Southeastern Regional Transmission Planning Process

2013 Economic Planning Studies Final Results

December 2013

Executive Summary

The Regional Planning Stakeholder Group ("RPSG") identified five Economic Planning Scenarios to be evaluated under the Southeastern Regional Transmission Planning ("SERTP") process. The SERTP Sponsors have performed analyses to assess the performance of the transmission systems of the participating Transmission Owners for these five transfer scenarios. 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 provide potential solutions to alleviate the limitations, planning-level cost estimates, and the projected need-date for projects to accommodate the power flows associated with the transfers in the five Economic Planning Scenarios. Additionally, projects are identified as potential solutions to address the identified constraints and are based on the economic 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. 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 load levels evaluated were Summer Peak and Shoulder

  (93% of Summer Peak load) unless otherwise indicated below.
- Each request was evaluated for the particular year identified below, as selected by the RPSG
- The following Economic Planning Scenarios were assessed according to the reliability criteria of each of the participating Transmission Owners:
  - Southern to SCPSA Border – 500 MW
    - Year: 2015
    - Load Level: Winter Peak
    - Type of Transfer: Generation to Load
    - Source: Southern Generation
    - Sink: Uniform load scale of SCPSA area
  - Southern to SCE&G Border – 500 MW
    - Year: 2015
    - Load Level: Winter Peak
    - Type of Transfer: Generation to Load
    - Source: Southern Generation
    - Sink: Uniform load scale of SCE&G area

- TVA Border to Southern – 1500 MW
  - Year: 2017
  - Load Level: Spring Valley (≈40% of Summer Peak load)
  - Type of Transfer: Load to Generation
  - Source: Uniform load scale of TVA area
  - Sink: Southern Generation

- TVA Border to Southern – 1500 MW
  - Year: 2017
  - Load Level: Summer Peak
  - Type of Transfer: Load to Generation
  - Source: Uniform load scale of TVA area
  - Sink: Southern Generation

- Southern to PJM Border – 1000 MW
  - Year: 2023
  - Load Level: Summer Peak
  - Type of Transfer: Generation to Load
  - Source: Southern Generation
  - Sink: Uniform load scale of the PJM area. The resulting allocation is shown in Table 1 below:

Table 1: Southern to PJM Border – Sink Allocation

PJM Area #	Area #	Participation Factor (%)	MW Allocation
Allegheny Power	201	5.32%	53
American Transmission Systems	202	8.15%	82
American Electric Power	205	13.89%	139
Dayton Power & Light	209	2.16%	22
Duke Energy Ohio & Kentucky	212	3.21%	32
Duquesne Light Company	215	1.86%	19
Commonwealth Edison	222	14.28%	143
Pennsylvania Electric Company	226	1.89%	19
Metropolitan Edison Company	227	1.77%	18
Jersey Central Power & Light	228	3.71%	37
PPL Electric Utilities	229	4.57%	46
PECO Energy Company	230	5.52%	55
PSE&G	231	6.35%	63
Baltimore Gas & Electric	232	4.36%	44
Potomac Electric Power	233	4.12%	41
Atlantic Electric	234	1.65%	17
Delmarva Power & Light	235	2.56%	26
UGI Utilities	236	0.12%	1

PJM Area #	Area #	Participation Factor (%)	MW Allocation
Rockland Electric	237	0.27%	3
East Kentucky Power Cooperative	320	1.30%	13
Dominion Virginia Power	345	12.94%	129
Total		**100.00%**	**1000**

- PSS/E and/or MUST were used for the study.
- Generation, interchange, and other assumptions were coordinated between participating Transmission Owners and Stakeholders.

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 "2013 Series, Version 2A", cases were used as a starting point for the analysis of the Economic Planning Scenarios.

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 results on elements of 115 kV and greater within their respective service area based on:

- Thermal loadings greater than 100% (with potential solutions).
- Thermal loadings greater than 90% that increase with the addition of the transfer.
- 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 Scenarios. 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 Scenarios requested by the stakeholders.
- 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 construction schedules 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 Scenario, the results of that study including:
    1. Limits to the transfer
    2. Selected solution alternatives to address the limit
    3. Rough, planning-level cost estimates and in-service dates for the selected solution alternatives

Southern to SCPSA

500 MW

Study Structure and Assumptions

Transfer Sensitivity	Transfer Amount	Transfer Source	Transfer Sink	Study Year
Southern to SCPSA Border	500 MW	Southern	SCPSA Border	2015
Load Flow Cases				
2013 Series Version 2A Cases: Winter Peak				
Source Modeled				
The source for this transfer was Southern generation.				

Transmission System Impacts

Table 1.1 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.

Southern Balancing Authority

Table 1.1. Pass 0 – Transmission System Impacts With No Enhancements – *Southern Balancing Authority*
The following table identifies constraints in the Southern Balancing Authority ("SBA") without any enhancements to the transmission system.

AREA	Limiting Element	Rating (MVA)	Thermal Loadings (%) Without Request	Thermal Loadings (%) With Request	Contingency	Scenario	Project
The following constraints have been identified as directly attributable to the above defined transfer.							
SBA	903 CHATSWORTH 115 904 COOSAWATTEE 115 1	137	91.9	102.4	200 E DALTON 230 202 CARTERS DAM 230 1	1	P1

Scenario Explanations:

1) T.A. Smith Unit #2 Offline, Winter Peak Case

Table 1.2. Pass 1 – Transmission System Impacts With Proposed Enhancement "P1" – *Southern Balancing Authority*

SERTP 2013 Economic Study Results
December 2013

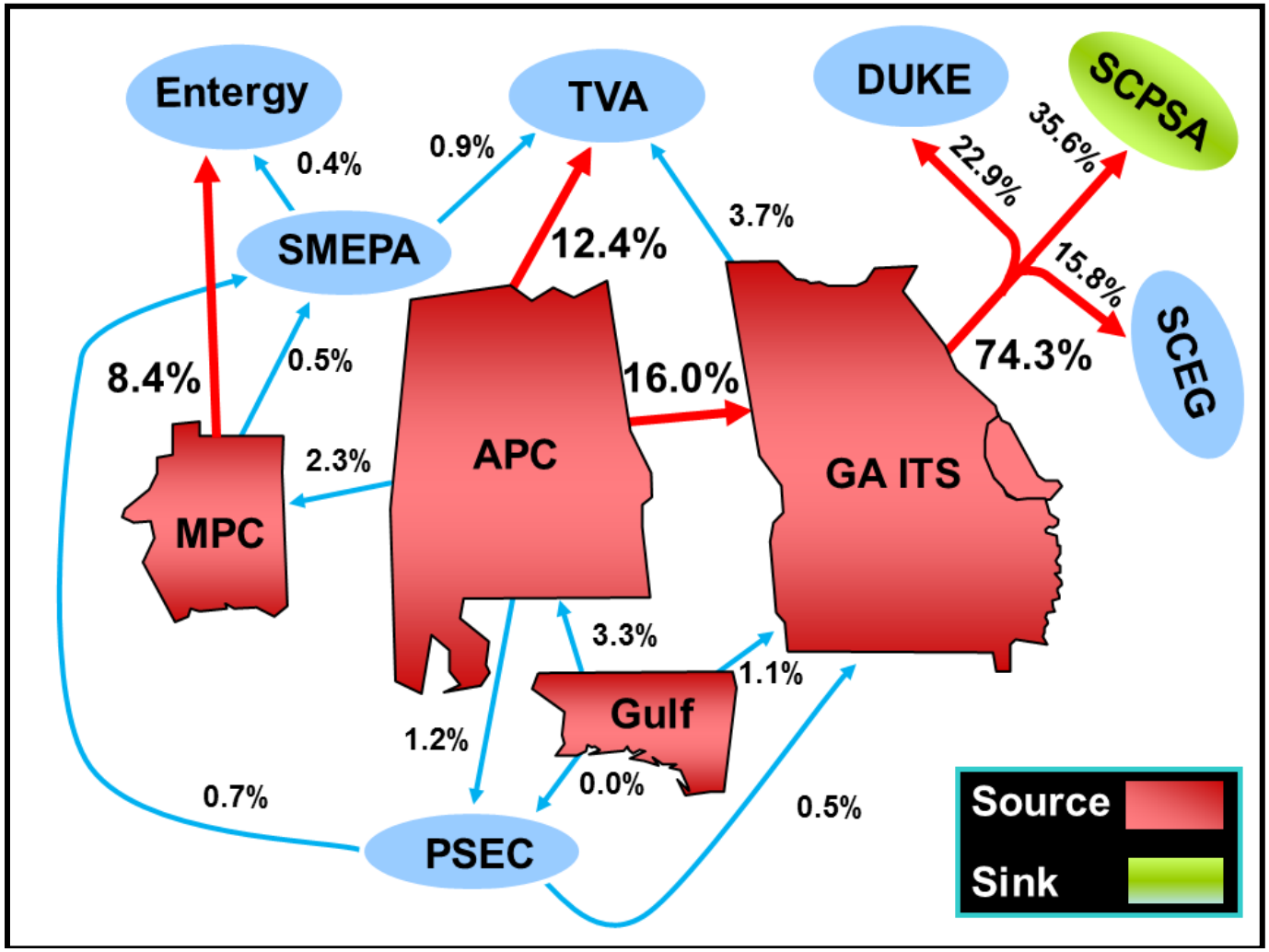
The following table identifies significant constraints in the Southern Balancing Authority ("SBA") with the proposed enhancement "P1" applied to the transmission system. The resulting facilities in the table below could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the 2015 study year.

