Cooks Point Distribution Study

March XX, 2016

EXECUTIVE SUMMARY

The purpose of this study is to evaluate the viability of distribution system improvements to meet growing electrical demands in the northeastern portion of the Bluebonnet Electric Cooperative (BBEC) system. Specifically, this study reviews an area in Burleson and Lee counties in the vicinity of the existing Lexington, Lyle Wolz and Lyons substations. The increasing demand on the area electric system, particularly due to oil and water well loads, in conjunction with the existing Lexington, Lyle Wolz, and Lyons substations/feeders[1] presents limited distribution system alternatives to meet planning criteria reliability requirements.

The study reviews options to meet planning criteria and concludes they cannot be met in future years with improvements to the distribution system alone.

Various distribution system improvements were given consideration in this study, including conductor upgrades, voltage conversions, voltage regulator additions, voltage regulator relocations, and capacitor additions. With these improvements, which are estimated at a total cost of $5,600,000, the distribution system voltage will not meet the existing planning criteria for distribution system voltage after 2020.

Bluebonnet Electric Cooperative follows the distribution system planning criteria for optimum conductor loading of 60% of the conductor emergency rating. Based on the criteria, the following feeder loadings were experienced in 2014 and are projected for 2021-2022:

The actual peak demand for feeders LW20 and LN50 reached 38% and 19%, respectively, of optimum conductor loading in the Winter of 2014. The actual peak demand for feeders LW20 and LN50 reached 41% and 21%, respectively, of optimum conductor loading in the Summer of 2014. Without any distribution or substation solutions, Feeders LW20 and LN50 will exceed 100% of optimum conductor loading by 2022 and 2021, respectively.

Additionally, due to the line miles and loading of LW20, LN50 and adjacent feeders, LW20 and LN50 cannot be completely backfed to alleviate congestion and address contingencies. This is due in part to the location of the study area relative to the edge of BBEC's service territory, which also abuts a neighboring utility outside of the ERCOT transmission grid.

Based on the cost of distribution system improvements versus the useful life of the distribution system improvements, it is recommended that a new substation be located in the northeastern portion of the Bluebonnet Electric Cooperative service territory. The new substation is projected to serve 16 MW in 2021 and 21 MW in 2023. Based on the load projections and the LCRA TSC Transmission System Planning Criteria (Appendix B), it is recommended that the new substation receive looped transmission service.

[1] The two feeders which serve the area with increasing oil and water well loads are Lyle Wolz Feeder 20 (LW20) and Lyons Feeder 50 (LN50). LW20 and LN50 are currently supplied by Lyle Wolz Power Transformer T1 (LW T1) and Lyons Power Transformer T1 (LN T1), respectively. Lyle Wolz Power Transformer T2 (LW T2) is projected to begin supplying approximately 7 MW of LW T1 load, including LW20, in the Summer of 2016.

BACKGROUND

The BBEC system study area under evaluation is located in Burleson and Lee counties in the vicinity of the existing Lexington, Lyle Wolz, and Lyons substations. This area, which is served primarily by Lyle Wolz Feeder 20 (LW20) and Lyons Feeder 50 (LN50), is illustrated in Exhibit 1 along with areas projected for high oil production and water pumping load growth.

Oil Production (Exhibit 1)

There has been an increase in oil drilling activity in Burleson County this past year. Although there is still some new activity in the Austin Chalk, most of the activity has been in the Eagle Ford and Woodbine trends. Where both are targeted, this is referred to as Eaglebine. There has been significant activity in Brazos County, with this activity now moving southeast into Burleson County, where a number of successful oil wells have been drilled.

There are currently two known 3D seismic surveys in progress in Burleson County. The surveys include most of the area served by the Lyons Substation and significant portions served by Lyle Wolz Substation, including the area around Cooks Point. These surveys are usually precursors to increased drilling activity, as they allow for better targeting of oil resources. Although not impacting the feeders in the Cooks Point area, there are two seismic surveys in Lee County which impact the Lyle Wolz Substation. One survey is in progress while the other survey was completed last year. There are a number of new and planned wells, to be served by the Lyle Wolz Substation, in the survey that was completed last year. The 3D seismic survey that was completed last year also includes most of the area served by the Lexington Substation, as well as portions served by Paige and Giddings substations. Additionally, one of the 3D seismic surveys currently in progress includes much of the remainder of the area served by Giddings Substation. Potential growth on the Giddings and Paige substations would preclude any possibility of shifting load from Lexington to Paige or Giddings or shifting load from Lyle Wolz to Giddings. Drilling activity will be extremely limited in the near future due to current low oil prices, but will resume when prices rise. The 3D seismic survey areas are illustrated in Exhibit 1.

Typically, the wells in the area in the Austin Chalk are horizontal and include several hundred acres in the lease. Each lease has a single well with, in most cases, a 30-40 HP motor. Eagle Ford – Woodbine Leases are similar in acreage, although sometimes slightly larger. However, there are usually several closely spaced wells, as many as 12, with a 50-100 HP motor serving each well. The number of wells vary, but in the Burleson County area, three or four wells with 50 HP motors are common.

Based on the existing 165 wells served by the LW20 feeder (assuming 15 wells are Eagle Ford - Woodbine and the remaining 150 wells are Austin Chalk), we conservatively estimate the following:

- 100 Eagle Ford - Woodbine additional leases
- 3 wells per lease
- Average load of 20 kW per well

- Resultant load addition of 6 MW by Year, beginning in 2017 through 2023

Likewise, based on the existing 127 wells served by LN50 feeder (assuming 12 wells are Eagle Ford-Woodbine and the remaining 115 wells are Austin Chalk), we conservatively estimate the following:

- 75 Eagle Ford - Woodbine additional leases
- 3 wells per lease
- Average load of 20 kW per well
- Resultant load addition of 4.5 MW by Year, beginning in 2017 through 2023

Water Pumping (Exhibit 2)

There is significant potential for water development in Burleson and Lee Counties.

Burleson County

Cross County Water Supply Corporation has been adding load to the Lyle Wolz Substation. This load will increase to supply the water needs along the SH130 corridor via a pipeline constructed from Burleson County to Travis County in May 2011. There are plans to add a few additional wells and upgrade the pumping stations. This is expected to add 2-3 MW to Lyle Wolz Substation within ten years.

The SAWS Vista Ridge Water Project appears to be moving forward. Local individual landowners in Burleson County have signed over 3,400 leases to provide their water from the Carrizo and Simsboro Aquifers in that county[2]. A 142-mile pipeline is planned from Burleson County to San Antonio. This load will be generally located near and to the north of the Lyle Wolz Substation. Power requirements are around 12 MW. This is planned to be online around 2018 or 2019.

A development firm is planning water wells which will result in the addition of 5 MW of load to the Lyons Substation and 1.5 MW to the Lyle Wolz Substation. This load could double as there are two aquifers that could be tapped at the same location. Additionally, there is the potential of a future 6 MW load on the Lyle Wolz Substation near the Cooks Point area. This load could also double. This would be a potential addition of 10 MW on the Lyons Substation and 15 MW on the Lyle Wolz Substation. This well activity is anticipated to occur in 2019 – 2024.

- Resultant average load addition of 4.1 MW by Year, beginning in 2016 through 2024

Lee County

The Lost Pines Groundwater Conservation District has approved a settlement agreement and an operating permit which will allow Forestar Real Estate Group to pump up to 28,500 acre-feet of

[2]http://www.saws.org/your_water/waterresources/projects/vistaridge/docs/SAWS_VistaRidge_PipelineFactSheet.pdf

groundwater per year from the Simsboro Aquifer in Lee County. Forestar had originally sought 45,000 acre-feet of water per year to supply growing communities in Hays, Travis and Williamson counties. Although the Lost Pines Water District policies severely restrict water development, there will be some load growth on the Lexington Substation due to this settlement agreement[3].

- Resultant average load addition of 0.3 MW by Year, beginning in 2018 through 2024

Distribution Issues

Conservatively assuming half of the potential water load in the Cooks Point area would be added to the LW20 feeder, or 90% of the oil load, distribution improvements would not be able to enhance the performance of the feeder to comply with the guidelines of the planning criteria. This is without considering other potential growth.

System Planning

BBEC performs a distribution system load forecast annually. This load forecast provides the basis for determining the performance of the distribution system over a given 10-year planning horizon. BBEC reviews historical growth patterns, anticipated load additions, and scheduled load transfers to derive forecasts for each substation and associated feeders. The load forecast is supported by historical growth patterns and/or documentation of new load additions. The load forecast is also developed to support the Annual Load Data Request (ALDR) by the Electric Reliability Council of Texas (ERCOT).

System improvement plans (SIP) are used to document system improvement projects, schedule the work force, coordinate other functions such as maintenance, prioritize projects, and budget expenditures. SIP are developed based on two (2) areas of input; the system load forecast and reliability. SIP are reviewed and updated annually in conjunction with the load forecast. The BBEC Distribution System Planning Criteria is included in Appendix A.

The distribution system planning process utilizes two sets of complementary planning criteria as the basis for engineering the distribution system. First, the document in Appendix A - BBEC Distribution System Planning Criteria represents the set of reliability guidelines that have been adopted by the Cooperative for use in making reliable distribution planning engineering decisions. The BBEC Distribution System Planning Criteria is similar to the LCRA TSC Substation Delivery Planning Criteria and other industry standards. Additionally, the Cooperative participates in a joint transmission planning process with its Transmission Operator, the Lower Colorado River Authority Transmission Services Corporation (LCRA TSC), for planning necessary transmission and substation improvements as a result of the load growth and distribution planning needs of the Cooperative. Through a contractual agreement with the LCRA TSC (the "Lease"), the collaborative process, which includes LCRA TSC and other distribution utilities participating in the Lease, seeks to develop system transmission and substation projects

[3] http://m.statesman.com/news/news/local/lost-pines-groundwater-district-approves-forestar-/npqFr/

for the Central Texas Area to maintain acceptable levels of reliability, meet the growing needs of the system, and optimize engineering and operations expenses.

Planning Criteria Violations

The "distribution system only" analysis that follows is the result of planning criteria violations that are the result of continued growth in Burleson and Lee counties:

From the BBEC Distribution System Planning Criteria:

> Section 1.1 Normal Conditions: Under normal operating conditions, the primary distribution system shall be planned to maintain +/- 5% of a nominal 120 volt basis (114-126 volts) at the member's meter base (ANSI C84.1-1977 Range A limits and REA Bulletin 169-4).
>
> Section 2.1 A loading level of 60% of emergency ratings shall be used as a general guideline for optimum conductor loading. A loading level of 100% of normal ratings shall be used as a general guideline for critical conductor loading.
>
> Section 5.1 Voltage regulators on the distribution system shall be limited to one set in the substation and two cascaded line units on any distribution line.

The application of these criteria to the distribution system in Burleson and Lee counties has precipitated the need for this distribution study and will be the subject planning criteria for the remainder of the report.

DISTRIBUTION SYSTEM ONLY ANALYSIS AND DISCUSSION

Objective

Evaluate a distribution system only solution which will eliminate planning criteria voltage violations on feeders LW20 and LN50 in conjunction with high forecasted load growth in Burleson and Lee counties.

Study Approach

The existing system was modeled with previously approved projects and the forecast loads discussed earlier in this report. (Table 2 – Load Projections without Cooks Point Substation)

System performance was assessed versus the applicable criteria. The following violations were found:

1. System voltages below 5% of nominal voltage beginning in 2017.
2. Primary conductor loading exceeding 60% of emergency rating beginning in 2018.
3. Cascading voltage regulators are currently maximized for LW20.

Alternative Evaluation

We examined several alternatives to address these criteria violations. These violations can be addressed by distributions system improvements through 2020. After this timeframe, the distribution system improvements no longer provide acceptable results.

Description

The distribution system solution involves many projects over a series of years (2017 – 2020) in order to support voltage on feeders LW20 and LN50. Extensive use and upgrade of existing facilities are required. (Exhibit 3)

This alternative consists of the following:

- Upgrade 5.6 miles of existing single phase #4 ACSR to three phase 1/0 ACSR.
- Upgrade 14 miles of existing three phase distribution lines to 336 ACSR.
- Convert 257 miles of existing distribution lines from 12.47 kV to 24.9 kV.
- Install 578 A voltage regulators.
- Relocate and upgrade existing voltage regulators.

