TAG Meeting
September 18, 2014

Webinar

TAG Meeting Agenda

1. **Administrative Items – Rich Wodyka**
2. **FERC Order No. 1000 - Rule on Transmission Planning and Cost Allocation – Ben Harrison**
3. **2014 Reliability Study Activities – Mark Byrd**
4. **NCTPC 2013 Collaborative Transmission Plan Mid-year Update – Mark Byrd**
5. **Joint Inter-regional Study Scope and Study Activities – Bob Pierce**
6. **Operations Reliability Coordination Agreement (ORCA) Report – Bob Pierce**
7. **Regional Studies Update – Bob Pierce**
8. **2014 TAG Work Plan Update – Rich Wodyka**
9. **TAG Open Forum – Rich Wodyka**

FERC Order No. 1000 Rule on Transmission Planning and Cost Allocation Compliance Update

Ben Harrison – Duke Energy Carolinas

on behalf of the North Carolina Transmission Planning Collaborative

For the 9/18/14 TAG Meeting

NCTPC Regional Compliance Filings

- Oct 11, 2012 – DEC/DEP submitted regional compliance filing.
- Feb 21, 2013 – FERC issued order rejecting the NCTPC as an Order No. 1000 region.
- Mar 25, 2013 – DEC/DEP filed a request for rehearing/clarification of the order.
- Dec 19, 2013 – FERC issued order largely denying the DEC/DEP rehearing request. Order required some changes to the NCTPC local planning process. Duke given 60 days to submit revised compliance filing.

SERTP Filings

- May 22, 2013 – DEC/DEP submitted a revised Order No. 1000 regional compliance filing with FERC.
  - Retained NCTPC as the “local” transmission planning process
  - Proposed the SERTP for the “regional” transmission planning process
- July 10, 2013 – SERTP Sponsors submitted their interregional compliance filing – haven’t received any FERC response.
- July 18, 2013 – FERC issued their order on SERTP 1st regional compliance filing.

SERTP Filings (cont.)

- Aug 19, 2013 – SERTP Sponsors filed request for rehearing/clarification of FERC's 1st regional compliance order.
- Sept 30, 2013 – SERTP Sponsors filed with FERC the following:
  1. A request for an extension of time till January 14, 2014 to submit their revised regional compliance filing; and
  2. Requested an effective date of June 1, 2014 to implement the Order No. 1000 regional compliance.
- Oct 17, 2013 – FERC granted the above Sept 30th requests.

SERTP Filings (cont.)

- Jan 14, 2014 – DEC/DEP along with other SERTP Sponsors submitted the 2nd regional compliance filing (for Duke – only filed the transmittal letter).
- Feb 10, 2014 – DEC/DEP submitted the 2nd regional compliance filing which included revised NCTPC local areas as well as SERTP regional compliance areas.

FERC Order on SERTP 2nd Regional Filing

- On June 19th, FERC issued their 2nd regional compliance order for the SERTP region which also included a response to the rehearing requests.
  - FERC granted rehearing on one issue related to recognizing state or local laws and regulations, such as right-of-way, as a threshold matter in the regional transmission planning process.
- FERC basically approved the following areas of compliance:
  - Cost allocation – use of avoided transmission cost plus transmission losses
  - Withdrawal provisions – ability for non-FERC jurisdictional entities to withdraw from the SERTP

FERC Order on SERTP 2nd Regional Filing

- FERC required a number of compliance changes.
- July 21st – SERTP Sponsors filed request for rehearing/clarification of FERC's 2nd regional compliance order.
- August 18th – SERTP submitted their 3rd regional compliance filing.
- Importantly, through the June 19th order, FERC has approved the NCTPC "local" planning process as identified in the tariff language.

Transmission Planning Stakeholder Participation

- NCTPC – NCTPC will continue to function as the "local" transmission planning venue.
- SERTP – The regional planning process for Order No. 1000 purposes will be through the SERTP.
  - SERTP website link: http://www.southeasternrtp.com
  - Sign-up for SERTP email updates: http://www.southeasternrtp.com/email_signup.asp
  - September 30th – SERTP Stakeholder Meeting
    - Note: To sign up for this meeting go to http://www.southeasternrtp.com/contactus.asp and identify in the comments section that you would like to participate in the meeting either in person or by webinar. RSVP is requested by September 19th.

Questions ?

NCTPC
2014 Study Activities

Mark Byrd

Duke Energy Progress

Studies for 2014

- **Annual Reliability Study**
  - **Assess DEC and DEP transmission systems' reliability and develop a single Collaborative Transmission Plan**
- **Economic Study**
  - **Thermal analysis of transferring 250 MW from TVA to CPLW**
- **Special Request from NCUC**
  - **Assess potential impact of external transfers on the transmission grid in North Carolina**

Steps and Status of the Study Process

Completed

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

Study Assumptions Selected

- **Study Years for reliability analyses:**
  - **Near-term: 2019 Summer, 2019/2020 Winter**
  - **Longer-term: 2024 Summer**
- **LSEs provided:**
  - **Input for load forecasts and resource supply assumptions**
  - **Dispatch order for their resources**
- **Interchange coordinated between Participants and neighboring systems**

Study Criteria and Methodologies Established

- **NERC Reliability Standards**
  - **Current standards for base study screening**
  - **Current SERC Requirements**
- **Individual company criteria**
- **Thermal Power Flow Analysis**
- **Each system (DEC & DEP) will be tested for impact of other system's contingencies**

Base Case Models Developed

- Started with 2013 series MMWG cases
- Latest Updates to Detailed models for DEC and DEP systems are included
- Adjustments were made based on additional coordination with neighboring transmission systems
- Planned transmission additions from updated 2013 Plan were included in models

Resource Supply Options Selected

- **Last year**
  - **Hypothetical 1000 MW import/export scenarios**
  - **Coordination with PJM for modeling transfers**
- **This year**
  - **Special request from NCUC**

Technical Analysis
Base Reliability

- Conducted thermal screenings of the 2019 and 2024 base cases
- No new issues were observed that do not have planned mitigation

Technical Analysis Economic Study & Joint PJM/MISO/NCTPC Study

- 250 MW transfer from TVA to CPLW study results being analyzed
- Joint Study analysis is underway

Questions ?

NCTPC 2013 Collaborative Transmission Plan Update

Mark Byrd

Duke Energy Progress

2014 Mid-Year Update to the 2013 Collaborative Transmission Plan

- **Two DEC projects and Five DEP projects were placed in-service**
- **Two DEP projects added (Harlowe & Piney Green)**
- **One DEP project removed (BR1-Jacksonville 230 kV)**
- **Total Reliability Project Cost changed from $223M to $209M and Merger Projects Cost changed from $67M to $73M (Kinston Dupont-Wommack 230 kV added)**

Reliability Projects in 2013 Plan		
Reliability Project	**TO**	**Planned I/S Date**
Harris-RTP 230 kV line	DEP	May 23, 2014
Brunswick 1 - Jacksonville 230 kV Line Loop -in to Folkstone 230 kV substation	DEP	Cancelled
Greenville-Kinston Dupont 230 kV line	DEP	May 12, 2014
Raeford 230 kV substation, Loop-In Richmond – Ft Bragg Woodruff St 230 kV Line and add 3rd bank	DEP	June 2018

Reliability Projects in 2013 Plan (continued)		
Reliability Project	**TO**	**Planned I/S Date**
Durham-RTP 230kV Line, Reconductor	DEP	June 2023
Reconductor Caesar 230 kV Lines (Pisgah Tie-Shiloh Switching Station)	DEC	December 3, 2013
Jacksonville-Piney Green 230 kV Line and Piney Green 230/115 kV Substation	DEP	June 2020
Newport-Harlowe 230 kV Line, Newport SS and Harlowe 230/115 kV Substation	DEP	June 2020

Merger Projects in 2013 Plan		
Merger Project	**TO**	**Planned I/S Date**
Lilesville-Rockingham 230kV Line #3 – Construct new line	**DEP**	**December 22, 2013**
Person-(DVP) Halifax 230kV Line – Reconductor DVP section (DVP work)	**DEP**	**April 30, 2014**
Antioch 500/230kV Substation – Replace Two Transformer Banks	**DEC**	**May 1, 2014**
Kinston Dupont-Wommack 230 kV Line - Reconductor	**DEP**	**May 12, 2014**

Questions ?

Joint MISO-NCTPC-PJM Reliability and Economic Study

Bob Pierce

Duke Energy Carolinas

Joint Study

Reliability Study

- Base model - 2016S peak load based on 2013 series MMWG model with detailed internal models of participants included
- MISO & PJM market dispatch incorporated including resources from PJM's 2016/2017 Base Residual Capacity Auction
- Contingency analysis has been run and impacts are being evaluated
- Final report will include reliability & economic study results

Joint Study

"Merged Case" – 2013 series 2015 Summer Peak MMWG power flow where PJM, MISO, and NC systems were replaced by 2016 versions of each region. Interchanges were preserved as of the MMWG case with exception of the addition of a new transaction from Manitoba into MISO in the order of 673MW.

"Base Case" – using the Merged Case, modeled the *BRA units with confirmed transmission service* sending power to PJM (4,886MW).

"Changed Case" – using the Base Case, modeled additionally the *MISO BRA units that have not yet secured firm transmission service* sending power to PJM (1,940MW).

"Sensitivity" – using the Changed Case, modeled additionally *remaining BRA units that have not yet secured transmission service (All BRA units)* sending power to PJM (836MW).

Joint Study

Economic Study

- Performed by Duke Energy Resource Planning and PJM Interregional Planning Department using production costing models
- Have shared/coordinated data for generation, load forecast, resource plan, fuel prices….
- Linear analysis (MUST) has been performed to identify the impact on transfer capability of the resources identified in the reliability study
- Pipe & bubble type analysis of production cost will be performed utilizing FCITC results from the reliability study model

Joint Study

Schedule

Reliability Study – Complete 10/14

Economic Study – Complete 12/14

Questions ?