			Thermal Loadings (%)				
AREA	**Limiting Element**	**Rating (MVA)**	**Without Request**	**With Request**	**Contingency**	**Scenario**	**Project**
The following facilities could become potential constraints in future years or with different queuing assumptions							
SBA	848 PINE GRV DS 115 1464 HAZLE J 115 1	128	95.5	97.0	843 VIDALIA B1 115 1476 W LYONS J2 115 1	2	--
SBA	461 JACKSON LK 115 1917 S COV J 115 1	99	92.0	93.1	746 S GRIFFIN 115 750 GA BRD CORR 115 1	1	--

Scenario Explanations

1) Hatch Unit #1 Offline, Winter Peak Case
2) McIntosh CC #11 Offline, Winter Peak Case

Southern to SCPSA Border: Transfer Flows within the SERTP



Note: Red arrows indicate transfer percentages of greater than 5%.

Potential Solutions for Identified Constraints

The following projects are 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 current projected enhancements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission system expansion plans could also impact the results of this study. These potential solutions only address constraints identified within the SERTP Sponsors' areas that are associated with the proposed transfer. Other Balancing Areas were not monitored which could result in additional limitations and required system improvements.

Table 1.3. Potential Solutions for Identified Constraints – *Southern Balancing Authority*

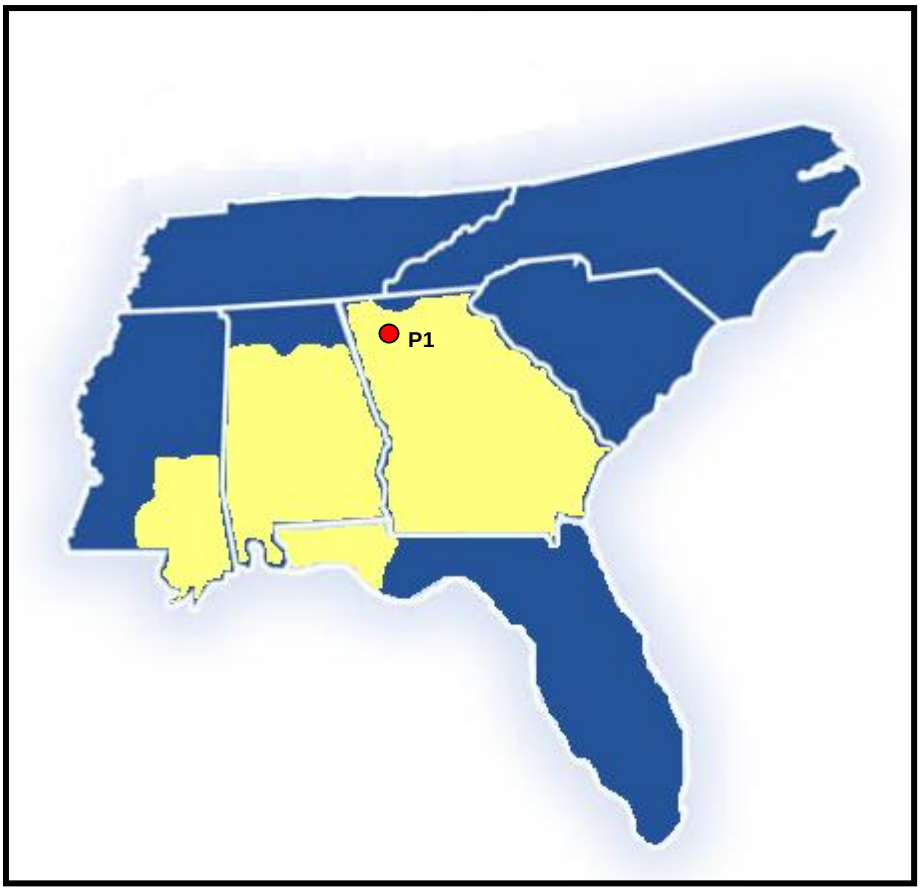
Item	Potential Solution	Estimated Need Date	Estimated Cost
P1	**Chatsworth – Coosawattee 115 kV T.L.** • Reconductor approximately 12 miles of 336 ACSR 115 kV transmission line with 795 ACSR at 100 ºC.	2015	$9,000,000
SBA Total ($2013)			$9,000,000

Table 1.4. Total Cost of the Southern to SCPSA Border 500 MW Transfer

Area	Estimated Cost
SBA Total	$9,000,000
TOTAL ($2013)	**$9,000,000[(1)]**

[(1)] Total cost does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by 11/1/2015. The studied transfer depends on these projects being in-service by 11/1/2015. If any of these projects are delayed or cancelled, the cost to support the study transfer could be greater than the total shown above.

Diagram 1.1. Approximate Location of Potential Solutions



Interchange Assumptions

Table 1.5. Additional Transactions Modeled in Cases

OASIS Ref. #	POR	POD	Amount (MW)
73509914	GTC	TVA	200
959840	SOCO	Duke	88
959841	SOCO	Duke	88
982928	SOCO	DUKE	60

Southern to SCE&G Border

500 MW

Study Structure and Assumptions

Transfer Sensitivity	Transfer Amount	Transfer Source	Transfer Sink	Study Year
Southern to SCE&G Border	500 MW	Southern	SCE&G Border	2015
Load Flow Cases				
2013 Series Version 2A Cases: Winter Peak				
Source Modeled				
The source for this transfer was Southern generation.				

Transmission System Impacts

Table 2.1 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.

Southern Balancing Authority

Table 2.1. Pass 0 – Transmission System Impacts With No Enhancements – *Southern Balancing Authority*
The following table identifies constraints in the Southern Balancing Authority ("SBA") without any enhancements to the transmission system.

			Thermal Loadings (%)				
AREA	**Limiting Element**	**Rating (MVA)**	**Without Request**	**With Request**	**Contingency**	**Scenario**	**Project**
The following constraints have been identified as directly attributable to the above defined transfer.							
SBA	903 CHATSWORTH 115 904 COOSAWATTEE 115 1	137	91.9	102.4	200 E DALTON 230 202 CARTERS DAM 230 1	1	P1

Scenario Explanations

1) T.A. Smith Unit #2 Offline, Winter Peak Case

Table 2.2. Pass 1 – Transmission System Impacts With Proposed Enhancement "P1" – *Southern Balancing Authority*

