APPENDIX U

OCONEE NUCLEAR STATION DROUGHT STUDY TRANSMISSION IMPACTS REPORT

DUKE ENERGY CAROLINAS
TRANSMISSION PLANNING CAROLINA

OCONEE NUCLEAR STATION
DROUGHT STUDY
TRANSMISSION IMPACTS

FINAL

November 6, 2013

TRANSMISSION STUDY PARTICIPANTS

Representative	**Department**
Brian D. Moss (Power Flow)	Transmission Planning Carolina
Daniel I. Fain (Stability)	System Operations Engineering Carolinas (Transmission Planning Carolina, at time of analysis)

PURPOSE OF STUDY

Duke Energy, the U.S. Army Corp of Engineers (USACE) and the Southeastern Power Administration (SEPA) are jointly investigating the possibility of modifying the 1968 Operating Agreement regarding water releases from Duke Energy's Keowee-Toxaway Project. A Project Delivery Team (PDT) consisting of members from each of the organizations has defined a Scope of Work to facilitate preparation of a Comprehensive Environmental, Engineering, and Economic Impact Analysis Report. The purpose of this study is to assess the transmission impacts of an Existing License (EL) Alternative that potentially requires the controlled shutdown of all three nuclear units at Duke Energy's Oconee Nuclear Station (ONS). The studied extreme drought scenario impacts generator availability and transmission flows for all utilities operating along the Savannah River basin. The results of this study will identify any transmission power flow and stability issues that would require mitigation under the EL Alternative and provide a cost basis for comparing to four other alternatives. This study builds on and updates the previous study completed as part of the 2011 draft Comprehensive Environmental, Engineering, and Economic Impact Analysis Report, completed in October 2011, which refers to the EL Alternative as the No Action Alternative (NAA).

OVERVIEW OF THE STUDY PROCESS

The scope of the study process included the following steps:

1. **Study Assumptions**
   - Study assumptions selected
2. **Study Criteria**
   - Establish the criteria by which the study results will be measured
3. **Case Development**
   - Develop the models needed to perform the study
4. **Study Methodology**
   - Determine the methodologies that will be used to carry out the study
5. **Technical Analysis and Study Results**
   - Perform the technical analysis (thermal, voltage, and stability as needed) and produce the study results
6. **Assessment and Potential Issues Identification**
   - Evaluate the results to identify potential issues
7. **Mitigation Cost Analysis**
   - Estimate the solutions and project costs to mitigate potential issues

STUDY ASSUMPTIONS

- Based on a series of hydrological model runs completed to simulate the operations of the hydroelectric facilities along the Savannah River basin under varying water withdrawal and return conditions, it was determined that, under the EL Alternative, extreme drought conditions may occur requiring the controlled shutdown of all three nuclear units at Duke Energy's ONS in a future year. Based on the times of year that this event are forecasted to occur, a complete study would focus its analysis on summer peak, fall peak, fall valley, and winter peak load levels. While the event is most likely to occur during a fall peak or fall valley load level, the forecasted time of year is close enough to warrant the additional analysis of both summer and winter peak load levels to provide an upper bound for our analysis should the event occur at these higher load levels. Based on the results of the previous study completed as part of the 2011 draft Comprehensive Environmental, Engineering, and Economic Impact Analysis Report, the projects driven by this event would mostly come from the summer peak analysis. This study focused only on summer peak load levels with a recommendation to add 10% to the total cost to account for the winter peak, fall peak and fall valley periods that were not studied in this analysis.
- The years studied (study year) are 2013, 2017, and 2021. These years were chosen based on the currently available transmission planning models and the potential generation availability scenarios that each study year could be used to simulate.

