TAG Meeting
October 18, 2022

Webinar

TAG Meeting Agenda

1. Administrative Items – Rich Wodyka
2. 2022 Study Activities Update – Sid DeSouza and Orvane Piper
3. Duke Supplemental Study for RZEP Projects – Sammy Roberts
4. Regional Studies Update – Bob Pierce
5. 2022 TAG Work Plan – Rich Wodyka
6. TAG Open Forum – Rich Wodyka

2022 Study Activities Update

Orvane Piper - Duke Energy Carolinas
Sid DeSouza - Duke Energy Progress

Study Process Steps

Completed

1. Assumptions Selected
2. Study Criteria Established
3. Study Methodologies Selected
4. Models and Cases Developed
5. Technical Analysis Performed
6. Problems Identified and Solutions Developed
7. Collaborative Plan Projects Selected
8. Study Report Prepared

Assumptions Selected

- **Study Years for reliability analyses:**
  - **Near-term: 2027 Summer, 2027/2028 Winter**
  - **Longer-term: 2032/2033 Winter**

Study Criteria Established

- NERC Reliability Standards
  - Current standards for base study screening
  - Current SERC Requirements
- Individual company criteria

Study Methodologies Selected

- Thermal Power Flow Analysis
- Each system (DEC and DEP) will be tested for impact of other system's contingencies

Models and Cases Developed

- **Annual Reliability Study**
  - **Near-term: 2027 Summer, 2027/2028 Winter**
  - **Longer-term: 2032/2033 Winter**
- **Local Economic Study**
  - **Evaluate a total of 14 hypothetical transfers in 2032/33 Winter**
- **Public Policy Study**
  - **The study request scope of work could not be finalized in time to complete the analysis in 2022. Will solicit new public study requests for 2023 in January.**

Resource Supply Options for Hypothetical Transfer Scenarios

ID	Resource From	Sink	Test Level (MW)
1	PJM	DUK	1,000
2	SOCO	DUK	1,000
3	CPLE	DUK	1,000
4	TVA	DUK	1,000
5	PJM	CPLE	1,000
6	DUK	CPLE	1,000
7	DUK	SOCO	1,000
8	PJM	DUK/CPLE	1,000/ 1,000
9	DUK/CPLE	PJM	1,000/ 1,000
10	CPLE	PJM	1,000
11	DUK	PJM	1,000
12	DUK	TVA	1,000
13	DUK	SCPSA	750
14	PJM	SCPSA	500

Technical Analysis

- Conduct thermal screenings of the 2027S, 2027/28W and 2032/33W base cases
- Conduct thermal screenings for transfer scenarios in 2032/33W

Problems Identified and Solutions Developed

- Identify limitations and develop potential alternative solutions for further testing and evaluation
- Estimate project costs and schedule

New Projects in 2022 Plan		
Reliability Project	**TO**	**Planned I/S Date**
Wateree 100 kV Line, Six-Wire	DEC	11/2023
Silas 100 kV Line (Mocksville-Idols Tap), Upgrade	DEC	4/1/2025
North Greenville Tie, Breaker Installations and Replacements plus Bank Replacement	DEC	6/1/2025

New Projects in 2022 Plan (continued)		
Reliability Project	**TO**	**Planned I/S Date**
Wylie 100 kV Line (Wylie-Arrowood Retail), Upgrade	DEC	12/2026
Morning Star Tie, Upgrade (3) 230/100 kV Transformers	DEC	6/1/2028

New Projects in 2022 Plan (continued)

Reliability Project	TO	Planned I/S Date
Davidson River 100 kV Line (North Greenville-Marietta), Upgrade	DEC	Conceptual
Harley 100 kV Line (Tiger-Campobello), Upgrade	DEC	Conceptual
Sandy Ridge 230 kV Line (Newport-Morning Star), Add Second Circuit	DEC	Conceptual
Skybrook 100 kV Line (Winecoff-Eastfield Retail), Upgrade	DEC	Conceptual

Collaborative Plan Projects Selected

- Compare all alternatives and select preferred solutions

Study Report Prepared

- Prepare draft report and distribute to TAG for review and comment

TAG Input Request

- **TAG is requested to provide any feedback and/or propose alternative solutions to the OSC on the 2022 Preliminary Reliability Study Results.**
- **Provide input by November 4th to**

Rich Wodyka (rich.wodyka@gmail.com)

Questions ?

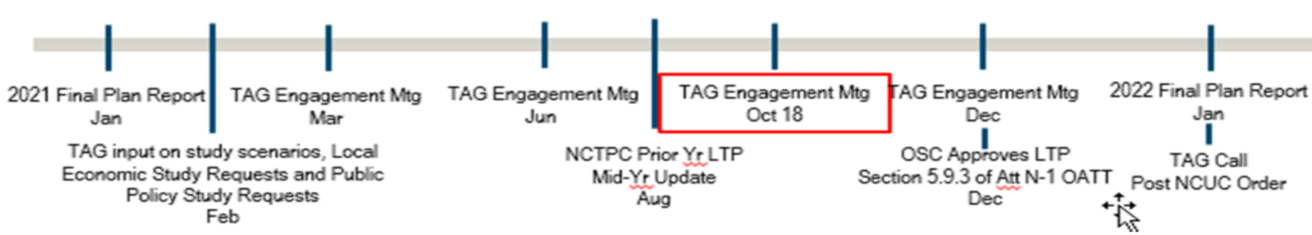
Duke Supplemental Study for RZEP Projects

Sammy Roberts
Duke Energy Progress

NCTPC Schedule / TAG Engagement Meeting

- Following Local Transmission Planning Process as defined in Attachment N-1 of Joint OATT and effectuated by the NCTPC
- Presented RZEP projects as generator interconnection study informed and described need for projects to OSC in March
- Shared initial mapping of queue request studies to RZEP projects with OSC in April
- Provided updated information on number of generator interconnection studies reflecting RZEP upgrades to OSC, PWG in June
- Presented the draft 2021 Plan Mid-year Update Report with the RZEP projects included at the June 27 TAG meeting
- Solicited TAG feedback/input during the June 27 TAG meeting as well as a period after the TAG meeting
- Removed RZEP projects from 2021 Plan Mid-year Update Report to allow more time to consider in light of NCUC directive in June 10 Order approving 2022 Solar Procurement and TAG Stakeholder feedback in July
- Conducted Supplemental Studies after engagement with Public Staff to further evaluate RZEP projects as being necessary for interconnecting solar - August
- Presenting results of Supplemental Studies to TAG stakeholders – October 18
- Providing projected timeline for RZEP projects being included in 2022 Local Transmission Plan – October 18

NCTPC Process



OATT Attachment N-1 Local Transmission Planning Process

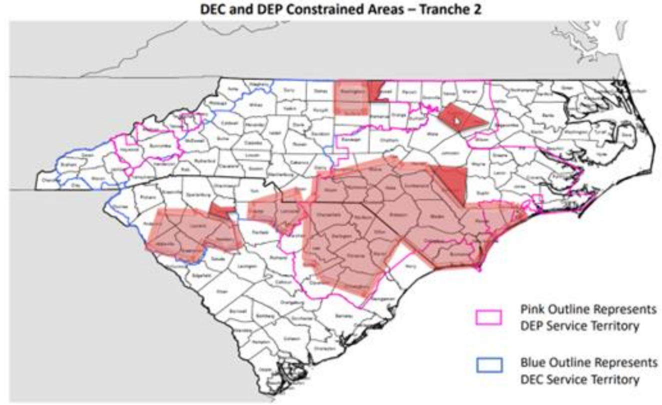
OATT Attachment N-1, Section 4.1.3

- The following are the steps in the Local Planning Processes
  - 4.1.3 The process will allow for flexibility to make modifications to the development of the Local Transmission Plan throughout the year as needs change, new needs arise, or new solutions to problems are identified.

Red-Zone Constraints Resolved Only Through Network Upgrades

- Identified RZEP upgrades will start to unlock the red-zone for additional solar to interconnect
- Even though this red-zone guidance has been provided since CPRE began, developers still request interconnections in the red-zone as evidenced in the TCS and 2022 DISIS due to:
  - Lower land lease rates
  - Availability of larger land parcels
  - NREL GHI Map shows slightly better irradiance