SERTP 2013 Economic Study Results
December 2013

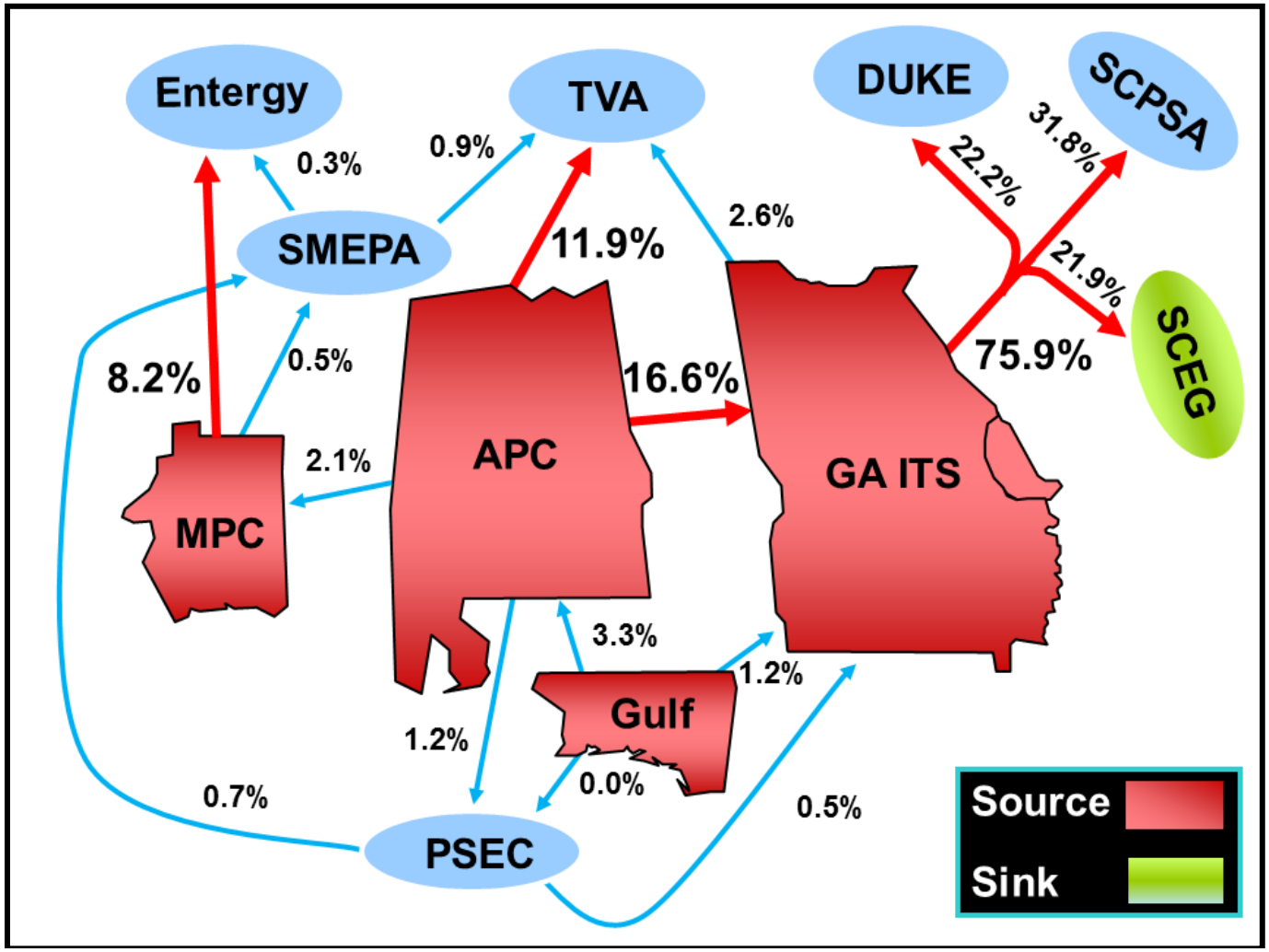
The following table identifies significant constraints in the Southern Balancing Authority ("SBA") with the proposed enhancement "P1" applied to the transmission system. The resulting facilities in the table below could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the 2015 study year.

AREA	Limiting Element	Rating (MVA)	Thermal Loadings (%)		Contingency	Scenario	Project
			Without Request	With Request			
The following facilities could become potential constraints in future years or with different queuing assumptions							
SBA	848 PINE GRV DS 115 1464 HAZLE J 115 1	128	95.5	97.0	843 VIDALIA B1 115 1476 W LYONS J2 115 1	2	--
SBA	461 JACKSON LK 115 1917 S COV J 115 1	99	92.0	93.1	746 S GRIFFIN 115 750 GA BRD CORR 115 1	1	--

Scenario Explanations

1) Hatch Unit #1 Offline, Winter Peak Case
2) McIntosh CC #11 Offline, Winter Peak Case

Southern to SCE&G: Transfer Flows within the SERTP



Note: Red arrows indicate transfer percentages of greater than 5%

Potential Solutions for Identified Constraints

The following projects are 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 current projected enhancements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission system expansion plans could also impact the results of this study. These potential solutions only address constraints identified within the SERTP Sponsors' areas that are associated with the proposed transfer. Other Balancing Areas were not monitored which could result in additional limitations and required system improvements.

Table 2.3. Potential Solutions for Identified Constraints – *Southern Balancing Authority*

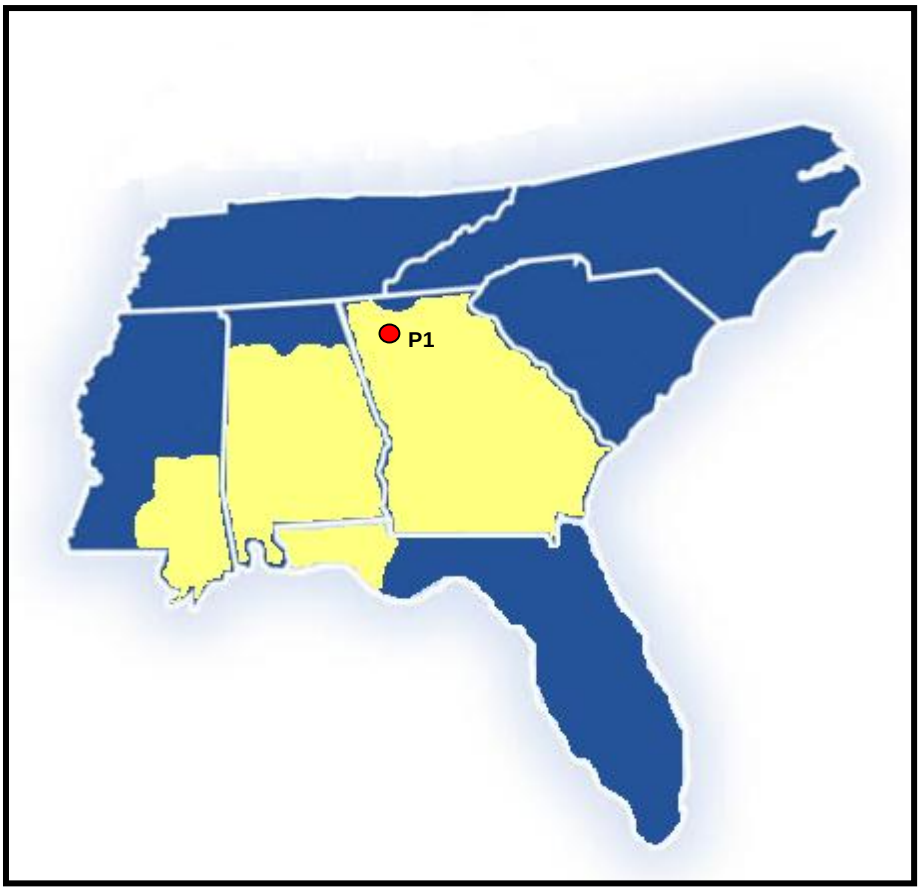
Item	Potential Solution	Estimated Need Date	Estimated Cost
P1	**Chatsworth – Coosawattee 115 kV T.L.** • Reconductor approximately 12 miles of 336 ACSR 115 kV transmission line with 795 ACSR at 100 ºC.	2015	$9,000,000
SBA Total ($2013)			$9,000,000

Table 2.4. Total Cost of the Southern to SCE&G Border 500 MW Transfer

Area	Estimated Cost
SBA Total	$9,000,000
TOTAL ($2013)	**$9,000,000[(1)]**

[(1)] Total cost does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by 11/1/2015. The studied transfer depends on these projects being in-service by 11/1/2015. If any of these projects are delayed or cancelled, the cost to support the study transfer could be greater than the total shown above.

Diagram 2.1. Approximate Location of Potential Solutions



Interchange Assumptions

Table 2.5. Additional Transactions Modeled in Cases

OASIS Ref. #	POR	POD	Amount (MW)
73509914	GTC	TVA	200
959840	SOCO	Duke	88
959841	SOCO	Duke	88
982928	SOCO	DUKE	60

Southern to PJM

1000 MW

Study Structure and Assumptions

Transfer Sensitivity	Transfer Amount	Transfer Source	Transfer Sink	Study Year
Southern to PJM	1000 MW	Southern	PJM	2023
Load Flow Cases				
2013 Series Version 2A Cases: Summer Peak				
Source Modeled				
The source for this transfer was Southern generation.				

Transmission System Impacts

Table 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.

Southern Balancing Authority

Table 3.1. Pass 0 – Transmission System Impacts With No Enhancements – *Southern Balancing Authority*
The following table identifies significant constraints in the Southern Balancing Authority ("SBA") without any enhancements to the transmission system.