MISO/Entergy Integration Operations Reliability Coordination Agreement (ORCA)

Bob Pierce

Duke Energy Carolinas

MISO/Entergy Integration

MISO South

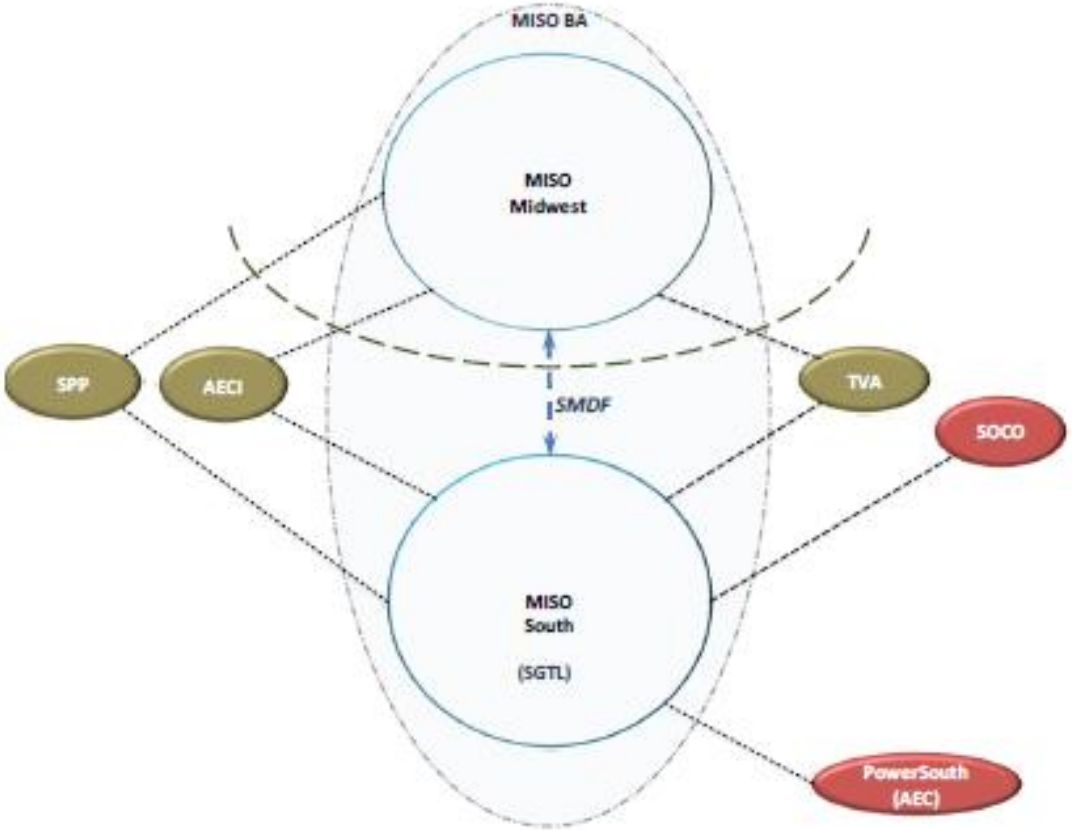
- Entergy Operating Companies (including, but not limited to, Entergy Arkansas, Inc., Entergy Gulf States Louisiana, L.L.C., Entergy Louisiana LLC, Entergy Mississippi, Inc., Entergy New Orleans, Inc. and Entergy Texas, Inc.),
- Louisiana Energy and Power Authority,
- Lafayette Utilities System,
- South Mississippi Electric Power Association,
- Cleco Corporation,
- NRG/Louisiana Generating, LLC (including West Memphis, North Little Rock and Conway)

MISO/Entergy Integration

- The Joint Parties (SPP, TVA, Southern, AECI, PowerSouth, Louisville Gas and Electric, and Kentucky Utilities) entered into an Operating Reliability Coordination Agreement (ORCA) with MISO.

- The ORCA provides a long term road map for coordination and study between the Parties to ensure reliability in the consolidated MISO BA that stretches from the gulf coast through middle America to the US Canadian border.

MISO/Entergy Integration

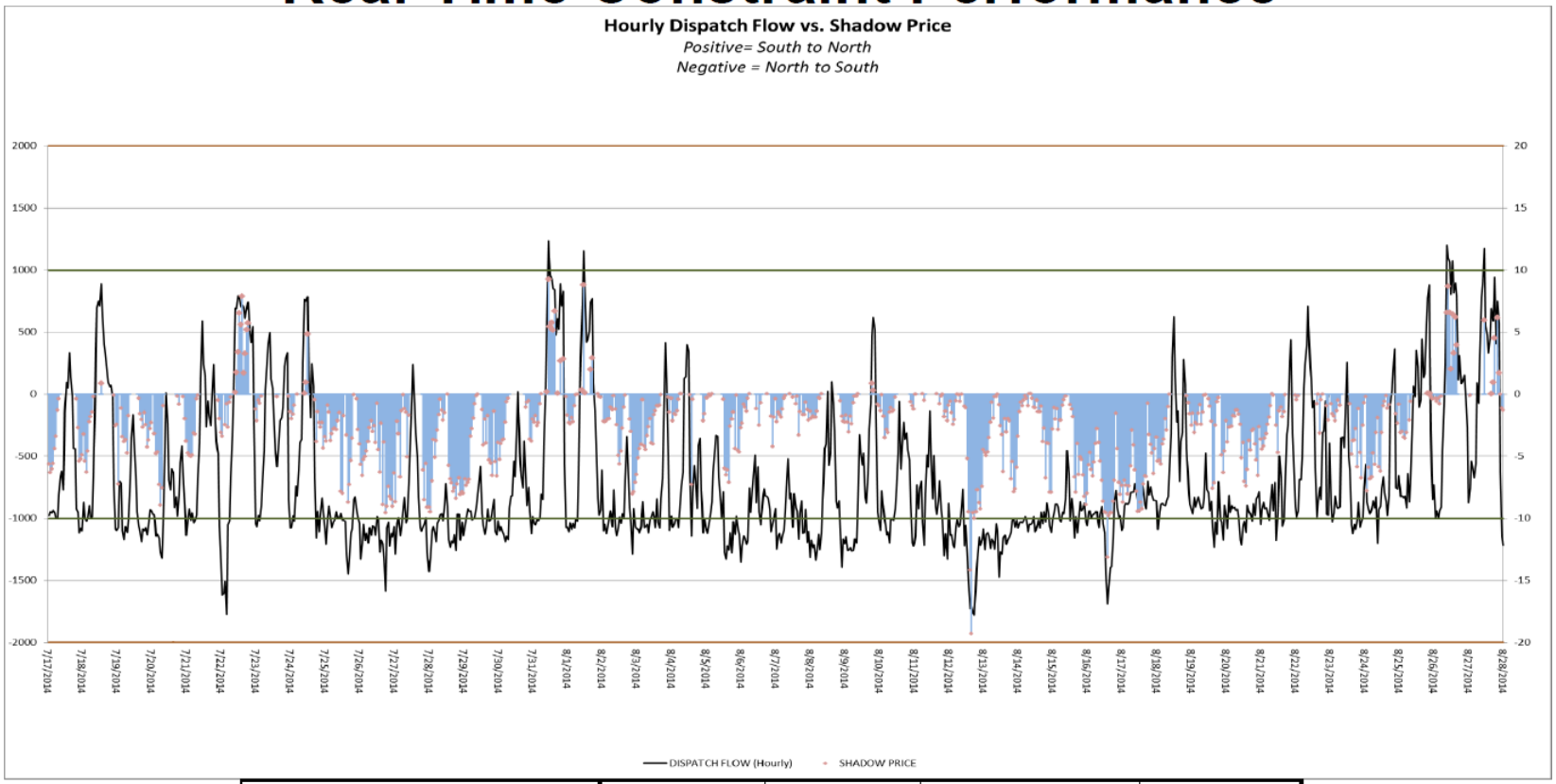


ORCA Phase Description

Phase 1	Phase 2	Phase 3
Through April 19 2014*	**Through Oct. 01 2014***	**Through April 01 2015**
2000MW Dispatch Flow Limit	Dispatch Flow limit set with two day ahead process*	Dispatch Flow limit set with one day ahead process*
MISO adjusts Dispatch Flow between 1500MW and 2000MW for congestion	Respect 2 day ahead Dispatch Flow limit	Respect 1 day ahead dispatch flow limit
If Dispatch Flow < 1500MW, use pre-existing congestion management processes (TLR)	If Dispatch Flow < 2 DA Limit, use pre-existing congestion management processes (TLR)	If Dispatch Flow < 1 DA Limit, use pre-existing congestion management processes (TLR)
Use Intra-day adjustment process to increase limit*	Use Intra-day adjustment process to increase limit*	Use Intra-day adjustment process to increase limit*
Develop Phase 2 process	Develop Phase 3 process	Develop Seams Agreement

* or upon completion of testing and validation

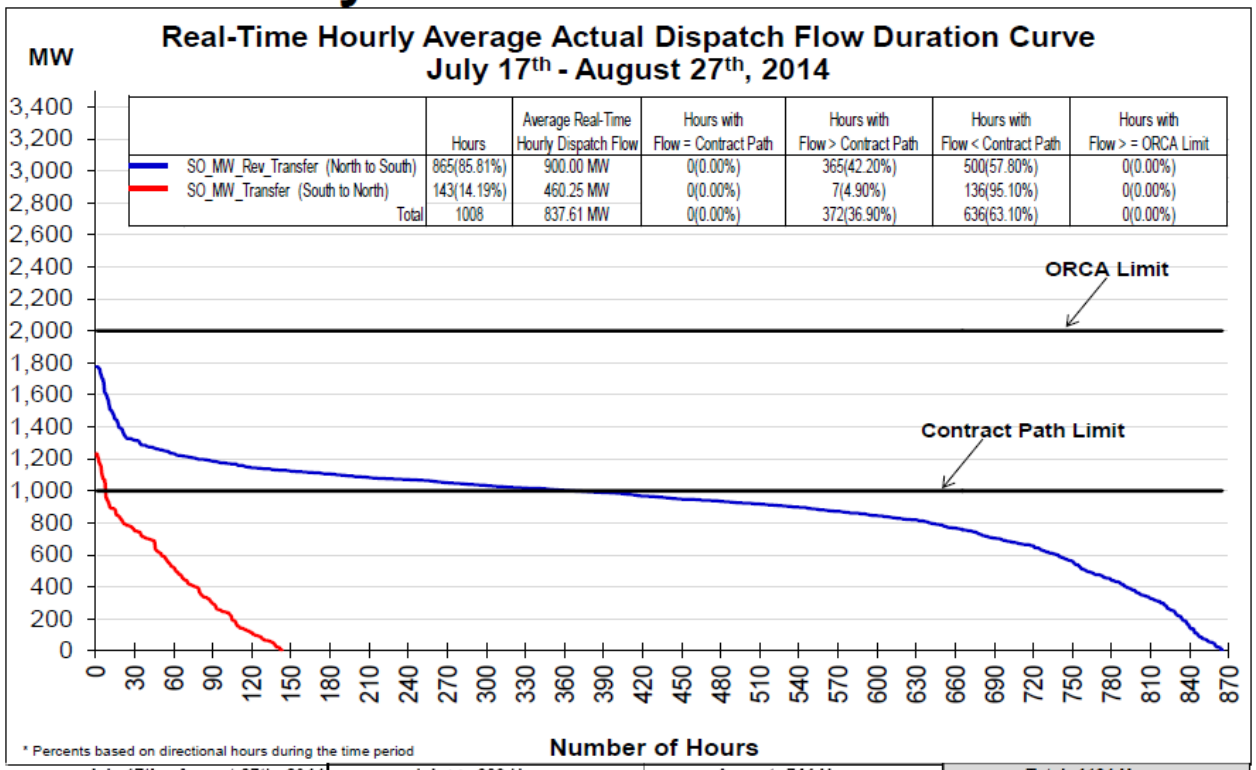
Real-Time Constraint Performance



Dispatch Flow July 17th - August7th	Average (MW)	Periods <1000	Periods >1000	Periods>2000
North to South	899.5	500	365	0
South to North	460.2	136	7	0
Shadow Price July 17th - August7th	**Average ($/MW)**	**Periods < $9.57**	**Periods = $9.57**	**Periods> $9.57**
North to South	-3.17	652	5	5
South to North	-3.54	46	0	0

