ENERGIZING THE FUTURE: LOAD ANALYSIS AND PROPOSED GRID MODIFICATIONS FOR THE TEXAS INTERCONNECT

An Undergraduate Research Scholars Thesis

by

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ABSTRACT

Energizing the Future: Future Load Analysis and Proposed Grid Modifications for the Texas Interconnect

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Texas is home to ten of the fifteen fastest growing cities in the United States. These dramatic and concentrated increases in population will place an increased strain on the Texas power grid, and maintaining its stability and resiliency is of upmost importance. Grid modifications, specifically the addition of high voltage transmission lines, are critical to designing a grid that will be able to provide ample power to these growth hotspots for years to come. Proposed here are a set of modifications to a synthetic model of the Texas grid that accommodate this increased demand. These modifications were optimized and validated using PowerWorld, which models the synthetic grid and tests its response to these increases in load under contingency failure conditions. This was all done given a reasonable constraint on the proposed length and capacity of these additional transmission lines with the goal of maximizing the length of time into the future the grid will be able to effectively handle the predicted load growth. Adding transmission capacity at these strategic locations produced a more stable, resilient grid that better handles peak demand hours and brought major contingency violations down 32% from the base case given a 10% load increase in the North Central Zone of the synthetic grid.

ACKNOWLEDGEMENTS

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Finally, I would like to thank my family for always being supportive of my decisions yet encouraging me to never settle and always push to better myself.

NOMENCLATURE

ERCOT	Electric Reliability Council of Texas
MVA	Mega Volt-Amp
MW	Megawatt
p.u.	Per Unit
PW	PowerWorld
TL	Transmission Line

CHAPTER I

INTRODUCTION

Increased load demands in Texas will place new strains on the existing power grid infrastructure. Outages during peak demand hours in the summer, even if they are planned rolling outages, can result in economic losses for business and even loss of life in extreme cases. Modifications to the grid are inevitable and can be very beneficial but the placement of these modifications is critical. Often there are many valid solutions but finding the best solution that maximizes the capitalized cost-benefit analysis can be challenging.

Benefits of Transmission

High voltage transmission lines have many benefits including “lower electricity costs, access to renewable energy such as wind and hydro, locating power plants away from large population centers, and access to alternative generation sources when primary sources are not available” [1]. Transmission line planning has historically been done by individual utilities but with the addition of renewable power generation long distances away from the end user, state and nationwide transmission planning is becoming ever more important [1].

Constraints

Anyone can design a system of transmission lines, but without constraints it is impossible to evaluate the effectiveness of these modifications. For the purposes of this study, the total length of new transmission line is to be 500 miles or less. Aside from strictly cost constraints there are also thermal overloading and bus voltage constraints that have to be considered when making modifications to the synthetic grid [2].

Geographical Zones

To aid in the design, Texas has been split into geographical zones similar to what was done in the “10-Year Transmission System Assessment” [3] done by the American Transmission Company (ATC) for Michigan and Illinois. To determine which zone should be scaled, a general assessment was done on each of these zones to see which were most sensitive to a 10% increase in load demand. New transmission lines were then added to support the most sensitive zone to accommodate the simulated expected growth over the coming years. PowerWorld [4] was used to evaluate the benefits of these additions. The original designs were modified as needed to further optimize and integrate these proposed modifications.

Final Evaluations

Each set of proposed transmission lines were first tested individually using PowerWorld for increases in load capacity and redundancy. The proposals were then ranked on how well they handled future load growth and also on their resilience in the face of contingency failures. This was done using contingency analysis within PowerWorld to ensure the system is “N-1 Reliable”, meaning there is no one transmission line that would jeopardize the entire system if taken out of service. The act of removing any one element from the system is known as a contingency, and this can result in lines overloading or voltages falling below predetermined thresholds which is known as a contingency violation. From this contingency analysis the best set of modeled proposals were chosen for the final solution.

CHAPTER II

METHODS

Scaling Load in the North Central Zone

Due to the size of the synthetic grid being used it isn’t feasible to scale the entire system for this short of a study. Instead the North Central Zone was scaled to 110% of its normal demand. This zone was chosen because it was deemed the most sensitive to this level of load increase, largely because this zone serves the largest load in the synthetic grid. After the load in a particular zone was scaled, a contingency analysis was run and the results were then compared to determine the zone that had the most contingency failures under these conditions. To achieve this, the North Central Zone was scaled by 10% from a base load of 22,263 MW to 24,489 MW. During this process only the load was scaled, the generation capacity was not increased and generator limits were enforced. This allows for the more accurate simulation of transmission line congestion due to the increased load.

Resulting Contingency Analysis

In the unedited base case there were 287 total contingency violations, with a maximum overloading of 125% under these contingency conditions. After running a contingency analysis in the 110% load scaled condition, there were 324 total violations with a max overloading of 133%. The longest overloaded line was 136 miles long and there were 3 lines with 5 or more associated contingency violations. The area around these failures was part of the main focus of this study since they were some of the most problematic for the system. While ideally all of these violations would be corrected, the goal is to minimize these failures while limiting transmission line additions to less than 500 miles.

