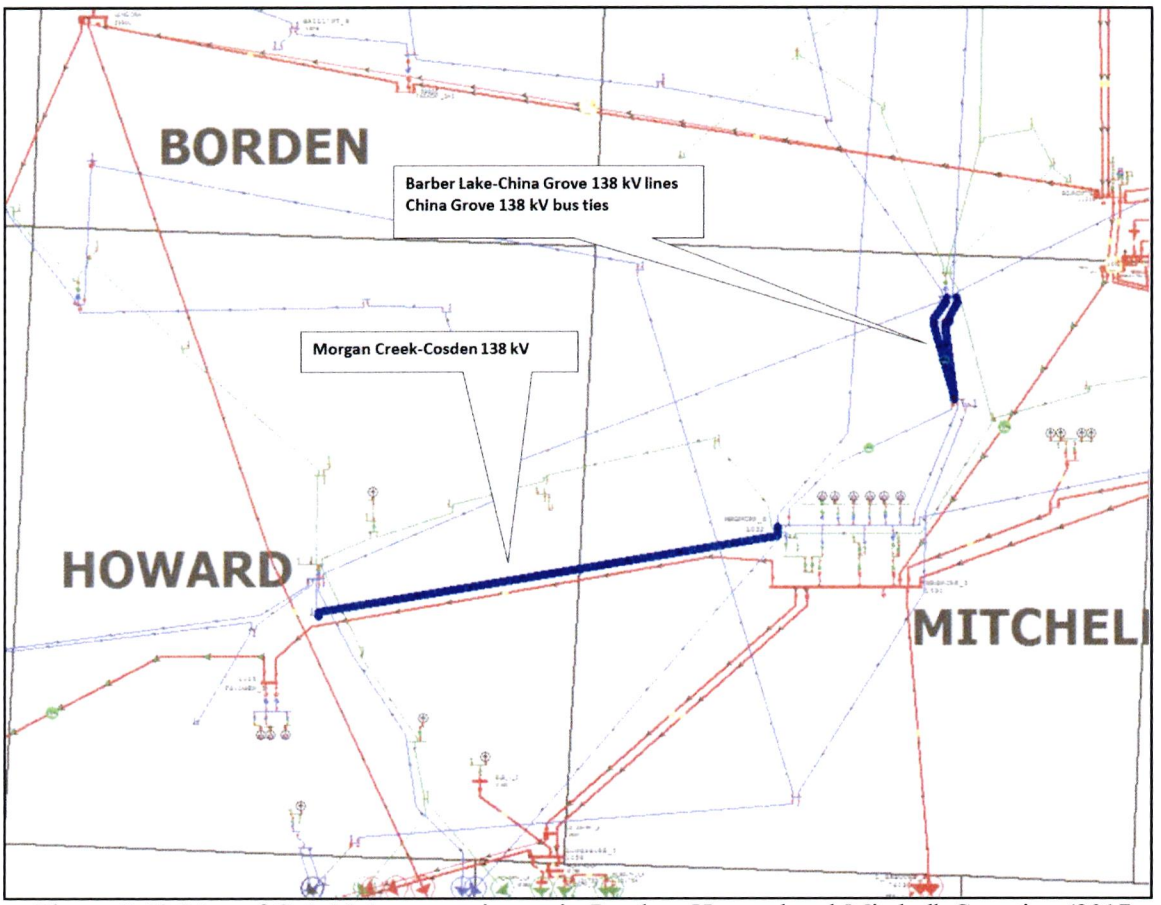


Figure 3.12 Map of G-1+N-1 system issues in Borden, Howard and Mitchell Counties (2017 normal load condition)

13. G-1+N-1 Reliability Project for Reagan, Upton, Irion and Tom Green Counties

The G-1+N-1 study result indicates the overload of the Big Lake-Twin Buttes 138 kV line and the San Angelo Concho-San Angelo Mathis 69 kV line for the loss of certain transmission line

under the prior outage of either the combined cycle units (498 MW) at Odessa or the combined cycle units (250 MW) at Quail.

To address the thermal issues identified in Figure 3.13, the following projects need to be done:

#1 Construct a new 345/138 kV substation at the junction where the Bakers Field-Big Hill 345 kV line (CREZ line) and the Ringtail-Big Lake 138 kV line cross (50% of the Bakers Field-Big Hill 345 kV line, 5 miles north of Ringtail 138 kV bus in 2017 case)

#2 Loop the Bakers Field-Big Hill 345 kV line into the new substation

#3 Loop the Big Lake-Ringtail 138 kV line into the new substation

#4 Install a new 345/138 kV transformer at the new substation (Minimum emergency rating assumed: 500 MVA)

#5 Upgrade the existing 138 kV line from Ringtail to the new substation (~5 miles, Minimum emergency rating assumed: 326 MVA)

The projects are needed in order to meet the reliability criteria in the 2017 case.

The 345 kV source injected to the region improves the voltage of the 138 kV and 69 kV buses such as Big Lake, Ringtail, Yucca and Barnhart Phillips Tap. It also relieves the heavy flow on the 138 and 69 kV lines such as the North McCamey-Big Lake -Twin Buttes 138 kV lines.

The overload issues and the worst contingencies are listed in the table below. More details of the system problems can be found in Appendix A and B.