AREA	Limiting Element	Rating (MVA)	Thermal Loadings (%) Without Request	Thermal Loadings (%) With Request	Contingency	Scenario	Project
The following constraints have been identified as directly attributable to the above defined transfer.							
SBA	115 VOGTLE 230 370308 SRS 230 1	1020	97.8	104.5	8 VOGTLE 500 9 W MCINTOSH 500 1	1	N/A [1]
SBA	4334 MORG XRD 115 5936 GS STEEL B1 115 1	112	87.6	100.4	4324 GADSDEN B1 115 5935 GADSDEN B2 115 1	2	P1

[1] The limiting element of this tie-line constraint is located within SCE&G

Scenario Explanations:
1) McIntosh CC #11 Offline, Shoulder (93% Load Level)
2) Farley Unit #1 Offline, Summer Peak Case

Table 3.2. Pass 1 – Transmission System Impacts With Proposed Enhancements "P1" through "P2" – *Southern Balancing Authority*

SERTP 2013 Economic Study Results
December 2013

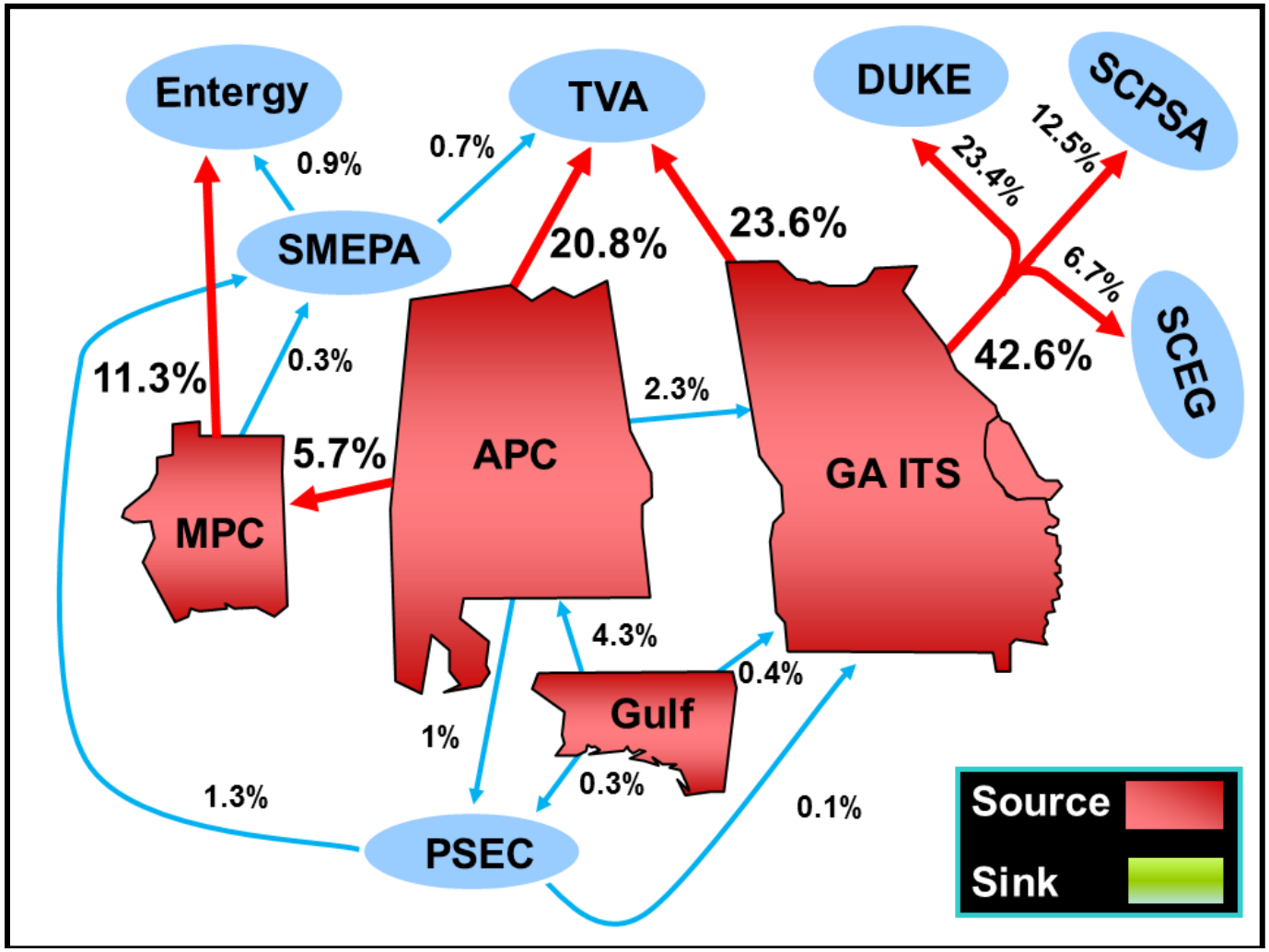
The following table identifies significant constraints in the Southern Balancing Authority ("SBA") with the proposed enhancements "P1" applied to the transmission system. The resulting facilities in the table below could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the 2023 study year.

			Thermal Loadings (%)				
AREA	**Limiting Element**	**Rating (MVA)**	**Without Request**	**With Request**	**Contingency**	**Scenario**	**Project**
The following facilities could become potential constraints in future years or with different queuing assumptions							
SBA	1 KLONDIKE 500 3 NORCROSS 500 1	2439	93.9	99.5	1 KLONDIKE 500 1919 R_KLONDIKE 230 1	1	--
SBA	4950 DUNCANVL 230 5140 BRAD RD 230 1	433	95.9	99.2	84 FAIRBURN 1 230 123 YATES 230 1	3	--
SBA	129 S COWETA 230 719 S COWETA B1 115 1	400	96.7	97.8	2265 CUMBERLAND 230 2711 JACK MCD B1 230 1	5	--
SBA	7116 JAY RD2 115 7120 MUNSON 115 1	100	94.0	96.9	36 JACK MCD B2 230 41 PEACHTREE 230 1	6	--
SBA	515 THOMSON 115 517 KIOKEE J 115 1	124	91.1	95.2	5425 MOUNDVIL6 230 5426 MOUNDVIL3 115 1	7	--
SBA	4629 EMCSTOCK 115 4701 BARRY 3 115 1	212	93.5	94.6	16 OHARA 500 171 OHARA LS 230 1	2	--
SBA	4348 S.TUSC 3 115 4349 KAULGMTP 115 1	210	92.2	94.4	7124 ALLIGATR 230 7309 ANTIOCH 230 1	3	--
SBA	1655 AULTMAN RD 115 1676 SLEEPY HOL 115 1	124	88.1	93.2	8 VOGTLE 500 9 W MCINTOSH 500 1	3	--
SBA	4485 FAUNSDAL 115 4744 SONGALTP 115 1	138	90.1	92.3	4612 BREWT TP 115 4627 FLOMATON 115 1	2	--
SBA	1691 ROBINS CT 115 2337 ANCHOR A JC 115 1	188	87.2	92.2	4348 S.TUSC 3 115 5033 ALBERTA 115 1	3	--
SBA	2408 ETOWAH 115 2435 REAVIS MTN 115 1	124	90.7	92.1	804 BONAIRE B1 115 806 96 HWY 115 1	4	--
SBA	4951 S.TUSC 6 230 5140 BRAD RD 230 1	433	63.8	92.0	4324 GADSDEN B1 115 5289 ELMWOOD 115 1	3	--
SBA	7061 CRIST3 B1 115 7111 PACE2 115 1	155	84.4	92.0	4471 GREENCO6 230 4489 N SELMA6 230 1	6	--
SBA	9001 MCINTOSH 230 9021 MCINTOSH 115 1	400	88.1	91.5	370401 6OKATIE 230 370402 6JASPER1 230 1	3	--
SBA	804 BONAIRE B1 115 1657 RUSS PKY J 115 1	188	86.0	91.4	804 BONAIRE B1 115 1657 RUSS PKY J 115 1	5	--
SBA	4293 NHELENA6 230 4400 GASTON 230 1	497	86.9	91.1	5425 MOUNDVIL6 230 5426 MOUNDVIL3 115 1	3	--
SBA	7281 WRIGHT3 115 7300 W GATE T 115 1	155	89.7	91.1	7124 ALLIGATR 230 7309 ANTIOCH 230 1	6	--
SBA	7120 MUNSON 115 17424 HOLT 115 1	100	88.8	90.5	1691 ROBINS CT 115 2337 ANCHOR A JC 115 1	6	--

Scenario Explanations:

1) Bowen Unit #4 Offline, Shoulder (93% Load Level)
2) Farley Unit #2 Offline, Summer Peak Case
3) Gorgas Offline, Summer Peak Case
4) Hartwell Offline, Summer Peak Case
5) McDonough Unit #6 Offline, Summer Peak Case
6) Smith Unit #3 Offline, Summer Peak Case
7) Vogtle Unit #1 Offline, Summer Peak Case

Southern to PJM: Transfer Flows within the SERTP



Note: Red arrows indicate transfer percentages of greater than 5%.

Potential Solutions for Identified Constraints

The following projects are 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 current projected enhancements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission system expansion plans could also impact the results of this study. These potential solutions only address constraints identified within the SERTP Sponsors' areas that are associated with the proposed transfer. Other Balancing Areas were not monitored which could result in additional limitations and required system improvements.