DEC and DEP Constrained Areas – Tranche 2



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Attachment 1

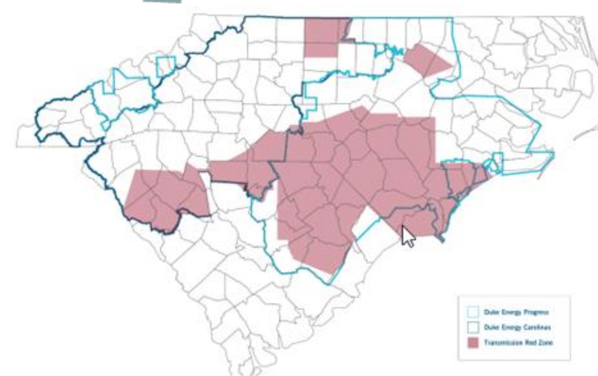
DEC and DEP Constrained Areas

5-9-2018

Attachment 1

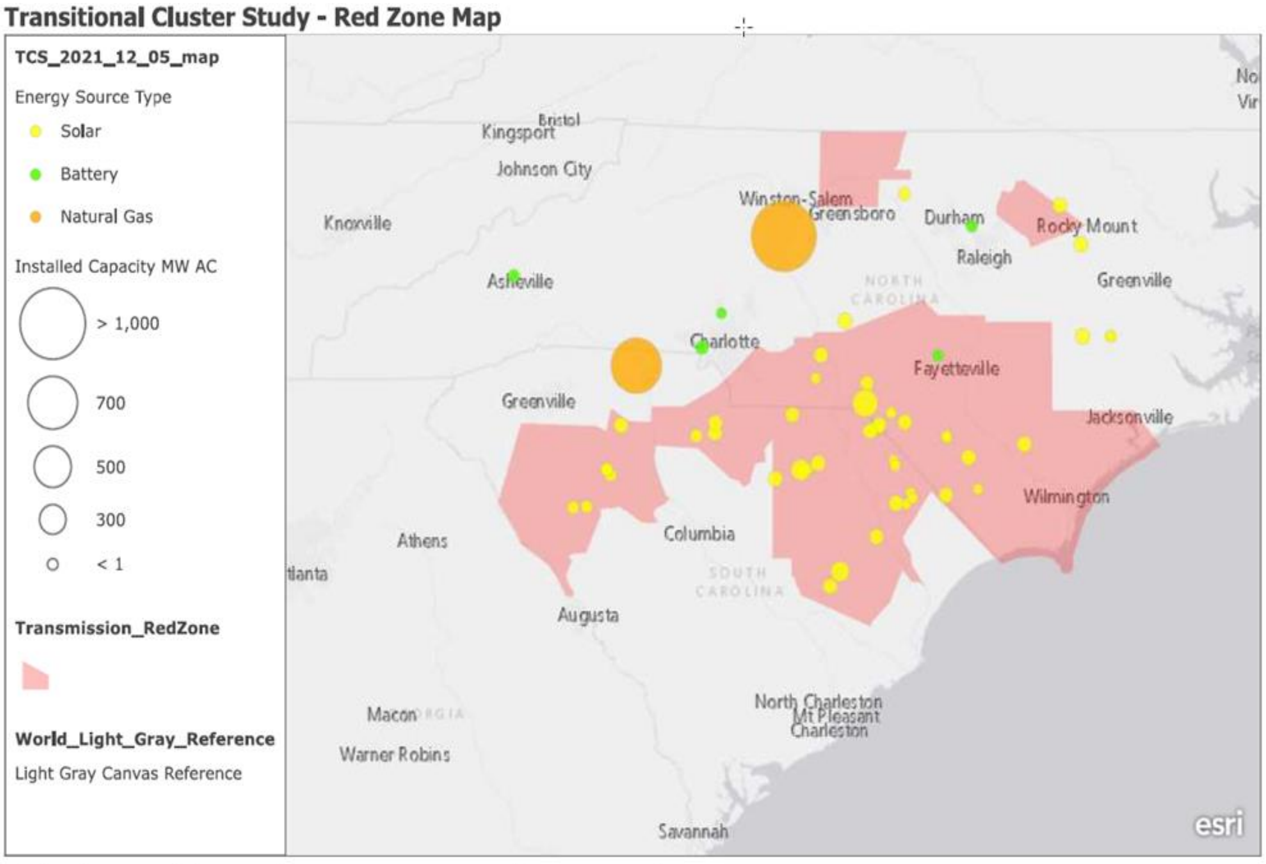
DEC/DEP Transmission "Red Zone" Map

5-20-2022



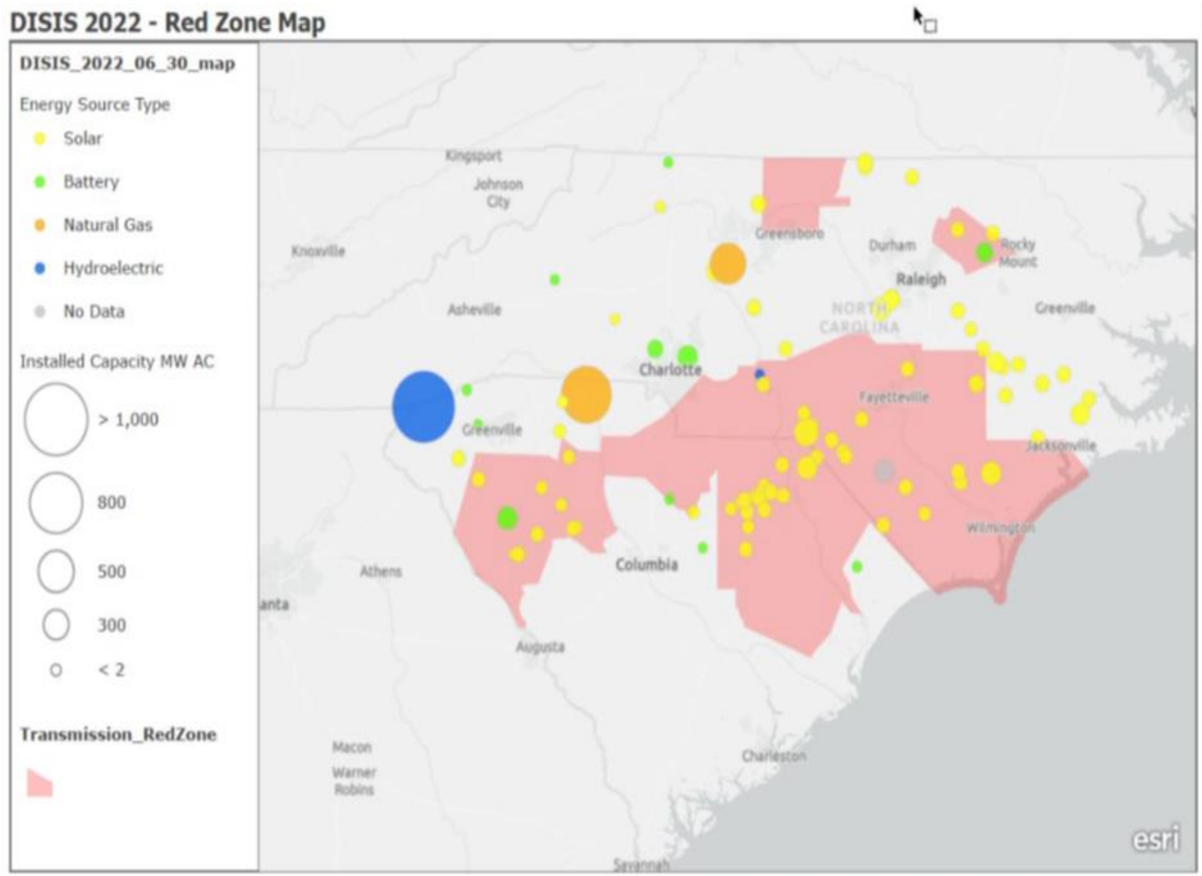
2021 TCS Resource Interconnection Request Map

- For the DEP Transitional Cluster Study, 35 out of 43 resources requesting interconnection, representing 1,445.9 MW, showed some level of dependency on what are known as the Friesian projects network upgrades in the red zone.
- Thirty projects requesting 1,860 MW of interconnection service withdrew after receiving Phase1 Transitional Cluster Study results and one 75 MW solar project remains in the DEP TCS.
- For DEC, approximately 176 MW of solar remains in the TCS out of the original 474 MW of solar and solar + storage requesting interconnection.



2022 DISIS Resource Interconnection Request Map

- Approximately 3500 MW of solar (out of approx 4900 MW) in the 2022 solar procurement is in a known red zone.
- For DEC, approximately 700 MW and for DEP approximately 2800 MW are in known red zones.
- DEC has about 850 MW total and DEP has about 4050 total solar projects in the 2022 solar procurement



Solar in Resource Plan Portfolios

The 2020 IRPs show 8 – 12 GW of additional solar identified in Portfolios B through F for meaningful CO_2 reductions

Duke Energy expects future IRPs to reveal increasing volumes of solar as we retire more coal generation

Carbon Plan Portfolios 1 through 4 – 70% CO_2 Reduction by 2030 - 2034

- 5.4 GW to 7.7 GW of additional new solar by 2030 - 2034
- Up to an additional 11.9 GW of new solar by 2035

Table I-2 from Appendix I of the Carbon Plan shows aggressive solar interconnection to meet 70% by 2030

Table I-2: Maximum Solar (MW) Allowed to Connect Annually (by Jan. 1 of year shown)

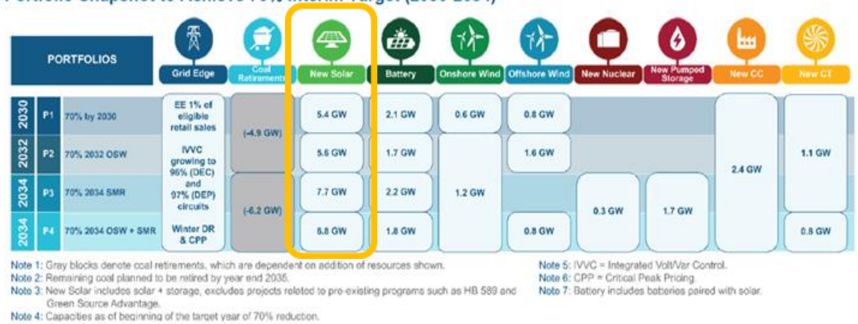
Beginning of Year	2027	2028	2029	2030+
70% by 2034 with Wind or Nuclear	750	1,050	1,350	1,350
70% by 2030	750	1,050	1,800	1,800

DUKE ENERGY. CAROLINAS

DEC / DEP COMBINED SYSTEM PORTFOLIO RESULTS TABLE

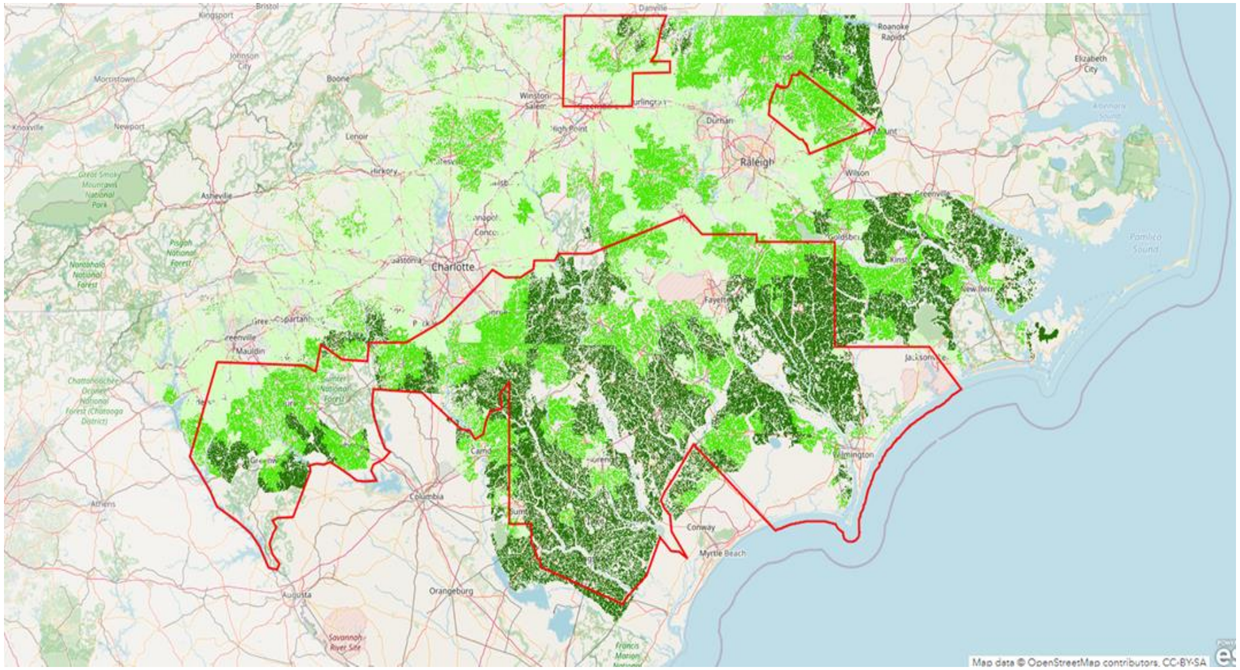
	Base without Carbon Policy		Base with Carbon Policy		Earliest Practicable Coal Retirements		70% CO_2 Reduction: High Wind		70% CO_2 Reduction: High SMR		No New Gas Generation	
PORTFOLIO	A		B		C		D		E		F	
System CO_2 Reduction (2030 | 2035)[1]	56%	53%	59%	62%	64%	64%	70%	73%	71%	74%	65%	73%
Present Value Revenue Requirement (PVRR) [$B][2]	$79.8		$82.5		$84.1		$100.5		$95.5		$108.1	
Estimated Transmission Investment Required [$B][3]	$0.9		$1.8		$1.3		$7.5		$3.1		$8.9	
Total Solar [MW][4, 5] by 2035	8,650		12,300		12,400		16,250		16,250		16,400	
Incremental Onshore Wind [MW][4] by 2035	0		750		1,350		2,850		2,850		3,150	
Incremental Offshore Wind [MW][4] by 2035	0		0		0		2,650		250		2,650	
Incremental SMR Capacity [MW][4] by 2035	0		0		0		0		1,350		700	
Incremental Storage [MW][4, 6] by 2035	1,050		2,200		2,200		4,400		4,400		7,400	
Incremental Gas [MW][4] by 2035	9,600		7,350		9,600		6,400		6,100		0	
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][7] by 2035	2,050		2,050		2,050		3,350		3,350		3,350	
Remaining Dual Fuel Coal Capacity [MW][4, 8] by 2035	3,050		3,050		0		0		0		2,200	
Coal Retirements	Most Economic		Most Economic		Earliest Practicable		Earliest Practicable[9]		Earliest Practicable[9]		Most Economic[10]	
Dependency on Technology & Policy Advancement												

