ERCOT Regional Planning:

Documented Results of 2007 Five-Year Plan

Version 1.3

Document Revisions

Date	Version	Description	Author(s)
1/29/2008	1.0	First draft	Harry Liu, Jeff Billo, Brad Schwarz, Jay Teixeira
2/13/2008	1.1	Reviewed and accepted most comments from Transmission Owners	Harry Liu, Jeff Billo, Brad Schwarz, Jay Teixeira
2/19/2008	1.2	Added text • describing Voltage Stability Study and how the results were modeled in UPLAN • Added wind curtailment impact section • Section on NERC standard satisfaction	Jay Teixeira, John Schmall, Harry Liu
4/2/2008	1.3	Reviewed and resolved comments received from RPG on version 1.2.	Jay Teixeira

Sign-Offs

Title

Name ____ Date ______________________________________

Title

Name ____ Date ______________________________________

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I. Executive Summary

The 2007 Five-Year Plan is the result of a coordinated planning process, performed by ERCOT staff with extensive review and input from Transmission Service Providers (TSPs) and other stakeholders, which addresses region-wide reliability and economic transmission needs for 2008 through 2012.

Planned improvements identified for the first time in the 2007 Five-Year Plan include a new 345-kV transmission line in the East weather zone to exit an existing SPS, a new 345-kV switching station in northwest Houston to address a reliability need, and additional autotransformer and 138-kV line upgrades in the Dallas-Fort Worth metropolitan area. In addition, two new 345-kV transmission lines and a new 345-kV switching station were included in the West region due to the approximately 6500 MW of wind generation that is installed or has completed an interconnection agreement in the West zone. However, these West zone upgrades may be superseded by the system improvements that will be ordered as a result of the Competitive Renewable Energy Zone (CREZ) process underway at the Public Utility Commission of Texas. Further, anticipated CREZ-related wind generation additions throughout five CREZ zones will necessitate the further study of projects for the West zone above and beyond what is provided in this report. ERCOT anticipates that initial CREZ-related system improvements will be identified during April 2008.

The following tables summarize the Reliability and Economic Driven projects identified in the 2007 Five-Year Plan that are in addition to the projects previously identified by ERCOT, other market participants and the TSPs and are included in the load flow base cases used in this study (See Appendix A):

Project Number	Project Name	2008	2009	2010	2011	2012
R1	Rothwood 345/138-kV switch station			✓	✓	✓
R2	Add a second 345/138-kV autotransformer at Forney					✓
R3	Roanoke Switch 345/138-kV autotransformer #1 upgrade			✓	✓	✓
R4	Roanoke Switch-Southlake 138-kV line upgrade		✓	✓	✓	✓
R5	Liggett 345/138-kV autotransformer upgrade					✓
R6	McCree-Shiloh 138-kV line upgrade		✓	✓	✓	✓
R7	Fairdale-Brand 138-kV line upgrade				✓	✓
R8	Lake Creek-Robinson 138-kV line upgrade					✓
R9	Coppell Tap-McKamy Tap 138-kV line upgrade					✓
R10	Construct a second McNeil-Summit 138-kV line					✓
R11	Cross Timbers-Roanoke 138-kV line upgrade				✓	✓
R12	Add a second 345/138-kV autotransformer at Lewisville					✓
R13	Temple North-Temple Elm Creek 138-kV circuit reconfigure		✓	✓	✓	✓
R14	West Denton-Fort Worth-Teasley 138-kV upgrade					✓
R15	Anderson-Westover Hills 138-kV line upgrade			✓	✓	✓

Table 1: Reliability Driven Projects and Year Needed

Project Number	Project Name	2008	2009	2010	2011	2012
E1	East Bernard-Orchard-Fort Bend 138-kV line upgrade		✓	✓	✓	✓
E2	Add a second 345/138-kV autotransformer at Concord		✓	✓	✓	✓
E3	Add a second 345/138-kV autotransformer at Whitney			✓	✓	✓
E4	Nacogdoches Southeast-Lufkin Switch 345-kV line					✓
E5	Moss-Odessa Southwest 138-kV line terminal equipment upgrade		✓	✓	✓	✓
E6	South McAllen-Las Milpas 138-kV line upgrade					✓
E7a	Clear Crossing 345-kV Switch Station		✓	✓	✓	✓
E7b	Lamesa area upgrades			✓	✓	✓
E7c	Paint Creek-Murray-Graham 138-kV line upgrade				✓	✓
E7d	Barton-Oran 138-kV line series reactor				✓	✓
E7e	Oklaunion-Bowman 345-kV line					✓
E7f	Red Creek-Killeen Switch 345-kV line					✓

Table 2: Economic Driven Projects and Completion Year

Additional, significant findings of the 2007 Five-Year Plan include:

The continued rapid increase in the installation of new wind generation in West Texas may result in congestion on multiple constraints and West to North transfers until new bulk transmission lines are added between West Texas and the rest of the ERCOT system. In the interim, ERCOT will work with TSPs in impacted areas to develop special protection systems (SPSs) or operating solutions that may assist in reducing the anticipated congestion.

While this report, limited to 2012 conditions and a wind generation level of 6,903 MW, identifies projects within and out of West Texas, the lines ordered as a result of the CREZ process may supersede some of these projects, especially those involving the 345-kV system. The CREZ Transmission Optimization (CTO) Study will identify the recommended lines to be constructed.

The proposed completion years shown in the 2007 Five-Year Plan Report were chosen to timely address reliability and economic needs. The TSPs will attempt to meet these dates, but may need to adjust the completion dates due to factors such as availability of construction clearances, delay in receiving required regulatory or governmental approvals, equipment availability and resource constraints.

II. Assumptions and Process:

ERCOT System Planning conducts the Five-Year Plan study for the entire ERCOT system every year. In this annual Five-Year Plan, ERCOT's Regional Planning department studies the reliability and efficiency of the transmission system according to the NERC and ERCOT reliability standards, works with Transmission Service Providers to upgrade and improve the existing system, and proposes new transmission projects to ensure system reliability and relieve system congestion.

A. Assumptions:

This study is dependent upon data calculated and compiled by numerous parties both inside and outside of ERCOT. The required data includes: system demand, generation supply and starting network topology. This data is updated and established each year before ERCOT begins the five-year plan study.

1. Demand:

The Steady State Working Group (SSWG) peak load from each summer peak base case was used in the reliability analysis. The peak load in the SSWG case is the forecasted peak load from TSPs. This peak load is higher than the peak load from ERCOT's econometric load forecasting. ERCOT's econometric load forecasting was based on a "normalized" weather profile. Because extreme weather conditions can occur, it is reasonable to analyze the transmission system at a higher peak load to ensure that system load could be served reliably. Analyzing the system using the SSWG peak load also provides a system that can reliably accommodate local area peak load conditions.

In the economic analysis, however, it is more appropriate to use a normalized or expected load level. Because the objective of the economic analysis is to forecast the expected economic benefit of transmission projects given a mean load. Hence, in the economic analysis, ERCOT's load forecasting is used

2. Generation Assumptions:

The following assumptions were used for generation:

- The model includes all generators that were in the SSWG 2007 DSB cases updated 08/30/2007 plus:
  - Hackberry Wind, 165 MW, Shackelford County
  - Wildhorse Mountain Wind, 120 MW, Howard County
  - Gulf Wind, 188 MW, Kenedy County
  - Penascal Wind, 201 MW, Kenedy County
  - Bosque 5, 255 MW, Bosque County

- Future generation that had a signed interconnection agreement (IAs) as of September 11, 2007 were included and modeled for the entire year that they entered if the in-service date was September or earlier and modeled the entire next year if the in-service date was after September
- Mothballed units were placed back on active status if the reserve margin fell below 12.5%
- DFW-area non-SCR units were removed from the model for 2009 through 2012
- The average natural gas price was $7/MMBTU for all years
- The total wind plant capacity for the 2009 year was 6903 MW (including 389 MW in south Texas) and stayed the same throughout the study for future years.

3. Starting transmission topology for each year:

The SSWG 2007 Data Set B 2008 through 2012 summer peak base cases updated in May 2007 were used as the starting point models for the transmission topology. A case comparison was performed to document all of the transmission bus and line changes between each year's cases. The 2008 summer peak case was compared to the SSWG 2007 Data Set A 2007 summer peak base case.

All of the system changes were documented and classified as being either Regional Planning Group (RPG) reviewable projects or non-RPG reviewable projects. The RPG reviewable projects were further categorized depending on whether they had already received RPG acceptance, they were currently undergoing RPG review, or they still needed to be RPG reviewed.

The list of projects was sent to the TSPs for their review. This review enabled the TSPs to correct misclassifications and to update projected in-service dates of projects.

Once the TSPs comments were received, projects that required but had not yet received RPG review and acceptance were removed from the cases. These conditioned cases served as the starting point for the Five-Year Plan study. The list of projects is included in Appendix A.

4. Application of Five-Year Plan toward satisfaction of NERC Standards

This Five-Year Plan document satisfies NERC TPL-001-0 and TPL-002-0 standards in their entirety. Partial satisfaction of TPL-003-0 is accomplished with higher system performance requirements than NERC Table I for all NERC Category C contingencies listed below as tested since loss of load was not allowed.

For the Reliability and Economic Phases of this plan, all NERC Category A and B contingencies were tested with the additions or exceptions listed below.

The following additions to NERC Category A and B were tested:

- Loss of double circuit tower line (NERC Category C).
- Loss of double circuit tower line with a specific generator not available for dispatch (NERC Category C tested in Reliability Phase only).

The following NERC Category B contingencies were not tested:

- Loss of single generator (Economic Phase only – considered to be covered in Reliability Phase)

The contingencies tested in the Stability Phase were slightly different than for the Reliability and Economic Phases and included all NERC Category A and B plus the following NERC Category C contingencies:

- Loss of line/transformer/generator followed by loss of another generator (could be considered Category D because manual system adjustments weren't made).
- Loss of double circuit tower line.
- Loss of double circuit tower line plus loss of a generator (a more severe disturbance than Category C, but not explicitly listed as Category D).

The following NERC Category C events were not explicitly tested:

- Loss of line/transformer followed by loss of another line transformer.
- Bus Section faults.
- Breaker faults.
- Faults with delayed clearing (breaker failure).

None of the specific events identified as Category D in NERC Table I were tested.

B. Five-Year Plan process:

After the load, generation, and beginning topology assumptions were finalized, analysis of the system began to determine what projects were needed to meet ERCOT and NERC reliability requirements. The conditioned 2012 case served as the starting point for this analysis. Once projects were identified for 2012, the analysis was performed for each of the previous years in the study. By starting the analysis with the model for the latest year in the study, the optimal solution set of projects could be determined and applied to prior years as necessary.

After the reliability improvements were identified, the updated models served as the starting point for the economic analysis. With the 2012 case serving as the starting point for the economic portion of the study, projects were identified for 2012, and the analysis was repeated for each of the previous years in the study. The following diagram illustrates the steps taken for the five-year plan study (See Chart 1):

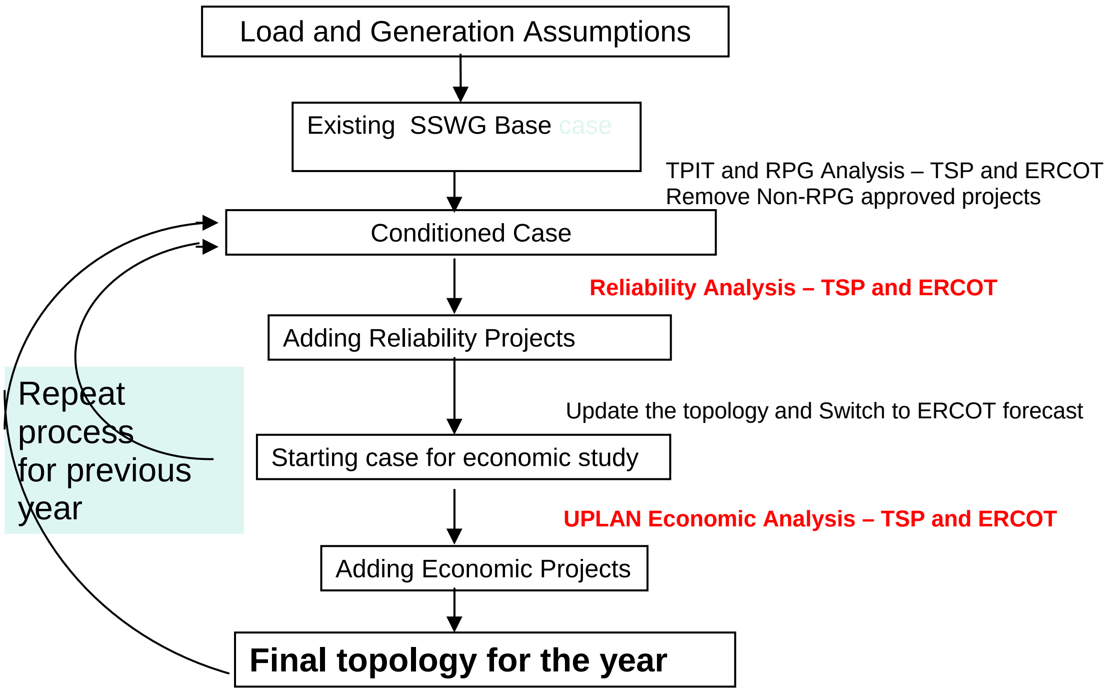


Chart 1: Five-year plan process flow chart

1. Reliability analysis:

Reliability projects are those system improvements (projects) that are needed to meet NERC or ERCOT reliability criteria which could not otherwise be met by any dispatch of the existing generation.

The conditioned case for each year was input into UPLAN (a vendor supplied software program) to determine if all the loads could be served under N-0 and N-1 conditions for every hour of the year. UPLAN uses a security constrained economic unit commitment and security constrained economic dispatch for every hour. If there was load in any hour that could not be served (unserved energy) under the N-0 and N-1 conditions, system improvements or other measures such as SPS, Remedial Action Plan (RAP), etc were developed until the entire load could be served reliably. The list of unserved energy (loads and locations/buses) that could not be served reliably were identified along with the contingencies and limiting elements which caused the unserved energy.

The list of projects along with the corresponding limiting elements and contingencies was communicated to the appropriate TSP. TSPs reviewed the initial list of reliability driven projects for their technical feasibility and estimated date of completion. They also provided project cost estimates and in some cases alternatives. Intermediate and final results were presented to stakeholders at regularly scheduled RPG meetings in order to solicit comments and suggestions.

Once feedback had been received, the refined set of improvements was implemented in the model. However, since many of the upgrades were developed independent of each other, some may not be necessary. For this reason, once all the unserved energy was removed from the system by adding the reliability driven projects, a “back out” analysis was conducted. Each reliability project was backed out from the model one at a time. If a project was backed out and all the loads could still be served reliably, this project was removed from the reliability driven project list. The back out analysis was stopped when no project could be backed out without causing unserved energy.

After the back out analysis, the remaining projects formed the final set of the reliability driven projects. The improved topology was used for the starting case for the economic analysis for each year.

2. Stability Analysis:

Voltage stability analysis was done upon the completion of the reliability phase and after adding the Red Creek to Killeen 345 kV circuit to the model to determine an interface limit for use in the DC UPLAN application during the Economic Phase of the Analysis. The analysis was completed using the Powertech Voltage Security Assessment Tool (VSAT). Transfers were modeled in VSAT from the West Congestion Management Zone to the rest of ERCOT using both Generation to Generation and Generation to Load transfer methods. The limit derived from the Generation to Load transfer method seemed to be less representative of West Texas exports and more the result of the system’s inability to supply the increasing load in the DFW area.

For this reason the Generation to Generation method was chosen. An interface had to be defined to measure the transfer and provide an Interface limit to enter into UPLAN. The Interface was defined as:

From Bus	To Bus	Ckt ID	From Bus Name	Volt	To Bus Name	Volt
1430	1873	'1'	GRHAMSES1_5	345	BENBRK_5	345
1430	1436	'1'	GRHAMSES1_5	345	PARKER_5	345
1429	988	'1'	JACKSBRO_5	345	W_DENT_5	345
1429	1421	'1'	JACKSBRO_5	345	WILLOWCK_5	345
6444	1440	'1'	SARC7A	345	COMCHESS1_5	345

The direction of flow on the interface is positive from the “From Bus” to the “To Bus”. The flow on each line is summed pre-contingency and compared to the limit entered for the Interface in UPLAN. The limit for the Generation to Load transfer with the 345 kV line added was calculated to be 1978 MW. This limit was very restrictive and due to this and the reason described above, the Generation to Generation interface limit of 2548 MW was chosen.

3. Economic Analysis:

Economic Driven Projects are those system improvements that were needed to allow NERC and ERCOT reliability criteria to be met at a lower total cost (total system variable production cost plus carrying cost of new projects) than the continued dispatch of higher cost generation.

After the completion of the reliability analysis, the SSWG peak load was replaced by ERCOT's forecasted peak load. Although all the loads could be served reliably, some low cost generation could be curtailed due to congestion in the transmission network. Effort was spend to identify Economically Driven projects to relieved system congestion.

To identify the economically driven projects, UPLAN was run based on the load, generation and the conditioned topology plus the newly identify reliability projects. From this run, a list of all congested lines and contingencies causing the congestion was produced. Using this information, a preliminary set of improvements was designed by ERCOT Staff and TSPs to solve or reduce the congestion. Projects were put into the model one by one and an annual production cost analysis was performed. Production cost results before and after a project, were compared. According to ERCOT's economic planning criteria, economic projects are defined as projects that reduce production costs such that the ratio of the capital cost of the project to the annual production cost savings associated with that project is less than 6.0.

Improvements were developed iteratively by focusing on the most heavily congested areas in the system. Projects developed later in the process may impact the economics of those developed earlier. Projects developed at the same time but separately may also impact each other. To make sure all the potential economic driven projects were still economic with all the other projects in place, a back out analysis was conducted similar to the back out analysis performed for the reliability driven projects. In the back out analysis, all the potential economic projects were backed out from the model one by one. Total system production cost before and after a backed out improvement were compared to ensure the upgrade still met the criterion.

After the completion of the back-out analysis, projects that did not pass the economic criterion were taken out from the model. The remaining projects became the final set of economically driven projects. This final set of economically driven projects for 2012 was used to select projects for the prior year's models if similar congestion was observed and the project could be constructed by that year.

The final topology for each year, containing all of the identified reliability and economically driven projects will serve as the base case for RPG project reviews performed by ERCOT Staff over the next year.

III. Reliability Driven Projects

A. Reliability Driven Projects with all generation units available

Table 1 shows the reliability driven projects identified in the 2007 Five-Year Plan:

Project Number	Project Name	2008	2009	2010	2011	2012
R1	Rothwood 345/138-kV switching station			✓	✓	✓
R2	Add a second 345/138-kV autotransformer at Forney					✓
R3	Roanoke Switch 345/138-kV autotransformer #1 upgrade			✓	✓	✓
R4	Roanoke Switch-Southlake 138-kV line upgrade		✓	✓	✓	✓
R5	Liggett 345/138-kV autotransformer upgrade					✓
R6	McCree-Shiloh 138-kV line upgrade		✓	✓	✓	✓
R7	Fairdale-Brand 138-kV line upgrade				✓	✓
R8	Lake Creek-Robinson 138-kV line upgrade					✓
R9	Coppell Tap-McKamy Tap 138-kV line upgrade					✓
R10	Construct a second McNeil-Summit 138-kV line					✓
R11	Cross Timbers-Roanoke 138-kV line upgrade				✓	✓
R12	Add a second 345/138-kV autotransformer at Lewisville					✓
R13	Temple North-Temple Elm Creek 138-kV circuit reconfigure		✓	✓	✓	✓
R14	West Denton-Fort Worth-Teasley 138-kV upgrade					✓
R15	Anderson-Westover Hills 138-kV line upgrade			✓	✓	✓

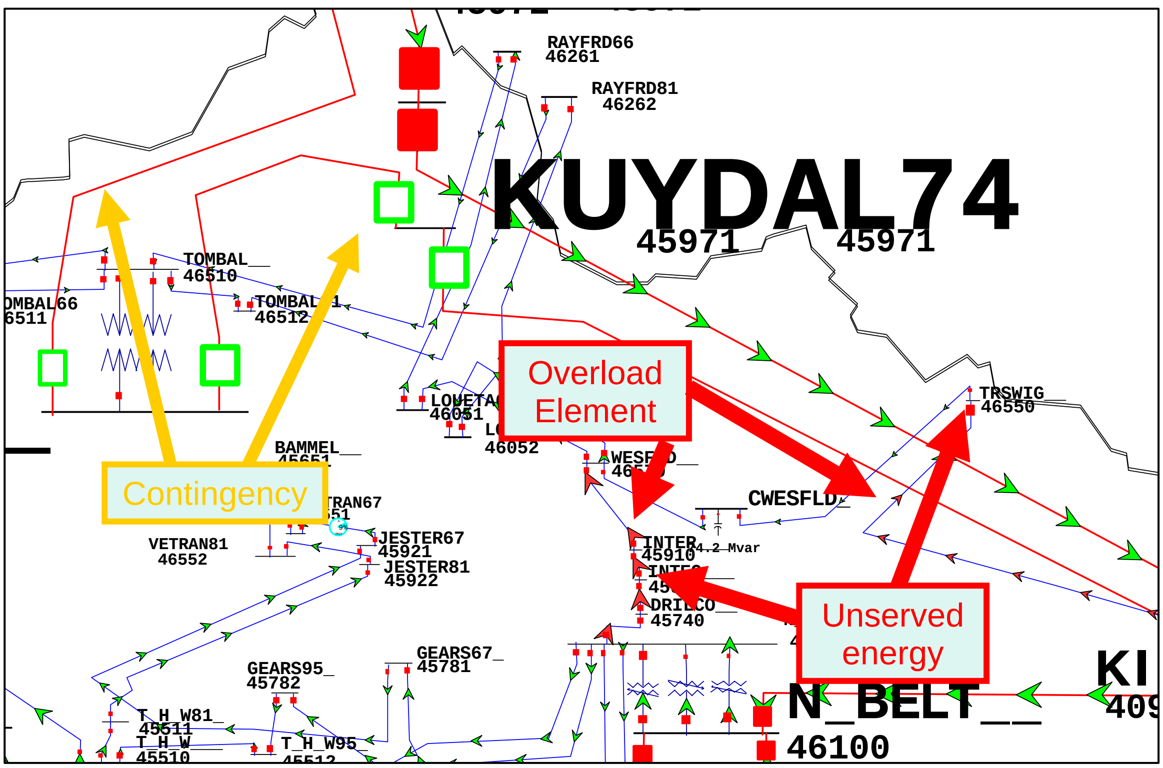
Table 1: Reliability Driven Projects and Year Needed

The followings are the brief description of the reliability driven projects on the above table.