Table 3.13 Thermal overload issues (G-1-N-1, in Reagan, Upton, Irion and Tom Green Counties)

Overloaded Element	Worst Contingency	Percent Overload	
		2015	2017
San Angelo Concho - San Mathis Field 138 kV	Big Lake - Tempbltb4a 138 kV	NA	103 57
Big Lake - Tempbltb4a 138 kV	Temprank4A - North McCamey 138 kV	NA	102 06
Twin Buttes - Tempbltb4a 138 kV	Temprank4A - North McCamey 138 kV	NA	102 06

460

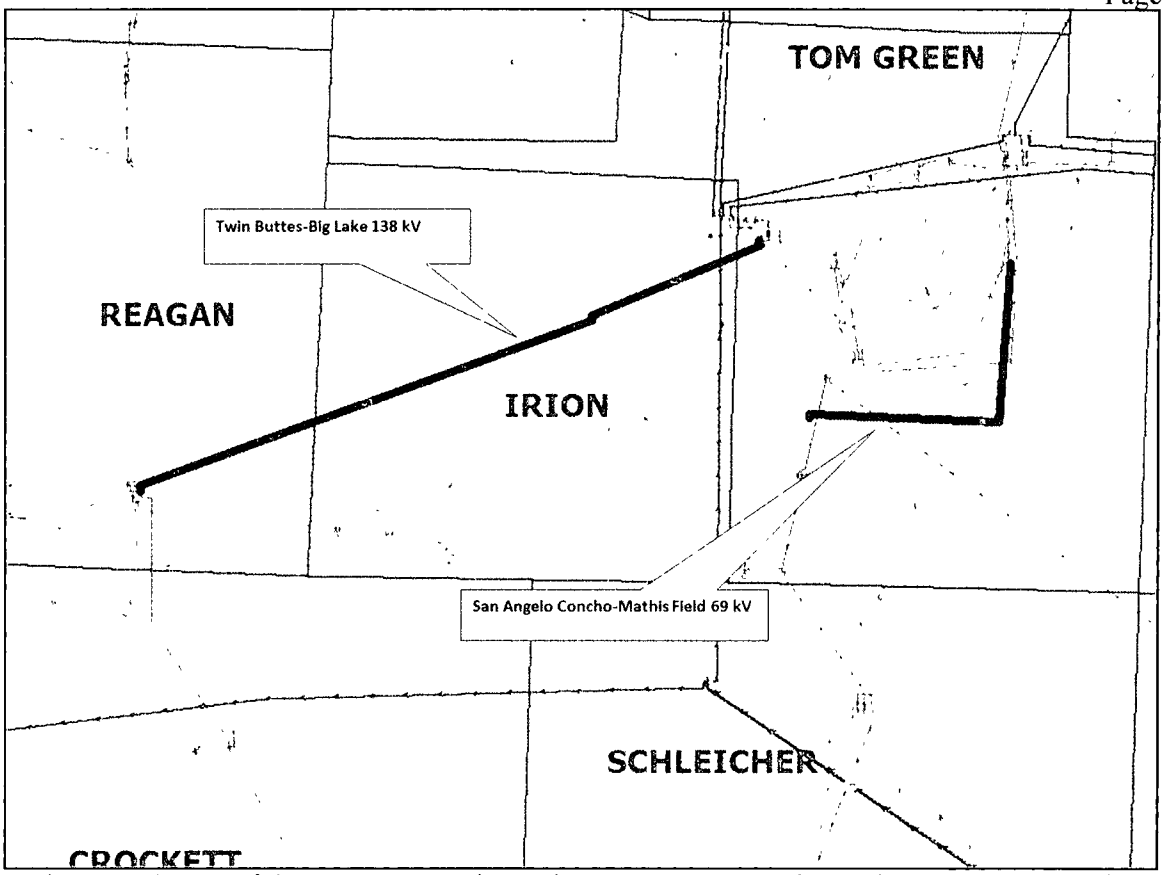


Figure 3.13 Map of G-1+N-1 system issues in Reagan, Upton, Irion and Tom Green Counties (2017 normal load condition)

IV. Sensitivity Analysis of 2017 High Load Condition

As part of the West Texas Sensitivity Study, ERCOT also conducted a sensitivity analysis of the 2017 West Texas high load case. The main purposes of testing the high load condition are to:

- Check the strength of the preferred projects identified for the system issues in the 2017 West Texas Sensitivity Study normal load case.
- Determine if any significant modification needs to be made to the preferred projects of the 2017 West Texas Sensitivity Study normal load case

The 2017 high load base case was built based on the high load forecast of the year 2017 provided by each load serving entity. As shown in Table 4.1, significant amount (486 MW) of additional load is modeled in the 2017 high load case compared to the 2017 normal load case. In addition to the additional load, all the potential projects in Section III (Reliability Project of 2017 normal load case) were modeled to build the 2017 high load base case.

Table 4.1 Comparison of the total MW load of the study area

Total MW Load of each Weather zone in Study Area	2017 (Normal Load)	2017 (High Load)
WEST	2585	2696
FAR WEST	3569	3944
TOTAL	6154	6640

As a result of the sensitivity analysis using the 2017 high load case, it is concluded that the system issues of the high load case would not cause any significant impact on the potential projects found for the system issues of the 2017 normal load case. The study result indicates that the system issues of the 2017 high load case occur in local areas, and can be addressed by incremental transmission reinforcement on top of the potential projects of the 2017 normal load case. The incremental reinforcement may include upgrading the existing lines, upgrading the existing transformers, installing capacitor banks and constructing a new 138 kV line. Potential options addressing the system issues of the high load condition are not discussed in this report based on the study purpose.

Divided by three geographical regions of the study area, the system issues of the 2017 high load base case are summarized in the following sections. More details of the system issues can be found in Appendix C.

1. System Issue in Northwest Region of Study Area

Figure 4.1 illustrates the system issue in the northwest region of the study area. Due to additional load modeled in the 2017 high load case, the system in the area is depressed, particularly the 69 kV transmission system owned by Oncor and 138 kV transmission system owned by Sharyland Utilities in the Midland, Glasscock, Upton and Reagan Counties area. The key issues in the area are the overloads of

- Skywest-Driver Tap1-Driver- Driver Tap2-Midkiff 138 kV lines
- Pembrook-Stiles and St. Lawrence-E. Stiles 138 kV lines
- Spraberry-Peck Tap 69 kV line
- Glasscock-Reagan Shell-Pembrook-Midkiff 69 kV line
- Garden City-Tex Harvey 69 kV line

The worst contingency causing the overload of the 138 kV lines is the loss of the 138 kV line(s) out of the Einstein 345/138 kV substation. The 69 kV lines are susceptible to overload under various contingency conditions such as the loss of the Midkiff 138/69 kV transformer and the loss of the 69 kV line out of Spraberry.