Table 3.3. Potential Solutions for Identified Constraints – *Southern Balancing Authority*

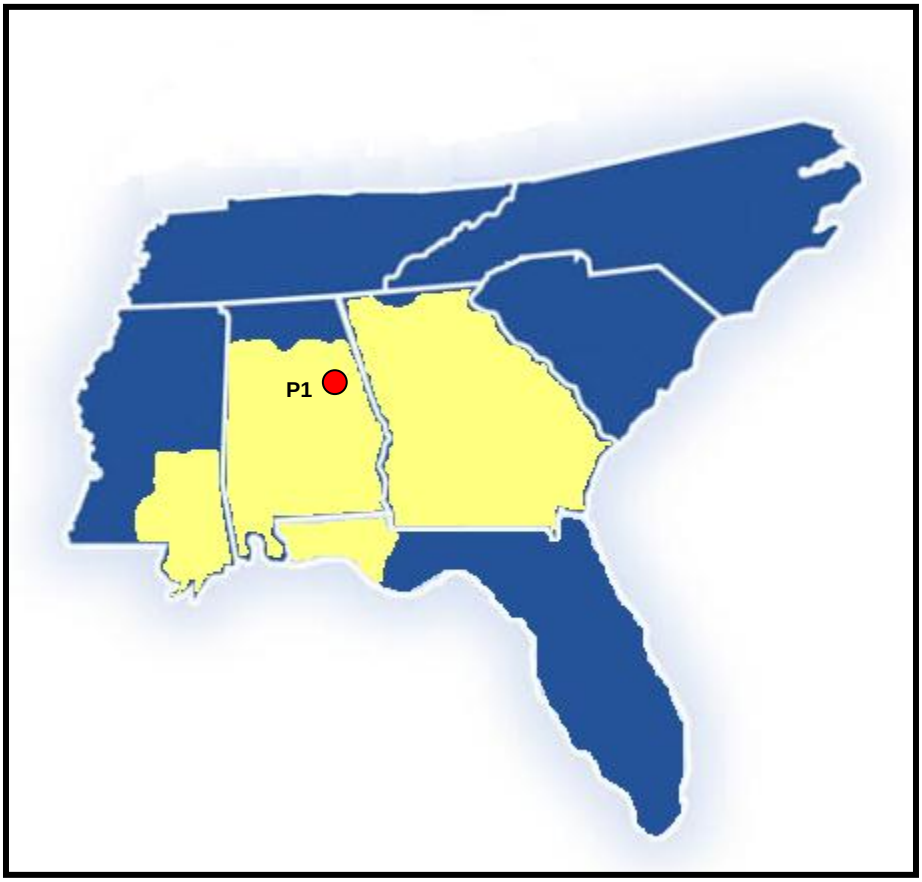
Item	Potential Solution	Estimated Need Date	Estimated Cost
P1	**Morgan Crossroads – Gulf States Steel 115 kV T.L.** • Upgrade approximately 2.5 miles from 75°C to 100 °C operation along the Morgan Crossroads – Gulf States Steel 115 kV transmission line.	2023	$920,000
SBA Total ($2013)			$920,000

Table 3.4. Total Cost of the Southern to PJM 1000 MW Transfer

Area	Estimated Cost
TOTAL ($2013)	**$920,000[(1)]**

(1) Total cost does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by 6/1/2023. The studied transfer depends on these projects being in-service by 6/1/2023. If any of these projects are delayed or cancelled, the cost to support the study transfer could be greater than the total shown above.

Diagram 3.1. Approximate Location of Potential Solutions



Interchange Assumptions

Table 3.5. Additional Transactions Modeled in Cases

OASIS Ref. #	POR	POD	Amount (MW)
73509914	GTC	TVA	200
959840	SOCO	Duke	88
959841	SOCO	Duke	88
982928	SOCO	DUKE	60

TVA Border to Southern

1500 MW

Spring Valley

Study Structure and Assumptions

Transfer Sensitivity	Transfer Amount	Transfer Source	Transfer Sink	Study Year
TVA Border to Southern	1500 MW	TVA Border	Southern	2017
Load Flow Cases				
2013 Series Version 2A Cases: Spring Valley				
Source Modeled				
The source for this transfer was a uniform load reduction in the TVA area.				

Transmission System Impacts

The 1500 MW transfer from the TVA Border to Southern results in no thermal constraints attributable to the requested transfer.

Southern Balancing Authority

Table 4.1. Pass 0 – Transmission System Impacts With No Enhancements – *Southern Balancing Authority*
The following table depicts loadings of transmission facilities in the Southern Balancing Authority ("SBA") that could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the 2017 study year.
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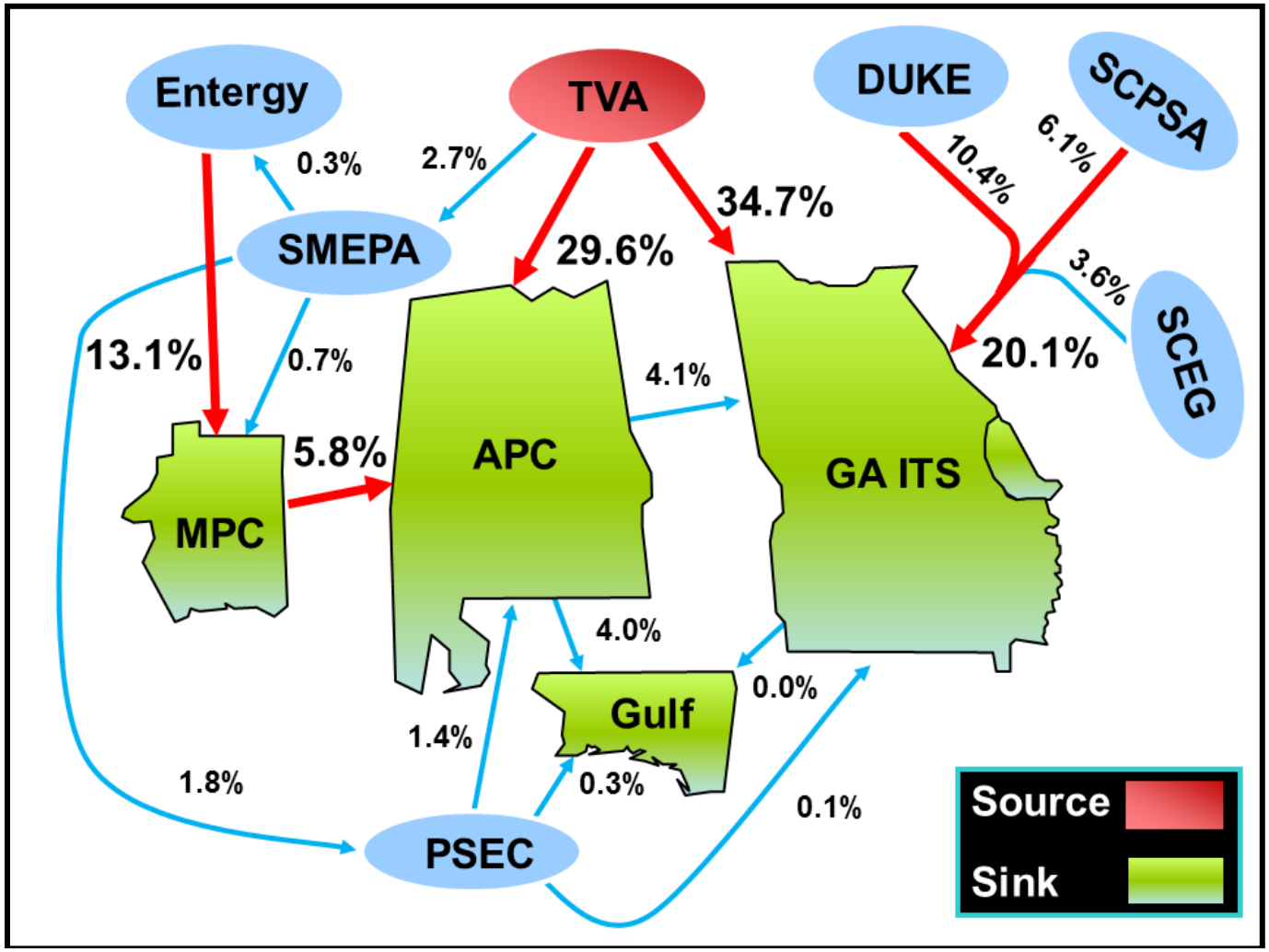
AREA	Limiting Element	Rating (MVA)	Thermal Loadings (%) Without Request	Thermal Loadings (%) With Request	Contingency	Scenario	Project
The following facilities could become potential constraints in future years or with different queuing assumptions							
SBA	N/A						--

TVA Border to Southern: Transfer Flows within the SERTP



Note: Red arrows indicate transfer percentages of greater than 5%.