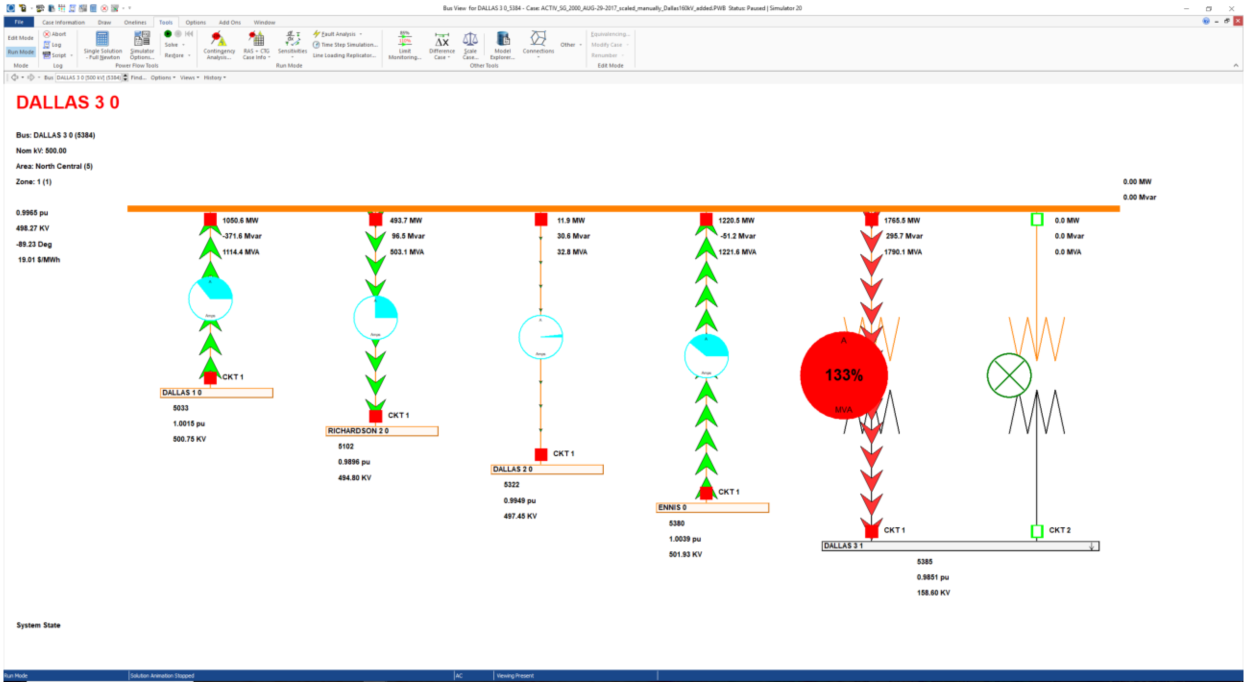
Problem Areas and Overloaded Lines

While adding the additional load did cause some new lines to become overloaded under contingency failure conditions, the main result was increasing the amount by which existing problematic transmission lines would exceed their limit when under contingency failure conditions. It is acceptable for lines to exceed their rating to some degree under these contingency conditions because they are capable of operating over their rating, but if they are forced to endure this overload for long they will start to overheat and safety fuses will blow. This can cause a domino affect on other lines, which could ultimately cause a blackout in a worse case scenario. In the base case, there were already hundreds of contingency violations, but many of them are due to lines becoming 1-10% overloaded in some contingency event. However, many of those overloads became significantly worse with the additional loading demands on the system to the point where they can no longer be ignored.

While it isn’t possible to mitigate every contingency violation in this case, the contingencies that are addressed here were not chosen at random. They were prioritized by the maximum amount of overloading, the number of lines overloaded as well as the size of the line being overloaded by any one contingency.

Dallas 3 Substation Transformer Overloading Contingency

Even though it doesn’t even involve transmission lines, one of the most significant violations actually occurred within the ‘DALLAS 3’ substation between the 500kV and 169kV busses. There were two transformers in parallel tying these busses together, both operating at near 50% in the base case, but after the load was scaled they were operating at over 50% capacity causing significant overloading if either one was taken out of service as shown below in **Fig 1**.



DALLAS 3 0

Bus: DALLAS 3 0 (5384)
Nom kV: 500.00
Area: North Central (5)
Zone: 1 (1)

0.9965 pu
498.27 KV
-89.23 Deg
19.01 $/MWh

Figure 1: 500kV to 169kV Transformer Overloading

If this second transformer were to trip it would cause 9 other transmission lines to become overloaded, several of them over 120% of their rated capacity. This would quickly cause a domino effect that would ultimately cause a blackout. There are similar situations at the 'Magnolia 1' substation as well as the 'San Antonio 51' substation.

Olney 1 to Jacksboro 1 Contingency

While this contingency doesn't hold the record for the most violations or the most overloading. It is a combination of several factors that draw special attention. Firstly, not only does this single 500kV contingency cause four 161kV lines in north Texas to become overloaded as shown in **Fig. 2**. But it also causes one of the major 500kV arteries carrying up to 2.3 GW of power from the west to the east side of the state to become 108% overloaded. While this isn't an extraordinary level of overloading, if in any situation this major 500kV line were to trip off the entire system would instantly blackout so it is desirable to stay well away from this line's limits.

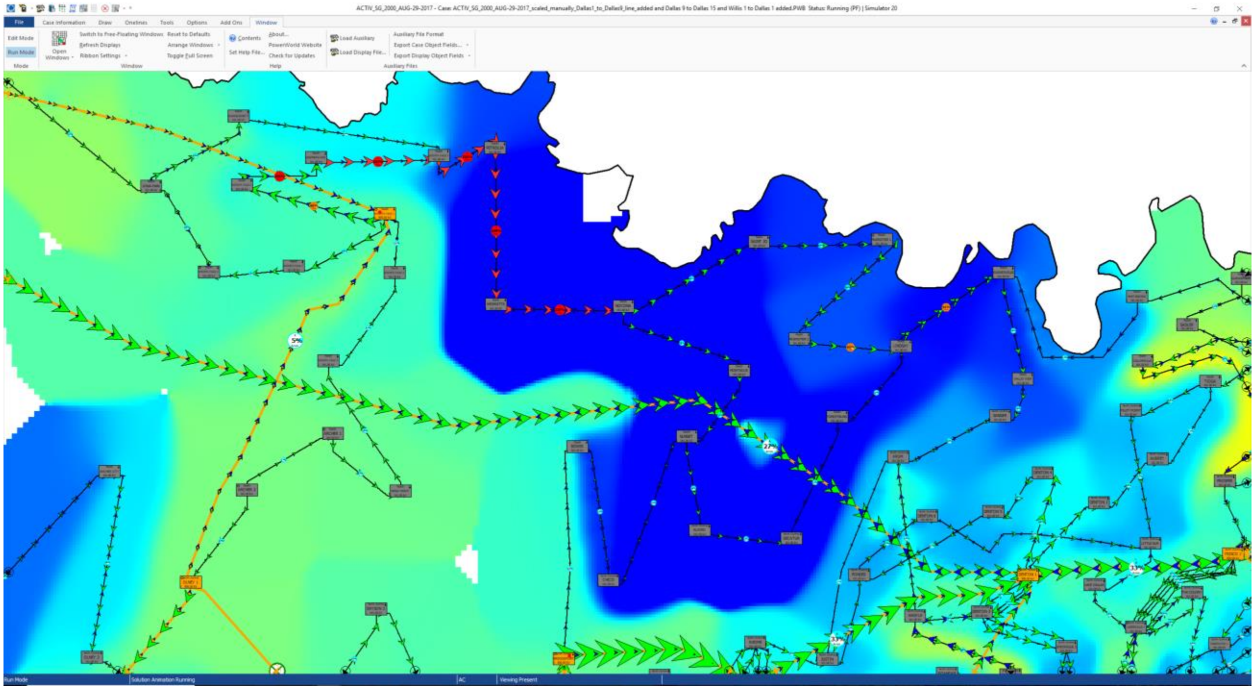


Figure 2: 161kV Overloading and Low Voltages due to Olney 1 to Jacksboro 1 Contingency

There are also 2 other contingencies involving the major 500kV lines between 'Glen Rose 1' and 'Mansfield 0' as well as between 'Denton 1' and 'Frisco 2'.

Solutions to Problem Areas

To resolve these contingency failures, new transmission lines had to be added. For some solutions this also required the addition of new busses and transformers to tie into the existing 500kV system. All of these additions have resistive and inductive parameters based on other instantiations within the case. Rather than just adding more transmission lines in parallel with the overloaded lines, the focus of the new additions was between new, previously unconnected buses to further strengthen the system. These new lines were also evaluated to be as cost effective as possible. This means seeking any potential paths that could solve two contingency failures with one additional line, or even adding lines that would not only prevent some contingency violations but also reduce transmission losses during normal operation.