Other overload issues found in this region are

- Odessa EHV 345/138 transformer #2 and Odessa EHV- Liquid Air-Odessa 138 kV line

- Wink-Vest-Midway 69 kV line
- Sandridge-Odessa Basin 69 kV line
- Permian-Wink and Permian-Ward Gulf Tap 138 kV lines

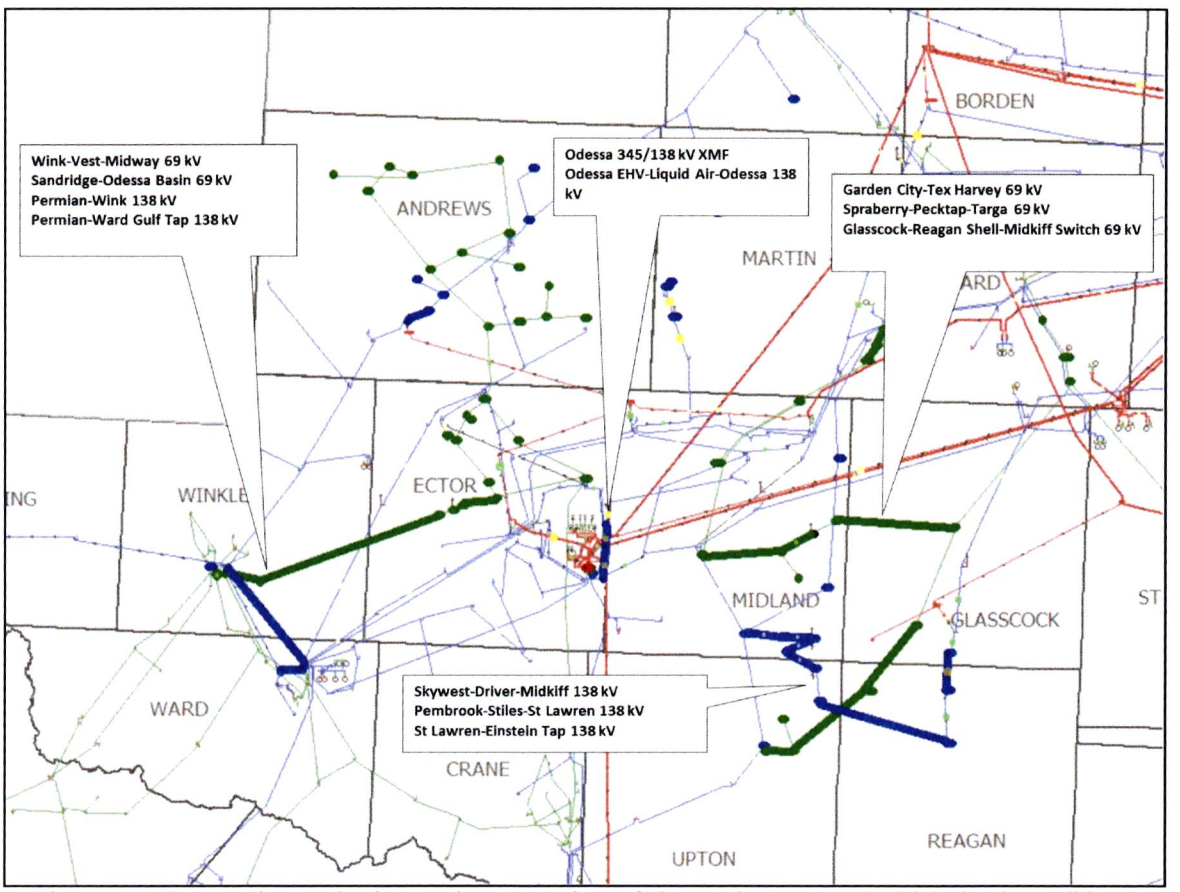


Figure 4.1 System issues in the northwest region of the study area (2017 high load condition)

2. System Issue in South Region of Study Area

As shown in Figure 4.2, relatively few system issues were found in the southern region of the study area under contingency conditions. The portion of the Big Lake-Ringtail 138 kV line is overloaded under various contingency conditions such as the loss of the Bakers Field-North McCamey 345 kV line. The Big Lake-Barnhart 69 kV line is slightly overloaded for the loss of the Yucca-Ringtail 138 kV line. There are no other major issues in the region.

