Southeastern Regional TRANSMISSION PLANNING

ECONOMIC PLANNING STUDIES
PRELIMINARY RESULTS

2015

# Southeastern Regional Transmission Planning (SERTP)

## ECONOMIC PLANNING STUDIES PRELIMINARY RESULTS

Associated Electric Cooperative Inc.

Dalton Utilities

Duke Energy

Georgia Transmission

LG&E KU

MEAG Power

OVEC IKEC

PowerSouth Energy Cooperative

Southern Company

TVA

**Original: September 14, 2015**
**Revised: September 22, 2015**

# Table of Contents

# I. Overview of Economic Planning Studies

## *Executive Summary*

The Regional Planning Stakeholder Group ("RPSG") identified three economic planning studies to be evaluated under the Southeastern Regional Transmission Planning ("SERTP") process. The SERTP Sponsors have performed analyses to assess potential constraints on the transmission systems of the participating transmission owners for the stakeholder requested economic planning studies selected by the Regional Planning Stakeholder Group ("RPSG"). The assessments include the identification of potentially limiting facilities, the impact of the transfers on these facilities, and the contingency conditions causing the limitations. The assessments also identify potential transmission enhancements within the footprint of the participating transmission owners necessary to accommodate the economic planning study requests, planning-level cost estimates, and the projected need-date for projects to accommodate the economic planning study requests. For economic study requests that involve multiple sources and/or sinks, separate analysis would be required to assess the transmission impacts of a singular source/sink included in these study requests. The information contained in this report does not represent a commitment to proceed with the recommended enhancements nor implies that the recommended enhancements could be implemented by the study dates. The assessment cases model the currently projected improvements to the transmission system. However, changes to system conditions and/or the transmission system expansion plans could also impact the results of this study. Planning staff of the participating transmission owners performed the assessments and the results are summarized in this report.

## *Study Assumptions*

The specific assumptions selected for these evaluations were:

- The load levels evaluated were Summer Peak unless otherwise indicated below. Additional load levels were evaluated as appropriate.
- Each request was evaluated for the particular year identified below, as selected by the RPSG
- The following economic planning studies were assessed:

A. **Santee Cooper Border to Duke – 500 MW**
   - **Year:** 2018
   - **Load Level:** Summer Peak
   - **Type of Transfer:** Load to Generation
   - **Source:** Uniform load scale within Santee Cooper
   - **Sink:** Generation within Duke using the participation factors shown in Table 1 below:

**Table 1: Duke – Participation Factors**

| Entity | Participation Factor (%) | MW Allocation |
|---|---|---|
| Duke Energy Carolinas | 61.6% | 308 |
| Duke Energy Progress East | 35.9% | 179 |
| Duke Energy Progress West | 2.5% | 13 |
| Total | 100.0% | 500 |

B. **TVA (Shelby) to Southern/TVA/Duke – 3500 MW**
   - **Year:** 2020
   - **Load Level:** Summer Peak
   - **Type of Transfer:** Generation to Generation
   - **Source:** A new generator interconnection to the existing Shelby 500 kV substation (TVA)
   - **Sink:** Generation within Southern Company (1200MW), TVA (1639MW), Duke Energy Carolinas (407MW), and Duke Energy Progress (254MW)

C. **Southern & SCE&G to PJM Border – 500 MW**
   - **Year:** 2020
   - **Load Level:** Summer Peak
   - **Type of Transfer:** Generation/Load to Load
   - **Source:** Generation within Southern Company and uniform load scale within SCE&G using the participation factors shown in Table 2 below:
   - **Sink:** Uniform load scale within PJM using the participation factors shown in Table 3 below:

**Table 2: Southern Company & SCE&G – Participation Factors**

| Entity | Participation Factor (%) | MW Allocation |
|---|---|---|
| Southern Company | 50.0% | 250 |
| SCE&G | 50.0% | 250 |
| Total | 100.0% | 500 |

**Table 3: PJM Border – Participation Factors**

| PJM Area # | Area # | Participation Factor (%) | MW Allocation |
|---|---|---|---|
| Allegheny Power | 201 | 5.56% | 28 |
| American Transmission Systems | 202 | 8.24% | 41 |
| American Electric Power | 205 | 13.23% | 66 |
| Dayton Power & Light | 209 | 2.11% | 11 |
| Duke Energy Ohio & Kentucky | 212 | 3.44% | 17 |
| Duquesne Light Company | 215 | 1.88% | 9 |
| Commonwealth Edison | 222 | 14.14% | 71 |
| Pennsylvania Electric Company | 226 | 1.81% | 9 |
| Metropolitan Edison Company | 227 | 1.87% | 9 |
| Jersey Central Power & Light | 228 | 3.69% | 19 |
| PPL Electric Utilities | 229 | 4.48% | 22 |
| PECO Energy Company | 230 | 5.47% | 27 |
| PSE&G | 231 | 6.30% | 32 |
| Baltimore Gas & Electric | 232 | 4.44% | 22 |
| Potomac Electric Power | 233 | 4.16% | 21 |
| Atlantic Electric | 234 | 1.67% | 8 |
| Delmarva Power & Light | 235 | 2.59% | 13 |
| UGI Utilities | 236 | 0.12% | 1 |
| Rockland Electric | 237 | 0.29% | 2 |
| East Kentucky Power Cooperative | 320 | 1.46% | 7 |
| Dominion Virginia Power | 345 | 13.04% | 65 |
| **Total** | | **100.00%** | **500** |

## *Study Criteria*

The study criteria with which results were evaluated included the following reliability elements:

- NERC Reliability Standards
- Individual company criteria (voltage, thermal, stability, and short circuit as applicable)

## Case Development

- For all evaluations, the "2015 Series, Version 2 SERTP Models" were used as a starting point for the analysis of the Economic Planning Scenarios.
- For the economic planning study request sourcing from a new generator interconnection to the existing Shelby 500kV substation in TVA, a new Lagoon Creek – Jackson 500 kV transmission line in TVA was modeled per RPSG request.

## Methodology

Initially, power flow analyses were performed based on the assumption that thermal limits were the controlling limit for the reliability plan. Voltage, stability, and short circuit studies were performed if circumstances warranted.

## Technical Analysis and Study Results

The technical analysis was performed in accordance with the study methodology. Results from the technical analysis were reported throughout the study area to identify transmission elements approaching their limits such that all participating transmission owners and stakeholders would be aware of any potential issues and, as such, suggest appropriate solutions to address the potential issues if necessary. The SERTP reported, at a minimum, results on elements of 115 kV and greater within the participating transmission owners' footprint based on:

- Thermal loadings greater than 90% for facilities that are negatively impacted by the proposed transfers and change by +5% of applicable rating with the addition of the transfer(s)
- Voltages appropriate to each participating transmission owner's planning criteria (with potential solutions if criteria were violated)

## Assessment and Problem Identification

The participating transmission owners ran assessments in order to identify any constraints within the participating transmission owners' footprint as a result of the economic planning study requests. Each participating transmission owner applied their respective reliability criteria for its facilities and any constraints identified were documented and reviewed by each participating transmission owner.

## *Solution Development*

- The participating transmission owners, with input from the stakeholders, will develop potential solution alternatives due to the economic planning studies requested by the RPSG.
- The participating transmission owners will test the effectiveness of the potential solution alternatives using the same cases, methodologies, assumptions and criteria described above.
- The participating transmission owners will develop rough, planning-level cost estimates and in-service dates for the selected solution alternatives.

## *Report on the Study Results*

The participating transmission owners compiled all the study results and prepared a report for review by the stakeholders. The report contains the following:

- A description of the study approach and key assumptions for the Economic Planning Scenarios
- For each economic planning study request, the results of that study including:
    1. Limit(s) to the transfer
    2. Selected solution alternatives to address the limit(s)
    3. Rough, planning-level cost estimates and in-service dates for the selected transmission solution alternatives