1. Rothwood 345/138-kV switch station

The contingency of Tomball–Jewett (Singleton) and King–Kuykendahl-Tomball 345-kV double circuit caused overloads on the North Belt–Westfield 138-kV line and the Humble–Treaschwig 138-kV line. This contingency and overload pair caused unserved energy at the Intercontinental, Drilco, Inteq, and Treaschwig buses. (See table and graphs below)

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
INTER___	3,134.33	-0.7104	DRILCO__	N_BELT__	TOMBAL__	JEWETT_N	KING____	KUYDAL74
DRILCO__	1,584.02	-0.8149	DRILCO__	N_BELT__	TOMBAL__	JEWETT_N	KING____	KUYDAL74
INTEQ___	1,008.25	-0.7691	DRILCO__	N_BELT__	TOMBAL__	JEWETT_N	KING____	KUYDAL74
TRSWIG__	194.88	-0.452	HUMBLE__	TRSWIG__	TOMBAL__	JEWETT_N	KING____	KUYDAL74



To remove the unserved energy, CenterPoint Energy and ERCOT studied two options:

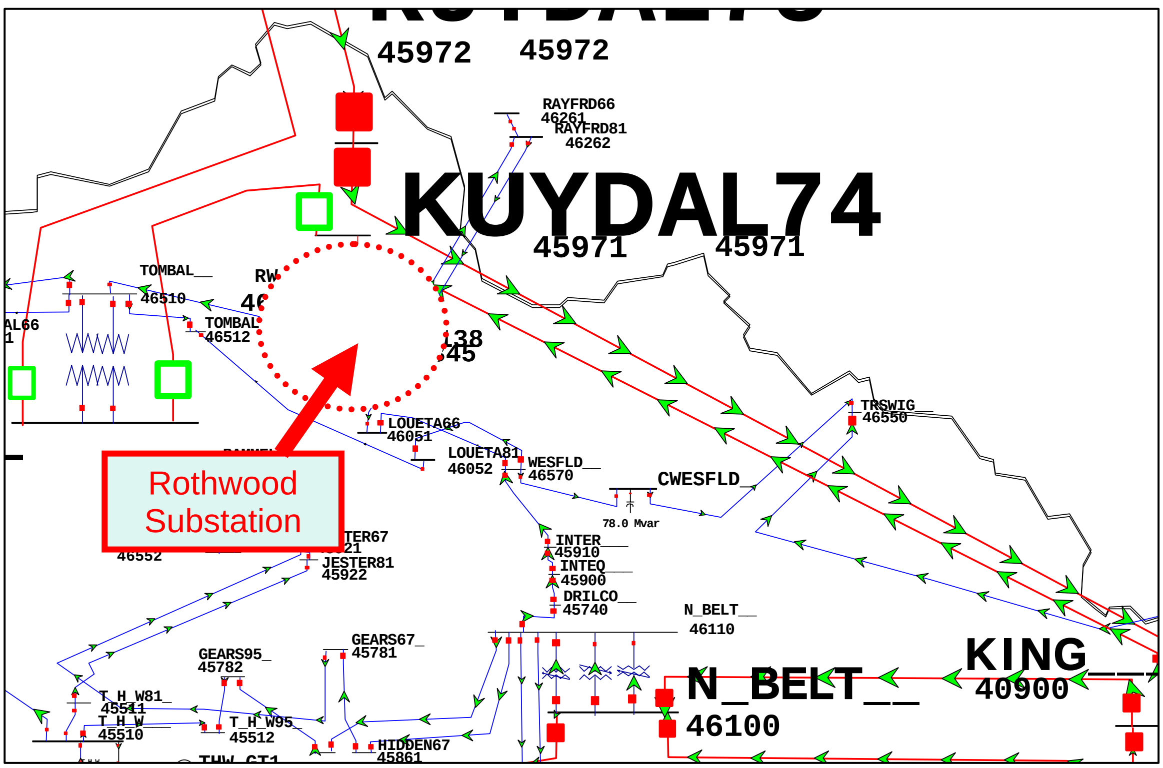
Option 1 was to reconductor the limiting elements: North Belt-Westfield 138-kV line and Humble–Treaschwig 138-kV line. CenterPoint Energy estimated the cost of this upgrade to be $8.18 million. However, these upgrades do not have any effect on loading of the two 800 MVA

Tomball autotransformers. Both CenterPoint Energy and ERCOT analyses show an overload of one Tomball autotransformer for the loss of the other autotransformer when considering the continuous rating. A project to add additional autotransformer capability to resolve this overload will be needed in the near future. Consequently, Option 1 would be followed shortly by the Rothwood project discussed in Option 2. In light of this, Option1 then becomes $8.18 million in transmission upgrades followed by another $20.5 million project two years later.

Option 2 included building the Rothwood 345/138-kV switching station. This consisted of looping the Kuykendahl-King 345-kV circuit 74 and the Tomball-Rayford Tap 138-kV circuit 66 into the new station. An 800-MVA 345/138 kV autotransformer was used to tie the 345-kV and 138-kV buses together. CenterPoint Energy estimated the cost of this project to be $20.5 million.

Option 2 was chosen because while building Rothwood appears to be needed under any circumstance, building it now avoids the transmission upgrades necessary to the North Belt to Westfield and Humble to Treaschwig circuits. Therefore, it reduces the overall cost of the project and avoids requiring any outages to the two industrial customers (DRILCO and INTEQ) during the North Belt to Westfield upgrade. This project was first needed in 2010.

The following graph shows the local network after the substation is built. There are no overloads in the area after the project.



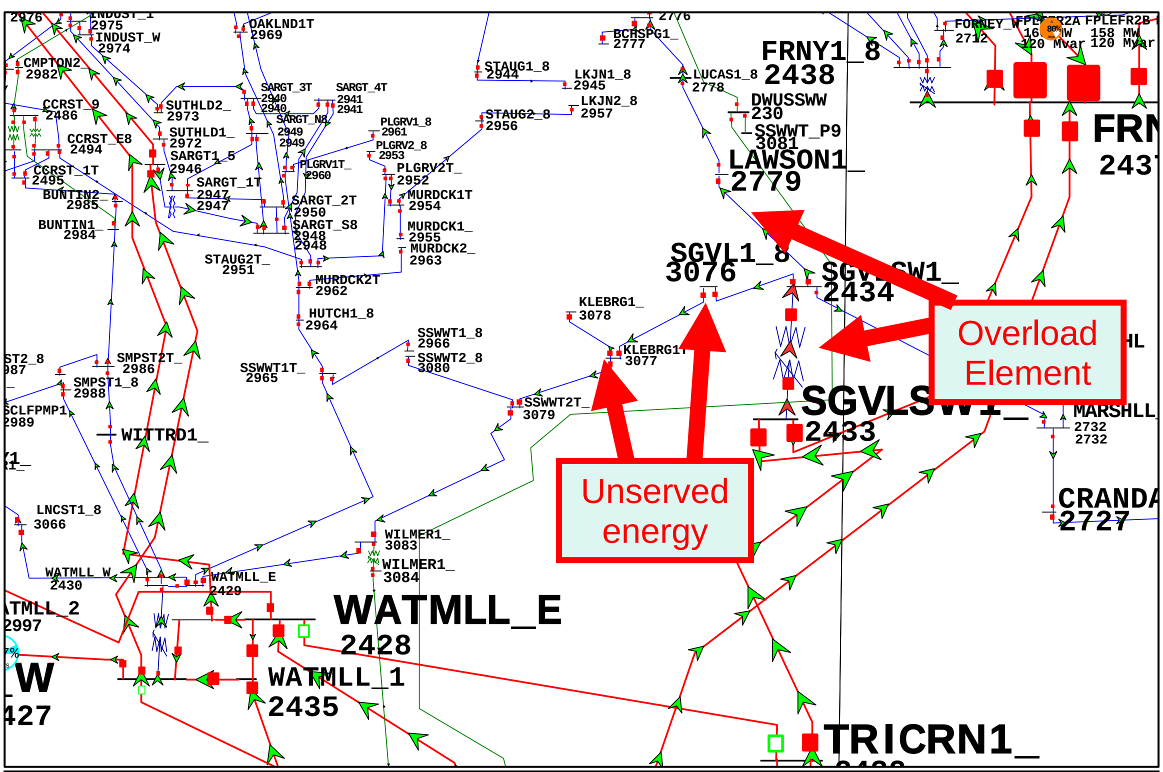
2. Add a second 345/138-kV autotransformer at Forney

Currently, there is a 750-MVA (Rate B) 345/138-kV autotransformer at Forney and a 504-MVA 345/138-kV autotransformer at Seagoville Switch. Oncor plans to replace the 504-MVA autotransformer at Seagoville Switch with a 600-MVA autotransformer in spring 2008. The 504-MVA autotransformer will be left in place, but kept out of service.

In the 2012 conditioned case the Seagoville Switch 600-MVA autotransformer overloads under the contingency loss of the Watermill-Tricorner/ Watermill-Trinidad 345-kV double circuit. This caused unserved energy in the UPLAN model, meaning there was no dispatch that was able to resolve the overload during peak hours. (See the following table and graph for more detail). Additionally, when Lake Hubbard 2 was taken out of service there were various other n-1 post-contingency overloads.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
SGVL1_8	2,178.77	-0.422	SGVLSW1_	SGVLSW1_	WATMLL_W	TRINDAD1	WATMLL_E	TRICRN1_
KLEBRG1_	107.01	-0.3605	SGVLSW1_	SGVLSW1_	WATMLL_W	TRINDAD1	WATMLL_E	TRICRN1_

Solution Options



Option 1 involved upgrading the new 600-MVA autotransformer at Seagoville Switch. The 600-MVA rating on the new Seagoville Switch autotransformer is the “nameplate” rating for the autotransformer. It has been Oncor’s experience that the 600-MVA autotransformers can be rated to have an emergency rating (Rate B) between 680 MVA and 750 MVA once the equipment is installed in the field and tested.

The Seagoville Switch autotransformer rate B was changed to 750 MVA in the case and the UPLAN model rerun. Unserved energy was slightly decreased in this case; however, the contingency loss of the Watermill-Tricorner and Watermill-Trinidad 345-kV double circuit caused unserved energy due to overloading of the Tricorner-Seagoville Switch 345-kV line.

After further analysis it was determined that this constraint had a related constraint: the Royse 345/138-kV autotransformer (2474-2473) overloading for the loss of the other Royse autotransformer (2483-2460). UPLAN needed to back down the Forney units to prevent overloading the Royse autotransformer, but this caused the Tricorner-Seagoville Switch 345-kV line to overload. Based on this it was determined that more autotransformer capacity was needed in the area.

Since the 504-MVA autotransformer at Seagoville Switch is planned to be left in place, the model was modified to place this autotransformer in service in parallel with the new Seagoville Switch autotransformer. The UPLAN analysis of this case revealed new unserved energy caused by the overload of the Lawson-Lucas-Balch Springs Tap 138-kV line due to the contingency loss of the Forney autotransformer.

The Lawson-Lucas-Balch Springs Tap line was then upgraded to bring the Rate B to 478 MVA (from 372 MVA) and the UPLAN model was rerun. With this upgrade the unserved energy was solved.

To check to make sure there was no unserved energy for the planning criteria contingency of loss of a unit and loss of an element, Lake Hubbard 2 – the largest unit in the local area – was taken out of service and n-1 contingency analysis was rerun. The following additional unserved energy overloads were observed: Balch Springs Tap-Mesquite-East Side Tap 2-East Mesquite 138-kV line overloads for the loss of the Forney 345/138-kV autotransformer; the Centerville Switch 345/138-kV autotransformer overloads for the loss of the other Centerville Switch autotransformer.

To alleviate the Balch Springs Tap-Mesquite-East Side Tap 2-East Mesquite 138-kV line overload the line was upgraded to 478 MVA. A potential Remedial Action Plan (RAP) was used to relieve the overload of the Centerville Switch autotransformer. The RAP entails switching in the existing Centerville Switch-Garland Road 138-kV line series reactors and opening the Centerville Switch-Lake Hubbard 138-kV double circuit. Since this contingency involves the loss of a unit it was deemed acceptable to plan for a RAP to mitigate the overload.

The final list of Option 1 upgrades is as follows:

- Upgrade the new Seagoville Switch autotransformer to 750 MVA[1]
- Place the old Seagoville Switch autotransformer in-service in parallel with the new one
- Upgrade the Lawson-Lucas-Balch Springs Tap-Mesquite-East Side Tap 2-East Mesquite 138-kV line (~4.75 miles) so that the Rate B is 478 MVA

Option 2 entails installing a second 750-MVA autotransformer at Forney. As an alternative to adding autotransformer capacity at Seagoville Switch, a second 345/138-kV autotransformer, identical to the existing Forney autotransformer was added at Forney to the 2012 conditioned case. UPLAN analysis was run and it was found that this upgrade eliminated all unserved energy from the case.

To check to make sure there was no unserved energy for the planning criteria contingency of loss of a unit and loss of an element, Lake Hubbard 2 was again taken out of service and n-1 contingency analysis was rerun. It was found that the Centerville Switch 345/138-kV autotransformer overloads for the loss of the other Centerville Switch autotransformer. The same RAP that was employed for this overload with Option 1 was found to relieve the overload for Option 2 as well.

The Option 2 upgrade was added to the 2012 economic model in place of Option 1 and production cost analysis was run to determine if there were any congestion savings when compared to Option 1. It was found that Option 2 saved approximately $1 million per year in production cost. This was most likely due to the elimination of the following congestion found in the analysis with Option 1:

- Royse 345/138-kV autotransformer congested for the contingency loss of the other Royse 345/138-kV autotransformer
- Royse-Allen 345-kV line congested for the contingency loss of the Collin-Anna 345-kV line

In conclusion, both options studied eliminated the reliability overloads. The below table illustrates the production cost difference (congestion) and capital cost difference between the options.

Option	Capital Cost	Production Cost Difference in 2012
1	$3.5 million	Baseline
2	$6.0 million	- $1 million

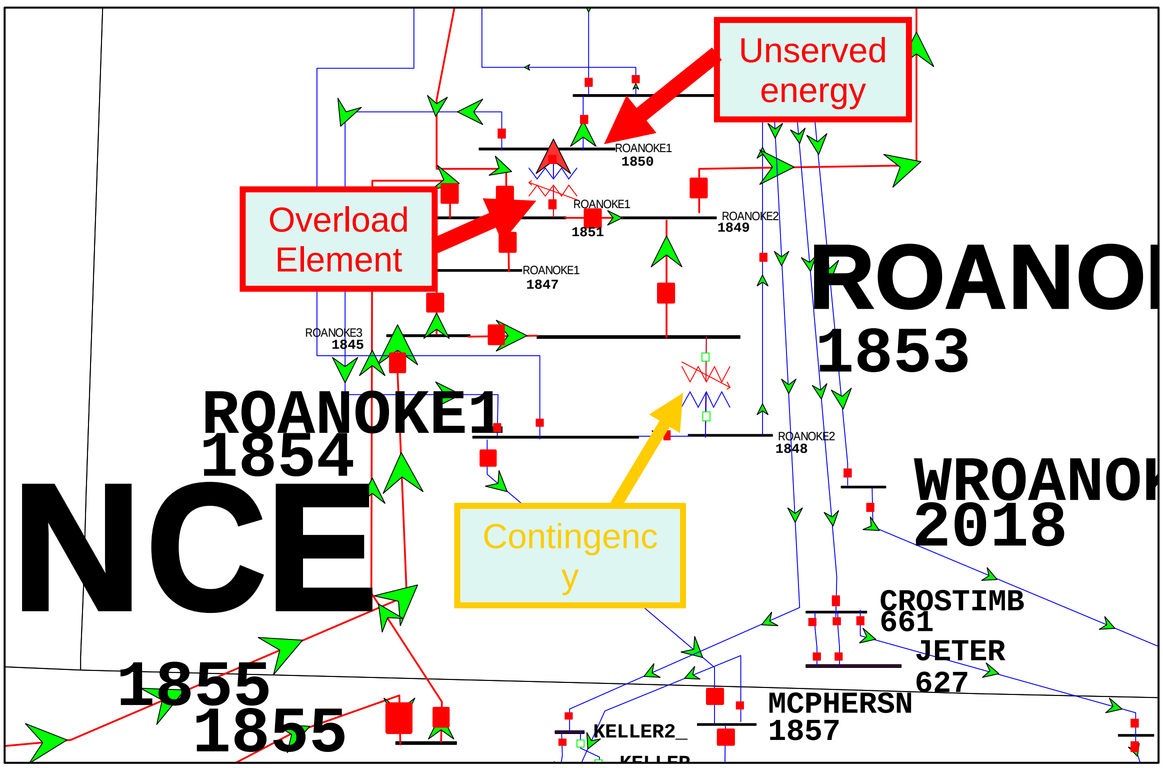
Based on the economic analysis, Option 1 was the least expensive upgrade alternative, but the production cost savings associated with Option 2 would offset the additional capital cost in less than three years. Therefore, it is recommended that a second 345/138-kV autotransformer be installed at Forney by summer 2012 as described in Option 2.

3. Roanoke Switch 345/138-kV autotransformer #1 upgrade

[1] The upgrade of the Seagoville Switch autotransformer may not be necessary with the addition of the parallel autotransformer. Further analysis may be required if this option is selected.

There are currently two 345/138-kV autotransformers at Roanoke Switching Station. Autotransformer #1 is an older transformer and is rated 472/472/517 MVA. Autotransformer #2 was recently upgraded and is rated 700/750/750 MVA. The contingency of the Roanoke Switch autotransformer #2 overloaded the Roanoke Switch autotransformer #1 in the model. This contingency overloading pair caused unserved energy at Roanoke Switch and other two buses. See the following table and graph for details.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
ROANOKE1	1,697.42	-0.4183	ROANOKE1	ROANOKE1	ROANOKE2	ROANOKE2		
MCPHERSO	229.75	-0.4074	ROANOKE1	ROANOKE1	ROANOKE2	ROANOKE2		
ELIZCRK1	23.92	-0.4152	ROANOKE1	ROANOKE1	ROANOKE2	ROANOKE2		

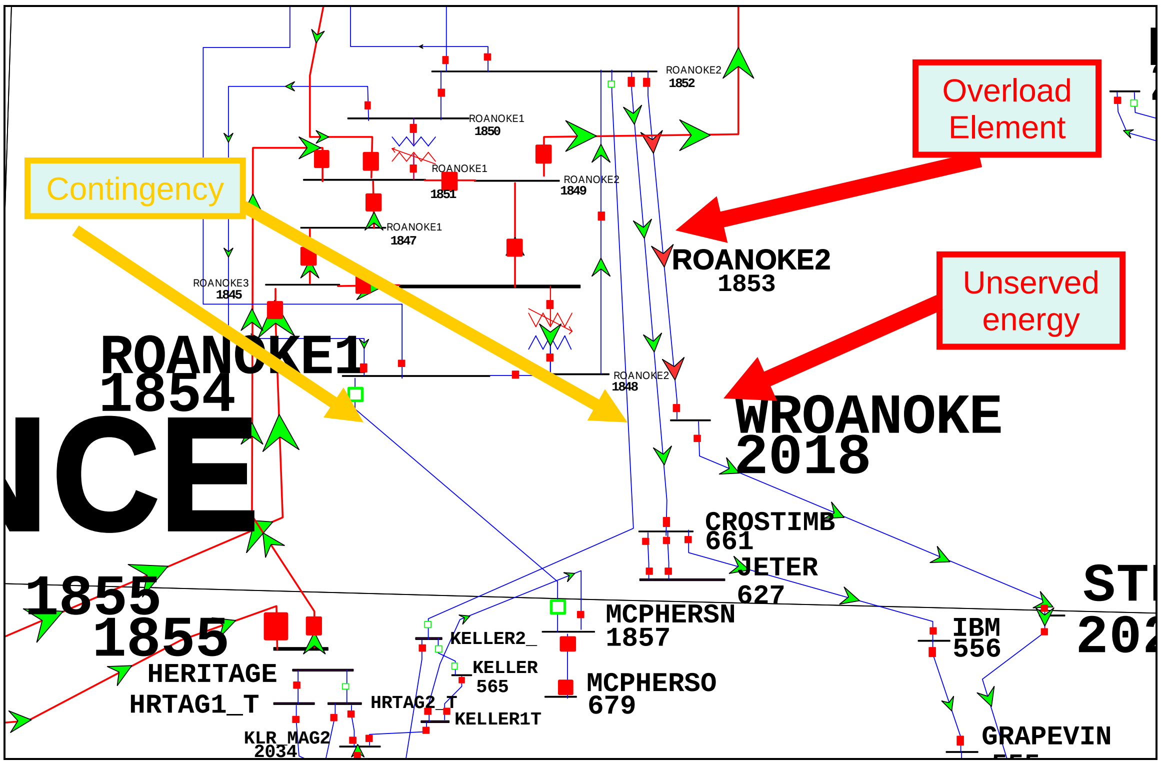


Oncor Electric Delivery suggested the solution of replacing the existing autotransformer #1 with a new autotransformer with the same rating as the other transformer at the station, rated 700/750/750 MVA. This upgrade resolved the unserved energy observed. Oncor Electric Delivery estimated the cost of this project to be $5.25 million. The project was first needed in the 2010 model.

4. Upgrade Roanoke Switch–Southlake 138 kV line

The contingency of Roanoke Switch–Keller 138-kV line and the Roanoke Switch–McPherson 138-kV line overloaded the Roanoke Switch-West Roanoke-Southlake 138-kV line. This contingency overloading pair caused unserved energy at West Roanoke. See the following chart and graph for detail.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
WROANOKE	441.89	-0.7544	ROANOKE2	WROANOKE	ROANOKE2	KELLER2_	ROANOKE1	MCPHERSN

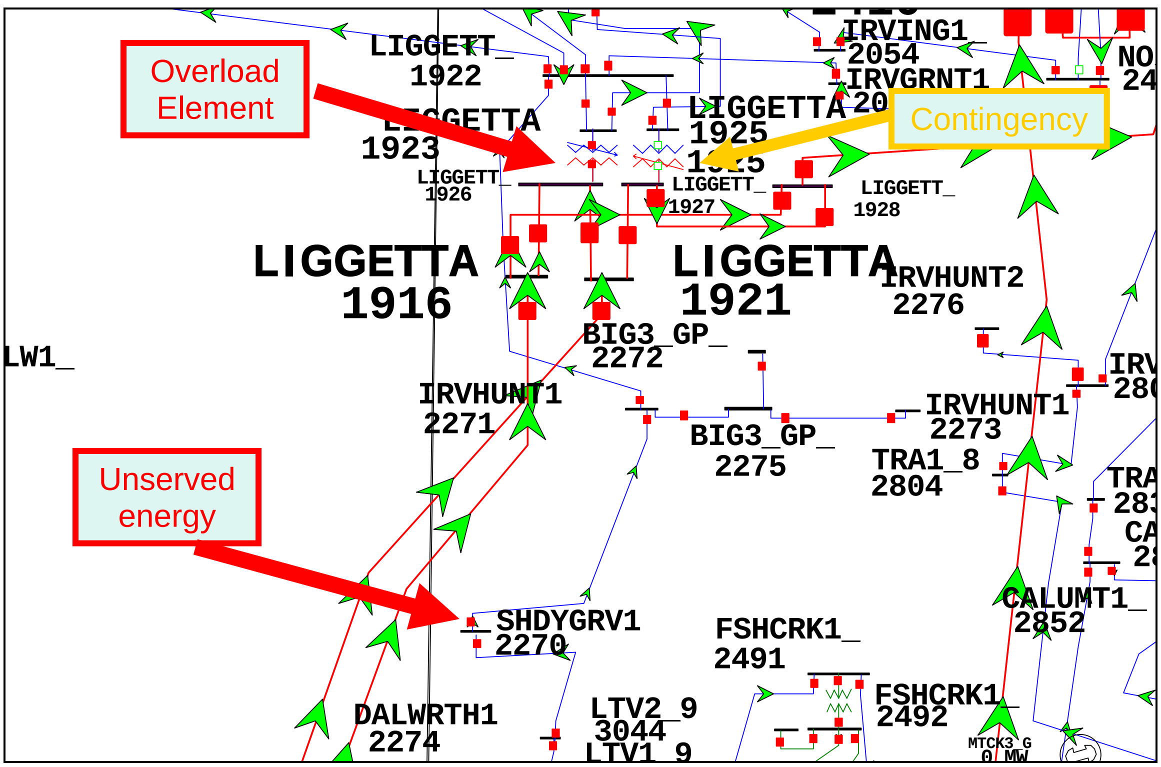


To remove the unserved energy, the existing Roanoke Switch-West Roanoke-Southlake 138-kV line was reconductored using a higher rating conductor. After the reconductoring, the rating of the line was increased to 478/478/478 MVA. This resolved the unserved energy. Oncor Electric Delivery estimated the project cost to be $3.4 million. This project was first needed in 2009.