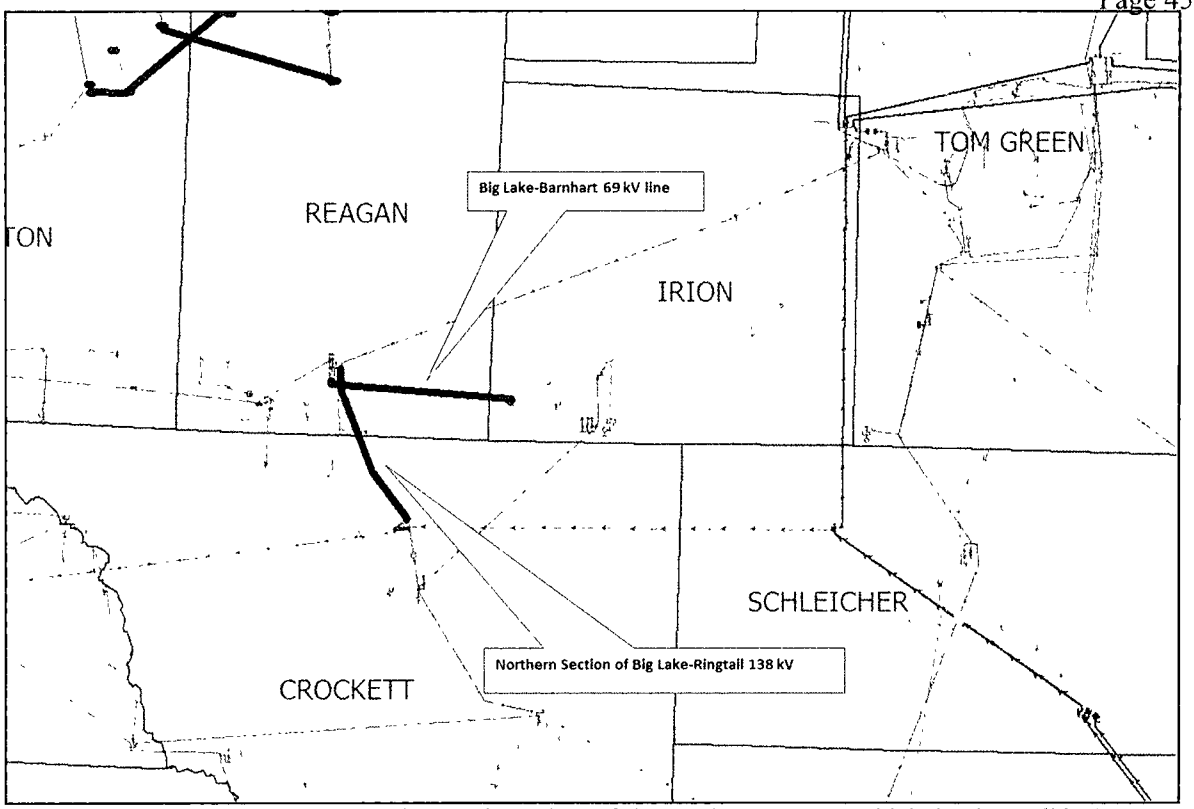


Figure 4.2 System issues in the south region of the study area (2017 high load condition)

3. System Issue in Northeast Region of Study Area

As shown in Figure 4.3, several local transmission system issues were found in the northeast region of the study area. The local issues are the overloads of

- Ennis Creek 138/69 kV transformer
- Morgan Creek 345/138 kV transformer #2
- Barber Lake-China Grove 138 kV lines
- Abilene NW-Ely Rea Tap 69 kV line

Among them, the Ennis Creek 138/69 kV transformer at the northeast of Scurry County is overloaded under system intact condition. The Morgan Creek 345/138 kV transformer #2 is overloaded for the loss of the Morgan Creek 345/138 kV transformer #1. The 138 kV line from Barber Lake to China Grove is also overloaded for the loss of one of the two 138 kV lines. The Abilene N.W.-Ely Rea Tap 69 kV line in Taylor County is overload for the loss of the Eskota 138/69 kV transformer in Nolan County.

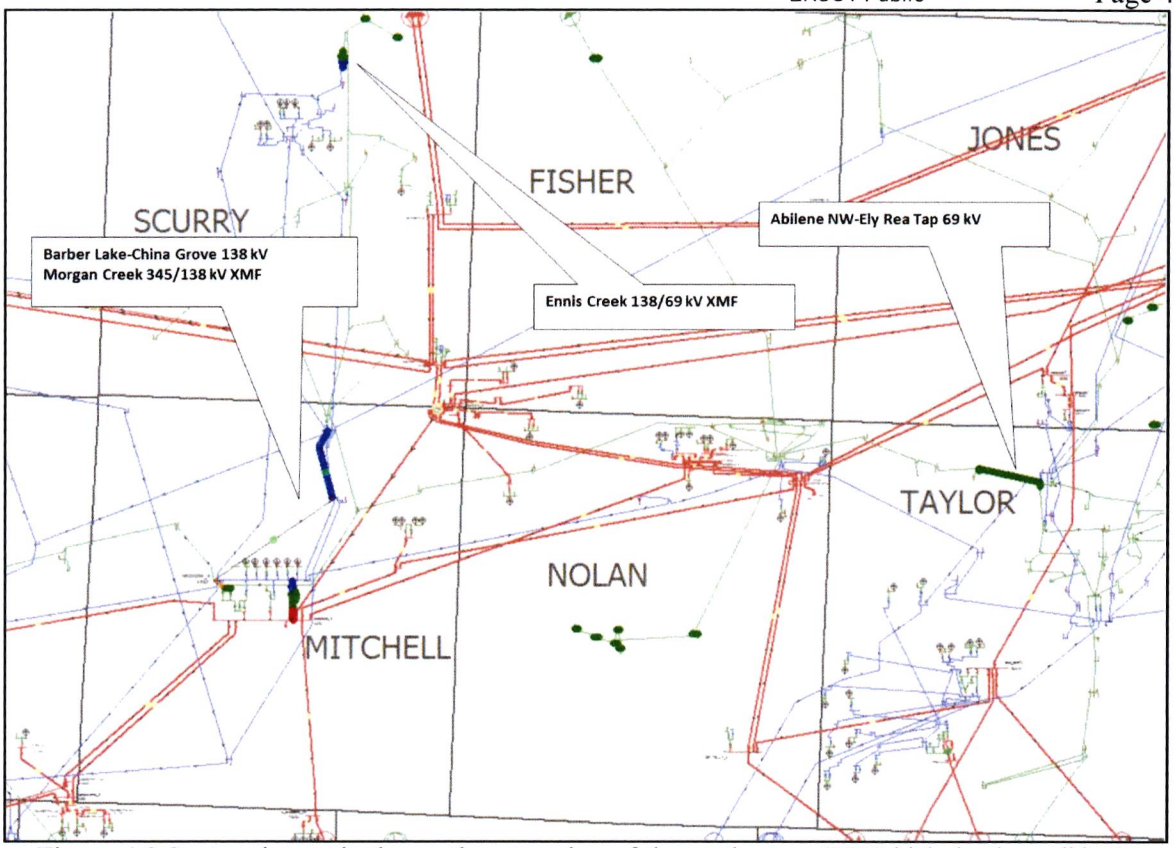


Figure 4.3 System issues in the northeast region of the study area (2017 high load condition)