Figure 3-1: Portfolio Snapshot to Achieve 70% Interim Target (2030-2034)



Solar Viability Map Reflects RZEP Need

- Using the ESRI Mapping Application
- This Map reflects:
  - NREL provided exclusion areas based on wetlands, national and state parks, federal lands
  - Solar viability based on population density, forestation, land availability
  - Moderate solar viability (lime green)
  - Maximum solar viability (dark green)



Red Zones demarcated by red lines

Supplemental Studies - Purpose

➢ The purpose of Supplemental Studies is to:

- Analyze the need for proactive transmission upgrades to help Duke Energy meet Carbon Plan and Integrated Resource Plan goals in the Carolinas.

- Respond to the NCUC's June 10 Order in the 2022 Solar Procurement Hearing Dockets (E-2, Sub 1297; E-7, Sub 1268) to provide substantial evidence to support the need for the RZEP projects.

Supplemental Studies – Criteria and Scope

Criteria applied with selection of past generator interconnection requests

- For DEC, only one request was considered per 44kV circuit due to the significant impact that would result from two or more requests being considered for the same circuit
- For DEC and DEP, no solar interconnection requests greater than 175 MW were included in the study due to the localized impact that these projects have on network upgrades needed for interconnection

Scope

- Starting with the Transitional Cluster Study generator interconnection requests, go back just far enough in history to get to at least 5.4 GW of solar requesting interconnection meeting the criteria above and a 40/60 DEC/DEP split
  - **41 projects in DEC representing 1,937 MW were studied**
  - **45 projects in DEP representing 3,527 MW were studied**
- The study was performed as a cluster-type study with results reported in a similar manner to the Transitional Cluster Study

Supplemental Studies – DEC Results

- The DEC study results reflected the four RZEP projects are needed to enable 981 MW of solar projects to be interconnected in the red-zone.
  1. **Lee 100kV line (Lee - Shady Grove)**
  2. **Piedmont 100kV line (Lee - Shady Grove)**
  3. **Newberry 115kV line (DESC - Bush River)**
  4. **Clinton 100kV line (Bush River - Laurens)**
- Other network upgrades were identified in the study, however multiple solar projects impacted the four transmission lines identified as RZEP projects
- With some solar projects studied outside the red zone, transmission upgrades were identified outside the red zone
- The complete study report is posted on the DEC OASIS site

Supplemental Studies – DEP Results

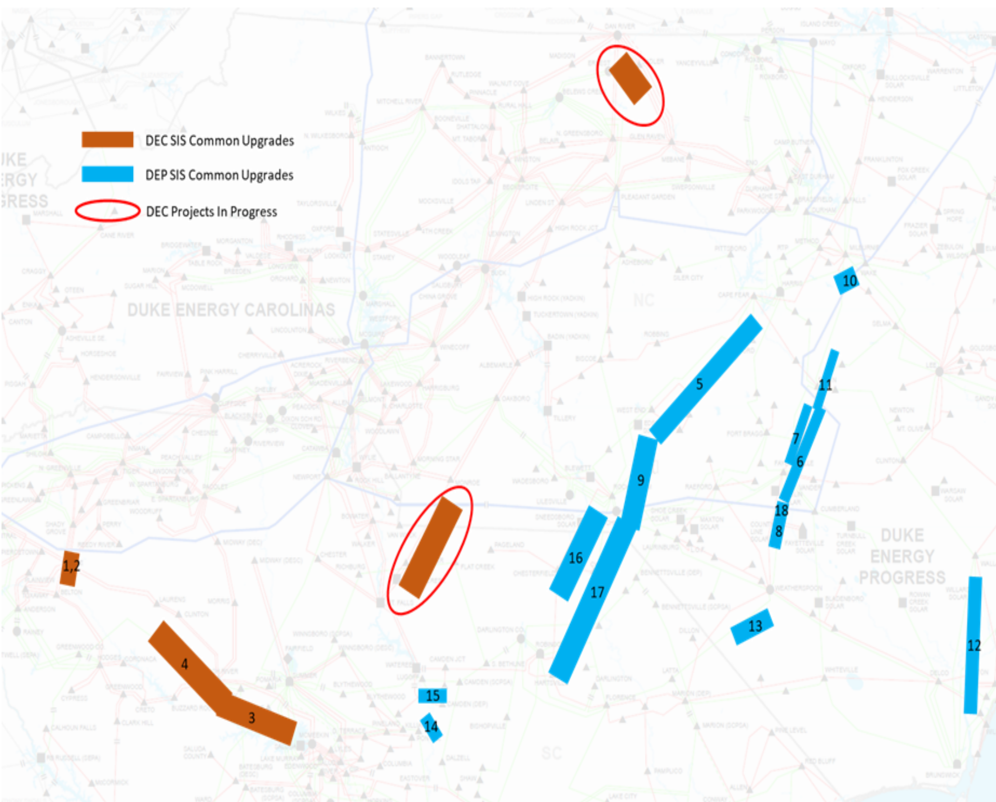
- The DEP study results reflected the 11 of the original 14 RZEP projects are needed to enable 2,778 MW of solar projects to be interconnected in the red-zone.
  1. **Cape Fear Plant – West End 230kV Line**
  2. **Erwin – Fayetteville East 230kV Line**
  3. **Erwin – Fayetteville 115kV Line**
  4. **Fayetteville-Fayetteville Dupont 115kV Line – 3.2 mile section**
  5. ~~**Rockingham – West End 230kV West Line**~~
  6. **Milburnie 230kV Substation**
  7. ~~**Erwin-Milburnie 230kV Line**~~
  8. ~~**Sutton Plant-Wallace 230kV Line**~~
  9. **Weatherspoon-Marion 115kV Line**
  10. **Camden-Camden Dupont 115kV Line**
  11. **Camden Junction-DPC Wateree 115kV Line**
  12. **Robinson Plant-Rockingham 115kV Line**
  13. **Robinson Plant-Rockingham 230kV Line**
  14. **Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section**

Table Reflecting RZEP Projects For Inclusion in 2022 LTP

Project #	Owner	Project	Acknowledge need for inclusion in the 2022 Local Plan	Continued evaluation for inclusion in post-2022 Local Transmission Plans
1	DEC	Lee 100 kV (Lee-Shady Grove)	X	
2	DEC	Piedmont 100 kV (Lee-Shady Grove)	X	
3	DEC	Newberry 115 kV (Bush River-DESC)	X	
4	DEC	Clinton 100 kV (Bush River-Laurens)	X	
5	DEP	Cape Fear Plant – West End 230kV Line	X	
6	DEP	Erwin – Fayetteville East 230kV Line	X	
7	DEP	Erwin – Fayetteville 115kV Line	X	
8	DEP	Fayetteville-Fayetteville Dupont 115kV Line –	X	
9	DEP	Rockingham – West End 230kV West Line		X
10	DEP	Milburnie 230kV Substation	X	
11	DEP	Erwin-Milburnie 230kV Line		X
12	DEP	Sutton Plant-Wallace 230kV Line		X
13	DEP	Weatherspoon-Marion 115kV Line	X	
14	DEP	Camden-Camden Dupont 115kV Line		X
15	DEP	Camden Junction-DPC Wateree 115kV Line	X	
16	DEP	Robinson Plant-Rockingham 115kV Line	X	
17	DEP	Robinson Plant-Rockingham 230kV Line	X	
18	DEP	Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section	X	

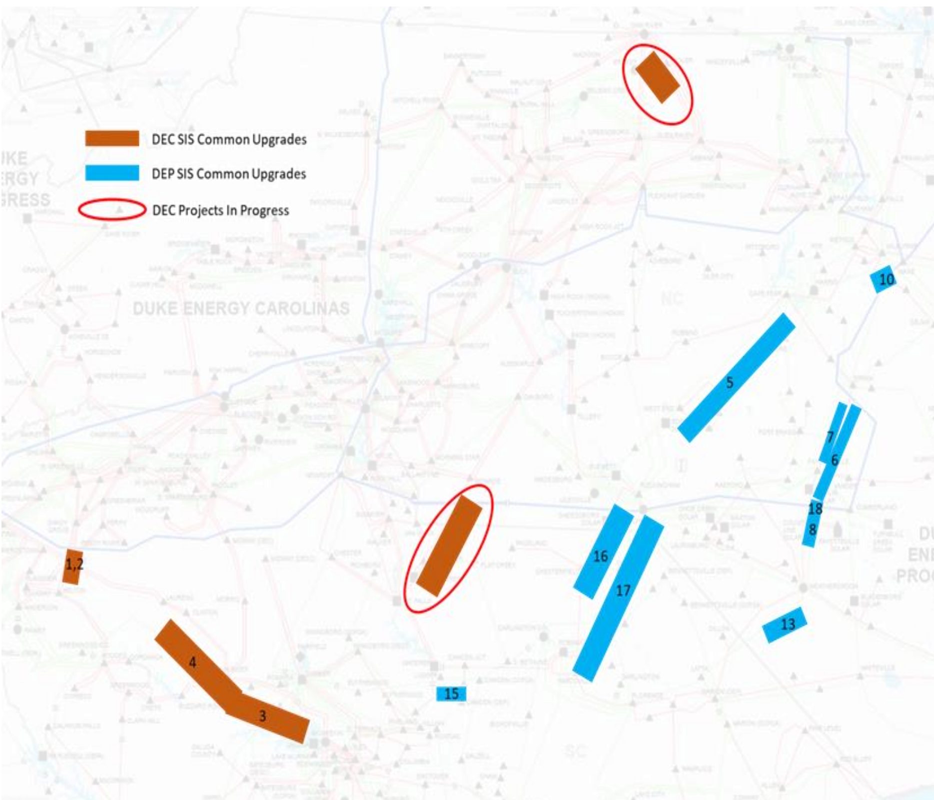
Exhibit 3 in Transmission Panel Rebuttal Testimony filed in Carbon Plan Docket