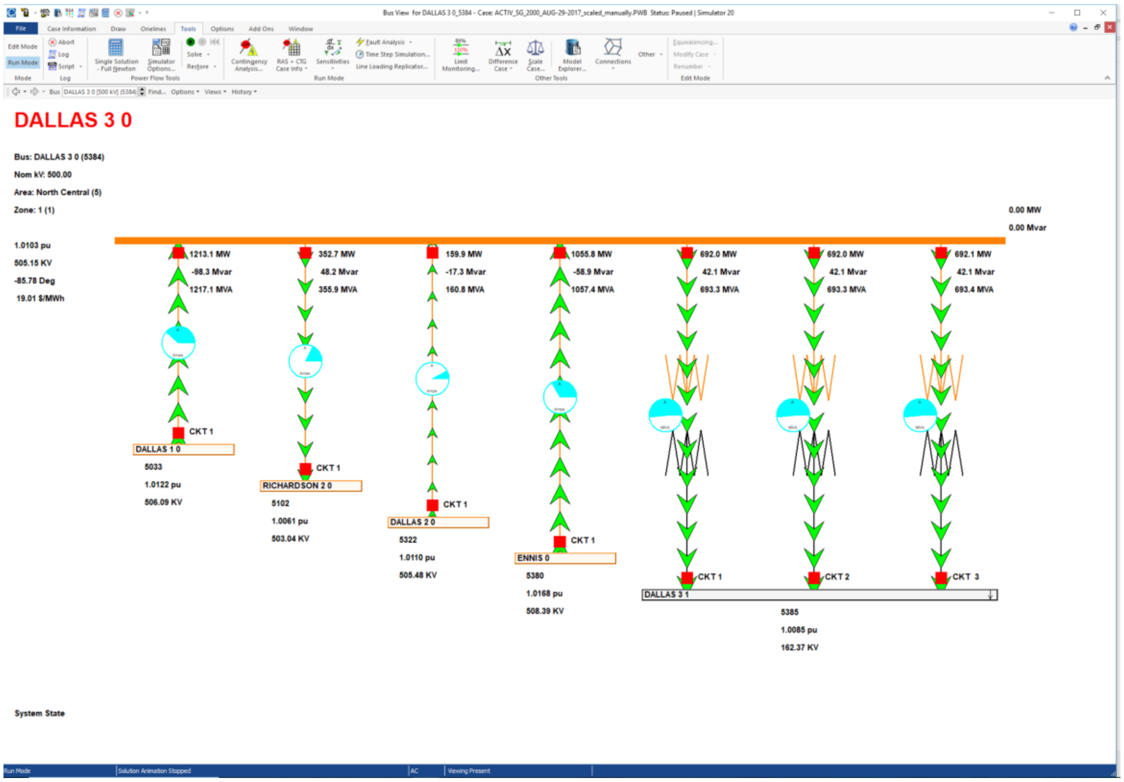
CHAPTER III

RESULTS

Solution Simulations

Dallas 3 Substation Transformer Overloading Contingency

The easiest way to solve these types of transformer overloading situations is to simply add another transformer in parallel with the existing ones. This additional transformer can be seen in **Fig. 3** below when compared to **Fig. 1**. There was potential to add some additional 500kV lines and associated busses, not only to alleviate strains on the transformers at ‘Dallas 3’ but also to lower the losses on the 161kV lines from ‘Dallas 3’ to ‘Dallas 5’. While these types of modifications were tested, such as adding a 500kV transmission from ‘Dallas 1’ to ‘Dallas 5’ or ‘Dallas 1’ to ‘Dallas 9’ (seen in **Fig. 4)** along with the needed 500kV busses and additional transformers, none of them had any substantial benefits. First, all of these solutions still require at least one additional transformer and adding more transmission to either the ‘Dallas 5’ or the ‘Dallas 9’ busses actually causes additional 161kV transmission lines to exceed their limits when in contingency situations. Based on this analysis the best solution was to simply add the additional transformer to the ‘Dallas 3’ substation and take advantage of the extensive 161kV transmission network that already exists in that area.



DALLAS 3 0

Bus: DALLAS 3 0 (5384)
Nom kV: 500.00
Area: North Central (5)
Zone: 1 (1)

1.0103 pu
505.15 KV
-85.78 Deg
19.01 $/MWh

0.00 MW
0.00 Mvar

System State

Figure 3: Dallas 3 Substation Transformer Addition

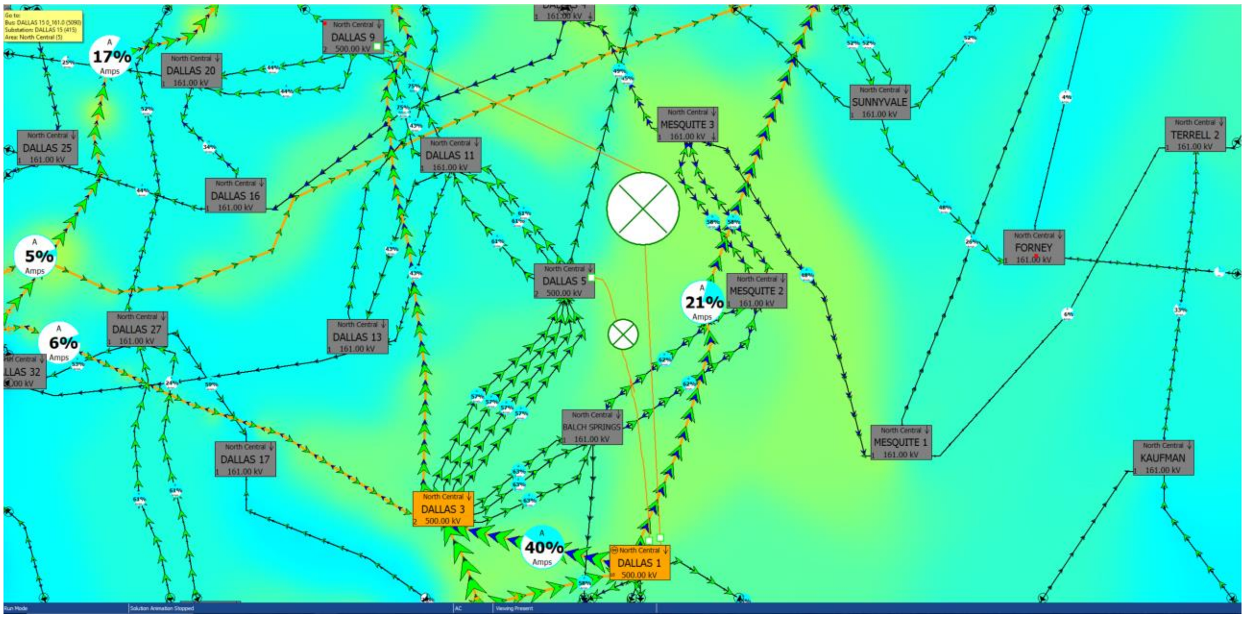


Figure 4: Attempted 500kV Transmission Addition and Substation Upgrade Example

San Antonio 51 Substation Transformer Overloading

This contingency is very similar to the previous one, with one exception; the ‘San Antonio 51’ substation is home to a large capacitor bank. Since this bus under normal conditions was operating at 1.03 p.u., this capacitor bank was taken out of service. While this did not reduce the loading on the transformers enough to make further modifications unnecessary it did bring the substations p.u. voltage down to 1.006. When a contingency analysis was run both with and without this capacitor bank it actually removed 2 violations so the modification was adopted. As to addressing the transformer overloading, it was again determined that due to the adequate sizing of the existing transmission lines, the only needed modification was to add an additional transformer to that substation, preventing 7 additional violations. This process was used to evaluate several more transformer overloads and the results are concluded in the following sections.