V. Sensitivity Analysis of A-1+N-1 Condition

A high-level contingency analysis was performed under a prior outage of the new 345/138 kV transformer identified as the potential project. The main purpose of the study is to check if a need of any significant modification to the potential project exists due to the system issues under contingency following the outage of a 345/138 kV transformer.

The result of the A-1+N-1 analysis showed no significant system issues that require modification of the potential projects identified for the 2017 normal load case. It is found that the system issues due to A-1+N-1 can be addressed by either installing a second 345/138 kV transformer or bringing an additional 345 kV source from a different direction. A detailed A-1+N-1 analysis will be deferred until ERCOT performs a system wide analysis as part of the 2014 Regional Transmission Plan.

VI. Economic Project

For years 2015 and 2017 an economic analysis was conducted by performing production cost simulation. Where congestion was identified, projects were tested by comparing the simulation results for models with and without the projects. If the project met the economic planning criteria per ERCOT Protocol Section 3.11.2 (5), Planning Criteria it was recommended. If the production cost savings equals or exceeds the annual revenue requirement for the project, the project is economic from a societal perspective and will be recommended. In this study, it is assumed that the first year annual revenue requirement for the transmission project is approximately one sixth (1/6) of the total transmission project cost. Oftentimes the cost to implement a transmission project outweighs the cost of the congestion it is designed to solve. If a project did not meet the economic planning criteria the projected congestion will remain on the system.

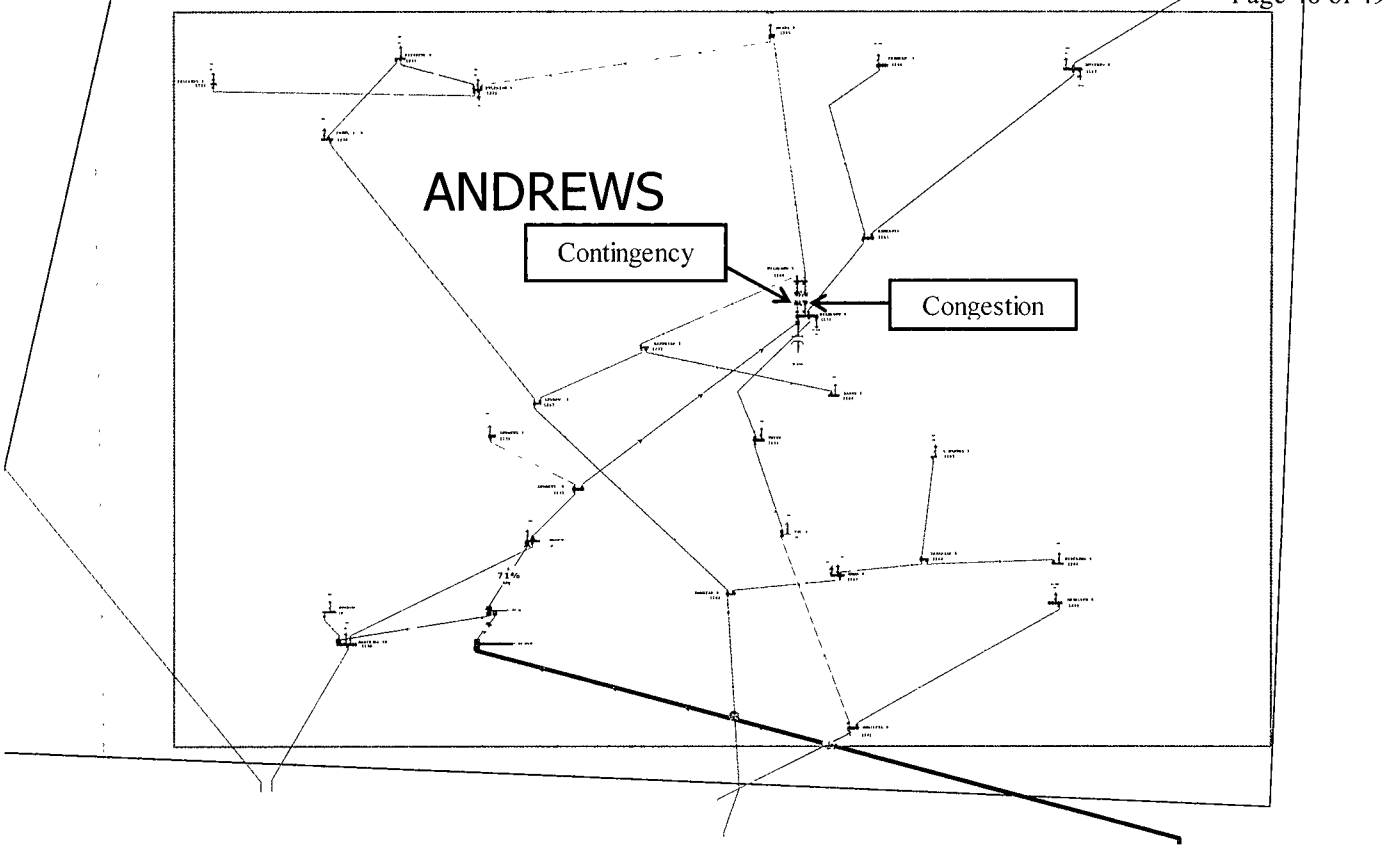
1. Andrews North 138/69 kV transformer upgrade

Currently the emergency ratings of the two Andrews North 138/69 kV transformers were 41 MVA and 84 MVA respectively. The Andrews North 138/69 kV transformer #1 with 41 MVA was congested 5.15% of the hours in 2017 under the contingency loss of the Andrews North 138/69 kV transformer #2. The congested element is marked on the map below.