# II. Economic Planning Study Results

***Santee Cooper to Duke***

*2018*

*500 MW*

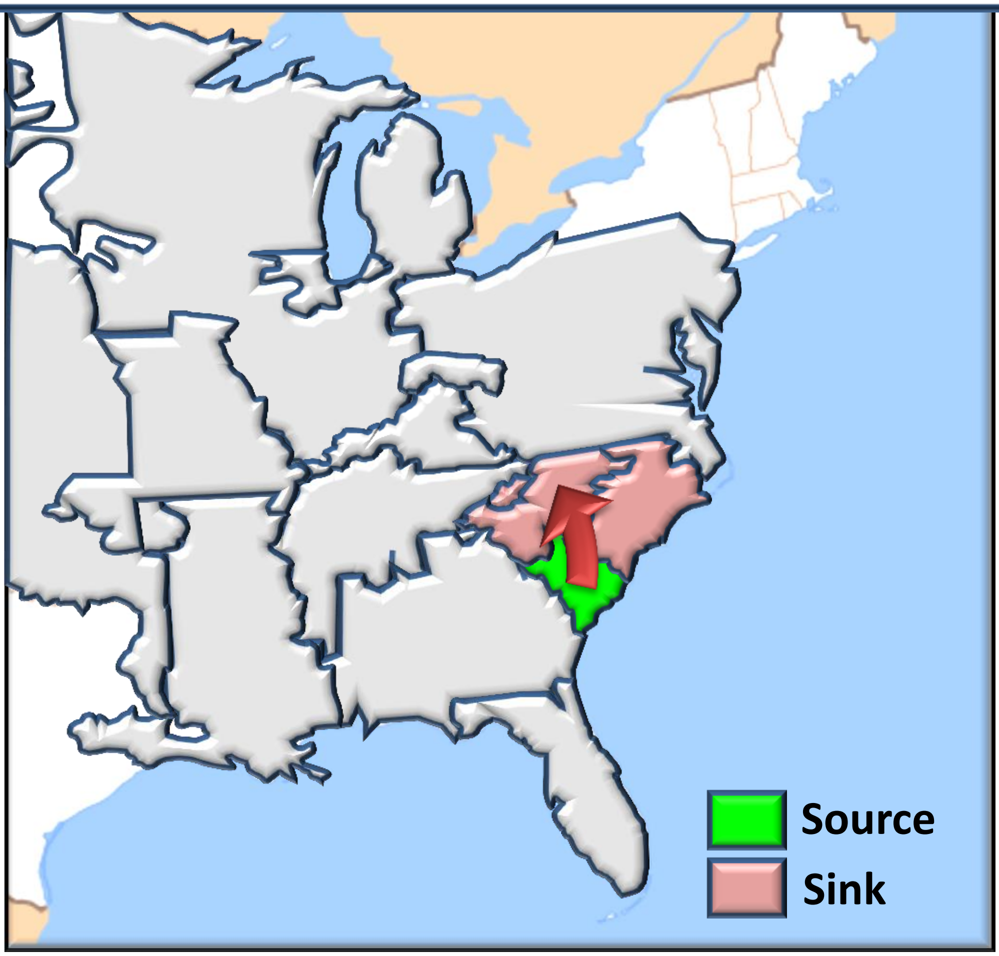
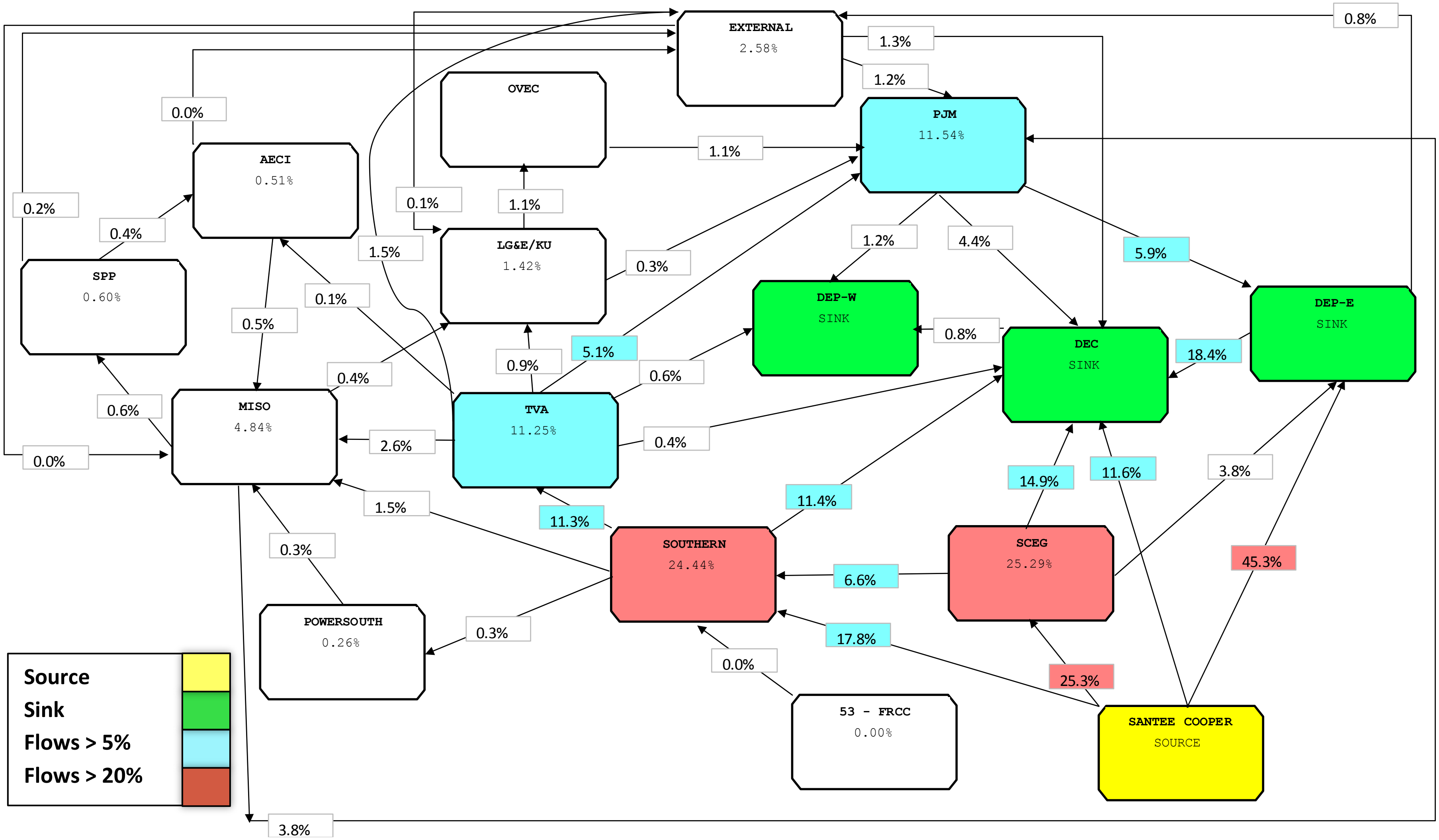


**Table II.1.1** Total Cost Identified by the SERTP Sponsors

| Balancing Authority | Planning Level Cost Estimate |
|---|---|
| Associated Electric Cooperative (AECI) | $0 |
| Duke Carolinas (DEC) | $10,000,000 |
| Duke Progress East (DEPE) | $0 |
| Duke Progress West (DEPW) | $0 |
| Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) | $0 |
| Ohio Valley Electric Cooperative (OVEC) | $0 |
| PowerSouth (PS) | $0 |
| Southern (SBA) | $0 |
| Tennessee Valley Authority (TVA) | $0 |
| **TOTAL ($2015)** | **$10,000,000** |

**Diagram II.1.1** **Transfer Flows with the SERTP**



# *Associated Electric Cooperative Balancing Authority (AECI) Results*

## Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Santee Cooper to Duke | 500 MW | Santee Cooper Border | Duke | 2018 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models:  Summer Peak | | | | |

## Transmission System Impacts

The 500 MW transfer from Santee Cooper to Duke results in no thermal constraints attributable to the requested transfer.

### Table II.2.1. Pass 0 – Transmission System Impacts with No Enhancements – *AECI*

The following table identifies significant **AECI** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| AECI | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table II.2.2 Potential Solutions for Identified Problems – AECI**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **AECI TOTAL ($2015)** | | | **$0 (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.

## *Duke Carolinas Balancing Authority (DEC) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Santee Cooper to Duke | 500 MW | Santee Cooper Border | Duke | 2018 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

Table II.3.1 below identifies thermal constraints attributable to the requested transfer for the contingency and scenario that resulted in the highest facility loading for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

### Table II.3.1 Pass 0 – Transmission System Impacts with No Enhancements – *DEC*

The following table identifies significant **DEC** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| DEC | 306041 LEE 100.00 306151 BUS 306151 100.00 1 | 65 | 81.0 | 103.3 | 306041 LEE 100.00 308492 PERRYT B 100.00 1 | 1 | P1 |

**Scenario Explanations:**

1. Summer Peak Case

**Table II.3.2 Pass 1 – Transmission System Impacts with Proposed Enhancements – *DEC***

The following table depicts loadings of **DEC** transmission facilities that could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the study year.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| DEC | 306275 IND 306275 100.00 306307 WALDEN T 100.00 1 | 91 | 95.7 | 99.8 | 308800 BUS 308800 306198 TIGER 1 | 1 | -- |
| DEC | 306041 LEE 100.00 308492 PERRYT B 100.00 1 | 249 | 97.0 | 99.2 | 306041 LEE 308715 LAUECLIC 1 | 1 | -- |
| DEC | 306335 6RIPP 230.00 308652 6DIXON_SCH 230.00 1 | 671 | 91.2 | 94.4 | 308652 6DIXON_S 306335 6RIPP 2 | 2 | -- |
| DEC | 306335 6RIPP 230.00 308652 6DIXON_SCH 230.00 2 | 671 | 91.2 | 94.4 | 308652 6DIXON_S 306335 6RIPP 1 | 2 | -- |
| DEC | 306172 LAUEC25 100.00 306216 LAUEC31 100.00 1 | 120 | 90.6 | 94.1 | 306133 CANE CRK 306186 PELHAM R 1 | 1 | -- |
| DEC | 306183 OAKVALE 100.00 306195 SHADY GR 100.00 1 | 292 | 91.3 | 92.6 | 306183 OAKVALE 306195 SHADY GR 2 | 3 | -- |
| DEC | 306183 OAKVALE 100.00 306195 SHADY GR 100.00 2 | 292 | 91.3 | 92.6 | 306183 OAKVALE 306195 SHADY GR 1 | 3 | -- |
| DEC | 306004 6CENTRAL 230.00 306104 6SHADYTB 230.00 1 | 464 | 90.8 | 92.5 | 306004 6CENTRAL 306105 6SHADYTW 2 | 4 | -- |
| DEC | 306004 6CENTRAL 230.00 306105 6SHADYTW 230.00 2 | 464 | 90.8 | 92.5 | 306004 6CENTRAL 306104 6SHADYTB 1 | 4 | -- |
| DEC | 306041 LEE 100.00 306151 BUS 306151 100.00 1 | 120 | 86.4 | 92.1 | 306041 LEE 308492 PERRYT B 1 | 1 | -- |
| DEC | 306066 TOXAWAY 100.00 308622 LEE CC 100.00 1 | 105 | 88.7 | 91.8 | 306017 CENTRAL 306041 LEE 1 | 4 | -- |
| DEC | 306066 TOXAWAY 100.00 308622 LEE CC 100.00 2 | 105 | 88.7 | 91.8 | 306017 CENTRAL 306041 LEE 1 | 4 | -- |

**Scenario Explanations:**

1. No Unit Offline, Summer Peak Case
2. Buck CC #11 Offline / #10 Derated, Summer Peak Case
3. Cliffside Unit #5 Offline, Summer Peak Case
4. Lee Combine Cycle Plant Offline, Summer Peak Case

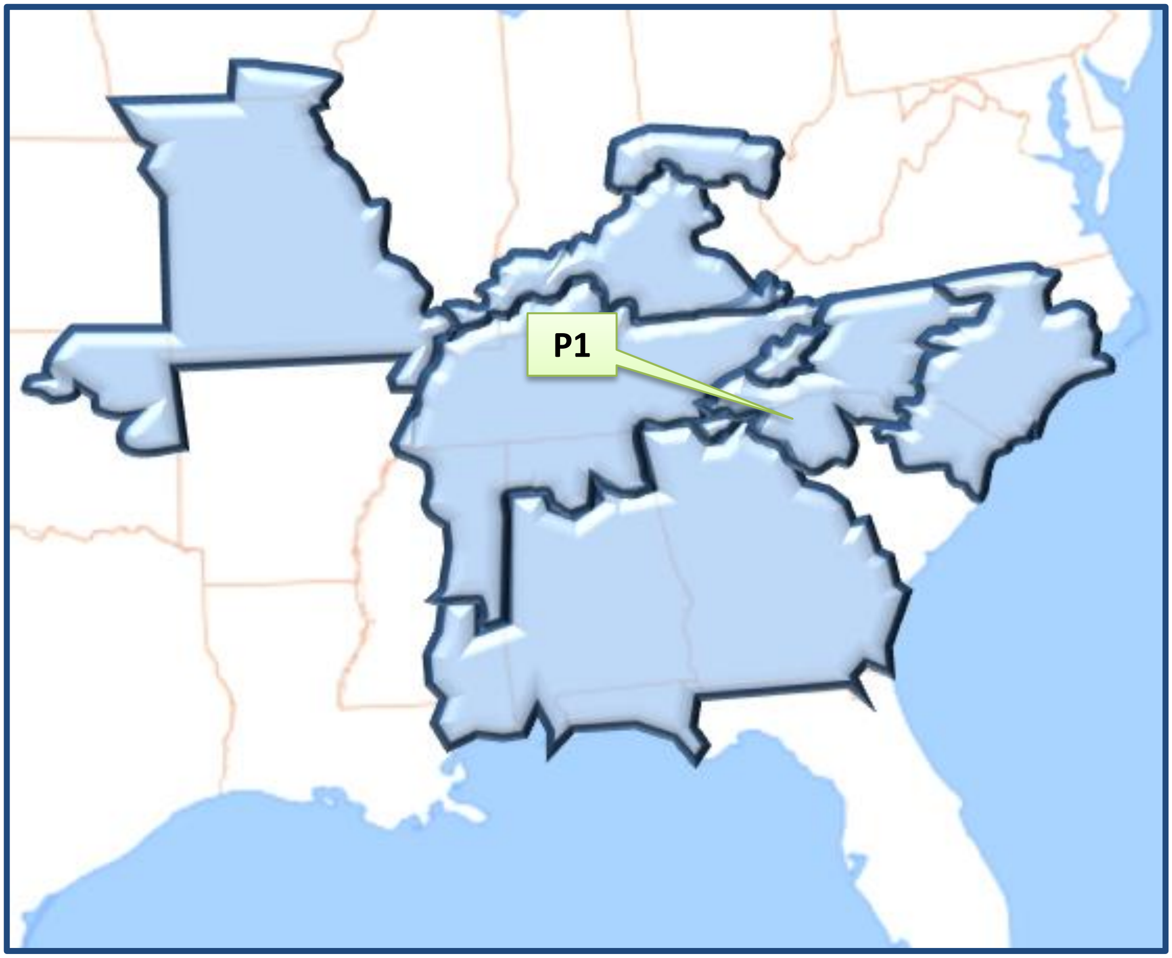
**Table II.3.3 Potential Solutions for Identified Problems – DEC**

The following projects are identified as potential solutions to address the identified constraints and are based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| **P1** | **Lee – Shady Grove 100 kV T.Ls.**<br>• Rebuild 9.62 miles of double circuit 100kV transmission lines from Lee to Estes Tap to 477 ACSS/TW | 2018 | $10,000,000 |
| **DEC TOTAL ($2015)** | | | **$10,000,000 [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.