Table 1, on the following page, provides a breakdown of the individual projects by year, the planning criteria violation resolved, project description, miles of facilities affected, and the estimated individual project cost.

Tables 2 - 3, on Page 9, provides the loading and improvement summaries for the feeders affected by the high oil production and water pumping loads.

Table 4, on Page 10, provides the historical loads and projected loads for the substations and feeders affected by the high oil production and water pumping loads.

Figures 1 - 4, on Pages 11 - 12, graphically illustrate the substation and feeder load projections.

Table 1 - Distribution Only Projects

Project	Needed By	Violation Resolved	Description	Miles	Estimated Cost
LW20 CR 104 Phase Conversion	Winter 2017	Voltage Levels	#4 single phase to 1/0 3 phase	2.58	$250,280.64
LW20 CR 328- CR329 Phase Conversion	Winter 2017	Voltage Levels	#4 single phase to 1/0 3 phase	2.97	$288,113.76
LW20 FM1362 North Voltage Conversion	Winter 2017	Voltage Levels	Voltage Conversion	59.4	$739,701.40
LW20 Chriesman Voltage Conversion	Winter 2018	Voltage Levels	Voltage Conversion	68.41	$679,280.51
LN50 336	Winter 2018	Voltage Levels	Upgrade to 336 ACSR	6.96	$1,014,935.04
LN50 North East Voltage Conversion	Summer 2019	Voltage Levels	Voltage Conversion	34.34	$310,948.74
LW20 FM1362 South Voltage Conversion	Summer 2019	Voltage Levels	Voltage Conversion	29.14	$269,489.54
LN50 Regulator	Summer 2019	Voltage Levels	Install Regulator (578)		
Add Capacitors	Summer 2019	Voltage Levels	Install Capacitors (3300 kVAR)		$112,681.00
LW20 336	Winter 2019	Voltage Levels	Upgrade to 336 ACSR	4.19	$611,002.56
LW20 Relocate Regulators	Winter 2019	Voltage Levels	Optimize Regulator Locations & Upgrade		$233,333.39
LW20 FM2000 Voltage Conversion (West)	Winter 2019	Voltage Levels	Voltage Conversion	16.09	$152,547.99
LW20 FM1368 North 336	Summer 2020	Voltage Levels	Upgrade to 336 ACSR	2.84	$414,140.16
LN50 North West Voltage Conversion	Summer 2020	Voltage Levels	Voltage Conversion	26.11	$241,288.21
LW20 FM2000 Voltage Conversion (North)	Winter 2020	Voltage Levels	Voltage Conversion	23.74	$274,180.14
Distribution Improvements no longer able to maintain voltage levels after 2020					
				TOTAL	**$5,591,923.08**

Table 2 - Lyle Wolz 20 (LW 20) Loading and Improvement Summary

Annual actual/forecast	Winter Loading (60% rule - Max load for 336 ACSR is 18,662 kW)	Summer Loading (60% rule - Max load for 336 ACSR is 13,738 kW)	Planned Improvement Cost
2014 (1)	7,155 (38%)	5,624 (41%)	
2016 (2)	7,643 (41%)	5,961 (43%)	$1.3M to support 2017 Winter load
2017 (2)	8,532 (48%)	6,471 (47%)	$700k to support 2018 Winter load
2018-2019 (2)	11,811 (63%)	9,718 (71%)	$325k to support 2019 Summer load
2019 (2)	11,811 (63%)	9,718 (71%)	$1M to support 2019 Winter loading
2019 (2)	11,811 (63%)	9,718 (71%)	$400k to support 2020 Summer load
2019 (2,3)	11,811 (63%)	9,718 (71%)	275k to support 2020 Winter loading
2020 (4)	12,702 (68%)	10,592 (77%)	
2022	15,986 (86%)	13,842 (101%)	
2023	21,874 (117%)	19,718 (144%)	

1. Actual kW experienced
2. Studied improvements considered to sustain system reliability
3. No other solutions available per design criteria to leverage
4. Distribution solutions become obsolete

Table 3 - Lyons 50 (LN 50) Loading and Improvement Summary

Annual actual/forecast	Winter Loading (60% rule - Max load for 336 ACSR is 18,662 kW)	Summer Loading (60% rule – Max load for 336 ACSR is 13,738 kW)	Planned Improvement Cost
2014 (1)	3,472 (19%)	2,835 (21%)	
2017 (2)	4,375 (23%)	3.377 (25%)	$1M to support 2018 Winter load
2018 (2)	5,023 (27%)	4,017 (29%)	$400k to support 2019 Summer load
2019 (2,3)	10,670 (57%)	9,658 (70%)	$250k to support 2020 Summer load
2020 (4)	11,318 (61%)	10,300 (75%)	
2021	16,966 (91%)	15,941 (116%)	
2025	18,538 (100%)	17,740 (129%)	

1. Actual kW experienced
2. Studied improvements considered to sustain system reliability
3. No other solutions available per design criteria to leverage
4. Distribution solutions become obsolete

Table 4 - Load Projections without Cooks Point Substation (kW)

	RATING (kVA)	2010	2011	2012	2013	2014	2015	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Lyle Wolz T1 S Historical	22400	14497	16033	14845	15304	14468	15598											
Lyle Wolz T1 W Historical	29600	18837	15292	14938	18012	17952												
Lyle Wolz T1 S Projected	22400								**8863**	**9135**	**22301**	**22488**	**22675**	**22861**	**23048**	**23235**	**23422**	**23609**
Lyle Wolz T1 W Projected	29600							**19142**	**10674**	**11000**	**24203**	**24427**	**24651**	**24876**	**25100**	**25324**	**25548**	**25772**
Lyle Wolz T2 S Historical	33600																	
Lyle Wolz T2 W Historical	44400																	
Lyle Wolz T2 S Projected	33600								**7054**	**7613**	**8535**	**10958**	**11881**	**14305**	**15229**	**21154**	**26720**	**26869**
Lyle Wolz T2 W Projected	44400								**8858**	**9796**	**10734**	**13173**	**14113**	**16554**	**17495**	**23432**	**28660**	**28809**
Lyons T1 S Historical	33600	10358	10799	10152	10889	10273	10250											
Lyons T1 W Historical	44400	13828	10672	10315	10613	12709												
Lyons T1 S Projected	33600								**10567**	**10894**	**11231**	**16462**	**16693**	**22454**	**22703**	**22958**	**23218**	**23487**
Lyons T1 W Projected	44400							**12959**	**13352**	**13756**	**14173**	**19459**	**19745**	**25911**	**26222**	**26539**	**26863**	**27186**
Feeder Forecasts																		
LN50 S Historical	13738					2835	2897											
LN50 W Historical	18662					3472												
LN50 S Projected	13738								**2947**	**3377**	**4017**	**9658**	**10300**	**15941**	**16582**	**17224**	**17609**	**17740**
LN50 W Projected	18662							**3590**	**3728**	**4375**	**5023**	**10670**	**11318**	**16966**	**17616**	**18261**	**18399**	**18538**
LW20 S Historical	13738					5624	5864											
LW20 W Historical	18662					7155												
LW20 S Projected	13738								**5961**	**6471**	**7344**	**9718**	**10592**	**12967**	**13842**	**19718**	**25235**	**25335**
LW20 W Projected	18662							**7502**	**7643**	**8532**	**9421**	**11811**	**12702**	**15094**	**15986**	**21874**	**27053**	**27153**

Notes

1. Load projections reflect normal loading conditions without contingency load.
2. Lyle Wolz T1 will no longer accommodate the load of Lyle Wolz T2 under emergency conditions beginning in 2018.
3. Lyle Wolz T2 will no longer accommodate the load of Lyle Wolz T1 under emergency conditions beginning in 2023.