To relieve the congestion, the Andrews North 138/69 kV transformer #1 was upgraded to a new emergency rating of 84 MVA. The estimated capital cost to upgrade this transformer is estimated to cost $5 million. The result of the annual production cost saving including the upgrade for 2017 is shown in the table below.

Year	Annual Production Cost Saving ($M)	Capital Cost / Saving
2017	12	< 1

The simulation result showed that upgrading the Andrews North 138/69 kV transformer 1 would reduce the annual production cost in 2017. Since the annual production cost saving in 2017 exceeded the corresponding project capital cost, the upgrade was recommended to be in service by 2017. There currently is a project in TPIT to replace this transformer in 2015.



VII. Appendices

Appendix A: AC Contingency Result of 2015 Normal Load Case	 WT 2015 Normal Load Base Case - Cor
Appendix B: AC Contingency Result of 2017 Normal Load Case	 WT 2017 Normal Load Base Case - Cor
Appendix C: AC Contingency Result of 2017 High Load Case with All Normal Load Projects in Service	 WT 2017 High Load Base Case with all No
Appendix D: Project Log (Projects and System Issues)	 West Texas Study_NL_Projects Lc
Appendix E: Transmission Model Updates	 WT Topology Updates.xlsx

DOCKET NO. 45414

REVIEW OF THE RATES OF SHARYLAND UTILITIES, L.P.	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

DIRECT TESTIMONY

AND EXHIBITS

OF

ELLEN S. BLUMENTHAL

ON BEHALF OF

SHARYLAND UTILITIES, L.P.

April 29, 2016

DOCKET NO. 45414

REVIEW OF THE RATES OF SHARYLAND UTILITIES, L.P.	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

TABLE OF CONTENTS

EXHIBITS

Q. ARE THE MONTHLY PREPAYMENT BALANCES SHOWN ON SCHEDULE II-B-10 THE AMOUNTS RECORDED ON THE COMPANY'S BOOKS AND RECORDS DURING THE TEST YEAR?

A. Yes. The 13 monthly balances are shown on this schedule. The amount included in rate base is the average of the thirteen monthly balances ending with December 31, 2015.

5. *Plant Acquisition Adjustment*

Q. IS SHARYLAND SEEKING TO INCLUDE A $28,970,159 PLANT ACQUISITION ADJUSTMENT IN RATE BASE?

A. Yes.

Q. WHAT IS THE BASIS FOR THE $28,970,159 PLANT ACQUISITION ADJUSTMENT?

A. Early in 2014, Sharyland acquired certain transmission facilities from Southwestern Public Service Company ("SPS"). Sharyland paid $37,117,614 for the assets, which had a net book value of $7,781,230. The $29,336,384 difference between the purchase price and the net book value was recorded in FERC account 114, Electric Plant Acquisition Adjustments. Accumulated amortization of $336,225 has been recorded resulting in $28,970,159 net balance included in rate base as shown on Schedule II-B.

Q. PLEASE DESCRIBE THE ACQUIRED FACILITIES.

A. As more fully described in the direct testimony of Mr. Meyer, the facilities include approximately 66 miles of two transmission lines (the Hobbs to Midland line and the Grassland to Borden line), two substations, and associated land rights and facilities. The need for the acquired facilities and the reasonableness of the acquisition as opposed to new construction is described by Sharyland witness Mr. Meyer.

Q. ARE THE ASSETS THAT SHARYLAND PURCHASED FROM SPS CURRENTLY USED AND USEFUL IN THE PROVISION OF TRANSMISSION SERVICE TO THE PUBLIC?

A. Yes. The two transmission lines and associated facilities were connected to the Sharyland system and put into service in 2015.

Q. WAS SHARYLAND'S $37.118 MILLION PURCHASE PRICE REASONABLE?

A. Yes. The $37.118 million purchase price was reasonable because, as explained in the direct testimony of Mr. Meyer, (1) the sale avoided burdening Electric Reliability Council of Texas ("ERCOT") ratepayers with approximately $135 million in costs associated with construction of new transmission facilities, and (2) the transaction provided reliability, congestion mitigation, and timing benefits.[3]

Q. HAS THE COMMISSION DETERMINED THE PURCHASE TO BE IN THE PUBLIC INTEREST?

A. Yes. In Docket No. 41430, the Commission found that the purchase was in the public interest and approved the transaction. In doing so, the Commission specifically stated in its final order:

> Taking into consideration the cost savings associated with the proposed transaction, the improvements to reliability and mitigation of congestion, and the timing benefits of utilizing existing transmission facilities rather than constructing new facilities, the purchase price of $37 million represents reasonable value for the facilities within the meaning of Public Utilities Regulatory Authority ("PURA") § 14.101(b)(1).[4]

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[3] *See Joint Report and Application of Sharyland Utilities, L.P., Sharyland Distribution & Transmission Services, L.L.C., and Southwestern Public Service Company for Approval of Purchase and Sale of Facilities, for Approval of Regulatory Accounting Treatment of Gain on Sale, and for Transfer of Certificate Rights*, Docket No. 41430, Order at 2, 9-13, 16-19 (Dec. 20, 2013).

[4] *Id.* at 19 (Conclusion of Law No. 8).