Original DEC and DEP Red Zone Transmission Expansion Plan



	Project	Owner	Project Description	Total Cost (FB, w/ contingency)	Estimate Class
1	Lee 100 kV (Lee-Shady Grove)	DEC	Upgrade	$45,000,000	5
2	Piedmont 100 kV (Lee-Shady Grove)	DEC	Upgrade	$45,000,000	5
3	Newberry 115 kV (Bush River-DESC)	DEC	Upgrade	$42,000,000	5
4	Clinton 100 kV (Bush River-Laurens)	DEC	Upgrade	$109,000,000	5
5	Cape Fear Plant – West End 230kV Line	DEP	Rebuild	$70,349,010	4
6	Erwin – Fayetteville East 230kV Line	DEP	Rebuild	$83,933,750	4
7	Erwin – Fayetteville 115kV Line	DEP	Rebuild	$21,288,975	4
8	Fayetteville-Fayetteville Dupont 115kV Line – 3.2 mile section	DEP	Rebuild	$14,106,625	4
9	Rockingham – West End 230kV West Line	DEP	Upgrade	$1,457,875	4
10	Milburnie 230kV Substation	DEP	Redundant Bus Protection	$4,324,127	4
11	Erwin-Milburnie 230kV Line	DEP	Rebuild	$5,300,000	5
12	Sutton Plant-Wallace 230kV Line	DEP	Upgrade	$500,000	5
13	Weatherspoon-Marion 115kV Line	DEP	Rebuild	$13,000,000	5
14	Camden-Camden Dupont 115kV Line	DEP	Rebuild	$2,600,000	5
15	Camden Junction-DPC Wateree 115kV Line	DEP	Rebuild	$10,000,000	5
16	Robinson Plant-Rockingham 115kV Line	DEP	Rebuild	$38,000,000	5
17	Robinson Plant-Rockingham 230kV Line	DEP	Rebuild	$43,100,000	5
18	Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section	DEP	Rebuild	$11,600,000	5
			Total	$560,560,362	

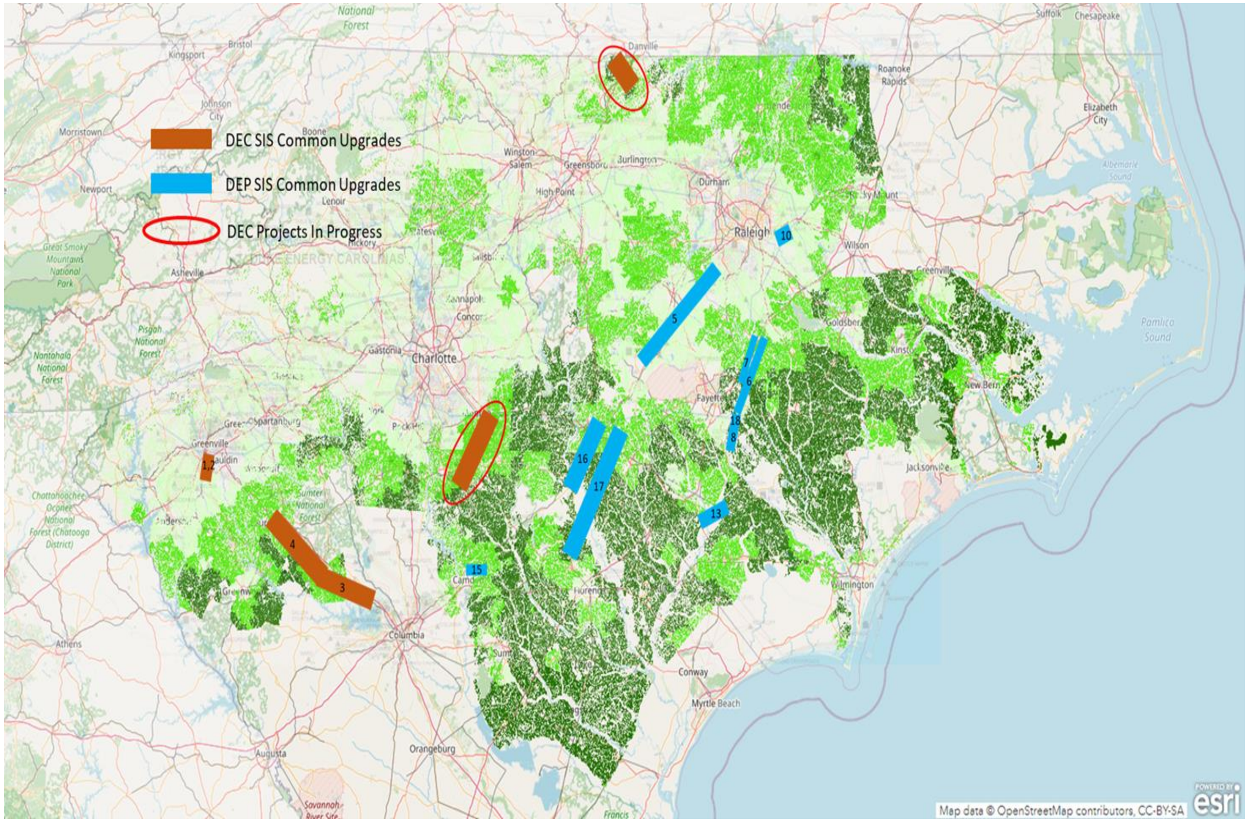
Modified DEC and DEP Red Zone Transmission Expansion Plan



	Project	Owner	Project Description	Total Cost (FB, w/ contingency)	Estimate Class
1	Lee 100 kV (Lee-Shady Grove)	DEC	Upgrade	$45,000,000	5
2	Piedmont 100 kV (Lee-Shady Grove)	DEC	Upgrade	$45,000,000	5
3	Newberry 115 kV (Bush River-DESC)	DEC	Upgrade	$42,000,000	5
4	Clinton 100 kV (Bush River-Laurens)	DEC	Upgrade	$109,000,000	5
5	Cape Fear Plant – West End 230kV Line	DEP	Rebuild	$70,349,000	4
6	Erwin – Fayetteville East 230kV Line	DEP	Rebuild	$83,933,750	4
7	Erwin – Fayetteville 115kV Line	DEP	Rebuild	$21,288,975	4
8	Fayetteville-Fayetteville Dupont 115kV Line – 3.2 mile section	DEP	Rebuild	$14,106,625	4
9	~~Rockingham – West End 230kV West Line~~	DEP	Upgrade		4
10	Milburnie 230kV Substation	DEP	Redundant Bus Protection	$4,324,127	4
11	~~Erwin-Milburnie 230kV Line~~	DEP	Rebuild		5
12	~~Sutton Plant-Wallace 230kV Line~~	DEP	Upgrade		5
13	Weatherspoon-Marion 115kV Line	DEP	Rebuild	$13,000,000	5
14	~~Camden-Camden Dupont 115kV Line~~	DEP	Rebuild		5
15	Camden Junction-DPC Wateree 115kV Line	DEP	Rebuild	$10,000,000	5
16	Robinson Plant-Rockingham 115kV Line	DEP	Rebuild	$38,000,000	5
17	Robinson Plant-Rockingham 230kV Line	DEP	Rebuild	$43,100,000	5
18	Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section	DEP	Rebuild	$11,600,000	5
			Total	$550,702,477	

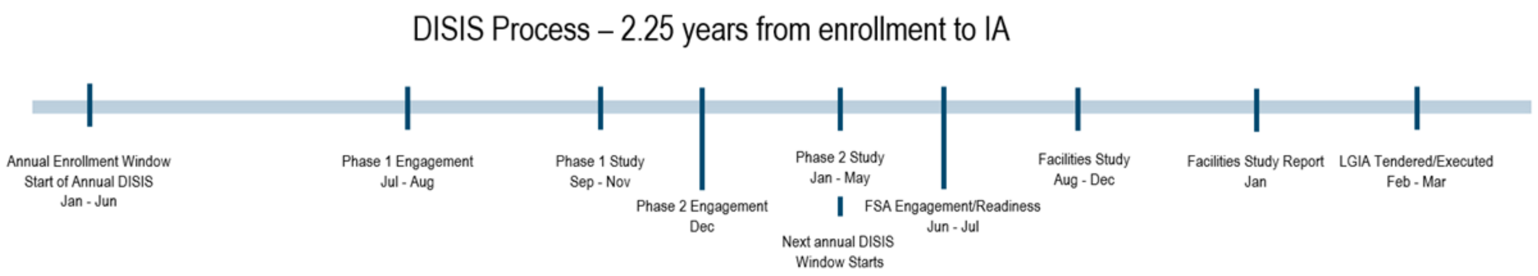
Solar Viability Map Reflects Current RZEP Project Need

- Using the ESRI Mapping Application
- This Map reflects:
  - NREL provided exclusion areas based on wetlands, national and state parks, federal lands
  - Solar viability based on population density, forestation, land availability
  - Moderate solar viability (lime green)
  - Maximum solar viability (dark green)



RZEP projects (excluding the two shown as "in progress") on this map represent the 14 projects (out of original 18) requesting Commission acknowledgement as needed to execute the Carbon Plan

Alternative Approach: Wait on DISIS Results to Produce IAs



- The DISIS Cluster Study Process takes 1.75 years from the end of Annual Enrollment to a signed Interconnection Agreement if no restudy is required
- Network Upgrade projects start when the IA is signed and are added to the transmission planning model based on estimated completion date
- Network Upgrade projects can take 3 to 5 years from project initiation to the in-service date – dependent on outage coordination and type of upgrade
- Thus, from Enrollment to Operation for a solar facility could take up to 5.75 years

Cost – Benefit Analysis for RZEP Projects

- Evaluation of Cost-Benefit using an industry wide application, the Interruption Cost Estimate or "ICE" Calculator data based on the probability of failure
- Utilizes value model that calculates reliability benefits based off asset deterioration curves and measures customer impact of an outage utilizing the ICE data for the probability of failure
- Using the asset replacement value model to quantify the reliability benefits from replacing aging infrastructure resulted in the following CBA scores for the RZEP projects:
  - For the four DEC RZEP projects identified in the supplemental study, the scores ranged from 5.1 to 22.5 with an average of 14.6
  - For the eleven DEP RZEP projects identified in the supplemental study, the scores ranged from 10.5 to 21.4 with an average score of 15.5
- These scores do not ascribe any value to carbon reduction
- In addition, with the RZEP projects enabling larger solar facilities, larger solar facilities have up to a $0.22/W benefit compared to those less than 80 MW. The 2022 DISIS has 3 large sites aggregating to 675 MW requesting interconnection in the red zones. If RZEP projects move forward and enable these sites to be interconnected in lieu of smaller projects, this would represent a $140 million benefit.

Takeaways

- Per the formal Local Transmission Planning Process, TAG Members have the opportunity to provide input during and after today's TAG meeting which includes input on whether to proactively include the RZEP projects in Local Transmission Plan
- RZEP Projects need to be considered for all future solar procurements to meet the volume and timing objectives for solar interconnections. Unlocking the red zones will allow for larger solar facilities to interconnect to the DEC and DEP systems
- RZEP Projects are shown through cost-benefit analysis using the Interruption Cost Estimate calculator to be cost effective and provide long-term benefit
- RZEP Projects have additional benefits for the DEC and DEP systems
    - Rebuild projects involve replacing aging structures with new more reliable and resilient equipment
    - New higher capacity conductors generally have lower impedance that reduces transmission losses
    - Subsequent studies performed at OSC member request showed the RZEP projects do not cause any significant impact on other transmission lines
- Provide input and questions on this Study by November 4th to Rich Wodyka (rich.wodyka@gmail.com)

Questions ?