Study Year Generation Scenarios[1]		
2013	***2017***	***2021***
2011 Generation plus Buck CC New Dan River CC New Cliffside 6 New Buck 3-6 Retired Riverbend 4-7 Retired Cliffside 1-4 Retired Dan River 1-3 Retired Buck, Dan River, Riverbend, and Buzzard Roost CTs Retired	2013 Generation plus Lee 1-2 Retired Watts Bar NP 2 (TVA) New VC Summer 2 (SCEG) New Vogtle 3-4 (SOCO) New	2017 Generation plus Bellefonte NP 1-2 (TVA) New VC Summer 3 (SCEG) New Lee Nuclear 1-2 New

[1] Generators from Duke Energy, Tennessee Valley Authority (TVA), South Carolina Electric and Gas (SCEG), and Southern Company (SOCO)

- Siemens' Power System Simulation for Engineers (PSS/E) Power Flow and Dynamics software are used for the power flow and stability portions of the study.
- An annual load growth assumption of 1.7% is used to estimate the future year (beyond the study year) in which a facility will exceed its thermal rating and require mitigation.
- Generation, interchange, and other assumptions are based on the 2012 series SERC Reliability Corporation Long-Term Study Group (SERC LTSG) base cases which were

wrapped around the Duke Energy internal models used as the starting points for study case and interchange development.

STUDY CRITERIA

- North American Electric Reliability Corporation (NERC) Reliability Standards
- Duke Energy Carolinas' Transmission Planning criteria (thermal, stability)

CASE DEVELOPMENT

- The 2012 series SERC LTSG base cases are used for the systems external to Duke Energy as a starting point for the study cases used by the Transmission Planning in their analyses.
- The study base cases are created by inserting the latest unequivalized detailed internal transmission planning models for Duke Energy and any existing transmission additions planned to be in-service for the given year (i.e. in-service by summer 2013 for 2013S cases) into a reduced version of the SERC LTSG base cases.
- The study base case interchanges are composed of the SERC LTSG coordinated interchanges and all the latest confirmed long term firm transmission reservations with roll-over rights applicable to the study year(s).
- Table A provides a summary of the 30 cases created to represent the potential summer peak load levels and generation dispatch sensitivities relevant to the EL Alternative. Generation dispatch sensitivities include the impact of Lee Nuclear 1-2 future availability, Keowee/Hartwell/Russell availability, and a non-Duke Energy generation outage sensitivity.
- The non-Duke Energy generation outage sensitivity involves the combined unavailability of Robinson 1 (Carolina Power and Light East, CPLE), Robinson 2 (CPLE), Scherer 1-4 (SOCO), and Rainey CC/CTs (South Carolina Public Service Authority, SCPSA) generation. These units were grouped together in one sensitivity due to their potential for being impacted by the EL Alternative, extreme drought condition and their electrical separation from one another. The generation unavailability is first replaced by other control area generation and secondly by a 50/50 import from PJM/SOCO if the remaining control area generation is insufficient. Due to the outage of Scherer 3, the SOCO swing machine is also moved to Barry 5.
- Keowee/Hartwell/Russell's generation unavailability is replaced by a 50/50 import from PJM/SOCO.
- For the stability analysis, two dynamic models were built. In the first of these models, a 2012 summer peak case was taken and modified by replacing the generation of all three ONS units with an economic redispatch of the remaining Duke Energy units. The second of these models is a 2012 off-peak case with about 60% load level. As with the previous case, the ONS generation was replaced with an economic redispatch. In the second case, all local generation was off, including Rainey and Hartwell, with Bad Creek and Jocassee

each with only one unit on and pumping. This analysis is unchanged from the previous study completed as part of the 2011 draft Comprehensive Environmental, Engineering, and Economic Impact Analysis Report.