5. Liggett 345/138-kV autotransformer upgrade

The contingency of the larger 345/138-kV autotransformer at Liggett (rated 625/682/682 MVA) overloaded the other autotransformer (rated 480/525/525 MVA). This contingency overload pair caused unserved energy at Shady Grove and International Airport. See the following table and graph for detail.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
SHDYGRV1	1,942.77	-0.1685	LIGGETTA	LIGGETT_	LIGGETT_	LIGGETTA		
INT_AIR1	547.85	-0.1663	LIGGETTA	LIGGETT_	LIGGETT_	LIGGETTA		

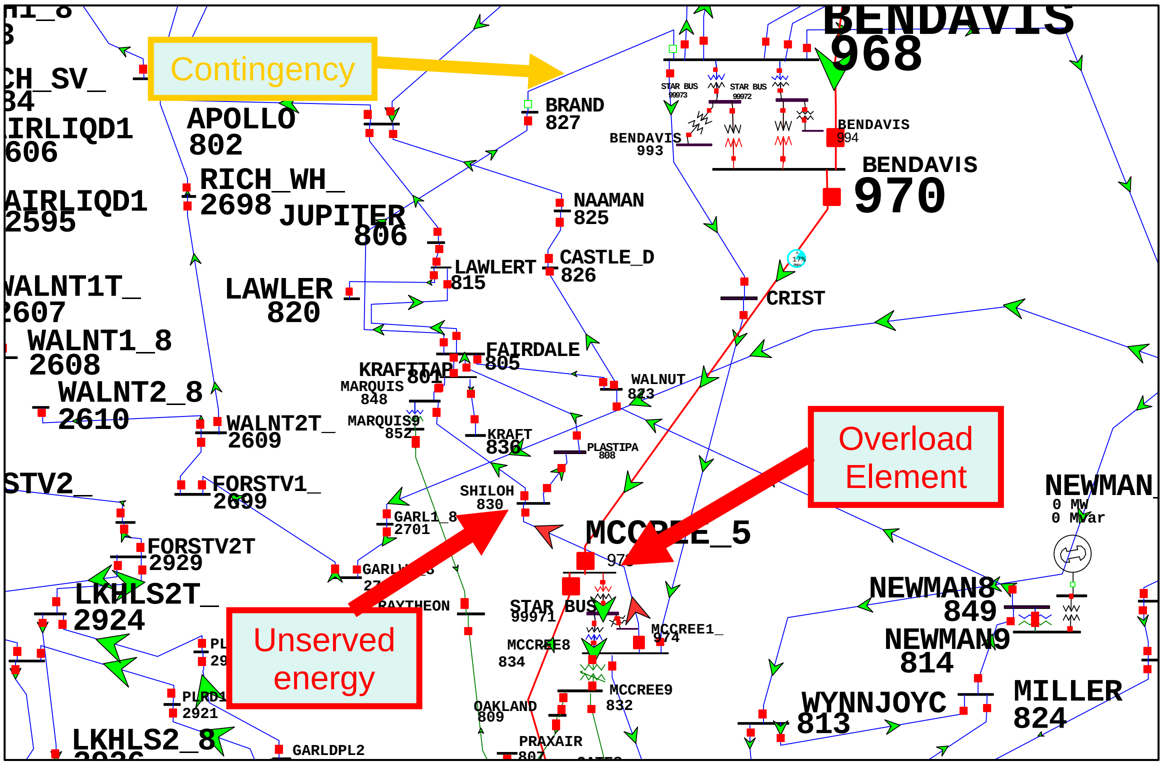


To remove the unserved energy, the existing smaller transformer rated 480/525/525 was replaced with a new autotransformer rated 700/750/750 MVA in the model. This eliminated the associated unserved energy. Oncor Electric Delivery estimated the cost of this improvement to be $5.3 million. This project was first needed in 2012.

6. McCree–Shiloh 138-kV line upgrade

The contingency of the Fairdale–Brand 138-kV line overloaded the Shiloh–McCree 138-kV line. This contingency overload pair created unserved energy at the Fairdale bus. See the following table and graph for details.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
FAIRDALE	1,624.78	-0.3574	FAIRDALE	BRAND	SHILOH	MCCREE8		

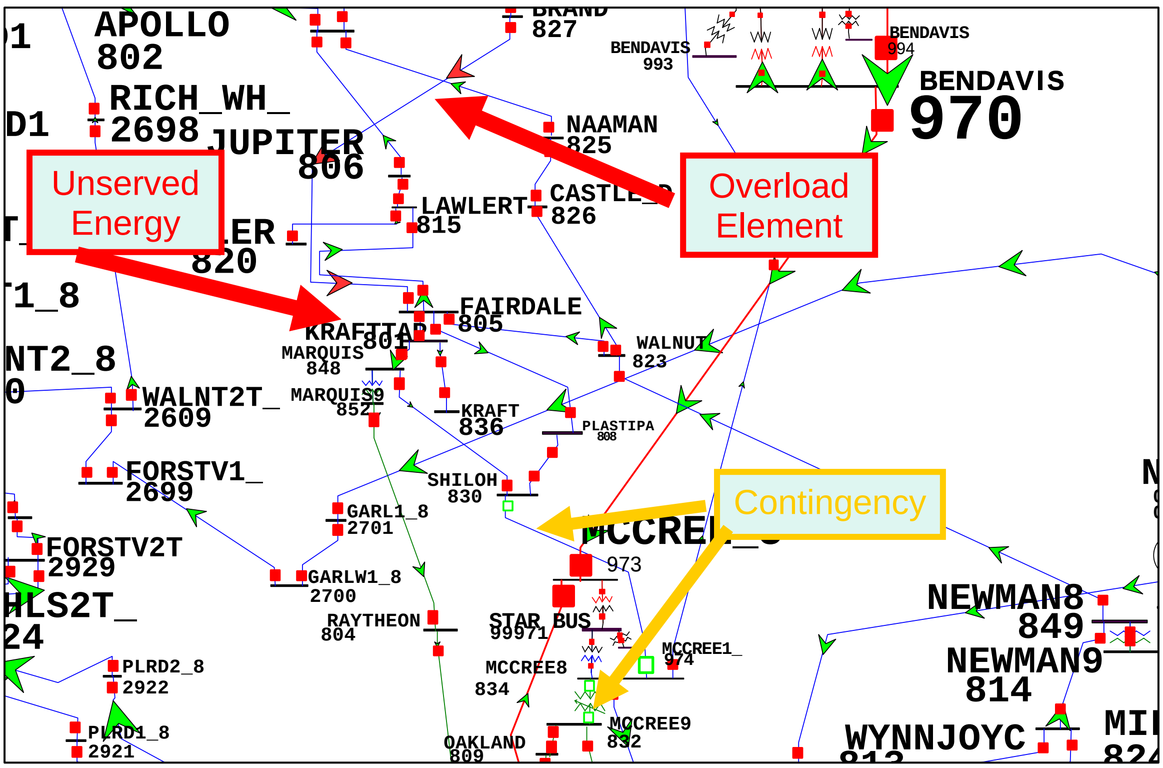


To remove the unserved energy, Garland Power and Light proposed reconductoring the Shiloh – McCree 138-kV line to achieve a rating of 326/326/326 MVA at a cost of $304,000. This project was first needed in 2009.

7. Fairdale–Brand 138-kV line upgrade

The contingency of the Shiloh–McCree 138-kV line and the McCree 345/138-kV autotransformer overloaded the Fairdale–Brand 138-kV line. This contingency overload pair caused unserved energy at the Fairdale and other nearby 138-kV buses. See the following table and graph for details.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
FAIRDALE	1,624.78	-0.3574	FAIRDALE	BRAND	SHILOH	MCCREE8	MCCREE9	MCCREE8
SHILOH	250.49	-0.3561	FAIRDALE	BRAND	SHILOH	MCCREE8	MCCREE9	MCCREE8
PLASTIPA	117.68	-0.3568	FAIRDALE	BRAND	SHILOH	MCCREE8	MCCREE9	MCCREE8
KRAFT	81.58	-0.3566	FAIRDALE	BRAND	SHILOH	MCCREE8	MCCREE9	MCCREE8



To remove the unserved energy, Garland Power and Light proposed to reconductor the existing Fairdale–Brand 138-kV line to get a circuit rating of 326/326/326 MVA at a cost of $834,000. This upgrade resolved the unserved energy in the model.

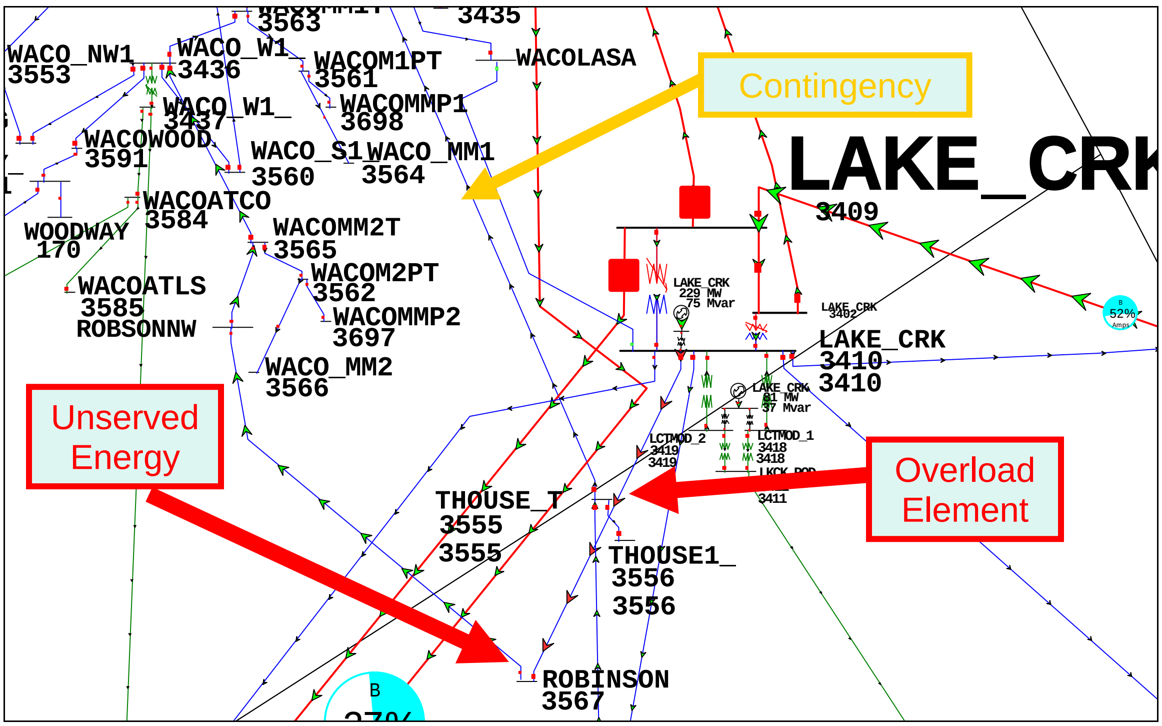
An alternative to upgrading the Fairdale–Brand 138-kV line and McCree-Shiloh 138-kV line was explored. The alternative involved looping the Crist-McCree 138-kV line into the Walnut substation and reconductoring the newly formed Walnut-Crist-Ben Davis 138-kV line. The estimated cost of this improvement was $5.3 million. Since this was considerably more expensive than the proposed upgrades it was not considered further.

The Fairdale–Brand 138-kV line upgrade was first needed in 2011.

8. Lake Creek–Robinson 138-kV line upgrade

The contingency of the Lake Creek–Waco Lasalle 138-kV line overloaded the Lake Creek–Robinson 138-kV line. This contingency overload pair created unserved energy at the Robinson bus. See the following table and graph for details.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
ROBINSON	2,062.20	-0.6447	LAKE_CRK	ROBINSON	LAKE_CRK	WACOLASA		

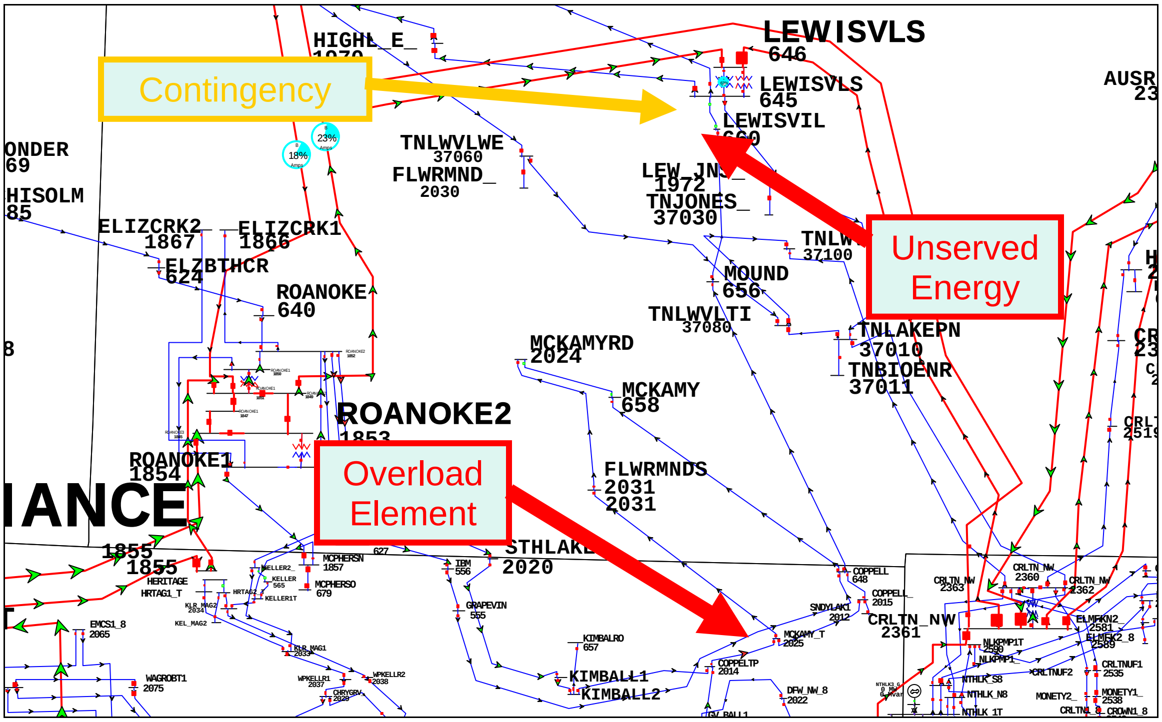


To remove the unserved energy, Oncor Electric Delivery proposed to upgrade the Lake Creek-Robinson 138-kV line to 478 MVA at a cost of $3.9 million. The upgrade removed the unserved energy in the model. This project was first needed in the year 2012

9. Coppell Tap–McKamy Tap 138-kV line upgrade

The contingency of the Lewisville South–Lewisville 138-kV line overloaded the Coppell Tap–McKamy Tap 138-kV line. This contingency overload pair caused unserved energy at the Lewisville bus. See the following table and graph for details.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
LEWISVIL	14.60	-0.7046	COPPELTP	MCKAMY_T	LEWISVLS	LEWISVIL		

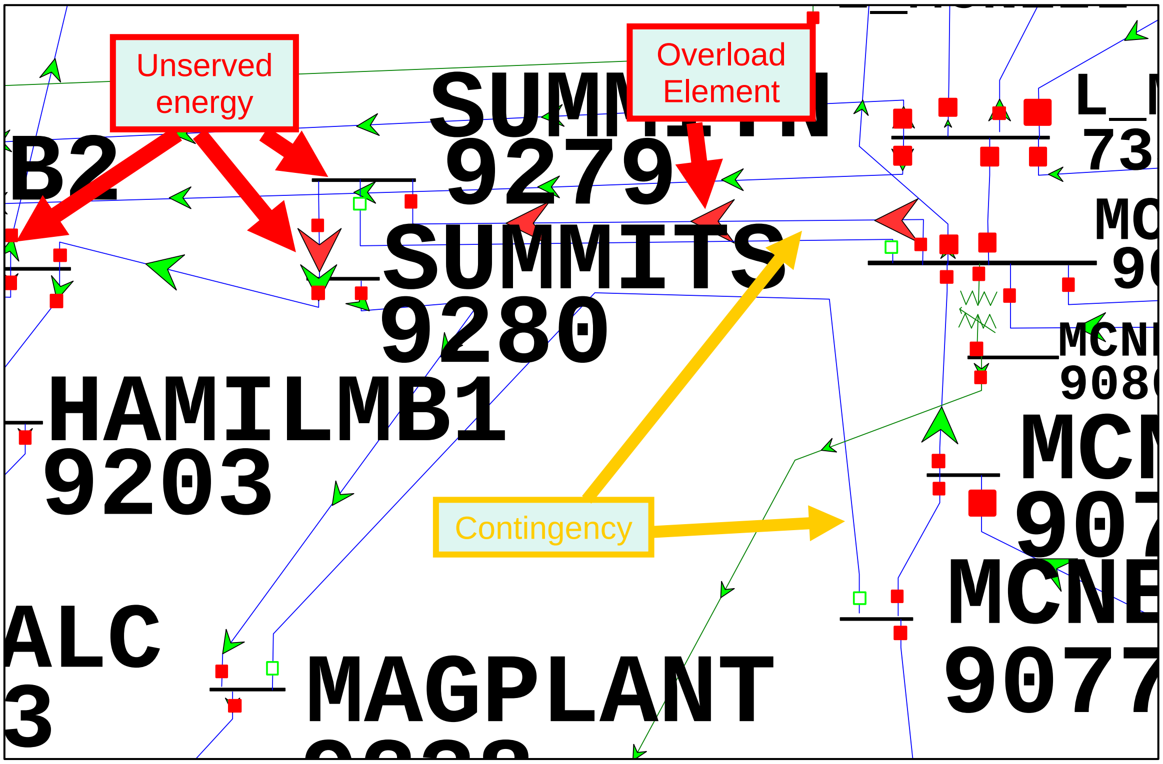


To remove the unserved energy, Oncor Electric Delivery proposed to upgrade the existing 138-kV line to 326/326/326 MVA at a cost of $1.3 million. This upgrade eliminated the unserved energy in the area in the model. This project was first needed in the 2012 model.

10. Construct a second McNeil-Summit 138-kV line

The contingency of the McNeil–Magnesium Plant/ McNeil–Summit 138-kV double circuit overloaded the McNeil–Summit 138-kV line. This contingency overload pair caused unserved energy at the Summit North and other nearby buses. See the following table and graph for detail.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
HAMILMB2	58.03	-0.5426	MCNEILN	SUMMITN	MCNEILS	MAGPLANT	MCNEILN	SUMMITN
SUMMITN	2,089.68	-0.6174	MCNEILN	SUMMITN	MCNEILS	MAGPLANT	MCNEILN	SUMMITN
SUMMITS	213.12	-0.6143	MCNEILN	SUMMITN	MCNEILS	MAGPLANT	MCNEILN	SUMMITN

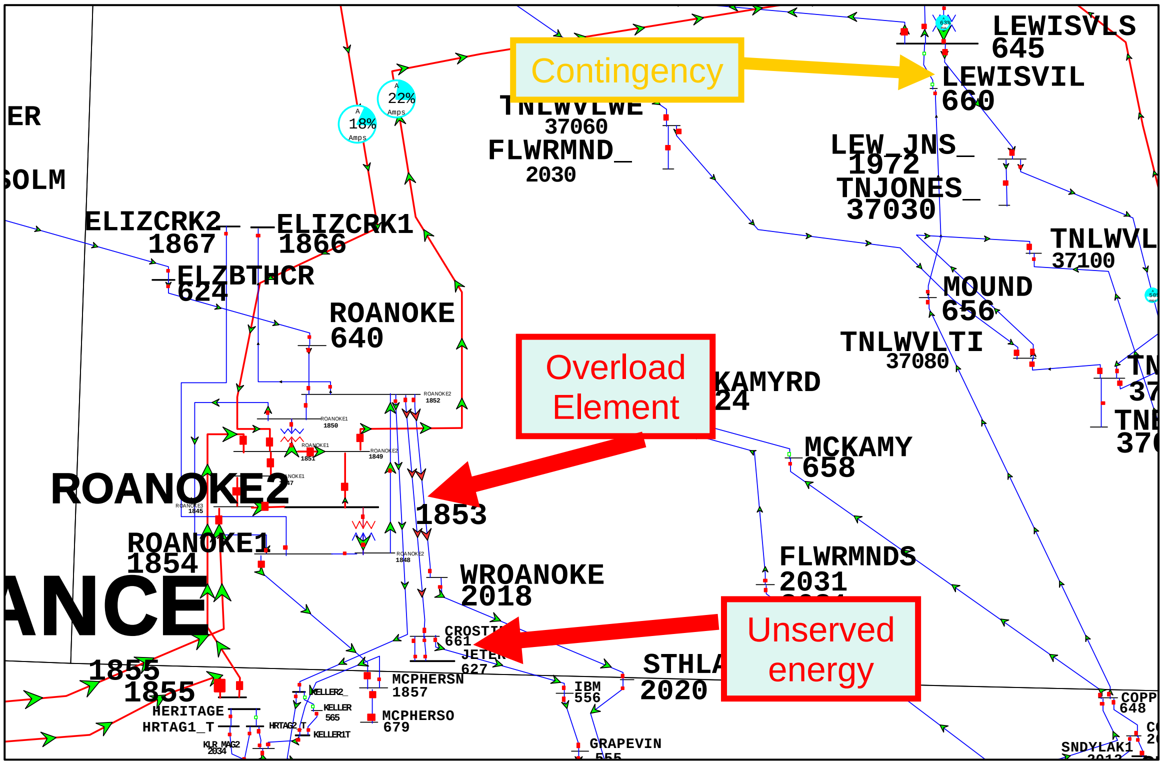


To remove the unserved energy, Austin Energy proposed building a new 138-kV transmission line between McNeil and Summit substations using bundled 795 ACSR conductors at a cost of $3.69 million. This project was first needed in 2012.

11. Cross Timbers–Roanoke 138-kV line upgrade

The contingency of the Lewisville South-Lewisville 138-kV line overloaded the Cross Timbers-Roanoke 138-kV line. This contingency overload pair caused unserved energy at Cross Timber 138-kV bus. See the following table and graph for details.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
CROSTIMB	795.29	-0.7545	CROSTIMB	ROANOKE2	LEWISVLS	LEWISVIL		

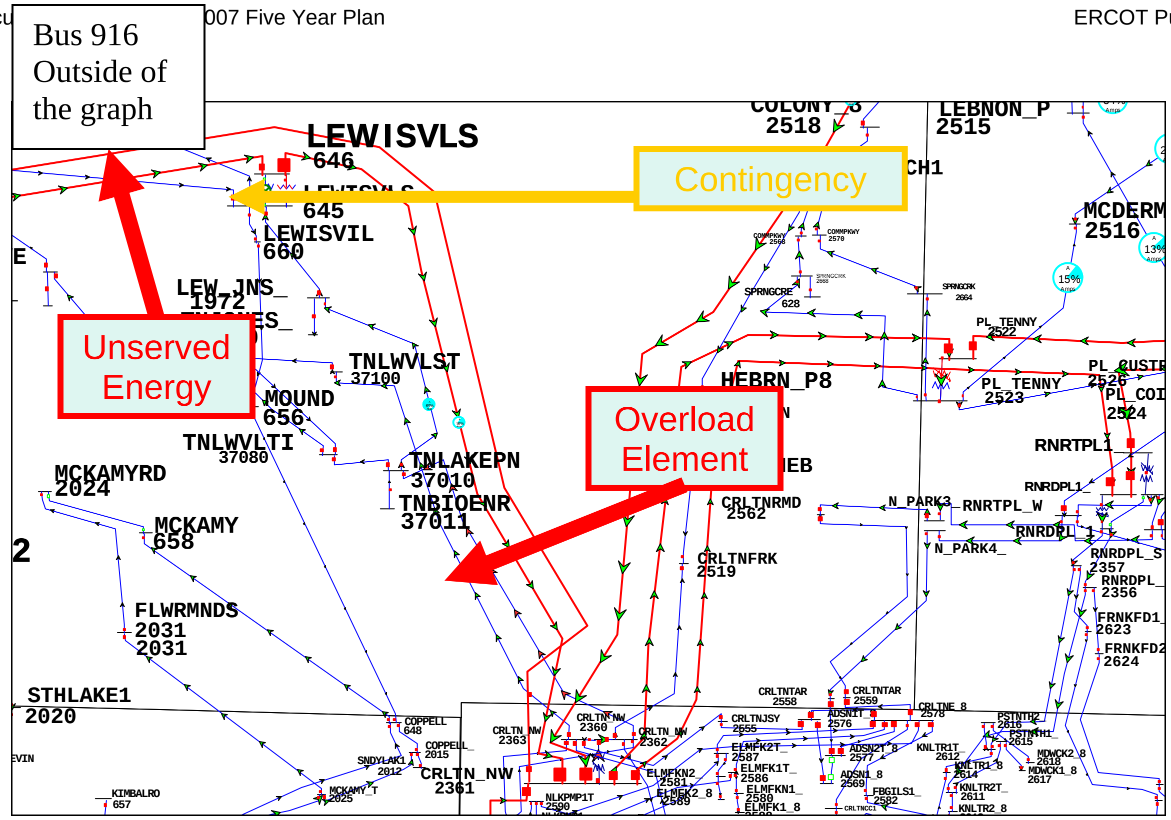


To remove unserved energy, Brazos Electric Cooperative proposed to reconductor a portion of the existing Cross Timbers-Roanoke 138-kV line to obtain a circuit rating of 356/356/356 MVA. This project was first needed in 2011.