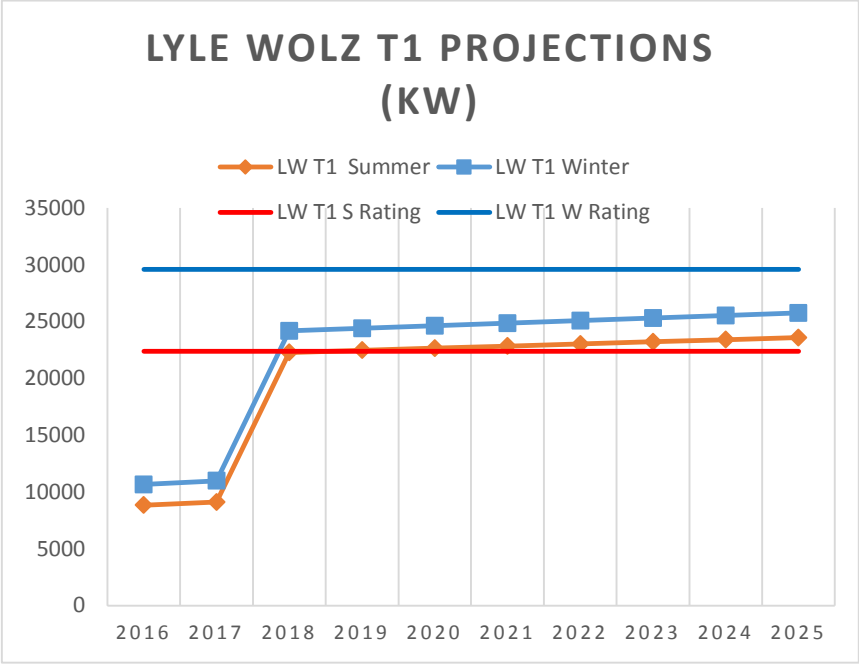


Figure 1

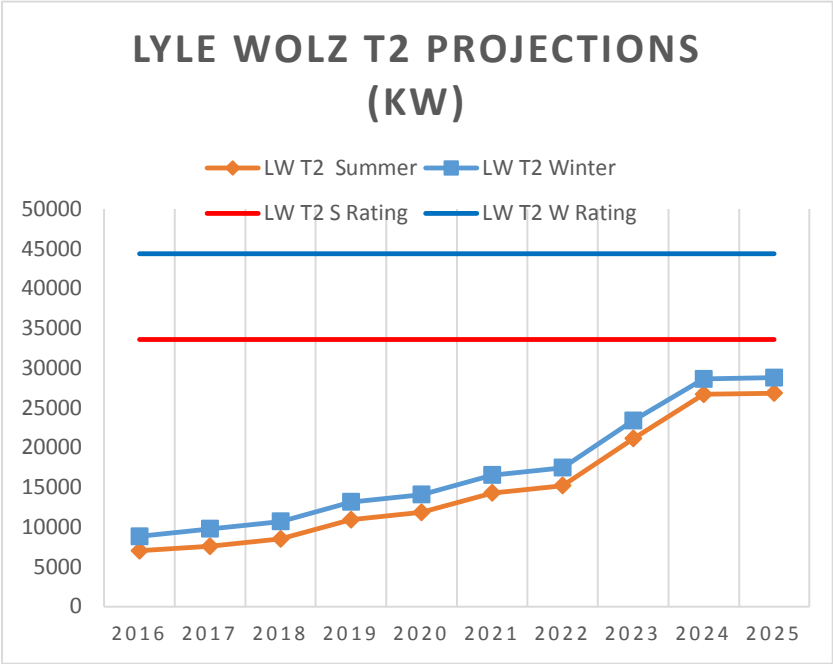


Figure 2

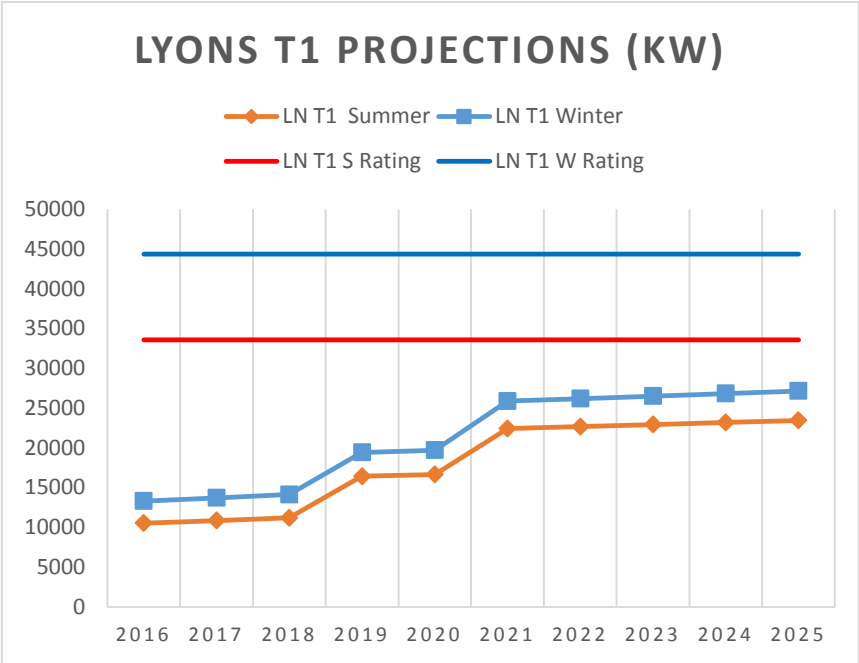


Figure 3

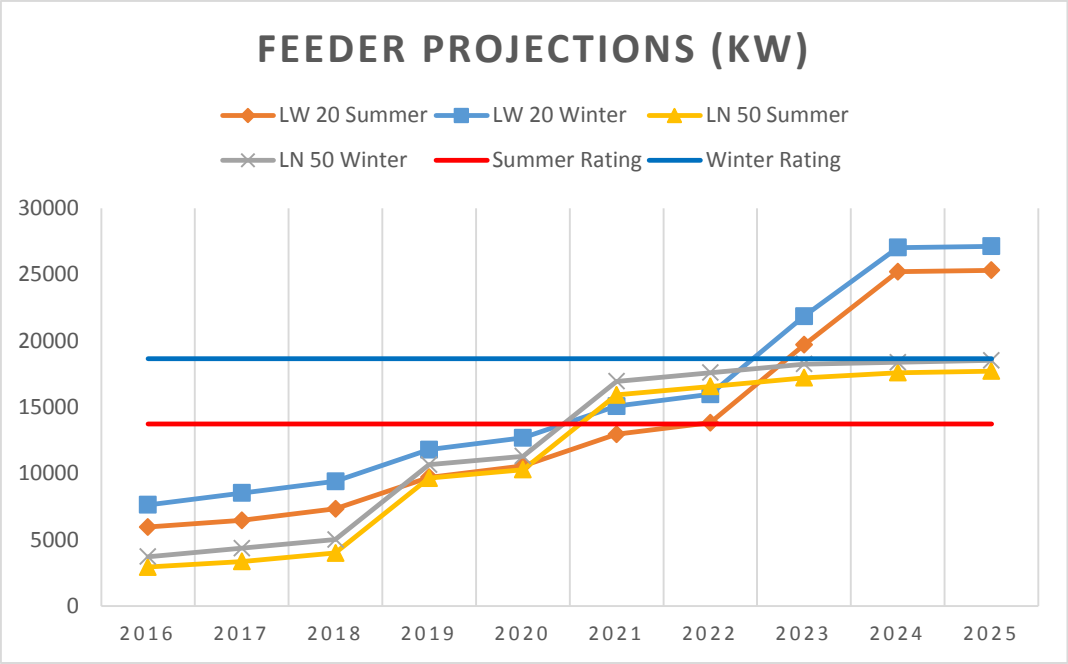


Figure 4

*Distribution solutions become obsolete in 2021.

Findings

Criteria violation #1

> Section 1.1 Normal Conditions: Under normal operating conditions, the primary distribution system shall be planned to maintain +/- 5% of a nominal 120 volt basis (114-126 volts) at the member's meter base (ANSI C84.1-1977 Range A limits and REA Bulletin 169-4).

The Bluebonnet Distribution System Planning Criteria for voltage levels under normal conditions will be violated for LW20 and LN50 beginning in Winter 2017 and Winter 2018, respectively. LW20 can no longer support adequate voltage levels once 12.9 MW is reached on the feeder. LN50 can no longer support adequate voltage levels once 15.9 MW is reached on the feeder. The distribution system voltage will no longer meet the existing planning criteria for distribution system voltage by 2021.

Criteria violation #2

> Section 2.1 A loading level of 60% of emergency ratings shall be used as a general guideline for optimum conductor loading. A loading level of 100% of normal ratings shall be used as a general guideline for critical conductor loading.

The Bluebonnet Distribution System Planning Criteria for optimum conductor loading will be exceeded for LW20 (101%) and LN50 (116%) by Summer 2022 and Summer 2021, respectively. Although Bluebonnet does not currently utilize or have material or design specifications for 795 AAC conductor, replacing the existing 336 ACSR on LW20 and LN50 with 795 AAC was given consideration in system modeling as a potential distribution solution. Based on current load projections, although 795 AAC provides increased conductor capacity as compared to 336 ACSR, this option will no longer meet the existing planning criteria for distribution system voltage by 2021.

Criteria violation #3

> Section 5.1 Voltage regulators on the distribution system shall be limited to one set in the substation and two cascaded line units on any distribution line.

The Bluebonnet Distribution System Planning Criteria for voltage regulation is maximized on LW20. LW20 cannot accommodate additional voltage regulators due to voltage regulation at the substation and two cascaded voltage regulation units on the distribution line. System modeling of current load projections reflect a second set of voltage regulators will be required for LN50 by Winter 2019, thereby maximizing voltage regulation on LN50.

Due to the distribution system configuration and the length of feeders in the northeastern portion of the Bluebonnet service territory, back feeding of feeders in the area to alleviate overloads and contingencies is extremely limited.

Potential load switching among Giddings, Lexington, Lyle Wolz, and Lyons substations in order to reduce the loading and voltage violations of LW20 and LN50 is extremely limited due to the potential growth across the area, length of the feeders, the isolation of LW20 in the most northeastern part of the service territory, and the limited ties with other feeders. LW20 entails 321 primary line-miles with the greatest load-to-substation distance of 27.5 miles. For LW20, over 80% of the load is greater than 11 miles from the substation. LN50 entails 196 primary line-miles with the greatest load-to-substation distance of 20 miles. LW60, an adjacent feeder to LW20, entails 233 primary line-miles with the greatest load-to-substation distance of 22.1 miles.

LW20 and LN50 are very limited in the ability to shed load to adjacent feeders in order to alleviate overloads and address contingencies. Currently, LW20 and LN50 can only shed 613 kW and 1,423 kW, respectively, under system peak conditions while maintaining adequate voltage levels. This is due to many factors, including:

- Length of feeders in the area
- Voltage drop (due to the length of the feeders)
- Stepdown transformer limitations (due to voltage conversions)

Additionally, other substations in the area do not match transmission phasing and have no established ties. (Exhibit 4)

Various distribution system improvements were given consideration in this study, including conductor upgrades, voltage conversions, voltage regulator additions, voltage regulator relocations, and capacitor additions. With these improvements, the distribution only alternative, with a cost estimate of $5,600,000, temporarily resolves the planning voltage criteria. The distribution system voltage will no longer meet the existing planning criteria for distribution system voltage by 2021. With an anticipated timeframe of four years to complete the distribution system improvements, the improvements will be obsolete by the time of completion.

No additional economically viable distribution system only options are available for providing voltage support to LW20 and LN50 as Burleson and Lee counties continue to experience growth. It is recommended that a new substation be located in the northeastern portion of the Bluebonnet Electric Cooperative service territory. The new substation is projected to serve 16 MW in 2021 and 21 MW in 2023 as shown in Table 5 and Figures 5 – 9 on the following pages. Based on the load projections and the LCRA TSC Transmission System Planning Criteria (Appendix B), it is recommended that the new substation receive looped transmission service. As a result of these findings, a transmission system study is recommended to serve the forecasted area load growth.

Table 5 - Load Projections with Cooks Point Substation (kW)

	RATING (kVA)	2010	2011	2012	2013	2014	2015	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooks Point T1 S Historical																		
Cooks Point T1 W Historical																		
Cooks Point T1 S Projected	33600								0	0	0	0	0	15340	15363	20387	25412	25418
Cooks Point T1 W Projected	44400							0	0	0	0	0	0	16118	16149	21181	26214	26224
Lyle Wolz T1 S Historical	22400	14497	16033	14845	15304	14468	15598											
Lyle Wolz T1 W Historical	29600	18837	15292	14938	18012	17952												
Lyle Wolz T1 S Projected	22400								8863	9135	22301	22488	22675	22861	23048	23235	23422	23609
Lyle Wolz T1 W Projected	29600							19142	10674	11000	24203	24427	24651	24876	25100	25324	25548	25772
Lyle Wolz T2 S Historical	33600																	
Lyle Wolz T2 W Historical	44400																	
Lyle Wolz T2 S Projected	33600								7054	7613	8535	10958	11881	9594	10501	11409	11957	12106
Lyle Wolz T2 W Projected	44400								8858	9796	10734	13173	14113	11416	12336	13251	13457	13606
Lyons T1 S Historical	33600	10358	10799	10152	10889	10273	10250											
Lyons T1 W Historical	44400	13828	10672	10315	10613	12709												
Lyons T1 S Projected	33600								10567	10894	11231	16462	16693	11825	12068	12316	12569	12832
Lyons T1 W Projected	44400							12959	13352	13756	14173	19459	19745	14931	15232	15539	15852	16165
Feeder Forecasts																		
LN50 S Historical	13738					2835	2897											
LN50 W Historical	18662					3472												
LN50 S Projected	13738								2947	3377	4017	9658	10300	5312	5947	6582	6960	7085
LN50 W Projected	18662							3590	3728	4375	5023	10670	11318	5986	6626	7261	7388	7517
LW20 S Historical	13738					5624	5864											
LW20 W Historical	18662					7155												
LW20 S Projected	13738								5961	6471	7344	9718	10592	8256	9114	9973	10472	10572
LW20 W Projected	18662							7502	7643	8532	9421	11811	12702	9956	10827	11693	11850	11950