STUDY METHODOLOGY

- Duke Energy's internal thermal screening power flow analysis was performed on all 30 study scenario cases. Thermal screening analysis begins with the creation of a set of additional generation maintenance study cases which simulate the outage of the largest generator on each voltage level at all major generating stations on the Duke Energy transmission system. These cases account for the real-time possibility of the loss of a generator on the system. The lost generation is replaced with an economic redispatch of the remaining Duke Energy generation.
- Each generator maintenance case is stressed by applying a complete set of system wide transmission and generation contingencies to identify potential violations of the Duke Energy Carolinas' Transmission Planning criteria as well as any thermal overloads found on Duke Energy's neighboring systems. Contingencies are chosen in accordance with the Transmission Planning (TPL) requirements of the NERC Reliability standards.
- For the stability analysis, the study was performed in two parts. First, a critical clearing time comparison was performed. This study evaluated the critical clearing times by applying a fault at each system bus 100 kV and above and determining the maximum simulated relay clearing time in which all units maintain stability. The clearing time for each faulted bus was then compared to the clearing time in the base cases to determine if any system buses had lower critical clearing times that could result in reduced stability performance. Second, individual contingencies were chosen which were determined to be the most severe and evaluated for stability concerns. The list of contingencies chosen is listed in Table C. This analysis is unchanged from the previous study completed as part of the 2011 draft Comprehensive Environmental, Engineering, and Economic Impact Analysis Report.

TECHNICAL ANALYSIS AND STUDY RESULTS

The technical analysis was performed in accordance with the study methodology. Results from the technical analysis are reported throughout the study area, including both Duke Energy and neighboring control areas, to identify transmission elements approaching their limits such that all potential issues are identified and appropriate steps can be identified to correct these issues.

- The screening results for each study scenario were compared to the screening results for the associated base case. The only difference between each study scenario and their associated base case is the outage of all three ONS units. This sole difference allows for the identification of those potential issues which can be directly attributed to the shutdown of the entire ONS plant as required by the potential extreme drought condition. Each study scenario and its associated base case are identified in Table A.
- The stability analysis identified no stability concerns. The lack of generation in the southern region does not appear to result in any potential voltage recovery or stability

concerns. This analysis is unchanged from previous study completed as part of the 2011 draft Comprehensive Environmental, Engineering, and Economic Impact Analysis Report.

ASSESSMENT AND POTENTIAL ISSUES IDENTIFICATION

Once all the study scenarios were screened, a comparison was made between the screening results for each scenario and its associated base case. This comparison identified all potential reliability issues under the study scenarios tested which can be directly attributed to the shutdown of the entire ONS plant as required by the potential extreme drought condition. A summary of the potential reliability issues identified in this assessment is provided in Table B.

- Each overloaded facility was reviewed to determine if the limiting component was a piece of ancillary equipment or a main component such as the transmission line conductor or transformer. Ancillary equipment needs were ignored in this assessment since the upgrade costs are much less when compared to rebuilding or replacing the main facility components.
- All required transmission line and transformer projects were classified as to (1) the year the upgrade was required and (2) whether the entire cost of the project or just an acceleration of the project cost could be attributed to the shutdown of the entire ONS plant.
- An annual load growth value of 1.7% was assumed to estimate the year a project would be required if it is less than 100% loaded in the study year. Load growth estimated project years were only assumed to be valid out to 5 years beyond the study year. This is due to the inherent uncertainty in modeling accuracy out beyond 5 years. Future generation distribution, interchange transactions, and transmission topology are assumed to be significantly different from the currently available models as the study year moves farther away from the current year. Within the first five years after the study year, the model and screening results accuracy are assumed to be sufficient for developing transmission expansion plans.

MITIGATION COST ANALYSIS

Based on the initial hydrological model runs, it was determined that, under the EL Alternative, a potential extreme drought condition may occur requiring the controlled shutdown of all three nuclear units at Duke Energy's ONS in a future year. This study focused its analysis on future summer peak load levels and generation scenarios to bound the potential reliability issues and project costs which could be required to support system reliability during the forecasted timing of the event. Based on the results of the previous study completed as part of the 2011 draft Comprehensive Environmental, Engineering, and Economic Impact Analysis Report, the projects driven by this event would mostly come from the summer peak analysis. This study focused only on summer peak load levels with a recommendation to add 10% to the total cost to account for the winter peak, fall peak and fall valley periods that were not studied in this analysis. A summary of the potential project costs identified in this assessment are found in Table B.