Hourly Constraint Performance

Real-Time Hourly Average Actual Dispatch Flow Duration Curve
July 17th - August 27th, 2014



	Hours	Average Real-Time Hourly Dispatch Flow	Hours with Flow = Contract Path	Hours with Flow > Contract Path	Hours with Flow < Contract Path	Hours with Flow > = ORCA Limit
SO_MW_Rev_Transfer (North to South)	865(85.81%)	900.00 MW	0(0.00%)	365(42.20%)	500(57.80%)	0(0.00%)
SO_MW_Transfer (South to North)	143(14.19%)	460.25 MW	0(0.00%)	7(4.90%)	136(95.10%)	0(0.00%)
Total	1008	837.61 MW	0(0.00%)	372(36.90%)	636(63.10%)	0(0.00%)

* Percents based on directional hours during the time period

July 17th - August 27th, 2014	July++: 360 Hours		August: 744 Hours		Total: 1104 Hours	
CONSTRAINT_NAME	Average Dispatch Flow (MW)	Number of Hours	Average Dispatch Flow (MW)	Number of Hours	Average Dispatch Flow (MW)	Number of Hours
SO_MW_Rev_Transfer (North to South)	904.29	293 (81.3%)	897.80	572 (76.9%)	900.00	865 (78.4%)
SO_MW_Transfer (South to North)	454.95	67 (18.6%)	464.91	76 (10.2%)	460.25	143 (13.0%)
Grand Total	820.66	360 (100.0%)	847.03	648 (87.1%)	837.61	1008 (91.3%)

*Percents based on total hours in the month

++Hurdle Rate implemented on July 17, 2014

Day-Ahead Market Performance

- The Day-Ahead Market bound in 800 hours (79.4%) from July 17th – August 27th
  - SO_MW_Rev_Transfer (North to South) bound in 756 hours (75.0%)
  - SO_MW_Transfer (South to North) bound for 44 hours (4.4%)
- Average hourly shadow price was -$3.94/MW
  - SO_MW_Rev_Transfer (North to South): -$3.98/MW
    - August to-date declined 8.8% from July++
  - SO_MW_Transfer (South to North): -$3.22/MW
    - August to-date dropped 53.9% from July++
- Day-Ahead production cost savings exceeded the hurdle rate about 7.1% of the time[1]

July 17th - August 27th	July++: 360 Hours		August: 744 Hours		Total: 1104 Hours	
CONSTRAINT_NAME	Average Shadow Price ($/MW)	Hours Bound	Average Shadow Price ($/MW)	Hours Bound	Average Shadow Price ($/MW)	Hours Bound
SO_MW_Rev_Transfer (North to South)	-$4.22	264 (73.3%)	-$3.85	492 (66.1%)	-$3.98	756 (68.5%)
SO_MW_Transfer (South to North)	-$4.49	21 (5.8%)	-$2.07	23 (3.1%)	-$3.22	44 (4.0%)
Grand Total	-$4.24	285 (79.2%)	-$3.77	515 (69.2%)	-$3.94	800 (72.5%)

*Percents based on total hours in the month

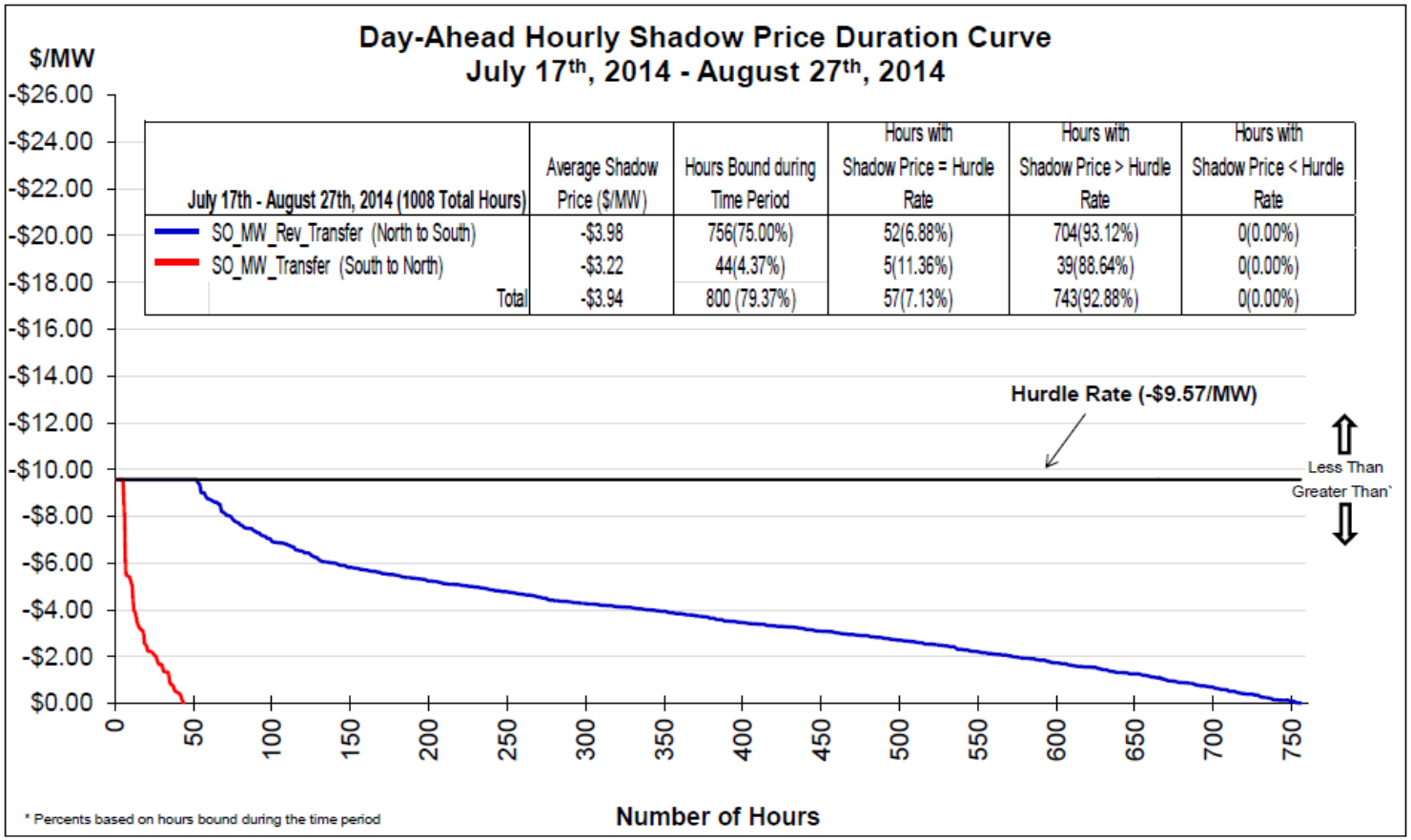
++Hurdle Rate implemented on July 17, 2014

[1] -Defined as the total number of intervals equal to the hurdle rate divided by the total number of hours bound

Day-Ahead Market Performance

Day-Ahead Hourly Shadow Price Duration Curve
July 17th, 2014 - August 27th, 2014

July 17th - August 27th, 2014 (1008 Total Hours)	Average Shadow Price ($/MW)	Hours Bound during Time Period	Hours with Shadow Price = Hurdle Rate	Hours with Shadow Price > Hurdle Rate	Hours with Shadow Price < Hurdle Rate
SO_MW_Rev_Transfer (North to South)	-$3.98	756(75.00%)	52(6.88%)	704(93.12%)	0(0.00%)
SO_MW_Transfer (South to North)	-$3.22	44(4.37%)	5(11.36%)	39(88.64%)	0(0.00%)
Total	-$3.94	800 (79.37%)	57(7.13%)	743(92.88%)	0(0.00%)



MISO

Real-Time Market Performance

- The Real-Time Market bound in 6356 intervals (52.5%) from July 17th – August 27th
  - SO_MW_Rev_Transfer (North to South) bound in 6051 intervals (50.0%)
  - SO_MW_Transfer (South to North) bound for 305 intervals (2.5%)
- Average 5-minute shadow price was -$4.25/MW
  - SO_MW_Rev_Transfer (North to South): -$4.14/MW
    - August to-date dropped 12.8% from July++
  - SO_MW_Transfer (South to North): -$6.44/MW
    - August to-date increased 13.7% over July++
- Real-Time production cost savings exceeded the hurdle rate about 9.7% of the time[1]

July 17th - August 27th	July++: 4320 Intervals		August: 8928 Intervals		Total: 13248 Intervals	
CONSTRAINT_NAME	Average Shadow Price ($/MW)	Intervals Bound	Average Shadow Price ($/MW)	Intervals Bound	Average Shadow Price ($/MW)	Intervals Bound
SO_MW_Rev_Transfer (North to South)	-$4.52	2077 (48.1%)	-$3.94	3974 (44.5%)	-$4.14	6051 (45.7%)
SO_MW_Transfer (South to North)	-$6.07	170 (3.9%)	-$6.90	135 (1.5%)	-$6.44	305 (2.3%)
Grand Total	-$4.64	2247 (52.0%)	-$4.04	4109 (46.0%)	-$4.25	6356 (48.0%)