**Diagram II.3.1** **Approximate Location of Potential Solution – DEC**



# *Duke Progress East Balancing Authority (DEPE) Results*

## Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Santee Cooper to Duke | 500 MW | Santee Cooper Border | Duke | 2018 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

## Transmission System Impacts

The 500 MW transfer from Santee Cooper to Duke results in no thermal constraints attributable to the requested transfer.

## Table II.4.1 Pass 0 – Transmission System Impacts with No Enhancements – *DEPE*

The following table depicts loadings of **DEPE** transmission facilities that could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the study year.

| | | | Thermal Loadings (%) | | | | |
|---|---|---|---|---|---|---|---|
| **AREA** | **Limiting Element** | **Rating (MVA)** | **Without Request** | **With Request** | **Contingency** | **Scenario** | **Project** |
| DEPE | 304348 6ROCKHAM230T 230 304638 6WADSBOR TA1 230 1 | 542 | 91.9 | 93.0 | 304348 6ROCKHAM230T 230 305046 6E11-ELLERBE 230 1 | 2 | -- |
| DEPE | 304020 6BRUN2 230 T 230 305005 6E1-SOUTHPOR 230 1 | 478 | 87.4 | 91.7 | 304020 6BRUN2 230 T 230 305009 6E1-DAWSCREE 230 1 | 1 | -- |

**Scenario Explanations:**

1. Brunswick Unit #1 Offline, Summer Peak Case
2. Harris Offline, Summer Peak Case

**Table II.4.2 Potential Solutions for Identified Problems – DEPE**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| DEPE TOTAL ($2015) | | | $0[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.

# *Duke Progress West (DEPW) Results*

## Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Santee Cooper to Duke | 500 MW | Santee Cooper Border | Duke | 2018 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

## Transmission System Impacts

The 500 MW transfer from Santee Cooper to Duke results in no thermal constraints attributable to the requested transfer.

## Table II.5.1 Pass 0 – Transmission System Impacts with No Enhancements – *DEPW*

The following table identifies significant **DEPW** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| DEPW | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table II.5.2 Potential Solutions for Identified Problems – DEPW**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | **None Identified** | -- | $0 |
| **DEPW TOTAL ($2015)** | | | **$0[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.

## *Louisville Gas & Electric and Kentucky Utilities Balancing Authority (LG&E/KU) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Santee Cooper to Duke | 500 MW | Santee Cooper Border | Duke | 2018 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 500 MW transfer from Santee Cooper to Duke results in no thermal constraints attributable to the requested transfer.

### Table II.6.1 Pass 0 – Transmission System Impacts with No Enhancements – *LG&E/KU*

The following table identifies significant **LG&E/KU** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| LG&E/KU | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table II.6.2 Potential Solutions for Identified Problems – LG&E/KU**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| LG&E/KU TOTAL ($2015) | | | $0 [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.

## *Ohio Valley Electric Corporation Balancing Authority (OVEC) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Santee Cooper to Duke | 500 MW | Santee Cooper Border | Duke | 2018 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 500 MW transfer from Santee Cooper to Duke results in no thermal constraints attributable to the requested transfer.

### Table II.7.1 Pass 0 – Transmission System Impacts with No Enhancements – *OVEC*

The following table identifies significant **OVEC** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| OVEC | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table II.7.2 Potential Solutions for Identified Problems – OVEC**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **OVEC TOTAL ($2015)** | | | **$0 [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.

# *PowerSouth Balancing Authority (PS) Results*

## Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Santee Cooper to Duke | 500 MW | Santee Cooper Border | Duke | 2018 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

## Transmission System Impacts

The 500 MW transfer from Santee Cooper to Duke results in no thermal constraints attributable to the requested transfer.

## Table II.8.1 Pass 0 – Transmission System Impacts with No Enhancements – *PS*

The following table identifies significant **PS** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| PS | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table II.8.2 Potential Solutions for Identified Problems – PS**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **PS TOTAL ($2015)** | | | **$0 [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.

## *Southern Balancing Authority (SBA) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Santee Cooper to Duke | 500 MW | Santee Cooper Border | Duke | 2018 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 500 MW transfer from Santee Cooper to Duke results in no thermal constraints attributable to the requested transfer.

### Table II.9.1 Pass 0 – Transmission System Impacts with No Enhancements – *SBA*

The following table identifies significant **SBA** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| SBA | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table II.9.2 Potential Solutions for Identified Problems – SBA**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **SBA TOTAL ($2015)** | | | **$0** (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.

## Interchange Assumptions – SBA

**Table II.9.3 Incremental Transactions Preserved to those Modeled in Version 2 SERTP Models**

| OASIS Ref. # | POR | POD | Amount (MW) |
|---|---|---|---|
| NS1117 | DUKE | PS LOAD on SOCO | 50 |
| NS1119 | MISO | SMEPA LOAD on SOCO | 125 |
| NS1117 | MISO | PS LOAD on SOCO | 150 |
| NL1112 | MISO | SOCO | 500 |
| 147615 | DUKE | OPC LOAD | 465 |
| 147613 | TVA | OPC LOAD | 310 |
| NL1132 | TVA | SOCO | 500 |
| NL1132 | MISO | SOCO | 250 |
| 79662312 | SOCO | DUKE | 27 |
| 80832892 | SOCO | DUKE | 132 |
| 80600833 | SOCO | DUKE | 132 |
| 959841 | SOCO | DUKE | 44 |
| 79822666 | GTC | TVA | 200 |
| NL1112 | SCPSA | SOCO | 50 |

**Table II.9.4 Capacity Benefit Margin Preserved (CBM)**

| SERTP Sponsor | Interface | Amount (MW) |
|---|---|---|
| Southern | Duke | 350 |
| Southern | TVA | 400 |
| Southern | MISO | 100 |
| Southern | SCPSA | 125 |
| Southern | SCEG | 75 |

**Table II.9.5 Transmission Reliability Margins Preserved (TRM)**

| SERTP Sponsor | Interface | Amount (MW) |
|---|---|---|
| Southern | From Duke | 200 |
| GTC | From Duke | 109 |
| MEAG | From Duke | 26 |
| Dalton | From Duke | 3 |
| Southern | From MISO | 216 |
| Southern | From TVA | 218 |
| GTC | From TVA | 48 |
| MEAG | From TVA | 11 |
| Dalton | From TVA | 1 |

# *Tennessee Valley Authority Balancing Authority (TVA) Results*

## Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Santee Cooper to Duke | 500 MW | Santee Cooper Border | Duke | 2018 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

## Transmission System Impacts

The 500 MW transfer from Santee Cooper to Duke results in no thermal constraints attributable to the requested transfer.

## Table II.10.1 Pass 0 – Transmission System Impacts with No Enhancements – *TVA*

The following table identifies significant **TVA** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| TVA | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table II.10.2 Potential Solutions for Identified Problems – TVA**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **TVA TOTAL ($2015)** | | | **$0** (1) |

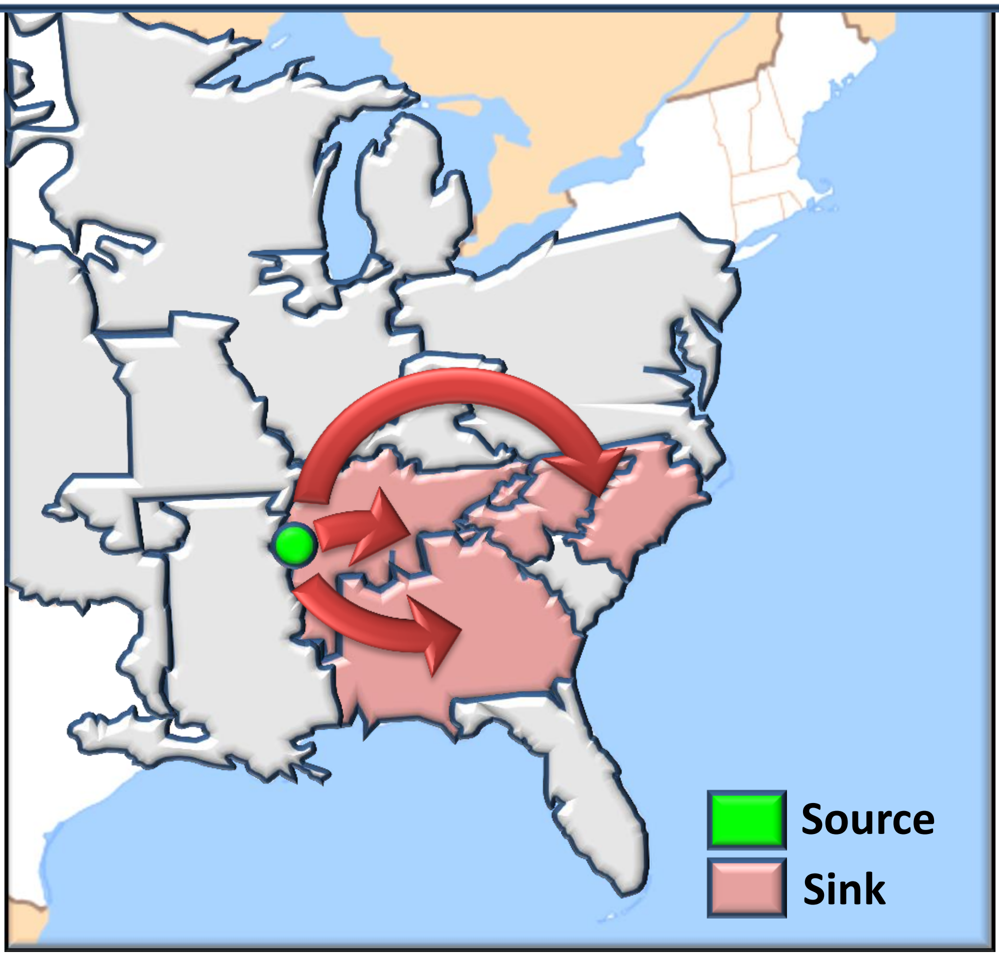
(1) Total planning level cost estimate does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by June 1st of the study year. The studied transfer depends on these projects being in-service, and the cost to support the study transfer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

