2015 SERC Operational Practices Survey Findings and Recommendations

SERC System-to-System Coordination Project – Current State Assessment of System Coordination and Visibility

Department	Document Type	Title/Subject			Number
General and Administrative	Survey	SERC System-to-System Coordination Project - Current State Assessment of System Coordination and Visibility			Surv-200-268
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1.0 Introduction

The SERC System-to-System Coordination Project is a 2015 corporate initiative to assure continued reliability of the Bulk Electric System (BES) through coordinated operations in a fully studied state. In March 2015, SERC finalized a project charter to define the project purpose, deliverables, and areas included in the project scope. The primary purpose of the project is to assess the current state of coordination and visibility and develop a plan to address any identified gaps. In April 2015, SERC disseminated a survey to the Balancing Authorities (BA), Transmission Operators (TOP), Reliability Coordinators (RC), Transmission Planners (TP), and Planning Coordinators (PC) registered functions in the SERC Region to identify the current state of the SERC Region's processes and to obtain suggestions for improvement. The survey is intended to support a broad regional assessment of the following areas:

1. Operations to Account for the Status of Facilities outside Stakeholder Individual Systems
2. The Effect of External Operations on the Stakeholder's Own Systems
3. Real-Time Contingency Analysis Modeling Validity
4. Data Information and Sharing
5. Communications – Seasonal Coordination
6. Transmission System Use
7. Reliability Threats
8. Visibility

The project includes two deliverables:

- Project Deliverable 1 is a current-state assessment of system coordination and visibility, due May 31, 2015. This deliverable assesses reliability risks to the SERC Region communicated via a summary of survey responses.
- Project Deliverable 2 is a system-to-system coordination resolution plan, due July 31, 2015, that will append to Project Deliverable 1. This plan includes recommendations and next steps to minimize reliability risks to the SERC Region.

2.0 Executive Summary

This report summarizes responses of BA, TOP, RC, TP, and PC functions in the SERC Region to the 2015 SERC Operational Practices Survey. The survey's purpose is to help SERC assess the current state of coordination and visibility, and to develop a resolution plan that addresses identified gaps.

The survey consists of 41 questions spanning eight categories. Approximately 80 percent of surveyed functions in the SERC Region provided survey responses to SERC. Thus, the survey responses depict the current state of coordination and visibility of a significant portion of the

SERC Region and the Eastern Interconnect. Overall, survey responses support a strong reliability culture among stakeholders in the SERC Region.

The first two sections of the survey cover these topics, which are relevant to the concept of operation by golden rule:

Operations to Account for the Status of Facilities outside Stakeholder Individual Systems

The Effect of External Operations on the Stakeholder's Own Systems

Simply stated, these sections ask, "Do you and your neighbors operate your local transmission system and the Eastern Interconnect in a mutual fashion?"

Survey responses indicate overall coordination and visibility are strong in the SERC Region, but improvement is suggested to operate the system in a fully studied state. SERC Regional Criteria state that registered entities should expand focus to include external facilities that impact bulk power system reliability. Areas that require additional review for improvement and inclusion in SERC's subsequent resolution plan recommendations include:

- Develop more transparent generation dispatch.
- Improve accuracy of next-day studies.
- Enhance model validation practices.

The third section in the survey, replies to Real-Time Contingency Analysis Modeling Validity, reveals inconsistent processes for confirming the validity of real-time contingency analysis results. Periodicity varies significantly when comparing real-time contingency analysis and planning models. Awareness of the effects of external operations on a registered entity's system could be improved. One solution is to expand the list of external contingencies simulated to better predict and monitor transfers through the registered entity's system.

The survey reveals that real-time contingency analysis is robust. A high percentage of respondents are using real-time facility ratings of internal networked sub-100 kV systems to monitor performance and trigger alarms when necessary.

Survey responses in the sections labeled Data and Information Sharing and Communications validate coordinated study activities among survey respondents. One noteworthy response describes an overload condition that has a significant impact on a neighboring system. This response is subject to inclusion in SERC's resolution plan recommendations.

The next section, Transmission System Use, examines operational practices. Generally, loop flow is defined as the difference between scheduled flow and physical flow. Transmission system use combines reserved and unreserved usages. Deviation from historical practice to serve specific load may be construed as a reliability issue. A further complication is the need to identify unreserved usages associated with internal or non-interchange transactions. Loop flows are difficult to manage and may lead to unintended consequences such as local congestion, equipment failure, or cascading outage. Survey respondents indicated that a significant percentage of loop flow situations on their systems are not typically associated with tagged schedules and coordinated market flow. Additionally, many respondents noted that they cannot identify the causes of loop flow situations that impact their systems. The risk is that respondents may be operating their systems in a state that is not fully studied. These concerns require additional analysis.

The last two survey sections, Reliability Threats and Visibility, discuss threat elements and entity visibility into neighboring systems. A positive common theme among all survey respondents regarding threats is communication involving the RC. A possible threat to reliability is that some registered entities now require bilateral, corporate-level Non-Disclosure Agreements, possibly at the individual level. These Agreements must be signed before conversations can occur about system changes and study results. SERC will analyze this issue to identify recommendations and next steps to minimize reliability risks to the SERC Region.

More than 80 percent of survey respondents indicate they monitor some elements in adjacent systems that are sensitive to changes to their systems' operations. Some respondents recommend using more detailed state estimator models with greater modeling in neighboring areas to increase visibility and situational awareness, while others indicated the current processes are sufficient.

3.0 Operations to Account for the Status of Facilities outside Stakeholder Individual Systems

3.1 To what extent do you include line or bus details of external systems in your next-day study models? How do you decide the extent to which you model the external system and where you begin to equivalize?

- The Energy Management System (EMS) model includes topology of neighboring BES systems. The EMS study package includes the full production model. The registered entity begins to equivalize at the far reaching points of its model, particularly where telemetry is not available.
- The respondent uses the full Long-Term Study Guide (LTSG) and Multiregional Modeling Working Group (MMWG) model, with no additional equivalent.
- Cases include the entire Eastern Interconnect, and the cases are not equivalized. TOP runs a complete n-1 scan on its neighboring system to see if outages cause its neighbors any issues.
- The external model is modeled at breaker/switch detail for a number of layers out before it gets down to a bus/branch model with equivalent branches at the outer edges. This was done through a combination of analysis and engineering judgment. Additionally, the SERC Near-Term Study Group (NTSG) seasonal Open Access Same-Time Information System (OASIS) cases are used to develop the next-day study models. For facilities external to RC Area, all 500 kV and 230 kV equipment is modeled and the respondent conducts an n-1 AC analysis on the RC area on any element that is five buses out.
- Real-Time: three to four buses deep (minimum); Off-line: full MMWG models are used.

- The respondent models explicitly each element on each tie line and in the first station beyond our BA/TOP border connected to the respective tie lines. All other external facilities and elements beyond that are modeled from the results of an equivalent model reduction application.

3.2 To what extent do you include line or bus details of external systems in your real-time contingency analysis? How do you decide the extent to which you model the external system and where you begin to equivalize?

- In general, the respondent models at least one substation beyond each tie station in detail. The registered entity begins to equivalize at the far reaching points of its model, particularly where telemetry is not available. The respondent prefers to truncate and model equivalent injections rather than using a mathematical equivalent.
- The real-time state estimator utilizes a detailed model of the wide-area and also includes facilities needed for system visibility and solution quality. Outside of the detailed model is a combination of PSS/E type bus branch and equivalent modeling.
- For facilities external to its area, all 500 kV and 230 kV equipment is modeled, and the registered entity conducts an n-1 AC analysis on its area on any element that is “five buses out.” A majority of networked 100 kV is modeled as well.
- A minimum of all tie lines are included in the Real-time Contingency Analysis (RTCA). The respondent has also developed and maintains a Security Analysis Program that utilizes distribution factors and real-time flows to expand the “view” of overall real-time security assessment.
- The respondent models all buses and branches of its neighboring BAs/TOPs for voltages of 100 kV and above in our RTCA. Beyond those areas an equivalent.
- First tier registered entities are modeled completely in our RTCA. Equivalizing of voltage levels below 100 kV may occur in some first tier registered entities. Equivalizing of the EMS model begins largely on external registered entities to first tier areas.
- Typically, external systems are modeled several buses into a neighboring system, but have been expanded farther and in more detail when real-time operations have shown a benefit of using more expanded detail.
- The respondent models contingencies for loss of external elements based on known impacts from any external element. This falls out of the equivalent model analysis, planning studies, or known operational situations. For loss of (L/O) contingencies, we explicitly model the complete contingent element pair(s) for the modeled contingency.
- RTCA simulates a select number of external contingencies known to potentially have a significant impact on the respondent’s system. The real time network model

includes full bus/branch/breaker topology and telemetry (as available) for internal facilities and at least one bus out from the respondent's system for external facilities. The "outside world" portion of the respondent's model is equivalized at a minimum of three buses away from the respondent's system.

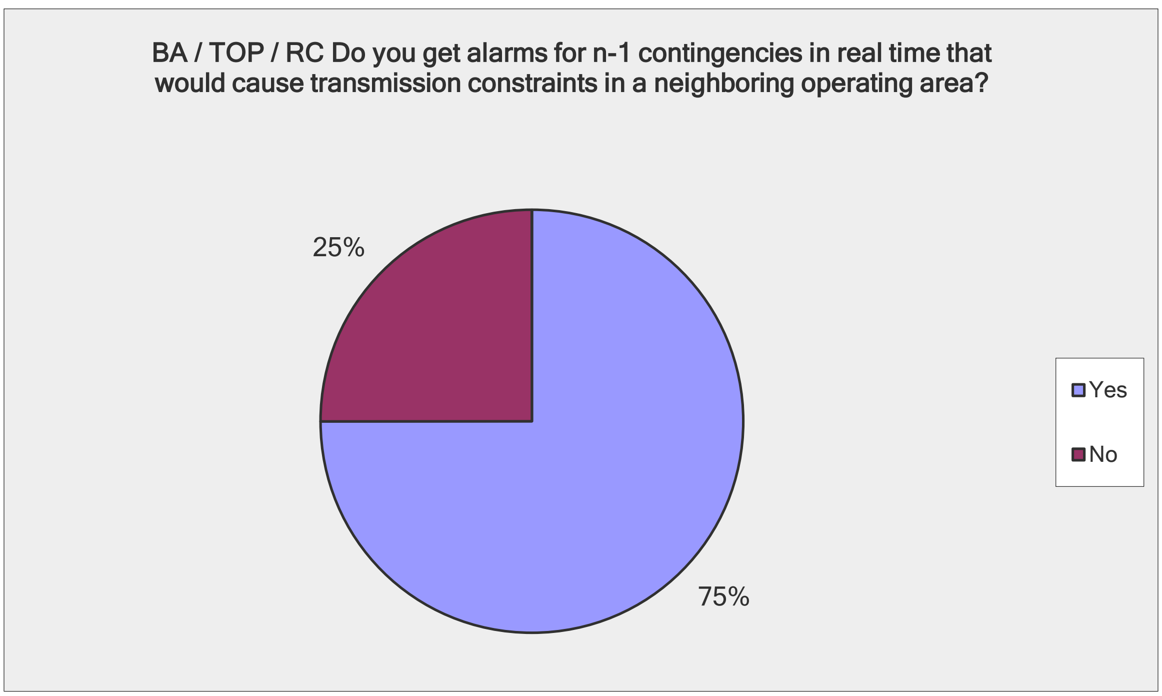
3.3 How much of the neighboring systems are reported from a State Estimator or planning model perspective in your next-day study? In real-time contingency analysis? Examples: One bus away from your system, two buses outside system, or other method.