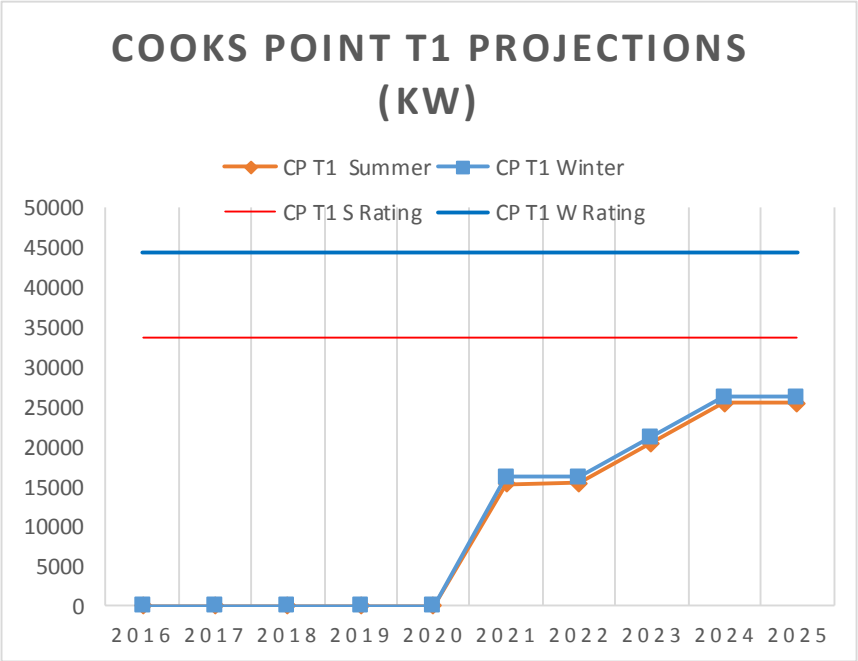


Figure 5

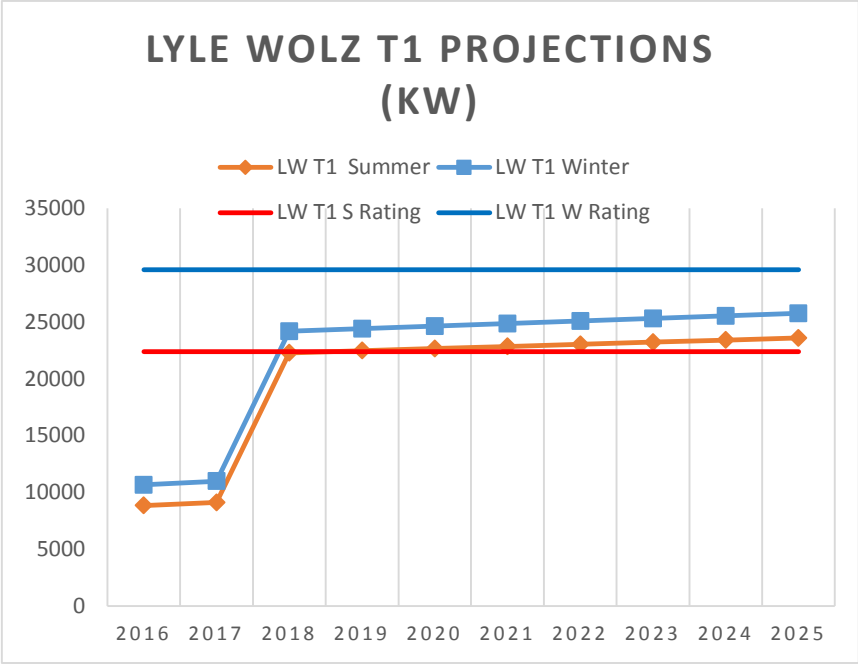


Figure 6

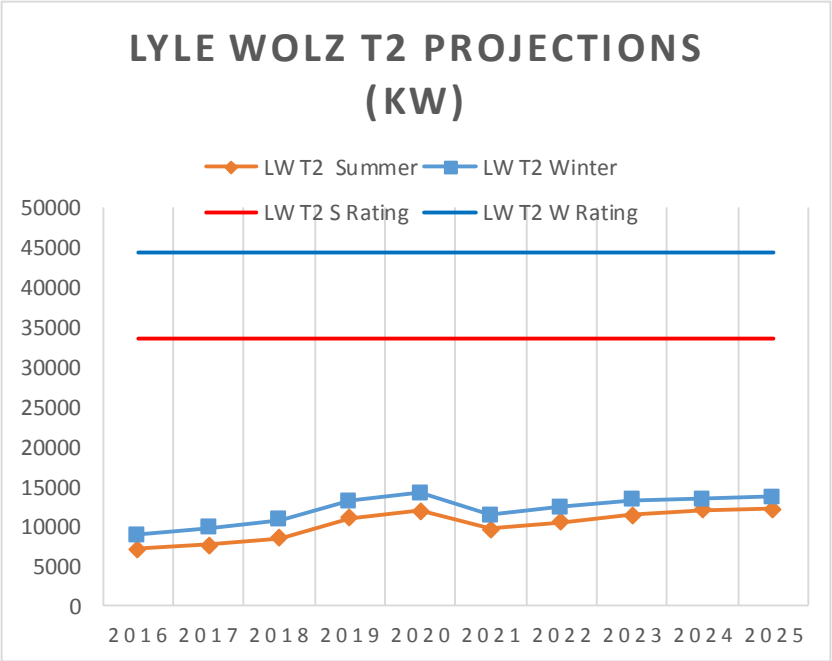


Figure 7

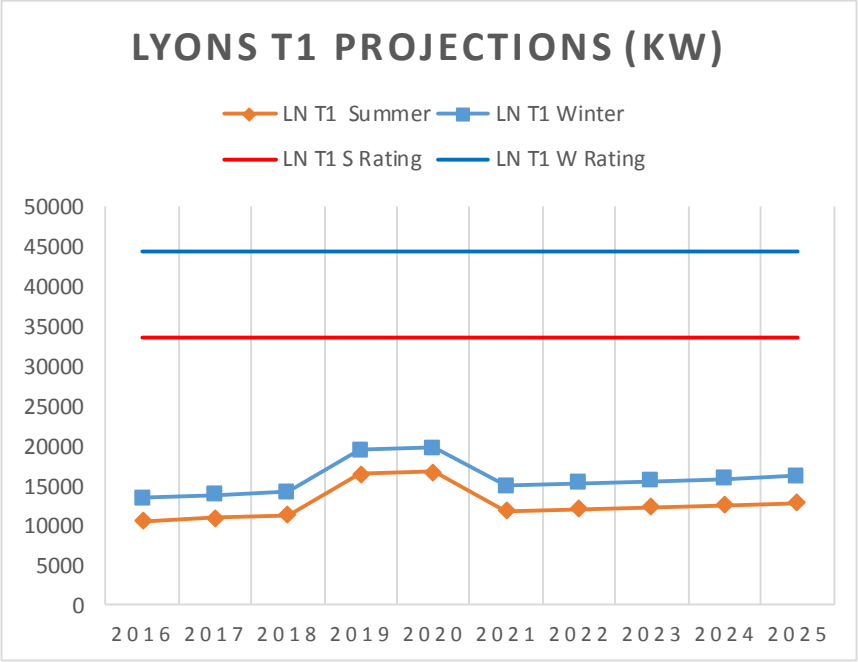


Figure 8

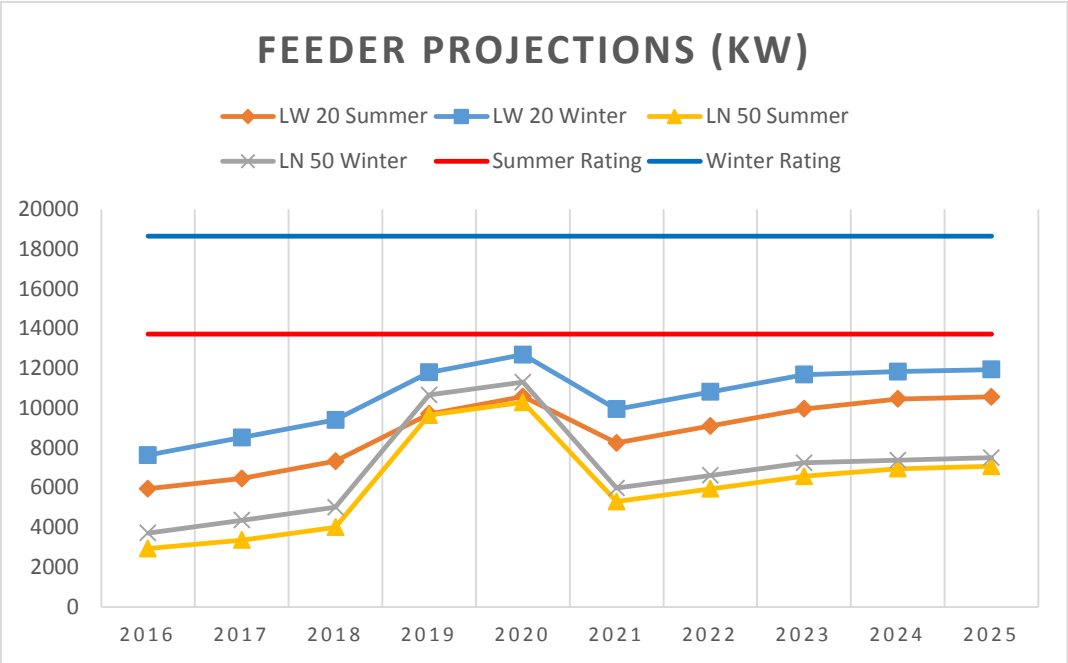

FEEDER PROJECTIONS (KW)
LW 20 Summer
LW 20 Winter
LN 50 Summer
LN 50 Winter
Summer Rating
Winter Rating
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025

Figure 9

Appendix A

Bluebonnet

Distribution System Planning Criteria

April 20, 2007

INTRODUCTION

The purpose of this Distribution System Planning Criteria is to serve as a declaration of Bluebonnet's commitment to the quality of the power we supply to our membership. This Distribution System Planning Criteria forms the guideline to be utilized in the development of documents such as the Long Range Plan, the System Improvement Plan, and in general planning for new construction. The Distribution System Planning Criteria is a guideline upon which a decision may be made, but is not intended to replace sound engineering judgment.

System Improvement Process

The electric distribution system is a very dynamic system. The burden on the electric distribution system is affected by many things such as a new subdivision development, a particular process in a commercial member's facility, the weather, or the distribution system configuration dictated by Bluebonnet operational projects. To keep up with dynamics of the electric distribution system, system improvement planning must be flexible.

The process to accommodate the dynamics of the distribution system includes many reviews throughout the year. Meetings of Bluebonnet Engineering and System Operations personnel are scheduled every quarter and electronic status reports are sent every month. This process will provide an environment for strong communication among those involved and allow multiple opportunities for input and feedback regarding system improvement projects.

Development of System Improvement Plans

System improvement plans are used to document system improvement projects, schedule the work force, coordinate other functions such as maintenance, prioritize projects, and budget expenditures. System improvement plans are developed based on two (2) areas of input; the system load forecast and reliability.

Annual updates of the distribution system load forecast shall provide the basis for determining the performance of the distribution system over a given planning horizon. It is the responsibility of the Bluebonnet Engineering Department to review historical growth patterns, anticipated load additions, and scheduled load transfers to derive forecasts for each substation. All forecasts shall be supported by historical growth patterns and/or documentation of new load additions.

To provide the best service that is economically feasible, reliability standards are needed to quantify the level of service continuity necessary to meet the needs of the member. Due to the diversity of urban and rural distribution systems in terms of line exposure and accessibility, environmental conditions, and backup potentials, acceptable levels as defined by Bluebonnet are detailed in a separate Maintenance Plan. Areas with electric service reliability that is deemed below standard will be addressed through the system improvement process. Also, any suggestions about proactively improving electric service reliability will be considered in the system improvement process.

When the criteria described in this guideline are not met in terms of distribution system performance, improvements to the electric system should be investigated to enhance performance and comply with the guidelines of these criteria in the most economical manner possible. The following are improvements to be considered.

- Transfer of load to adjacent substation feeders where surplus capacity is available provided the transfer will not adversely affect system performance.
- Installation of voltage regulators.
- Installation of shunt capacitors as needed to maintain a minimum delivery point power factor of 97% lagging during on-peak loading conditions and a maximum delivery point power factor of 97% leading during off-peak loading conditions.
- Installation of sectionalizing devices and/or lightning arresters.
- Upgrading conductor size on existing distribution lines.
- Conversion of single-phase distribution lines to three-phase.
- Construction of new feeders.
- Construction of distribution tie lines.
- Conversion of distribution lines to a higher operating voltage.
- Increasing of power transformer capacity at existing substation sites.

PLANNING CRITERIA

1.0 Voltage Levels

1.1 Normal Conditions: Under normal operating conditions, the primary distribution system shall be planned to maintain +/- 5% of a nominal 120 volt basis (114-126 volts) at the member's meter base (ANSI C84.1-1977 Range A limits and REA Bulletin 169-4). Allowing for a maximum 6 volt drop through the distribution transformer and secondary/service, feeders shall be planned so as to maintain no less than 120 volts on a 120 volt basis on the distribution primary, and no more than 126 volts on a 120 volt basis at the regulated substation bus.

1.2 Emergency Conditions: ANSI C84.1-1977 Range B limits of 110 volts to 127 volts on a 120 volt basis are permissible at the member's meter base under emergency conditions. At these voltage extremes, caution should be exercised to ensure proper equipment performance. In order to avoid these voltage extremes, the critical level for planning is defined as 112-127 volts at the member's meter base. Again, allowing for a maximum 6 volt drop through the distribution transformer and secondary/service, feeders shall be deemed critical if the voltage is less than 118 volts on a 120 volt basis on the distribution primary or more than 127 volts on a 120 volt basis at the regulated substation bus.

2.0 Conductor Loading

2.1 Some areas of the Bluebonnet service area are voltage limited, meaning proper voltage levels are difficult to maintain due to distance from source. Other areas of the Bluebonnet service area are capacity limited, meaning proper voltage levels are difficult to maintain due to the nature of the high load density area. For these reasons, it is important to establish a standard, relating to the maximum loading of conductors. Due consideration should be given to economic conductor loading studies to determine optimum conductor loading levels in an effort to minimize line losses and to ensure available capacity during higher than anticipated load conditions. A loading level of 60% of emergency ratings shall be used as a general guideline for optimum conductor loading. A loading level of 100% of normal ratings shall be used as a general guideline for critical conductor loading. The optimum and critical loading levels are based on the operating loading levels as defined below and illustrated in Appendix A.