Regional Studies Reports

Bob Pierce

Duke Energy Carolinas

SERC Long Term Working Group Update

SERC Long Term Working Group

- Completed 2027 Summer Study
- Building 2022 series MMWG cases
  - Steady state cases effectively complete
  - Beginning Stability cases development

SERTP

SERTP

- 3rd Quarter Meeting (WebEx) was held on September 29th
  - 2022 Economic Planning Studies Results
- 4th Quarter Meeting (Webex) on December 14th @ 10 AM

SERTP

Economic Planning Study

No.	Requestor	Source	Sink	MW	Year
1	NCEMC	Southern	DEC	1000	2032 (s)
2	NCEMC	SCE & G	DEC	1000	2032 (s)
3	Santee Cooper	SOCO	SC	600	2027 (w)
4	Santee Cooper	SOCO	SC	500	2024 (s)
5	Santee Cooper	DEC	SC	600	2027 (w)

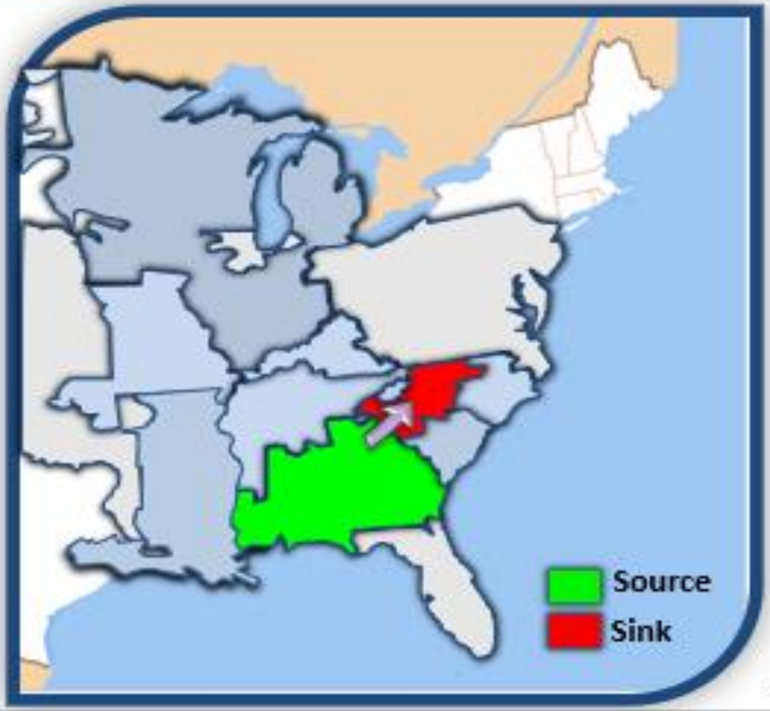
SERTP

Southeastern Regional TRANSMISSION PLANNING

SOCO – DEC 1000 MW

Study Assumptions

- **Source:** Generation within SOCO
- **Sink:** Generation within DEC
- **Transfer Type:** Generation to Generation
- **Year:** 2032
- **Load Level:** Summer Peak



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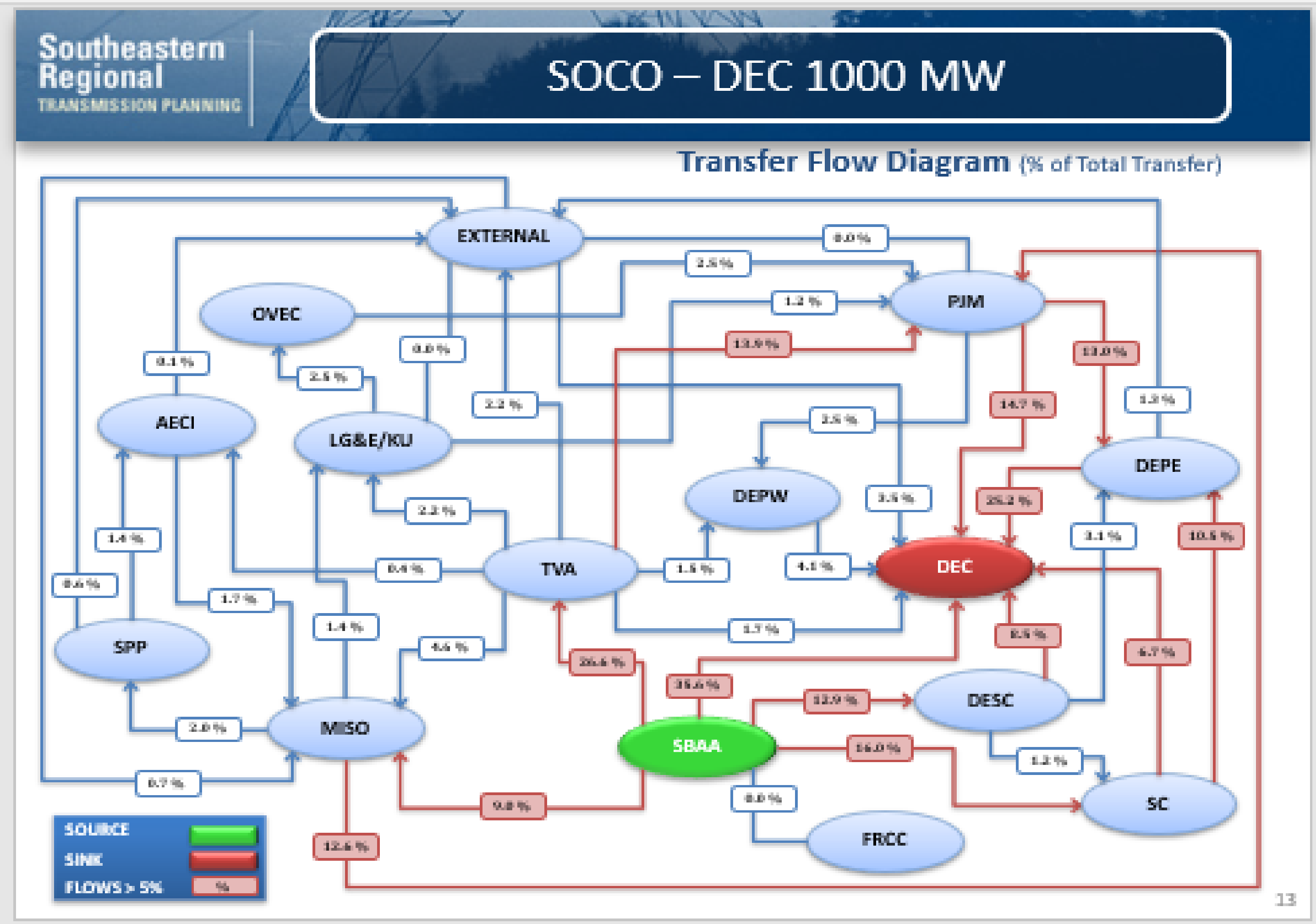
SERTP


Southeastern Regional
TRANSMISSION PLANNING
SOCO – DEC 1000 MW
Transfer Flow Diagram (% of Total Transfer)
EXTERNAL
PJM
OVEC
AECI
LG&E/KU
DEPE
DEPW
DEC
TVA
SPP
MISO
SBAA
DESC
SC
FRCC
SOURCE
SINK
FLOWS > 5%
%
13

SERTP

Southeastern Regional TRANSMISSION PLANNING

SOCO – DEC 1000 MW

Transmission System Impacts – *SERTP*

Table 3: Transmission System Impacts - SERTP

Balancing Authority	Planning Level Cost Estimate
Associated Electric Cooperative (AECI)	$0
Duke Carolinas (DEC)	$169 Million
Duke Progress East (DEPE)	$0
Duke Progress West (DEPW)	$0
Louisville Gas & Electric and Kentucky Utilities (LG&E/KU)	$0
PowerSouth (PS)	$0
Southern (SBAA)	$5.1 Million
Tennessee Valley Authority (TVA)	$0
SERTP TOTAL ($2022)	**$174.1 Million**

15

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Southeastern Regional
TRANSMISSION PLANNING

SOCO – DEC 1000 MW

Significant Constraints Identified – *DEC*

Table 1: Significant Constraints - DEC

Potential Enhancement	Limiting Element	Rating (MVA)	Thermal Loadings (%) Without Request	Thermal Loadings (%) With Request
P1	Lee Steam – Shady Grove Tie 100 kV TL (Lee Line)	132	88.1	94.5
P1	Lee Steam – Shady Grove Tie 100 kV TL (Piedmont Line)	132	94.5	101
P2	Wateree Switching – Great Falls Switching 100 kV TL	116	89	116.1
NA*	Catawba Nuclear – Allen Steam 230 kV TL	1055	92.6	104.1

*Project to address is in the current expansion plan, but not in version 1 models
+Potential future constraints can be found in the Economic Studies Report on the SERTP Website

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Southeastern Regional TRANSMISSION PLANNING