Q. WAS THE PURCHASE OF THE ASSETS FROM SPS THE LEAST COST ALTERNATIVE FOR SHARYLAND AND ITS RATEPAYERS?

A. Yes. In Docket No. 41430, Sharyland demonstrated that it would have had to construct the necessary transmission facilities if it had been unable to purchase the assets from SPS. By purchasing the SPS assets, Sharyland saved ratepayers approximately $135 million in avoided transmission costs.

Q. DOES THE FERC USOA CONTEMPLATE THAT A UTILITY MAY PURCHASE ASSETS FOR SOMETHING OTHER THAN NET BOOK VALUE?

A. Yes. The USoA requires utilities to record plant at its original cost. Account 114, Electric Plant Acquisition Adjustments, however, was included in the USoA to accommodate property purchased for an amount other than its net book value (original cost less accumulated depreciation). The creation of FERC account 114 supports the view that there can be valid reasons for a public utility to pay an unrelated party a fair and reasonable price that is an amount greater than net book value for an asset. Such is the case in Sharyland's purchase because the assets purchased from SPS enabled Sharyland to obtain necessary assets for much less than the cost of new construction.

Q. HAVE YOU INCLUDED THE COST OF THE PURCHASED ASSETS IN RATE BASE IN THIS CASE?

A. Yes. The net book value of the purchased assets is included in Sharyland's net plant in service in Schedule II-B. The acquisition adjustment is shown as such on Schedule II-B. The amortization of the acquisition adjustment is included in the revenue requirement as amortization expense (see Schedule II-E-1).

Q. OVER WHAT PERIOD OF TIME IS SHARYLAND PROPOSING TO AMORTIZE THE ACQUISITION ADJUSTMENT?

A. Sharyland is proposing to amortize the acquisition adjustment over the remaining useful life of the purchased assets. According to Mr. Watson's depreciation study, the remaining life results in an annual depreciation rate of 2.28 percent. Applying this rate to the approximately $29 million acquisition adjustment results

in annual amortization of $670,090. This calculation is shown on WP-II-E-1/7, and the amortization is included on Schedule II-E-1.

Q. IS THE ORIGINAL COST OF THE ASSETS THAT WERE PURCHASED FROM SPS INCLUDED IN NET PLANT IN SERVICE?

A. Yes. The original cost when the assets were first placed into service, net of the accumulated depreciation balance, at the end of the Test Year is included in net plant in service on Schedule II-B.

The acquisition adjustment is also included in rate base because (1) the Commission found in Docket No. 41430 that the purchase price of the plant was reasonable, and (2) the Commission found in Docket No. 41430 that ratepayers benefit from the purchase. The specific benefits to ratepayers more than offset the difference between the purchase price and the net book value of the assets purchased. As discussed previously, the savings to ratepayers from purchasing the existing assets rather than building new infrastructure was quantified as approximately $135 million.[5]

6. *Accumulated Deferred Federal Income Taxes ("ADFIT")*

Q. PLEASE DESCRIBE THE LEVEL OF ADFIT REFLECTED IN THE COMPANY'S DETERMINATION OF INVESTED CAPITAL.

A. ADFIT is included in rate base pursuant to 16 TAC § 25.231(c)(2)(C)(i). ADFIT represents a source of cost-free capital that largely arises from differences between book depreciation and tax depreciation. I discuss tax normalization later in this testimony.

Q. WHERE IN THE RATE FILING PACKAGE IS THE DETAIL OF THE ADFIT BALANCE THAT IS INCLUDED IN RATE BASE?

A. Schedule II-E-3.5 details the ADFIT balance that is included in rate base for the Test Year.

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[5] Docket No. 41430, Order at 12, 16-17 (Finding of Fact Nos. 65 & 85) (Dec. 20, 2013).

SOAH DOCKET NO. 473-16-4051
PUC DOCKET NO. 45414

REVIEW OF THE RATES OF	§	**BEFORE THE STATE OFFICE**
SHARYLAND UTILITIES, L.P.,	§	
ESTABLISHMENT OF RATES FOR	§	
SHARYLAND DISTRIBUTION &	§	
TRANSMISSION SERVICES, L.L.C.,	§	**OF**
AND REQUEST FOR GRANT OF A	§	
CERTIFICATE OF CONVENIENCE	§	
AND NECESSITY AND TRANSFER OF	§	
CERTIFICATE RIGHTS	§	**ADMINISTRATIVE HEARINGS**

REBUTTAL TESTIMONY

AND EXHIBITS

OF

RALPH G. GOODLET, JR.

ON BEHALF OF

SHARYLAND UTILITIES, L.P.

AND

SHARYLAND DISTRIBUTION & TRANSMISSION SERVICES, L.L.C.

REVENUE REQUIREMENT

March 16, 2017

SOAH DOCKET NO. 473-16-4051
PUC DOCKET NO. 45414

REVIEW OF THE RATES OF	§	**BEFORE THE STATE OFFICE**
SHARYLAND UTILITIES, L.P.,	§	
ESTABLISHMENT OF RATES FOR	§	
SHARYLAND DISTRIBUTION &	§	
TRANSMISSION SERVICES, L.L.C.,	§	**OF**
AND REQUEST FOR GRANT OF A	§	
CERTIFICATE OF CONVENIENCE	§	
AND NECESSITY AND TRANSFER OF	§	
CERTIFICATE RIGHTS	§	**ADMINISTRATIVE HEARINGS**

TABLE OF CONTENTS

PAGE

EXHIBITS

REBUTTAL TESTIMONY AND EXHIBITS OF RALPH G. GOODLET, JR.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ralph G. Goodlet, Jr. My business address is 1900 N. Akard Street, Dallas, Texas 75201.