2.2 <u>Normal Summer Loading</u> --- The loading on conductors that cannot back up neighboring feeders shall be limited to a level that does not exceed their ampacity rating based upon 40°C ambient air temperature and maximum conductor temperature of 75°C as per the calculations described in IEEE Std. 738-1993. Loading on conductors that can back up neighboring feeders shall be limited to a level that will allow load transfers to the feeder without exceeding their

emergency condition summer rating or adversely impacting system performance in terms of these criteria.

2.3 Normal Winter Loading --- The loading on conductors that cannot back up neighboring feeders shall be limited to a level that does not exceed their ampacity rating based upon 0°C ambient air temperature and maximum conductor temperature of 75°C as per the calculations described in IEEE Std. 738-1993. Loading on feeder conductors that can back up neighboring feeders shall be limited to a level that will allow load transfers to the feeder without exceeding their emergency condition winter rating or adversely impacting system performance in terms of these criteria.

2.4 Emergency Summer Loading --- Loading on conductors shall be limited to a level that does not exceed their ampacity rating based upon 40ºC ambient air temperature and maximum conductor temperature of 93.3ºC as per the calculations described in IEEE Std. 738-1993.

2.5 Emergency Winter Loading --- Loading on conductors shall be limited to a level that does not exceed their ampacity rating based upon 0ºC ambient air temperature and maximum conductor temperature of 93.3ºC as per the calculations described in IEEE Std. 738-1993.

3.0 Substation Transformer Loading

3.1 In areas with rapid growth, the timely anticipation of substation loading problems is a crucial area of planning. When a substation transformer is loaded at a level of 90% of its rated capacity, plans need to be in place to relieve this capacity problem. This is accomplished by either transferring load to another existing substation, constructing a new substation in the area, or increasing the capacity at the existing substation by installing a higher capacity transformer or an additional transformer. A loading level of 90% of ratings shall be used as a general guideline for optimum substation transformer loading. Power transformer loading shall be limited to 100% of its maximum allowable 55ºC or 65ºC average winding temperature rise rating (whichever is higher) as specified by the manufacturer. The optimum loading level is based on the operating loading levels as defined below and illustrated in Appendix B.

3.2 Normal Summer Loading --- The loading on a substation transformer that cannot back up neighboring substations should be limited to a level which does not exceed 90% of its maximum allowable 55ºC or 65ºC average winding temperature rise rating as specified by the manufacturer. Loading on a substation transformer that can back up neighboring substations should be limited to a level that allows load transfers to the transformer without exceeding its emergency condition summer rating.

3.3 Normal Winter Loading --- The loading on a substation transformer that cannot back up neighboring substations should be limited to a level that does not exceed 90% of its maximum 8 hour, no loss of life rating at 0ºC ambient air temperature with 70% preloading as specified by ANSI/IEEE C57.92-1981. Loading on a

substation transformer that can back up neighboring substations should be limited to a level that allows load transfers to the transformer without exceeding its emergency condition winter rating.

3.4 Emergency Summer Loading --- The loading on a substation transformer shall be limited to a level that does not exceed its maximum 8 hour, 1% loss of life rating at 40°C ambient air temperature with 70% preloading as specified by ANSI/IEEE C57.92-1981.

3.5 Emergency Winter Loading --- The loading on a substation transformer shall be limited to a level that does not exceed its maximum 8 hour, 1% loss of life rating at 0°C ambient air temperature with 70% preloading as specified by ANSI/IEEE C57.92-1981.

4.0 Step Transformers

4.1 RUS Bulletin 161-22 "Application Guide for Transformers" provides guidelines for transformer loading. Bulletin 161-22 states a 2-hour overload shall not exceed 2.0 times the transformer nameplate kVA during winter and 1.60 times the transformer nameplate kVA during summer.

4.2 It has been observed that in cold load pickup situations, the load in winter increases by a factor of 2.8 and the load in the summer increases by a factor of 2.0. Most cold load pickup situations return to normal load within two hours. Therefore, step transformers should not be regularly loaded more than 75%. The 75% maximum loading criteria for step transformers will allow reserve capacity in situations where back-feeding of an adjacent feeder is possible. Also, when this maximum value is maintained under normal feed conditions and under steady state peak conditions, the step transformer will closely match the RUS guidelines.
Winter = 2.8 x 75% = 2.1
Summer = 2.0 x 75% = 1.5
Peak loading of step transformers over 75% shall be reviewed individually and in no case be allowed to exceed 90% without the initiation of a system improvement project.

5.0 Voltage Regulation

5.1 Voltage regulators on the distribution system shall be limited to one set in the substation and two cascaded line units on any distribution line.

5.2 Similar to the justification provided in the step transformer section, regulators should not be regularly loaded more than 75%. The 75% maximum loading criteria for regulators will allow reserve capacity in situations where back-feeding of an adjacent feeder is possible. Peak loading of regulators over 75% shall be reviewed individually and in no case be allowed to exceed 90% without the initiation of a system improvement project.

5.3 Observable and objectionable limits on voltage flicker caused by motor starting, reactive device switching, or load cycling will be governed by the guidelines provided in ANSI/IEEE Std. 141-1993.

6.0 Capacitors

6.1 Energy Reliability Council of Texas (ERCOT) standards state that "sufficient static reactive power capability shall be installed…in substations and on the distribution voltage system to maintain at least 0.97 lagging power factor for the maximum net active power…" Based on this standard, the planning criteria for the distribution system shall be as follows. The power factor at all substations and feeders shall be maintained at a minimum of 97% lagging during on-peak loading conditions and maintained at a maximum of 97% leading during off-peak loading conditions. This power factor standard will be maintained by the placement and control of capacitor banks.

7.0 Sectionalizing

7.1 The goal of sectionalizing is to minimize the number of affected members and minimize the duration of power outages while maintaining safety standards for Bluebonnet employees and the general public. Considerations allowing adequate sectionalizing are:

- 7.1.1 Coordination of device operation to ensure that a downstream device will clear a fault before the upstream device goes to lockout
- 7.1.2 Adequate device interrupting value (greater than maximum fault magnitude)
- 7.1.3 Assurance of device operation under minimum fault conditions
- 7.1.4 Adequate device capacity based on load

7.2 The methods and procedures for accomplishing the first three (3) bulleted items are documented in a previously developed document titled Bluebonnet Sectionalizing Philosophy Manual. The last bulleted item is addressed below.

7.3 Ensuring adequate device capacity based on load is important to prevent protective devices such as reclosers and fuses from interrupting electric service due to overload. When load reaches the minimum trip setting of a protective device, the device will operate. To prevent this from occurring, protective devices will be limited to loading that is 75% of the device rating. Peak loading of protective devices over 75% shall be reviewed individually and in no case be allowed to exceed 90% without the initiation of a system improvement project. (It is important to note that the trip setting for hydraulic reclosers and fuses is 2X the rating.)

7.4 This criterion will allow an adequate time period for the planning and construction of the necessary system improvement. For those parts of the service area that are growing at 20%, the 75% criterion will provide one year prior to reaching the 90% critical level. For those parts of the service area that are growing at 10%, the 75% criterion will provide two years prior to reaching the 90% critical level.

8.0 Phase Balancing

8.1 Maintaining a high level of load balance between phases is important in the efficient operation of the distribution system. To determine the load balance between phases, calculate U as a function of the three (3) phase currents A, B, and C. The equation for U is described below.

$$U = \frac{\text{Maximum Deviation of A, B, or C from Average of A, B, and C}}{\text{Average of A, B, and C}}$$

8.2 When U is greater than 20%, the imbalance situation becomes critical. Phase balance projects should be prioritized based on U, the amount of load, and the key accounts on the feeder. The criterion for phase balancing is to maintain a value of U that is less than 20% on all circuits.

9.0 Summary of Planning Criteria

The distribution system planning criteria defined in this document is an important guideline for providing exceptional power quality to our membership. These planning criteria also form the guideline to be utilized in the development of system improvement documents. Throughout this document, all planning characteristics of a distribution system are defined and the planning and critical levels of performance for each characteristic are established. The following chart summarizes the document.

	Planning Level	**Critical Level**
Voltage Level	114-126 volts @ meter 120-126 volts @ primary	112-127 volts @ meter 118-127 volts @ primary
Conductor	60% of emergency rating	100% of normal rating
Substation Transformer	90% of maximum rating	100% of maximum rating
Step Transformer	75%	90%
Voltage Regulator	75%	90%
Capacitor	97% (substation) 97% (feeder)	<97% (substation) <95% (feeder)
Protective Device	75%	90%
Phase Balance	20%	NA

Appendix A --- Conductor Loading

IEEE Std. 738-1993

Conductor		Summer Rating			Winter Rating		
Type	Strands	Optimum	Normal	Emergency	Optimum	Normal	Emergency
795 ACSR	26 / 7	552	730	920	744	1130	1240
477 ACSR	26 / 7	402	530	670	540	820	900
336 ACSR	26 / 7	318	430	530	432	650	720
4/0 ACSR	6 / 1	234	320	390	318	490	530
2/0 ACSR	6 / 1	174	240	290	234	360	390
1/0 ACSR	6 / 1	150	210	250	204	310	340
2 ACSR	6 / 1	102	140	170	138	220	230
4 ACSR	6 / 1	78	110	130	108	170	180
795 AAC	37	534	700	890	720	1090	1200
477 AAC	19	390	520	650	522	800	870
336 AAC	19	312	410	520	414	640	690
4/0 AAC	19	228	310	380	312	470	520
2/0 AAC	19	174	230	290	228	350	380
1/0 AAC	19	150	200	250	198	310	330
4/0 CU	19	294	390	490	396	600	660
2/0 CU	7	216	300	360	294	450	490
1/0 CU	7	186	260	310	252	390	420
2 CU	7	138	190	230	186	290	310
4 CU	3	108	150	180	144	220	240
6 CU	3	78	110	130	108	170	180
8 CU	1	54	80	90	72	120	120

All ratings are based upon the following constants:

Wind velocity = 2 feet/second
Elevation = 600 feet
Emissivity = 0.5
Solar Absorptivity = 0.5
Line Orientation = North-South
Latitude = 30 ^{o}
Atmosphere = Clear
Time of Day = 2:00 PM

All ratings shown in amps.
All ratings for normal loading are based upon a maximum conductor temperature of 75°C.

All ratings for emergency loading are based upon a maximum conductor temperature of 93.3^{o}C.

All ratings for summer loading are based upon 40°C ambient air temperature.

All ratings for winter loading are based upon 0°C ambient air temperature.
All ratings for optimum loading are based upon 60% of the emergency conductor rating.