Olney 1 to Jacksboro 1 Open Line Contingency

As mentioned previously, this contingency is very concerning because it involves the overloading of one of the largest transmission lines in the system that has an MVA limit of over 2 GVA. If this major artery is taken out of service the entire system blacks out. That is why this contingency is getting special attention. As seen in **Fig. 5**., the primary function of both of these transmission lines is to transfer power from the western half of the state, where much of the generation is, to the eastern half of the state. Therefore, the only sensible solution to this overloading is adding more eastern-western transmission ties.

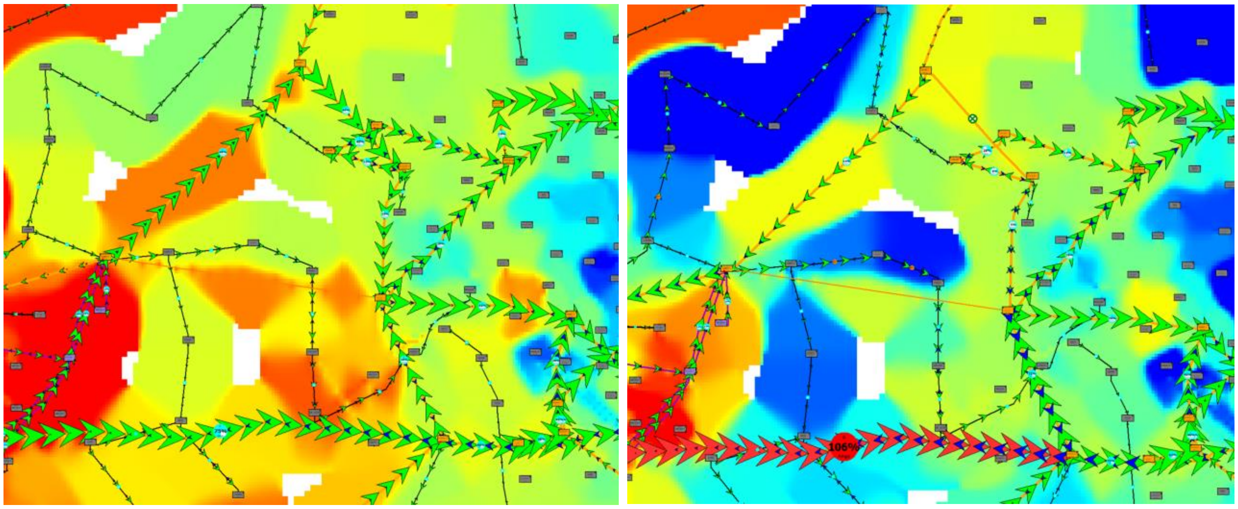


Figure 5: Olney 1 to Jacksboro 1 TL Closed (left) vs. Open (right)

South of the 2 GW line there are relatively few 500kV busses, however north of this line there are many 500kV busses with adequate infrastructure to handle and additional eastern-western tie. These various options were tested and the results of a contingency analysis after each modification can be seen below in **Table 1**. It is important to note that all of these solutions prevent overloading on the 2 GW transmission line. Based on this experimentation the ‘Albany 1’ to ‘Palo Pinto 1’ was chosen because it provides the most benefits for the least about of added transmission and avoids producing any “unsolvable” contingency cases.

*Table 1: Eastern-Western Northern 500kV Additions (*includes unsolvable conditions)*

Eastern Bus	**Western Bus**	**Length (miles)**	**Resulting Contingency Violations (#)**	**Maximum Overloading (%)**
N/A	N/A	BASE CASE	313	131%
Albany 1	Graham	48.5	310	133%
Albany 1	Keller 2	115.5	307	131%
Albany 1	**Palo Pinto 1**	**56.23**	**307**	**131%**
Olney 1	Keller 2	76.83	306*	131%

‘La Grange’ to ‘Rockdale 1’ 500kV Transmission Addition

This area was originally flagged because of a relatively routine transformer overload. However, upon further inspection it can be seen in **Fig. 6** that a significant amount of power was being brought to the ‘La Grange’ substation via 500kV transmission lines, stepped down to 230kV at both the ‘La Grange’ and ‘Winchester’ substations for transmission to the ‘Bastrop’ substation where it was then stepped back up to 500kV before being exported to other busses. Not only was this causing these 500 to 230kV transformers to overload in some contingency situations, but it was also causing significant amounts of unnecessary system losses, both in the transformers themselves and in the 230kV transmission lines. Instead of merely adding an additional transformer, like in the previous example, the most sensible addition was adding a 500kV connecting the 500kV busses directly instead of relying on the 230kV network and associated transformers.

This addition, shown to the right in **Fig. 6** turned out to be one of the most beneficial lines added in this whole study. The addition of this single transmission line not only prevented the original transformer from overloading, but it actually removed 31 additional contingency violations.

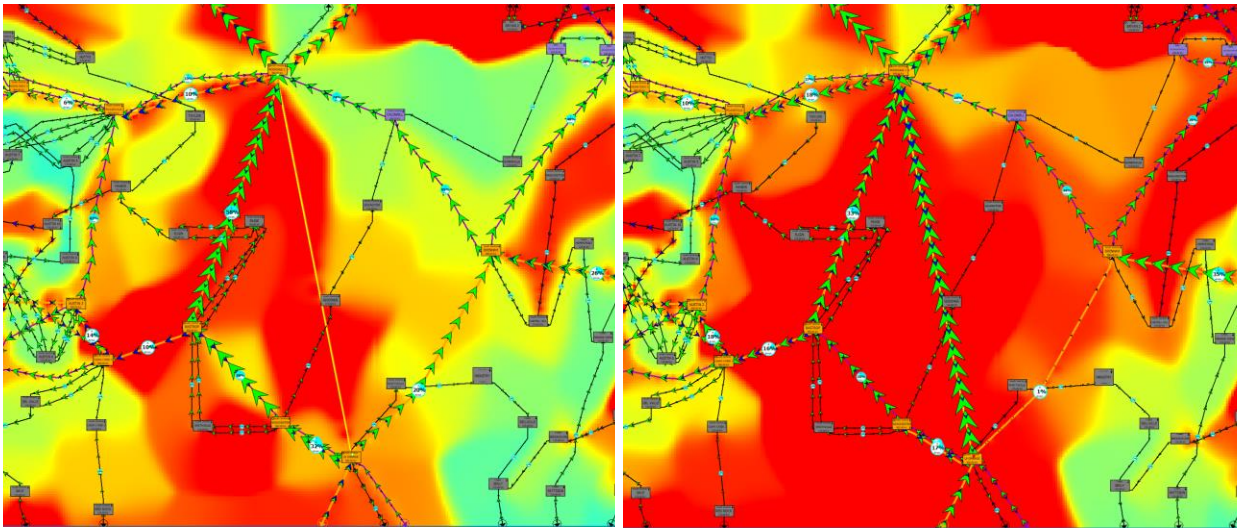


Figure 6: La Grange Area Before (left) vs. After (right) 500kV Transmission Addition