Potential Solutions for Identified Constraints

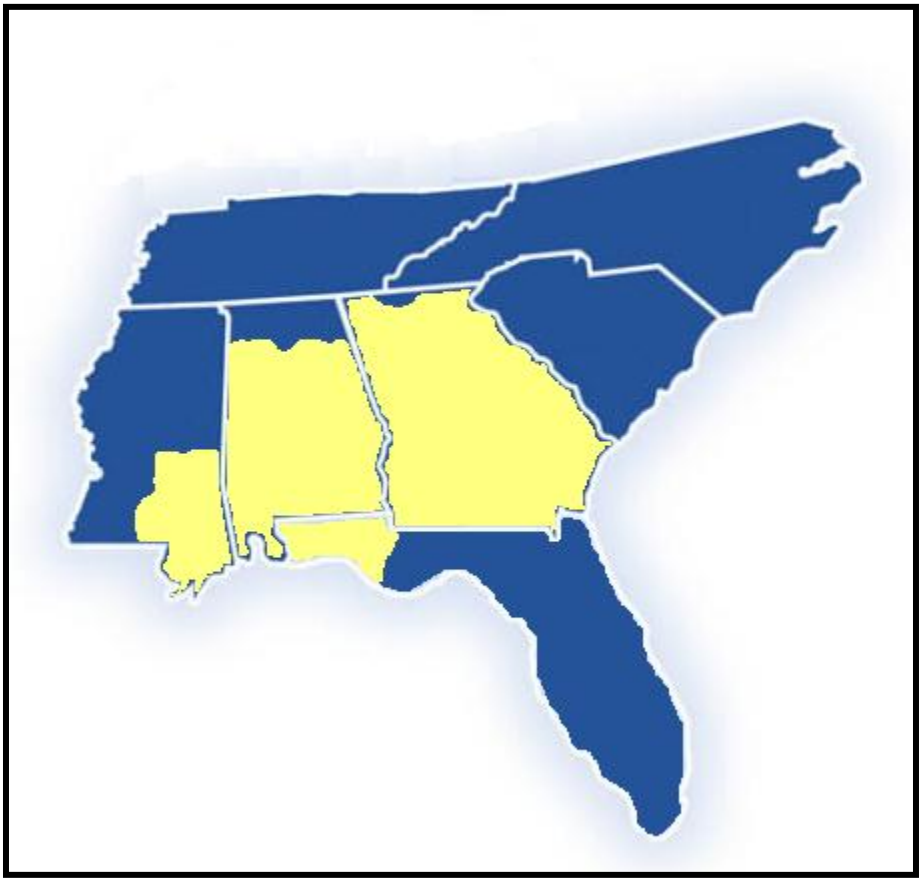
There were no identified constraints based on the assumptions used in this study and, and therefore, no potential solutions were identified. It must be noted that changes to the load forecast, and/or changes in the expansion plan could occur, and would impact the results of this study. In addition, the current projected enhancements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission system expansion plans could also impact the results of this study. Other Balancing Areas were not monitored which could result in additional limitations and required system improvements.

Table 4.2. Total Cost of the TVA Border to Southern 1500 MW Transfer (Spring Valley)

Area	Estimated Cost
TOTAL ($2013)	**$0**[(1)]

(1) Total cost does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by 3/1/2017. The studied transfer depends on these projects being in-service by 3/1/2017. If any of these projects are delayed or cancelled, the cost to support the study transfer could be greater than the total shown above.

Diagram 4.1. Approximate Location of Potential Solutions



Interchange Assumptions

Table 4.3. Additional Transactions Modeled in Cases

OASIS Ref. #	POR	POD	Amount (MW)
1005700	DUKE	PS LOAD	50
147615	DUKE	OPC LOAD	465
147613	TVA	OPC LOAD	310
1009082	TVA	SOCO	500
854479	EES	SMEPA LOAD	45
1005698	EES	PS LOAD	150
1009038	EES	SOCO	195
1026030	EES	SOCO	202
1033066	EES	SOCO	59
1033067	EES	SOCO	41
1033068	EES	SOCO	3
946923	EES	GTC	100
921615	EES	GTC	50
911948	EES	GTC	50
1009095	EES	SOCO	250

Table 4.4. Capacity Benefit Margin Preserved (CBM)

Transmission Owner	Interface	Amount (MW)
Southern	Duke	350
Southern	TVA	400
Southern	EES	100
Southern	SCPSA	125
Southern	SCEG	75

Table 4.5. Transmission Reliability Margins Preserved (TRM)

Transmission Owner	Interface	Amount (MW)
Southern	From Duke	194
GTC	From Duke	106
MEAG	From Duke	25
Dalton	From Duke	3
Southern	From Entergy	206
Southern	From TVA	232
GTC	From TVA	51
MEAG	From TVA	12
Dalton	From TVA	1

TVA Border to Southern

1500 MW

Summer Peak

Study Structure and Assumptions

Transfer Sensitivity	Transfer Amount	Transfer Source	Transfer Sink	Study Year
TVA Border to Southern	1500 MW	TVA	Southern	2017
Load Flow Cases				
2013 Series Version 2A Cases: Summer Peak				
Source Modeled				
The source for this transfer was a uniform load reduction in TVA.				

Transmission System Impacts

Tables 5.1 – 5.3 below identify 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.

Southern Balancing Authority

Table 5.1. Pass 0 – Transmission System Impacts With No Enhancements – *Southern Balancing Authority*

The following table identifies significant constraints in the Southern Balancing Authority ("SBA") without any enhancements to the transmission system.

			Thermal Loadings (%)				
AREA	**Limiting Element**	**Rating (MVA)**	**Without Request**	**With Request**	**Contingency**	**Scenario**	**Project**
The following constraints have been identified as directly attributable to the above defined transfer.							
SBA	2499 CONASAUGA 500 360662 8BRADLEY TN 500 1	2598	88.0	104.2	11 S HALL 500 306008 8OCONEE 500 1	3	N/A [1]
SBA	2766 S HALL B1 230 3067 CANDLER 230 1	509	93.8	103.0	3 NORCROSS 500 11 S HALL 500 1	1	P1
SBA	198 PINSON 230 199 OOSTANAULA 230 1	664	85.5	101.2	21 MOSTELLER 500 2499 CONASAUGA 500 1	2	P1
SBA	94 BIO 230 105 VANNA 230 1	433	96.0	101.1	11 S HALL 500 306008 8OCONEE 500 1	1	P1
SBA	104 LEXINGTON 230 339100 6RUSSEL 230 1	596	95.1	100.4	11 S HALL 500 306008 8OCONEE 500 1	1	P1

[1] The limiting element of this tie-line constraint is located within TVA

Scenario Explanations

1) McDonough Unit #6 Offline, Summer Peak Case
2) Bowen Unit #1 Offline, Summer Peak Case
3) T.A. Smith Unit #1 Offline, Summer Peak Case

Table 5.2. Pass 1 – Transmission System Impacts With Proposed Enhancement "P1" – *Southern Balancing Authority*

The following table identifies constraints in the Southern Balancing Authority ("SBA") with the proposed enhancements "P1" applied to the transmission system. Enhancements were identified to alleviate these constraints.

AREA	Limiting Element	Rating (MVA)	Thermal Loadings (%) Without Request	Thermal Loadings (%) With Request	Contingency	Scenario	Project
The following facilities could become potential constraints in future years or with different queuing assumptions							
SBA	4128 JWALTTP 161 4978 BERRY 161 1	193	103.2(1)	126.8	4157 MILLER8 500 5307 WVERN SS8 500 1	1	P2
SBA	4332 ATTALLA5 161 360283 5ALBERTVILLE 161 1	193	96.8	122.7	4234 CLAY 6 230 4247 ONEONTA6 230 1	2	P3
SBA	4131 OAKMANTP 161 4978 BERRY 161 1	193	102.8(1)	123.4	4157 MILLER8 500 5307 WVERN SS8 500 1	1	P2
SBA	4131 OAKMANTP 161 4135 GORGAS 161 1	193	102.8(1)	123.4	4157 MILLER8 500 5307 WVERN SS8 500 1	1	P2
SBA	4234 CLAY 6 230 5039 ARGO DS 230 1	602	87.9	108.7	4156 MILLER6 230 4157 MILLER8 500 1	2	P4
SBA	4241 LEEDSTS6 230 5039 ARGO DS 230 1	602	84.5	105.3	4156 MILLER6 230 4157 MILLER8 500 1	2	P4

(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.

Scenario Explanations

1) Gorgas Offline, Shoulder (93% Load Level) Case
2) Gaston Unit #5 Offline, Shoulder (93% Load Level Case)
3) T.A. Smith Unit #1 Offline, Summer Peak Case

Table 5.3. Pass 2 – Transmission System Impacts With All Proposed Enhancements – *Southern Balancing Authority*

SERTP 2013 Economic Study Results
December 2013

The following table identifies constraints in the Southern Balancing Authority ("SBA") with the proposed enhancements "P1" through "P4" applied to the transmission system. The resulting facilities in the table below could become potential constraints in future years or with different queuing assumptions, but are not overloaded in the 2017 study year.