*Percents based on total intervals in the month

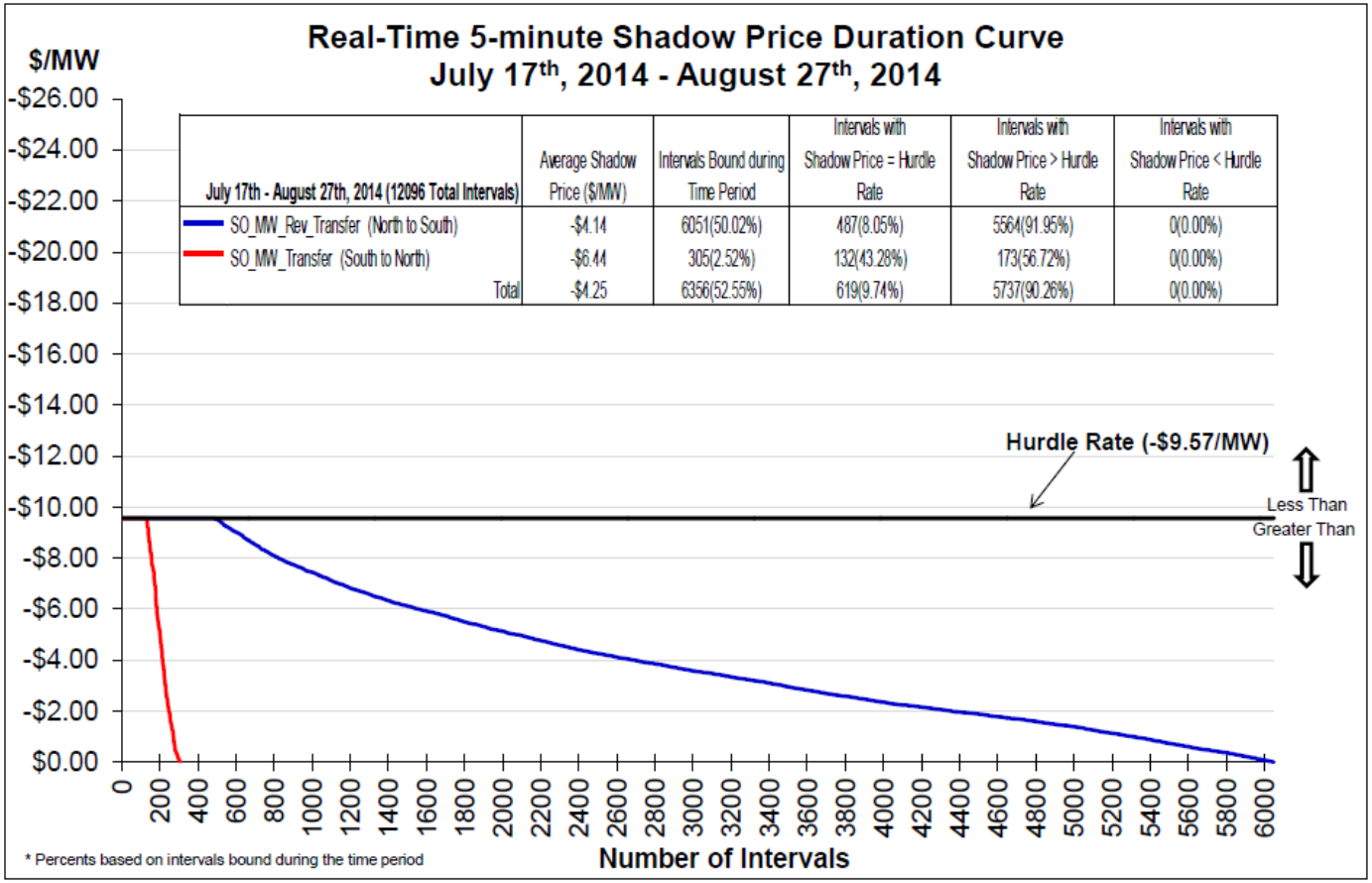
++Hurdle Rate implemented on July 17, 2014

[1] -Defined as the total number of intervals equal to the hurdle rate divided by the total number of hours bound

Real-Time Market Performance

Real-Time 5-minute Shadow Price Duration Curve
July 17th, 2014 - August 27th, 2014

July 17th - August 27th, 2014 (12096 Total Intervals)	Average Shadow Price ($/MW)	Intervals Bound during Time Period	Intervals with Shadow Price = Hurdle Rate	Intervals with Shadow Price > Hurdle Rate	Intervals with Shadow Price < Hurdle Rate
SO_MW_Rev_Transfer (North to South)	-$4.14	6051(50.02%)	487(8.05%)	5564(91.95%)	0(0.00%)
SO_MW_Transfer (South to North)	-$6.44	305(2.52%)	132(43.28%)	173(56.72%)	0(0.00%)
Total	-$4.25	6356(52.55%)	619(9.74%)	5737(90.26%)	0(0.00%)



* Percents based on intervals bound during the time period

Key Takeaways

- July 16th, 2014, MISO filed a revision to its Tariff to modify demand curves associated with the Sub-Regional Power Balance Constraints (SRPBC) effective at 00:00 EST on July 17th, 2014

- SO_MW constraint to provide a hurdle rate and cost recovery mechanism

- ORCA constraint demand curve to manage ORCA related transfer limits
  - Day-Ahead Market production cost savings exceeded the hurdle rate 7.1% of the time
  - Real-Time Market production cost savings exceeded the hurdle rate 9.7% of the time

Questions ?

Regional Studies Reports

Bob Pierce - Duke

National Offshore Wind Energy Grid Interconnection Study

NOWEGIS

Bob Pierce

Duke Energy Carolinas

NOWEGIS

Study

- DOE funded to help address barriers to commercial offshore wind development
- Potential to achieve 54 GW capacity by 2030 and 10 GW by 2020
- Two critical objectives to address; 1) reduction in cost of energy and 2) reduction in deployment timelines

NOWEGIS

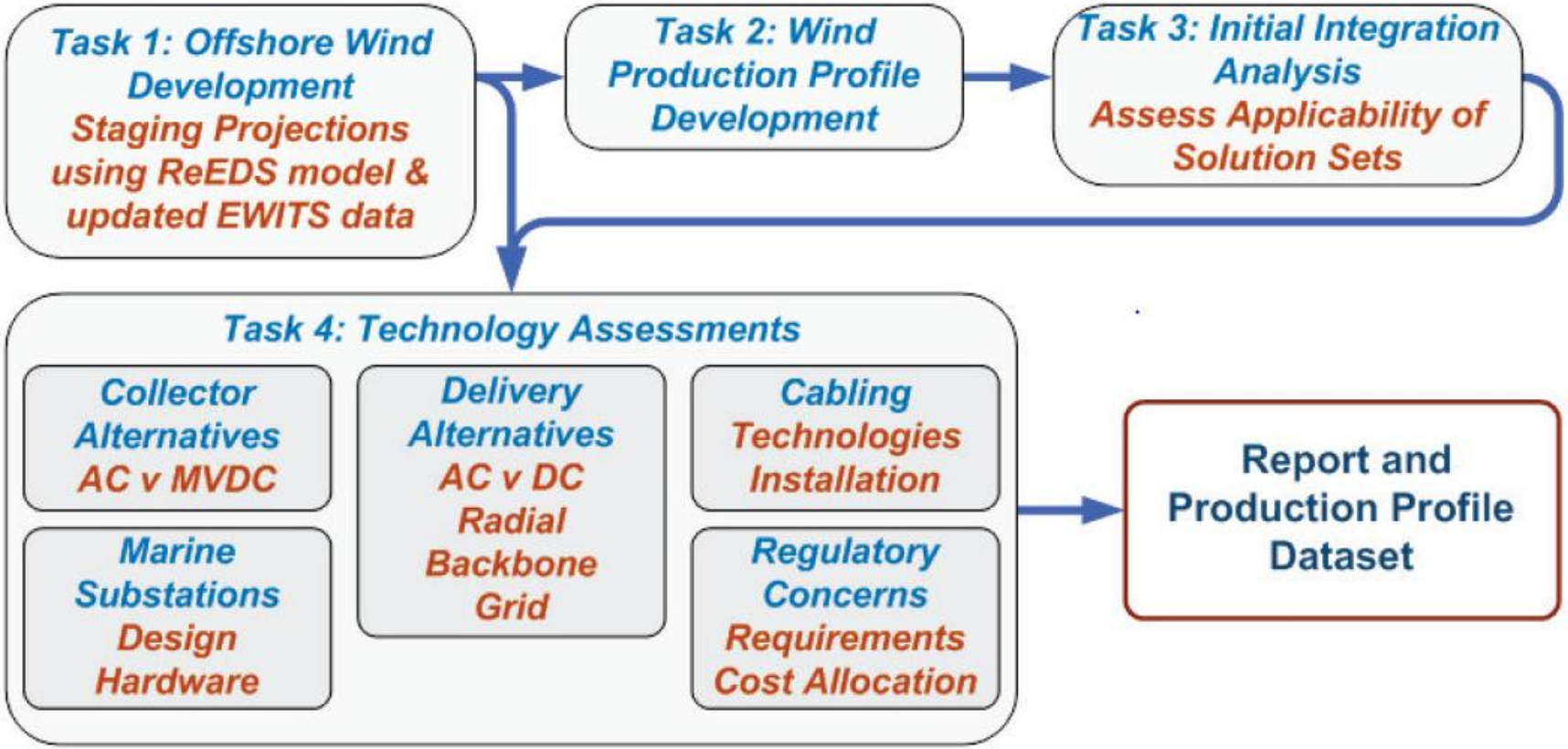


Figure 1-1. NOWEGIS tasks and study flow

NOWEGIS

Table ES-1. Installed Offshore Capacity by GridView Region

Interconnection	GridView Region	Offshore Wind Capacity (GW)
Eastern	PJM	18.2
	New England	13.1
	Carolinas	8.3
	MISO	6.0
Western	Northern California	2.9
	NWPP	2.9
Texas	ERCOT	2.8