Transformer and Transmission Line Sizing

Oftentimes, even after further inspection, the best course of action to correct a transformer bank that had a tendency to overload when in contingency situations was to simply add another transformer. The model parameters, including the MVA limits, of all added transformers were assumed to be identical to the ones currently in use at that particular substation. This not only helps keep power flow balanced equally among them but is also good practice from a real-world installation and maintenance point of view.

Determining the circuit parameters of the added transmission lines however is more complicated. No two transmission lines are completely identical, their parameters are heavily dependent on the conductor type, spacing, length and even the geometry of the towers supporting them. For preliminary testing, rough values were initially chosen based on similar lines nearby. This was a good enough approximation to determine their general effect on the system since much of the power flows depend largely on the voltage angles at each bus and their respective magnitudes. If the line was beneficial enough to keep as a permanent addition to the system, the MVAs flowing across the approximated line were used to determine the minimum ideal line capacity by doubling this observed value to keep the lines at around 50% capacity in the non-contingency conditions. This nominal capacity, along with their nominal voltage and total length were then used to better approximate the line parameters in their final instantiations using conductors or bundles of conductors shown in **Appendix Fig. 1** [7]. Anything 345kV or below was assumed to use single conductors while the 500kV lines were assumes to be 2 conductor bundles with bundle spacing and phase spacing shown in **Appendix Fig. 2** [7].

Ideal Solution

As mentioned before, the idea of an “ideal solution” is somewhat of an illusion because when designing any system there are trade-offs. Originally the goal was to add 500 miles of transmission enabling the case to function more reliably with the scaled load. It later became evident that in fact, it was often the overloading transformers in the system that were the weakest elements. Even after load scaling, only 183 miles of added transmission were really needed to make the case as reliable and actually more reliable from a contingency analysis point of view than the unscaled base case. This however would not have been possible without the addition of 8 transformers throughout the system. Below in **Table 2.** is the full list of all modifications selected for the final grid model. These include 5 transmission lines, 7 transformers and 8 capacitor bank modifications that will be addressed in the next section.

Table 2: Final Proposed Set of Synthetic Grid Modifications

Type	Modification	Bus 1	Bus 2	Nominal Voltage	Length/New Value	Nominal MVA Limit
Line	Add New	ALBANY 1	Palo Pinto 1	500kV	55.85 miles	2,000
Line	Add New	Sebastian 1	Harlingen 2	115kV	14.78 miles	500
Line	Add New	Rockdale 1	La Grange	500kV	48.2 miles	2,000
Line	Add New	Riesel 1	Midlothian 1	500kV	57.31 miles	2,000
Line	Add New	Dallas 5	Mesquite 3	161kV	7.43 miles	5,00
Transformer	Add Additional	Dallas 3 0	Dallas 3 1	500/161kV	N/A	1,346
Transformer	Add Additional	San Antonio 51 0	San Antonio 51 1	230/115kV	N/A	172.8
Transformer	Add Additional	Alvin 1	Alvin 2	230/115kV	N/A	213.0
Transformer	Add Additional	Magnolia 1 0	Magnolia 1 1	230/115kV	N/A	161.4
Transformer	Add Additional	Laredo 4 0	Laredo 4 1	230/115kV	N/A	459.00

Transformer	Add Additional	Fannin 0	Fannin 2	230/115kV	N/A	148.8
Transformer	Add Additional	Pasadena 1 1	Pasadena 1 2	230/115kV	N/A	280
Capacitor Bank	Remove	San Antonio 51 0	N/A	230kV	0 Mvar	N/A
Capacitor Bank	Remove (1 of 2)	Lufkin 3 1	N/A	115kV	170 Mvar	N/A
Capacitor Bank	Modify	Iowa Park	N/A	161kV	90Mvar	N/A
Capacitor Bank	Modify	Weslaco 0	N/A	115kV	90Mvar	N/A
Capacitor Bank	Modify	Pharr 0	N/A	115kV	250Mvar	N/A
Capacitor Bank	Modify	Irving 3	N/A	161kV	250Mvar	N/A
Capacitor Bank	Remove	Laredo 4 1	N/A	115kV	0Mvar	N/A
Capacitor Bank	Remove	Winchester 2	N/A	115kV	0Mvar	N/A

System Wide Solution Testing

All of the above modifications were taken into consideration to solve one or a set of particular contingency violations. Individually they were selected as the best method of mitigating these contingency failures. Each of these changes in not independent of the others however and every addition to the system changes the dynamics of the entire system. This is why system wide solution testing is so vital. Many of these alterations had unintended consequences, and most of these involved high bus voltages. To help counter act these effects and prevent these modifications from causing excessive high bus voltage violations many of the nearby capacitor banks had to be modified. There were also some cases where the addition of one modification would actually make previously planned modifications completely unnecessary and in this case one of the modifications was dropped and therefore didn’t make it into **Table 2**.

Final Results

After implementing all of the above-mentioned modifications, a final contingency analysis was run. The modified case had a total of 219 violations with a max overload value of 124% (on a 98 MVA line). The total system losses were measured to be 1801 MW. These results are contrasted with the load-scaled base case in the upcoming sections.

CHAPTER IV

CONCLUSION

Pre/Post Modification Comparison

From a numerical standpoint, the proposed modifications improved the stability and redundancy of the case dramatically. This summery of the pre and post-modification contingency analysis can be seen below in **Table 3**. While this is a rough indicator of the overall health of the system it does not tell the whole story. For instance, these violations do not take into account the size of the transmission line or if it would trigger a domino effect if any particular line tripped. Special attention was given to major transmission arteries that could blackout the whole system, even if they were the most overloaded from a percentage point of view such as in the *Olney 1 to Jacksboro 1 Open Line Contingency* as described above. It is also interesting to note the decrease in overall system losses. While this was not a direct goal, it is an added benefit and is to be expected anytime 500kV transmission is added or more direct routes are added for power to flow on, thereby reducing $\boldsymbol{I^2R}$ losses and making the entire system more efficient.