- The production model is used in the EMS study package and includes neighboring modeling. The state estimator calculates flows for equipment. The respondent does not use a planning model for next-day studies relying on the EMS study package that provides a full production model for analysis.
- The respondent runs a complete n-1 scan on its neighboring system (all lines within its neighboring system), and the respondent monitors five buses into each neighboring system. The respondent will report on any outage that causes an impact on its system.
- For a next-day study, neighboring systems are included if an internal contingency causes an overload in a neighbor's system within Tier 1 (and Tier 2 (200 kV and above), with no limits on how many buses away. In real-time, the respondent monitors the wide-area for its RTCA, with known System Operating Limits (SOLs) included in the model.
- Using the SERC NTSG model, an extensive planning model is used for the next day study (NDS) analysis. As for the respondent's state estimator, equipment is modeled, though some is equivalized.
- The state estimator covers, at a minimum, direct ties and selected external system facilities along with equivalized representations of all neighboring systems, while the RTCA covers, at a minimum, direct ties. The planning models include details of external models included in the SERC NTSG study process.
- Issues on neighboring systems are typically not reported, as the respondent focuses primarily on the issues in its own system. There are a few exceptions to this, where the respondent has seen that its results may differ from neighbors, and it seeks to compare results. There are also a few neighboring facilities that it monitors because operating experience has shown that neighbors are sensitive to changes in the respondent's system.
- All first tier registered entities at 230 kV and above are included in the respondent's next day studies. The RTCA monitors 100 kV and above of first tier registered entities.
- The respondent utilizes offline power system simulation for engineering (PSSE) models for its next-day studies and therefore, neighboring systems are modeled in

full bus/branch topology. Its real-time network state estimator (SE) model includes full bus/branch/breaker topology and telemetry (as available) for internal facilities and at least one bus out from its system for external facilities. The "outside world" portion of its model is equivalized at a minimum of three buses away from its system. The next-day studies only monitor internal facilities. The RC also performs next-day studies on the respondent’s behalf and these studies monitor internal, as well as external, facilities for potential issues.

- The state estimation application is not applicable in a next-day study perspective. Its purpose is to mathematically develop an initial-state matrix from real-time supervisory control and data acquisition (SCADA) telemetry for the contingency analysis (CA) power flow. The respondent models external facilities in its next-day planning model using the System Data Exchange (SDX) outages and engineering judgment. For known problem areas, the respondent initiates phone calls and coordinated studies (both parties study) to verify configurations and CA results of the study element impacts.

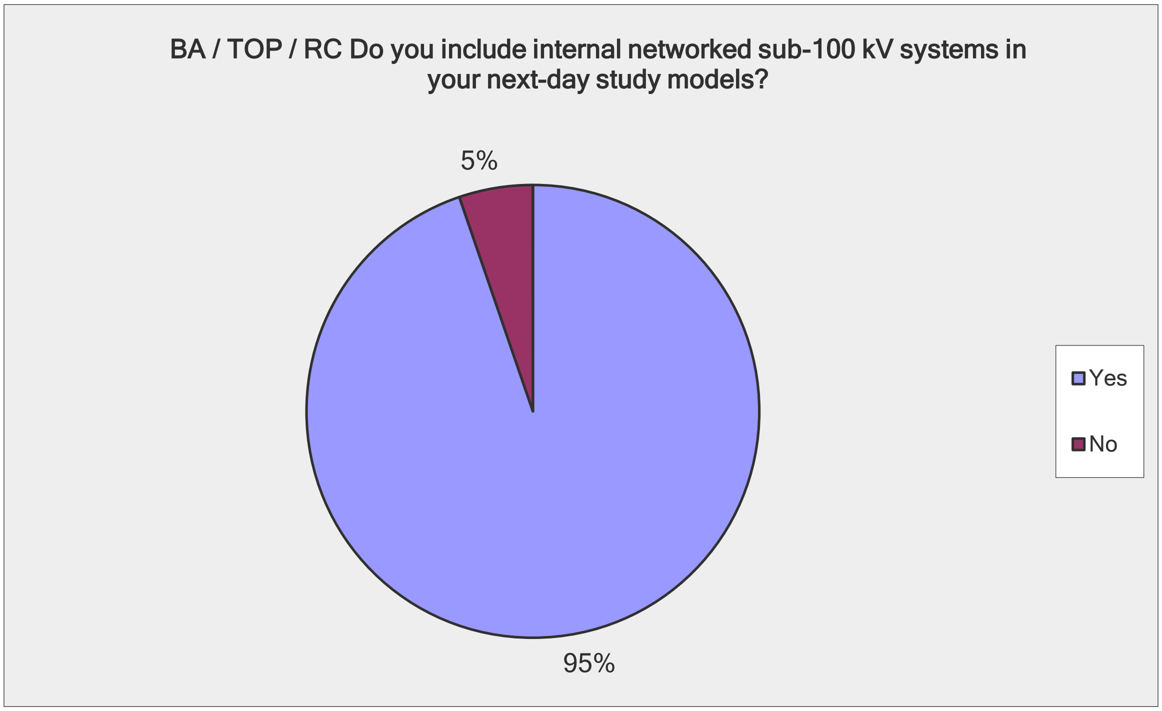
3.4 Do you get alarms for n-1 contingencies in real-time that would cause transmission constraints in a neighboring operating area? (Graph includes Yes/No responses only)



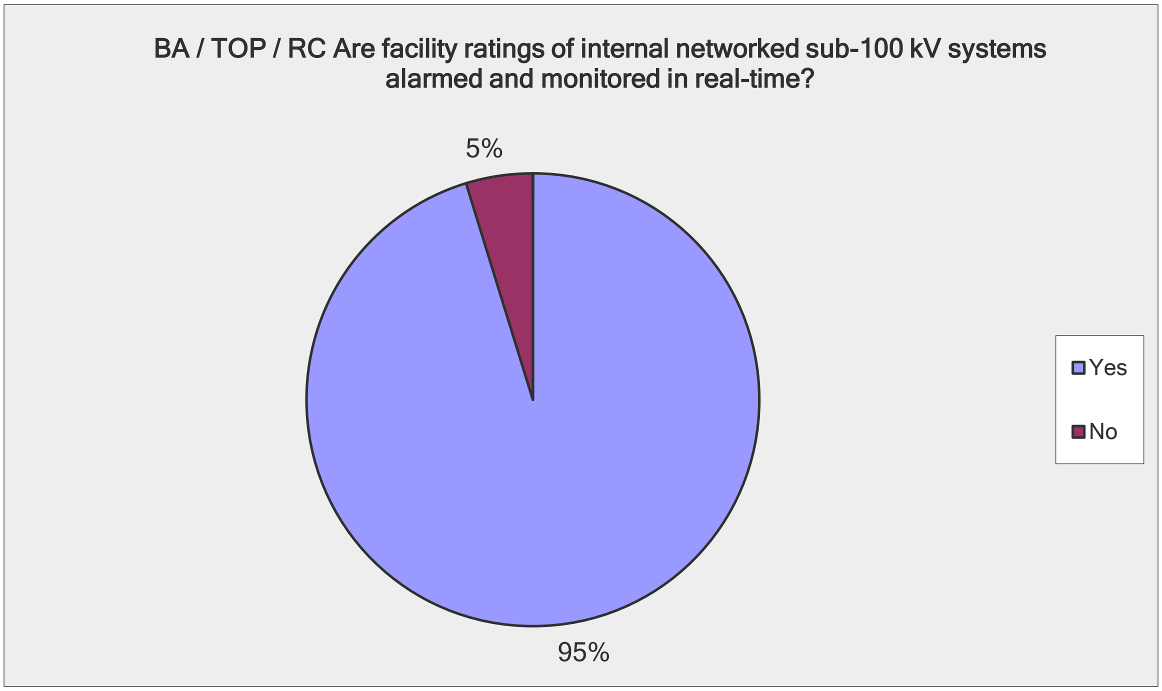
3.5 If response to 3.4 is yes, do you have communication plans in place for these events; if yes, please describe.

- 93% of Yes respondents have communication plans in place for these events.
  - As RC, action includes verification of the constraint with the neighboring RC and help to develop action plans as necessary.
  - Develop operational guides that provide system operators with procedural steps designed to mitigate known areas of congestion. The guides require neighboring system operators to contact each other for discussions regarding analysis and steps of mitigation.
  - As an RC, contact the affected registered entities to inquire if they are seeing the limit and to validate loading levels and ratings. If the limit is valid, the respondent coordinates a Mitigation Plan.
  - The RC contacts the neighboring RC to verify the rating of the equipment. The RC would also verify if the neighboring RC saw the same contingency causing a constraint.
  - Typically, the RC operator is familiar with the limited number of internal contingencies that may cause a constraint on a neighboring registered entity versus those that are more suspect due to modeling or data limitations. When there is a reasonable expectation that the contingency is real, or the contingency has not been observed previously and may be the result of abnormal system conditions (e.g., dispatch, load, configuration, etc.), the RC operator will contact the affected registered entity to validate the observation against the neighbor's analysis and, if required, coordinate a Mitigation Plan.

3.6 Do you include internal networked sub-100 kV systems in your next-day study models?



3.7 Are facility ratings of internal networked sub-100 kV systems alarmed and monitored in real-time? (Graph includes Yes/No responses only)



3.8 To what extent do you receive real-time notifications from neighboring operators of changes of status of their facilities that impact your facilities?

- Inter-control Center Communication Protocol (ICCP) is the primary source of notification from neighboring operators of changes of status of their facilities that impact our facilities.
- Notice of facility status changes from neighboring TOPs and RCs is received on an as-needed basis based on pre-identified facilities as the survey respondent requested outage notification. The respondent also receives real-time telemetry from neighboring registered entities via interregional security network (ISN or NERCnet) links. Outage information from neighboring systems is also available via the NERC SDX. Joint Operating Agreements (JOAs) with neighboring registered entities include notification requirements for specific equipment outages (planned or otherwise). Also, the respondent participates in daily conference calls during which expected outage information and potential congestion is shared.
- For the facilities of neighboring operators directly interconnected to the RC member registered entities, the RC receives real-time notification alarms for breaker status indications from 500 kV facilities and a significant amount from 230 kV facilities.