12. Add a second 345/138-kV autotransformer at Lewisville

The contingency of the Lewisville 345/138-kV autotransformer overloaded the Carrollton Northwest–Lakepointe 138-kV line. This contingency overload pair caused unserved energy at the Jim Crystal 138-kV bus. See the following table and graph for detail.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
JMCRSTL1	1,032.12	-0.0939	TNLAKEPN	CRLTN_NW	LEWISVLS	LEWISVLS		

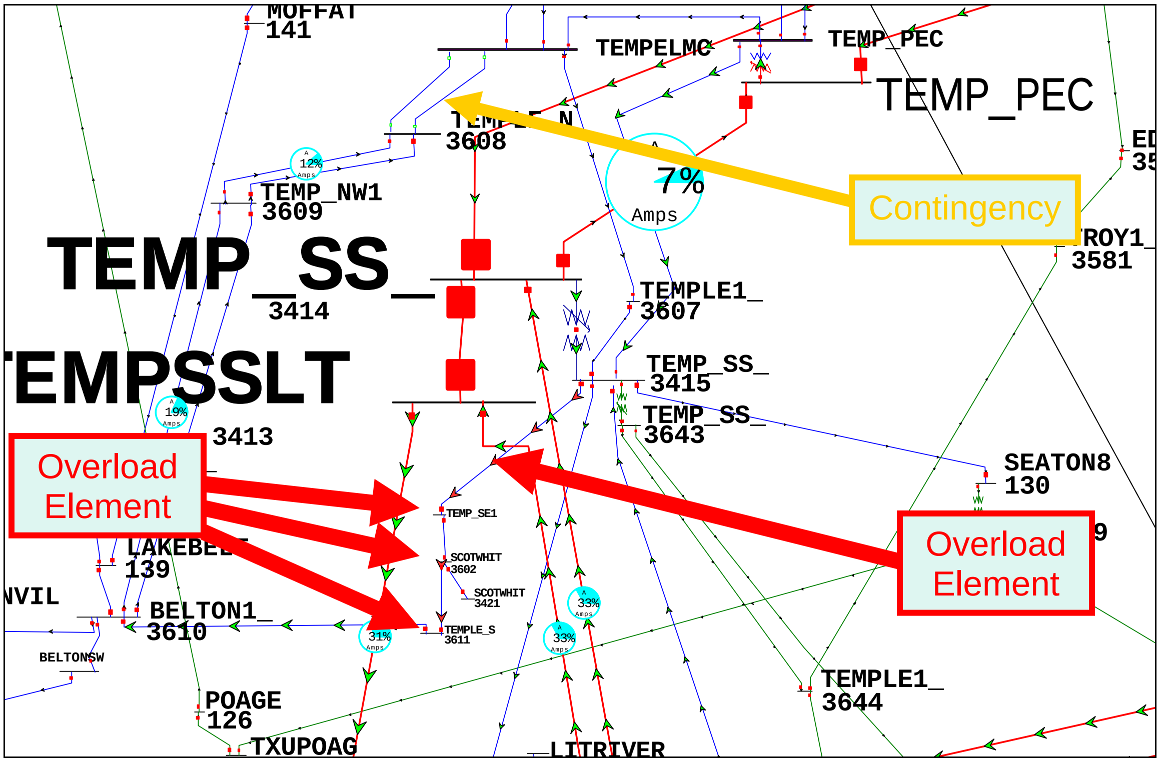


To remove the unserved energy, Brazos Electric Cooperative proposed to add a second autotransformer at Lewisville with a rating of 700/750/750 MVA. This resolved the unserved energy in the model. This project was first needed in year 2012.

13. Temple North–Temple Elm Creek 138-kV circuit reconfigure

The contingency of the Temple North–Temple Elm Creek 138-kV double circuit overloaded the Temple Switching Station–Temple Southeast 138-kV line. This contingency overload pair caused unserved energy at the Temple Southeast 138-kV bus and other nearby buses. See the following table and graph for detail.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
TEMP_SE1	375.98	-0.7333	TEMP_SS_	TEMP_SE1	TEMPLE_N	TEMPELMC	TEMPLE_N	TEMPELMC
SCOTWHIT	102.53	-0.7251	TEMP_SS_	TEMP_SE1	TEMPLE_N	TEMPELMC	TEMPLE_N	TEMPELMC
TEMPLE_S	92.02	-0.7136	TEMP_SS_	TEMP_SE1	TEMPLE_N	TEMPELMC	TEMPLE_N	TEMPELMC



To remove the unserved energy, Oncor Electric Delivery proposed to reconfigure the existing lines to different structures to eliminate the double circuit contingency. This project was first needed in 2009.

14. West Denton-Fort Worth-Teasley 138-kV upgrade

The contingency loss of the West Denton-Jim Crystal 138-kV line overloaded the West Denton-Fort Worth-Teasley 138-kV line. This caused unserved energy at the Fort Worth 138-kV bus. This unserved energy was first observed in the 2012 model.

The unserved energy was resolved in the model by upgrading the West Denton- Fort Worth-Teasley 138-kV line to have rating of 250/250/250 MVA. However, TMPA and the City of Denton proposed several other options:

Option 1: Create a West Denton-Argyle 138-kV line by adding a second circuit to the available position on a portion of the West Denton-Fort Worth-Teasley 138-kV line. This option would require approximately 0.38 miles of line to be constructed on new Right of Way (ROW).

Option 2: Add the second circuit to the available position on the West Denton-Fort Worth-Teasley 138-kV line.

Option 3: Tie the West Denton-Jim Crystal 138-kV line into a new station on the Argyle-Krum 138-kV line.

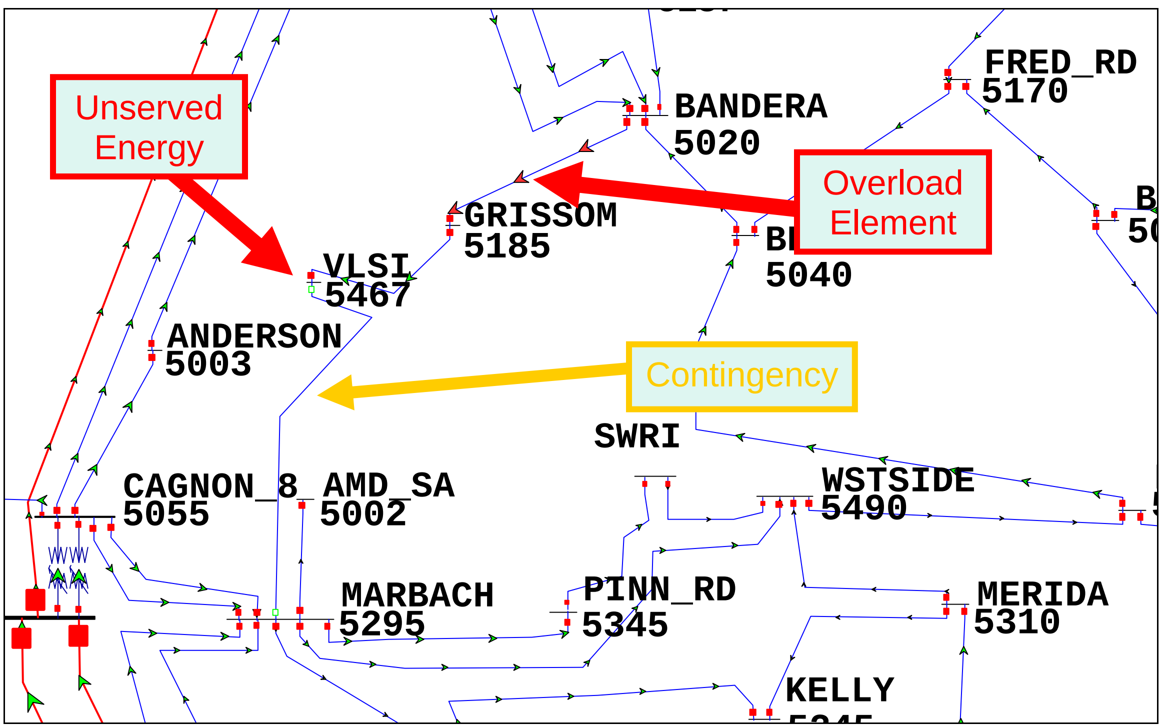
Due to time constraints these options were not fully explored in the 2007 Five-Year Plan. This should be analyzed more in future studies.

15. Anderson–Westover Hills 138-kV line upgrade

The contingency of Marbach-VLSI 138kV line overloaded the Bandera-Grissom 138kV line. This contingency overload caused unserved energy at the VLSI and Westover Hills busses.

Rapid load growth in the western part of the CPS Energy service area is due to the development of several high load commercial customers in a very short time period. The Westover Hills substation will be energized by April 2009 to accommodate this rapid growth. The substation will be radial fed from a new 138kV line extending from the VLSI substation.

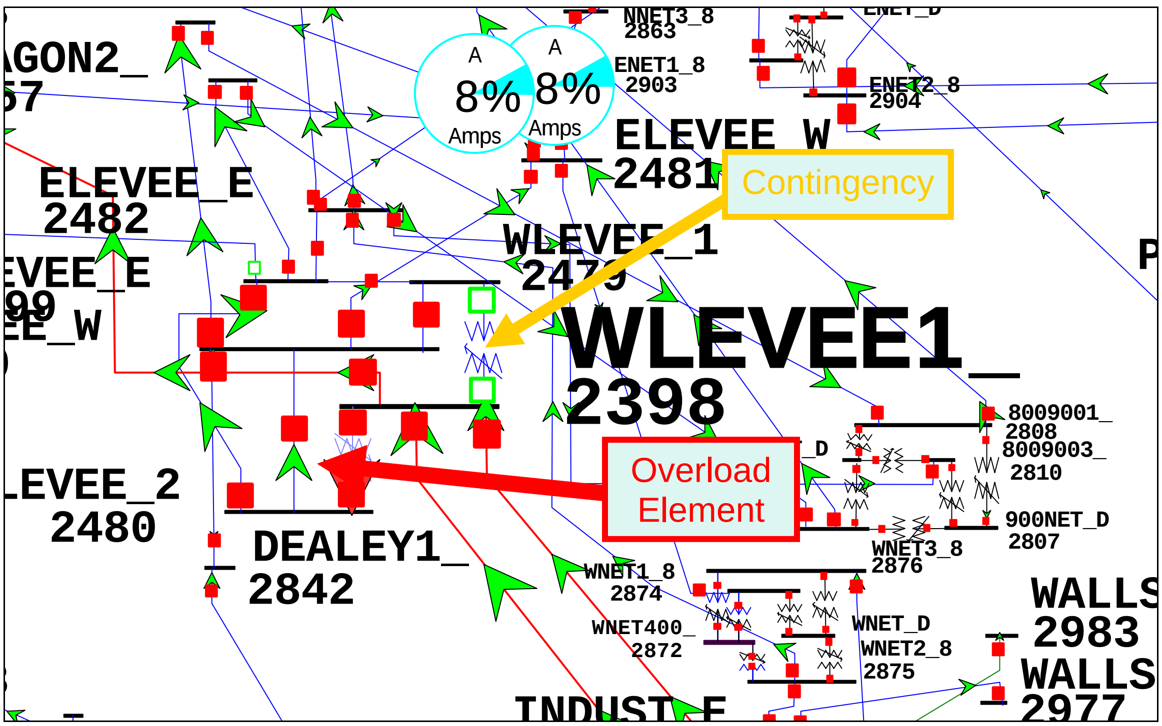
Initial assessments indicated that the Bandera-Grissom overload would occur by peak of 2011. New load projections indicate that the overload will first occur by peak of 2010. The Anderson-Westover Hills 138kV transmission line was determined to be the best solution to relieve the contingency overload causing the un-served energy.



16. West Levee Remedial Action Plan

The contingency of one of the West Levee 345/138-kV autotransformers overloaded the other West Levee autotransformer. This contingency overload pair created unserved energy at 800 Network, Dragon and other buses. See the following table and graph for detail.

Bus Name	Unserved Energy	PTDF/OTDF	Overload Element		Contingency Line 1		Contingency Line 2	
			From Bus	To Bus	From Bus	To Bus	From Bus	To Bus
800NET_D	265.30	-0.2575	WLEVEE1_	WLEVEE_2	WLEVEE1_	WLEVEE_1		
DRAGON2_	220.62	-0.2609	WLEVEE1_	WLEVEE_2	WLEVEE1_	WLEVEE_1		
DRAGON1_	174.96	-0.26	WLEVEE1_	WLEVEE_2	WLEVEE1_	WLEVEE_1		
900NET_D	160.31	-0.2575	WLEVEE1_	WLEVEE_2	WLEVEE1_	WLEVEE_1		
REAGAN2_	36.80	-0.2563	WLEVEE1_	WLEVEE_2	WLEVEE1_	WLEVEE_1		
LMOALT2_	6.57	-0.2563	WLEVEE1_	WLEVEE_2	WLEVEE1_	WLEVEE_1		



To remove the unserved energy, Oncor proposed several options:

Option1 – Install a 2-ohm series reactor on the 345/138-kV West Levee autotransformers to prevent the overload. This option was not pursued because it was found that the West Levee substation does not have enough room to install the series reactors.

Option 2 – Remedial Action Plan: If one autotransformer goes out, open some circuits and bus ties to direct power away from the other auto. This is option removed unserved energy and at no cost. This RAP was first needed in 2009.

Option 3 – Oncor also suggested installing a 345/138-kV autotransformer at Sargent Road as the long term solution for the issue. This option was not fully studied because the option was suggested after the completion of the study. ERCOT and Oncor Electric Delivery will study this option further in future studies.

B. Unserved Energy under N-1 condition without Critical Unit(s)

In section 5.1.4 of the ERCOT Operating Guides, the ERCOT system, with any single generating unit unavailable, must be able to withstand the contingency loss of a single transmission element without having to drop firm load.

The TARA program was used to determine critical units in the ERCOT system that would be studied. Of the subset of units identified by TARA, in 2012 Ferguson and Lake Hubbard 2 caused additional unserved energy when the unit outage was simulated. All critical units were tested for earlier years, but only 2012 showed additional unserved energy due to the critical units being out.

With Ferguson on outage, the contingency of Whitestone–Buttercup 138-kV line overloaded the Lago Vista–Marble Falls 138-kV line. Also, the contingency of Gabriel–Glasscock 138-kV line overloaded the Whitestone–Buttercup 138-kV line. Both of the overloaded lines are scheduled to be upgraded in 2012 and the upgrades are sufficient to relieve the overloads.

With Lake Hubbard 2 on outage, the contingency of one Centerville Switch 345/138-kV autotransformer overloaded the other Centerville Switch 345/138-kV autotransformer. Placing the series reactors in service on the Centerville Switch-Garland Road 138-kV circuits and developing a RAP that opens the 138-kV breakers looking back towards Lake Hubbard relieved the unserved energy in the system. See the description of the second Forney autotransformer above for more detail.

IV. Economic Analysis:

Table 2 shows the economically driven projects identified in the 2007 Five-Year Plan:

Project Number	Project Name	2008	2009	2010	2011	2012
E1	East Bernard-Orchard-Fort Bend 138-kV line upgrade		✓	✓	✓	✓
E2	Add a second 345/138-kV autotransformer at Concord		✓	✓	✓	✓
E3	Add a second 345/138-kV autotransformer at Whitney			✓	✓	✓
E4	Nacogdoches Southeast-Lufkin Switch 345-kV line					✓
E5	Moss-Odessa Southwest 138-kV line terminal equipment upgrade		✓	✓	✓	✓

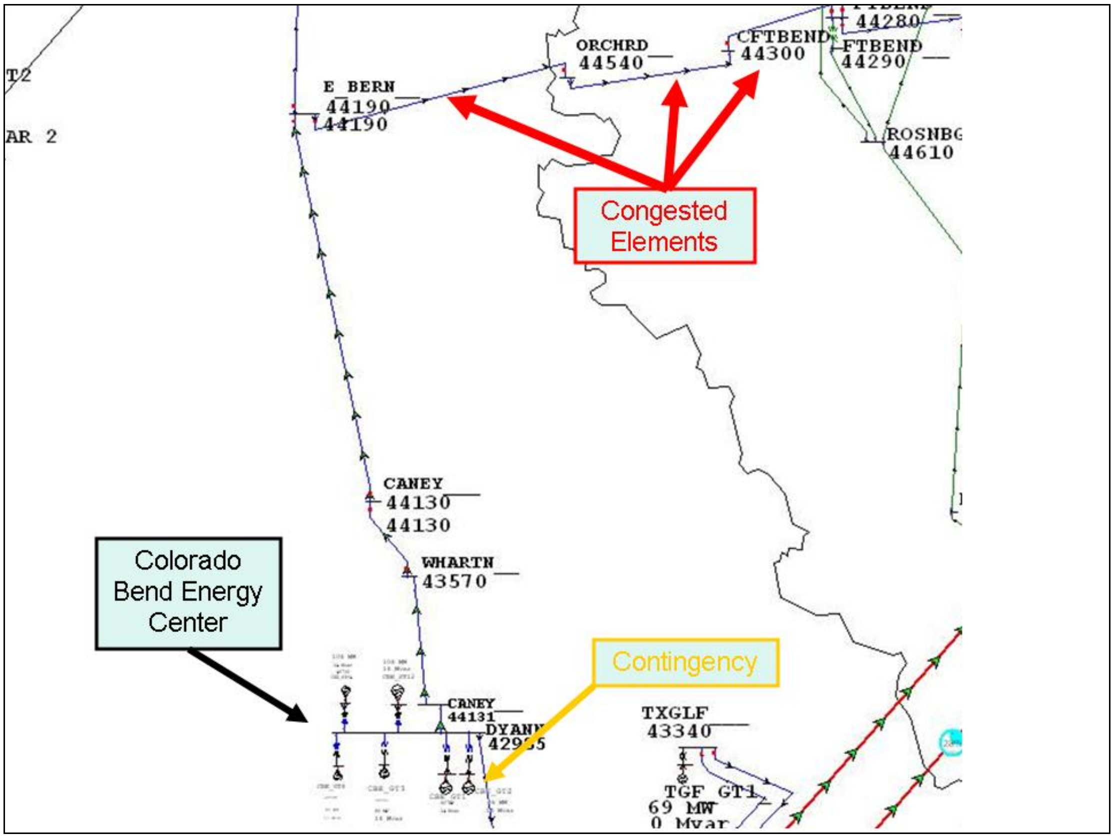
E6	**South McAllen-Las Milpas 138-kV line upgrade**					✓
E7a	**Clear Crossing 345-kV Switch Station**		✓	✓	✓	✓
E7b	**Lamesa area upgrades**			✓	✓	✓
E7c	**Paint Creek-Murray-Graham 138-kV line upgrade**				✓	✓
E7d	**Barton-Oran 138-kV line series reactor**				✓	✓
E7e	**Oklaunion-Bowman 345-kV line**					✓
E7f	**Red Creek-Killeen Switch 345-kV line**					✓

Table 2: Economic Driven Projects and Completion Year

The following are the descriptions of the economically driven projects analyzed.

1. East Bernard-Orchard-Fort Bend 138-kV line upgrade

The planned addition of the second phase of the Colorado Bend Energy Center combined cycle natural gas plant will bring the total plant capability to 550 MW in the spring of 2008. With both phase 1 and phase 2 online the model showed significant congestion on the East Bernard-Orchard-Fort Bend 138-kV circuit for the contingency loss of the Dyann-South Lane City 138-kV line. The East Bernard-Orchard-Fort Bend 138-kV line currently has an emergency rating of 220 MVA. In the 2009 model this line showed to be a binding constraint 18% of the hours of the year causing the Colorado Bend Energy Center plant to be curtailed.



CenterPoint Energy has already planned to upgrade the line on each of the East Bernard-Orchard-Fort Bend line segments to bring the normal rating of the circuit to 441 MVA and the emergency rating to 526 MVA in 2008. The cost of this project is $7.7 million. The upgrade was added to the model for years 2009 through 2012 and production cost analysis was performed. Table 3 shows the production cost savings for each year.

Year	Production Cost Savings ($M)	Capital Cost/ Savings
2009	1.92	4.0
2010	2.36	3.3
2011	3.24	2.4
2012	1.33	5.8

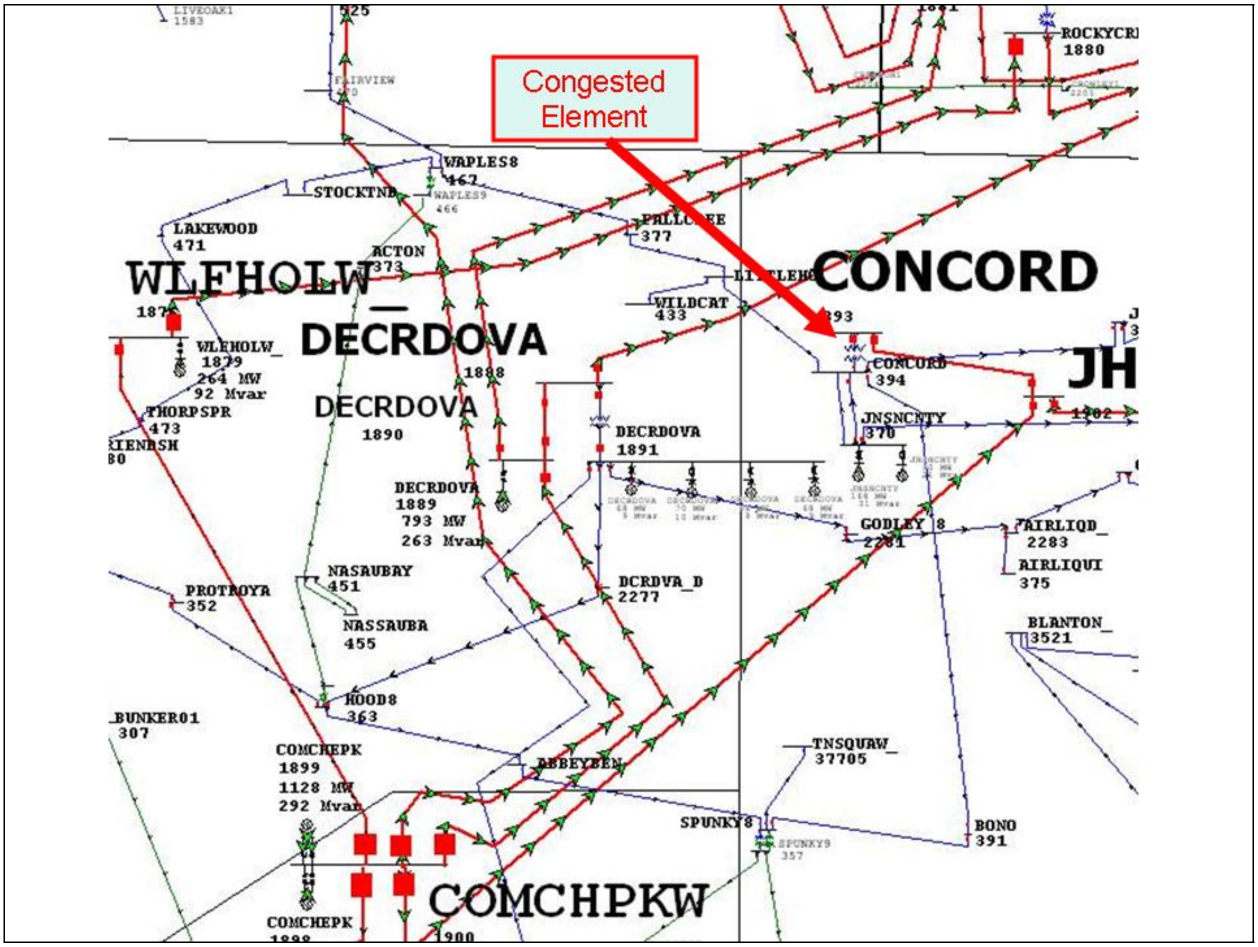
Table 3: Production cost results for East Bernard-Orchard-Fort Bend 138-kV upgrade

The results show that the circuit upgrade met the capital cost/ savings ratio goal of less than 6.0 in each of the years studied. Furthermore, there was no more congestion on the East Bernard-Orchard-Fort Bend 138-kV line once the upgrade was added. It is recommended that CenterPoint Energy proceed with the upgrade as planned.