SOCO – DEC 1000 MW

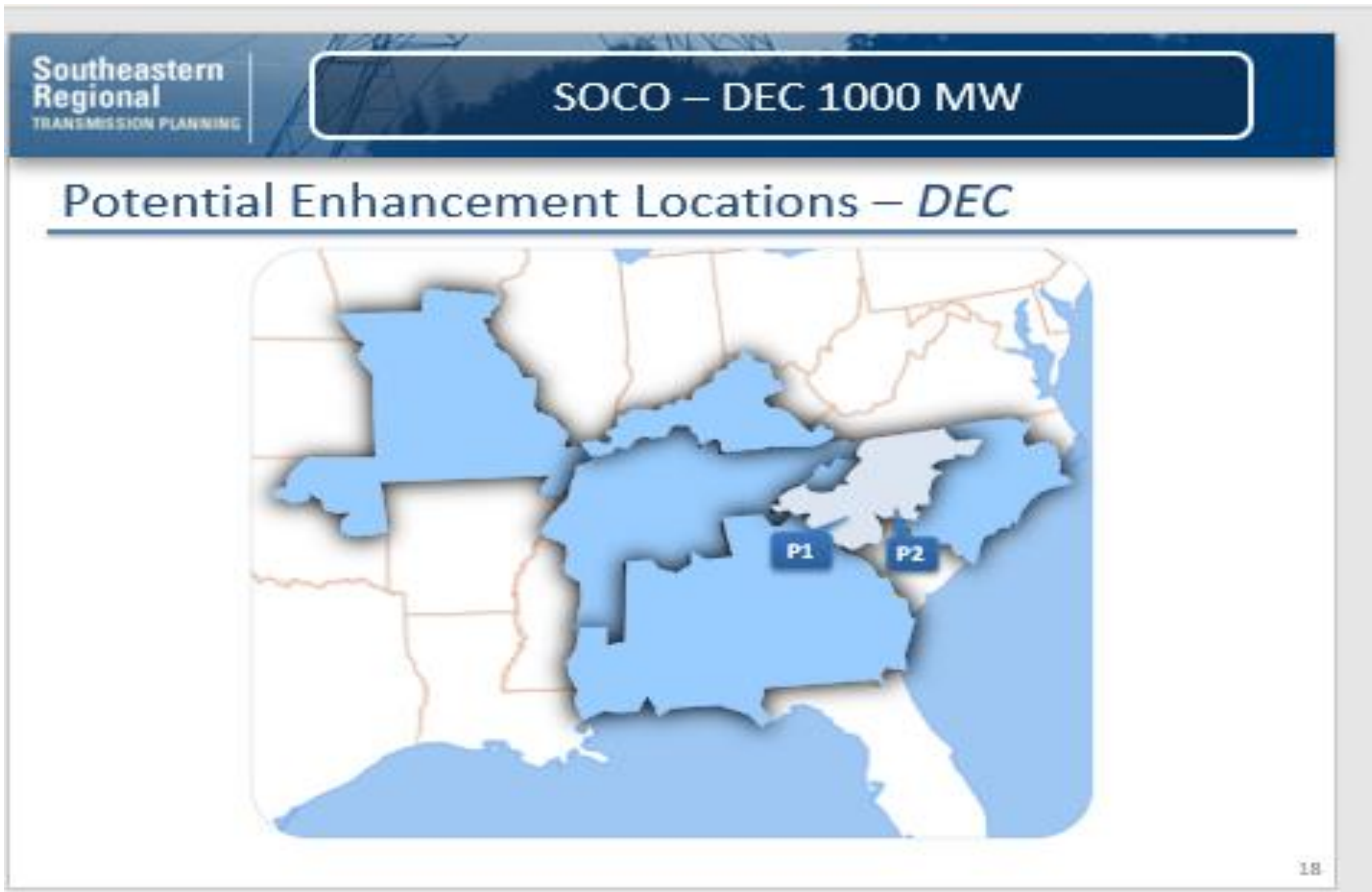
Potential Enhancements Identified – *DEC*

Table 2: Potential Enhancements - DEC

Item	Potential Enhancement	Planning Level Cost Estimate
P1	**Lee Steam Station – Shady Grove Tie 100 kV T.L.** • Rebuild both Lee Steam Station – Shady Grove Tie 100 kV Transmission Lines with 1158 ACSS/TW rated at 200˚C. Total rebuild length is 24.5 miles	**$90 Million**
P2	**Wateree Switching Station–Great Falls Switching Station 100 kV T.L.** • Rebuild 19.8 miles of the Wateree Switching Station – Great Falls Switching Station 100 kV T.L. with 954 ACSR rated at 120˚C	**$79 Million**
DEC TOTAL ($2022)		**$ 169 Million**[1]

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

SERTP


Southeastern Regional
TRANSMISSION PLANNING
SOCO – DEC 1000 MW
Potential Enhancement Locations – DEC
P1
P2
18

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Southeastern Regional
TRANSMISSION PLANNING

SOCO – DEC 1000 MW

Significant Constraint (P1) – *DEC*

19

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Southeastern Regional TRANSMISSION PLANNING

SOCO – DEC 1000 MW

Potential Enhancement (P1) – *DEC*

20

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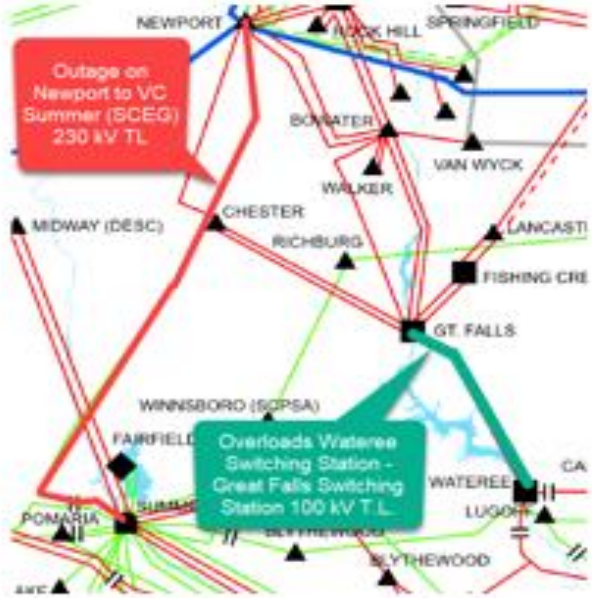
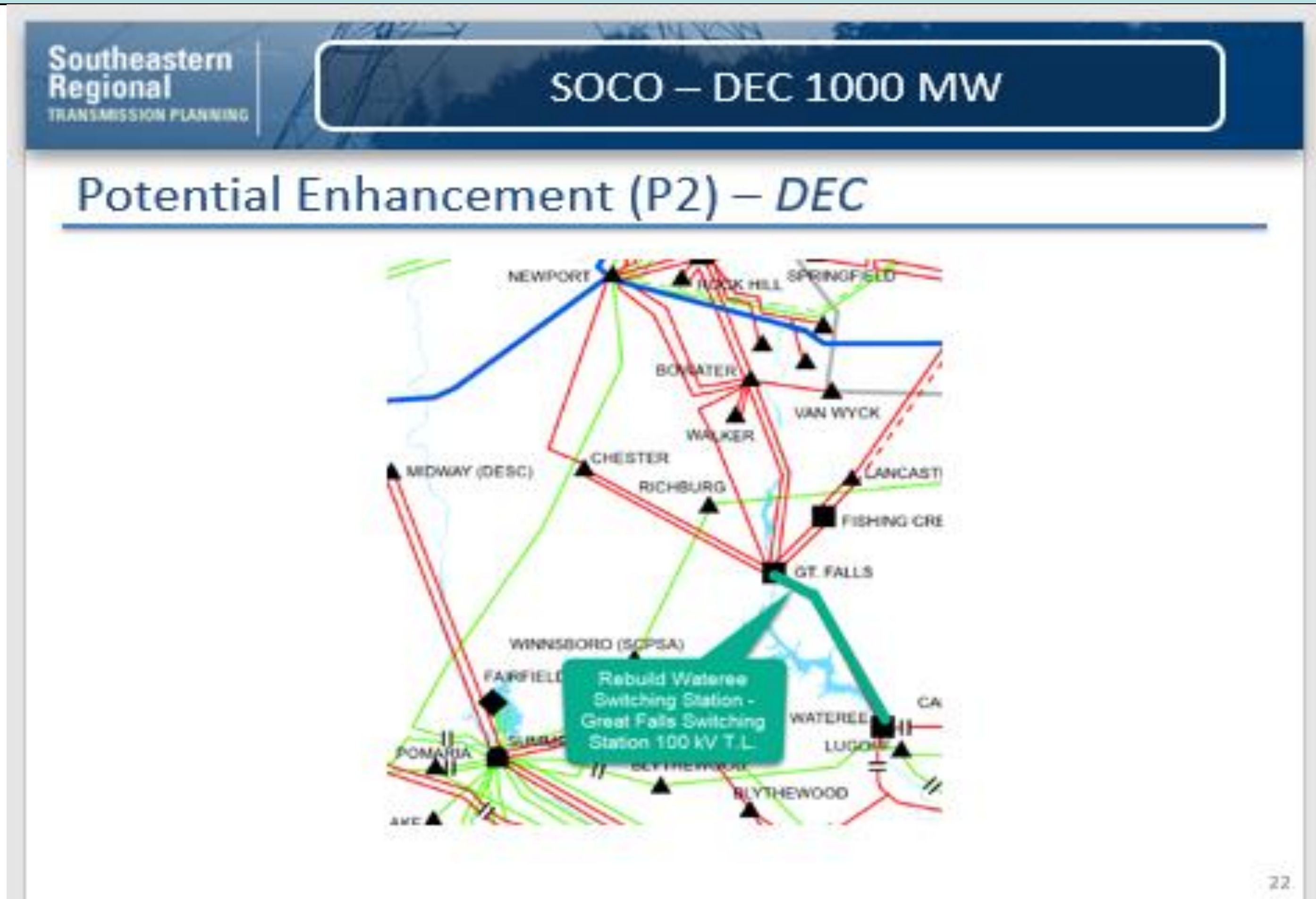
Southeastern Regional TRANSMISSION PLANNING

SOCO – DEC 1000 MW

Significant Constraint (P2) – *DEC*



SERTP


Southeastern Regional TRANSMISSION PLANNING
SOCO – DEC 1000 MW
Potential Enhancement (P2) – *DEC*
NEWPORT
ROCK HILL
SPRINGFIELD
BOWATER
VAN WYCK
WALKER
CHESTER
MIDWAY (DESC)
RICHBURG
LANCASTI
FISHING CRE
GT. FALLS
WINNSBORO (SCPSA)
FAIRFIELD
Rebuild Wateree Switching Station - Great Falls Switching Station 100 kV T.L.
WATEREE
LUGOFF
POMARIA
BLYTHEWOOD
22

SERTP

These potential solutions and estimated need dates represent the extrapolation beyond the traditional 10-year study timeframe of DEC facilities that were identified as 90% or greater of the thermal rating in the 2022 studies. It is important to note that there may be additional constraints that could be identified in models for years beyond the specific study year used for these evaluations.

The solutions listed are provided as information only and do not represent any commitment to build.

Table A.1. Solutions for Identified Potential Problems for Study 1: 1000 MW SOCO - DEC

Item	Potential Solution	Estimated Need Date	Planning Level Cost Estimate
A1	**Lee Combustion – Belton Tie 100 kV TL** Rebuild the Lee Combustion – Belton Tie 100 kV TL with 1272 ACSR rated at 120 °C (6.4 miles)	2039	$26,000,000
A2	**Clark Hill 115/100 kV Transformer** Upgrade the lowside terminal of the 115/100 kV Transformer to improve rating of transformer	2035	$3,000,000
A3	**Central Tie – Shady Grove Tie 230 kV TL** Reconductor the Central Tie – Shady Grove Tie 230 kV TL with 1158 ACSS/TW rated at 200°C (17.8 Miles)	2038	$89,000,000
A4	**Lee Combustion – Toxaway Tie 100 kV TL** Rebuild the Lee Combustion – Toxaway Tie 100kV TL with 1272 ACSR rated at 120 °C (13.5 miles)	2034	$54,000,000
A5	**Riverbend Switching – Dixon School Rd Switching 230 kV TL** Upgrade the terminal at Riverbend Switching Station of the Riverbend Switching – Dixon School Rd Switching 230 kV TL to increase the rating of the line	2040	$5,000,000
DEC TOTAL ($2022)			**$177,000,000** (1)