- The respondent has telemetry for external facilities, typically in the one to two bus out range. Facility status is communicated with the RC and neighboring BAs and TOPs via ICCP. Phone calls are also sometimes received from neighbors for significant events.
- Respondent explicitly models neighboring facilities through the first connected bus and attaches real-time ICCP (ISN) based telemetry to each of the elements derived from the neighboring company's EMS for 65% of its tie lines. For those elements the respondent does not telemeter, it relies on operating agreements and procedures for notifications of outages/changes to the network that it would be telemetering. Alarming for network changes at telemetered facilities is graduated based on impact such that the direct tie line elements (e.g., line switches, terminating breakers) provide a continuous audible tone that must be acknowledged and managed while other elements within the remote station provide a single stroke audible tone. Anything beyond the first connected bus elements that the respondent is not directly notified about would only be addressed if they cause network application solution issues (e.g., state estimator, power flow). Otherwise, the respondent considers them to not be impactful.

3.9 To what extent do you provide real-time notifications to neighboring operators of changes of status of your facilities that impact their facilities?

- ICCP is the primary source of notification to neighboring operators of changes of status to facilities that impact neighbors' facilities. Large generators and high voltage BES elements that could impact other facilities are also routinely communicated in an RC-to-RC call. Loss of large generation units above 500 MWs is communicated to neighboring RCs via Reliability Coordinator Information System (RCIS). The respondent's BA utilizes tie line check-out tools for outages on tie lines. The TOP uses phone conversation when switching out a tie line or responding to a tie line operating due to relay action.
- JOAs with neighboring registered entities include notification requirements for specific equipment outages (planned or otherwise) on the respondent's system. Normal operating practices require respondent registered entity personnel to notify neighboring registered entities of impactful outages on the respondent's system prior to actual switching or as soon as possible after an event occurs. The respondent's electronic outage system is designed to prompt personnel when external notification is required. The respondent has developed a list of internal facilities with each neighboring registered entity to facilitate outage notification during outage coordination and real-time operations. The respondent makes outage notification for facilities that have been identified by neighboring registered entities.
- The respondent makes transmission equipment status available via ICCP. If a company is receiving the respondent's ICCP data and has the equipment modeled, it will receive the respondent's equipment operations on the 500 kV, 230 kV, and networked 100 kV systems.

- The respondent makes available all digital and analog data from its SCADA system to neighboring operators upon request. This data is shared in real-time via ICCP.
- The respondent makes available, in real-time, the breaker statuses that are requested by its neighboring operators and submits outages in SDX.
- The respondent notifies the RC for all unplanned major network configuration changes when they happen, posts those changes on SDX, and notifies any applicable adjacent TOP. The respondent also publishes all of its SCADA data on the ISN (ICCP) and by default supplies read permission to the adjacent BAs, TOPs, and RCs. Respondent supplies its EMS network model quarterly to all members of the SERC Reliability Modeling Working Group (RWMG).

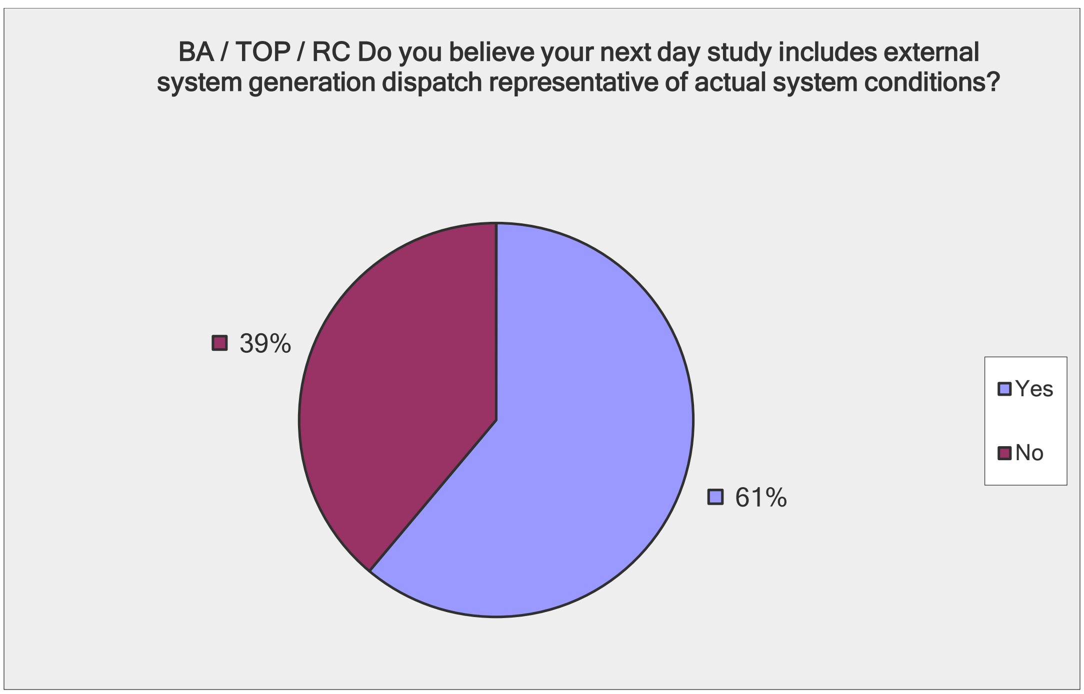
4.0 The Effect of External Operations on the Stakeholder's Own Systems

4.1 Do your next-day studies consider generation dispatch, System Operating Limits/Interconnection Reliability Operating Limits, and load external to your BA/TOP/RC area?

- The TOP's Next-Day scan incorporates a large neighbor's day-ahead dispatch if it is received before the Next-Day scan is due (TOP procedures require the Next-Day Scan due mid-day; the neighbor's day-ahead dispatch is received around 2:00 p.m. CST). Otherwise, the TOP will estimate the dispatch based on current generator outages or previous day's dispatch. Once the day-ahead dispatch is received, it is reviewed to make sure there were no significant changes in generation. Also, the TOP builds the cases using approved outages in another neighbor's Transmission Automated Outage Request System (TAORS) and outages and loads in the SDX system. The TOP runs an n-1 scan and reports on contingencies. The TOP will also report on all outages that may have an impact in the next day. The TOP will then scan the cases for any Interconnection Reliability Operating Limits (IROLs) or any nuclear off-site power issues.
- External generation, SOL/IROL, and load are included in the respondent's next-day studies to the extent that the modeling and information is available.
- The respondent uses block dispatch files provided by each neighboring BA to dispatch its system according to their load submitted to SDX. Long-term firm schedules and generator outage and de-rate information are also pulled from SDX and included in the base case. The respondent uses operating limits defined in the SERC NTSG OASIS cases and updates them if changes are identified. External area loads to the respondent's RC Area are updated according to the loads being submitted by the BAs to SDX for the applicable time period being studied. Monitored and contingency lists include every single element in the RC footprint and any facility that is five buses out from the respondent's RC Area.
- Import load forecasts submitted via SDX into respondent's next-day studies. Also incorporate generation dispatch from the day-ahead market.

- Next-day studies are performed using an offline PSSE model. These studies take into account external generator outages that have a significant impact on the respondent's system. External generation and load for some selected nearby registered entities are scaled proportionately. The RC notifies respondent if a next-day study indicates a potential SOL exceedance on a facility external to its BA/TOP area.
- External generation dispatch (including commitment) is modeled in a block dispatch-type manner considering outages of generation (and lines) as provided in SDX. Load is generally modeled as a result of using similar day starting points, although both load and interchange are adjusted as required based on best available information at the time of the study, which can change significantly as the next day becomes the current day. In addition to next-day studies, an additional "two day out" forward looking power-flow model is constructed that is representative of two day out expected system conditions. As with the next-day studies, the two day out studies include expected system conditions and the best estimate of Tier 1 neighbors' generation dispatch and loads and consider SOL/IROLs of Tier 1 neighbors.

4.2 Do you believe your next day study includes external system generation dispatch representative of actual system conditions? (Graph includes Yes/No responses only)



- Merit order block dispatches can be inaccurate if not updated often as fuel prices change. They also lose a significant amount of accuracy when used for markets.

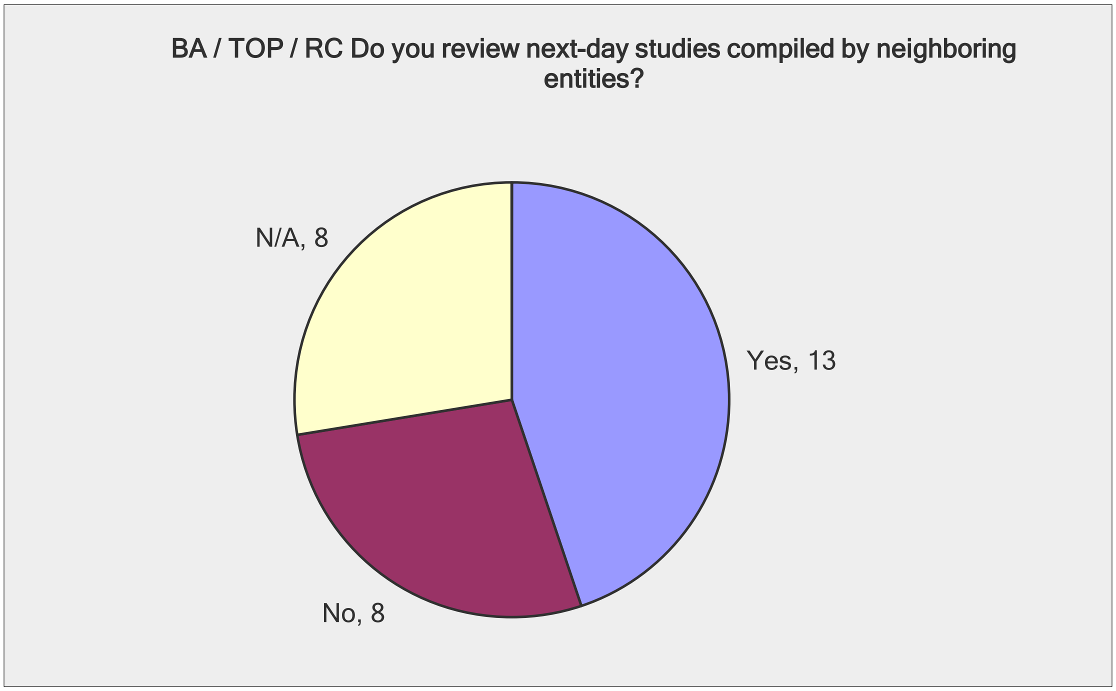
Another way to accurately model generation dispatch for external systems would be to have the day-ahead unit specific generator dispatch. This data would allow respondent to model each generator at its expected generation. Obtaining this data from the neighboring registered entities (market and non-market) has also been difficult. Neighboring registered entities also have trouble providing the data in a timely manner such that the data is accurate for the next-day analysis. Certain interchange transactions are also unknown day-ahead and assumptions have to be made.