- Capital project cost data available in 2012$ is assumed to be equivalent to 2013$.

- An 8.75% discount rate, 2.5% inflation rate, and a 40-year useful life are used to calculate net present values (NPVs) and convert them to capital costs in 2013$ for the cost analysis. These are standard numbers currently used by the Duke Energy Carolinas' Power Delivery department.
- The Adjusted Cost (2013$) column includes capital costs for both entire projects and accelerated capital costs in 2013$.

CONCLUSIONS

Results of the assessment and cost analysis show that the potential project costs required to mitigate the potential extreme drought condition at summer peak load levels would be approximately $211 million. Since this study focused only on summer peak load levels, Transmission Planning recommends adding 10% to the total cost to account for potential project costs attributed to the winter peak, fall peak and fall valley periods that were not studied in this analysis.

Season Load Level *(Table)*	**Line Section/ Transformer Upgrades**	**Capital Costs (2013$)**		
		Non-Duke Energy	***Duke Energy***	***Total***
Summer Peak *(B)*	31 / 5	$60,793,592	$149,934,803	$210,698,395
Overall with 10% added	34 / 6	$66,839,952	$164,928,284	$231,768,236

- Based on the hydrological runs, this event is more likely to occur during a fall peak or fall valley load level.
- Based on the results of the previous study completed as part of the 2011 draft Comprehensive Environmental, Engineering, and Economic Impact Analysis Report, the analysis of summer peak load levels provides some upper bounds for the cost analysis should the event occur at these higher load levels. There is a lower probability of these higher load levels occurring during the fall time period.
- Since insufficient information was available to determine with complete confidence the need and/or cost of the non-Duke Energy projects, project costs were broken out between non-Duke Energy and Duke Energy projects. The impacted companies (SOCO, SCEG, TVA, CPLW) were contacted for preliminary information (conductor, line mileage, ancillary equipment upgrades, etc.) and a discussion of potential project needs, but additional contact would be required to develop complete scopes of work and actual costs for these projects. Preliminary discussions support the need for these projects.
- Line upgrades often require long construction times over multiple years/seasons due to the inability to complete the work in one season or during the time the transmission line is allowed to be taken out of service by the SOC/TCC. This type of work typically

cannot be done during winter and summer peak load levels due to system reliability concerns. This determination is handled on a case by case basis.

- Given 10-14 days advanced notice, there is a possibility that some of these potential overloads could be operated around through transmission topology and/or generation dispatch adjustments. This would require a detailed review by Grid Operations Engineering/TCC/SOC to determine the transmission system's ability to avoid these potential reliability issues. This determination would be handled on a case by case basis looking at real-time operations under the forecasted load levels and system conditions expected during the event. It is much less likely that Duke Energy would be able to operate around these reliability issues during summer and winter peak load levels. There may also be additional costs associated with (1) any generation redispatch out of economic order and (2) any transmission topology changes that produce an increase in system losses such that additional generation availability would be required.