2. Add a second 345/138-kV autotransformer at Concord

Presently, there is one 345/138-kV autotransformer with an emergency rating of 300 MVA at Concord Switch Station. This autotransformer was congested 3.0%, 4.7%, 5.4%, and 3.6% of the hours in the 2009, 2010, 2011, and 2012 respectively. The following contingencies caused this congestion:

- Comanche Peak-DeCordova/ Comanche Peak-Wolf Hollow 345-kV double circuit
- Comanche Peak-DeCordova/ Wolf Hollow-Rocky Creek 345-kV double circuit



Brazos Electric Cooperative estimated that a second autotransformer could be placed in parallel to the existing one by 2009 at a cost of $5.86 million. The second autotransformer at Concord was modeled as being identical to the existing autotransformer and production cost analysis was run for each of the years. The results are shown in Table 4.

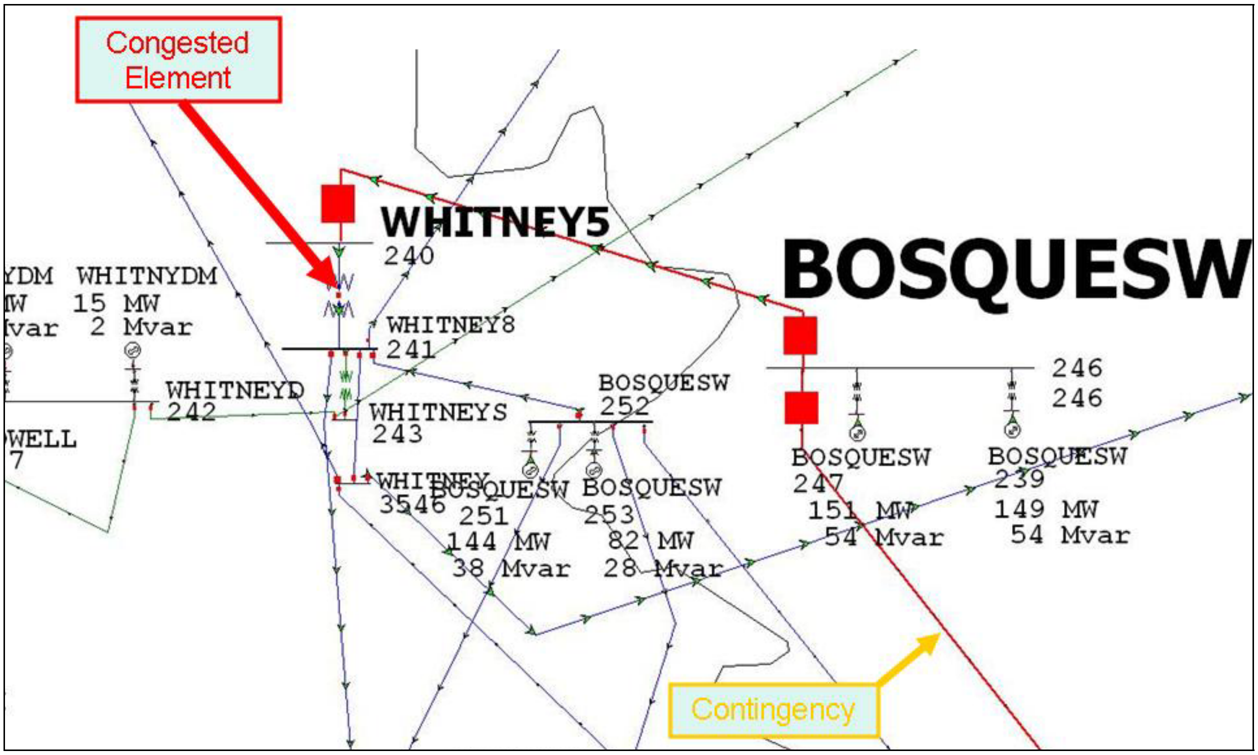
Year	Production Cost Savings ($M)	Capital Cost/ Savings
2009	3.98	1.5
2010	2.00	2.9
2011	0.86	6.8
2012	1.84	3.2

Table 4: Production cost results for a second autotransformer at Concord

The addition of the second autotransformer removed the autotransformer congestion at Concord. The model results showed positive production cost savings in all years and the cost to savings ratio was below the target of 6.0 in all years except for 2011. However, the savings during the first two years alone was enough to offset the capital cost. It is recommended that Brazos Electric Cooperative install a second 345/138-kV autotransformer at Concord.

3. Add a second 345/138-kV autotransformer at Whitney

The Bosque power plant is planned to be expanded by 255 MW by the summer of 2009. The expansion will bring the total Bosque generation injecting at the 345-kV bus to approximately 555 MW. The existing 345/138-kV autotransformer at Whitney has an emergency rating of 450 MVA. This expansion causes congestion on the Whitney 345/138-kV autotransformer under the contingency loss of the Bosque-Elm Mott 345-kV line because the contingency will cause the plant to be connected radially to the Whitney 345-kV bus and therefore force all of the plant power to flow through the Whitney autotransformer.



Brazos Electric Cooperative estimated that a second autotransformer could be placed in parallel to the existing one at a cost of $5.0 million by 2010. The second autotransformer at Whitney was modeled as being identical to the existing autotransformer. Production cost analysis was run for the years 2010 through 2012 and the results are shown in Table 5.

Year	Production Cost Savings ($M)	Capital Cost/ Savings
2010	3.63	1.4
2011	3.60	1.4
2012	2.27	2.2

Table 5: Production cost results for a second autotransformer at Whitney

The production cost analysis illustrated that adding a second autotransformer at Whitney was economical and met the cost to savings ratio goal of less than 6.0 in all years studied.

An alternative would be to place a 345/138-kV autotransformer at Bosque. This option was not analyzed in depth for the following reasons:

1. Whitney has six 138-kV lines exiting the switchyard with a total emergency MVA capability of 1771 MVA and a 75 MVA 138/69-kV autotransformer while Bosque has four 138-kV lines exiting the switchyard with a total emergency MVA capability of 828 MVA.
2. The Bosque 138-kV switchyard already has 230 MW of generation injecting directly from Bosque units 3 and 4 while Whitney has just 30 MW of generation from Whitney Hydro injecting indirectly through the 69-kV system.
3. Analysis of 2012 peak load conditions showed more than 100 MW flowing from Bosque to Whitney on the Bosque-Whitney 138-kV line under normal conditions.

Given these facts it was assumed that Whitney would be a better injection location for power from the 345-kV system.

It is recommended that Brazos Electric Cooperative install a second 345/138-kV autotransformer at Whitney. If the autotransformer cannot be installed before the generation expansion at Bosque is completed a special protection scheme (SPS) may have to be utilized until the upgrade has been completed.

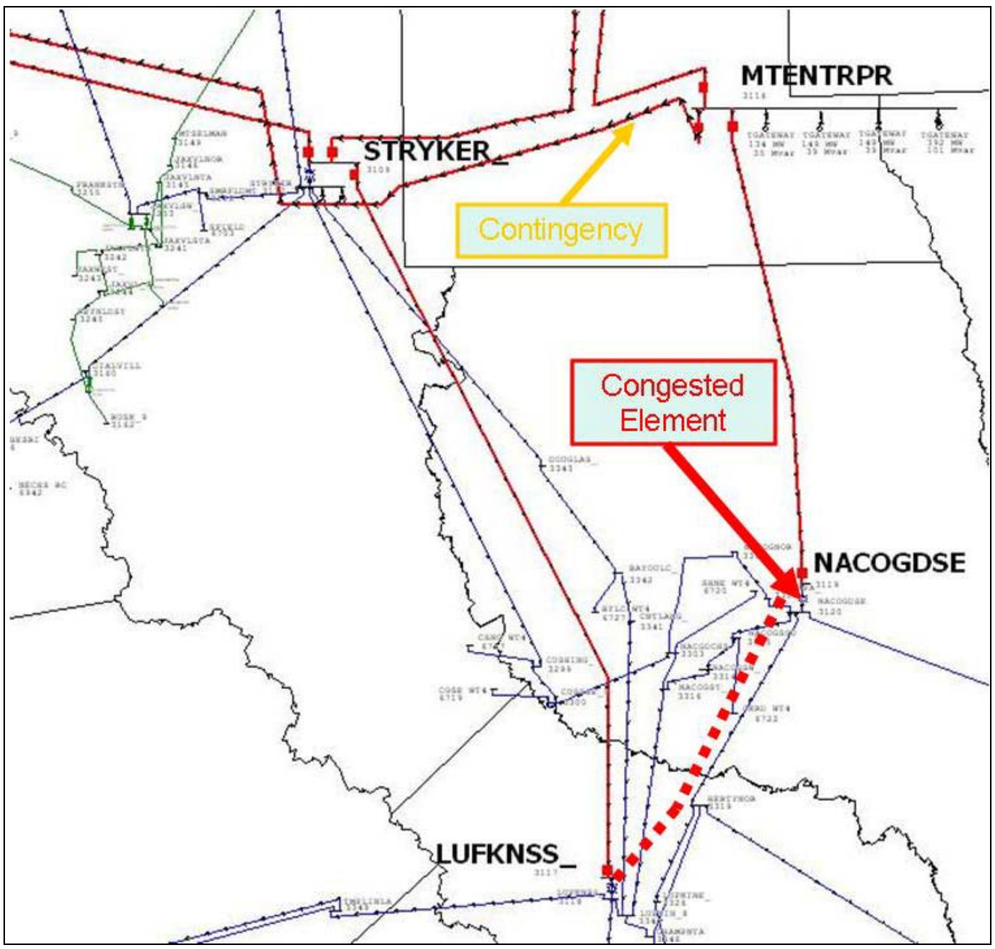
4. Nacogdoches Southeast –Lufkin Switch 345-kV line

The Gateway combined cycle gas plant is interconnected at the Mount Enterprise 345-kV Switch Station. The Mount Enterprise Switch Station has a ring bus configuration and is connected to Martin Lake and Trinidad via a double circuit 345-kV line and also has the Nacogdoches Southeast Switch Station connected radially from it. There is an existing SPS at Mount Enterprise that will back down generation at Gateway for the contingency loss of the Mount Enterprise-Martin Lake/ Mount Enterprise-Trinidad 345-kV double circuit line. This is because the contingency loss of this double circuit line will cause a transient stability problem at the Gateway plant. It is desirable to exit this SPS. Furthermore, the SPS does not prevent congestion in the area.

With the SPS removed significant congestion was observed in the area in the study model. The 2012 model showed that the Nacogdoches Southeast 345/138-kV autotransformer was congested over 2400 hours primarily for the contingency loss of the Mount Enterprise-Martin Lake/ Mount Enterprise-Trinidad 345-kV double circuit line. The contingency loss of the Martin Lake-Stryker Creek/ Mount Enterprise-Trinidad 345-kV double circuit line also caused congestion on the Nacogdoches Southeast autotransformer. Two transmission upgrade alternatives to solve this congestion were studied:

Option 1: Move the Mount Enterprise-Martin Lake 345-kV circuit off of the Mount Enterprise-Trinidad 345-kV circuit structures such that a single tower outage would not cause the loss of both circuits. Approximately 5 miles of new 345-kV line would have to be constructed on new ROW to accomplish this. Additionally, the Mount Enterprise Switch Station would have to be reconfigured so that a single breaker failure would not cause the loss of both circuits.

Option 2: Create a new Nacogdoches Southeast-Lufkin Switch 345-kV line. This upgrade would entail adding conductor to existing 345-kV structures for 13.0 miles from Nacogdoches Southeast to Herty North and constructing a 10.0 mile new double circuit capable (with one circuit in place) 345-kV line on new ROW from Herty North to Lufkin Switch. Oncor Electric Delivery estimated the capital cost of this option to be approximately $30 million.



The expected in-service date for both options was 2012. Both options were assumed to resolve the transient stability issues in the area. Production cost analysis for 2012 was run for both options and is summarized in Table 6.

Option	Production Cost Savings ($M)
1	7.2
2	13.4

Table 6: Production cost results for Mount Enterprise area

Further analysis of option 1 revealed that while congestion on the Nacogdoches Southeast autotransformer was reduced, it was still congested over 1100 hours for the contingency loss of the Martin Lake-Stryker Creek/ Mount Enterprise-Trinidad 345-kV double circuit line. This congestion was eliminated with option 2 and explains why option 2 saved $6.2 million more in 2012 than option 1 saved.

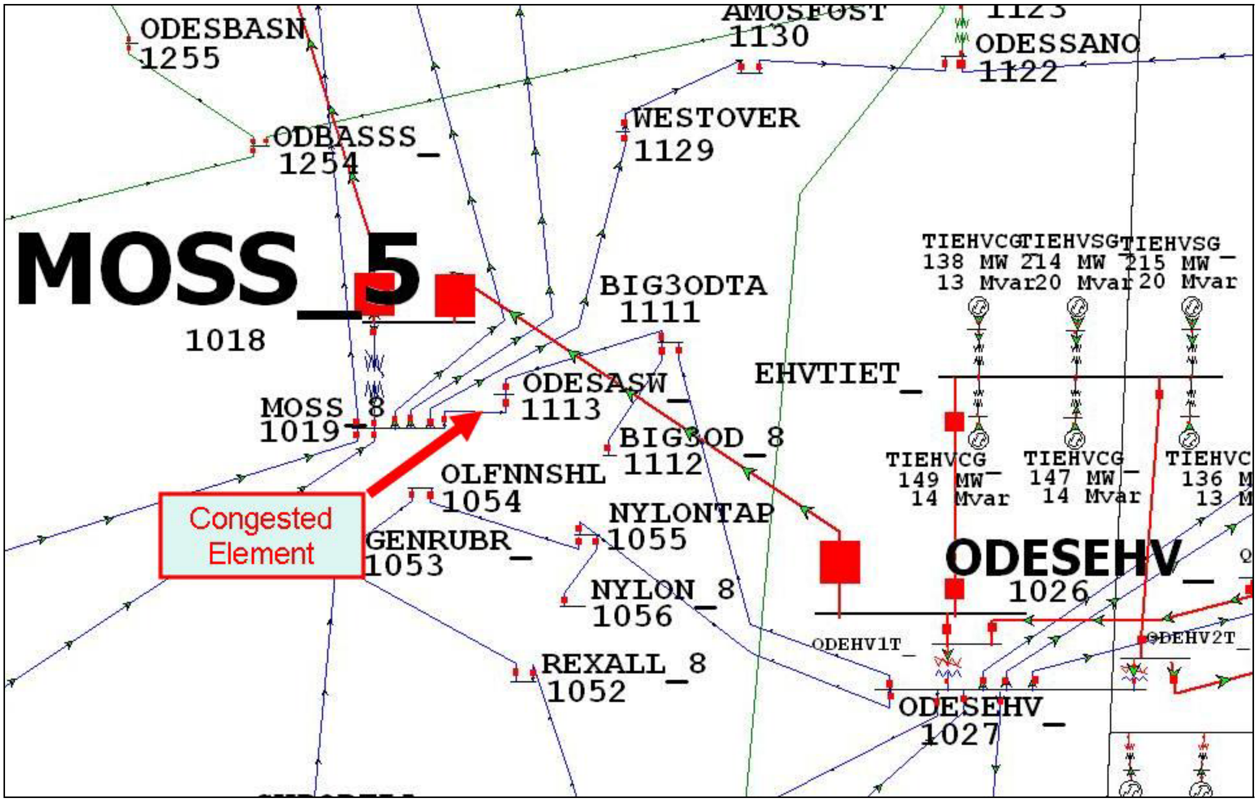
Capital cost estimates for option 1 were not obtained, but it would be reasonable to assume it would cost significantly less than option 2 since option 2 has a bigger scope. However, the additional production cost savings realized by option 2 ($6.2 million in 2012) meets the economic planning criterion of a capital cost to production cost savings ratio of less than 6.0. In other words, even if option 1 were constructed it would be economically justifiable to construct option 2 to remove all congestion on the Nacogdoches Southeast autotransformer. Furthermore, option 2 alone removes all congestion on the Nacogdoches Southeast autotransformer and meets the economic planning criterion.

Option 2 has the additional benefits of allowing for expansion to accommodate future load growth and providing better voltage support for the Lufkin and Nacogdoches areas since it would tie together two long, radial 345-kV lines. These benefits were not quantified in this analysis since the project was justified without these additional advantages. This 345 kV line was identified as economic in ERCOT’s Long Term System Assessment (LTSA) study as well.

It is recommended that a transient stability study be performed to verify that option 2 solves the stability problem. If the results of this study confirm this, then it is recommended Oncor Electric Delivery constructing the Nacogdoches Southeast-Lufkin Switch 345-kV line.

5. Moss-Odessa Southwest 138-kV line terminal equipment upgrade

The Moss-Odessa Southwest 138-kV line currently has a circuit emergency rating (Rate B) of 143 MVA. The conductor limit, however, is 214 MVA which indicates that the emergency rating is based on terminal equipment limits. This line was found to be congested 2.2%, 3.1%, 3.1%, and 3.0% of the hours in 2009, 2010, 2011, and 2012 respectively. Two contingencies caused the congestion on this line: 1. Moss 345/138-kV autotransformer and 2. Moss-Odessa EHV 345-kV line.



Oncor Electric Delivery estimated that the terminal equipment can be upgraded to bring the circuit emergency rating up to 214 MVA at a cost of $1 million. This upgrade was simulated in the model and production cost analysis was run for 2009, 2010, 2011, and 2012. The results are summarized in Table 7.

Year	Production Cost Savings ($M)	Capital Cost/ Savings
2009	1.56	0.6
2010	1.89	0.5
2011	0.45	2.2
2012	1.99	0.5

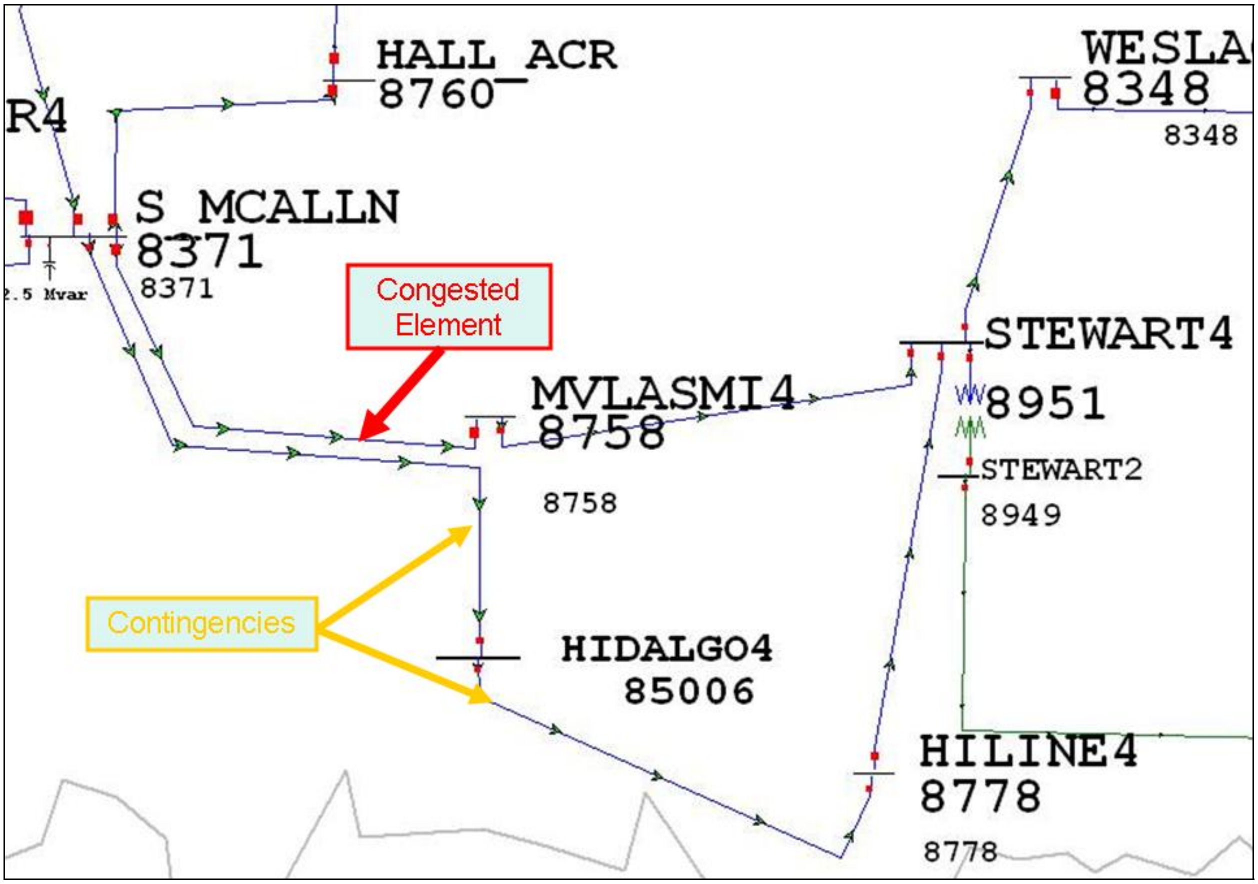
Table 7: Production cost results for Moss-Odessa Southwest 138-kV upgrade

The results indicate that the upgrade meets the capital cost/ savings ratio target for all years studied. With the upgrade the Moss-Odessa Southwest 138-kV line was no longer congested in the study models. Therefore, it is recommended that Oncor Electric Delivery upgrade the Moss-Odessa Southwest 138-kV line terminal equipment by the summer of 2009.

6. South McAllen-Las Milpas 138-kV line upgrade

The South McAllen-Las Milpas 138-kV line was congested 1.7%, 3.5%, 5.0%, and 6.5% of the hours respectively in the 2009, 2010, 2011, and 2012 models for the contingency loss of the

South McAllen-Hidalgo 138-kV line or the Hidalgo-Hi Line 138-kV line. Currently, the South McAllen-Las Milpas 138-kV line has a Rate B of 152 MVA and is 5.9 miles long.



AEP proposed upgrading this line to have a Rate B of 365 MVA at a cost of $4.425 million. This upgrade was modeled in the 2009 through 2012 models and production cost analysis was performed. The results are shown in Table 8.

Year	Production Cost Savings ($M)	Capital Cost/ Savings
2009	0	No Savings
2010	0.1	44.3
2011	0.6	7.4
2012	2.5	1.8

Table 8: Production cost results for South McAllen-Las Milpas 138-kV line upgrade

The results show that the capital cost to savings ratio was below 6.0 in the 2012 model, but not in the other years. Because of this it is recommended that the South McAllen-Las Milpas 138-kV line be upgraded as described by 2012.

7. West Region Upgrades

The western portion of the ERCOT system was heavily congested in the models for all years studied. This is mostly due to the dramatic increase in wind generating resources in the west. Overall, the wind energy in the 2012 model was curtailed 7.2% before any improvements were implemented.

The majority of this congestion was observed on the underlying 138-kV and 69-kV system connecting the west to the north for the contingency loss of one of the bulk 345-kV lines. Table 9 illustrates some of the most heavily congested lines in the 2012 model. In general it was found that upgrading the underlying transmission elements was not economical because these are typically expensive upgrades that only provide marginal benefit. Two solutions to resolve this issue are presented. First, many of the lower voltage circuits can be opened so that the regional transfer of power from the west is forced onto the bulk 345-kV transmission lines. Second, additional 345-kV transmission lines can be constructed to provide alternate paths out of the west for the contingency loss of the existing 345-kV lines.