- The respondent is currently working with neighboring registered entities to share day ahead (DA) unit commitment with the intent of improving next-day studies.
- It is very difficult to accurately capture external system generation dispatch in the larger BAs. The respondent has to depend on the block dispatch files that are submitted to the SDX by each neighboring BA to be accurate.
- The next-day studies typically include significant external generator outages. However, it is difficult to model an exact generation dispatch representative of actual system conditions in an offline next-day model.

4.3 Do you include external networked sub-100 kV systems in your next-day study models?

- Five out of 29 respondents indicate that they do not include sub-100 kV systems in its next-day study model.

4.4 Do you review next-day studies compiled by neighboring registered entities?



4.5 Describe your company's process and periodicity of validating dynamic models and power-flow models.

- Validates dynamic and power-flow models as needed for specific system events such as the Northeast Blackout.
- Validates dynamic models and power-flow models on a monthly basis.
- Participates in several regional and inter-regional model coordination efforts. These include the Eastern Interconnection Reliability Assessment Group (ERAG) MMWG, SERC LTSG, SERC NTSG, SERC DSG, and SERC Short Circuit Database Working Group (SCDWG).
- TO-OP-MOD-007 Model Validation and Issuing Master Models: The purpose of this procedure is to detail the steps that will be taken to validate survey respondent's production model against official data sources for the respondent's system. This procedure also describes the tools and steps necessary to issue the production models, or Master Models.
- Performs a comparison between the EMS snapshot of the previous summer peak and planning power-flow model to validate the basic parameters since a complete review of all parameters in the models is not practical. The snapshot comparison between the EMS and planning model should lead to identification of serious modeling errors, leading to parameter discrepancies between them. This validation is performed about every two years. For validating dynamic models, transmission planning will perform an event recreation simulation after a qualified dynamic event in the system occurs. The dynamic model validation is performed on an event trigger basis rather than the periodic basis.
- Dynamics models and data parameters are validated using the vendor's software validation tools. These include open circuit and short circuit excitation system tests and governor step tests. Excitation systems and power system stabilizers and their models are validated upon commissioning, the implementation of significant changes, or as scheduled, in accordance with the *SERC Regional Criteria for System Modeling Data Requirements*. In addition, dynamics models and data parameters are verified at least annually as part of the SERC Dynamics Study Group (DSG) model update process. Dynamic and power-flow models are benchmarked against significant system events. In addition, the power-flow model is validated against survey respondent's state estimator for conditions as close to system peak as possible. This comparison is performed no less than once every five years in accordance with the *SERC Regional Criteria for System Modeling Data Requirements*. Steady state reactive loads are validated no less than every two years using either metered data or a state estimator comparison in accordance with the *SERC Regional Criteria for System Modeling Data Requirements*.
- Compare current topology between power-flow cases on a seasonal basis.

- Power-flow case comparisons occur at least once a year.
- Steady state power-flow models are created annually and updated throughout the year in coordination with Southern Company Services' transmission planning and other planning coordinators. Dynamic models are updated whenever testing is performed by a generator by submitting the new data to the SERC DSG. This generally occurs at least once a year.
- Compares models at least once every five years to an internal EMS snapshot near system peak based on real-time SCADA measurements.
- Twice per year, the registered entity takes a saved case of the real time network analysis (RTNET) solution during the summer and winter peak hours and it is shared with the Transmission Planning Unit (TPU). The peak load snapshots are compared to the TPU models used for planning studies to validate the accuracy of the planning models. Feedback to the ECC also helps the accuracy of their models.
- Performed on a five-year basis and work with our Regional Entity to provide the proper modeling information. Work with the SERC DSG.

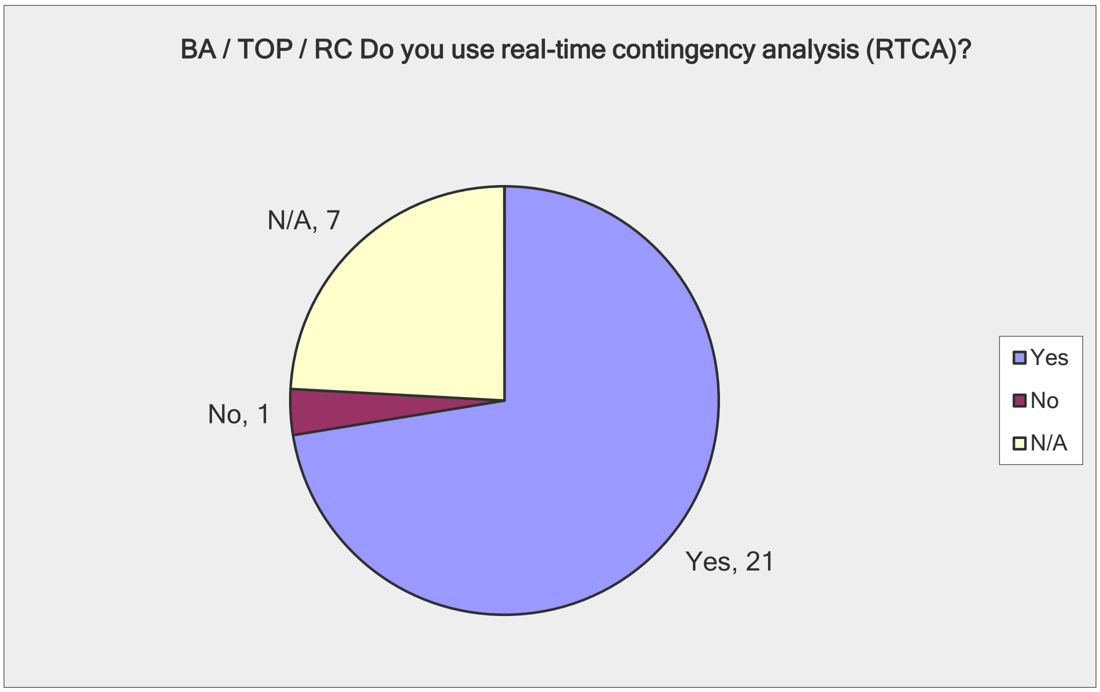
4.6 How do you suggest improving the assessment of the impact of neighboring operations on your own system?

- The NERC Parallel Flow Visualization project is underway and scheduled for completion within 18 months. This project shall help the Eastern Interconnect understand impacts of neighboring operations on their own system. This initiative includes generation to load impacts reported to the Interchange Distribution Calculator (IDC) on a real-time basis.
- Openly communicate the cause and effect of issues you see to your neighbors. Share more data, including better generation dispatch and interchange information.
- Include more accurate market dispatches and system transfers.
- Coordinated studies and improved modeling/analysis capability would help.
- The respondent would like to receive its neighboring utilities' next-day scans. Increase sharing of relevant data between registered entities, such as next-day studies.
- Registered entities should be required to produce a day-ahead firm unit specific generation dispatch and a day-ahead firm and non-firm unit specific generation dispatch. The generation unit names must be aligned with the IDC model names and the data must be produced before noon Eastern in order for the neighboring registered entities to have time to conduct their next-day studies. In general, operational planning models must be improved to reflect expected real-time flows. Currently, NTSG-type cases contain very little transfers and very little market flows. It is quite possible that one transmission model will no longer be enough to get an accurate picture of possible reliability issues when assessing the transmission

system. The study groups could develop bounding cases that reflect non-firm market flows and high transfers. These cases then could be used to study and adequately inform the system operators of what could happen in real-time if the non-firm flows were to occur.

- Provide the most updated control area, block dispatch files, and subsystem files to have an accurate model. Update the base case with the most updated topology of the system.

4.7 Do you use real-time contingency analysis (RTCA)?



4.8 If No to 4.7, how do you monitor RTCA for real-time operations? – No response

4.9 If Yes to 4.7, do you share RTCA results with neighbors? If so, to what extent?

- Allow the TOPs in the respondent's RC reliability area to view the results of the RTCA. The respondent does not give neighboring RCs access to its state estimator results. If n-1 exceedances are identified on neighboring systems, the respondent's RC will call the neighboring RC, verify the possible constraint or exceedances, and discuss possible Mitigation Plans. At times, the respondent's RC will run parallel studies with other RC registered entities and compare its results.

- Shared with neighbors through the RC if a real-time issue occurs.
- Posts DA study results on our secure website and provides access to neighboring engineers once credentials are confirmed and, if necessary, a signed Non-Disclosure Agreement (NDA) is submitted.
- If the respondent RC notices a reliability issue in RTCA, it contacts the affected company, validates the issue, and develops an operating plan.
- Results are not shared in real-time; however, results are communicated when issues are identified that require coordination with the RC and/or a neighboring system.
- If the RC operator notices a potential external reliability issue in RTCA, the RC operator will contact the affected neighbor to validate the observation and, if necessary, coordinate a Mitigation Plan.
- To the extent an issue may impact a neighbor, the respondent discusses the issue and what it has done to manage it via phone calls and the afternoon 3:00 Eastern call with the RC and neighbors.

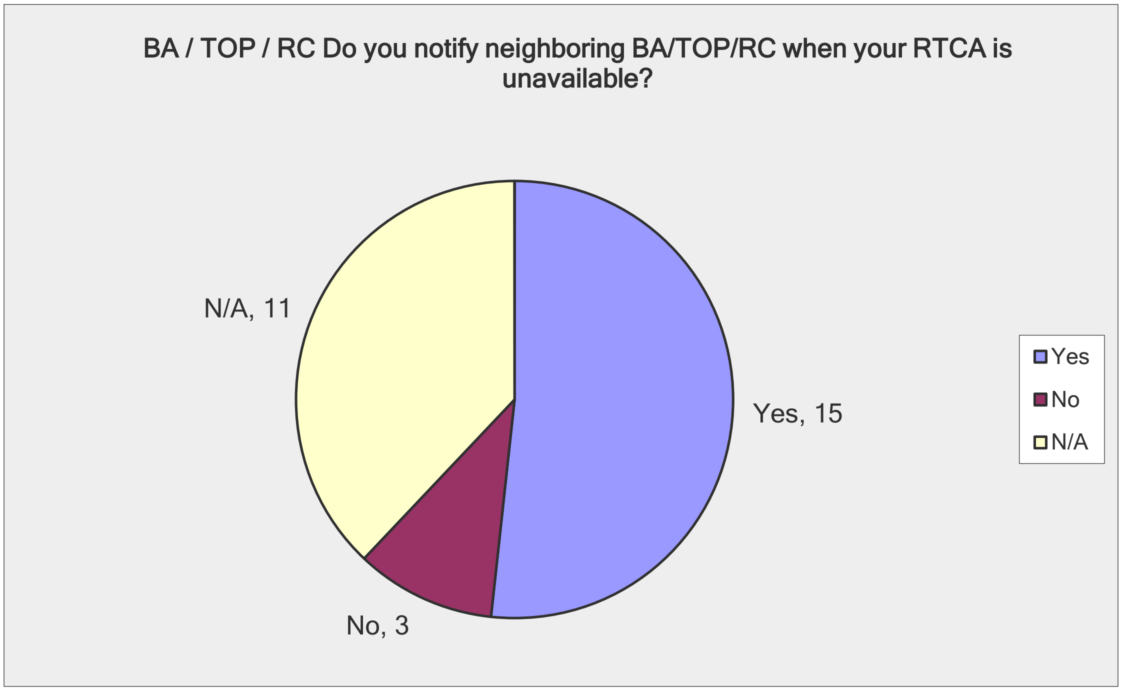
4.10 How do you confirm the validity of RTCA results?