TABLE A
STUDY SCENARIOS

	Base			No ONS												
Year/Season	XXx_999	Lee 1	Lee 2	XXx_999_NoONS	PJM Import	SOCO Import	Bad Creek	Jocassee	Keowee	Hartwell	Russell	Thurmond	Lee 1	Lee 2	Non-Duke Energy Outage Sensitivity	Scenario Identifier ("XXXX" can be "Base" or "NoONS")
2013 Summer Peak	X	-	-	X	1144	1145	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	-	-	SCPSA Import 164	13s_XXXX_A
				X	642	642	X	X	X	X	X	X	-	-	SCPSA Import 164	13s_XXXX_B
				X	1062	1063	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	-	-	-	13s_XXXX_C
				X	560	560	X	X	X	X	X	X	-	-	-	13s_XXXX
2017 Summer Peak	X	-	-	X	1777	1778	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	-	-	X	17s_XXXX_A
				X	1225	1225	X	X	X	X	X	X	-	-	X	17s_XXXX_B
				X	1777	1778	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	-	-	-	17s_XXXX_C
				X	1225	1225	X	X	X	X	X	X	-	-	-	17s_XXXX
2021 Summer Peak	X PJM/SOCO Import (1200)	-	-	X	3002	3003	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	-	-	X	21s_XXXX_A
				X	2500	2500	X	X	X	X	X	X	-	-	X	21s_XXXX_B
				X	3002	3003	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	-	-	-	21s_XXXX_C
				X	2500	2500	X	X	X	X	X	X	-	-	-	21s_XXXX
2021 Summer Peak	X	X	-	X	1842	1843	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	X	-	X	21s_XXXX_LNS1_A
				X	1300	1300	X	X	X	X	X	X	X	-	X	21s_XXXX_LNS1_B
				X	1842	1843	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	X	-	-	21s_XXXX_LNS1_C
				X	1300	1300	X	X	X	X	X	X	X	-	-	21s_XXXX_LNS1
2021 Summer Peak	X	-	X	X	1842	1843	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	-	X	X	21s_XXXX_LNS2_A
				X	1300	1300	X	X	X	X	X	X	-	X	X	21s_XXXX_LNS2_B
				X	1842	1843	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	-	X	-	21s_XXXX_LNS2_C
				X	1300	1300	X	X	X	X	X	X	-	X	-	21s_XXXX_LNS2
2021 Summer Peak	X	X	X	X	1242	1243	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	X	X	X	21s_XXXX_LNS12_A
				X	700	700	X	X	X	X	X	X	X	X	X	21s_XXXX_LNS12_B
				X	1242	1243	X	X	ReDispatch	PJM/SOCO	PJM/SOCO	X	X	X	-	21s_XXXX_LNS12_C
				X	700	700	X	X	X	X	X	X	X	X	-	21s_XXXX_LNS12