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

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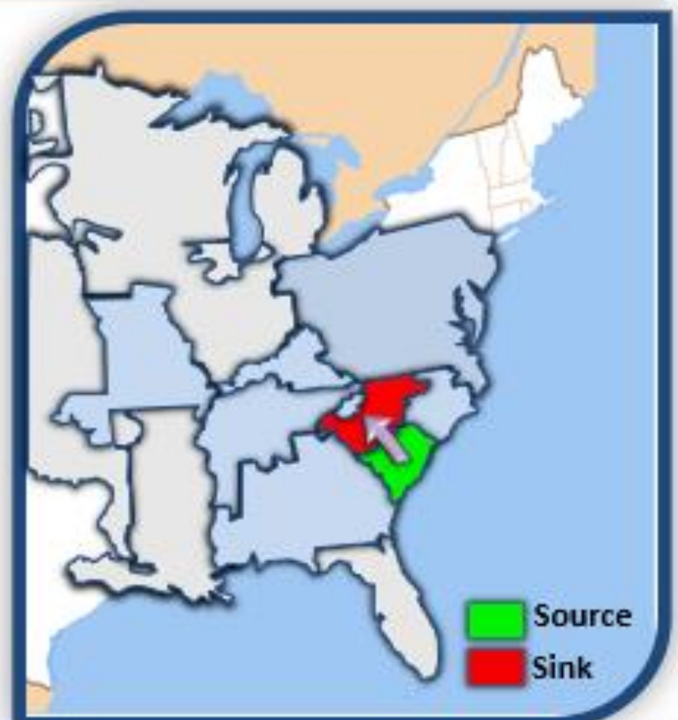
Southeastern Regional TRANSMISSION PLANNING

DESC – DEC 1000 MW

Study Assumptions

- **Source:** Generation Scale within DESC
- **Sink:** Generation with DEC
- **Transfer Type:** Generation to Generation
- **Year:** 2032
- **Load Level:** Summer Peak



29

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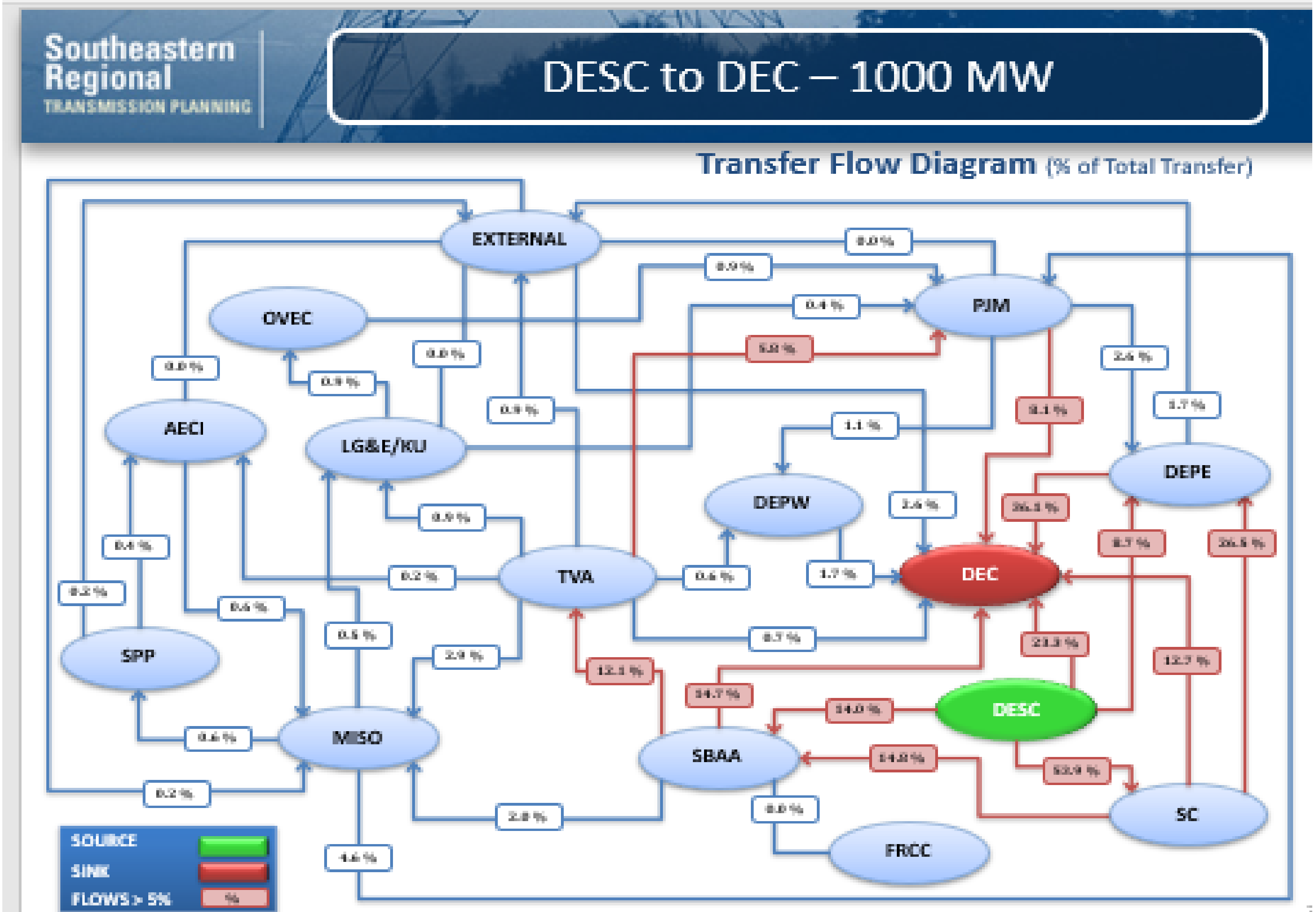
Southeastern Regional
TRANSMISSION PLANNING
DESC to DEC – 1000 MW
Transfer Flow Diagram (% of Total Transfer)
EXTERNAL
OVEC
PJM
AECI
LG&E/KU
DEPE
DEPW
TVA
DEC
SPP
DESC
MISO
SBAA
SC
FRCC
SOURCE
SINK
FLOWS > 5%

SERTP

Southeastern Regional TRANSMISSION PLANNING

DESC – DEC 1000 MW

Transmission System Impacts – *SERTP*

Table 6: Transmission System Impacts - SERTP

Balancing Authority	Planning Level Cost Estimate
Associated Electric Cooperative (AECI)	$0
Duke Carolinas (DEC)	$281 Million
Duke Progress East (DEPE)	$0
Duke Progress West (DEPW)	$0
Louisville Gas & Electric and Kentucky Utilities (LG&E/KU)	$0
PowerSouth (PS)	$0
Southern (SBAA)	$0
Tennessee Valley Authority (TVA)	$0
SERTP TOTAL ($2022)	**$0**

32

SERTP

Southeastern Regional TRANSMISSION PLANNING

DESC – DEC 1000 MW

Significant Constraints Identified – *DEC*

Table 1: Significant Constraints - DEC

Potential Enhancement	Limiting Element	Rating (MVA)	Thermal Loadings (%) Without Request	With Request
P1	Lee Steam – Shady Grove Tie 100 kV TL (Lee Line)	132	88.1	94.5
P1	Lee Steam – Shady Grove Tie 100 kV TL (Piedmont Line)	132	94.5	101
P2	Clark Hill 115/100 kV Transformer	125	91.4	101.4
P3	Laurens Tie – Bush River Tie 100 kV TL	65	89.5	107.1
P4	Wateree Switching – Great Falls Switching 100 kV TL	116	89	130.4
NA*	Catawba Nuclear – Allen Steam 230 kV TL	1055	92.6	104.1

*Project to address is in the current expansion plan, but not in version 1 models
+Potential future constraints can be found in the Economic Studies Report on the SERTP Website

SERTP

Southeastern Regional TRANSMISSION PLANNING

DESC – DEC 1000 MW

Potential Enhancements Identified – *DEC*

Table 2: Potential Enhancements - DEC

Item	Potential Enhancement	Planning Level Cost Estimate
P1	**Lee Steam Station – Shady Grove Tie 100 kV T.L.** • Rebuild both Lee Steam Station – Shady Grove Tie 100 kV Transmission Lines with 1158 ACSS/TW rated at 200°C. Total rebuild length is 24.5 miles	**$90 Million**
P2	**Clark Hill 115/100 kV Transformer.** • Upgrade lowside terminal of the 115/100 kV transformer to improve rating	**$3 Million**
P3	**Laurens Tie – Bush River Tie 100 kV T.L.** • Rebuild 29.25 miles of the Laurens Tie – Bush River Tie 100 kV Transmission Lines with 1158 ACSS/TW rated at 200°C.	**$109 Million**
P4	**Wateree Switching Station–Great Falls Switching Station 100 kV T.L.** • Rebuild 19.8 miles of the Wateree Switching Station – Great Falls Switching Station 100 kV T.L. with 954 rated at 120°C	**$79 Million**
	DEC TOTAL ($2022)	**$ 281 Million**[1]

(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer could be greater than the total shown above if any of these projects are delayed or cancelled.

34

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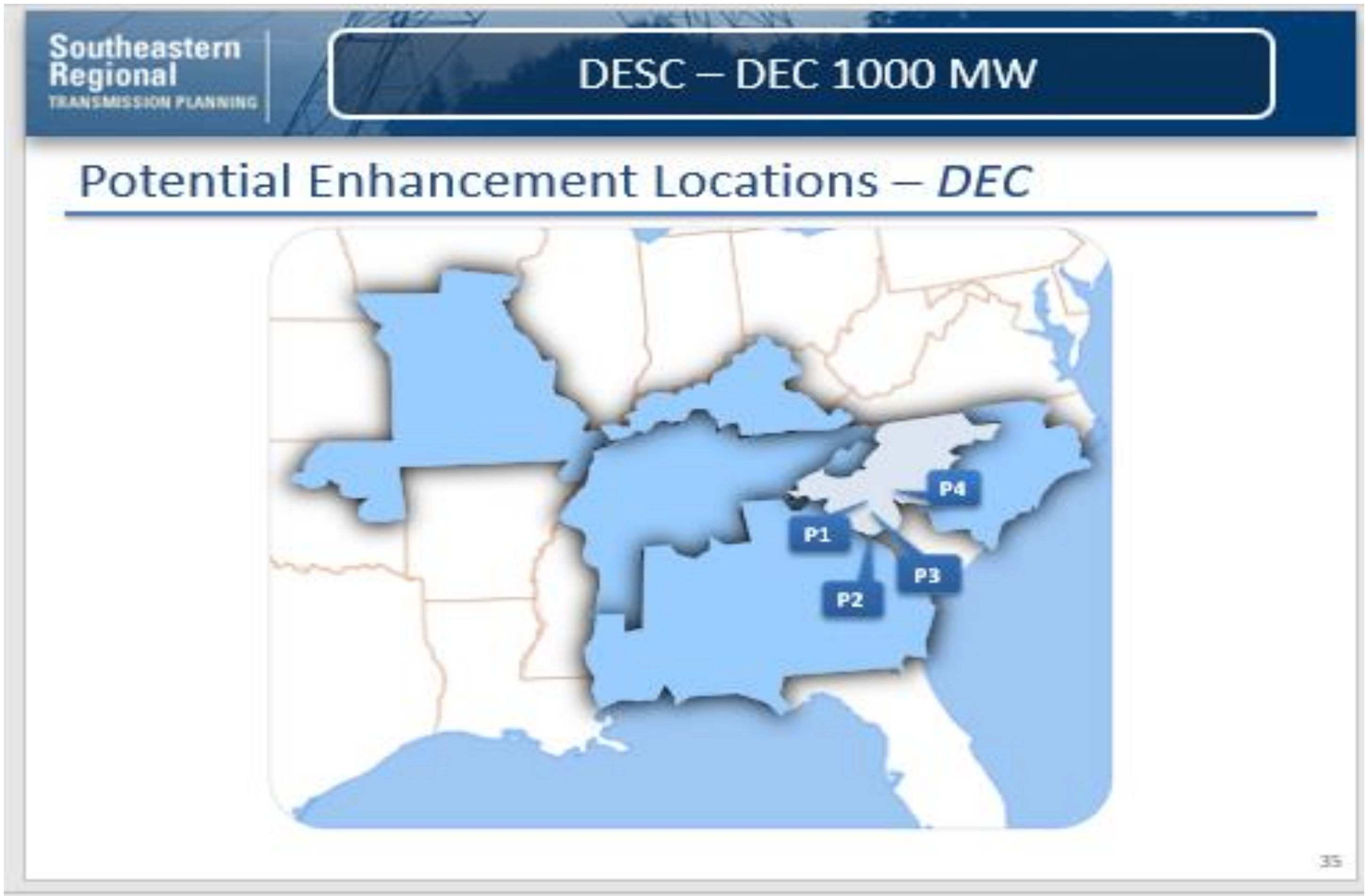
Southeastern
Regional
TRANSMISSION PLANNING
DESC – DEC 1000 MW
Potential Enhancement Locations – *DEC*
P1
P2
P3
P4
35