NOWEGIS

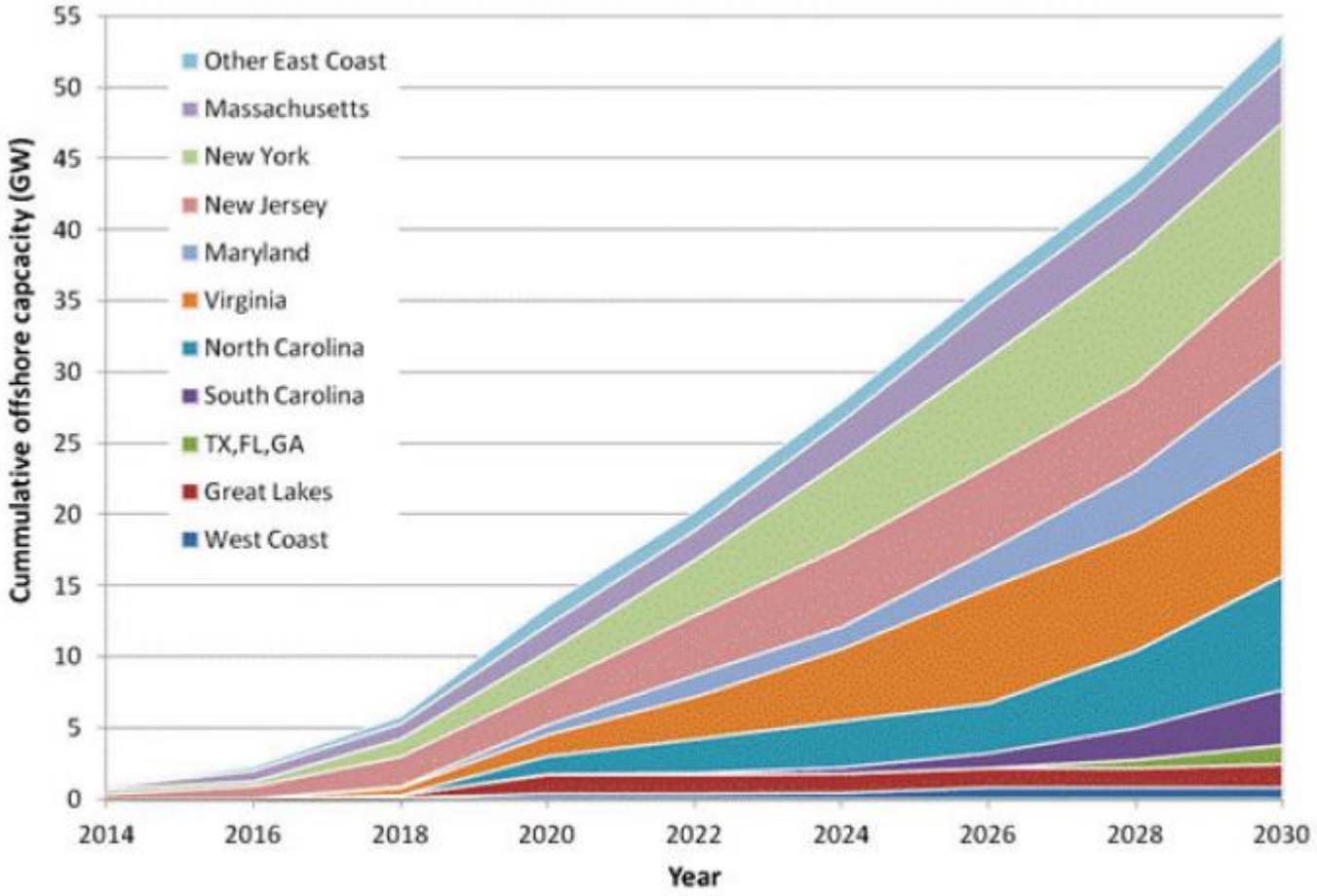
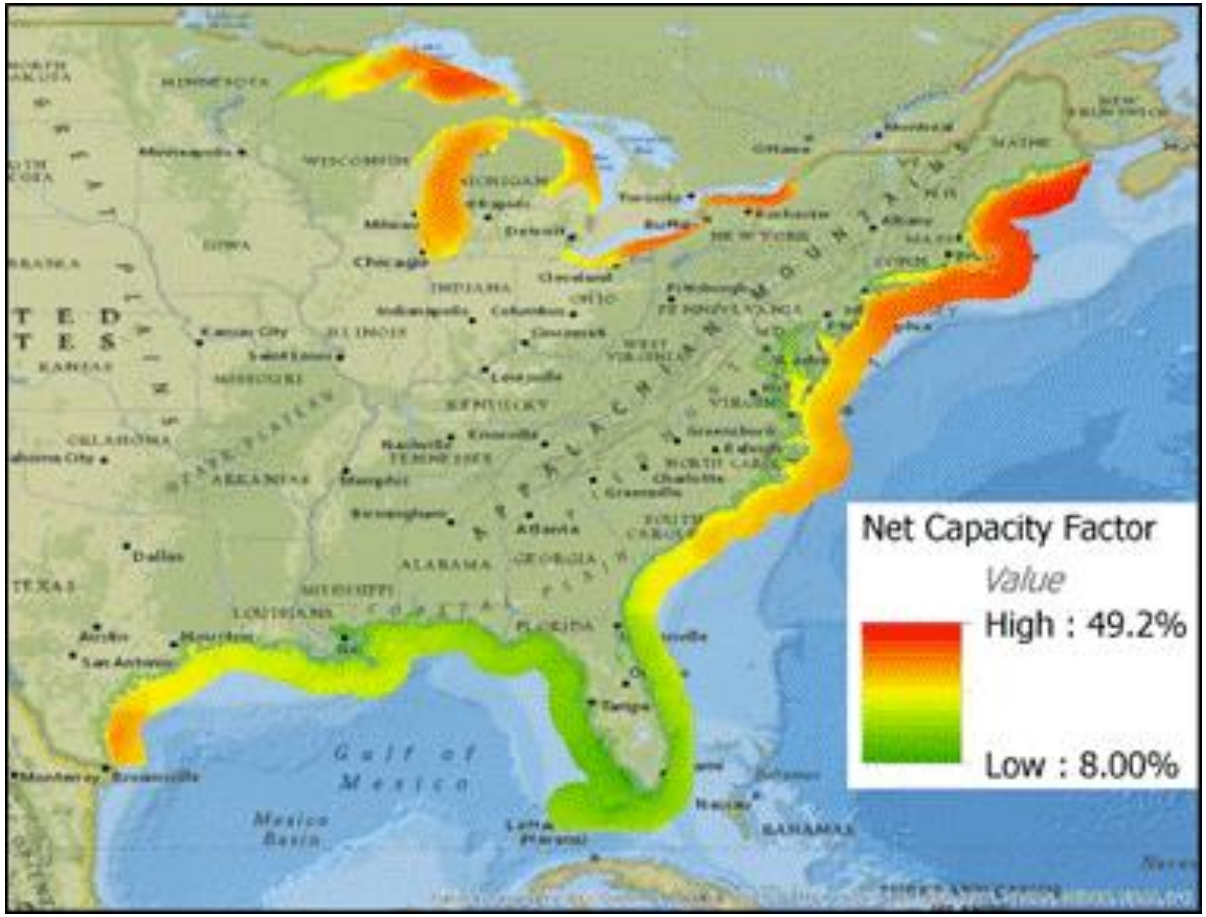


Figure 2-10. Installed wind capacity by state

NOWEGIS


Net Capacity Factor
Value
High : 49.2%
Low : 8.00%
Gulf of Mexico
Mexico Basin
Chicago
Detroit
Cleveland
Atlanta
Dallas
Houston
San Antonio
Miami
Tampa
Charlotte
Nashville
Memphis
Kansas City
Minneapolis
Montreal
Ottawa
Toronto
Buffalo
Boston
New York
Philadelphia
Pittsburgh
Columbus
Indianapolis
Louisville
Knoxville
Birmingham
Monterrey
Bahamas

NOWEGIS

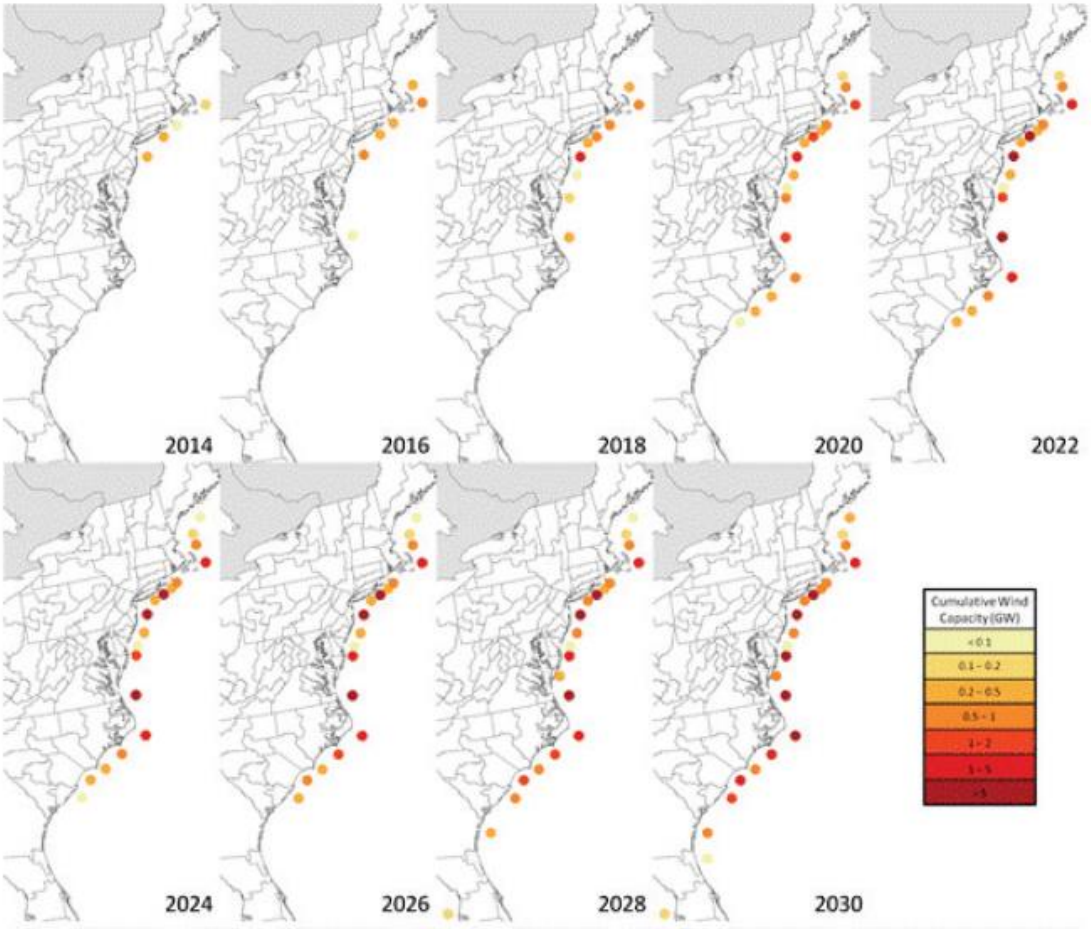


Figure 2-11. Offshore wind build-out for the East Coast

NOWEGIS

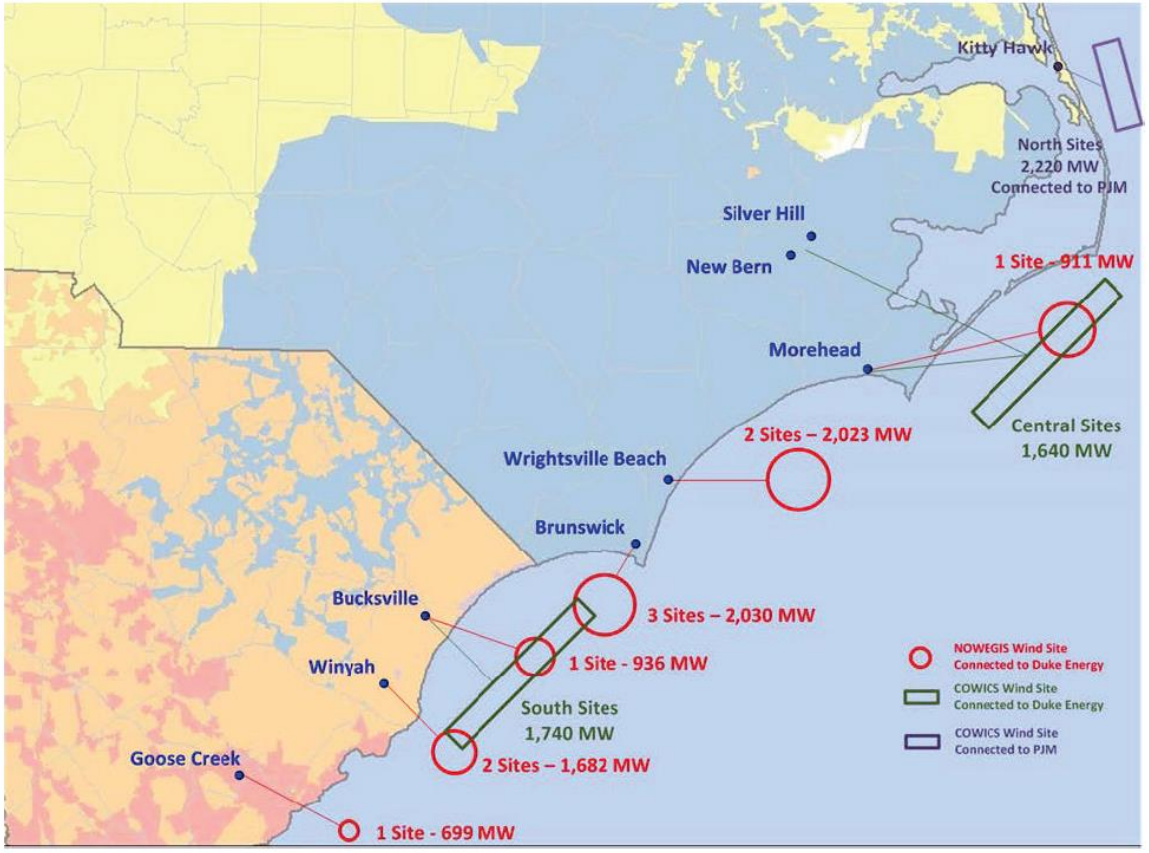


Figure 6-27. Map of wind site locations and onshore interconnections—NOWEGIS compared to COWICS

http://energy.gov/eere/downloads/national-offshore-wind-energy-grid-interconnection-study-nowegis

DOE National Congestion Study

- The draft study has been released for public comment for a period of 60 days.
- The comment period will close at 5 p.m. Eastern Daylight Time, October 20, 2014.
- After the close of the public comment period, the Department of Energy will review and consider all comments received, make changes as appropriate, and issue a final version of the

National Electric Transmission Congestion Study.