TABLE B
SUMMARY OF POTENTIAL RELIABILITY ISSUES
SUMMER PEAK

Study Year	Summer Peak			
	Facility	Impact	Upgrade	Adjusted Cost (2013$)
2013	Shelby-Christopher Rd Retail (Dairyhill) 100 kV Line	Accelerated 17 years (2032 >>> 2015)	1.63 miles 336 ACSR Reconductor	$2,341,818
	Lawsons Fork-Pinewood Retail (Pinewood) 100 kV Line	Accelerated 10 years (2027 >>> 2013)	1.08 miles 477 ACSR Reconductor	$1,771,200
	UNA Retail-Pinewood Retail (Pinewood) 100 kV Line	Accelerated 17 years (2030 >>> 2013)	2.99 miles 477 ACSR Reconductor	$4,903,600
	Tiger-BMW (Taylors) 100 kV Line	Loading Increase <70% to 97.5% (2015)	2.68 miles 477 ACSR Reconductor	$3,850,352
	Oconee-Jocassee (Jocassee) 230 kV Line	Loading Increase <70% to 96.7% (2015)	12.28 miles 2156 ACSR Reconductor	$23,344,241
	Broad River EC 16-Cliffside (Duncan) 100 kV Line	Loading Increase <70% to 99.3% (2014)	13.92 miles 2/0 Cu Reconductor	$17,592,768
2017	SRS-Vogtle 230 kV Line (SOCO-SCEG Tie)	Accelerated 9 years (2026 >>> 2017)	230 kV Line Reactors (SCEG)	$3,500,000
	Christopher Rd Retail-PPG Tap (Dairyhill) 100 kV Line	Accelerated 15 years (2033 >>> 2018)	3.76 miles 336 ACSR Reconductor	$4,412,353
	Cumming-McGrau Ford 230 kV Line (SOCO)	Accelerated 17 years (2038 >>> 2021)	21.65 miles 1351 ACSR Reconductor	$27,303,667
	Mills River-Asheville 115 kV Line (CPLW Tie)	Accelerated 10 years (2032 >>> 2022)	2.64 miles 1272 ACSR Clearances	$541,425
	E Durham-Stallings Tap (Ashe Street) 100 kV Line	Accelerated 6 years (2024 >>> 2018)	0.03 miles 477 ACSR Reconductor	$12,147
	Horseshoe-Nix Rd Tap (Echo) 100 kV Line	Accelerated 2 years (2019 >>> 2017)	4.41 miles 477 ACSR Reconductor	$707,553
	Upward-Asheville Hwy (Echo) 100 kV Line	Accelerated 6 years (2026 >>> 2020)	4.78 miles 477 ACSR Reconductor	$1,719,367
	Asheville Hwy-Nix Rd Tap (Echo) 100 kV Line	Accelerated 5 years (2026 >>> 2021)	0.97 miles 477 ACSR Reconductor	$281,827
	Cliffside 230/100/44 kV Transformer	Accelerated 3 years (2020 >>> 2017)	New Transformer Capacity	$2,948,754
	Bush River-Clinton Tap (Clinton) 100 kV Line	Loading Increase <70% to 127.8% (2017)	SPS + 100 kV Capacitor at Laurens Tie	$765,911
	White Rock-Saluda 115 kV Line (SCEG)	Loading Increase <70% to 118.1% (2017)	15.29 miles 266.8 ACSR Reconductor	$1,322,937
	Clark Hill-Thurmond (Clark Hill) 115 kV Line (Duke Energy)	Loading Increase <70% to 118% (2017)	35.75 miles 397 ACSR Reconductor	$36,964,741
	Chesnee-Spartan Tap-Horsehead Tap (Cherokee) 100 kV Line	Loading Increase <70% to 98.2% (2019)	4.67 miles 2/0 Cu Reconductor	$4,211,907
	Nantahala-Fontana 161 kV Line (TVA Tie)	Loading Increase <70% to 95.2% (2020)	Fix Clearances, Jumper at Fontana	$748,007
2021	Bush River 115/100 kV Transformer 7 (SCEG owned)	Accelerated 11 years (2032 >>> 2021)	New Transformer Capacity	$1,678,129
	Bush River-White Rock (Newberry) 115 kV Line (SCEG Tie)	Accelerated 23 years (2044 >>> 2021)	23.99 miles 266.8 ACSR Reconductor	$13,524,253
	Lookout-Stamey (Beulah) 100 kV Line	Accelerated 8 years (2031 >>> 2023)	6.52 miles 795 ACSR Reconductor	$5,388,783
	WID CRK FP-SEQUOYAH NP 500 kV Line (TVA)	Accelerated 11 years (2035 >>> 2024)	Fix Clearances, 500 kV Breakers (3)	$5,858,192