# III. Economic Planning Study Results

***TVA (Shelby) to Southern/TVA/Duke***

*2020*

*3500 MW*

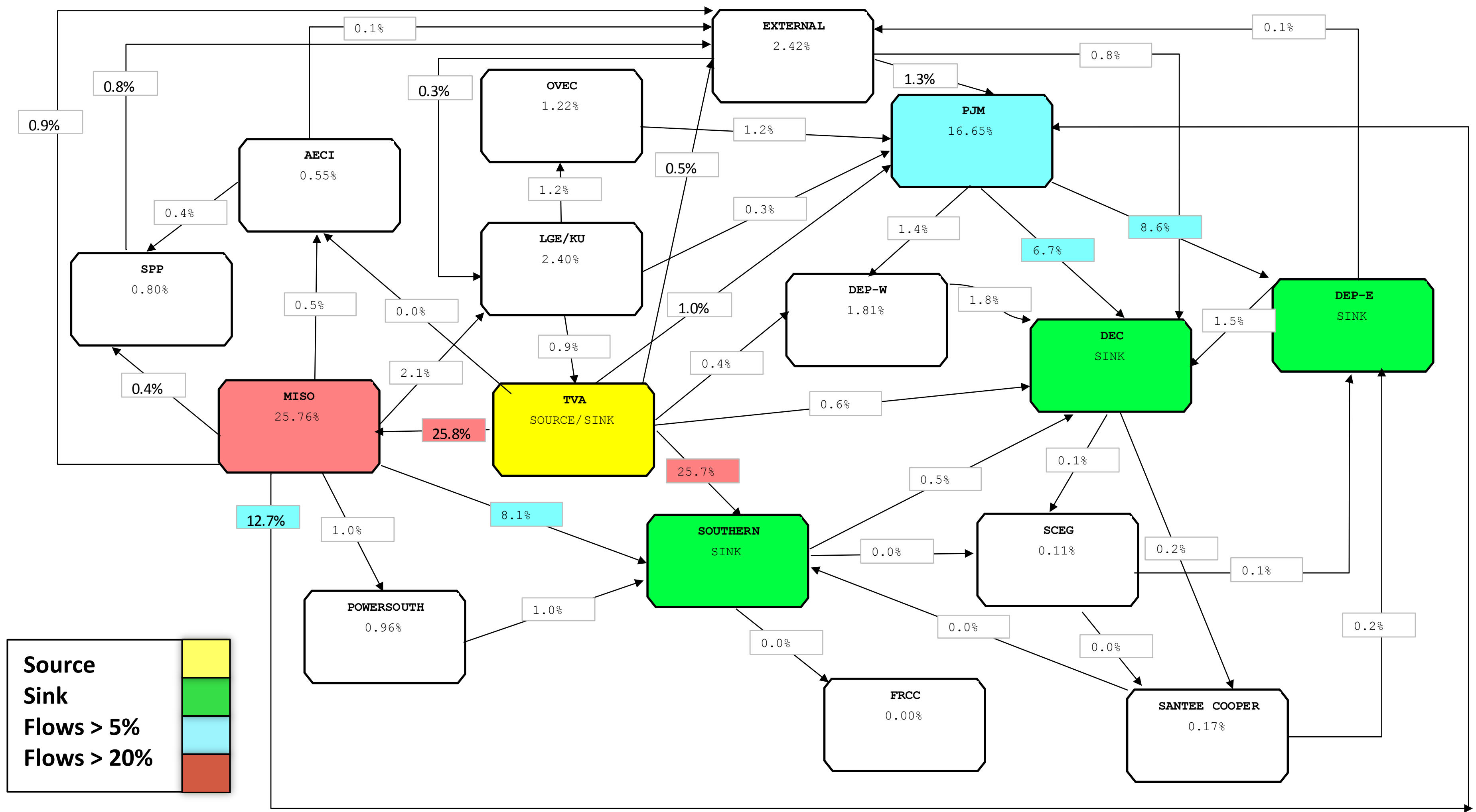


<u>Table III.1.1.</u> **Total Cost Identified by the SERTP Sponsors**

| Balancing Authority | Planning Level Cost Estimate |
|---|---|
| Associated Electric Cooperative (AECI) | $0 |
| Duke Carolinas (DEC) | $0 |
| Duke Progress East (DEPE) | $0 |
| Duke Progress West (DEPW) | $0 |
| Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) | $0 |
| Ohio Valley Electric Cooperative (OVEC) | $0 |
| PowerSouth (PS) | $0 |
| Southern (SBA) | $181,500,000 |
| Tennessee Valley Authority (TVA) | $141,000,000 [1] |
| **TOTAL ($2015)** | **$322,500,000** |

(1) This cost includes the Lagoon Creek – Jackson 500 kV T.L. project, which has been modeled within the SERTP economic study at the request of the RPSG and is not a part of TVA's expansion plan. The estimated cost of this project has been included in the total project cost of the economic study.

**Diagram III.1.1.** **Transfer Flows with the SERTP**



## *Associated Electric Cooperative Balancing Authority (AECI) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| TVA (Shelby) to Southern/TVA/Duke | 3500 MW | TVA (Shelby) | Southern/TVA/Duke | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 3500 MW transfer results in no thermal constraints attributable to the requested transfer.

### Table III.2.1 Pass 0 – Transmission System Impacts with No Enhancements – *AECI*

The following table identifies significant **AECI** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| AECI | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table III.2.2 Potential Solutions for Identified Problems – AECI**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **AECI TOTAL ($2015)** | | | **$0** (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.

## *Duke Carolinas Balancing Authority (DEC) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| TVA (Shelby) to Southern/TVA/Duke | 3500 MW | TVA (Shelby) | Southern/TVA/Duke | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 3500 MW transfer results in no thermal constraints attributable to the requested transfer.

### Table III.3.1. Pass 0 – Transmission System Impacts with No Enhancements – *DEC*

The following table depicts loadings of **DEC** transmission facilities that could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the study year.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| DEC | 306578 ENRG U19 100.00 306652 STONEWATER 100.00 1 | 120 | 92.2 | 94.5 | 306469 LINCOLNT 308946 BUS 308946 1 | 1 | - |
| DEC | 306164 HORSESHO 100.00 308740 ASHVHWYW 100.00 1 | 117 | 88.2 | 93.8 | 306164 HORSESHO 308471 NIXRDTAP 1 | 2 | - |
| DEC | 306763 MITCHL R 100.00 306835 SRYYDKN7 100.00 1 | 105 | 91.6 | 93.5 | 306763 MITCHL R 308027 WH PLAIN 1 | 3 | - |
| DEC | 306709 BUS 306709 100.00 306758 MADISON 100.00 1 | 120 | 90.6 | 91.6 | 306809 WALNUT C 306753 BUS 306753 1 | 4 | - |
| DEC | 306758 MADISON 100.00 308021 BUS 308021 100.00 1 | 120 | 90.6 | 91.6 | 306809 WALNUT C 308909 BUS 308909 1 | 4 | - |
| DEC | 306737 DAN RIV 100.00 306810 WENTWRTH 100.00 1 | 96 | 90.4 | 91.5 | 309434 1N GRNB 309525 NGB3 3 | 4 | - |
| DEC | 306155 GREENVLE 100.00 306182 N GRNVLE 100.00 2 | 207 | 90.1 | 91.1 | 306182 N GRNVLE 306155 GREENVLE 3 | 5 | - |
| DEC | 306155 GREENVLE 100.00 306182 N GRNVLE 100.00 3 | 207 | 90.1 | 91.1 | 306182 N GRNVLE 306155 GREENVLE 2 | 5 | - |

**Scenario Explanations:**

1. Marshall Unit #3 Offline, Summer Peak Case
2. Cliffside Unit #5 Offline, Summer Peak Case
3. Belews Unit #1 Offline, Summer Peak Case
4. Buck CC Offline, Summer Peak Case
5. Lee CC Offline, Summer Peak Case

**Table III.3.2 Potential Solutions for Identified Problems – DEC**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **DEC TOTAL ($2015)** | | | **$0** (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.

# *Duke Progress East Balancing Authority (DEPE) Results*

## Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| TVA (Shelby) to Southern/TVA/Duke | 3500 MW | TVA (Shelby) | Southern/TVA/Duke | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

## Transmission System Impacts

The 3500 MW transfer results in no thermal constraints attributable to the requested transfer.

## Table III.4.1 Pass 0 – Transmission System Impacts with No Enhancements – *DEPE*

The following table depicts loadings of **DEPE** transmission facilities that could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the study year.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| DEPE | 304716 3CAMDEN TAP 115 304725 3CAMDEN115 T 115 1 | 107 | 95.3 | 97.7 | 304725 3CAMDEN115 T 115 304731 3IND104 115 1 | 2 | -- |
| DEPE | 304020 6BRUN2 230 T 230 305005 6E1-SOUTHPOR 230 1 | 478 | 89.0 | 93.6 | 304020 6BRUN2 230 T 230 305009 6E1-DAWSCREE 230 1 | 1 | -- |
| DEPE | 304615 6BARNCRK E T 230 304621 6TOWN CRK TT 230 2 | 600 | 87.8 | 92.5 | 304020 6BRUN2 230 T 230 305005 6E1-SOUTHPOR 230 1 | 1 | -- |
| DEPE | 304731 3IND104 115 304732 3ELGIN TAP 115 1 | 95 | 88.6 | 91.7 | 304716 3CAMDEN TAP 115 304725 3CAMDEN115 T 115 1 | 2 | -- |

**Scenario Explanations:**

1. Brunswick Unit #1 Offline, Summer Peak Case
2. Harris Offline, Summer Peak Case

**Table III.4.2 Potential Solutions for Identified Problems – DEPE**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **DEPE TOTAL ($2015)** | | | **$0** (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.

## *Duke Progress West (DEPW) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| TVA (Shelby) to Southern/TVA/Duke | 3500 MW | TVA (Shelby) | Southern/TVA/Duke | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 3500 MW transfer results in no thermal constraints attributable to the requested transfer.

### Table III.5.1 Pass 0 – Transmission System Impacts with No Enhancements – *DEPW*

The following table identifies significant **DEPW** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| DEPW | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table III.5.2 Potential Solutions for Identified Problems – DEPW**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **DEPW TOTAL ($2015)** | | | **$0** (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.

## *Louisville Gas & Electric and Kentucky Utilities Balancing Authority (LG&E/KU) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| TVA (Shelby) to Southern/TVA/Duke | 3500 MW | TVA (Shelby) | Southern/TVA/Duke | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 3500 MW transfer results in no thermal constraints attributable to the requested transfer.

### Table III.6.1 Pass 0 – Transmission System Impacts with No Enhancements – *LG&E/KU*

The following table identifies significant **LG&E/KU** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| LG&E/KU | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table III.6.2 Potential Solutions for Identified Problems – LG&E/KU**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **LG&E/KU TOTAL ($2015)** | | | **$0** (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.

## *Ohio Valley Electric Corporation Balancing Authority (OVEC) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| TVA (Shelby) to Southern/TVA/Duke | 3500 MW | TVA (Shelby) | Southern/TVA/Duke | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 3500 MW transfer results in no thermal constraints attributable to the requested transfer.

### Table III.7.1 Pass 0 – Transmission System Impacts with No Enhancements – *OVEC*

The following table identifies significant **OVEC** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| OVEC | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table III.7.2 Potential Solutions for Identified Problems – OVEC**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **OVEC TOTAL ($2015)** | | | **$0** (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.