SERTP

Southeastern Regional TRANSMISSION PLANNING

DESC – DEC 1000 MW

Significant Constraint (P1) – *DEC*

36

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Southeastern Regional
TRANSMISSION PLANNING

DESC – DEC 1000 MW

Potential Enhancement (P1) – *DEC*

37

North Carolina Transmission Planning Collaborative

SERTP

Southeastern Regional
TRANSMISSION PLANNING

DESC – DEC 1000 MW

Potential Constraint (P2) – *DEC*

38

North Carolina Transmission Planning Collaborative

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Southeastern Regional Transmission Planning

DESC – DEC 1000 MW

Significant Enhancement (P2) – *DEC*

39

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Southeastern Regional
TRANSMISSION PLANNING

DESC – DEC 1000 MW

Significant Constraint (P3) – *DEC*

40

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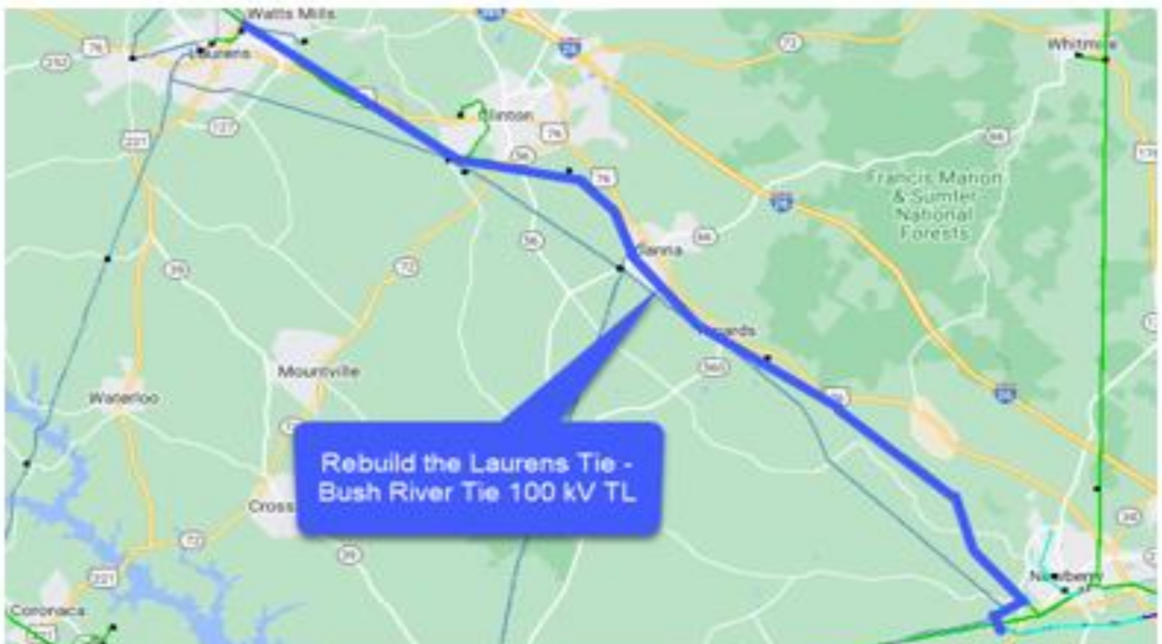
Southeastern Regional TRANSMISSION PLANNING

DESC – DEC 1000 MW

Potential Enhancement (P3) – *DEC*



41

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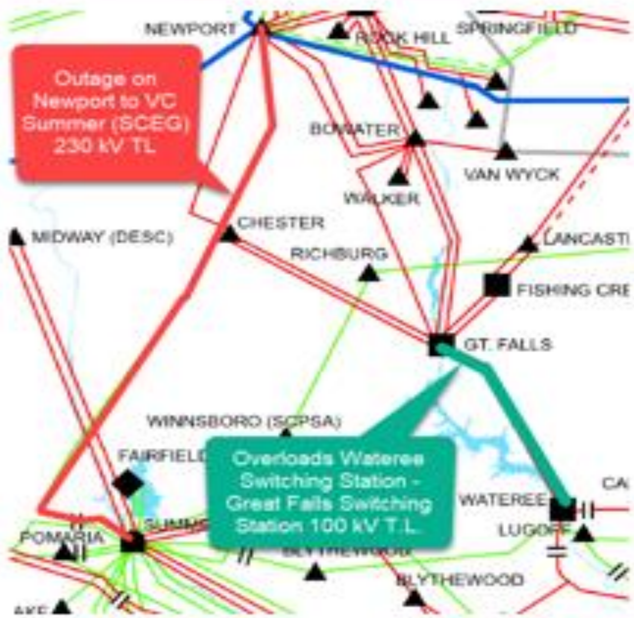
Southeastern Regional TRANSMISSION PLANNING

DESC – DEC 1000 MW

Significant Constraint (P4) – *DEC*



42

North Carolina Transmission Planning Collaborative

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Southeastern Regional
TRANSMISSION PLANNING

DESC – DEC 1000 MW

Potential Enhancement (P4) – *DEC*

43

SERTP

Southeastern Regional TRANSMISSION PLANNING

2022 Regional Analyses

List of Alternative Regional Transmission Projects

http://www.southeasternrtp.com/

EIPC

EIPC

https://www.energy.gov/gdo/national-transmission-planning-study

NERC

NERC

- Response to FERC Interconnection NOPR
- ERCOT 2022 Odessa Report

NERC

The ERO Enterprise asks that the Commission:

- (i) Modify the LGIP/SGIP and LGIA/SGIA to require:
  - a. Model validation with actual installed equipment prior to interconnection; and
  - b. A “true-up” of modeling and studies to address any discrepancies between what was studied and what is installed;
- (ii) Modify the LGIP/SGIP and LGIA/SGIA to require inclusion of electromagnetic transient (“EMT”) studies to ensure accurate modeling of nonsynchronous generation; and

NERC

- (iii) Modify the LGIP/SGIP and LGIA/SGIA to incorporate elements of NERC Reliability Standards, Reliability Guidelines, and IEEE standards ; and
- (iv) Enact the Commission's proposed enhancements to increase the efficiency and effectiveness of the interconnection queue

NERC

ERCOT Meeting Power Point

Questions ?

2022 TAG Work Plan

Rich Wodyka
Administrator

NCTPC Overview Schedule

Reliability Planning Process

- Evaluate current reliability problems and transmission upgrade plans
- Perform analysis, identify problems, and develop solutions
- Review Reliability Study Results

Local Economic Planning Process

- Propose and select Local Economic Studies and Public Policy Study scenarios
- Perform analysis, identify problems, and develop solutions
- Review Local Economic Study and Public Policy Results

Coordinated Plan Development

- Combine Reliability and Local Economic Study and Public Policy Results
- OSC publishes DRAFT Plan
- TAG review and comment
- OSC publishes FINAL Plan

TAG Meetings

1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter

January - February – March

➢ 2021 Study Update

- ✓ **Receive Final 2021 Collaborative Transmission Plan Report**
- ✓ **Receive Draft 2021 Public Policy Study Report**
  - – ***TAG provide input to the OSC on Public Policy Study results***

➢ 2022 Study – Finalize Study Scope of Work

- ✓ **Receive request from OSC to provide input on proposed Local Economic Study scenarios and interfaces for study**
  - – ***TAG provide input to the OSC on proposed Local Economic Study scenarios and interfaces for study***
- ✓ **Receive request from OSC to provide input in identifying any public policies that are driving the need for local transmission**
  - – ***TAG provide input to the OSC in identifying any public policies that are driving the need for local transmission for study***
- ✓ **Receive final 2022 Reliability Study Scope for comment**
  - – ***TAG review and provide comments to the OSC on the final 2022 Study Scope***

January - February – March

First Quarter TAG Meeting – March 28th

- **2021 Public Policy Study Analysis**
  - ✓ **Receive report on and discuss the final draft of the 2021 Public Policy Study Report**
- **2022 Study Update**
  - ✓ **Receive a report on the Local Economic Study scope and any public policy scenarios that are driving the need for local transmission for study**
  - ✓ **Receive a progress report on the Reliability Planning study activities and the final 2022 Study Scope**

April - May – June

Second Quarter TAG Meeting – June 27

- **2022 Study Update**
  - ✓ **Receive a progress report on study activities**
  - ✓ **Receive update status of the upgrades in the 2021 Collaborative Plan**
  - ✓ **TAG is invited to provide any additional comments or questions to the OSC on the 2022 Mid-Year Update to the 2021 Collaborative Transmission Plan and proposed RZEP Projects. Provide input by July 6, 2022 to Rich Wodyka (rich.wodyka@gmail.com)**

July - August – September

Third Quarter TAG Meeting – October 18

- **2022 Study Update**

  - ✓ **Receive a progress report on the study activities and Preliminary Reliability Study Results**

  - ✓ **TAG is requested to provide feedback to the OSC on the technical analysis performed, the problems identified as well as proposing alternative solutions to the problems identified. Provide input by November 4, 2022 to Rich Wodyka (rich.wodyka@gmail.com)**

October - November - December

<u>Fourth Quarter TAG Meeting – TBD</u>

➢ 2022 Study Update

- **TAG will receive feedback from the OSC on any alternative solutions that were proposed by TAG members**
- **Receive and discuss final draft of the 2022 Collaborative Transmission Plan Report**

➢ 2023 Study Scope

- **Discuss potential study scope scenarios for 2023 studies**

Questions ?

TAG
Open Forum Discussion

Comments or Questions ?