Table 3: Final Contingency Analysis Results Comparison

Field	**Unscaled Unmodified Case**	**Scaled Unmodified Case**	**Scaled Case with Modifications**	**% Improvement (modified vs. unmodified)**
Violations	287	**324**	**219**	**32%**
Max Overloaded Line %	125.1 (172 MVA limit)	133.0% (1346 MVA limit)	124.6% (98 MVA limit)	Reduction in Major Line Overloading
Total System Losses	1847 MW	1943 MW	1881 MW	3.1%

Estimated Cost of Implementation

Getting an accurate estimate of the cost of making these proposed modifications can be very difficult as this is just a synthetic model. Below are some rough estimates of transmission line as well as transformer costs found in WECC's "Capital Cost for Transmission and Substations" made back in 2014 [5]. These baseline cost can be seen below in **Fig. 7** and **Fig. 8**. Based on the voltage, MVA rating (and length for transmission line), the total cost of these additions was estimated to be around $345 million, this included approximately $309 million worth of 500kV transmission and $24.3 million in additional transformers. This doesn't take into account the cost of modifications to capacitor banks because those modifications don't require any additional hardware.

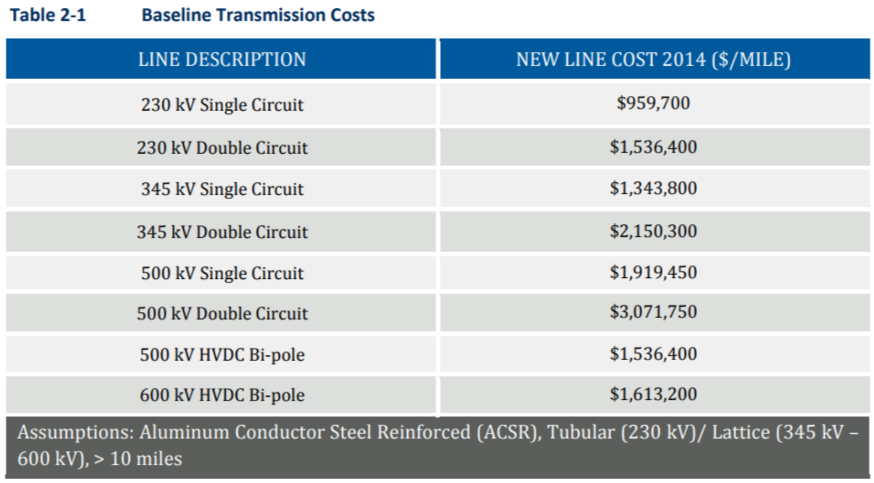


Table 2-1 Baseline Transmission Costs

LINE DESCRIPTION	NEW LINE COST 2014 ($/MILE)
230 kV Single Circuit	$959,700
230 kV Double Circuit	$1,536,400
345 kV Single Circuit	$1,343,800
345 kV Double Circuit	$2,150,300
500 kV Single Circuit	$1,919,450
500 kV Double Circuit	$3,071,750
500 kV HVDC Bi-pole	$1,536,400
600 kV HVDC Bi-pole	$1,613,200

Assumptions: Aluminum Conductor Steel Reinforced (ACSR), Tubular (230 kV)/ Lattice (345 kV – 600 kV), > 10 miles

Figure 7: Baseline Transmission Costs [5}

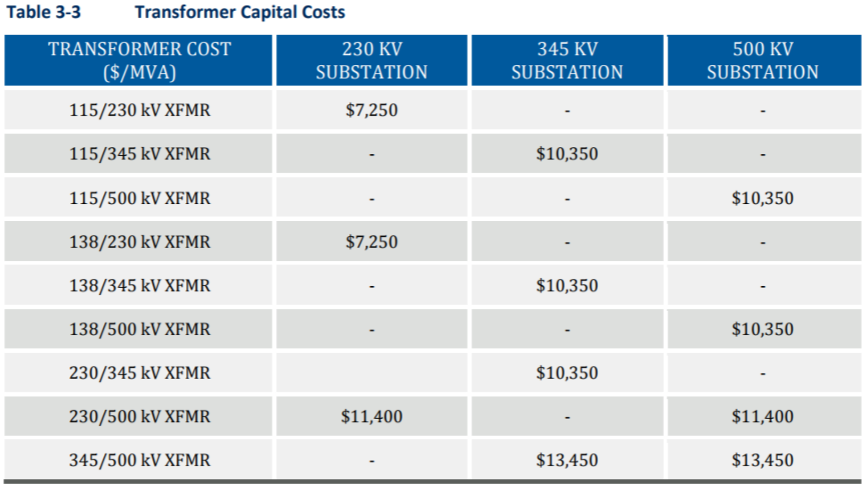


Table 3-3 Transformer Capital Costs

TRANSFORMER COST ($/MVA)	230 KV SUBSTATION	345 KV SUBSTATION	500 KV SUBSTATION
115/230 kV XFMR	$7,250	-	-
115/345 kV XFMR	-	$10,350	-
115/500 kV XFMR	-	-	$10,350
138/230 kV XFMR	$7,250	-	-
138/345 kV XFMR	-	$10,350	-
138/500 kV XFMR	-	-	$10,350
230/345 kV XFMR		$10,350	-
230/500 kV XFMR	$11,400	-	$11,400
345/500 kV XFMR	-	$13,450	$13,450

Figure 8: Baseline Transformer Costs [5]

Another thing to consider when determining the total cost of the system is the value of the energy saved from reducing system losses. In the scaled, unmodified case, the total system losses were 1943 MW. After the modifications were made, the total system losses decreased to 1881MW. This 62 MW improvement equates to around $10.9 million in savings per year using the average cost of $20/MWh [6]. This brings the total cost of the system down significantly when these savings are considered over the long term.

Future Improvements and Considerations

This study only focuses on load scaling within the North Central Zone, however this could easily be expanded to other zones within Texas. To make this scaling more realistic the scaling at each bus could be customized to more accurately reflect the expected growth based on the population increases as well as industrial development within every county. It would also help to take into account the upcoming retirement of generation plants as well as the locations of any new installations and the impact of distributed solar generation. As mentioned in the beginning, there is no “right answer” to these types of problems and in the real world adding transmission lines is far from trivial, requiring many approvals, rights-of-way and years of time in most cases. I believe this study acts as a good example of how to improve the grid in the future and mitigate overloading by expanding the 500kV network instead of adding or upgrading lengthy stretches of 161kV that inevitably produce more losses than their 500kV counter parts.