- Real-time cases are pulled into a study environment, as needed. Also, studies are conducted by engineering staff in other power-flow tools such as Power World and PSS/E. When appropriate, the results are also verified by neighboring RCs.
- Validity of RTCA results are confirmed with data validation, using power-flow study tools such as Power World and by comparing results with the RC and planning groups.
- Contact neighboring registered entities to confirm analysis when external constraints are observed in day-ahead analysis. Analysis is compared and if discrepancies exist, the survey respondent will contact neighboring registered entities to resolve discrepancies.
- Validates RTCA results through the use of engineering judgment, operational experience, and power-flow tools in the Energy Management System.
- Perform occasional benchmarks of outages before and after the respondent starts to compare what RTCA predicted versus what was actually seen once the outage started.
- RTCA results are best confirmed by comparing "after" actual observations to the "before" RTCA results during planned and unplanned actual outages by operators as well as through engineering studies off-line.
- Respondent’s typical practice is that operations engineers review RTCA results to confirm their validity when a potential issue shows up. This can be done several different ways, but typically respondent will confirm validity of RTCA results by comparing the pre-contingent flow to the telemetry value to make sure the RTCA

was not underestimating or overestimating and by confirming the line outage distribution factor (LODF) with an offline model. RTCA results are also compared with the RC's RTCA results to confirm validity.

- Result of respondent's automated model builder (AMB) process includes Branch and Voltage Violations which are shared and discussed in the next-day study weekly call.

4.11 Do you notify neighboring BA/TOP/RC when your RTCA is unavailable?



4.12 How do you suggest improving awareness concerning effects of external operations on your system?

- Several of the respondent's neighboring RCs are organized markets. As such, the respondent is impacted greatly by their dispatch based on their unit dispatch system and processes. Currently, markets only calculate market flow impact on Flowgates that are considered "coordinated Flowgates." This means that for Flowgates that aren't considered "coordinated Flowgates," there is no way to see what the market flow impact is on the Flowgate. A large number of non-coordinated Flowgates are still significantly impacted by the markets with market flows making up a significant portion of the flows on the Flowgates, but because the Flowgates don't pass the market coordination test, market flow visibility is lacking in real-time on these Flowgates. If markets were required to provide market flow data on Flowgates that were requested by neighboring registered entities, regardless of whether or not it is coordinated, it would give everyone greater visibility and awareness of the impact of external operations. It should be noted for non-market Flowgates, the impacts can be seen for all Flowgates. The IDC tool used by all RCs could be equipped to be able to display the impact of all market and non-market area operations on Flowgates. Too many times, unknown flows are generically classified as loop-flows and have become accepted as a part of doing business. With all of the unknown loop flows it is very difficult to understand, predict, and model the impacts of neighboring registered entities for planning and operational planning studies. All utilities, markets and non-markets alike, should be required to consider, and bind on, more neighboring registered entity facilities, in their day-ahead unit commitment. Currently, certain utilities only include a limited number of neighboring Flowgates in their day-ahead unit commitment processes; therefore, possibly committing units in such a way that an unknown reliability impact on neighboring systems occurs. By not checking neighboring system impacts when committing units, respondent is essentially planning the system to put neighboring systems in a Transmission Loading Relief (TLR) 3 or TLR 5. The transmission system should be operationally planned to operate without TLR 3 and TLR 5, and those tools should be reserves for unexpected system changes or conditions.

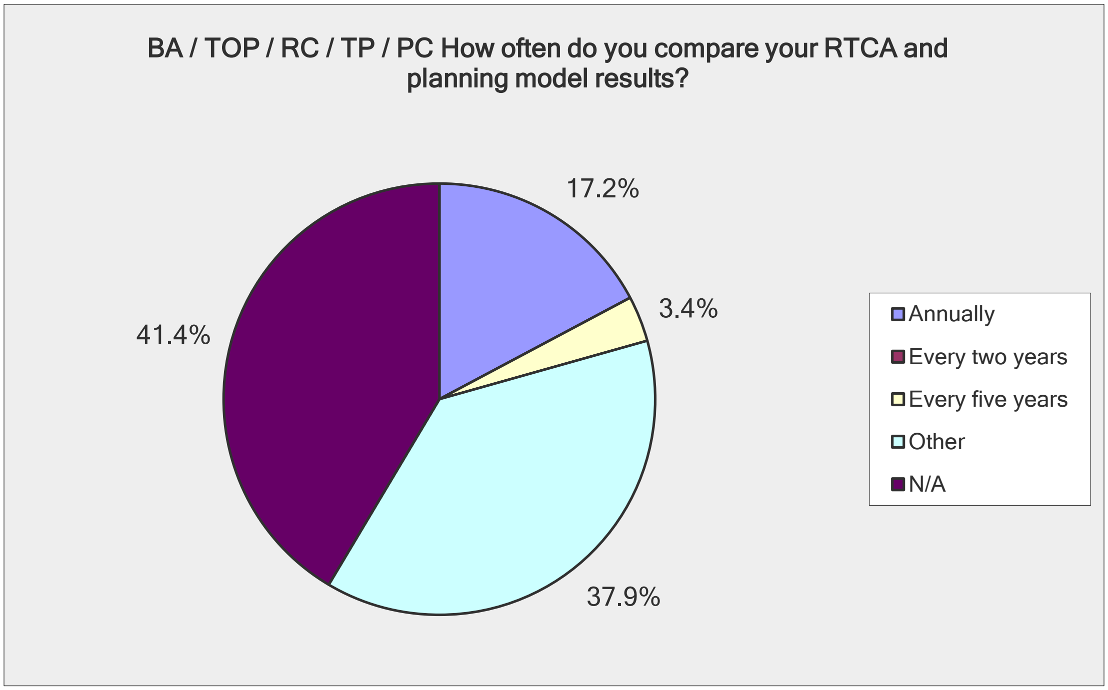
- Continued communication during real-time operations. Follow up on analysis discrepancies with the goal of improving existing modeling and including additional modeling in future model builds.
- Each TOP should sufficiently model its neighboring systems to truly see potential reliability impacts. Also, improved communication and timely model change information being shared in the Real-time Modeling Working Group (RWMG) is important.
- Increase accuracy on expected next-day system conditions for neighboring operations.
- Openly communicate the cause and effect of identified issues to neighbors. Share more data, including better generation dispatch and interchange information.
- Continually obtaining operator observations on abnormal/unexplained system conditions, performing analysis of possible external causes, and then adjusting models to reflect the observations in a study environment.
- Awareness of the effects of external operations on respondent's system could be improved by expanding the list of external contingencies simulated in the RTCA that could have a significant impact on its system and also by having a better method to accurately predict and monitor transfers through its system.
- Better coordination with the Regions. Respondent is very close to another RC and has found some issues with RC-to-RC communications not finding all issues that arise on the system with planned outages.

5.0 Real-Time Contingency Analysis Modeling Validity

5.1 How do you assure consistency in modeling between your RTCA model and planning models?

- The respondent compares modeling on a monthly basis. Events on the system during real-time operations requiring Planning attention are converted to PSS/E format for analysis.
- There is currently very little consistency between RTCA models and planning models. The models required to be built for Transmission Planning (TPL), TPL compliance, and expansion planning require assumptions that significantly deviate the models from RTCA time period models. The impact of firm and non-firm market flows are also missing from the planning models. Some of the assumptions used in the long-term planning models differ from real-time models for valid reasons. Such as, modeling non-firm flow in real-time models. These non-firm flows should not be present in the long-term planning models in order to avoid registered entities building transmission facilities in order to support their neighbors' non-firm loop-flows. If these non-firm loop-flows are built into the planning cases, it essentially forces registered entities to fix overloads caused by neighboring non-firm loop flows. A possible solution to these issues would be to build more bounding models in the planning horizon.
- The respondent participates in a biweekly meeting, The Model Advisory Group (MAG). Representatives from groups involved in planning, operations, and EMS model development are present where issues involving observations of actual operations relative to behavior seen in planning, EMS, and RTCA models is discussed. Actions are taken when necessary to resolve unexplained differences. In addition, when model changes are developed for planning models, these changes are shared with those responsible for RTCA modeling.
  For the EMS RTCA model, the respondent also participates in the RMWG to share EMS model data with each other to facilitate maintenance of detailed external models (i.e., breaker/switch models).
- The RMWG is the primary oversight for this area. In the interim, with each EMS upload, modeling of individual contingencies is checked to make sure they are still correct and any issues are corrected.
- The real-time models are built from planning models (PSSE). Periodic updates are made to the real-time model as changes occur after being reflecting in the planning models.

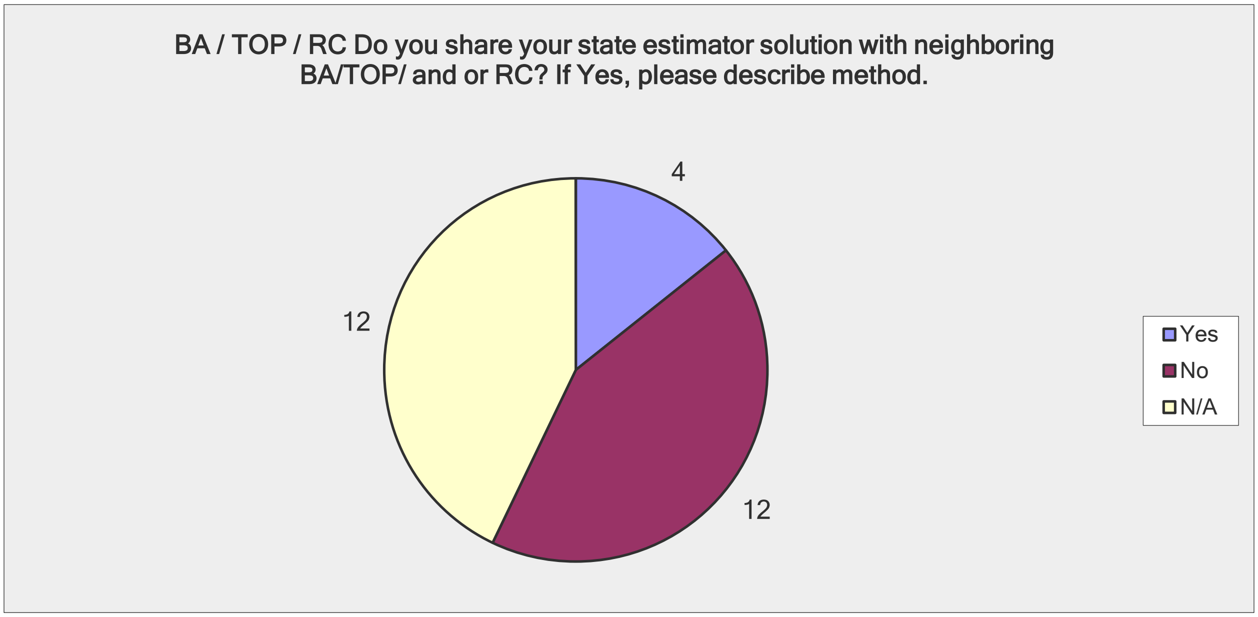
5.2 How often do you compare your RTCA and planning model results?