## *PowerSouth Balancing Authority (PS) Results*

**Study Structure and Assumptions**

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| TVA (Shelby) to Southern/TVA/Duke | 3500 MW | TVA (Shelby) | Southern/TVA/Duke | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

**Transmission System Impacts**

The 3500 MW transfer results in no thermal constraints attributable to the requested transfer.

**Table III.8.1 Pass 0 – Transmission System Impacts with No Enhancements – *PS***

The following table identifies significant **PS** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| PS | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table III.8.2 Potential Solutions for Identified Problems – PS**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| PS TOTAL ($2015) | | | $0 (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.

## *Southern Balancing Authority (SBA) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| TVA (Shelby) to Southern/TVA/Duke | 3500 MW | TVA (Shelby) | Southern/TVA/Duke | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

Table III.9.1 below identifies thermal constraints attributable to the requested transfer for the contingency and scenario that resulted in the highest facility loading for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

**Table III.9.1 Pass 0 – Transmission System Impacts with No Enhancements – *SBA***

The following table identifies significant **SBA** constraints without any enhancements to the transmission system.

| | | | Thermal Loadings (%) | | | | |
|---|---|---|---|---|---|---|---|
| **AREA** | **Limiting Element** | **Rating (MVA)** | **Without Request** | **With Request** | **Contingency** | **Scenario** | **Project** |
| SBA | 384121 5FAYET TS 161 384127 5FAY COTN 161 1 | 193 | 105.6[1] | 133.5 | 384157 8MILLER8 500 385307 8WVERN SS8 500 1 | 5 | P1 |
| SBA | 388420 3NASA 115 388426 3LOGTWN W3 115 1 | 216 | 110.7[1] | 120.6 | 388400 6KILN 6 230 388425 6LOGTWN W6 230 1 | 1 | P2 |
| SBA | 384131 5OAKMANTP 161 384135 5GORGAS 161 1 | 193 | 93.4 | 123.0 | 384157 8MILLER8 500 385307 8WVERN SS8 500 1 | 5 | P1 |
| SBA | 336898 3MORTON 115 388114 3FORINDT2 115 1 | 155 | 104.1[1] | 119.0 | 360631 8FRENCH CAMP 500 360654 8CHOCTAW MS 500 1 | 2 | P3 |
| SBA | 380199 6OOSTANAULA 230 381122 6DALTON 6 230 1 | 664 | 93.6 | 109.4 | 380021 8MOSTELLER 500 382499 8CONASAUGA 500 1 | 3 | P4 |
| SBA | 384241 6LEEDSTS6 230 385039 6ARGO DS 230 1 | 602 | 98.0 | 109.0 | 384157 8MILLER8 500 384375 8S.BESS 8 500 1 | 4 | P5 |
| SBA | 360283 5ALBERTVILLE 161 384332 5ATTALLA5 161 1[2] | 193 | 81.3 | 108.3 | 380021 8MOSTELLER 500 382499 8CONASAUGA 500 1 | 8 | P6 |
| SBA | 303222 6ANGIE 230 388270 6HATBG SW6 230 1 | 463 | 96.1 | 107.6 | 303223 6FR_BRANCH 230 336137 6SLIDEL! 230 1 | 7 | P7 |
| SBA | 384234 6CLAY 6 230 385039 6ARGO DS 230 1 | 602 | 92.0 | 104.7 | 384157 8MILLER8 500 384375 8S.BESS 8 500 1 | 4 | P5 |
| SBA | 384156 6MILLER6 230 384172 6BOYLESM1 230 1 | 602 | 92.6 | 102.6 | 384157 8MILLER8 500 385312 8CLAY 8 500 1 | 4 | P9 |
| SBA | 388702 6DANIEL6 230 388710 6MOSSPT E6 230 1 | 922 | 97.1 | 102.4 | 384642 6BIG CK 6 230 388702 6DANIEL6 230 1 | 1 | P8 |
| SBA | 388816 3WADE SS3 115 388832 3HARLESTN 115 1 | 107 | 90.5 | 101.4 | 384642 6BIG CK 6 230 388702 6DANIEL6 230 1 | 1 | P8 |
| SBA | 380086 6CUMMING 230 381135 6MCGRAU F B1 230 1 | 596 | 96.8 | 100.6 | 380011 8S HALL 500 382035 6S HALL LS 230 1 | 6 | P10 |

(1) A current operating procedure is sufficient to alleviate this identified constraint without the addition of the proposed transfer. However, the additional transfer exacerbates the loading on this transmission facility such that the operating procedure becomes insufficient.
(2) This is a tie-line constraint with TVA.

**Scenario Explanations:**
1. Crist Offline, Summer Peak Case
2. Ratcliffe Offline, Shoulder (93% Load Level) Case
3. Hammond Offline, Summer Peak Case
4. Gaston Unit #5 Offline, Shoulder (93% Load Level) Case
5. Gorgas Offline, Shoulder (93% Load Level) Case
6. Vogtle Unit #1 Offline, Summer Peak Case
7. Ratcliffe Offline, Summer Peak Case
8. Gaston Unit #5 Offline, Summer Peak Case

## Table III.9.2 Pass 1 – Transmission System Impacts with All Proposed Enhancements – *SBA*

The following table depicts loadings of **SBA** transmission facilities that could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the study year.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| SBA | 384655 3N MOBILE B1 115 385942 3N MOBILE B2 115 1 | 415 | 88.4 | 99.9 | 384638 6CHICK 6 230 384642 6BIG CK 6 230 1 | 4 | |
| SBA | 384331 3ATTALLA3 115 384332 5ATTALLA5 161 1 | 108 | 68.2 | 98.9 | 384331 3ATTALLA3 115 384332 5ATTALLA5 161 2 | 5 | |
| SBA | 384156 6MILLER6 230 384157 8MILLER8 500 1 | 1613 | 90.4 | 98.4 | 384157 8MILLER8 500 384375 8S.BESS 8 500 1 | 6 | |
| SBA | 380196 6CARTERVL B1 230 381125 6CARTERVL B2 230 1 | 829 | 96.7 | 98.1 | 380195 6BOWEN 230 381125 6CARTERVL B2 230 1 | 3 | |
| SBA | 360662 8BRADLEY TN 500 382499 8CONASAUGA 500 1 | 2598 | 81.8 | 98.0 | 306008 8OCONEE 500 380011 8S HALL 500 1 | 7 | |
| SBA | 384638 6CHICK 6 230 384700 6BARRY 6 230 1 | 833 | 96.2 | 97.2 | 384638 6CHICK 6 230 384642 6BIG CK 6 230 1 | 4 | |
| SBA | 384126 5KING JCT 161 384866 5S.VERNTP 161 1 | 377 | 79.5 | 96.3 | 384157 8MILLER8 500 385307 8WVERN SS8 500 1 | 6 | |
| SBA | 371308 SRS2 230 380115 6VOGTLE 230 1 | 1017 | 94.4 | 95.8 | 380008 8VOGTLE 500 380009 8W MCINTOSH 500 1 | 1 | |
| SBA | 384374 6S.BESS 6 230 384375 8S.BESS 8 500 1 | 1593 | 92.5 | 95.8 | 385123 8BILLNGSS 500 385178 8AUTAUSS8 500 1 | 8 | |
| SBA | 380025 8MCGRAU FORD 500 380088 6MCGRAU F LS 230 1 | 2016 | 83.0 | 94.1 | 380020 8BOWEN 500 380021 8MOSTELLER 500 1 | 2 | |
| SBA | 384642 6BIG CK 6 230 389510 NEWSITE6 230 1 | 602 | 84.0 | 94.0 | 384642 6BIG CK 6 230 388702 6DANIEL6 230 1 | 4 | |
| SBA | 384374 6S.BESS 6 230 384950 6DUNCANVL 230 1 | 502 | 85.0 | 93.8 | 385123 8BILLNGSS 500 385178 8AUTAUSS8 500 1 | 10 | |
| SBA | 384233 3CLAY 3 115 384234 6CLAY 6 230 1 | 477 | 83.5 | 92.7 | 384234 6CLAY 6 230 385039 6ARGO DS 230 1 | 9 | |
| SBA | 388100 3NEWTON 115 388101 3HICKORY 115 1 | 155 | 72.1 | 91.4 | 388210 6LAUREL E6 230 388270 6HATBG SW6 230 1 | 8 | |
| SBA | 384200 3BESSEMER B2 115 384202 6BESSGRCO 230 1 | 392 | 83.0 | 90.9 | 385123 8BILLNGSS 500 385178 8AUTAUSS8 500 1 | 9 | |

**Scenario Explanations:**
1. McIntosh Offline, Shoulder (93% Load Level) Case
2. Bowen Unit # 1 Offline, Summer Peak Case
3. McDonough Unit #5 Offline, Summer Peak Case
4. Crist Offline, Summer Peak Case
5. Hillabee Offline, Shoulder (93% Load Level) Case
6. Gorgas Offline, Shoulder (93% Load Level) Case
7. T.A. Smith Unit #1 Offline, Summer Peak Case
8. Ratcliffe Offline, Shoulder (93% Load Level) Case
9. Gaston Unit # 5 Offline, Shoulder (93% Load Level) Case
10. Ratcliffe Offline, Summer Peak Case