Recent Nation-wide Trends Affecting Transmission Constraints and Congestion Since the 2009 Congestion Study

- Transmission constraints and congestion are influenced both by broad, economy-wide trends or conditions and by unique regional and sometimes local circumstances.

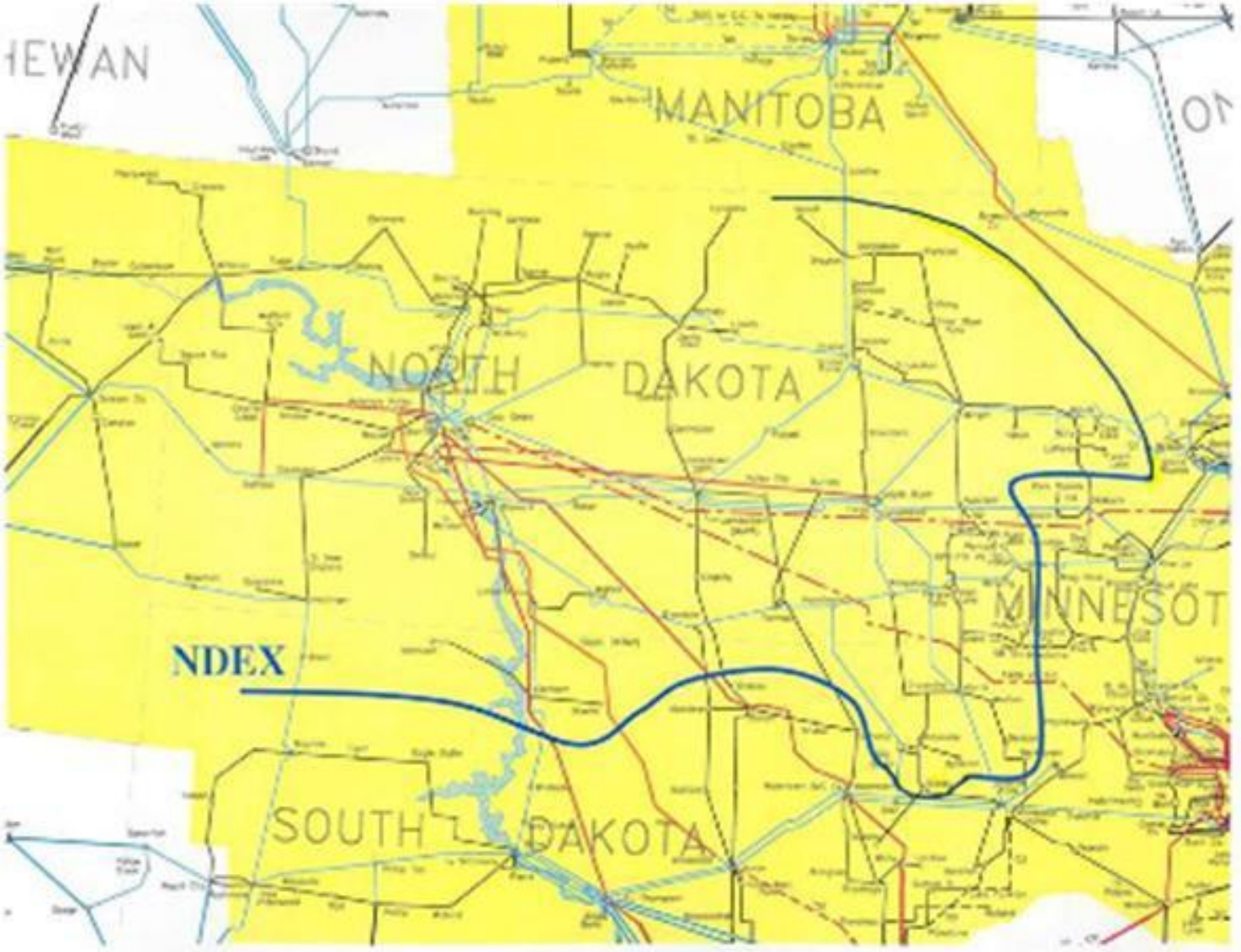
- Several broad, nation-wide trends have affected transmission usage patterns since the publication of the 2009 Congestion Study. Most, but not all, of these trends have tended to reduce the incidence of congestion and its economic costs.

These trends are:

- Modest economic growth since the end of the 2008 recession. Slower economic growth has reduced the rate of electricity demand growth. Lower electricity demand frequently means lower transmission usage and lower congestion.

- State and federal governments and many utilities are implementing policies to improve energy efficiency. These improvements in efficiency put downward pressure on electricity demand across the country.

- Compliance with state RPSs requirements. In response to the RPSs, renewable output has risen sharply. Increased generation from renewables in remote locations, though generally beneficial, is increasing congestion in some areas. The following slide shows the North Dakota Export Limit (NDEX), a long constraint that crosses parts of North Dakota, Minnesota, and South Dakota.


MANITOBA
NORTH DAKOTA
NDEX
SOUTH DAKOTA

- Abundant supplies of natural gas, at low prices. Two effects:

  1. Some gas-fired generators are being used more intensively, and some coal-fired generators are being used less intensively. Because the gas plants are often sited closer to load centers than the capacity being displaced, transmission usage and congestion are reduced.

  2. Lower natural gas costs mean somewhat lower overall fuel costs for generation, and lower overall wholesale electricity prices. This means that even if a transmission constraint forces a buyer to purchase from an alternate generator, the cost premium to the buyer may be lower than previously.

- Construction of major new transmission projects in many areas has also helped to reduce congestion.

- New environmental regulations affect the composition and usage of regional generation fleets. As coal-fired and other plants are retired or retrofitted, grid operators will modify dispatch patterns according to the economics of available generation and transmission capacity in relation to fluctuating electricity demand. Appropriate actions will be taken to maintain grid reliability, but congestion may increase or decrease in specific locations. The full effects of this complex interaction will not be known for several years.

- Recent trends in retirement of both nuclear and coal-fired power plants have been changing generation profiles in many areas of the country.

Regional Findings: Southeast

The Southeast region covers North and South Carolina, Tennessee, Arkansas, Georgia, Alabama, Mississippi, Louisiana, Florida and parts of (non-ERCOT) Texas. It includes some or all of the NERC regions of SERC, SPP and FRCC (Florida).

The Department's findings regarding congestion in the Southeast are:

- There are no clear trends in the application of administrative congestion management procedures over the period 2006-2011 with the exception of an increase in level 5 TLR's called by ICTE (Entergy's Independent Coordinator of Transmission).

- There are no reports of persistent transmission constraints within the region.

- Transmission is being built in coordination with generation additions following long-standing planning practices overseen by state and regional protocols.

Public comments requested:

- The Department is particularly interested in comments on the reliance on publicly available data to assess congestion and transmission constraints.

- The Department is also interested in feedback on whether the study's findings warrant consideration of National Corridors. Parties are invited to discuss potential corridors and explain whether the information provided in the study would help support designation of any specific location as a National Corridor, and why or why not.

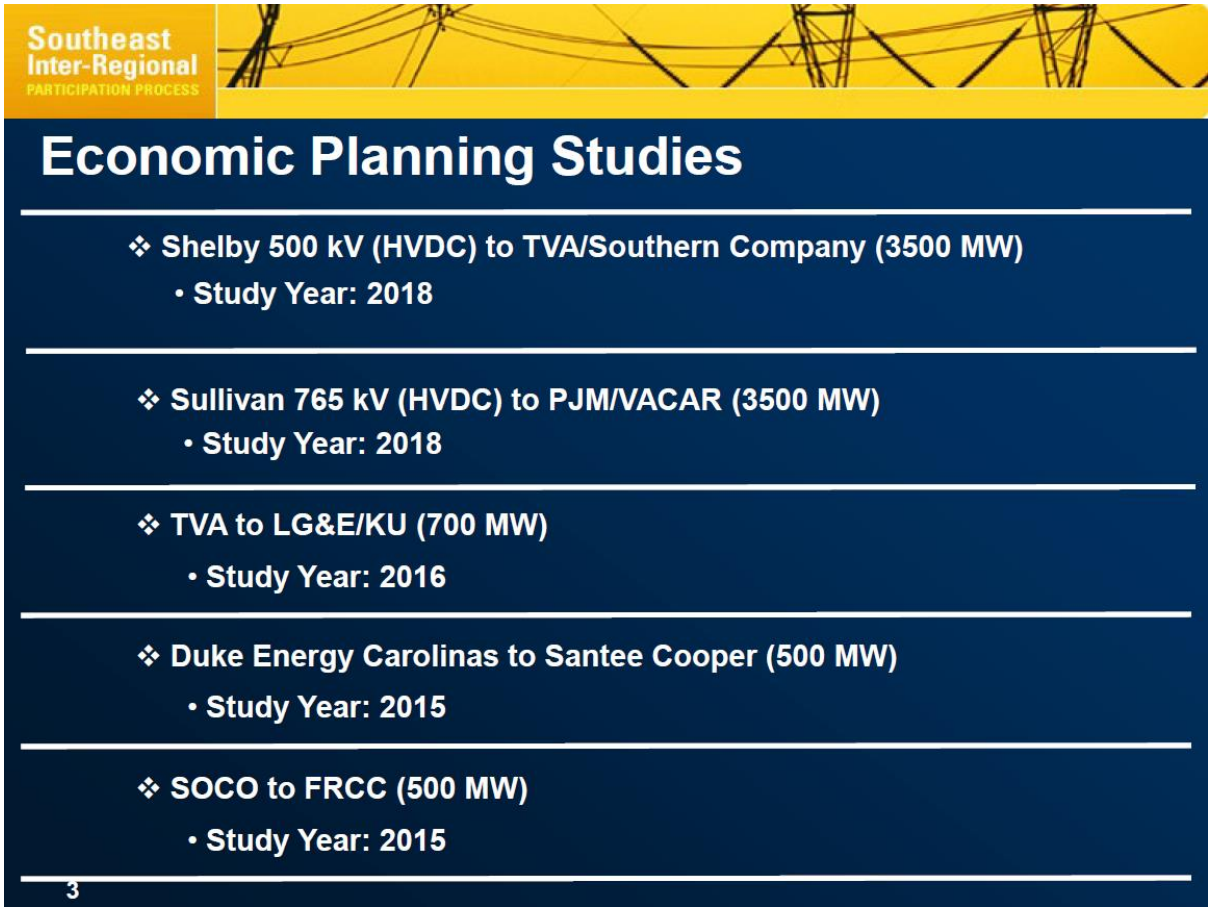
- The Department also invites comments on the usefulness and relevance of its triennial Congestion Study and of its authority to designate National Corridors in relation to ensuring that the Nation's transmission needs are met in a timely manner.