5.3 Do you validate next-day models with actual load, generation, and interchange?

BA / TOP / PC Do you validate next-day models with actual load, generation, and interchange?				
Answer Options	Yes	No	N/A	Response Count
Actual Load	17	0	11	28
Generation	17	0	11	28
Interchange	16	1	11	28

5.4 Do you share your state estimator solution with neighboring BA/TOP/ and or RC? If Yes, please describe method.



- The state estimator solution is shared upon request.
- Real-time analysis is shared with neighboring registered entities, particularly when there is congestion on the system that impacts both registered entities. The respondent does not share full state estimator solutions with neighboring registered entities.
- The respondent does not currently share its state estimator solution (e.g., via ICCP), though it is possible to do so, it's just not commonly done. The respondent may occasionally share selected values of flows and voltages via phone calls when we receive questions from our neighbors or vice-versa. The respondent has the ability to provide state estimator result snap shots in save cases and/or CSV file dumps if requested.
- When a state estimator solution indicates a potential issue at a close-in external area which could have reliability impacts on the internal system, the RC operator will contact the neighbor to validate the observation and coordinate any required mitigating actions.
- The state estimator application is EMS-based and would need translation/mapping and more explicit external modeling for it to be used in other platforms.

5.5 How do you suggest improving the quality and effectiveness of next-day studies?

- Registered entities should be required to produce a day-ahead firm and non-firm unit specific generation dispatch. Operational planning models need to be available that are reflective of expected real-time flows. Bounding cases that reflect non-firm market flows and high transfers will have to be created in order to adequately inform system operators what to expect in real time.
- By reducing the time it takes to create a quality Next-Day case will provide more time to analyze the results of the study. Suggest that the RC and the Transmission Owner (TO) actually compare next-day studies and then the quality can be validated between the two.
- Share DA unit commitments and improve modeling for neighboring systems.
- More accurate load modeling could improve NDS accuracy. Utilizing the pro-rata scaling of system load can lead to unrealistic load values, which is not a significant issue, but an area for improvement. Also, having more accurate next-day dispatches for the larger BAs would help the quality and effectiveness of NDS significantly.
- Inclusion of actual market dispatch and system transfers.
- Share more data, including better generation dispatch and interchange information.
- An enhancement that we are currently working on would be to create a process to use an exported EMS model. Another improvement would be to use the dispatch of neighboring areas.
- Find better ways to reflect non-firm interchange schedules, which will be difficult at best since they are not typically known until "day of".
- The quality of next-day studies could be improved by having the ability to accurately model transfers through our system.
- Improve study model granularity based on impact assessments of the complete system model analysis. Develop mapping between study application and SDX. Maintain SDX accuracy for both active and future outages. Improve dialogue between outage coordination, maintenance, and engineering organizations to maintain schedule accuracy.

6.0 Data and Information Sharing

6.1 Other than the SERC Intra-Regional Near-Term Study Group (NTSG) study process, describe your additional coordination efforts with neighbors through seasonal planning that identify significant contingencies.

- ERAG Seasonal Assessment, Southeastern Regional Transmission Planning group (SERTP), TPL-001-4 R3.4.1 and 4.4.1 (upcoming)
- Biannual meeting with host TO to discuss operational and planning issues.
- Hold seasonal (summer/winter) meetings with neighboring system operations personnel to share expectations (load forecast, reserves, expected congestion, areas of concern, etc.) and also to walk through emergency operations.
- Not involved in seasonal planning efforts. Significant contingencies are identified in other non-seasonal planning study efforts.
- Explicit coordination activities for seasonal planning beyond the NTSG are not performed. However, as a TP/PC, updated representations to models for seasonal periods are performed and coordinated with neighboring systems through model development activities
- Perform joint studies to ensure that the participants' transmission plans are simultaneously feasible. In addition, these studies evaluate any potential joint alternatives identified by studies which might improve the simultaneous feasibility of the participants' transmission expansion plans through potentially more efficient or cost-effective joint plans.
  Participates in a number of different coordination efforts with neighbors to identify contingencies. First tier neighbors participate in joint planning studies. Other interregional coordination efforts include: Congestion Management Process Council (CMPC) and Working Group (CMPWG), Eastern Interconnection Reliability Assessment Group (ERAG), Eastern Interconnection Planning Collaborative (EIPC), and Multiregional Modeling Working Group (MMWG).
- Studies to determine the First Contingency Total Transfer Capability for each Tier 1 interface for the next 13 months are performed every month. These studies include expected load, dispatch, planned outages, and transactions of Tier 1 neighbors and result in the identification of contingencies that are expected to be limiting to Tier 1 neighbor transfers. Additional coordination is conducted through long-term planning activities.
- Coordinate long-term studies through SERC's LTSG, short circuit and stability studies through SCDWG and DSG, as well as planning and contingencies with an RTO's Coordinated Seasonal Transmission Assessment (CSA), MISO Transmission Expansion Plan (MTEP), and MISO Model-On-Demand (MOD) efforts.

7.0 Communications – Seasonal Coordination

7.1 How are scheduled and unscheduled system outages (of up to 13 months) on your or your neighbor's systems communicated?

- For operational planning, NERC SDX, seams meetings, weekly conference calls, and emails. In real-time calls and RCIS.
- TOP has an outage coordination call with neighboring TOs every Wednesday. In this meeting, outages that impact each neighboring TO are shared. These outages are added to TAORS to make sure it is included in the Next-Day scans. TOP also utilizes SDX for outages that may have been missed on the phone call
- The primary method for sharing longer term outage information is the NERC SDX. The respondent schedules outage coordination meetings (typically monthly) to discuss impactful outages and the need for Operating Guides.
- Scheduled generation outages are communicated up to a year in advance via SDX. Scheduled transmission outages are posted to SDX as soon as they are scheduled, which can be anywhere from two weeks to one year in advance. Unscheduled outages, both generation and transmission, are reported to SDX as soon as possible.
- Scheduled and unscheduled system outages are communicated through the NERC SDX and the weekly outage coordination conference call.

7.2 How do you determine what outages will affect your neighboring systems?

- Monitor system based on an operational planning LODF study, using the respondent's Wide Area definition. The results from this study are applied to a filter in SDX and a report is generated for the weekly outage coordination calls with all neighboring RCs.
- Runs an n-1 on our system including our neighboring utilities and we monitor buses in neighboring systems.
- Analysis using the respondent's EMS and collaboration with neighboring registered entities based on their analysis.
- If our screening process indicates possible issues related to an outage, the neighboring TOP is notified and asked to verify if the contingency is valid.
- These impacts are determined through operational planning studies.
- Communicate our planned and unplanned outages to our neighbors. We typically let them make the determination as to whether those outages will affect their systems. They know their systems better and have it modeled with greater accuracy than we do, more than likely.

- Study every outage and monitor first tier areas. We have weekly phone calls to discuss all potential impacts that might occur and daily calls to discuss upcoming outages.
- Any outage at a tie location or within one bus of a tie point is considered to have an impact on our neighboring system. If a neighboring registered entity requests notification on any facility it will be provided to them.
- The RC notifies us if their studies indicate a potential SOL exceedance on a facility external to our BA/TOP area.

7.3 How do you communicate whether an n-1 contingency on your system would affect a neighboring system?

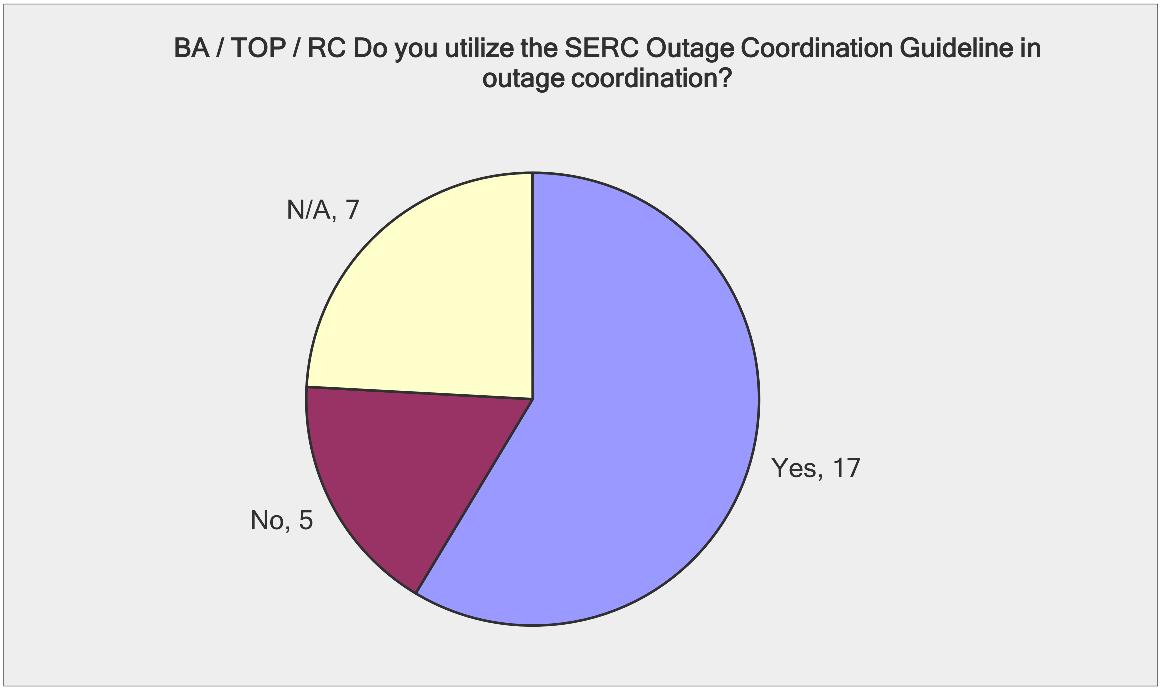
- Analysis using the respondent's EMS and collaboration with neighboring registered entities based on their analysis.
- Communicates the contingency via phone to the affected area and a Mitigation Plan is developed. In the day ahead/operations planning horizon, that is communicated on the daily scheduled next-day RC call for RC members and as needed with other external registered entities.
- Use weekly conference calls and emails. In real time, we use operator calls and next-day results are also shared via daily conference calls.
- During the operating horizon the registered entity communicates the contingency via phone to the affected area and a Mitigation Plan is developed. In the day ahead/operations planning horizon, that is communicated on the daily scheduled next-day RC call for RC members and as needed with other external registered entities.
- As a TP and PC, participates in a number of joint study activities with neighboring systems through the SERC LTSG, North Carolina Transmission Planning Collaborative (NCTPC), and the Carolinas Transmission Coordination Arrangement (CTCA). Through the results of these studies, neighboring systems are able to observe the impact of contingencies on the respondent's system.
- BA/TOP: If discovered during next-day studies, the affected system's outage coordinator will be contacted via phone call. If discovered during real time operations, the affected system's control room will be contacted via phone call.
- Transmission Planning participates in the SERC LTSG, ERAG MMWG, Southeastern Regional Transmission Planning (SERTP), NCTPC, the Eastern Interconnection Planning Collaborative (EIPC), and the CTCA. Results of joint studies are shared within the individual study groups.