**Table III.9.3. Potential Solutions for Identified Problems – SBA**

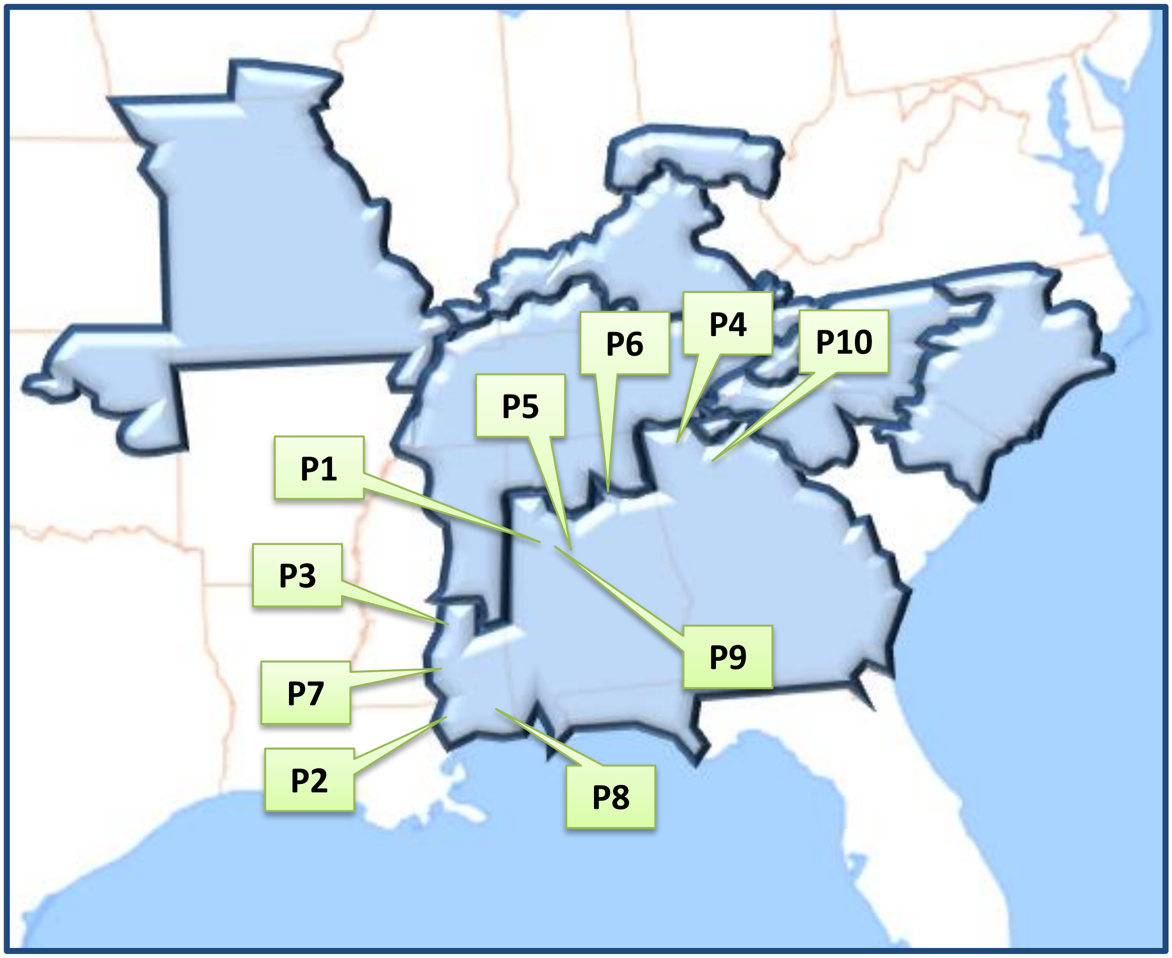
The following projects are identified as potential solutions to address the identified constraints and are based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| **P1** | **Fayette – Gorgas 161 kV T.L.**<br>• Rebuild approximately 36.7 miles along the Fayette – Gorgas 161 kV transmission line with 795 ACSS at 160°C. | 2020 | $37,000,000 |
| **P2** | **Nasa – Logtown 115 kV T.L. & 230/115 kV Transformer**<br>• Reconductor approximately 3 miles along the Nasa – Logtown 115 kV transmission line with 795 ACSS at 200 °C.<br>• Install new 230/115 kV transformer at Logtown. | 2020 | $5,000,000 |
| **P3** | **Morton – Forest Industrial 115 kV T.L.**<br>• Reconductor approximately 3.86 miles along the Morton – Forest Industrial 115 kV T.L. with 1033 ACSR at 100°C. | 2020 | $1,500,000 (2) |
| **P4** | **Oostanaula – Dalton 230 kV Substation**<br>• Replace the 1600 A PCB at Oostanaula with a 3000 A PCB. | 2020 | $500,000 |
| **P5** | **Clay TS – Leeds TS 230 kV T.L.**<br>• Upgrade approximately 17.3 miles along the Clay – Leeds 230 kV transmission line from 100 °C to 125 °C. | 2020 | $3,400,000 |
| **P6** | **Attalla – Albertville (TVA) 161 kV T.L.**<br>• Reconductor approximately 19.6 miles with 1351 ACSR at 100°C from Attalla to Albertville 161 kV transmission line (SOCO) | 2020 | $19,500,000 |
| **P7** | **Angie – Hattiesburg 230 kV T.L.**<br>• Reconductor approximately 31 miles along the Angie – Hattiesburg 230 kV transmission line with 1351 ACSS at 200 °C. | 2020 | $36,000,000 (2) |
| **P8** | **Daniel – Dawes 230 kV T.L.**<br>• Build 24 miles of new 230 kV transmission line from Daniel to Dawes with 1351 ACSS at 200 °C and a new 230 kV SS at Dawes. | 2020 | $54,000,000 |
| **P9** | **Miller – Boyles 230 kV T.L.**<br>• Upgrade approximately 17.9 miles along the Miller – Boyles 230 kV transmission line to 125°C operation. | 2020 | $3,600,000 |
| **P10** | **Cumming – McGrau Ford 230 kV T.L.**<br>• Reconductor approximately 21.7 miles along the Cumming – McGrau Ford 230 kV T.L. with 1351 ACSS at 170°C. | 2020 | $21,000,000 |
| **SBA TOTAL ($2015)** | | | **$181,500,000 (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.

(2) This transmission solution was proposed to alleviate the loading of a tie-line constraint between the **SBA** and a non-participating transmission owner. Therefore, the cost associated with the transmission solution is only for the portion of solution that is located within the participating transmission owners' territory. This solution effectively alleviates the identified constraint(s), however, the impacts to adjacent transmission systems that are external to the participating transmission owners were not evaluated.

**Diagram III.9.1.** **Approximate Location of Potential Solutions – SBA**



## Interchange Assumptions – SBA

**Table III.9.4 Incremental Transactions Preserved to those Modeled in Version 2 SERTP Models**

| OASIS Ref. # | POR | POD | Amount (MW) |
|---|---|---|---|
| NS1117 | DUKE | PS LOAD on SOCO | 50 |
| NS1119 | MISO | SMEPA LOAD on SOCO | 126 |
| NS1117 | MISO | PS LOAD on SOCO | 150 |
| NL1112 | MISO | SOCO | 500 |
| 147615 | DUKE | OPC LOAD | 465 |
| 147613 | TVA | OPC LOAD | 310 |
| NL1132 | TVA | SOCO | 500 |
| NL1132 | MISO | SOCO | 250 |
| 79662312 | SOCO | DUKE | 27 |
| 80832892 | SOCO | DUKE | 132 |
| 80600833 | SOCO | DUKE | 132 |
| 959841 | SOCO | DUKE | 44 |
| 79822666 | GTC | TVA | 200 |
| NL1112 | SCPSA | SOCO | 50 |

**Table III.9.5 Capacity Benefit Margin Preserved (CBM)**

| SERTP Sponsor | Interface | Amount (MW) |
|---|---|---|
| Southern | Duke | 350 |
| Southern | TVA | 400 |
| Southern | MISO | 100 |
| Southern | SCPSA | 125 |
| Southern | SCEG | 75 |

**Table III.9.6 Transmission Reliability Margins Preserved (TRM)**

| SERTP Sponsor | Interface | Amount (MW) |
|---|---|---|
| Southern | From Duke | 200 |
| GTC | From Duke | 109 |
| MEAG | From Duke | 26 |
| Dalton | From Duke | 3 |
| Southern | From MISO | 216 |
| Southern | From TVA | 218 |
| GTC | From TVA | 48 |
| MEAG | From TVA | 11 |
| Dalton | From TVA | 1 |

## *Tennessee Valley Authority Balancing Authority (TVA) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| TVA (Shelby) to Southern/TVA/Duke | 3500 MW | TVA (Shelby) | Southern/TVA/Duke | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

Table III.10.1 below identifies thermal constraints attributable to the requested transfer for the contingency and scenario that resulted in the highest facility loading for the conditions studied. Other unit out scenarios or contingencies may also result in constraints to these or other facilities.

### Table III.10.1 Pass 0 – Transmission System Impacts with No Enhancements – *TVA*

The following table identifies significant **TVA** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| TVA | SHELBY - CORDOVA #1 500-KV TL | 1732.1 | 56.0 | 113.6 | SHELBY - CORDOVA #2 500-KV TL | 1 | P1 |
| TVA | CORDOVA 500/161-kV #1 XFMR | 1243.0 | 95.0 | 108.8 | CORDOVA 500/161-kV #2 XFMR<br>CORDOVA - FREEPORT 500-KV TL<br>CORDOVA - HAYWOOD 500-kV TL | 2 | P2 |

**Scenario Explanations:**

1. Magnolia CC Unit #1 Offline, Summer Peak Case
2. No Unit Offline, Summer Peak Case

**Table III.10.2 Pass 1 – Transmission System Impacts with All Proposed Enhancements – *TVA***

The following table depicts loadings of **SBA** transmission facilities that could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the study year.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| TVA | JACKSON 500/161-kV #1 XFMR | 772.7 | 76.0 | 97.2 | JACKSON 500/161-kV #2 XFMR | 2 | -- |
| TVA | JACKSON 500/161-kV #2 XFMR | 750.0 | 78.0 | 99.4 | JACKSON 500/161-kV #1 XFMR | 2 | -- |
| TVA | SHELBY - CORDOVA #2 500-KV TL | 2120.9 | 44.0 | 90.2 | SHELBY - CORDOVA #1 500-KV TL | 1 | -- |

**Scenario Explanations:**

1. Magnolia CC Unit #1 Offline, Summer Peak Case
2. No Unit Offline, Summer Peak Case

**Table III.10.3 Potential Solutions for Identified Problems – TVA**

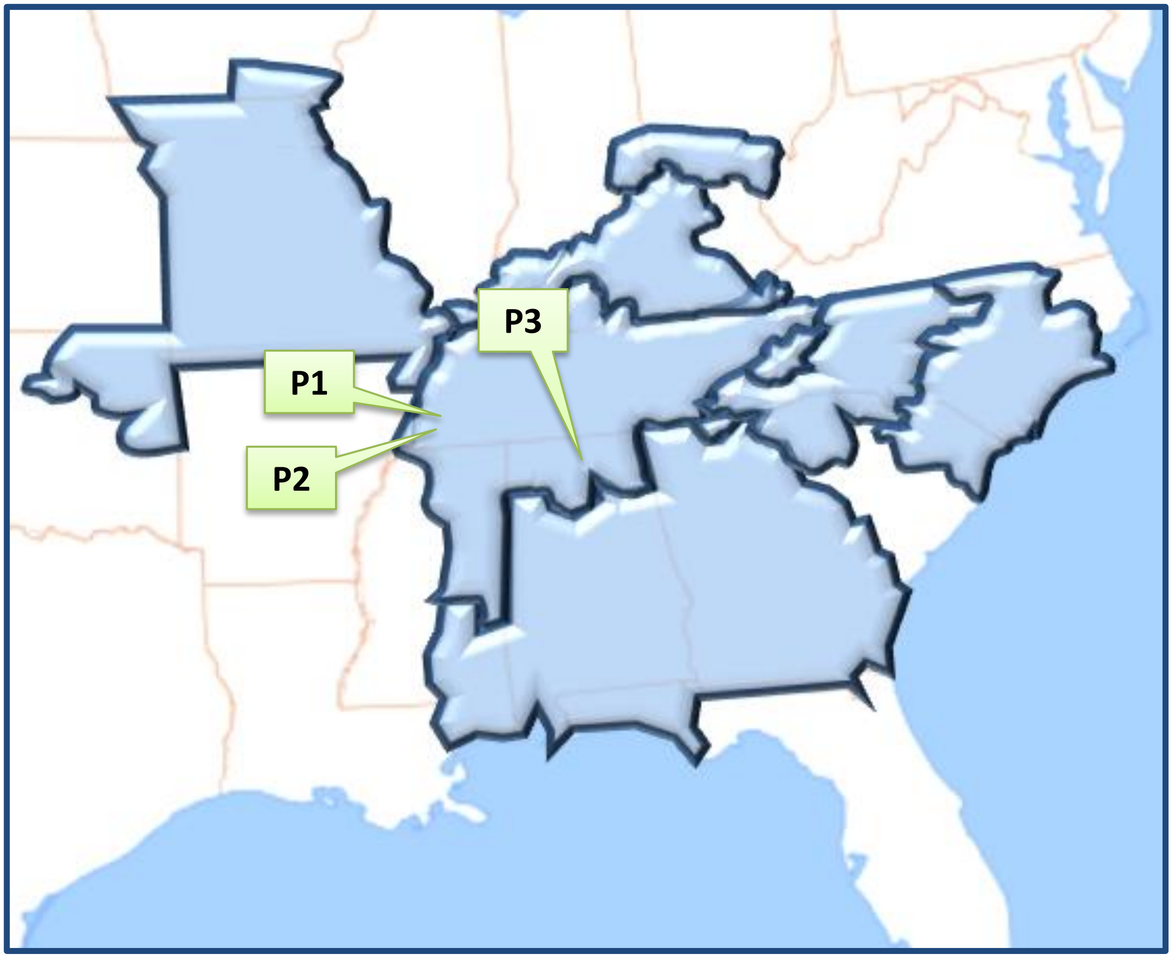
The following projects are identified as potential solutions to address the identified constraints and are based on the assumptions used in this study. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| **P1** | **Shelby – Cordova #1 500 kV T.L.**<br>• Uprate approximately 21 miles of 500 kV transmission line between Shelby and Cordova to 100°C and upgrade terminal equipment at both terminal end 500-kV substations. | 2020 | $9,000,000 |
| **P2** | **Cordova 500 kV Substation**<br>• Install 4 500-kV breakers to provide a complete double breaker configuration at Cordova. | 2020 | $8,000,000 |
| **P3** | **Albertville 161 kV Substation**<br>• Upgrade terminal equipment at Albertville 161 kV substation. | 2020 | $2,000,000 |
| -- | **Lagoon Creek – Jackson 500 kV T.L.**<br>• Build approximately 37 miles of transmission line between the Lagoon Creek and Jackson 500-kV substations sagged at 100°C. | 2020 | $122,000,000 (1) |
| **TVA TOTAL ($2015)** | | | **$141,000,000 (2)** |