Southeast Inter-Regional Participation Process (SIRPP)

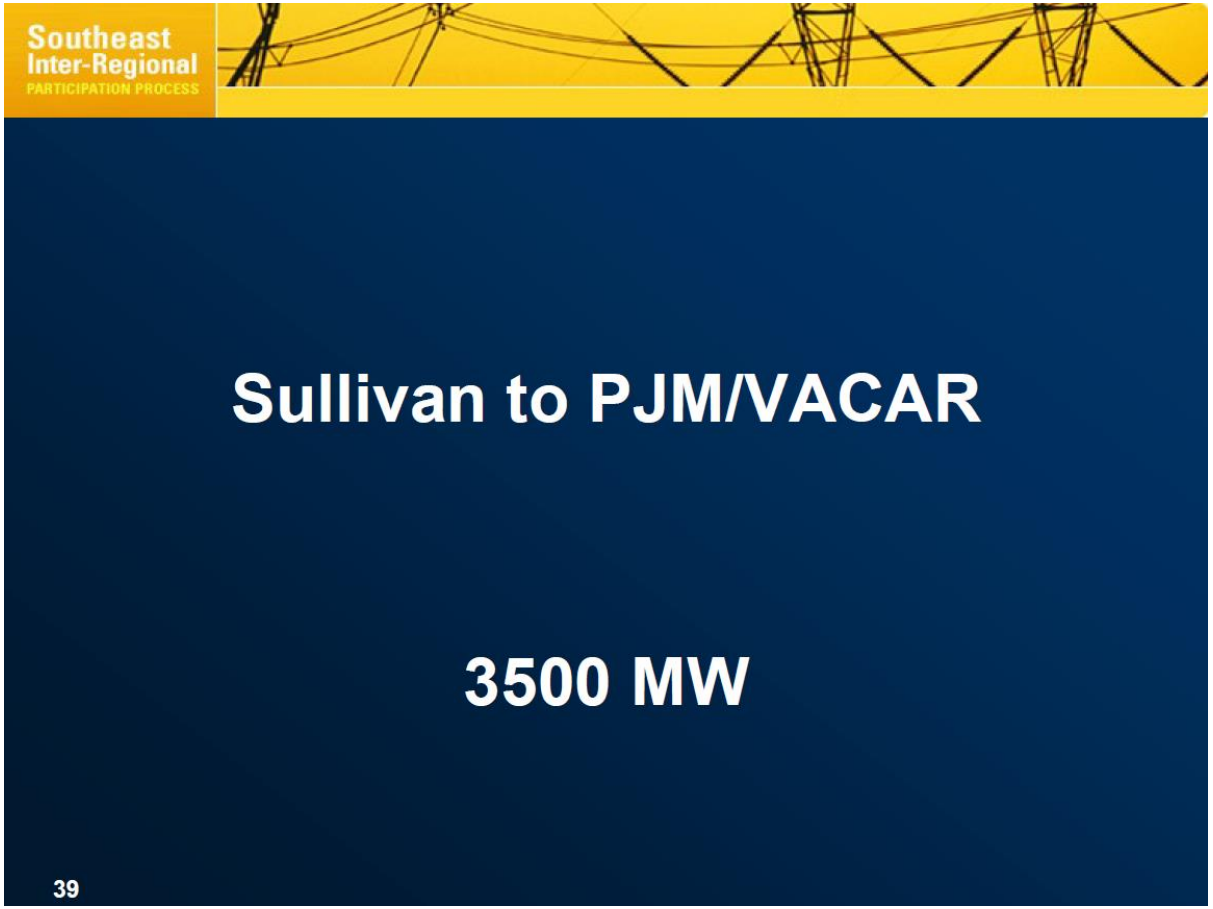
SIRPP

Final study results have been posted

SIRPP


Southeast
Inter-Regional
PARTICIPATION PROCESS
Economic Planning Studies
❖ Shelby 500 kV (HVDC) to TVA/Southern Company (3500 MW)
• Study Year: 2018
❖ Sullivan 765 kV (HVDC) to PJM/VACAR (3500 MW)
• Study Year: 2018
❖ TVA to LG&E/KU (700 MW)
• Study Year: 2016
❖ Duke Energy Carolinas to Santee Cooper (500 MW)
• Study Year: 2015
❖ SOCO to FRCC (500 MW)
• Study Year: 2015
3

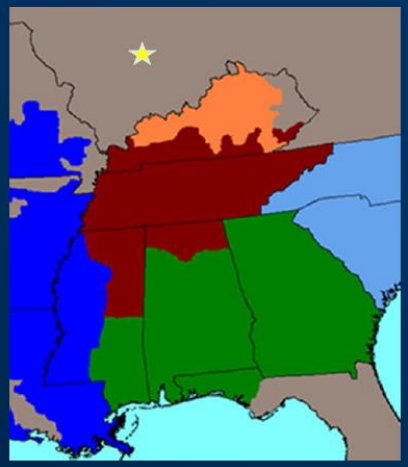
SIRPP


Southeast
Inter-Regional
PARTICIPATION PROCESS
Sullivan to PJM/VACAR
3500 MW
39

SIRPP

Southeast Inter-Regional PARTICIPATION PROCESS

Sullivan to PJM/VACAR



- **Source:**
  - New generator interconnection to existing Sullivan 765 kV Substation (3500 MW)
- **Sink:**
  - 2000 MW – PJM Load
  - 1500 MW – VACAR Generation
    - DEP 31.0% | DEC 47.5% | SCEG 10.8% | SCPSA 10.7%
- **Step 2 Evaluation**

40

SIRPP

Southeast Inter-Regional PARTICIPATION PROCESS

Sullivan to PJM/VACAR – DEC Screen Results

❖ Projects Identified

Item	Proposed Enhancements	Cost ($)
P1	Reconductor (Bundle) 0.97 mile 477 ACSR Asheville Hwy-Nix Rd Tap 100 kV Line	$ 434,190
P2	Reconductor 2.10 mile 2/0 Cu Campton Retail-Inman Tie 100 kV Line	$ 636,835
P3	Reconductor 5.27 mile 266.8 ACSR Tiger Tie-Springs Lyman Tap-Lelia Retail Tap 100 kV Line	$1,513,191
P4	Reconductor (Bundle) 4.63 mile 477 ACSR Pisgah Tie-Blantyre Retail 100 kV Line	$1,165,147
P5	Reconductor (Bundle) 11.53 mile 477 ACSR Horseshoe Tie-Blantyre Retail 100 kV Line	$2,280,267

48

SIRPP

Southeast Inter-Regional PARTICIPATION PROCESS

Sullivan to PJM/VACAR – DEC Screen Results

❖ Projects Identified

Item	Proposed Enhancements	Cost ($)
P6	Reconductor (Bundle) 1.53 mile 477 ACSR Verdae Retail Tap-Laurel Creek Retail Tap 100 kV Lines	$ 184,787