7.4 Please offer suggestions on how to improve transparency between systems for the purpose of reliability coordination of next-day studies.

- Registered entities should participate in the SERC NTSG group to the degree possible. Most SERC members have good processes in place for sharing generation and transmission outage information, as well as model topology and impedances. A couple of areas that need improvement are: sharing of planned generation dispatch and planned interchange.
- More accurate reporting of outages in SDX. As outage windows change, ensuring that the information in SDX is updated to reflect those changes.
- Again, improving existing modeling of neighboring systems and sharing DA unit commitment will help improve reliability coordination of next-day studies.
- Continued emphasis on keeping SDX information updated as well as sharing of best available dispatch and interchange information, even if it is an approximation. For example, even if non-firm tags have not been submitted for the next day, if there is a reasonable expectation of interchange being scheduled, then sharing of that knowledge to those affected by loop flows would be helpful.
- Study assumptions could be reviewed by neighboring areas to ensure accuracy.
- Updating the RTO model to include registered entities sub-100 kV facilities could make the comparisons more transparent.
- Transparency between systems for the purpose of reliability coordination of next-day studies can be improved if what constitutes a reliability impact is defined such that each registered entity has the same understanding. For the respondent, we would most likely deny an outage if it caused an n-1 exceedance, even if firm generation redispatch could be used to mitigate the exceedance. Other utilities, including markets members, on the other hand, allow mitigations including firm generation redispatch and do not consider these a reliability impact. This scenario can cause problems with some market registered entities approving outages on their own system even though it will most likely put the neighboring system in TLR 5.
- The respondent realizes that some firm generation redispatch in order to accommodate outages is inevitable on certain parts of the transmission system due to existing system topology and configuration. The respondent feels that firm generation redispatch, in order to accommodate transmission outages, should be the exception and not the norm. The needed transparency will become even more critical as registered entities start including non-firm transactions and non-firm market flows in their next-day analysis. The current process also lacks a defined responsibility. If a registered entity has a significant impact on a neighboring registered entity and causes an overload, nowhere does it require the registered entity to help mitigate the overload being caused on a neighboring system. It isn't very helpful if a neighboring RTO communicates to the respondent an overload of the respondent's transmission element that is caused by the RTO's expected

generation dispatch, if the registered entity doesn't also take responsibility in helping to mitigate the overload.

7.5 Do you utilize the SERC Outage Coordination Guideline in outage coordination?



8.0 Transmission System Use

In this section, operational practices regarding transmission system use is examined. Generally, loop flow is defined as the difference between scheduled flow and physical flow. Transmission system use is comprised of a combination of reserved usages and unreserved usages. Deviation from historical practice to serve specific load may be construed as a reliability issue. The ability to identify unreserved usages associated with internal or non-interchange transactions further complicate the matter. Loop flows are difficult to manage and may lead to unintended consequences such as local congestion, equipment failure, or cascading outage.

8.1 How do you take into account loop flows caused by neighboring systems in your next day study?

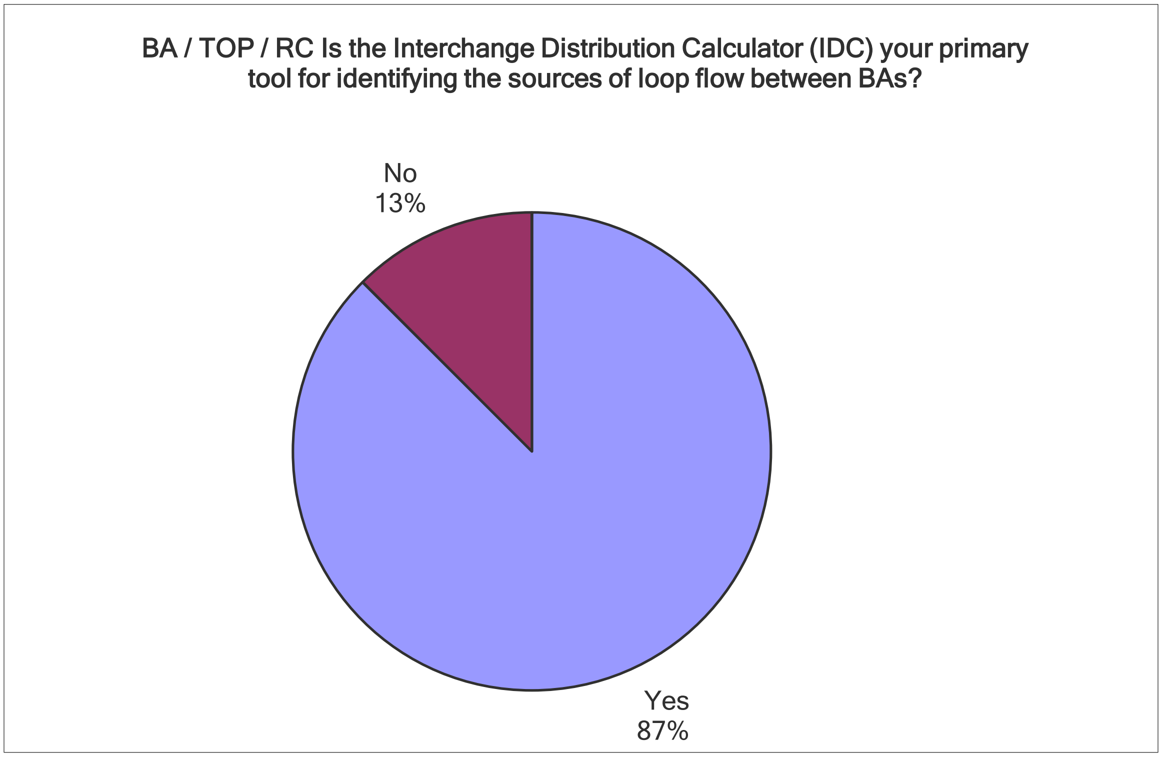
- It's difficult to account for loop flows, other unscheduled flows, or non-transparent flows, caused by neighboring systems in the next-day study. The subject registered entity continues to work with neighboring systems to obtain neighboring system unit specific generation dispatch and incorporating it into its study process. The respondent uses the load forecasts of neighboring BAs and load balancing areas (LBAs) and block merit order dispatches to approximate possible generation dispatch, but this only predicts a small part of the loop flow impacts from neighboring systems and introduces inaccuracies that may otherwise be attributed through better coordinated models, generation dispatch, and other methods previously discussed in this survey.

- Transactions from neighboring registered entities are built into the coordinated models. Interchanges are pulled into the daily cases from SDX when the load forecasts are pulled for the different areas. These are not validated. If the load forecast is greater than 130% of the modeled load or less than 70% of the modeled load, the load will be set to 0.0 and then, AMB will default to using the modeled load. The interchange does not have a similar feature programmed into it. If there is no interchange available from SDX for a particular utility, AMB will default to the coordinated model interchanges.
- Day-ahead analysis considers actual tie flows from and/or into neighboring areas. Congestion identified as a result of actual tie flows will result in an increased generation commitment. The respondent continues to work with neighboring registered entities to share day-ahead unit commitment which will help improve day-ahead analysis.
- Use of SDX to capture neighboring system's expected loads and facility outages to build models that incorporate the expected loop flows due to BAs serving their native load. The models also include long standing firm transactions built that illustrate how transactions impact specific systems.
- Use of the NERC SDX to capture neighboring system's expected loads and facility outages to build models that incorporate the expected loop flows due to BAs serving their native load. The models also include long standing firm transactions built that illustrate how transactions impact its system.
- Incorporate planned generation dispatch by our neighbors as well as planned interchange to the degree it has been reserved and/or tagged. However, this is very difficult to accurately capture and improvements are needed regionally.
- With great difficulty. "Natural" loop flows from generation in a BA serving load (i.e. network/native load from an IDC perspective) is easier to the extent generation dispatch can be somewhat known and modeled. Interchange (BA-to-BA) based on not-yet-tagged (i.e. non-firm scheduled current day) or non-modeled (i.e., pseudo-ties) is much more difficult and can really only be done by using operator judgment and similar day (i.e., it happened today so it probably will happen tomorrow) approximations.
- We do not have a method to predict loop flows on our system caused by neighbors in our next-day studies. We hope that this can be improved with new tools.