Limiting Element	Limiting Contingency	Hours Congested in 2012 Model
Vernon-Grayback 69-kV line	Oklaunion-Fisher Road-Bowman 345-kV line	5096
Fort Mason-Fredonia 69-kV line	Gillespie-Fort Mason 138-kV/ Gillespie-Phillips Mason Tap 69-kV double circuit	4652
Murray-Graham 138-kV line	Graham-Sweetwater/ Graham-Cook Field Road 345-kV double circuit	1799
Fredonia-Castell 69-kV line	Gillespie-Fort Mason 138-kV/ Gillespie-Phillips Mason Tap 69-kV double circuit	1165
Yellowjacket-Hext 69-kV line	Yellowjacket-Mason 138-kV line	1106
Lamesa-Paul Davis Tap 138-kV line	Quail Run-Morgan Creek/ Odessa EHV-Long Shore 345-kV double circuit	530

Table 9: Heavily congested lines in the 2012 model before economic improvements

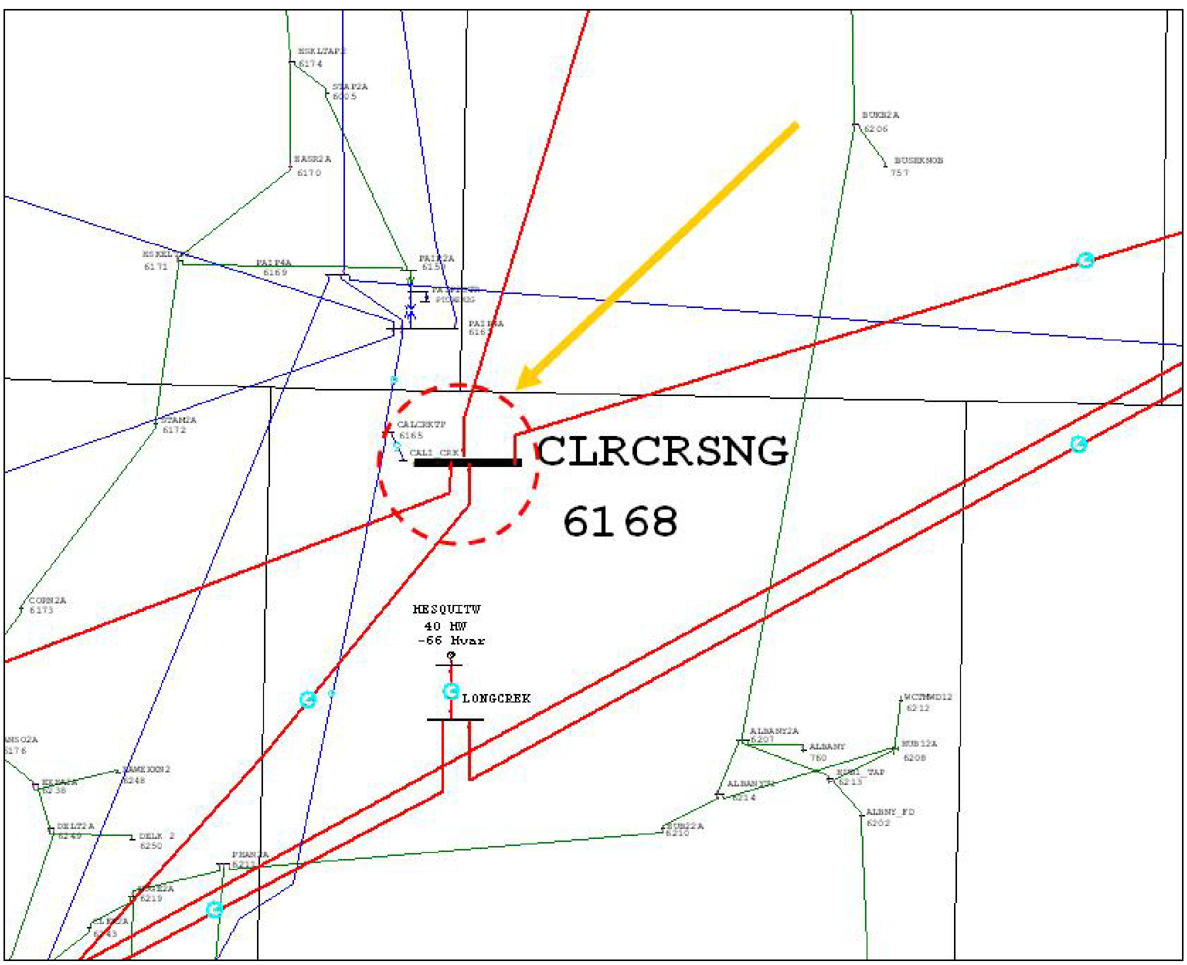
Additionally, there were several locations where wind generators were greatly congested due to local transmission constraints. Local system improvements as well as opening lower voltage circuits were explored as solutions for these cases.

Following is a discussion of each of the recommended projects in the western portion of the ERCOT system which are designed to reduce the large amount of congestion found in this area. Additionally, several of the alternative projects that were studied are presented.

a) Clear Crossing 345-kV Switch Station

The contingency loss of the Oklaunion-Fisher Road-Bowman 345-kV line caused the Long Creek-Cook Field Road-Graham 345-kV line to be congested 35.8%, 33.0%, and 35.1% of the hours in the 2009, 2010, and 2011 models respectively. It also made the congestion in some of the underlying 138 and 69 kV lines in the West region worse. The new Oklaunion-Bowman 345-kV line (discussed later) would solve the congestion on the Long Creek – Cook Field Road – Graham 345 kV line under the above contingency and reduces congestion on some of the 138 and 69 kV lines, because it parallels the contingency outaged line. However, this line cannot be constructed before 2012; therefore another solution was sought in the meantime.

The Oklaunion-Mulberry Creek and Tonkawa-Graham 345-kV lines cross at a point in Haskell County. Electrically tying these lines together at a switch station called Clear Crossing would create a parallel path for power flowing west to north on the Long Creek-Cook Field Road-Graham 345-kV line from the Oklaunion-Mulberry Creek 345-kV line by allowing power to flow to Graham from Clear Crossing. AEP estimated that the Clear Crossing Switch Station could be constructed by 2009 at a cost of $11 million.



Clear Crossing was modeled in the 2009 through 2012 models to determine if it reduced congestion. Table 10 shows the production cost savings for each year and its impact to overall wind generation dispatching capacity factor (CF).

Year	Production Cost Savings ($M)	Capital Cost/ Savings	Overall increase in Wind CF
2009	2.92	3.8	0.6%
2010	6.84	1.6	0.9%
2011	9.54	1.2	1.0%
2012	3.21	3.4	0.4%

Table 10: Production cost results for Clear Crossing 345-kV Switch Station

The results showed significant production cost savings in 2010 and 2011 and moderate savings in 2009 and 2012. The contingency loss of the Oklaunion-Fisher Road-Bowman 345-kV line no longer caused congestion in any of the study models. The Long Creek-Cook Field Road-Graham 345-kV line was still congested 3.6%, 1.9%, and 2.8% of the respective hours in 2009, 2010, and 2011 for the contingency loss of the Clear Crossing-Graham 345-kV line. However, this still represented a considerable reduction in congestion on this line. The Clear Crossing station also reduced congestion on some of the underlying 138 and 69 kV elements.

The savings in the 2012 model were not as great as the previous years because the Oklaunion-Bowman 345-kV line was assumed to be in-service in 2012. Even then, the project increased the total wind energy by 0.4% in the 2012 model and capital cost to production cost saving ratio is significantly lower than the 6.0 target.

The savings in 2009 were also notably less than in 2010 and 2011. This is most likely due to the fact that other improvements to reduce local congestion in the west will not be completed by 2009, thus causing some level of economic wind generation to be congested regardless of Clear Crossing. Nonetheless, the switch station showed positive production cost savings and met the capital cost to production cost savings ratio goal of less than 6.0 in all years studied. Furthermore, the savings in the first three years offset the capital cost of the project.

As mentioned earlier, the most effective alternative to implementing the Clear Crossing Switch Station would be to construct new bulk transmission lines such as the Oklaunion-Bowman 345-kV line or other lines connecting the west to the rest of ERCOT. However, it is unlikely that these improvements could be implemented faster than Clear Crossing since new lines on new ROW would be required to go through the CCN process.

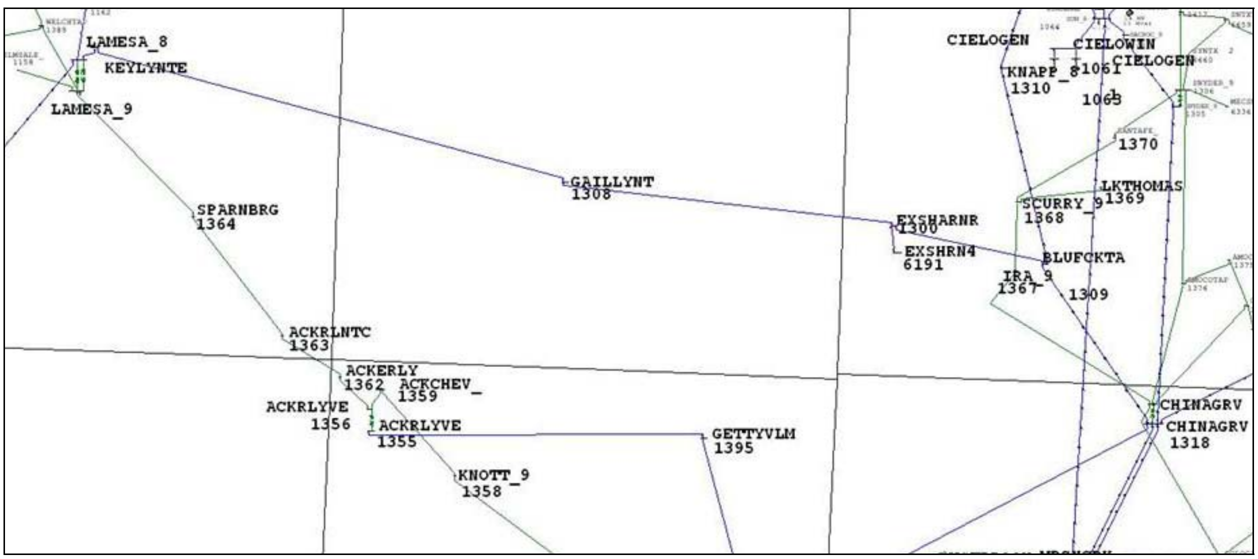
Another option would be to reconductor or rebuild the Long Creek-Cook Field Road-Graham 345-kV line with a larger conductor. This would also likely require upgrading the Sweetwater-Graham 345-kV line which shares structures with the Long Creek-Cook Field Road-Graham 345-kV line. Altogether, this would entail upgrading at least the 122.4 circuit miles of 345-kV line between Long Creek and Graham. Since this would be an expensive upgrade and would cause large amounts of congestion over a lengthy time while the lines were out for construction it was not considered further.

An additional improvement was analyzed to determine if disconnecting the Mulberry Creek 345-kV Switch Station from the Bitter Creek-Mulberry Creek-Long Creek 345-kV line would provide additional congestion reduction. AEP estimates that the improvements needed to accomplish this at Mulberry Creek would cost $10 million. Production cost analysis was performed with this improvement in addition to the Clear Crossing Switch Station. It was found that in each of the models for 2009 through 2012 there was only minimal production cost savings (less than $1 million in each of the years). This additional savings did not justify the additional cost for implementing the improvements at Mulberry Creek.

It is recommended that AEP and Oncor Electric Delivery construct the Clear Crossing 345-kV Switch Station as described.

b) Lamesa area upgrades

Two new wind plants are expected to go in-service in the second half of 2008 on the Lamesa-Bluff Creek 138-kV line. The 180 MW Airtricity Lamesa wind plant in Dawson County will be connected to a new switch station, Cotton, between the Key and Gail substations. The 180 MW Bull Creek wind plant in Borden County will be connected to a new switch station, Willow Valley, between the Gail and Exxon Sharon Ridge substations. Currently this line has a conductor rating of 186 MVA and is terminal equipment limited to an emergency rating of 143 MVA.



Because the total wind generation capacity on the line is 360 MW and the line is currently limited to 143 MVA, it is obvious that these plants will see substantial congestion without transmission system improvements and/ or an SPS. Many other lines in the area will also see congestion under contingency.

Oncor Electric Delivery suggested the following system improvements in order to reduce congestion in the Lamesa area due to the addition of the new plants:

- Rebuild the Lamesa – Key – Cotton 138-kV line sections (10.8 miles) with double circuit structures, one circuit in place, using conductor rated at 393 MVA
- Rebuild the Willow Valley – Exxon Sharon Ridge – Bluff Creek 138-kV line sections (17.4 miles) with double circuit structures, one circuit in place, using conductor rated at 393 MVA
- Rebuild the Bluff Creek – China Grove 138-kV line (12.8 miles) with double circuit structures, one circuit in place, using conductor rated at 393 MVA
- Rebuild the Lamesa – Ackerly Vealmoor 69-kV line (21.5 miles) with double circuit structures, both circuits in place, one operated at 138 kV with a rating of 393 MVA and one operated at 69 kV with a rating of 197 MVA
- Construction of a 138-kV breaker-and-half switchyard at Ackerly Vealmoor (four positions initially)
- Rebuild the Lamesa 138-kV switching station in a breaker and half arrangement to accommodate a minimum of 8 line positions
- Several terminal equipment upgrades

Oncor Electric Delivery estimates that these improvements can be constructed by 2010 at a cost of $40.5 million. Production cost analysis was performed to determine the economic benefit of the transmission upgrades in 2010, 2011 and 2012. The results are summarized in Table 11.

Year	Production Cost Savings ($M)	Capital Cost/ Savings	Overall increase in Wind CF
2010	7.14	5.6	0.5%
2011	8.00	5.0	0.6%
2012	6.65	6.0	0.7%

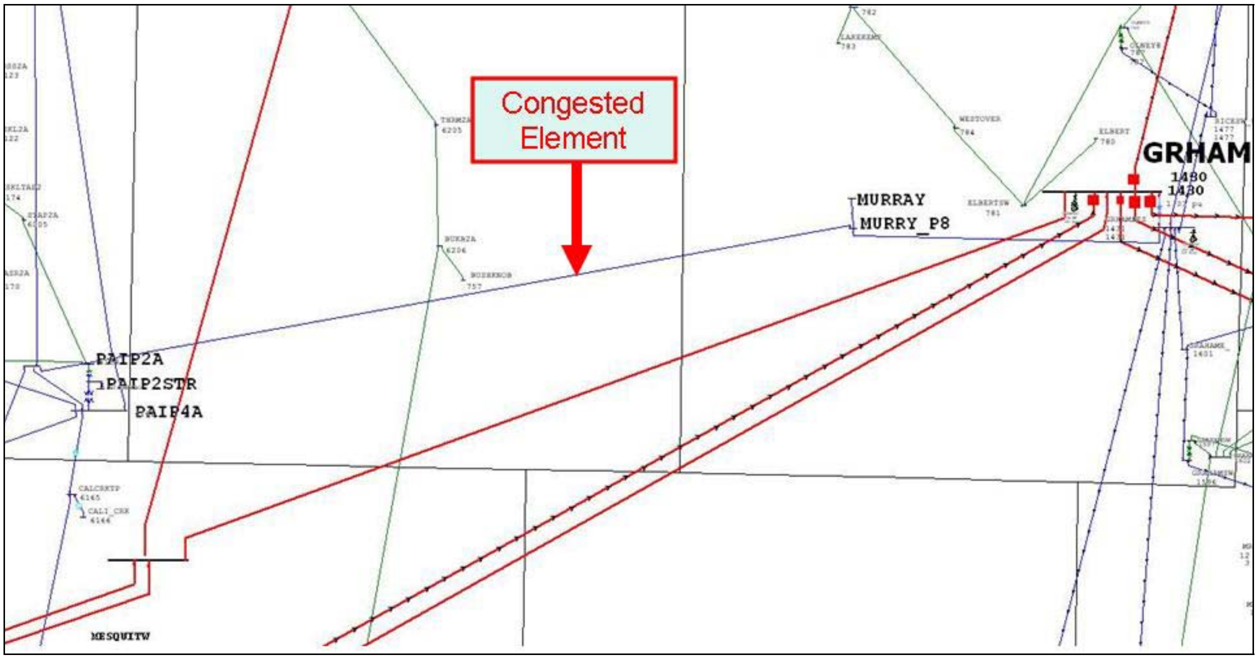
Table 11: Production cost results for the Lamesa area upgrades

The results show that congestion was reduced and that the upgrades met the economic planning criterion of the capital cost to savings ratio being less than or equal to 6.0 for all of the years studied. However, at the time of this report, Oncor had submitted a project for RPG review in the area with updated information. As a result, this project will be restudied as part of the RPG review. Further, the implementation of the upgrades should wait to ensure compatibility with the CTO study.

c) Paint Creek-Murray-Graham 138-kV line upgrade

The Paint Creek-Murray-Graham 138-kV line was congested 14.6%, 9.2%, 14.4%, and 13.9% of the respective hours in the 2009, 2010, 2011, and 2012 models. The following contingencies caused this congestion:

- Sweetwater-Graham/ Cook Field Road-Graham 345-kV double circuit
- Sweetwater-Graham/ Long Creek-Cook Field Road 345-kV double circuit
- Sweetwater-Graham/ Mulberry Creek-Long Creek 345-kV double circuit
- Cook Field Road-Graham 345-kV line
- Long Creek-Cook Field Road 345-kV line



The Murray-Graham portion of the line currently has terminal equipment that limits the circuit to an emergency rating of 143 MVA. The conductor rating is 186 MVA. The majority of the Paint Creek-Murray 39.2 mile line has a conductor rating of 186 MVA; however, there is an approximately one mile section that limits the circuit to 155 MVA. Oncor Electric Delivery estimates that this one mile section of line and the terminal equipment on the Murray-Graham portion can be upgraded to bring the entire circuit rating to 186 MVA for $0.5 million.

Production cost analysis was performed with this upgrade added to the model for the years 2009 through 2012. The results are summarized in Table 12.

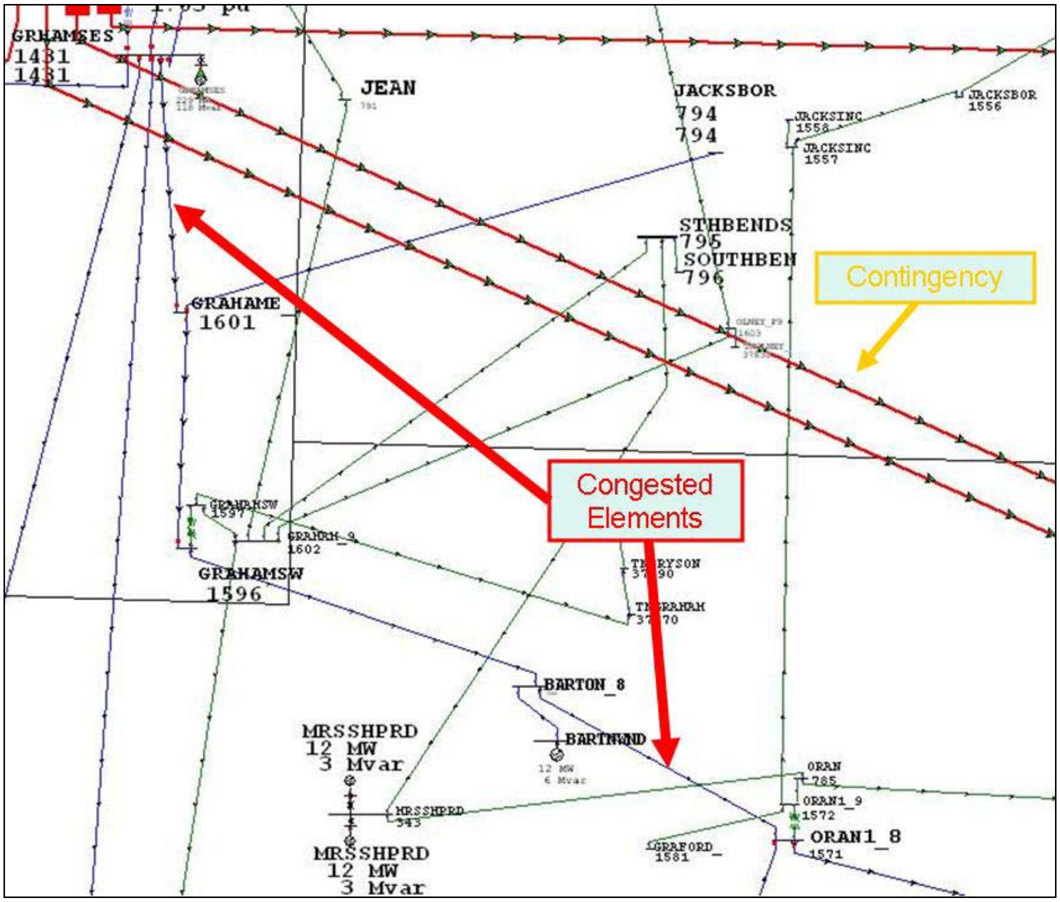
Year	Production Cost Savings ($M)	Capital Cost/ Savings
2009	0	No Savings
2010	0.07	7.1
2011	0.60	0.8
2012	0.16	3.1

Table 12: Production cost results for the Paint Creek-Murray-Graham 138-kV line upgrade

The results showed that the upgrade eliminated the congestion on the line; however, the production cost results were inconsistent. The model for 2009 and 2010 did not show enough production cost savings to justify the upgrade. However, the savings in 2011 alone offset the capital cost of the project. The savings continued in the 2012 model, although they were not as high. It is recommended that Oncor Electric Delivery and AEP upgrade the Paint Creek-Murray-Graham 138-kV line as described by 2011.

d) Barton-Oran 138-kV line series reactor

The contingency outage of the Graham-Parker/ Graham-Benbrook 345-kV double circuit causes the Barton-Oran and Graham-Graham East 138-kV lines to be congested 16.4%, 1.6%, 17.6%, and 11.6% of the respective hours in the 2009, 2010, 2011, and 2012 models.



Since the congestion was caused by the contingency loss of a 345-kV double circuit overloading an underlying 138-kV line, one solution to this problem would be to construct a parallel bulk transmission line to transfer the power out of west Texas. However, this solution, while still explored, would not likely be able to be constructed before 2012.

Another option would be to upgrade the approximately 35.2 miles of 138-kV line between Graham and Oran. This would likely be a costly upgrade. Oncor Electric Delivery proposed adding a series reactor up to 15 ohms in the Barton-Oran 138-kV line in order to prevent flow on the 138-kV system under contingency loss of the 345-kV lines.

Four options were explored:

1. Install a 9-ohm series reactor in the Barton-Oran 138-kV line and place it in service full time

2. Install a 12-ohm series reactor in the Barton-Oran 138-kV line and place it in service full time
3. Install a 15-ohm series reactor in the Barton-Oran 138-kV line and place it in service full time
4. Install a 12-ohm series reactor in the Barton-Oran 138-kV line and operate it as an SPS so that it is only in service if a contingency causes the lines to overload

The cost for all of the above options was assumed to be $1 million. Production cost analysis was performed for each of the options for the years 2009-2012. The results are summarized in Table 13.

Year	Barton-Oran Series Reactor Option	Production Cost Savings ($M)	Capital Cost/ Savings
2009	9-ohm, full time	-2.5	No Savings
	12-ohm, full time	-3.5	No Savings
	15-ohm, full time	-3.0	No Savings
	12-ohm, SPS	-1.3	No Savings
2010	9-ohm, full time	-2.8	No Savings
	12-ohm, full time	-2.5	No Savings
	15-ohm, full time	-2.8	No Savings
	12-ohm, SPS	-0.4	No Savings
2011	9-ohm, full time	0.4	2.5
	12-ohm, full time	0.9	1.1
	15-ohm, full time	0.1	10
	12-ohm, SPS	0.9	1.1
2012	9-ohm, full time	2.8	0.4
	12-ohm, full time	0.8	1.3
	15-ohm, full time	2.0	0.5
	12-ohm, SPS	2.1	0.5

Table 13: Production cost results for Barton-Oran 138-kV line series reactor options

Congestion analysis showed that all options except the 9-ohm series reactor eliminated congestion on the Barton-Oran and Graham-Graham East 138-kV lines in all years studied. All options caused an increase in production costs for the years 2009 and 2010, but a decrease in production costs for the years 2011 and 2012. It is not clear from the model why the production costs increased during the first two years.