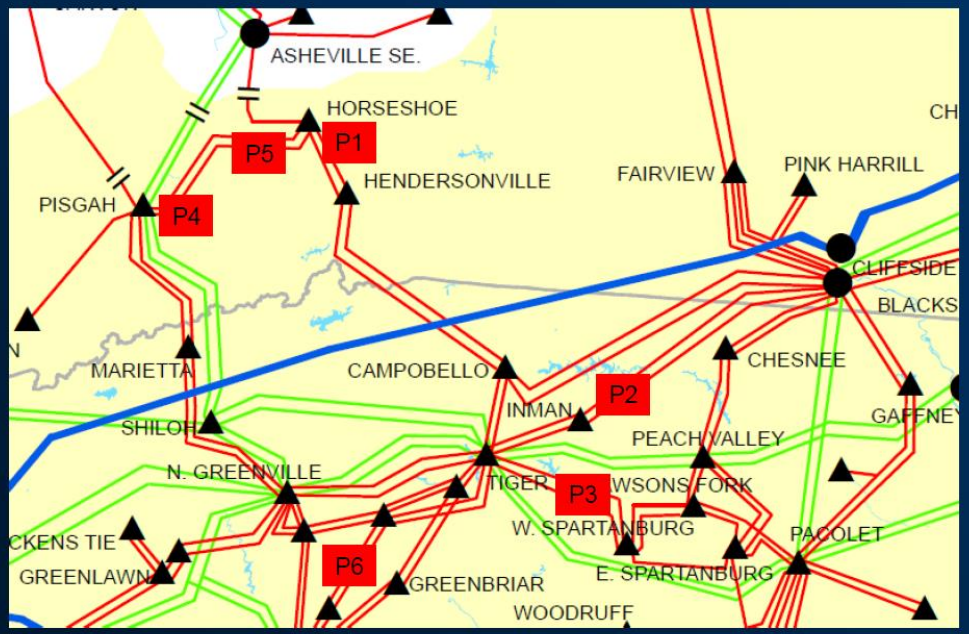
Total Cost (2014$) = $6,214,417

49

SIRPP

Southeast Inter-Regional PARTICIPATION PROCESS

Proposed Enhancements



50

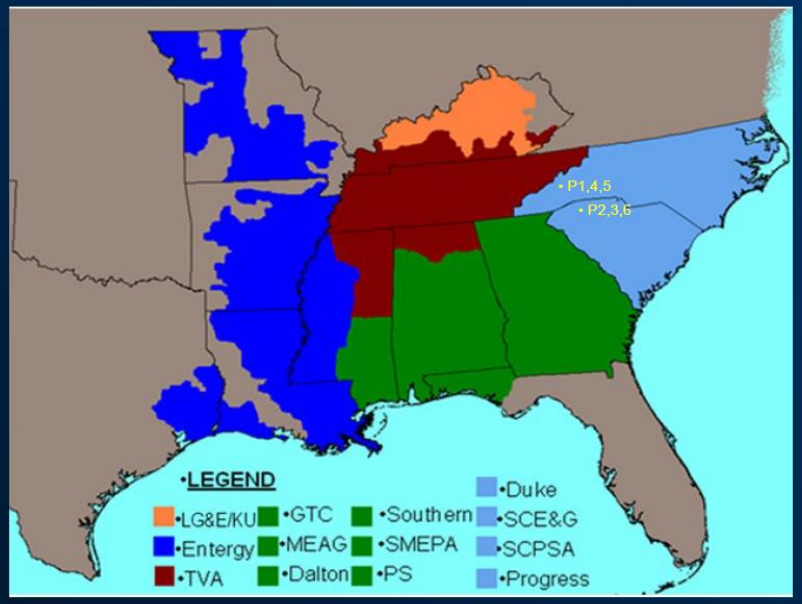
SIRPP

Item	Potential Solution	Estimated Need Date	Estimated Development Timeline	Estimated Cost
P1	Reconductor 0.97 mile 477 ACSR Asheville Hwy-Nix Rd Tap 100 kV Lines with 795 ACSS/TW	2020	1.5 Years	$404,000
P2	Reconductor 2.10 mile 2/0 Cu Campton Retail-Inman Tie 100 kV Lines with 556 ACSR	2022	1.5 Years	$421,000
P3	Reconductor 5.27 mile 266.8 ACSR Tiger Tie-Springs Lyman Tap-Lelia Retail Tap 100 kV Lines with 795 ACSR	2020	2 Years	$1,106,000
P4	Reconductor (Bundle) 4.63 mile 477 ACSR Pisgah Tie-Blantyre Retail 100 kV Lines with 795 ACSS/TW	2019	2 Years	$ 829,000
P5	Reconductor (Bundle) 11.53 mile 477 ACSR Horseshoe Tie-Blantyre Retail 100 kV Lines with 795 ACSS/TW	2025	3 Years	$1,821,000
P6	Reconductor (Bundle) 1.53 mile 477 ACSR Verdae Retail Tap-Laurel Creek Retail Tap 100 kV Lines with 795 ACSS/TW	2021	1.5 Years	$126,000
TOTAL ($2014)				$ 4,707,000

SIRPP

Southeast Inter-Regional PARTICIPATION PROCESS

SIRPP Region Map



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http://www.southeastirpp.com/

SERC Long Term Study Group Update

SERC Long Term Study Group

- Building 2014 series of MMWG cases
- Completed 2014 Winter MMWG model for ERAG study
- Working on report for 2016 Summer study including sensitivity case with PJM/MISO market dispatch
- Finalizing 2014 RAWG (Resource Adequacy Working Group) assessment report

Eastern Interconnection Planning Collaborative (EIPC)

EIPC

Planning Activities

- **Updated 2023S roll up case**
- **Will perform drought study**

EIPC

Summary of Transfer Results

- Objective was to demonstrate the affect case updates had on the Eastern Interconnection's ability to reliably move large amounts of power between areas
  - Analyzed 5,000 MW transfers between selected areas

- Monitored the following (100 kV and above):
  - N-0 branch overloads
  - N-1 branch overloads
    - Also included NYISO specific regional contingencies

- Updates to 2023 Roll-up did not have significant impact on the Eastern Interconnection transfer capability

Summary of Transfer Results

Source		Sink		Previous		New	
				FCITC (MW)	Lim. PA	FCITC (MW)	Lim. PA
A	FRCC	E	SERC	1600	DEF	1700	DEF
B	MISO	C	NPCC	3400	PENELEC-PJM	3100	PENELEC-PJM
B	MISO	D	PJM	>5000	N/A	>5000	N/A
B	MISO	E	SERC	>5000	N/A	>5000	N/A
B	MISO	F	SPP	650	EES	650	EES
C	NPCC	B	MISO	1800	NYISO	1350	NYISO
C	NPCC	D	PJM	1500	NYISO	1150	NYISO
D	PJM	B	MISO	1600	ALTW-MISO	1650	ALTW-MISO
D	PJM	C	NPCC	2100	PENELEC-PJM	2750	NYISO
D	PJM	E	SERC	>5000	N/A	>5000	N/A
E	SERC	A	FRCC	1900	SBA/FRCC	1900	SBA/FRCC
E	SERC	B	MISO	>5000	N/A	>5000	N/A
E	SERC	D	PJM	1900	BREC-MISO	4800	DVP-PJM
E	SERC	F	SPP	550	SWPA-SPP	500	SWPA-SPP
F	SPP	B	MISO	850	WERE-SPP	800	WERE-SPP
F	SPP	E	SERC	950	WERE-SPP	950	WERE-SPP

EIPC

Heat Wave and Drought Scenario Assumptions

- Submitted by: Eastern Interconnection States' Planning Council (EISPC)
- Study Case: Updated 2023 Summer Peak
- Premise: Model a severe and pervasive heat wave and drought condition in study year 2023
- Questions to be answered by analysis:
  - "What constraints arise when large amounts of power are transferred to areas of need during times of extremely high temperatures and drought conditions?"

EIPC

Heat Wave and Drought Scenario Assumptions

Modeling Parameters and Resource Modifications:

- Utilize updated 2023 summer peak roll-up model
- Model effect of heat wave condition on sink
  - Scale sink load up by 5% (~15,000 MW)
- Model effect of drought condition on sink
  - Scale sink generation down by 5% while assuming all unused capacity is unavailable (~15,000 MW)
- Model effect of power transfer from source
  - Scale available generation up while not violating generator limits (~30,000 MW)

EIPC

Heat Wave and Drought Scenario Assumptions

- Utilizing revised Heat Wave & Drought Scenario Model:
  - Perform N-1 contingency analysis on 200 kV and above
    - Except for areas where lower voltage levels are required
  - Monitor all lines 161 kV and above
  - Utilizing MUST transfers analysis to identify facilities with > 3% TDF
  - Assemble results into report to be presented to Stakeholders

http://www.eipconline.com/

SERTP

SERTP

- **Studying regional > 500 kV projects**
- **Developing 2014 SERTP Regional Transmission Plan format/contents**

http://www.southeasternrtp.com/

NERC Reliability Standards Update

- **CIP-014 Physical Security**

Questions ?

2014 TAG Work Plan

Rich Wodyka

ITP

2014 NCTPC Overview Schedule

Reliability Planning Process

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

Economic Planning Process

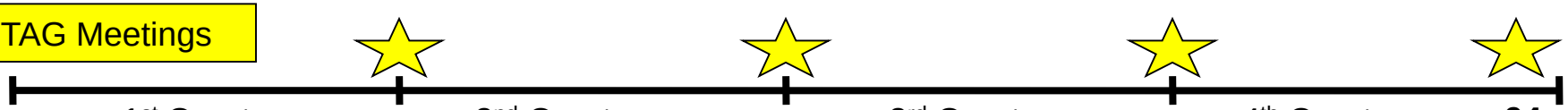
- Propose and select Economic scenarios and interface
- Perform analysis, identify problems, and develop solutions
- Review Economic Study Results

Coordinated Plan Development

- Combine Reliability and Economic Results
- OSC publishes DRAFT Plan
- TAG review and comment

FERC Order 1000 Updates

TAG Meetings



2014 TAG Work Plan

January – February

- **2014 Study – Finalize Study Scope of Work**
  - ✓ **Receive final 2014 Reliability Study Scope for comment**
  - ✓ **Review and provide comments to the OSC on the final 2014 Study Scope**
  - ✓ **Receive request from OSC to provide input on proposed Economic Transmission Access scenarios and interfaces for study**
  - ✓ **Provide input to the OSC on proposed Economic Transmission Access scenarios and interfaces for study**

March 11, 2014

TAG Meeting

- **2014 Study Update**
  - ✓ **Receive a progress report on the Reliability and Economic Planning study activities**
- **Order 1000 Update**
  - ✓ **Receive an update on the NCTPC activities as they relate to Order 1000 compliance**
- **Operations Reliability Coordination Agreement (ORCA)**
  - ✓ **Receive an update on the ORCA activities**

April - May - June

TAG Meeting – June 16, 2014

- **2014 Study Update**
  - ✓ **Receive a progress report on the Reliability and Economic Planning study activities**
- **Joint Inter-Regional Study Update**
  - ✓ **Receive a progress report on the Joint Inter-Regional study activities**
- **Order 1000 Update**
  - ✓ **Receive an update on the NCTPC activities as they relate to Order 1000 compliance**
- **Operations Reliability Coordination Agreement (ORCA)**
  - ✓ **Receive an update on the ORCA activities**

July - August - September

- **2014 Study - Technical Analysis, Problem Identification, and Solution Development**
  - **TAG will be requested to provide input to the OSC and PWG on the technical analysis performed, the problems identified as well as proposing alternative solutions to the problems identified.**
  - **TAG will be requested to provide input to the OSC and PWG on any proposed alternative solutions to the problems identified through the technical analysis.**

These activities are slightly delayed but still expect to complete study by end of the year.

July - August - September

- **2014 Study Update**
  - ✓ **Receive a progress report on the Reliability and Economic Planning study activities**
  - ✓ **Receive update status of the upgrades in the 2013 Collaborative Plan**

July - August - September

TAG Meeting – September 18,2014

- **2014 Study Update**
  - ✓ **Receive a progress report on the Reliability and Economic Planning study activities**
- **Joint Inter-Regional Study Update**
  - ✓ **Receive a progress report on the Joint Inter-Regional study activities**
- **Order 1000 Update**
  - ✓ **Receive an update on the NCTPC activities as they relate to Order 1000 compliance**
- **Operations Reliability Coordination Agreement (ORCA)**
  - ✓ **Receive an update on the ORCA activities**

October - November - December

- **2014 Study - Technical Analysis, Problem Identification, and Solution Development**
  - **TAG will be requested to provide input to the OSC and PWG on the technical analysis performed, the problems identified as well as proposing alternative solutions to the problems identified**
  - **TAG will be requested to provide input to the OSC and PWG on any proposed alternative solutions to the problems identified through the technical analysis**

October - November - December

- **2014 Study Update**
  - Receive a progress report on the Reliability and Economic Planning study activities and preliminary results
  - Receive and comment on final draft of the 2014 Collaborative Transmission Plan report
  - Discuss potential study scope for 2015 studies

- **2014 Selection of Solutions**
  - TAG will receive feedback from the OSC on any alternative solutions that were proposed by TAG members

October - November - December

- **Joint Inter-Regional Study Update**
  - **Receive a progress report on the Joint Inter-Regional study activities**
- **Order 1000 Update**
  - **Receive an update on the NCTPC activities as they relate to Order 1000 compliance**
- **Operations Reliability Coordination Agreement (ORCA)**
  - **Receive an update on the ORCA activities**

October - November - December

TAG Meeting – December TBD

- **2014 Study Update**
  - **Receive presentation on the draft report of 2014 Collaborative Transmission Plan**
  - **Discuss potential study scope for 2015 studies**
- **Joint Inter-Regional Study Update**
  - **Receive a progress report on the Joint Inter-Regional study activities**
- **Order 1000 Update**
  - **Receive an update on the NCTPC activities as they relate to Order 1000 compliance**
- **Operations Reliability Coordination Agreement (ORCA)**
  - **Receive an update on the ORCA activities**

Questions ?

TAG
Open Forum Discussion

Comments or Questions ?