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APPENDIX

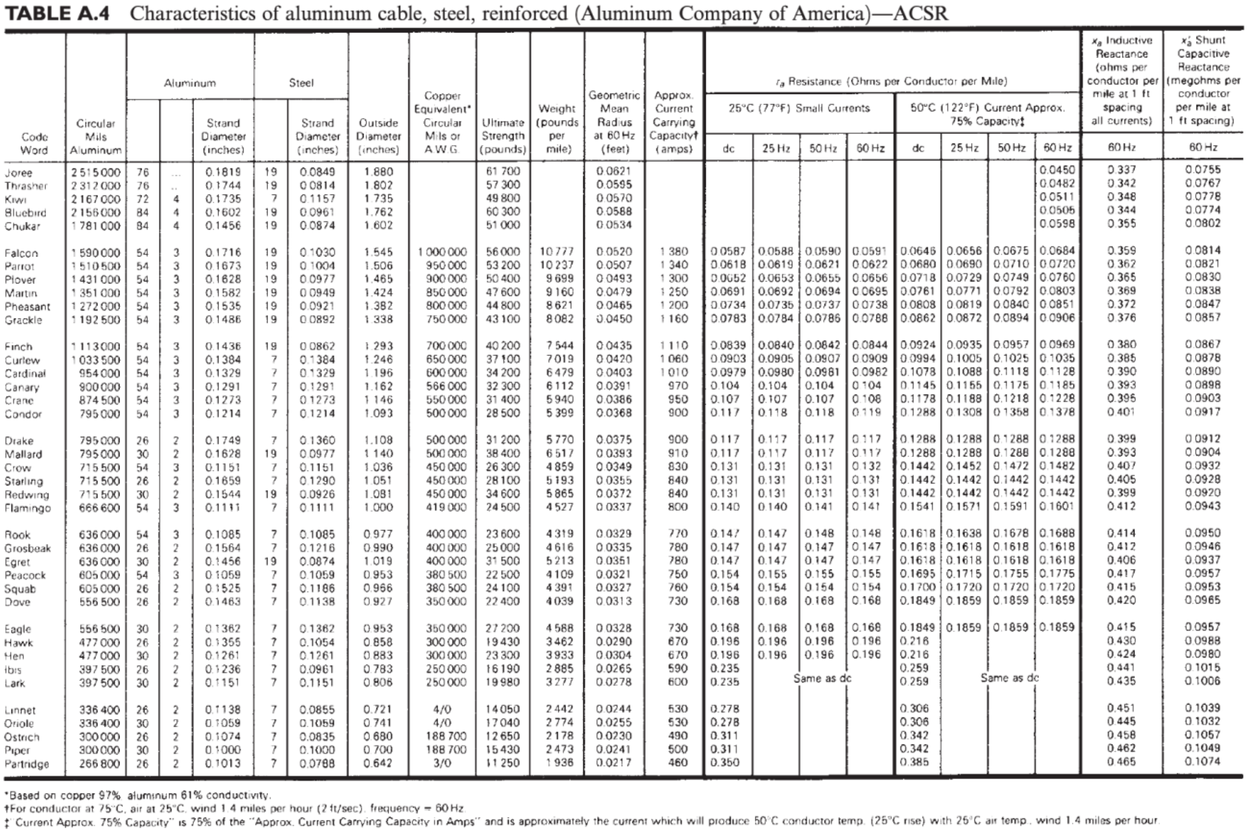


TABLE A.4 Characteristics of aluminum cable, steel, reinforced (Aluminum Company of America)—ACSR