Q. ARE YOU THE SAME RALPH GOODLET WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I provided direct testimony on behalf of Sharyland Utilities, L.P. ("Sharyland") and Sharyland Distribution & Transmission Services, L.L.C. ("SDTS") (collectively "Applicants").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to testimony filed by intervenors and Commission Staff on February 28 and March 7 respectively. In particular, I will address testimony relating to the acquisition adjustment associated with the purchase of the Hobbs-to-Midland and Grassland-to-Borden transmission lines from Southwestern Public Service Company ("SPS"); the deferred costs recorded on SDTS' books associated with Sharyland's initial development of the electrical infrastructure in Sharyland's McAllen division; transmission development; and TTCC2 costs.

II. ACQUISITION ADJUSTMENT

Q. ARE YOU THE ONLY WITNESS ADDRESSING THE ACQUISITION ADJUSTMENT ISSUE?

A. No. I will discuss the regulatory issues related to the acquisition adjustment associated with the purchase of the SPS lines raised by Ms. Dively on behalf of the Office of Public Utility Counsel ("OPUC") in her direct testimony. Mr. William O. Bojorquez will provide an update on the benefits realized by the acquisition of the lines in his rebuttal testimony.

Q. PLEASE BRIEFLY DESCRIBE THE BACKGROUND FOR APPLICANTS' REQUEST TO RECOVER THE ACQUISITION ADJUSTMENT.

A. The requested acquisition adjustment relates to SDTS's purchase in December 2013 of two 33-mile segments of SPS's Hobbs-to-Midland and Grassland-to-Borden lines, two substations, and associated land rights and facilities in West Texas in December 2013. The acquisition was approved by the Commission in Docket No. 41430.[1] Prior to the acquisition, the lines were connected to the Southwest Power Pool ("SPP"). The reason for the acquisition was to allow SDTS and Sharyland to avoid constructing new transmission facilities to effectuate the move of Sharyland's then Stanton and Colorado City divisions (now combined into a single division known as the Stanton division) from SPP to ERCOT as required by the Commission's Order in Docket No. 37990.[2] The estimated cost of building new transmission facilities to accomplish the move was $59.5 million, including construction of a new transmission line paralleling SDTS's Borden-to-Midland transmission line, which SPS had the right to require remain in SPP.

Q. WHY WOULD IT HAVE BEEN NECESSARY TO BUILD $59.5 MILLION OF NEW TRANSMISSION FACILITIES TO PARALLEL THE BORDEN-TO-MIDLAND LINE IF THE ACQUISITION WERE NOT APPROVED?

A. The Borden-to-Midland line served as the northern portion of the Sharyland Loop that served Sharyland's Stanton and Colorado City divisions pursuant to an order of the Commission approved in the 1990s that allowed Cap Rock Electric Cooperative ("Cap Rock") to interconnect to SPP. When SDTS and Sharyland acquired Cap Rock, the settlement approved by the Commission in Docket No.

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[1] *Joint Report and Application of Sharyland Utilities, L.P., Sharyland Distribution & Transmission Services, L.L.C., and Southwestern Public Service Company for Approval of Purchase and Sale of Facilities, for Approval of Regulatory Accounting Treatment of Gain on Sale, and for Transfer of Certificate Rights*, Docket No. 41430, Order (Dec. 20, 2013).

[2] *Joint Report and Application of Sharyland Utilities, L.P., Sharyland Distribution & Transmission Services, L.L.C., Hunt Transmission Services, L.L.C., Cap Rock Energy Corporation, and NewCorp Resources Electric Cooperative, Inc. for Regulatory Approvals Pursuant to PURA §14.01, 37.154, 39.262, and § 39 915,* Docket No. 37990, Finding of Fact No. 16(b)(ii) (Jul. 8, 2010).

37990 gave SPS the right to require that the Borden-to-Midland line remain in SPP if the Stanton and Colorado City divisions were moved to ERCOT in order to provide a connection between SPS's Hobbs-to Midland and Grassland-to-Borden lines. Subsequently, in Docket No. 39070, the Commission approved a settlement that required Sharyland to move the Stanton and Colorado City divisions to ERCOT by the end of 2013.[3] Because SPS exercised its right to require the Borden-to-Midland line remain in SPP, Sharyland would not be able to move that line to ERCOT when it implemented the planned transfer of the Stanton and Colorado City divisions to ERCOT and would have had to construct new transmission facilities to serve its customers at a cost of $59.5 million.[4] As a part of the transaction that was approved in Docket No. 41430 allowing SDTS to purchase the Hobbs-to-Midland and Grassland-to-Borden lines, SPS agreed to relinquish its right to require that the Borden-to-Midland line remain in SPP. As the Commission found in Docket No. 41430, that allowed Sharyland to interconnect the line to ERCOT with the remainder of its system and avoid constructing the new transmission.[5]

Q. IN ADDITION TO THE $59.5 MILLION IN SAVINGS ASSOCIATED WITH MOVING THE BORDEN-TO-MIDLAND LINE TO ERCOT, DID THE COMMISSION FIND ADDITIONAL BENEFITS TO THE PROPOSED ACQUISITION IN DOCKET NO. 41430?

A. Yes. In addition to the benefits of moving the Borden-to-Midland line to ERCOT, ERCOT concluded that acquisition by SDTS of the Hobbs-to-Midland and Borden-to-Grassland lines and interconnecting them to ERCOT would result in further savings of approximately $75 million to ERCOT ratepayers.[6] Thus, total estimated savings to ratepayers were approximately $135 million – well above the purchase price of $37 million, as found by the Commission in its Order

[3] *Application of Sharyland Utilities, L.P. to Approve Study and Plan Pursuant to the Commission's Order in Docket No. 37990 Concerning the Movement of Sharyland's Stanton and Colorado City Divisions From the Southwest Power Pool to ERCOT*, Docket No. 39070, Order (Jul. 11, 2011).

[4] Docket No. 41430, Finding of Fact No. 47.

[5] *Id.* at Finding of Fact No. 42.

[6] *Id.* at Finding of Fact No. 50.