			Thermal Loadings (%)				
AREA	**Limiting Element**	**Rating (MVA)**	**Without Request**	**With Request**	**Contingency**	**Scenario**	**Project**
The following facilities could become potential constraints in future years or with different queuing assumptions							
SBA	256 WEST END 115 285 GRADY B3 115 1	188	97.4	99.6	36 JACK MCD B2 230 41 PEACHTREE 230 1	1	--
SBA	198 PINSON 230 199 OOSTANAULA 230 1	664	85.5	99.3	21 MOSTELLER 500 2499 CONASAUGA 500 1	11	--
SBA	4762 LEHGH TP 115 5938 LEEDSTS3 B2 115 1	212	75.8	98.1	4233 CLAY 3 115 4246 SPRINGVL 115 1	2	--
SBA	2766 S HALL B1 230 3067 CANDLER 230 1	509	93.8	97.9	3 NORCROSS 500 11 S HALL 500 1	3	--
SBA	809 CAGLES 115 1626 KATHLEEN 115 1	114	96.5	97.8	804 BONAIRE B1 115 806 96 HWY 115 1	3	--
SBA	209 HOPEWELL 230 1931 R_HOPEWL 230 1	497	91.5	97.4	20 BOWEN 500 21 MOSTELLER 500 1	3	--
SBA	461 JACKSON LK 115 1917 S COV J 115 1	71	88.9	97.4	746 S GRIFFIN 115 750 GA BRD CORR 115 1	4	--
SBA	736 OHARA B2 115 2773 OHARA B2 230 1	300	94.9	97.1	171 OHARA LS 230 2771 OHARA B1 230 1	3	--
SBA	1122 DALTON 6 230 2498 LOOPERS ITS 230 1	828	85.2	96.8	21 MOSTELLER 500 2499 CONASAUGA 500 1	11	--
SBA	251 E POINT B2 115 264 E POINT 4 115 1	187	95.3	96.5	240 E POINT B1 115 303 COL PK 3 JN 115 1	1	--
SBA	1676 SLEEPY HOL 115 2319 PCH BLOSSOM 115 1	124	93.7	95.9	804 BONAIRE B1 115 806 96 HWY 115 1	5	--
SBA	1618 JEFFSONVL J 115 2351 BONAIRE B2 115 1	71	92.9	95.8	149 S MACON 230 2343 BONAIRE B1 230 1	6	--
SBA	736 OHARA B2 115 2773 OHARA B2 230 2	300	93.6	95.8	171 OHARA LS 230 2771 OHARA B1 230 1	3	--
SBA	2344 BONAIRE B2 230 2351 BONAIRE B2 115 1	400	92.2	95.6	804 BONAIRE B1 115 2343 BONAIRE B1 230 1	1	--
SBA	804 BONAIRE B1 115 2343 BONAIRE B1 230 1	400	92.2	95.6	2344 BONAIRE B2 230 2351 BONAIRE B2 115 1	1	--
SBA	8705 MPT EFR6 230 8708 R_DANIEL 230 1	866	92.3	95.5	4642 BIG CK 6 230 8702 DANIEL6 230 1	7	--
SBA	1135 MCGRAU F B1 230 1931 R_HOPEWL 230 1	509	89.8	95.5	20 BOWEN 500 21 MOSTELLER 500 1	3	--
SBA	888 DALTON 115 892 E DALTON B2 115 2	166	90.0	95.2	888 DALTON 115 892 E DALTON B2 115 1	2	--
SBA	25 MCGRAU FORD 500 88 MCGRAU F LS 230 1	2016	86.7	95.0	20 BOWEN 500 21 MOSTELLER 500 1	9	--
SBA	888 DALTON 115 892 E DALTON B2 115 1	166	89.5	94.7	888 DALTON 115 892 E DALTON B2 115 2	2	--
SBA	7320 NICEVLE 115 7324 VALPARAI B2 115 1	207	92.0	94.6	17117 FREEPT 3 115 17230 HAMBAYJC 115 1	7	--
SBA	2730 DYER ROAD 230 2731 DYER ROAD 115 1	400	86.8	94.2	2224 CORN CRIB 230 2730 DYER ROAD 230 1	8	--
SBA	1378 BOGGS RD 230 2031 PURCELL RD 230 1	509	86.2	94.1	11 S HALL 500 2035 S HALL LS 230 1	1	--
SBA	1101 GEORGE DAM 115 1893 FT GAINES 115 1	125	92.6	93.7	715 CEDAR SP J 115 4594 WEBB 3 115 1	7	--
SBA	208 NELSON 230 954 NELSON 115 2	176	88.8	93.5	208 NELSON 230 954 NELSON 115 1	3	--
SBA	1654 NORTHROP J 115 1655 AULTMAN RD 115 1	100	92.2	93.3	173 DORSETT 230 787 DORSETT 115 1	6	--
SBA	3067 CANDLER 230 3073 BRASELTON 230 1	509	89.2	93.3	3 NORCROSS 500 11 S HALL 500 1	3	--

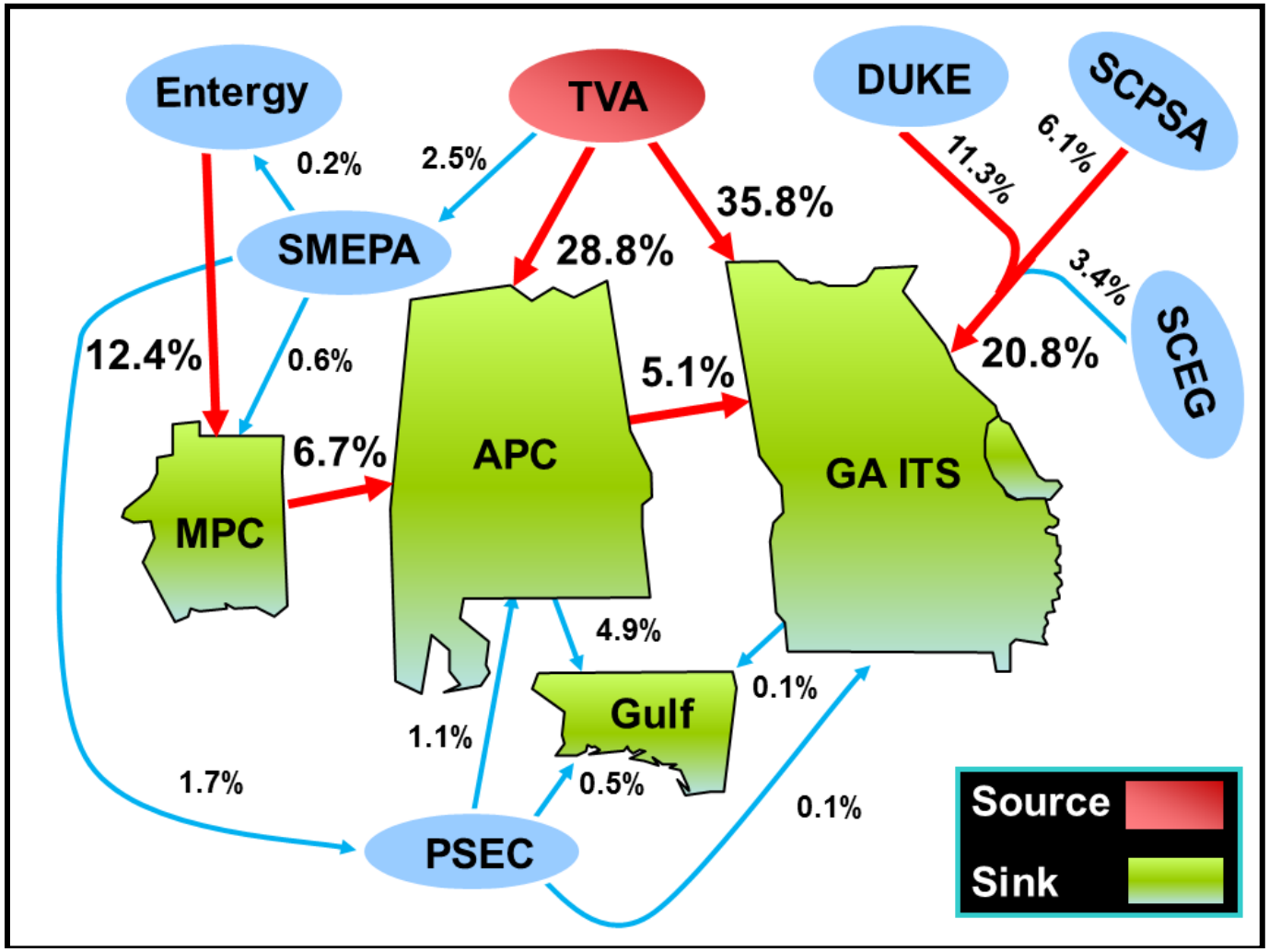
SERTP 2013 Economic Study Results
December 2013