Appendix B --- Substation Transformer Loading

ANSI/IEEE C57.92-1981

Transformer Cooling Type	Transformer Rating @ 55 ºC	Transformer Rating @ 65 ºC	Summer Rating			Winter Rating		
			Normal	Maximum	Emergency	Normal	Maximum	Emergency
OA	1		0.9	1	1.4	1.4	1.5	1.8
OA	1.5		1.4	1.5	2.0	2.1	2.3	2.7
OA	2.5		2.3	2.5	3.4	3.4	3.8	4.6
OA	3		2.7	3	4.1	4.1	4.6	5.5
OA	3.75		3.4	3.75	5.1	5.1	5.7	6.9
OA	3.75	4.2	3.8	4.2	5.3	5.4	6.0	7.2
OA	4.5		4.1	4.5	6.1	6.2	6.8	8.2
OA	5		4.5	5	6.8	6.8	7.6	9.2
OA	5	5.6	5.0	5.6	7.1	7.2	8.0	9.6
OA	5	5.75	5.2	5.75	7.3	7.4	8.2	9.8
OA	7.5		6.8	7.5	10.2	10.3	11.4	13.7
OA	7.5	8.4	7.6	8.4	10.7	10.8	12.0	14.4
OA	10		9.0	10	13.6	13.7	15.2	18.3
OA	12.5	14	12.6	14	17.8	18.0	20.0	23.9
OA / FA	2.2 / 2.8		2.5	2.8	3.8	3.6	3.9	4.7
OA / FA	2.5 / 3.125		2.8	3.125	4.2	4.0	4.4	5.3
OA / FA	2.5 / 3.125	2.8 / 3.5	3.2	3.5	4.4	4.3	4.7	5.5
OA / FA	3.75 / 4.687		4.2	4.687	6.3	5.9	6.6	7.9
OA / FA	3.75 / 4.687	4.2 / 5.25	4.7	5.25	6.6	6.4	7.1	8.3
OA / FA	4 / 5		4.5	5	6.8	6.3	7.1	8.4
OA / FA	4.6 / 5.75		5.2	5.75	7.8	7.3	8.1	9.7
OA / FA	5 / 6.25		5.6	6.25	8.4	7.9	8.8	10.5
OA / FA	5 / 6.25	5.6 / 7	6.3	7	8.8	8.5	9.5	11.1
OA / FA	5.6 / 7		6.3	7	9.5	8.9	9.9	11.8
OA / FA	7.5 / 9.375		8.4	9.375	12.7	11.9	13.2	15.8
OA / FA	7.5 / 9.375	8.4 / 10.5	9.5	10.5	13.2	12.8	14.2	16.6
OA / FA		10 / 12.5	11.3	12.5	15.8	15.2	16.9	19.8
OA / FA	10 / 12.5		11.3	12.5	16.9	15.9	17.6	21.0
OA / FA	10 / 12.5	11.2 / 14	12.6	14	17.6	17.0	18.9	22.1
OA / FA	15 / 20	16.8 / 22.4	20.2	22.4	28.2	27.2	30.2	35.4
OA / FA / FA	3.75 / 4.687 / 6	4.2 / 5.25 / 6.75	6.1	6.75	8.6	8.0	8.9	10.4
OA / FA / FA	7.5 / 9.375 / 12	8.4 / 10.5 / 13.5	12.2	13.5	17.3	16.0	17.8	20.8
OA / FA / FA	12/16/20		18.0	20	26.4	24.8	27.6	32.4
OA / FA / FA	12/16/20	13.4 / 17.9 / 22.4	20.2	22.4	28.7	26.6	29.6	34.5
OA / FA / FA	13.1 / 17.5 / 21.9	14.7 / 19.6 / 24.5	22.1	24.5	31.4	29.1	32.3	37.7
OA / FA / FA	15 / 20 / 25	16.8 / 22.4 / 28	25.2	28	35.8	33.3	37.0	43.1
OA / FA / FA		20 / 26.7 / 33.3	30.0	33.3	42.6	39.6	44.0	51.3
OA / FA / FA	18 / 24 / 30	20.2 / 26.9 / 33.6	30.2	33.6	43.0	39.9	44.4	51.7
OA / FA / FA	24 / 32 / 40	26.9 / 35.8 / 44.8	40.3	44.8	57.3	53.2	59.1	69.0

All ratings are based upon 70% preloading, 8 hour peak loading, and maximum allowable average winding temperature rise except the Summer Maximum Rating which is limited to the unit's maximum rating as specified by the manufacturer.
All ratings for normal loading are based upon 90% of maximum loading.
All ratings for maximum loading are based upon no power transformer loss of life.
All ratings for emergency loading are based upon a 1% power transformer loss of life.
All ratings for summer loading are based upon 40ºC ambient air temperature.
All ratings for winter loading are based upon 0ºC ambient air temperature.

Cooling Types:
- OA = Self Cooled
- OA / FA = Forced Air Cooled (one stage of fans)
- OA / FA / FA = Forced Air Cooled (two stages of fans)

All MVA values are based upon power transformer ratings rather than substation ratings.
Substation equipment such as regulators, buses, or fuses may reduce actual ratings.

Appendix B

LCRA Transmission Services Corporation
TRANSMISSION SYSTEM PLANNING CRITERIA

Original Publication Approved on 01/27/1998	
Revision A Approved on 08/24/1999 –	Revised Section III.B. System Reliability
Revision B Approved on 10/26/1999 –	Revised Section II. Add Table 1
Revision C Approved on 08/27/2002 –	Revised Section I –Substation Bus Design Criteria
Revision D Approved on 10/17/2005 –	Revised Sections E and F
Revision E Approved on 06/25/2008 –	Revised Sections E and F to state current application of criteria
Revision F Approved on 05/26/2010 –	Revised (update) several sections and title
Revision G Approved on 08/22/2012 –	Revised Section III. Add Section H
Revision H Approved on 02/25/2013 –	Removed references to AWC; removed criteria language already stated in NERC/ERCOT criteria; Address anticipated voltage performance at the Bakersfield Substation
Revision I Approved on 02/28/2014	Revised Sections III.A.1) - 3) and added Section III.A.4). Assessments, including recommended action plans, associated with criteria in Section III.A.4) shall be completed by no later than January 1, 2016.
Revision J Approved on 06/20/2015	Revised Section III.C to clarify that the Nominal Conductor Rating is the temperature adjusted rating appropriate to the season being analyzed, updated Table 1, and added the standard bus ratings developed with Substation Design to Section III.F.
Revision K Approved on 10/20/2015	Revised Section III.B to change the 20 MW threshold to 10 MW, fixed errata.

LCRA Transmission Services Corporation
TRANSMISSION SYSTEM PLANNING CRITERIA

I. INTRODUCTION

LCRA Transmission Services Corporation (LCRA TSC) employs reliability criteria for conducting assessments of its transmission facilities. In addition to requirements set forth in the North American Electric Reliability Corporation (NERC) Reliability Standards and the Electric Reliability Council of Texas (ERCOT) Planning Guide, LCRA TSC has adopted supplemental criteria set forth in this document to maintain an acceptable level of transmission reliability during normal and contingency conditions.

II. ASSUMPTIONS

In conducting assessments associated with the annual Transmission System Improvements Plan (TSIP), assumptions shall include but not be limited to the following:

- Do not include the generating capacity of hydro units within the Highland Lakes area.
- Switched shunt reactive devices (capacitors and reactors) are modeled as locked devices (either "ON" or "OFF").
- No Load Tap Changers (NLTC) on autotransformers and generator step-up transformers are modeled locked (at operating tap position).
- System equipment limits or impacts shall be within the applicable ratings as defined in Section III of this document.
- Transmission lines are defined to be within a common corridor if said lines are located in close proximity to each other such that catastrophic failure of one line could cause an outage or failure of another.
- For steady state assessments, events resulting in single contingency conditions shall include the loss of bus-to-bus elements.
- For dynamic and transient assessments, events shall represent the expected action of the protection system.

III. PERFORMANCE REQUIREMENTS (APPLICABLE RATINGS)

A. SYSTEM BUS VOLTAGE

The nominal voltage levels are 345-, 138-, and 69-kV.

1) The steady state transmission system voltages shall not exceed 105 percent nor fall below 95 percent of nominal voltage during normal conditions.
2) The steady state transmission system voltages shall not exceed 105 percent nor fall below 92 percent of nominal voltage during single, multiple, or extreme contingency conditions. Exception: Voltage at the Bakersfield Substation shall not exceed 110 percent of nominal voltage during singe, multiple, or extreme

contingency conditions. The addition of an autotransformer, line terminal, or shunt reactive device at Bakersfield Substation shall be planned in a manner such that this exception may be removed.

3) No single, multiple or extreme contingency shall result in more than a 7 percent change in steady state voltage at three or more substations.

4) For NERC single element contingencies, the transient voltage at load serving buses shall recover to a minimum of 0.92 per unit voltage within 90 cycles after normal fault clearing.

B. SYSTEM RELIABILITY

1) Any power transformer that experiences six or more outages per year or any combination of outages totaling more than five hours per year due to failures on the transmission and/or transformation system, shall be deemed to have inadequate reliability.

2) Reliability to radial-supplied station(s), exceeding 20 MW of peak load, shall be addressed by the most technically and economically feasible of the alternatives described below.

   a) Looped transmission service to the radial station may be provided by a separate transmission circuit configuration (separate transmission towers).

   b) Looped transmission service to the radial station may be provided by a double circuit transmission configuration (same transmission towers) from the same source or from multiple sources. If the looped transmission service is from the same source, the transmission source bus must be of a multiple bus construction, and the double circuit to the radial station is terminated on separate buses. Additionally, distribution back-up to support the double circuit supplied station load requirements must be provided. The source(s) of distribution back-up must have the available capacity to support the entire station load without violating emergency loading and voltage levels of the Distribution Planning Criteria. This alternative must include the cost required to limit emergency loading and voltage conditions to within 8 hours.

   c) Limit a radial station load to 20 MW and provide the added capacity requirements from available area stations.

3) In order to address current transmission service reliability requirements, in 2015 LCRA TSC revised its transmission planning criteria. The electric load threshold was revised from 20 MW (set in 1992) to 10 MW as applicable to non-breaker protected looped stations. Station(s) with looped transmission service, whose peak load exceeds 10 MW, shall be identified as requiring circuit breakers such that the total interrupted load is 10 MW or less.

C. CONDUCTOR RATINGS

Planned transmission line loading will be such that National Electrical Safety Code line-to-ground clearances will be maintained for all anticipated normal and contingency conditions. Transmission system power flow shall not exceed 100 percent of the nominal conductor thermal rating when assessing the performance of the transmission system. The nominal conductor thermal rating is the temperature adjusted rating appropriate to the season being evaluated as reported in the MLSE database or by Transmission Engineering staff.

To assist with selection of conductors and impedance values when evaluating alternatives to upgrade facilities, nominal conductor thermal ratings for commonly used transmission conductors are shown in Table 1 below. The ratings in Table 1 are derived consistent with the LCRA TSC Facility Rating Methodology. The ratings in Table 1 do not take into consideration the rating of ancillary equipment which may be impacted when evaluating alternatives to increase the rating of existing facilities. The ACSR conductor ratings are based upon a 100° C (212° F) average conductor temperature using coefficients of emissivity and absorptivity of 0.5. The ACSS/TW conductor ratings are based upon a 180° C (356° F) average conductor temperature using coefficients of emissivity and absorptivity of 0.5. Further, these nominal conductor thermal ratings for both kinds of conductor are based on an ambient temperature of 43.33° C (110° F), an elevation of 2,650 feet above sea level, a north-south line orientation, 31 degrees latitude, 2:00 PM solar conditions, clear atmosphere, and a wind velocity of 2 feet per second normal to the conductor. The actual operational ratings for specific lines may vary depending on the applicable ambient temperatures and elevations. Engineering maintains the data associated with conductor ratings.

Table 1. Typical conductor thermal ratings for planning purposes

Conductor Size	Conductor Ampacity	MVA Rating (69 kV)	MVA Rating (138 kV)	MVA Rating (345 kV)
1/O ACSR "Raven"	240	20	not used	not used
4/O ACSR "Penguin"	360	40	80	not used
4/Ox2 ACSR Bundled "Penguin"	720	80	170	not used
336 ACSR "Linnet"	540	60	120	not used
336x2 ACSR Bundled "Linnet"	1080	120	250	not used
477 ACSR "Hawk"	670	80	160	not used
795 ACSR "Drake"	930	110	220	not used
795x2 ACSR Bundled "Drake"	1870	220	440	1110
1590 ACSR "Falcon"	1420	160	330	not used
1590x2 ACSR Bundled "Falcon"	2850	340	680	1700
959 ACSS/TW "Suwannee"	1600	190	380	not used
959x2 ACSS/TW Bundled "Suwannee"	3210	380	760	1910
1433 ACSS/TW "Merrimack"	2000	230	470	not used
1433x2 ACSS/TW Bundled Merrimack"	4000	470	950	2390
1926 ACSS/TW "Cumberland"	2500	290	590	not used
1926x2 ACSS/TW Bundled "Cumberland"	5000	590	1190	2980

(1) Based on IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors (IEEE Std. 738-1993)

D. AUTOTRANSFORMER RATINGS

Planned loading on autotransformers, during normal, single, or multiple contingency conditions shall be limited to 100 percent of the auto-transformer's maximum MVA rating as derived consistent with the LCRA TSC Facility Rating Methodology. For planning project alternatives, the auto-transformer ratings assume that the auto-transformer will be the most limiting series element.