(1) This project has been modeled within the SERTP economic study at the request of the RPSG and is not a part of TVA's expansion plan. The estimated cost of this project has been included in the total project cost of the economic study.

(2) 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 by June 1st of the study year, 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.

**<u>Diagram III.10.1.</u> Approximate Location of Potential Solutions – TVA**



# IV. Economic Planning Study Results

***Southern/SCEG to PJM***

*2020*

*500 MW*

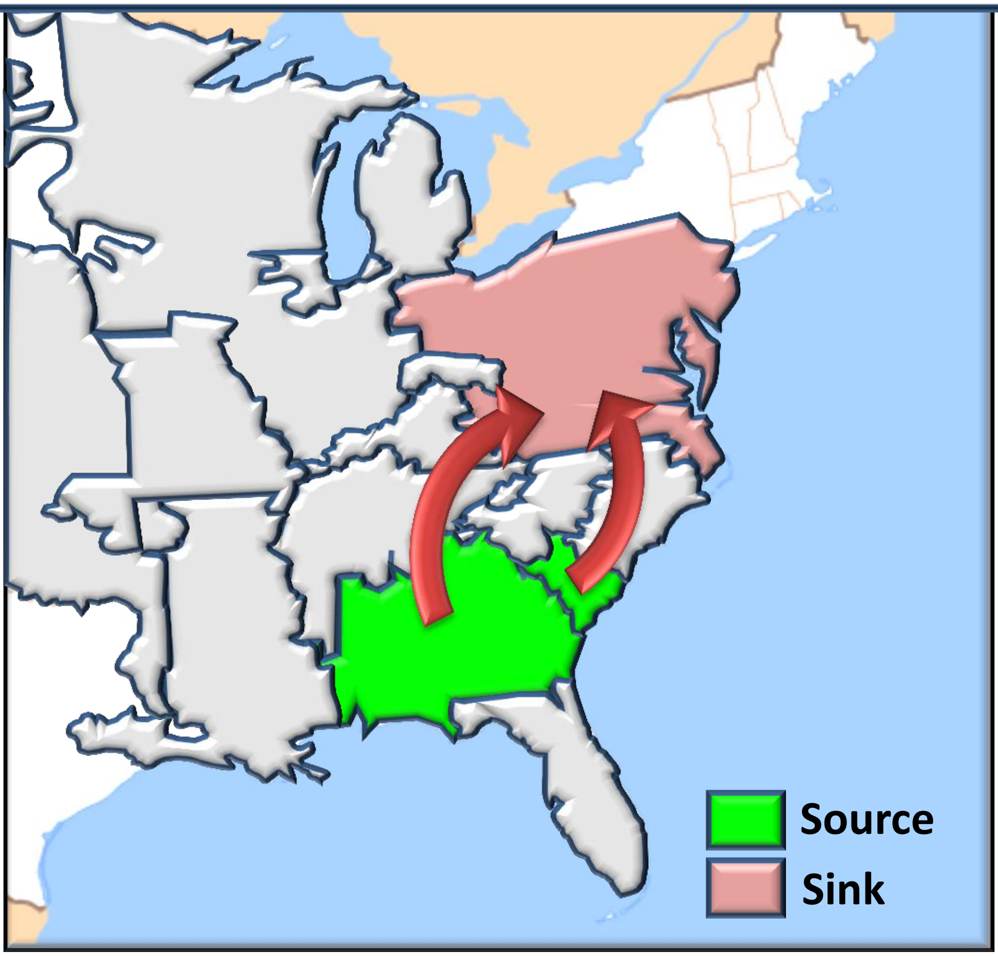
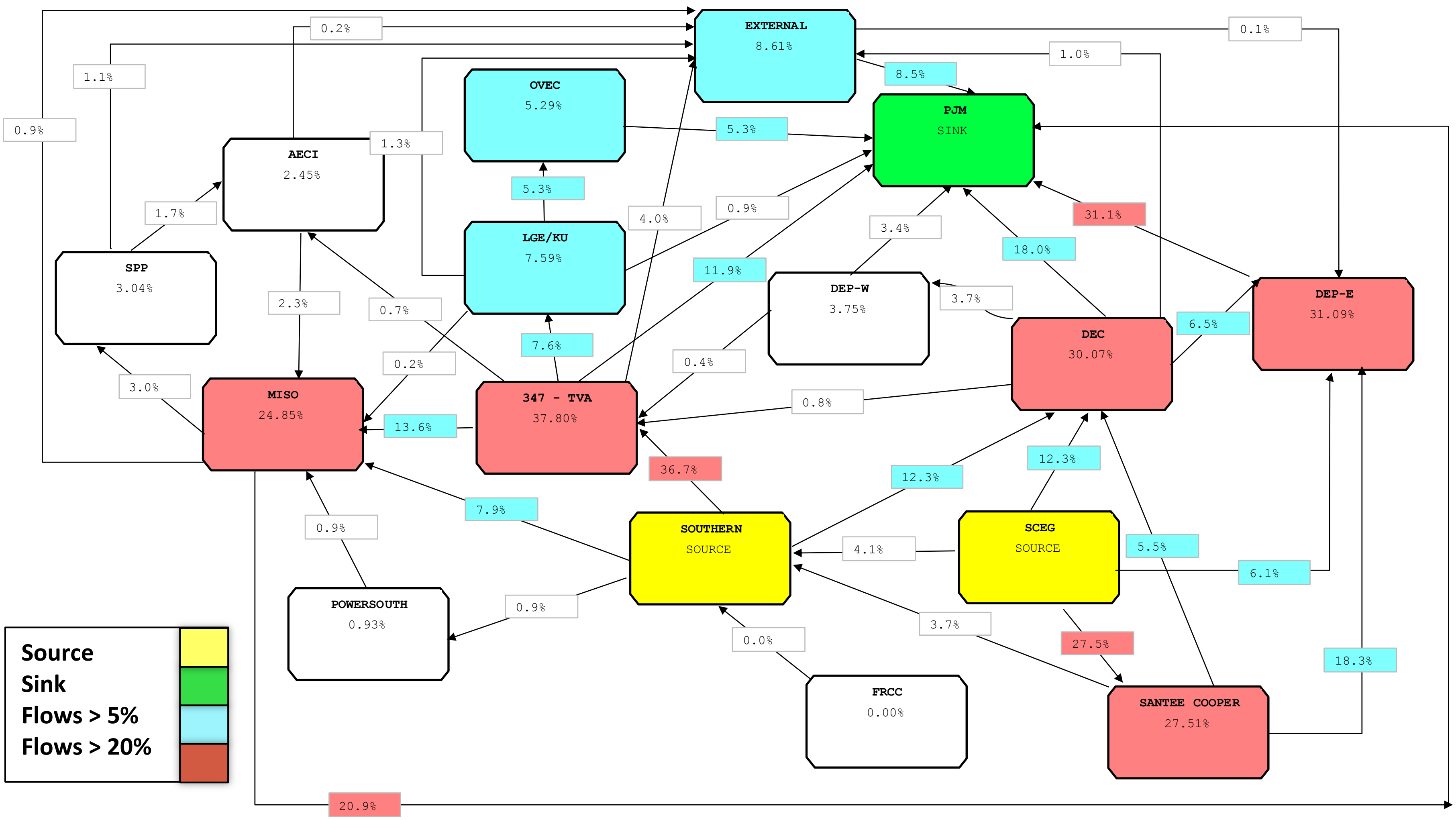


**Table IV.1.1.** **Total Cost Identified by the SERTP Sponsors**

| Balancing Authority | Planning Level Cost Estimate |
|---|---|
| Associated Electric Cooperative (AECI) | $0 |
| Duke Carolinas (DEC) | $0 |
| Duke Progress East (DEPE) | $0 |
| Duke Progress West (DEPW) | $0 |
| Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) | $0 |
| Ohio Valley Electric Cooperative (OVEC) | $0 |
| PowerSouth (PS) | $0 |
| Southern (SBA) | $0 |
| Tennessee Valley Authority (TVA) | $0 |
| **TOTAL ($2015)** | **$0** |

**Diagram IV.1.1. Transfer Flows with the SERTP**



# *Associated Electric Cooperative Balancing Authority (AECI) Results*

## Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Southern/SCEG to PJM | 500 MW | Southern/SCEG | PJM | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

## Transmission System Impacts

The 500 MW transfer from Southern Company and SCEG to PJM results in no thermal constraints attributable to the requested transfer.

### Table IV.2.1 Pass 0 – Transmission System Impacts with No Enhancements – *AECI*

The following table identifies significant **AECI** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| AECI | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table IV.2.2 Potential Solutions for Identified Problems – AECI**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **AECI TOTAL ($2015)** | | | **$0** (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.

# *Duke Carolinas Balancing Authority (DEC) Results*

## Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Southern/SCEG to PJM | 500 MW | Southern/SCEG | PJM | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

## Transmission System Impacts

The 500 MW transfer from Southern Company and SCEG to PJM results in no thermal constraints attributable to the requested transfer.