AREA	Limiting Element	Rating (MVA)	Thermal Loadings (%) Without Request	Thermal Loadings (%) With Request	Contingency	Scenario	Project
SBA	4334 MORG XRD 115 5936 GS STEEL B1 115 1	112	73.7	93.0	4324 GADSDEN B1 115 5935 GADSDEN B2 115 1	9	--
SBA	129 S COWETA 230 719 S COWETA B1 115 1	400	91.8	93.0	16 OHARA 500 171 OHARA LS 230 1	3	--
SBA	748 SPALDING 115 876 BROOKS 115 1	155	88.6	92.7	1629 WOOLSEY 230 2771 OHARA B1 230 1	1	--
SBA	4200 BESSEMER B2 115 4202 BESSGRCO 230 1	392	84.0	92.1	4156 MILLER6 230 4157 MILLER8 500 1	10	--
SBA	4297 MOODY SS 115 4762 LEHGH TP 115 1	212	69.8	92.0	4233 CLAY 3 115 4246 SPRINGVL 115 1	2	--
SBA	240 E POINT B1 115 303 COL PK 3 JN 115 1	135	90.5	92.0	251 E POINT B2 115 264 E POINT 4 115 1	1	--
SBA	1508 NEWNAN 8 230 2494 R_DRESDEN 230 1	596	88.4	91.2	123 YATES 230 2480 YELLOW DIRT 230 1	5	--
SBA	94 BIO 230 105 VANNA 230 1	433	96.0	91.2	11 S HALL 500 306008 8OCONEE 500 1	3	--
SBA	123 YATES 230 2730 DYER ROAD 230 1	693	78.2	90.4	13 BONAIRE 500 150 BONAIRE LS 230 1	1	--

Scenario Explanations

1) McIntosh CC #11 Offline, Summer Peak Case
2) Hammond Offline, Summer Peak Case
3) McDonough Unit 6 Offline, Summer Peak Case
4) Hatch Unit #1 Offline, Summer Peak Case
5) Yates Unit #7 Offline, Summer Peak Case
6) Vogtle Unit #1 Offline, Summer Peak Case
7) Smith Unit #3 Offline, Summer Peak Case
8) Harris Unit #1 Offline, Summer Peak Case
9) Bowen Unit #4 Offline, Summer Peak Case
10) Gorgas Offline, Summer Peak Case
11) Bowen Unit #1 Offline, Summer Peak Case
12) T.A. Smith Unit #1 Offline, Summer Peak Case

TVA Border to Southern: Transfer Flows within the SERTP



Note: Red arrows indicate transfer percentages of greater than 5%.

Potential Solutions for Identified Constraints

The following projects are 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 current projected enhancements to the transmission system were modeled in the cases. Changes to system conditions and/or the transmission system expansion plans could also impact the results of this study. These potential solutions only address constraints identified within the SERTP Sponsors' areas that are associated with the proposed transfer. Other Balancing Areas were not monitored which could result in additional limitations and required system improvements.

Table 5.4. Potential Solutions for Identified Constraints – *Southern Balancing Authority*

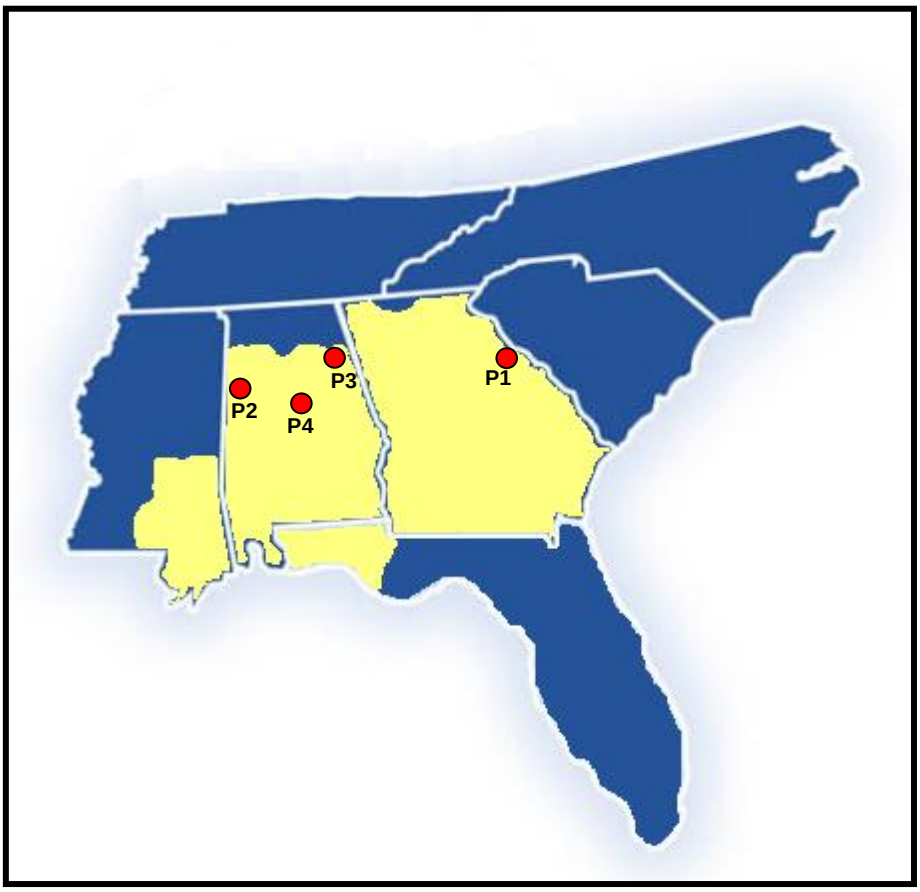
Item	Potential Solution	Estimated Need Date	Estimated Cost
P1	**Russell Dam – Athena 230 kV T.L.** • Construct approximately 45 miles of new 230 kV transmission line from Russell Dam to Athena with bundled (2) 1351 ACSR at 100°C. • Remove series reactors at East Watkinsville substation	2017	$60,000,000
P2	**Fayette – Gorgas 161 kV T.L.** • Rebuild approximately 38.8 miles along the Fayette – Gorgas 161 kV transmission line with 1351 ACSR at 100 °C.	2017	$36,300,000
P3	**Attalla – Albertville (TVA) 161 kV T.L.** • Reconductor approximately 19.6 miles with 1351 ACSR at 100°C from Attalla to Albertville 161 kV transmission line (SOCO) • Upgrade terminal equipment at Albertville 161 kV substation (TVA)	2017	$20,600,000
P4	**Clay TS – Leeds TS 230 kV T.L.** • Reconductor approximately 17.3 miles along the Clay – Leeds 230 kV transmission line with bundled (2) 1351 ACSR at 100 °C.	2017	$21,000,000
SBA Total ($2013)			$137,900,000

Table 5.5. Total Cost of the TVA Border to Southern 1500 MW Transfer

Area	Estimated Cost
SBA Total	$137,900,000
TOTAL ($2013)	**$137,900,000[(1)]**

[(1)] Total cost does not include the cost of projects that are included in SERTP Sponsors' expansion plans and are scheduled to be completed by 6/1/2017. The studied transfer depends on these projects being in-service by 6/1/2017. If any of these projects are delayed or cancelled, the cost to support the study transfer could be greater than the total shown above.

Diagram 5.1. Approximate Location of Potential Solutions



Interchange Assumptions

Table 5.6. Additional Transactions Modeled in Cases

OASIS Ref. #	POR	POD	Amount (MW)
OASIS Ref. #	POR	POD	Amount (MW)
1005700	DUKE	PS LOAD	50
147615	DUKE	OPC LOAD	465
147613	TVA	OPC LOAD	310
1009082	TVA	SOCO	500
854479	EES	SMEPA LOAD	123
1005698	EES	PS LOAD	150
1009038	EES	SOCO	195
1026030	EES	SOCO	202
1033066	EES	SOCO	59
1033067	EES	SOCO	41
1033068	EES	SOCO	3
946923	EES	GTC	100
921615	EES	GTC	50
911948	EES	GTC	50
1009095	EES	SOCO	250

Table 5.7. Capacity Benefit Margin Preserved (CBM)

Transmission Owner	Interface	Amount (MW)
Southern	Duke	350
Southern	TVA	400
Southern	EES	100
Southern	SCPSA	125
Southern	SCEG	75

Table 5.8. Transmission Reliability Margins Preserved (TRM)

Transmission Owner	Interface	Amount (MW)
Southern	From Duke	194
GTC	From Duke	106
MEAG	From Duke	25
Dalton	From Duke	3
Southern	From Entergy	206
Southern	From TVA	232
GTC	From TVA	51
MEAG	From TVA	12
Dalton	From TVA	1