Engineering maintains the data associated with autotransformer ratings.

E. STATION EQUIPMENT RATINGS

The criteria for determining the required performance related to station equipment is provided below. At ERCOT's direction and driven by potential congestion, station equipment upgrades may be necessary for performance above and beyond what is required in this criteria.

1) During any new transmission line project, all station equipment related to that line will be designed such that the continuous rating of all station equipment is greater than or equal to the continuous rating of the new line. During any transmission line upgrade project, station equipment related to that line will be upgraded as necessary such that the continuous rating of all station equipment allows for operating conditions described in 2 and 3 below.
2) Station equipment (circuit breakers, circuit switches, wave traps, jumpers, connectors, current transformers, relays, relay settings, etc.) connected in series with the conductor shall be upgraded (independent of a conductor upgrade) if either of the following two conditions are met:
   a) The continuous rating of the station equipment is less than or equal to 50 percent of the continuous rating of the conductor; or
   b) The loading through the station equipment during either normal or single contingency conditions is greater than or equal to 80 percent of the continuous rating of the station equipment.
3) Interrupting duty of station equipment switching devices (circuit breakers and circuit switchers) shall be planned as follows:
   a) The interrupting rating of gas and oil circuit breakers shall be at least 110 and 120 percent respectively of the maximum available close-in fault at the point of application.
   b) The interrupting rating of circuit switchers shall be at least 110 percent of the maximum available close-in fault at the point of application.

F. SUBSTATION BUS DESIGN CRITERIA

1) New Substation Consideration
   a) The ultimate layout for all new 345-kV stations or 345-kV interconnections shall be of the ring type, breaker-and-a-half type, or double bus-double breaker type ("improved bus arrangement").
   b) Except as noted below for tapped stations, the ultimate layout for all new 138-kV and 69-kV switching stations (i.e. stations with more than two circuits) should allow for an improved bus arrangement where

possible. Initial substation design should include facilities to allow remote control of transmission line switches to assist in meeting planning criteria requirement III.B. The type of improved bus arrangement shall be consistent with ultimate plans or potential growth of the substation. The table below lists the accepted improved bus arrangements based on the number of transmission elements connected to the substation. The most cost-effective improved bus arrangement shall be selected.

Transmission Elements*	Accepted Improved Bus Arrangements
Up to Five	1) Ring Bus, 2) Double Bus Double Breaker, or 3) Breaker-and-a-Half
Six-Nine	1) Double Bus Double Breaker, or 2) Breaker-and-a-Half
Ten and Larger	1) Breaker-and-a-Half

*Transmission elements include capacitor banks, reactor banks, generators, lines, or autotransformers.

c) For the interconnection of tapped stations below 150-kV onto an existing line, the following criteria shall be used. This criteria applies to interconnections on radial lines as well as new interconnections being connected to existing tapped sections. These minimum criteria may be enhanced based up on protective relaying limitations or operational flexibility and reliability requirements.

1. A station configuration that includes a circuit breaker at the point of interconnection is required for the following: If the length from either end of the interconnecting line to the tapped station exceeds the original interconnecting line length by 20%, or the tapped station interconnects a generating resource sized greater than 10 MVA. The breakered connection shall provide SCADA control and status indication and protective relaying in a 3-terminal Directional Comparison Blocking (DCB) or line differential scheme. An enhanced breaker configuration (e.g. ring bus) may be installed based on customer reliability requirements.
2. A station configuration that includes motor operated switches

(MOS) at the point of interconnection is required if the tapped circuit length exceeds 1 mile. The MOS interconnection shall provide SCADA control and status indication and be constructed in such a way as to allow a future breakered connection based on the "10 MW rule" described in III.B.3.

3. A station configuration that includes disconnect switches at the point of interconnection is required if the tapped circuit length is less than 1 mile. The disconnect switch interconnection shall provide physical access and clear visibility of switch status.

d) Whenever possible, bus design should minimize loss of transmission, generation and transformation facilities connected to the bus for a single breaker failure condition. Improved bus arrangements are required for 138-kV and 69-kV substations meeting the following considerations:

1. Transmission System Considerations
    a. The substation includes known plans or has a potential for more than two transmission elements to originate at the substation bus.
    b. The substation is located in high load growth or alternative generation corridor.
    c. The loss of the entire substation bus causes other elements in the system to reach loading levels above 90 percent of their maximum thermal capacity.
    d. The loss of the entire substation bus causes system voltage to fall below acceptable defined limits.
2. Load Considerations
    a. Substation includes multiple power transformers totaling more than 60 MW of capacity and without adequate transformer back-up.
    b. The loss of the entire substation bus causes outages at multiple substations (substation bus is the only source to radial supplied substation serving more than 10 MW).

e) Standard Bus Ratings

1. The rating requirements for new substation equipment shall be established by specifying a value in Amperes.
2. Rating requirements for new substation equipment should not

exceed:

a. 3000 Amp for 138 kV
b. 5000 Amp for 345 kV

3. To assist with determining minimum bus rating requirements, the following typical bus ratings are provided (actual bus ratings are provided in the MLSE database for existing facilities or by the substation engineer):
   a. 336 ACSR Linnet, 540 A
   b. 795 ACRS Drake, 930 A
   c. 4" Sch. 40 Al pipe, 2954 A
   d. 6" Sch. 40 Al pipe, 4435 A
   e. 6" Sch. 80 Al, pipe 5350 A

2) Existing Substation Consideration

This design guideline, incorporated into this planning criteria on August 2002, addresses all new projects. For systems existing or under development prior to this date, substation bus requirements shall be reviewed on a case by case basis to establish the need for a more reliable bus arrangement. Similarly, on a case by case basis, substation design should include facilities to allow remote control of transmission line switches to assist in meeting planning criteria requirement III.B. As major projects are identified through the annual planning process, consideration to items III.F.1)d)2. above will dictate the need for retrofitting an existing substation to an improved bus arrangement (e.g. when items III.F.1)d)1. above do not by themselves demonstrate the need). However, feasibility and cost to implement solutions that include improved bus designs shall be a factor in making this determination. If substation property constraints and associated costs prohibit the expansion of an existing substation to one of an improved bus arrangement, a single bus-single breaker design may be acceptable. However, relocation to another substation site should be considered.

G. STABILITY

The following criteria will be used to evaluate stability.

1) The critical clearing time for faults on the bulk electric system and near the point of interconnection with a generating facility shall be:
   a. 345-kV: the lesser of 25 cycles or the maximum length of time a fault can remain on the bulk electric system and not cause a machine to

lose synchronism or cause a generating facility to violate the voltage ride through requirements established by ERCOT for the generating facility;

b. 138 kV and 69 kV: 30 cycles or the maximum length of time a fault can remain on the bulk electric system and not cause a machine to lose synchronism or cause a generating facility to violate the voltage ride through requirements established by ERCOT for the generating facility.

2) P-V analysis shall not indicate voltage collapse within the expected range of area generation import levels.

3) Q-V analysis shall be performed to determine if reactive margins are sufficient to maintain voltage stability at load serving buses with area load increased by 5%.

H. TRANSMISSION FACILITY REHABILITATION

Transmission lines, identified by Maintenance and Engineering as needing a significant overhaul for all or a portion of the transmission line such as those that: are installed on structures beyond their design life and have deteriorated beyond acceptable standards; have required above-average maintenance; and/or require safety code-related or storm-hardening improvements in accordance with PUC requirements, shall be assessed for potential improvements. To determine whether rebuilding all or portions of the identified transmission line to a higher voltage rating and/or larger capacity would more efficiently and cost-effectively meet the long-term needs for the system, the transmission planner will consider factors such as current and forecasted area load, area generation, facility loading level, facility location, exhibited performance (asset availability) and the benefits of reduced maintenance, environmental impacts, community impacts and operational needs.

Exhibit 1

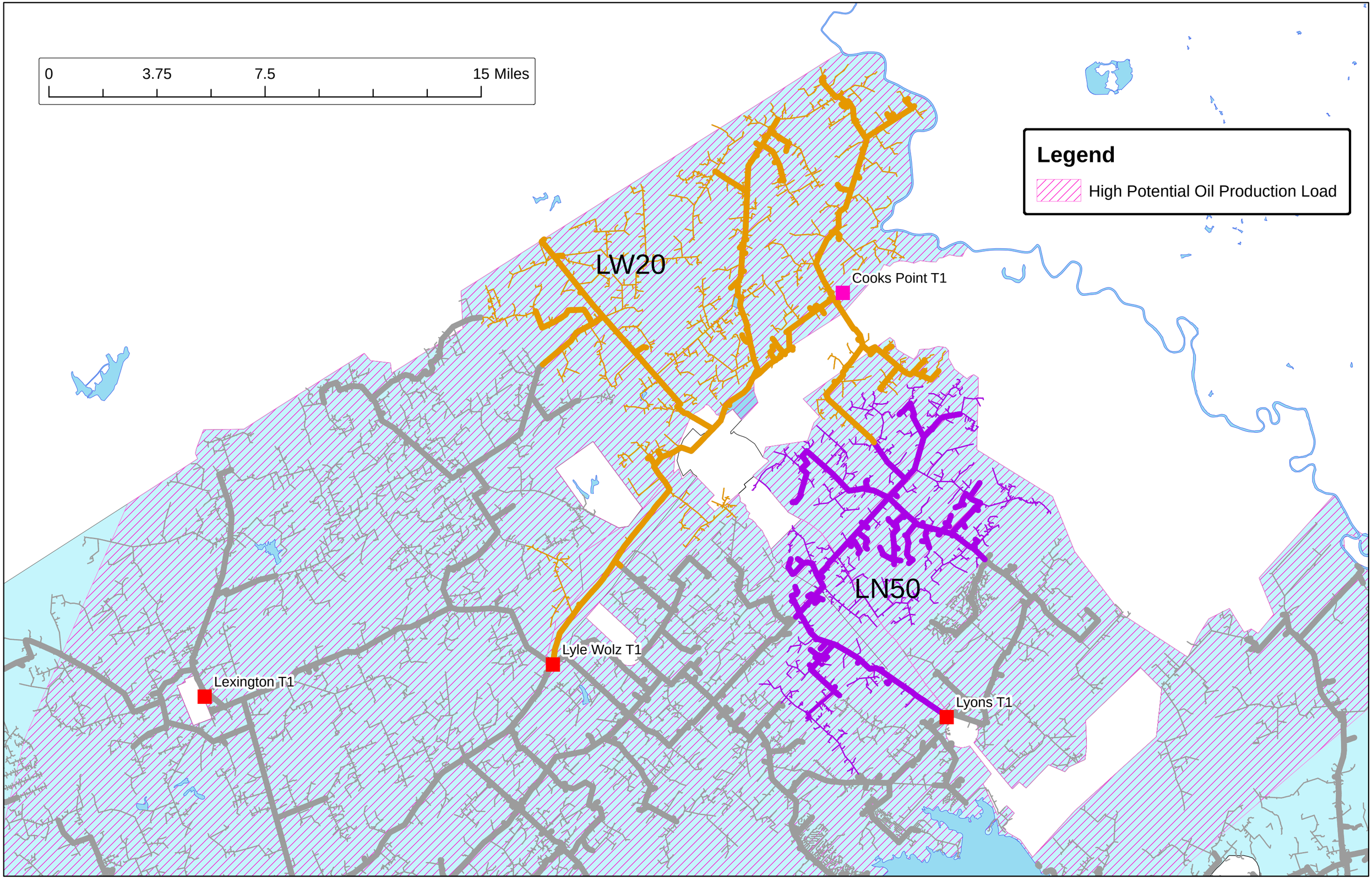

0
3.75
7.5
15 Miles
Legend
High Potential Oil Production Load
LW20
Cooks Point T1
LN50
Lyle Wolz T1
Lexington T1
Lyons T1