## Table IV.3.1. Pass 0 – Transmission System Impacts with No Enhancements – *DEC*

The following table depicts loadings of **DEC** transmission facilities that could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the study year.

| | | | Thermal Loadings (%) | | | | |
|---|---|---|---|---|---|---|---|
| AREA | Limiting Element | Rating (MVA) | Without Request | With Request | Contingency | Scenario | Project |
| DEC | 306041 LEE 100.00 308715 LAUECLICKVIL100.00 1 | 249 | 98.3 | 99.7 | 308498 LAUEC34 306191 REEDY RV 1 | 1 | - |
| DEC | 306041 LEE 100.00 308492 PERRYT B 100.00 1 | 249 | 95.4 | 96.8 | 306041 LEE 308715 LAUECLIC 1 | 1 | - |
| DEC | 306218 LAUEC30 100.00 306242 BUSH RIV 100.00 1 | 65 | 90.9 | 95.1 | 306242 BUSH RIV 308794 CLINTON 1 | 2 | - |
| DEC | 306443 6MARSHAL 230.00 306445 6STAMEY 230.00 1 | 796 | 93.0 | 94.7 | 306443 6MARSHAL 306445 6STAMEY 2 | 3 | - |
| DEC | 306847 6PARKWOD 230.00 306849 8PARKWOD 500.00 5 | 840 | 90.3 | 92.1 | 306849 8PARKWOD 306847 6PARKWOD 6 | 4 | - |
| DEC | 306183 OAKVALE 100.00 306195 SHADY GR 100.00 1 | 292 | 90.7 | 91.8 | 306183 OAKVALE 306195 SHADY GR 2 | 1 | - |
| DEC | 306183 OAKVALE 100.00 306195 SHADY GR 100.00 2 | 292 | 90.7 | 91.8 | 306183 OAKVALE 306195 SHADY GR 1 | 1 | - |
| DEC | 306366 FISHNG C 100.00 308254 BELTWNTP 100.00 1 | 166 | 88.4 | 90.1 | 306380 LANCASTR 306375 GT FALL1 1 | 5 | - |
| DEC | 306380 LANCASTR 100.00 308254 BELTWNTP 100.00 1 | 166 | 88.4 | 90.1 | 306380 LANCASTR 306375 GT FALL1 1 | 5 | - |

**Scenario Explanations:**

1. Cliffside Unit #5 Offline, Summer Peak Case
2. Lee CC Offline, Summer Peak Case
3. Belews Unit #1 Offline, Summer Peak Case
4. Catawba Unit #1, Summer Peak Case
5. McGuire Unit #1, Summer Peak Case

**Table IV.3.2 Potential Solutions for Identified Problems – DEC**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **DEC TOTAL ($2015)** | | | **$0** (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.

# *Duke Progress East Balancing Authority (DEPE) Results*

## Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Southern/SCEG to PJM | 500 MW | Southern/SCEG | PJM | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

## Transmission System Impacts

The 500 MW transfer from Southern Company and SCEG to PJM results in no thermal constraints attributable to the requested transfer.

## Table IV.4.1 Pass 0 – Transmission System Impacts with No Enhancements – *DEPE*

The following table depicts loadings of **DEPE** transmission facilities that could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the study year.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| DEPE | 304731 3IND104 115 304732 3ELGIN TAP 115 1 | 95 | 88.6 | 97.3 | 304716 3CAMDEN TAP 115 304725 3CAMDEN115 T 115 1 | 2 | -- |
| DEPE | 304327 6ELLERBE 230 304638 6WADSBOR TA1 230 1 | 512 | 93.7 | 95.5 | 304348 6ROCKHAM230T 230 305046 6E11-ELLERBE 230 1 | 2 | -- |
| DEPE | 304361 6WESTEND230T 230 305320 6EDENSOL-TAP 230 1 | 512 | 92.2 | 94.0 | 304348 6ROCKHAM230T 230 305046 6E11-ELLERBE 230 1 | 2 | -- |
| DEPE | 304287 3GOLDSB SS T 115 305052 3E13-ARBA 115 1 | 147 | 91.1 | 92.7 | 304474 6IND053 230 304500 6WOMMACK230T 230 1 | 1 | -- |
| DEPE | 304361 6WESTEND230T 230 305024 6E3-CNTR CRC 230 1 | 542 | 88.5 | 91.3 | 304377 8RICHMON500T 500 304391 8CUMBLND500T 500 1 | 2 | -- |
| DEPE | 304532 3VISTA 115 304545 3CASTLEH115T 115 1 | 179 | 89.7 | 91.0 | 304550 6CASTLEH230T 230 304564 6SCOTT TAP 230 1 | 1 | -- |
| DEPE | 304327 6ELLERBE 230 305320 6EDENSOL-TAP 230 1 | 512 | 89.0 | 90.9 | 304348 6ROCKHAM230T 230 305046 6E11-ELLERBE 230 1 | 2 | -- |
| DEPE | 304700 6SUMTER230 T 230 370101 6WATEREE1 230 1 | 478 | 86.8 | 90.8 | 304057 6DARLCNT230T 230 312734 6S BETH 230 1 | 3 | -- |
| DEPE | 304716 3CAMDEN TAP 115 304724 3CAMDEN CITY 115 1 | 107 | 83.6 | 90.6 | 304725 3CAMDEN115 T 115 304731 3IND104 115 1 | 2 | -- |
| DEPE | 304732 3ELGIN TAP 115 304734 3WATEREE115T 115 1 | 95 | 81.5 | 90.1 | 304716 3CAMDEN TAP 115 304725 3CAMDEN115 T 115 1 | 2 | -- |

**Scenario Explanations:**

1. No Unit Offline, Summer Peak Case
2. Harris Offline, Summer Peak Case
3. Robinson Unit #2 Offline, Summer Peak Case

**Table IV.4.2 Potential Solutions for Identified Problems – DEPE**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **DEPE TOTAL ($2015)** | | | **$0** (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.

## *Duke Progress West (DEPW) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Southern/SCEG to PJM | 500 MW | Southern/SCEG | PJM | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 500 MW transfer from Southern Company and SCEG to PJM results in no thermal constraints attributable to the requested transfer.

### Table IV.5.1 Pass 0 – Transmission System Impacts with No Enhancements – *DEPW*

The following table identifies significant **DEPW** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| DEPW | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table IV.5.2 Potential Solutions for Identified Problems – DEPW**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **DEPW TOTAL ($2015)** | | | **$0** (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.

## *Louisville Gas & Electric and Kentucky Utilities Balancing Authority (LG&E/KU) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Southern/SCEG to PJM | 500 MW | Southern/SCEG | PJM | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 500 MW transfer from Southern Company and SCEG to PJM results in no thermal constraints attributable to the requested transfer.

### Table IV.6.1 Pass 0 – Transmission System Impacts with No Enhancements – *LG&E/KU*

The following table identifies significant **LG&E/KU** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| LG&E/KU | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table IV.6.2 Potential Solutions for Identified Problems – LG&E/KU**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **LG&E/KU TOTAL ($2015)** | | | **$0** (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.

# *Ohio Valley Electric Corporation Balancing Authority (OVEC) Results*

## Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Southern/SCEG to PJM | 500 MW | Southern/SCEG | PJM | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

## Transmission System Impacts

The 500 MW transfer from Southern Company and SCEG to PJM results in no thermal constraints attributable to the requested transfer.

### Table IV.7.1 Pass 0 – Transmission System Impacts with No Enhancements – *OVEC*

The following table identifies significant **OVEC** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| OVEC | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table IV.7.2 Potential Solutions for Identified Problems – OVEC**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **OVEC TOTAL ($2015)** | | | **$0 (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.

## *PowerSouth Balancing Authority (PS) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Southern/SCEG to PJM | 500 MW | Southern/SCEG | PJM | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 500 MW transfer from Southern Company and SCEG to PJM results in no thermal constraints attributable to the requested transfer.

### Table IV.8.1 Pass 0 – Transmission System Impacts with No Enhancements – *PS*

The following table identifies significant **PS** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| PS | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table IV.8.2 Potential Solutions for Identified Problems – PS**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| -- | None Identified | -- | -- |
| **PS TOTAL ($2015)** | | | **$0** (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.

## *Southern Balancing Authority (SBA) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Southern/SCEG to PJM | 500 MW | Southern/SCEG | PJM | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 500 MW transfer from Southern Company and SCEG to PJM results in no thermal constraints attributable to the requested transfer.

### Table IV.9.1 Pass 0 – Transmission System Impacts with No Enhancements – *SBA*

The following table identifies significant **SBA** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) | | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| | | | Without Request | With Request | | | |
| SBA | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table IV.9.2 Potential Solutions for Identified Problems – SBA**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
|---|---|---|---|
| P1 | None Identified | -- | -- |
| SBA TOTAL ($2015) | | | $0 (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.

## Interchange Assumptions – SBA

**Table IV.9.3 Incremental Transactions Preserved to those Modeled in Version 2 SERTP Models**

| OASIS Ref. # | POR | POD | Amount (MW) |
|---|---|---|---|
| NS1117 | DUKE | PS LOAD on SOCO | 50 |
| NS1119 | MISO | SMEPA LOAD on SOCO | 126 |
| NS1117 | MISO | PS LOAD on SOCO | 150 |
| NL1112 | MISO | SOCO | 500 |
| 147615 | DUKE | OPC LOAD | 465 |
| 147613 | TVA | OPC LOAD | 310 |
| NL1132 | TVA | SOCO | 500 |
| NL1132 | MISO | SOCO | 250 |
| 79662312 | SOCO | DUKE | 27 |
| 80832892 | SOCO | DUKE | 132 |
| 80600833 | SOCO | DUKE | 132 |
| 959841 | SOCO | DUKE | 44 |
| 79822666 | GTC | TVA | 200 |
| NL1112 | SCPSA | SOCO | 50 |

**Table IV.9.4 Capacity Benefit Margin Preserved (CBM)**

| SERTP Sponsor | Interface | Amount (MW) |
|---|---|---|
| Southern | Duke | 350 |
| Southern | TVA | 400 |
| Southern | MISO | 100 |
| Southern | SCPSA | 125 |
| Southern | SCEG | 75 |

**Table IV.9.5 Transmission Reliability Margins Preserved (TRM)**

| SERTP Sponsor | Interface | Amount (MW) |
|---|---|---|
| Southern | From Duke | 200 |
| GTC | From Duke | 109 |
| MEAG | From Duke | 26 |
| Dalton | From Duke | 3 |
| Southern | From MISO | 216 |
| Southern | From TVA | 218 |
| GTC | From TVA | 48 |
| MEAG | From TVA | 11 |
| Dalton | From TVA | 1 |

## *Tennessee Valley Authority Balancing Authority (TVA) Results*

### Study Structure and Assumptions

| Transfer Sensitivity | Amount | Source | Sink | Year |
|---|---|---|---|---|
| Southern/SCEG to PJM | 500 MW | Southern/SCEG | PJM | 2020 |
| **Load Flow Cases** | | | | |
| 2015 Series Version 2 SERTP Models: Summer Peak | | | | |

### Transmission System Impacts

The 500 MW transfer from Southern Company and SCEG to PJM results in no thermal constraints attributable to the requested transfer.

### Table IV.10.1 Pass 0 – Transmission System Impacts with No Enhancements – *TVA*

The following table identifies significant **TVA** constraints without any enhancements to the transmission system.

| AREA | Limiting Element | Rating (MVA) | Thermal Loadings (%) Without Request | Thermal Loadings (%) With Request | Contingency | Scenario | Project |
|---|---|---|---|---|---|---|---|
| TVA | None Identified | -- | -- | -- | -- | -- | -- |

**Scenario Explanations:**

N/A

**Table IV.10.2 Potential Solutions for Identified Problems – TVA**

There were no identified constraints based on the assumptions used in this study, and therefore no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the currently projected improvements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission expansion plans could also impact the results of this study.

| Item | Potential Solution | Estimated Need Date | Planning Level Cost Estimate |
| --- | --- | --- | --- |
| -- | None Identified | -- | -- |
| TVA TOTAL ($2015) | | | $0 (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.