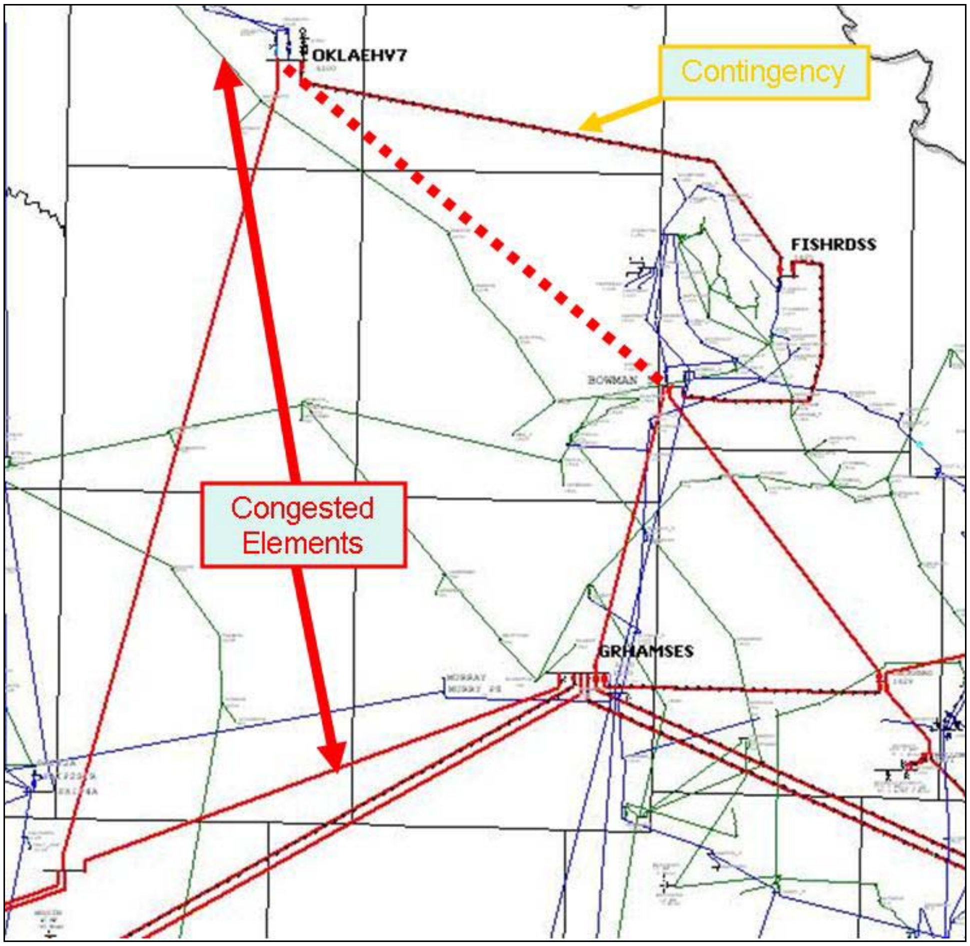
Based on the above analysis, the 9-ohm series reactor appears to save the most in terms of production costs in the 2011 and 2012 models. Because of this, the option of placing a 9-ohm series reactor in the Barton-Oran 138-kV line is recommended for 2011. However, since this is not a long lead time construction project, it should not proceed until after the CTO study has been completed.

e) Oklaunion-Bowman 345-kV line

In the 2012 model, the power from the Oklaunion coal plant and the power importing to ERCOT from the North DC tie at Oklaunion flowed towards the Dallas-Fort Worth area. The Oklaunion switch yard is connected to the rest of ERCOT via two 345-kV lines and two 345/138-kV autotransformers. For the contingency loss of the Oklaunion-Fisher Road 345-kV line the power was forced to flow through the Clear Crossing 345-kV switch station which overloaded the Clear Crossing-Graham 345-kV line and through the underlying 138-kV and 69-kV network between Oklaunion and the Dallas-Fort Worth area causing congestion on this part of the system as well.

One option would be to open up some of the lower-voltage underlying transmission lines. However, this solution only addresses part of the problem and causes the Clear-Crossing-Graham 345-kV line to become more congested. Furthermore, models with this option did not eliminate congestion on the underlying circuits, but simply shifted the congestion around to other 138-kV and 69-kV elements.

Constructing a new 345-kV line between the Oklaunion and Bowman switch stations was explored. This line would entail constructing a single circuit 345-kV line on approximately 37.5 miles of new ROW. Oncor Electric Delivery estimated that the cost to construct this line would be $71.3 million while AEP estimated the cost to be $60 million. For the purposes of this study the cost was assumed to be $71.3 million in order to be more conservative with the analysis.



The line was implemented in the 2012 model along with a variety of other planned improvements in the west including the Lamesa area upgrades, the Clear Crossing 345-kV Switch Station, the Paint Creek-Murray-Graham 138-kV line upgrade, and the Red Creek-Killeen Switch 345-kV line (discussed later). Before adding the line, the Vernon-Grayback 69-kV line was congested 42.1% of the hours in the model for the contingency loss of Oklaunion-Fisher Road-Bowman 345-kV line. The Clear Crossing-Graham 345-kV line was congested 6.4% of the hours for the contingency loss of the Sweetwater-Graham/ Cook Field Road-Graham 345-kV double circuit.

Congestion analysis showed that the project reduced production costs by $27.8 million in the 2012 model. This gave a capital cost to savings ratio of 2.6 which was below the target maximum ratio of 6.0. Furthermore, no underlying 69-kV or 138-kV circuits in the area overloaded. The congestion on the Clear Crossing-Graham 345-kV line was also reduced to 2.1% of the hours. This project also decreased wind curtailment by 1.1 percentage points.

Further analysis was conducted to determine if the Red Creek-Killeen Switch 345-kV line and related alternatives had a major impact on the effectiveness of the Oklaunion-Bowman line. Production cost analysis was run on a number of different scenarios with and without the Oklaunion-Bowman 345-kV line in the 2012 model. Some of the lines in the alternate scenarios will be discussed later. Table 14 summarizes the results of this analysis. The base scenario represents the 2012 model with the Lamesa area upgrades, the Clear Crossing 345-kV Switch Station, the Paint Creek-Murray-Graham 138-kV line upgrade, and the Red Creek-Killeen Switch 345-kV line.

Scenario	Production Cost Savings ($M) for Oklaunion-Bowman 345-kV line	Capital Cost/ Savings
Base	27.8	2.6
Base without Red Creek-Killeen Switch 345-kV line	31.9	2.2
Base with Long Creek-Hicks 345-kV line	25.0	2.9
Base without Red Creek-Killeen Switch 345-kV line; Long Creek-Hicks 345-kV line added	22.3	3.2
Base without Red Creek-Killeen Switch 345-kV line; Red Creek-Everman 345-kV line added	22.2	3.2

Table 14: Production cost savings for Oklaunion-Bowman 345-kV line in alternate scenarios

The results indicate that regardless of other bulk 345-kV lines that may be constructed from the west to the rest of ERCOT the Oklaunion-Bowman 345-kV line proved to have a significant amount of production cost savings in the 2012 model. Moreover, the capital cost to savings ratio met the target of being less than 6.0 for all scenarios studied.

For purposes of the 5-year plan the Oklaunion-Bowman 345-kV line is a recommended project. However, work should not begin on this line until after the CTO study is complete to determine if this upgrade will be superseded unless otherwise released through the RPG process due to constraints caused by additional generator interconnections.

f) West Texas 345-kV bulk system improvements

As discussed previously, there are a number of underlying 69-kV and 138-kV transmission circuits connecting the western portion to the rest of the ERCOT system that were congested in the model for the contingency loss of one of the bulk 345-kV lines. This is primarily due to the large increase in wind generation in the west. In order to reduce this congestion, several new bulk 345-kV lines were analyzed.

The 2012 model was used for this analysis since it is unlikely that long 345-kV lines on new ROW could be constructed before this time. This model contained the following aforementioned upgrades in the western region:

- Lamesa area upgrades
- Oklaunion-Bowman 345-kV line

- Clear Crossing 345-kV switch station
- Paint Creek-Murray-Graham 138-kV line upgrade

Before any additional upgrades were implemented the overall wind generation curtailment was 4.7%.

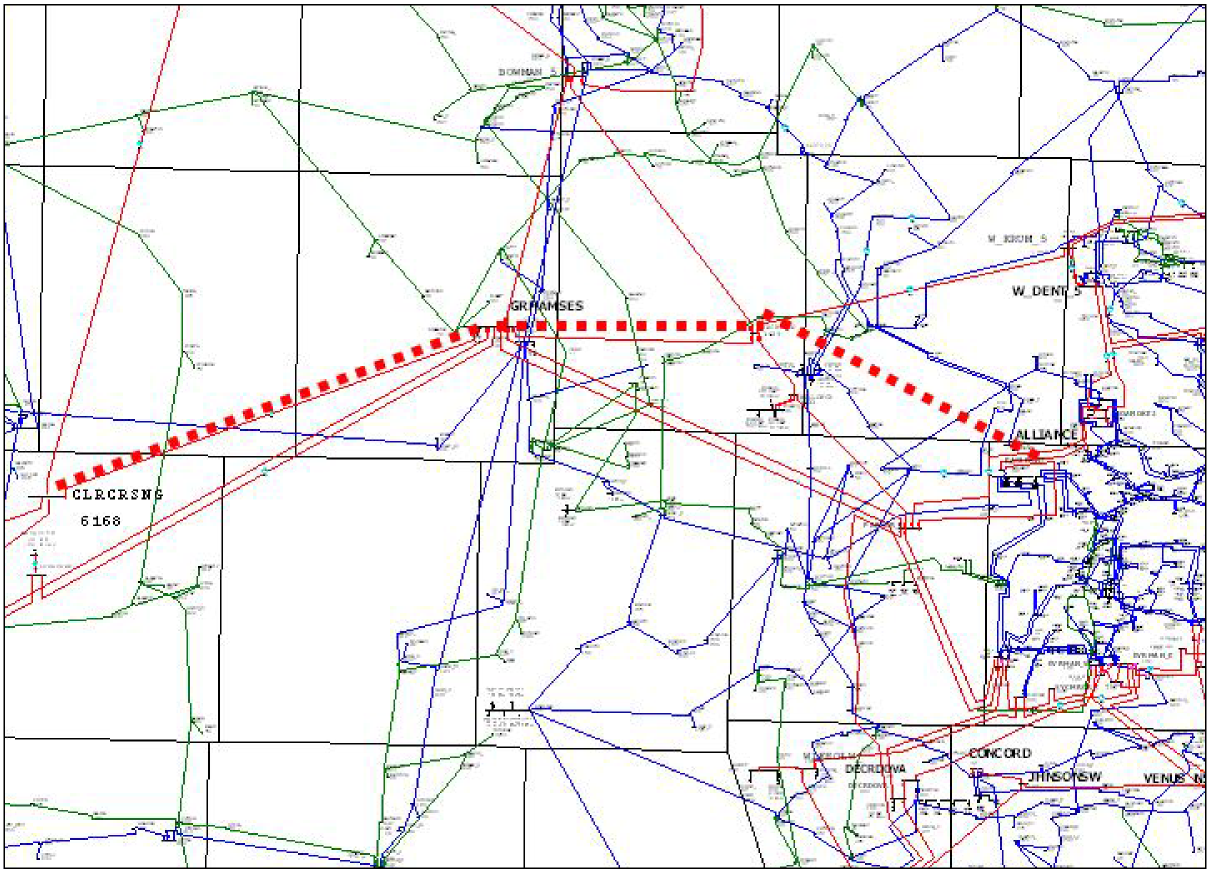
The following is a discussion of each of the major 345-kV system upgrades analyzed. During the analysis ERCOT developed cost estimates for each project based on generic cost data. If a project appeared to be viable based on the initial studies, cost estimates were obtained from AEP, Oncor Electric Delivery, and LCRA TSC as appropriate. The stated cost estimates below are based on these TSP estimates unless designated as an ERCOT staff developed estimate.

(1) Clear Crossing-Hicks 345-kV line

The 345-kV lines going into and out of the Graham station were observed to be congested and also to cause congestion on other lines for their contingency loss. Several new transmission line alternatives were explored to connect 345-kV stations west of Graham to 345-kV stations east of Graham. Tying new 345-kV lines into existing stations on the western portion of the Dallas-Fort Worth proved to cause significant congestion in those areas in the model.

Oncor Electric Delivery suggested terminating the line at a new 345-kV switch station approximately five miles east of Eagle Mountain tying into the Eagle Mountain-Alliance and Parker-Roanoke Switch 345-kV lines. This new potential switch station was called Hicks. An approximately 160-mile 345-kV single circuit line using 2-1590 ACSR conductor was modeled to connect the Clear Crossing 345-kV switch station to Hicks.

After some preliminary analysis it was found that this new line caused congestion on the Eagle Mountain 345/138-kV autotransformer. Two different autotransformer addition alternatives were analyzed. First, a second autotransformer with a Rate B of 750 MVA was modeled in parallel to the existing autotransformer at Eagle Mountain. The second alternative was to create a 138-kV bus at Hicks by tying into the Eagle Mountain-Wagley Robertson and Eagle-Mountain-Blue Mound 138-kV lines and installing a 750 MVA 345/138-kV autotransformer.



Congestion analysis proved that adding a second autotransformer at Eagle Mountain eliminated congestion in the area while the Hicks autotransformer alternative caused congestion on the Hicks-Wagley Robertson and Hicks-Blue Mound 138-kV lines. The second Eagle Mountain autotransformer was selected as the best approach.

The project eliminated congestion on the 345-kV lines connecting to Graham; however, the Mulberry Creek-Clear Crossing 345-kV line became congested 11.5% of the hours in the model for the contingency loss of the Sweetwater-Graham/ Cook Field Road-Graham 345-kV double circuit line.

ERCOT estimated that the cost of a 160-mile 345-kV line on new ROW with a new 5-terminal 345-kV switch station and a second autotransformer at Eagle Mountain would be approximately $230 million. The annual production cost savings for this project in the model was $11.1 million. This gave a capital cost to production cost savings ratio of 20.7, well in excess of the maximum ratio of 6.0.

Several alternative project modifications were explored in an effort to increase the production cost savings. These alternatives include:

- Adding a second Clear Crossing-Hicks 345-kV circuit,
- Adding series compensation on the Clear Crossing-Hicks 345-kV line,
- Tying Clear Crossing-Hicks into the Willow Creek 345-kV substation,

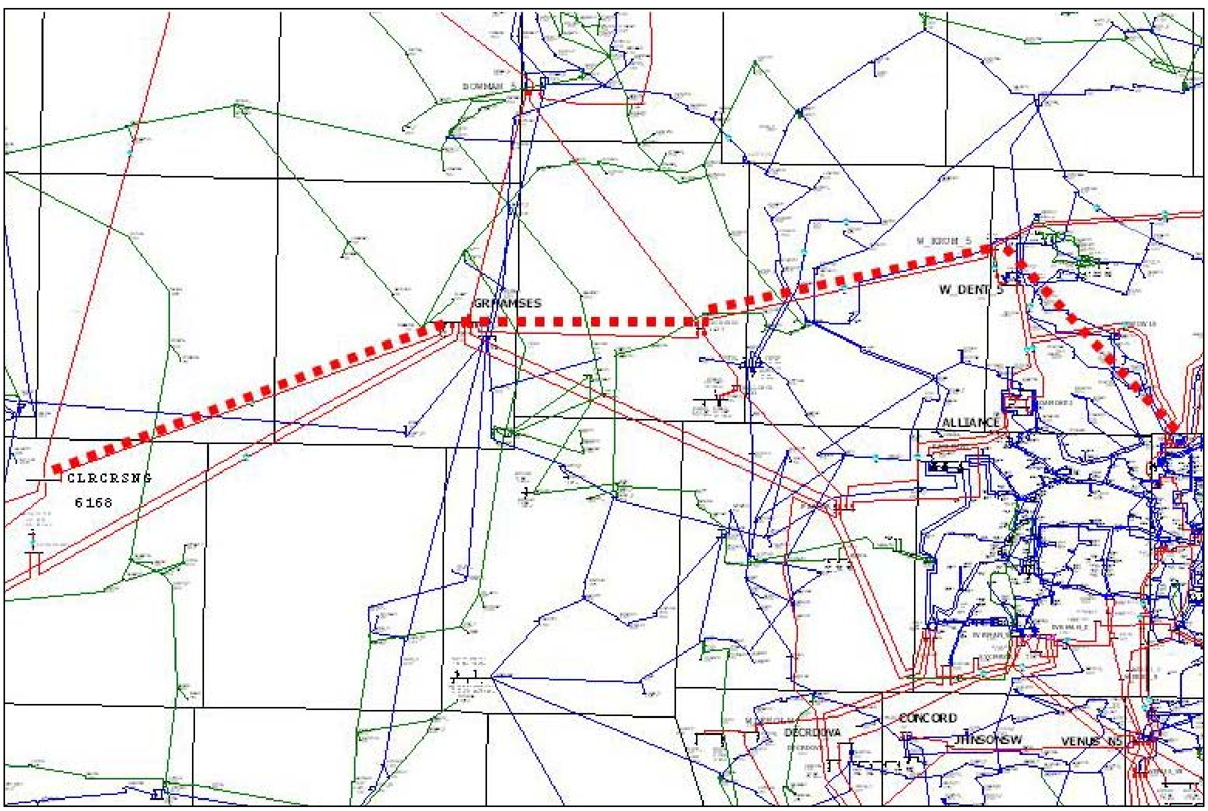
- Adding a Willow Creek-Hicks 345-kV line as a second circuit on a portion of the Clear Crossing-Hicks line, and
- Upgrading terminal equipment on the Eagle Mountain-Hicks-Alliance 345-kV line

None of the alternatives or combinations of alternatives significantly increased the production cost savings observed. This option was not pursued further.

(2) Clear Crossing-West Denton-Carrollton Northwest 345-kV line

In an effort to find a less expensive alternative to constructing the Clear Crossing-Hicks 345-kV line, an alternative that would use existing 345-kV structures that have an available open position was studied. This alternative consisted of constructing 345-kV line on new ROW from Clear Crossing to Graham and then adding a second circuit to the Graham-Jacksboro Switch and Jacksboro Switch-West Denton 345-kV lines, as well as adding a West Denton-Carrollton Northwest 345-kV line on existing structures. The circuit would be configured to terminate only at Clear Crossing, Jacksboro Switch, West Denton and Carrollton Northwest.

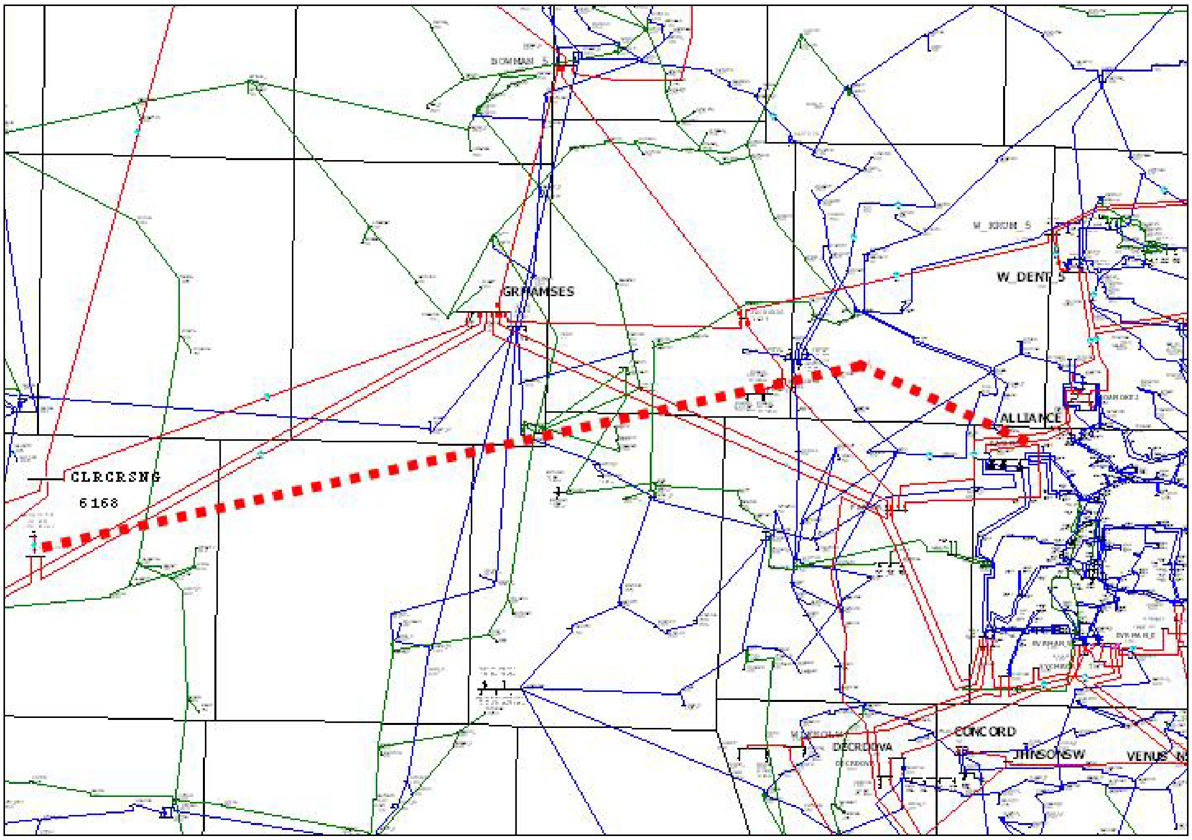
In sum, the line would involve constructing approximately 61 miles of 345-kV line on new ROW and adding 137 miles of circuit to existing structures with an open position. ERCOT estimated the cost of the project to be $140 million.



The line was added to the 2012 model and production cost analysis was performed. The project was found to save only $2.2 million in production costs. The project was not studied further.

(3) Long Creek-Hicks 345-kV line

Another pursued modification to the Clear Crossing-Hicks 345-kV project was to upgrade the Mulberry Creek-Clear Crossing 345-kV line. However, it was decided that it would be more cost effective to change the origin of the line from Clear Crossing to Long Creek in lieu of upgrading the network in-between the stations.



The Long Creek-Hicks 345-kV line was modeled as a 160-mile 345-kV single circuit line using 2-1590 ACSR conductor. A second 345/138-kV autotransformer was modeled at Eagle Mountain with a Rate B of 750 MVA. The project also included tying the Sweetwater-Graham 345-kV line into the Long Creek switch station. ERCOT estimated the cost of this project to be approximately $230 million.

Production cost analysis showed an annual savings of $24.1 million and the wind generation curtailment was lowered 2.5 percentage points. This gave a capital cost to savings ratio of 9.5 which exceeded the maximum of 6.0. Modifications to the project did not appreciably increase the production cost savings. This project was not studied further.