Exhibit 2

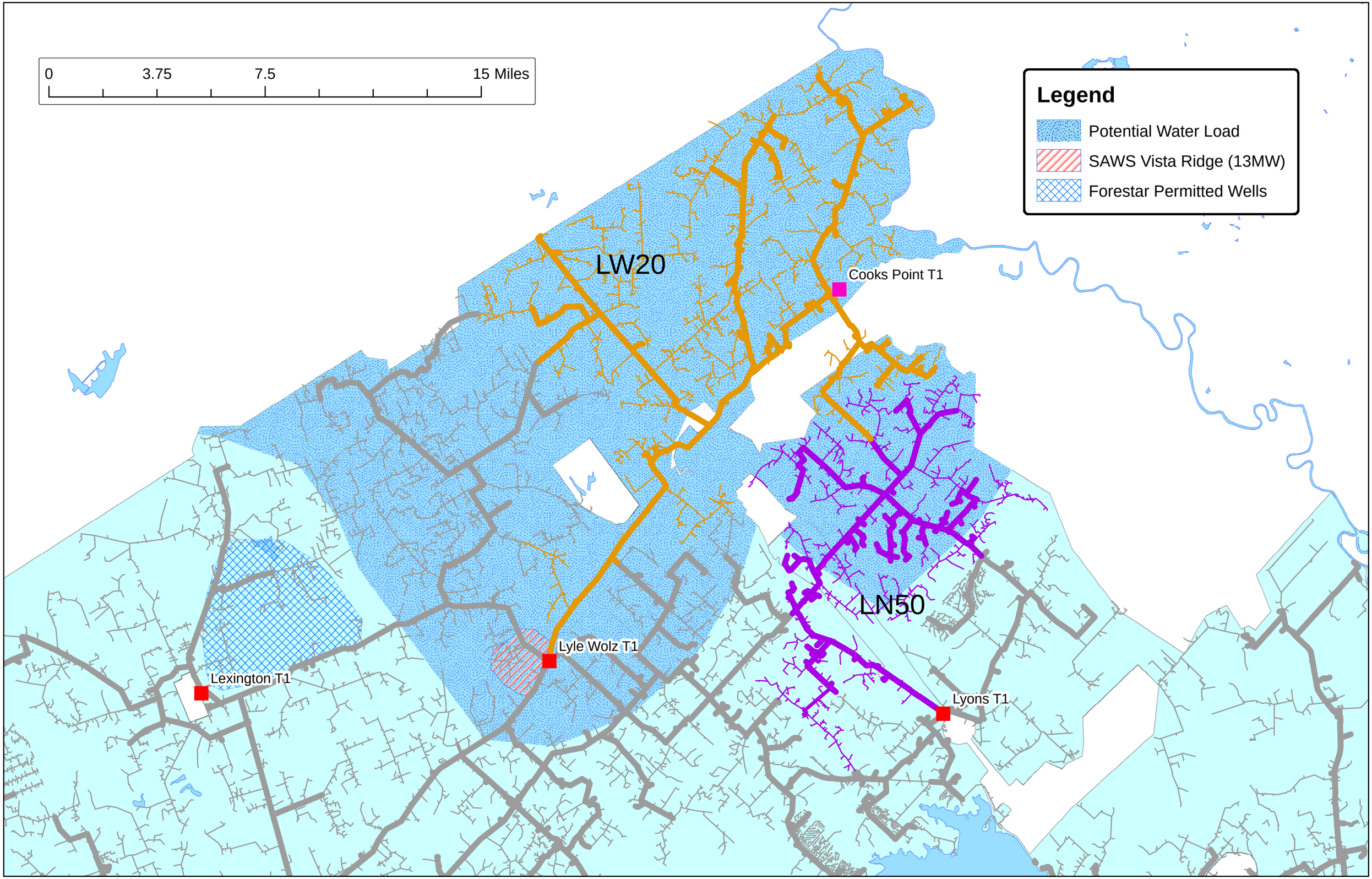

0
3.75
7.5
15 Miles
Legend
Potential Water Load
SAWS Vista Ridge (13MW)
Forestar Permitted Wells
LW20
Cooks Point T1
LN50
Lyle Wolz T1
Lexington T1
Lyons T1

Exhibit 3

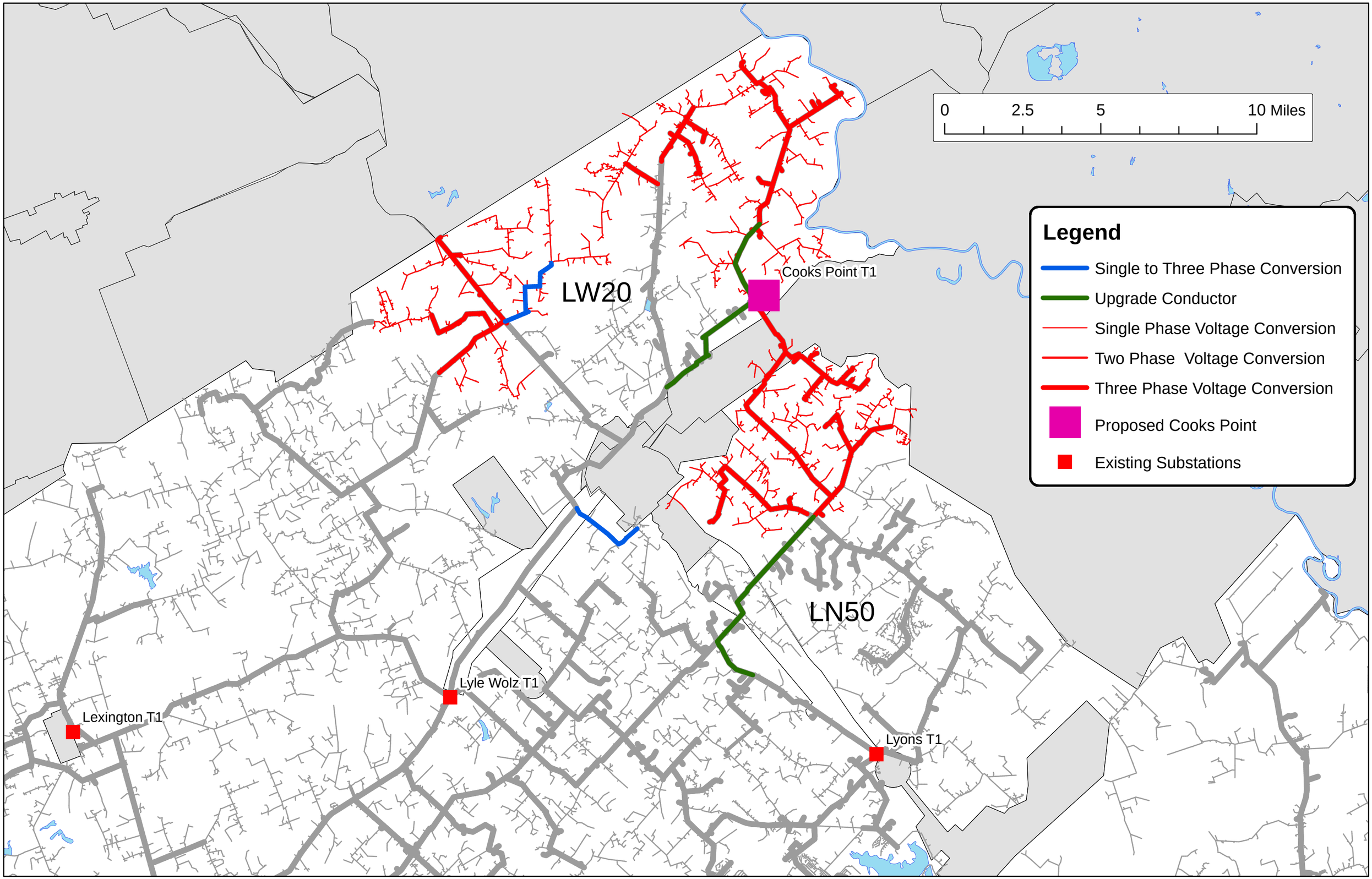
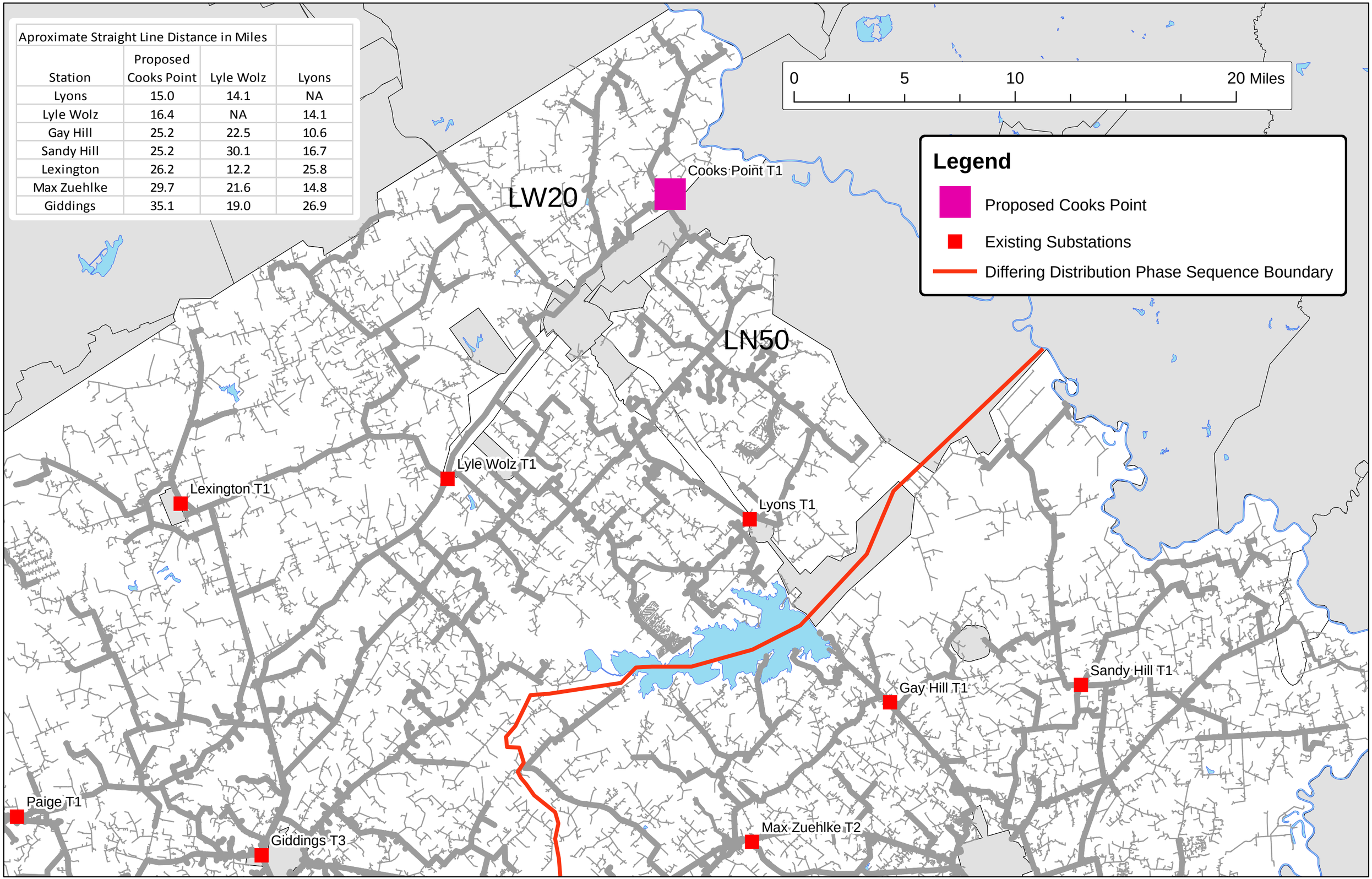

0
2.5
5
10 Miles
Legend
Single to Three Phase Conversion
Upgrade Conductor
Single Phase Voltage Conversion
Two Phase Voltage Conversion
Three Phase Voltage Conversion
Proposed Cooks Point
Existing Substations
LW20
LN50
Cooks Point T1
Lyle Wolz T1
Lexington T1
Lyons T1

Exhibit 4

Aproximate Straight Line Distance in Miles			
Station	Proposed Cooks Point	Lyle Wolz	Lyons
Lyons	15.0	14.1	NA
Lyle Wolz	16.4	NA	14.1
Gay Hill	25.2	22.5	10.6
Sandy Hill	25.2	30.1	16.7
Lexington	26.2	12.2	25.8
Max Zuehlke	29.7	21.6	14.8
Giddings	35.1	19.0	26.9