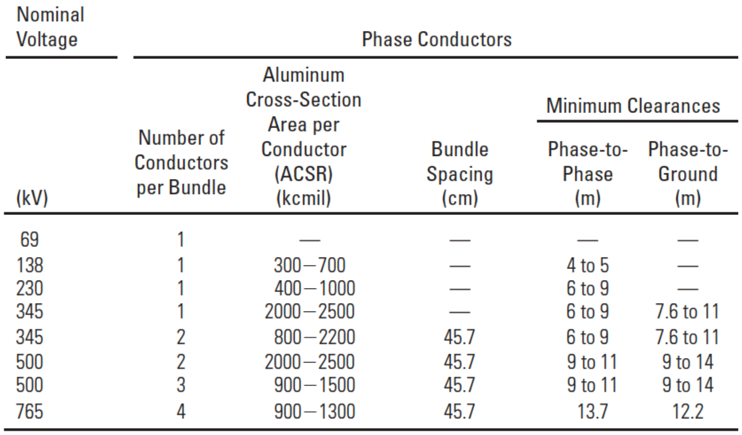
Code Word	Circular Mils Aluminum	Aluminum			Steel		Outside Diameter (inches)	Copper Equivalent* Circular Mils or A.W.G.	Ultimate Strength (pounds)	Weight (pounds per mile)	Geometric Mean Radius at 60 Hz (feet)	Approx. Current Carrying Capacity† (amps)	r_a Resistance (Ohms per Conductor per Mile)								x_a Inductive Reactance (ohms per conductor per mile at 1 ft spacing all currents)	x'_a Shunt Capacitive Reactance (megohms per conductor per mile at 1 ft spacing)
				Strand Diameter (inches)		Strand Diameter (inches)							25°C (77°F) Small Currents				50°C (122°F) Current Approx. 75% Capacity‡					
													dc	25 Hz	50 Hz	60 Hz	dc	25 Hz	50 Hz	60 Hz	60 Hz	60 Hz
Joree	2 515 000	76	...	0.1819	19	0.0849	1.880		61 700		0.0621									0.0450	0.337	0.0755
Thrasher	2 312 000	76	..	0.1744	19	0.0814	1.802		57 300		0.0595									0.0482	0.342	0.0767
Kiwi	2 167 000	72	4	0.1735	7	0.1157	1.735		49 800		0.0570									0.0511	0.348	0.0778
Bluebird	2 156 000	84	4	0.1602	19	0.0961	1.762		60 300		0.0588									0.0505	0.344	0.0774
Chukar	1 781 000	84	4	0.1456	19	0.0874	1.602		51 000		0.0534									0.0598	0.355	0.0802
Falcon	1 590 000	54	3	0.1716	19	0.1030	1.545	1 000 000	56 000	10 777	0.0520	1 380	0.0587	0.0588	0.0590	0.0591	0.0646	0.0656	0.0675	0.0684	0.359	0.0814
Parrot	1 510 500	54	3	0.1673	19	0.1004	1.506	950 000	53 200	10 237	0.0507	1 340	0.0618	0.0619	0.0621	0.0622	0.0680	0.0690	0.0710	0.0720	0.362	0.0821
Plover	1 431 000	54	3	0.1628	19	0.0977	1.465	900 000	50 400	9 699	0.0493	1 300	0.0652	0.0653	0.0655	0.0656	0.0718	0.0729	0.0749	0.0760	0.365	0.0830
Martin	1 351 000	54	3	0.1582	19	0.0949	1.424	850 000	47 600	9 160	0.0479	1 250	0.0691	0.0692	0.0694	0.0695	0.0761	0.0771	0.0792	0.0803	0.369	0.0838
Pheasant	1 272 000	54	3	0.1535	19	0.0921	1.382	800 000	44 800	8 621	0.0465	1 200	0.0734	0.0735	0.0737	0.0738	0.0808	0.0819	0.0840	0.0851	0.372	0.0847
Grackle	1 192 500	54	3	0.1486	19	0.0892	1.338	750 000	43 100	8 082	0.0450	1 160	0.0783	0.0784	0.0786	0.0788	0.0862	0.0872	0.0894	0.0906	0.376	0.0857
Finch	1 113 000	54	3	0.1436	19	0.0862	1.293	700 000	40 200	7 544	0.0435	1 110	0.0839	0.0840	0.0842	0.0844	0.0924	0.0935	0.0957	0.0969	0.380	0.0867
Curlew	1 033 500	54	3	0.1384	7	0.1384	1.246	650 000	37 100	7 019	0.0420	1 060	0.0903	0.0905	0.0907	0.0909	0.0994	0.1005	0.1025	0.1035	0.385	0.0878
Cardinal	954 000	54	3	0.1329	7	0.1329	1.196	600 000	34 200	6 479	0.0403	1 010	0.0979	0.0980	0.0981	0.0982	0.1078	0.1088	0.1118	0.1128	0.390	0.0890
Canary	900 000	54	3	0.1291	7	0.1291	1.162	566 000	32 300	6 112	0.0391	970	0.104	0.104	0.104	0.104	0.1145	0.1155	0.1175	0.1185	0.393	0.0898
Crane	874 500	54	3	0.1273	7	0.1273	1.146	550 000	31 400	5 940	0.0386	950	0.107	0.107	0.107	0.108	0.1178	0.1188	0.1218	0.1228	0.395	0.0903
Condor	795 000	54	3	0.1214	7	0.1214	1.093	500 000	28 500	5 399	0.0368	900	0.117	0.118	0.118	0.119	0.1288	0.1308	0.1358	0.1378	0.401	0.0917
Drake	795 000	26	2	0.1749	7	0.1360	1.108	500 000	31 200	5 770	0.0375	900	0.117	0.117	0.117	0.117	0.1288	0.1288	0.1288	0.1288	0.399	0.0912
Mallard	795 000	30	2	0.1628	19	0.0977	1.140	500 000	38 400	6 517	0.0393	910	0.117	0.117	0.117	0.117	0.1288	0.1288	0.1288	0.1288	0.393	0.0904
Crow	715 500	54	3	0.1151	7	0.1151	1.036	450 000	26 300	4 859	0.0349	830	0.131	0.131	0.131	0.132	0.1442	0.1452	0.1472	0.1482	0.407	0.0932
Starling	715 500	26	2	0.1659	7	0.1290	1.051	450 000	28 100	5 193	0.0355	840	0.131	0.131	0.131	0.131	0.1442	0.1442	0.1442	0.1442	0.405	0.0928
Redwing	715 500	30	2	0.1544	19	0.0926	1.081	450 000	34 600	5 865	0.0372	840	0.131	0.131	0.131	0.131	0.1442	0.1442	0.1442	0.1442	0.399	0.0920
Flamingo	666 600	54	3	0.1111	7	0.1111	1.000	419 000	24 500	4 527	0.0337	800	0.140	0.140	0.141	0.141	0.1541	0.1571	0.1591	0.1601	0.412	0.0943
Rook	636 000	54	3	0.1085	7	0.1085	0.977	400 000	23 600	4 319	0.0329	770	0.147	0.147	0.148	0.148	0.1618	0.1638	0.1678	0.1688	0.414	0.0950
Grosbeak	636 000	26	2	0.1564	7	0.1216	0.990	400 000	25 000	4 616	0.0335	780	0.147	0.147	0.147	0.147	0.1618	0.1618	0.1618	0.1618	0.412	0.0946
Egret	636 000	30	2	0.1456	19	0.0874	1.019	400 000	31 500	5 213	0.0351	780	0.147	0.147	0.147	0.147	0.1618	0.1618	0.1618	0.1618	0.406	0.0937
Peacock	605 000	54	3	0.1059	7	0.1059	0.953	380 500	22 500	4 109	0.0321	750	0.154	0.155	0.155	0.155	0.1695	0.1715	0.1755	0.1775	0.417	0.0957
Squab	605 000	26	2	0.1525	7	0.1186	0.966	380 500	24 100	4 391	0.0327	760	0.154	0.154	0.154	0.154	0.1700	0.1720	0.1720	0.1720	0.415	0.0953
Dove	556 500	26	2	0.1463	7	0.1138	0.927	350 000	22 400	4 039	0.0313	730	0.168	0.168	0.168	0.168	0.1849	0.1859	0.1859	0.1859	0.420	0.0965
Eagle	556 500	30	2	0.1362	7	0.1362	0.953	350 000	27 200	4 588	0.0328	730	0.168	0.168	0.168	0.168	0.1849	0.1859	0.1859	0.1859	0.415	0.0957
Hawk	477 000	26	2	0.1355	7	0.1054	0.858	300 000	19 430	3 462	0.0290	670	0.196	0.196	0.196	0.196	0.216				0.430	0.0988
Hen	477 000	30	2	0.1261	7	0.1261	0.883	300 000	23 300	3 933	0.0304	670	0.196	0.196	0.196	0.196	0.216				0.424	0.0980
Ibis	397 500	26	2	0.1236	7	0.0961	0.783	250 000	16 190	2 885	0.0265	590	0.235				0.259				0.441	0.1015
Lark	397 500	30	2	0.1151	7	0.1151	0.806	250 000	19 980	3 277	0.0278	600	0.235		Same as dc		0.259		Same as dc		0.435	0.1006
Linnet	336 400	26	2	0.1138	7	0.0855	0.721	4/0	14 050	2 442	0.0244	530	0.278				0.306				0.451	0.1039
Oriole	336 400	30	2	0.1059	7	0.1059	0.741	4/0	17 040	2 774	0.0255	530	0.278				0.306				0.445	0.1032
Ostrich	300 000	26	2	0.1074	7	0.0835	0.680	188 700	12 650	2 178	0.0230	490	0.311				0.342				0.458	0.1057
Piper	300 000	30	2	0.1000	7	0.1000	0.700	188 700	15 430	2 473	0.0241	500	0.311				0.342				0.462	0.1049
Partridge	266 800	26	2	0.1013	7	0.0788	0.642	3/0	11 250	1 936	0.0217	460	0.350				0.385				0.465	0.1074

*Based on copper 97%, aluminum 61% conductivity.

†For conductor at 75°C, air at 25°C, wind 1.4 miles per hour (2 ft/sec), frequency = 60 Hz.

‡"Current Approx. 75% Capacity" is 75% of the "Approx. Current Carrying Capacity in Amps" and is approximately the current which will produce 50°C conductor temp. (25°C rise) with 25°C air temp., wind 1.4 miles per hour.

Appendix Fig. 1: Transmission Line Parameters from "Power System Design and Analysis"



Nominal Voltage	Phase Conductors				
				Minimum Clearances	
(kV)	Number of Conductors per Bundle	Aluminum Cross-Section Area per Conductor (ACSR) (kcmil)	Bundle Spacing (cm)	Phase-to-Phase (m)	Phase-to-Ground (m)
69	1	—	—	—	—
138	1	300–700	—	4 to 5	—
230	1	400–1000	—	6 to 9	—
345	1	2000–2500	—	6 to 9	7.6 to 11
345	2	800–2200	45.7	6 to 9	7.6 to 11
500	2	2000–2500	45.7	9 to 11	9 to 14
500	3	900–1500	45.7	9 to 11	9 to 14
765	4	900–1300	45.7	13.7	12.2

Appendix Fig. 2: Typical Transmission Line Characteristics from "Power System Design and Analysis"