TABLE B (continued)
SUMMARY OF POTENTIAL RELIABILITY ISSUES
SUMMER PEAK

Study Year	Summer Peak			
	Facility	**Impact**	**Upgrade**	**Adjusted Cost (2013$)**
2021	Weaver Tap-Stallings Tap (Ashe Street) 100 kV Line	Accelerated 6 years (2029 >>> 2023)	1.40 miles 477 ACSR Reconductor	$421,650
	Bush River 115/100 kV Transformer 8 (Duke Energy)	Loading Increase <70% to 102.5% (2021)	New Transformer Capacity	$1,678,129
	Bush River 230/100/44 kV Transformer	Loading Increase <70% to 95.4% (2024)	New Transformer Capacity	$1,804,324
	Branch-Eaton C 230 kV Line (SOCO)	Loading Increase <70% to 95% (2025)	9.71 miles 1351 ACSR Reconductor	$9,173,684
	Bio-Vanna 230 kV Line (SOCO)	Loading Increase <70% to 92.5% (2026)	8.00 miles 795 ACSR Reconductor	$7,013,612
	PPL Spartanburg-Camp Croft (Avon) 100 kV Line	Accelerated 13 years (2039 >>> 2026)	0.78 miles 2/0 Cu Reconductor	$425,423
	Pacolet-Camp Croft (Avon) 100 kV Line	Accelerated 14 years (2039 >>> 2025)	11.45 miles 2/0 Cu Reconductor	$6,729,830
	Allen 230/100 kV Transformer 6	Accelerated 2 years (2025 >>> 2023)	New Transformer Capacity	$264,062
	Broad River EC 16-Mud Creek Retail (Duncan) 100 kV Line	Loading Increase <70% to 107.7% (2021)	4.00 miles 2/0 Cu Reconductor	$3,138,320
	West Spartanburg-Una Retail (Pinewood) 100 kV Line	Loading Increase <70% to 99.1% (2022)	1.18 miles 477 ACSR Reconductor	$1,047,766
	Cliffside-Fingerville (Cliffside) 100 kV Line	Loading Increase <70% to 97.8% (2023)	12.8 miles 2/0 Cu Reconductor	$8,708,491
	Cliffside-Cherokee Tap (Cliffside) 100 kV Line	Loading Increase <70% to 97.5% (2023)	6.76 miles 2/0 Cu Reconductor	$4,599,172
			Non-Duke Energy Cost (2013$)	**$60,763,592**
			Duke Energy Cost (2013$)	**$149,934,803**
			Total Cost (2013$)	**$210,698,395**
			Transmission Planning recommends adding 10% to account for Winter Peak, Fall Peak and Fall Valley periods that were not studied in this analysis.	

Transformer Owned by SCEG/Loaned to Duke Energy (Assume Replacement Cost Shared) or Tie Line Split by SCEG/Duke Energy (11.48 (Duke Energy) + 12.51 (SCEG) miles 266.8 ACSR Cost Split)

Assumptions:
1. 2/0 Cu conductor is rebuilt to 556 or 954 ACSR.
2. Non-bundled ACSR conductor is most likely bundled, but not in all cases.
3. Projects accelerated 8+ years are full cost, not acceleration cost.

TABLE C
SUMMARY OF TESTED CONTINGENCIES
STABILITY ANALYSIS

NERC TPL C3	
First Contingency	*Second Contingency*
Jocassee 500/230 kV	Oconee 500/230 kV
Jocassee 500/230 kV	Foothills 500 kV
Jocassee 500/230 kV	Asbury 500 kV
Jocassee 500/230 kV	South Hall 500 kV
Oconee 500/230 kV	Jocassee 500/230 kV
Oconee 500/230 kV	Foothills 500 kV
Oconee 500/230 kV	Asbury 500 kV
Oconee 500/230 kV	South Hall 500 kV
Robbinsville-Santeetlah	Fontana-Nantahala 161 kV
Asbury 500 kV	South Hall 500 kV
Asbury 500 kV	Foothills 500 kV
Foothills 500 kV	Asbury 500 kV
Foothills 500 kV	South Hall 500 kV
South Hall 500 kV	Asbury 500 kV
South Hall 500 kV	Foothills 500 kV
NERC TPL D4	
Tiger 230	
Oconee 230	
Jocassee 230	
Central 230	
N Greenville 230	
Anderson 230	
NERC TPL C5	
Central-Anderson 230 kV	

- NERC TPL C3 contingencies are performed by removing the first listed element from service in the power flow case and resolving. The second listed element is faulted with a 3LG fault and removed from service in the dynamic simulation.
- NERC TPL D4 contingencies are performed by applying a 3LG fault that clears with a delay due to a breaker failure.
- NERC TPL C5 contingencies are common tower contingencies where a 3LG fault is applied to both lines and cleared in normal relay timing.