(4) Red Creek to Hill Country Backbone Project

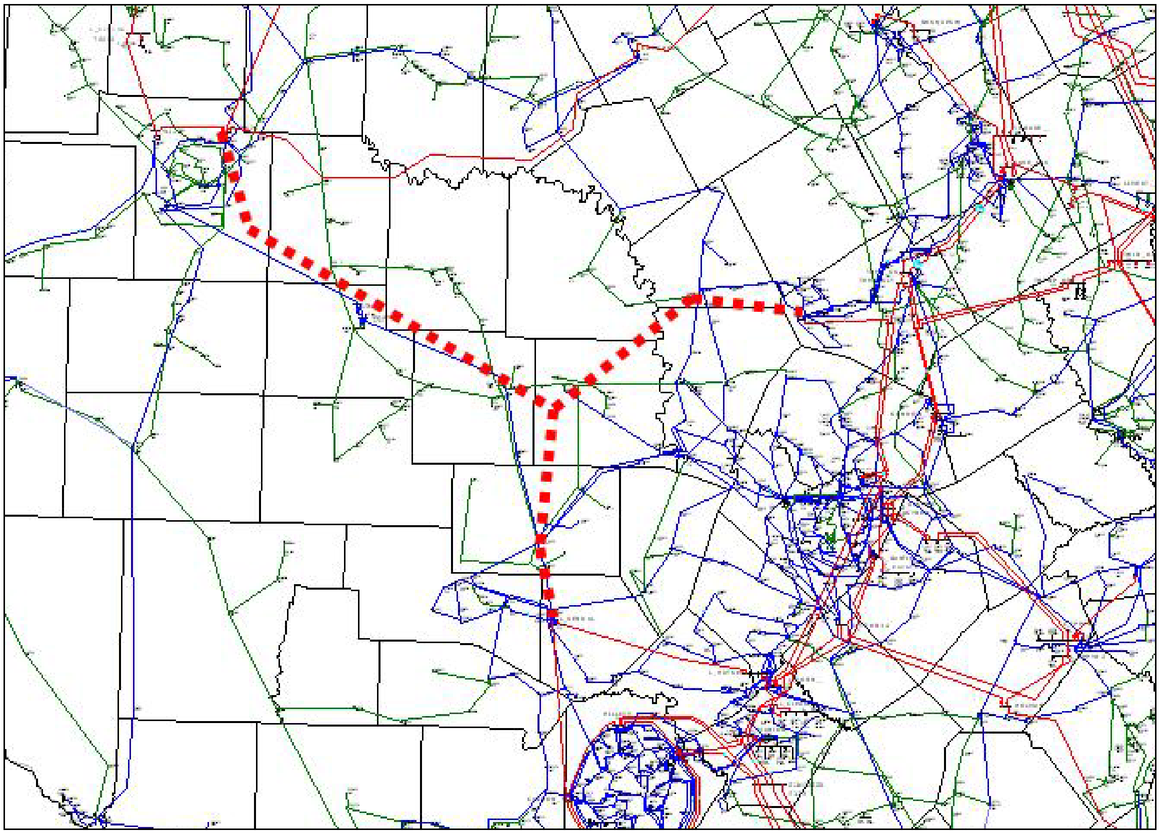
Presently, all of the 345-kV lines coming out of west Texas connect to stations in the Dallas-Fort Worth area. However, several underlying 138-kV and 69-kV lines between west Texas and central Texas were congested in the model. Several projects that entailed building new 345-kV lines from west Texas to central Texas were studied.

LCRA TSC proposed the construction of a new 345-kV backbone across the west side of the Texas Hill Country and then building a new 345-kV line from Red Creek to this backbone. This project initially consisted of the following improvements:

- Create at 345-kV bus at the existing 138-kV Gillespie substation and install two 600 MVA 345/138-kV autotransformers
- Create a Kendall-Gillespie 345-kV single circuit line (~20 miles) with a Rate B of 1959 MVA
- Create a new 345-kV switch station, West Gate north of Gillespie
- Create a Gillespie-West Gate 345-kV single circuit line (~22 miles) with a Rate B of 1959 MVA
- Create a 345-kV bus at the existing 138-kV and 69-kV Lampasas substation and install two 600 MVA 345/138-kV autotransformers
- Create a West Gate-Lampasas 345-kV single circuit line (~50 miles) with a Rate B of 1959 MVA
- Create a Lampasas-Killeen Switch 345-kV single circuit line (~36 miles) with a Rate B of 1959 MVA
- Create a new Willow 345-kV and 138-kV switch station southeast of West Gate with two 600 MVA 345/138-kV autotransformers; tie the 138-kV bus into the Gillespie-Ferguson and Gillespie-Horseshoe Bay 138-kV lines
- Create a West Gate-Willow 345-kV single circuit line (~10 miles) with a Rate B of 1959 MVA
- Upgrade the Willow-Ferguson and Willow-Horseshoe Bay-Ferguson 138-kV lines so that the Rate B for each is 493 MVA
- Create a Red Creek-West Gate 345-kV double circuit line with one circuit in place (~110 miles) with a Rate B of 1959 MVA with 50% series compensation

The estimated cost of this project was $401 million. The project was added to the 2012 model and production cost analysis was run to determine the economic benefit of the project. It was found that the project saved $38.3 million and lowered wind curtailment 3.4 percentage points to 1.3% overall wind curtailment in the 2012 model.

The model showed that the project caused congestion on the Kendall-Fredericksburg-Gillespie 138-kV line and also on both of the Ferguson-Wirtz 138-kV lines. However, upgrades to these lines did not significantly reduce production costs in the model.



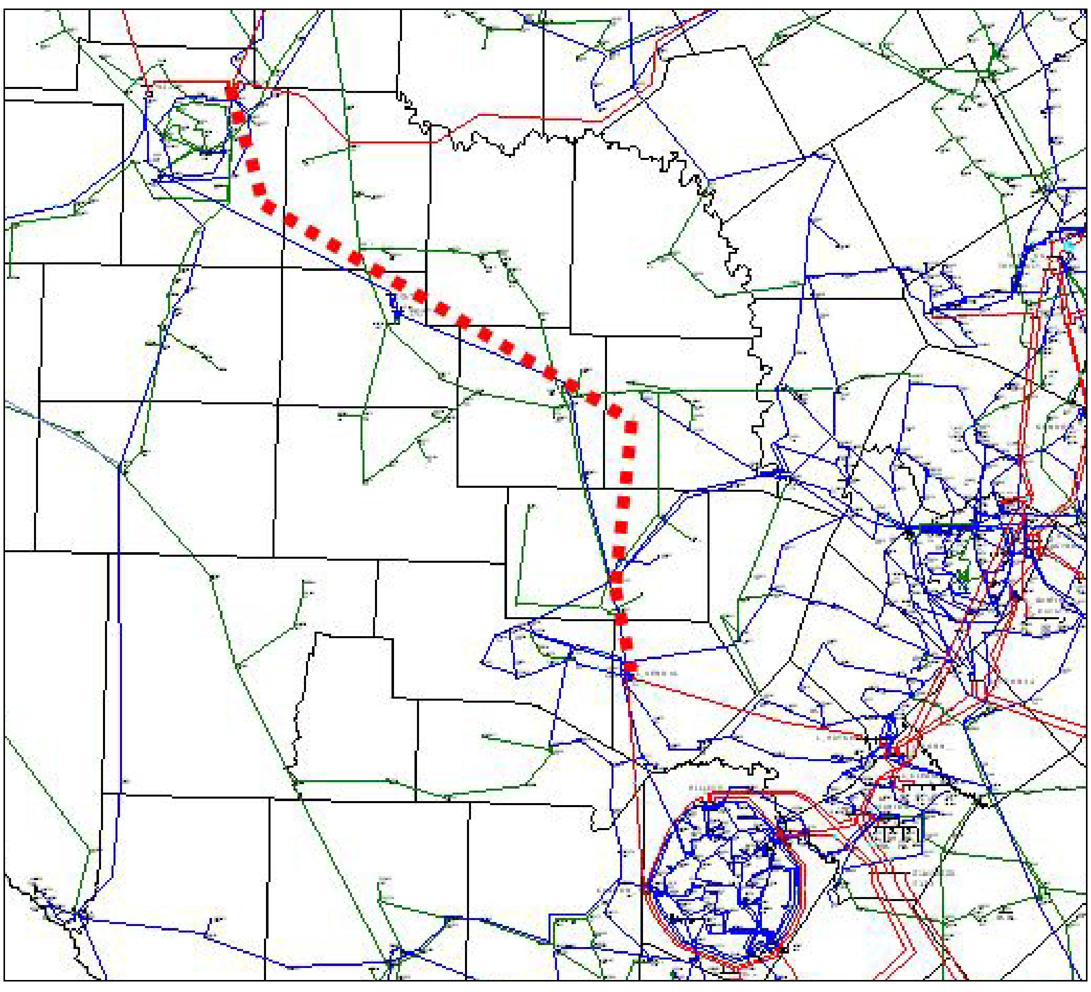
Because the capital cost was $401 million, in order to meet the economic planning criterion of the capital cost to savings ratio being less than 6.0, the production cost savings would have to be $61.8 million in order to economically justify the project. Based on several tests and calculations, it was estimated that for every one percentage point reduction in wind curtailment the production cost savings in the 2012 model would be roughly $10 million assuming no other economic benefit. Since the overall wind curtailment was 4.7% before the project was added, the available production cost savings for a project designed to reduce wind generation congestion was likely to be no more than $50 million if it eliminated all wind congestion. Therefore, it was unlikely that a project that primarily reduces wind congestion and costs more than $300 million could be economically justified.

It should be noted that this project also provides some reliability benefits due to the added voltage support in the Hill Country. However, these benefits were not quantified in this analysis. The project in this form was not studied further.

(5) Red Creek-West Gate-Gillespie-Kendall 345-kV project

From the above analysis of the Red Creek to Hill Country backbone project it was observed that there was a sizeable economic benefit to building a 345-kV line to the Hill Country from Red Creek, but that the cost of the project must be reduced. The following subset of the Red Creek to Hill Country backbone project was modeled to test the effect of eliminating the West Gate-Lampasas-Killeen Switch portion of the project:

- Create at 345-kV bus at the existing 138-kV Gillespie substation and install two 600 MVA 345/138-kV autotransformers
- Create a Kendall-Gillespie 345-kV single circuit line (~20 miles) with a Rate B of 1959 MVA
- Create a new 345-kV switch station, West Gate north of Gillespie
- Create a Gillespie-West Gate 345-kV single circuit line (~22 miles) with a Rate B of 1959 MVA
- Create a new Willow 345-kV and 138-kV switch station southeast of West Gate with two 600 MVA 345/138-kV autotransformers; tie the 138-kV bus into the Gillespie-Ferguson and Gillespie-Horseshoe Bay 138-kV lines
- Create a West Gate-Willow 345-kV single circuit line (~10 miles) with a Rate B of 1959 MVA
- Upgrade the Willow-Ferguson and Willow-Horseshoe Bay-Ferguson 138-kV lines so that the Rate B for each is 493 MVA
- Create a Red Creek-West Gate 345-kV double circuit line with one circuit in place (~110 miles) with a Rate B of 1959 MVA with 50% series compensation

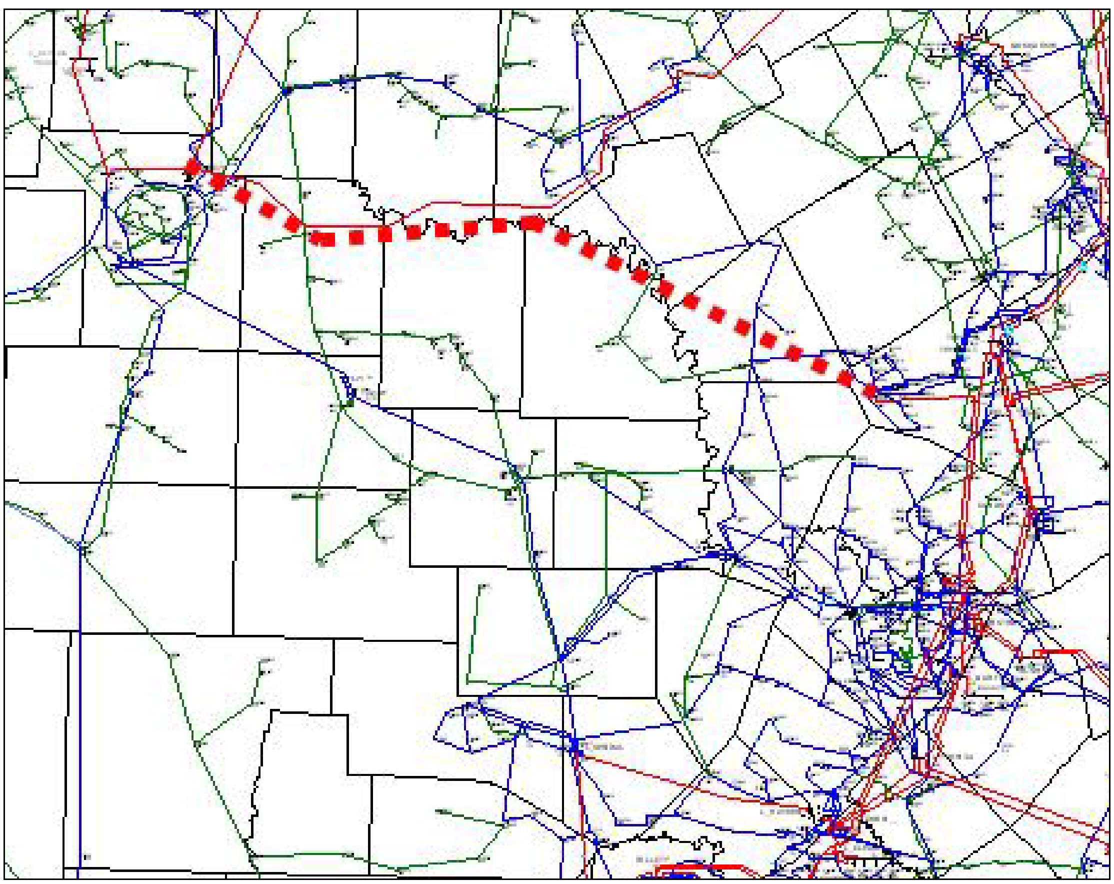


The estimated cost of this project was $273 million. The project was added to the model and production cost analysis was run. The production cost savings were found to be $33.1 million and the wind generation curtailment was reduced 2.9 percentage points. This gave a capital cost to savings ratio of 7.4 which exceeded the maximum of 6.0 for the economic planning criteria. This project was not studied further.

(6) Red Creek-Killeen Switch 345-kV line

The above two projects proved that there was considerable value in connecting a line from Red Creek to the Hill Country area, however, both of the previous projects were too costly to be able to justify construction at the 2012 conditions studied and at a wind generation level of 6,903 MW. A third alternative was sought to create a Red Creek to Hill Country area 345-kV line in the least expensive manner possible.

It was discovered that by creating a Red Creek-Killeen Switch 345-kV line (~175 miles) approximately half of the line could be constructed on existing towers by adding a second circuit to part of the Red Creek-Comanche Switch 345-kV line. This would create the double circuit contingency of both of these lines, but achieved the goal of minimizing the cost for a west Texas to central Texas 345-kV line.



The line was modeled assuming 2-1590 ACSR conductor which gave a Rate B of 1631 MVA. The cost of this line was estimated to be $172 million.

Production cost analysis was performed on the 2012 model. The project was found to save $19.0 million and reduced wind generation curtailment by 1.9 percentage points. This gave a capital cost to savings ratio of 9.1.

Since the project did not have enough production cost savings to justify the cost an alternative was analyzed to determine if installing series capacitors would increase the savings. The model was changed to reflect the addition of 50% series compensation. This effectively lowered the impedance which was expected to increase the flow on the line. It was estimated that this would add $20 million to the cost of the project for a total capital cost of $192 million. Production cost analysis was rerun on the model with this change.

With 50% series compensation the project saved $32.3 million and reduced wind generation curtailment by 3.1 percentage points to 1.6% overall curtailment in the 2012 model. This gave a capital cost to savings ratio of 5.9 which is below the maximum ratio of 6.0. Therefore, this project met the economic planning criterion for project justification.

(7) Red Creek-Everman 345-kV line

The Red Creek-Comanche Switch 345-kV line, Comanche Switch-Comanche Peak 345-kV line, Comanche Peak-Johnson Switch 345-kV line, and DeCordova-Everman 345-kV line are all on double circuit capable structures with only one circuit in place with two exceptions. The first is that the Stephenville-Comanche Peak 138-kV line shares towers with the Comanche Switch-Comanche Peak 345-kV line for approximately 18 miles. The second exception is that the DeCordova-Everman 345-kV line and the Comanche Peak-Johnson Switch 345-kV line share structures for approximately 1.5 miles.

The following project was studied in an effort to take advantage of these existing structures:

- Move the Stephenville-Comanche Peak 138-kV line from the Comanche Switch-Comanche Peak 345-kV line towers to separate structures on new ROW
- Create a Red Creek-Everman 345-kV line (~224 miles) by adding a second circuit to the Red Creek-Comanche Switch-Comanche Peak-Johnson Switch and DeCordova-Everman 345-kV lines; new structures on new ROW would be required for the 1.5 miles where the Comanche Peak-Johnson Switch and DeCordova-Everman 345-kV lines share structures; the circuit would consist of a combination of 2-1590 ACSR and 2-959 ACSS/TW conductor due to tower limitations for a Rate B of 1631 MVA
- Because the circuit was of considerable length, series capacitors were modeled for the line such that the line was 50% compensated

The project was estimated to cost $140 million. The project was added to the 2012 model and production cost analysis was performed. The model showed that the Hasse-Comanche-Comanche Switch 138-kV line was congested 16.5% of the hours in the model for the contingency loss of the Red Creek-Everman/ Comanche Switch-Comanche Peak 345-kV double circuit. This line was upgraded in the model and production cost analysis was rerun.

The model showed that the project saved $27 million and reduced wind generation curtailment by 3.0 percentage points. This gave a capital cost to savings ratio of 5.2 which passed the requirement of being less than 6.0.

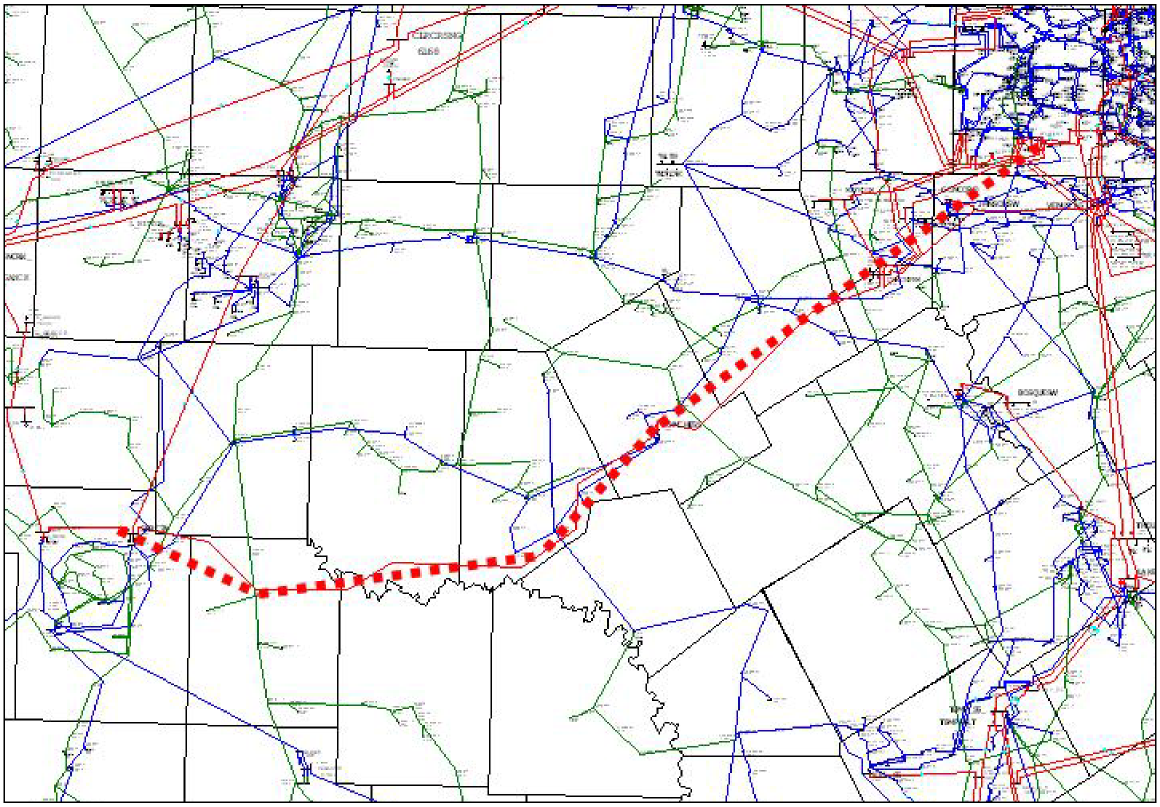


Table 15 summarizes the west Texas 345-kV bulk system improvement options studied and the production cost results for the best configuration of each in the 2012 model.

Option	**Capital Cost (Est. $M)**	**Production Cost Savings ($M)**	**Capital Cost/ Savings**	**Wind generation CF improvement**
Clear Crossing-Hicks 345-kV line	230	11.1	20.7	1.1%
Long Creek-Hicks 345-kV line	230	24.1	9.5	2.5%
Red Creek to Hill Country Backbone Project	401	38.3	10.5	3.4%
Red Creek-West Gate-Gillespie-Kendall 345-kV line	273	33.1	8.2	2.9%

Red Creek-Killeen Switch 345-kV line	192	32.3	5.9	3.1%
Red Creek-Everman 345-kV line	140	27.0	5.2	3.0%

Table 15: Production cost results for the studied west Texas bulk system improvements

Both the Red Creek-Killeen Switch 345-kV line and the Red Creek-Everman 345-kV line projects proved to be economically justified. It is possible that the Red Creek-Everman 345-kV line could be constructed one to two years earlier than the Red Creek-Killeen Switch 345-kV line. However, the Red Creek-Killeen Switch 345-kV line resulted in more production cost savings and less overall wind generation curtailment in the 2012 model. Furthermore, the Red Creek-Killeen Switch 345-kV line may better fit with long-term plans to connect west Texas to central Texas and could even become part of a modified Hill Country backbone plan as discussed in item (4) earlier in this report.

Under normal planning circumstances, both options should be studied further to quantify the above benefits and to determine each project's impact on system stability. Because it resulted in the most production cost savings, for the purposes of the Five-Year Plan, the Red Creek-Killeen Switch 345-kV line is the recommended solution. However, in light of the CTO study it is likely that either option would be superseded by new CREZ-related transmission lines. For this reason neither option will be studied further at this time.

8. Line segment opening

Throughout the economic analysis, several lower voltage transmission lines were identified as congested but no economic projects to correct the congestion were found. For these lines the option of opening the circuit to prevent through flow was explored. The following table shows the production cost benefits of opening these highly congested lines.

Line	**Production Cost Savings ($M)**				
	2008	**2009**	**2010**	**2011**	**2012**
Seymour-Bomarton 69-kV line	35.3	53.6	58.1	63.7	15.6
Rock Springs-Friess Ranch 69-kV line	1.7	3.6	2.5	4.6	4.7
KMA-Electra 69-kV line	12.9	7.8	9.4	11.1	*Note
Fort Stockton-Barilla 69-kV line	2.6	0.9	0.1	0.4	0.5

Table 16: Production cost savings results for opening heavily congested lines
* Note: This line is not congested in 2012

It should be noted that the KMA-Electra 69-kV line ceased to be congested once the Oklaunion-Bowman 345-kV line was constructed. Additionally, when the Red Creek-Killeen Switch 345-kV line was added to the model the Bradshaw-Winters 69-kV line became heavily congested. Opening this line saved $3.8 million in the 2012 model.

Based on these results the TSPs and ERCOT Operations should pursue opening the Seymour-Bomarton 69-kV line, Rock Springs-Friess Ranch 69-kV line, KMA-Electra 69-kV line, and Fort Stockton-Barilla 69-kV line. Also, the Bradshaw-Winters 69-kV line may be a candidate to be opened in the future.

V. Impact of Five-Year Plan projects on Wind Generation

The projects identified in this plan decreased the curtailment of wind generation throughout the years of the study. In the table below, a steady decrease in overall GWh curtailment and % Curtailment occurs from 2008 to 2012. The second column, labeled "Final 5 Year Plan Cases with No Constraints (GWh)", represents the maximum wind energy output available from AWS Truwind profiles. The third column represents the actual wind energy produced each year in the final 5 Year Plan economic cases. These cases have all the projects listed in Tables 1 and 2 and all the line openings in Table 16 modeled.

A Year	B Final 5 Year Plan Cases with No Constraints (GWh)	C Final 5 Year Plan Cases with Constraints (GWh)	D Curtailment (GWh) (Col B - C)	E % Curtailment (Col D/B)
2008	21082.72	19015.25	2067.47	9.8%
2009	23412.47	21866.33	1546.14	6.6%
2010	23413.94	22179.23	1234.71	5.3%
2011	23417.84	22282.99	1134.85	4.8%
2012	23507.03	23117.48	389.55	1.7%

Table 17: Per Cent Curtailment of all Wind Units

The 2008 case had slightly less nameplate wind capacity than the other four years so its "No Constraint" wind energy is lower than years 2009 to 2012. Years 2009 to 2011 had the same nameplate wind capacity but the AWS Truwind profiles differed slightly each year. 2012 also had the same nameplate wind and different AWS Truwind profile but it is also a leap year so its energy is higher than years 2009 to 2011.

VI. Appendices

Appendix A: Planned improvements in the SSWG base cases	07sum-12sum transmission improvei
Appendix B: Modeling data for economic projects	Economic_Project_Line_Data.xls