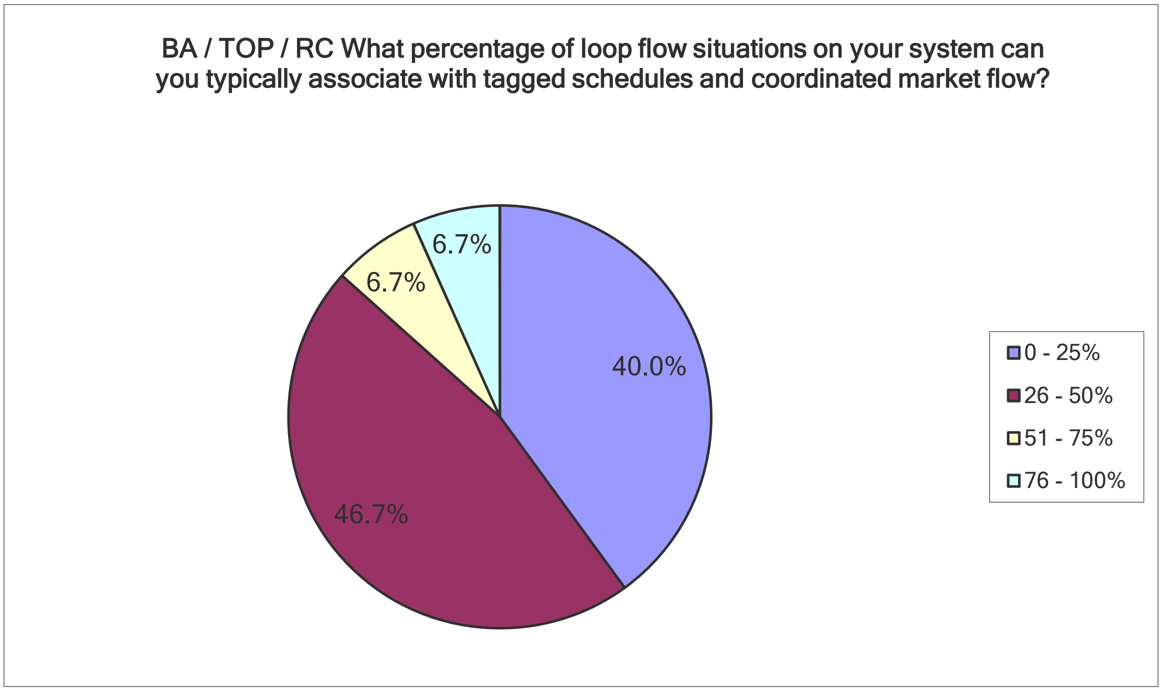
8.2 How do you take into account loop flows for the calculation of available transmission capacity in your next-day study?

- Loop flows are accounted via Transmission Reliability Margin (TRM) in our Available Transmission Capacity (ATC) process; however, it's not included in our next-day studies, for purposes of ATC, the respondent only accounts for known, scheduled or reserved use of its transmission system. In its next-day models, the respondent only accounts for limited loop flows generated by the merit order dispatches provided by neighboring utilities.
- ATC is set by an internal group and acts as a cap for total interchange. Resultant loop flows are controlled during real-time operations by generation re-dispatch and if necessary, TLR.
- The next-day study is not used to calculate ATC. The ATC calculation process uses SDX information to build models containing load, generation outages, and transmission outages for the applicable time period. Depending on the timing of the study, the tag dump file is used to incorporate all currently scheduled tags of TOPs into the model building process, as outlined in the registered entity ATC ID, to model loop flows. If the tag dump file is not used, files containing confirmed Transmission Service Reservations (TSR) from all of our neighbors are used to calculate those loop flow impacts in the ATC calculation process.
- Conservatively create a worst case scenario by maxing out external generation that is close to the seam in order to identify potential constraints.
- The development of the power flow used to calculate transfer limits that ultimately leads to the calculation of ATC includes the inclusion of "expected to be scheduled" transactions both with Tier 1 neighbors and between our Tier 1 neighbors. Modeling of these transactions results in an estimation of loop flows across our footprint.
- ATC calculations are not part of the next-day study.
- Use of the Flowgate methodology for calculating ATCs. The models used in the next day calculations include information from our own and neighboring systems concerning loads, generation, transmission outages and other long term uses of the transmission system. In addition, OASIS reservations that are not included in the base models are deducted from the available Flowgate capacities as they are submitted on OASIS.

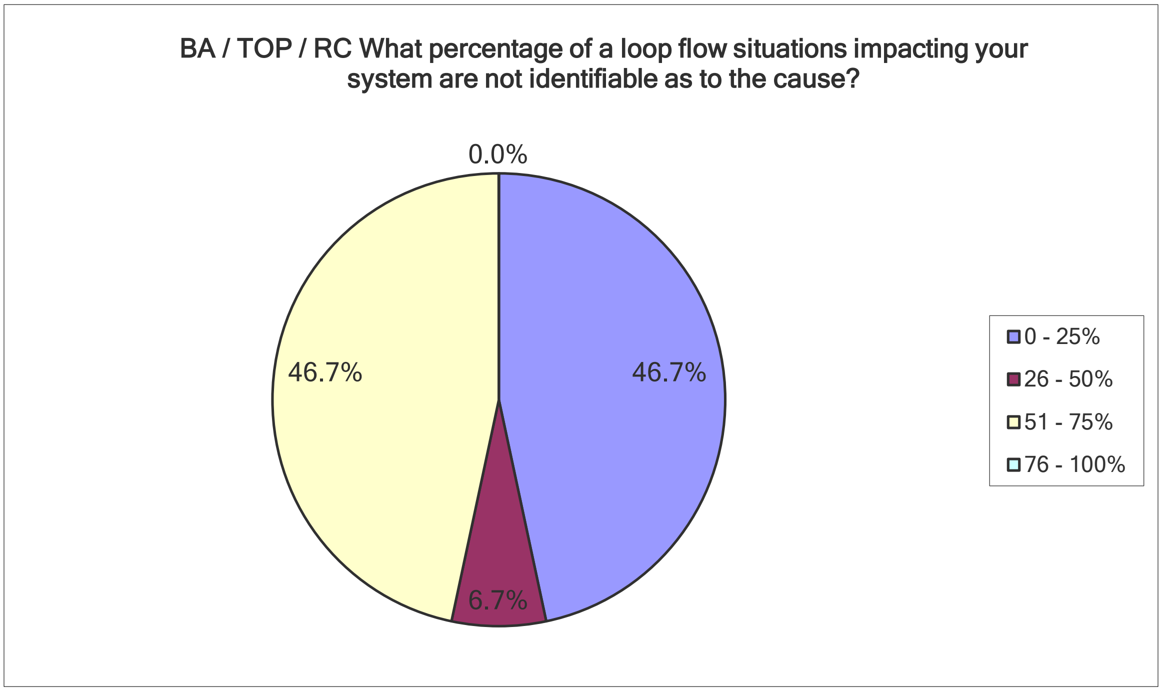
8.3 Is the Interchange Distribution Calculator (IDC) your primary tool for identifying the sources of loop flow between BAs? (Graph includes Yes/No responses only)



8.4 What percentage of loop flow situations on your system can you typically associate with tagged schedules and coordinated market flow?



8.5 What percentage of a loop flow situations impacting your system are not identifiable as to the cause?



9.0 Reliability Threats

This section is relevant to the communication of reliability threats that may originate in your area that may affect another area and awareness concerning reliability threats potential impacting your area that may originate external to your system. A common theme among all respondents is communication involving the RC.

9.1 How are you made aware of reliability threats outside of your area?

The overwhelming reply involved contact between a registered entity and an RC via telephone/hotline verbal communication methods or RCIS (and MISO Communications System).

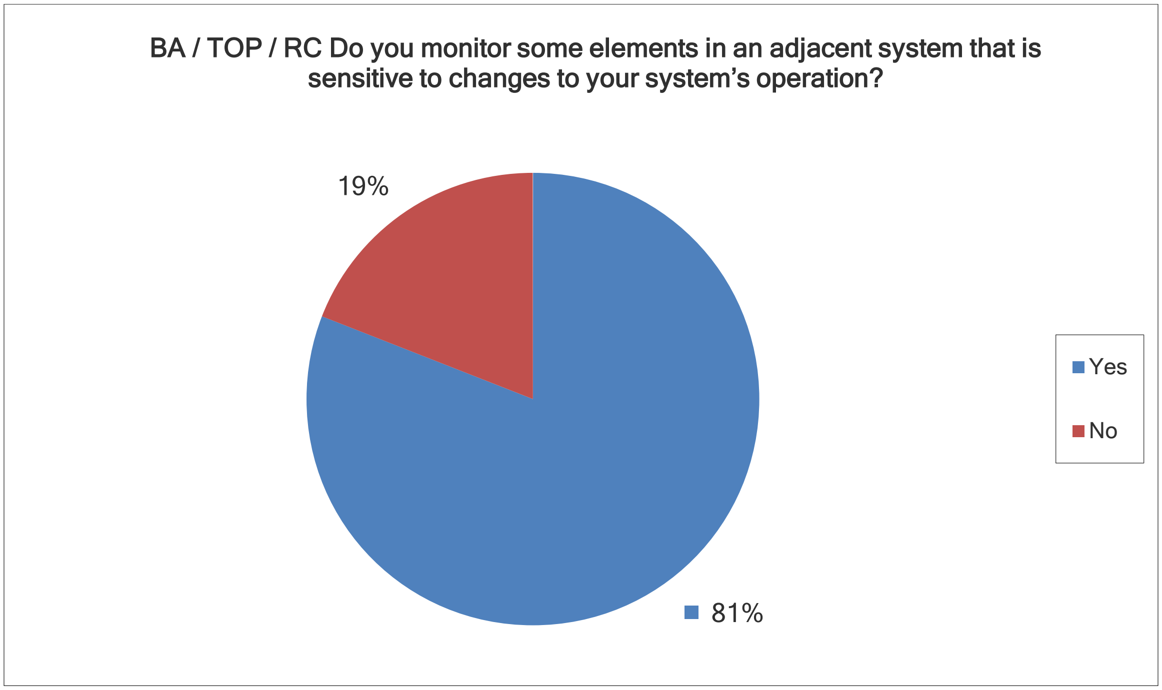
9.2 How do you communicate reliability threats in your area that may affect another area?

- RCIS, RC-to-RC phone call, hotline calls, and other means of direct operator-to-operator communication.

- In real-time, the threats are communicated through the RC, in addition to communicating directly with the neighbors. For planning, the threats are communicated through OASIS or regional outage coordination calls.
- The registered entity will contact direct neighbors to communicate reliability threats and will also post on the RCIS for broader awareness.
- Through calls to other RCs, SERC and NERC Hotline calls, calls to neighboring registered entities, and RCIS.
- "Reliability threats" in this response referring to operational situations and not cyber or physical attack by sabotage. Communications of an evolving or potential internal reliability threat typically would be made directly via phone by the RC operator to the affected neighboring RC(s). In some circumstances, communication via RCIS of a Conservative System Operations Watch/Warning would provide the notification. In some circumstances, RC management will also directly contact neighboring RC management to discuss the situation.
- A telephone call to the RC allows the RC to make others (i.e. SERC and NERC) aware as necessary. SERC would be notified via email and the electric sector information sharing and analysis center (ES-ISAC) could be used to notify NERC.

10.0 Visibility

10.1 Do you monitor some elements in an adjacent system that is sensitive to changes to your system's operation? (Graph includes Yes/No responses only)



10.2 How do you suggest enhancing real-time data sharing to increase visibility and situational awareness?

- More detailed state estimator models with greater modeling in neighboring areas would be helpful. In order for this to more readily occur, standardization of naming for EMS network models is needed. This would allow for an easier exchange of state estimator models and enhance the ability to use neighbors' state estimator models. Common Information Model (CIM) has not come to fruition and isn't very helpful. Markets should be required to provide market flow data on any Flowgate requested by neighboring registered entities, even non-coordinated Flowgates. This would increase real-time visibility and situational awareness. Also, the IDC tool used by all RCs should be equipped to be able to display the impact of all market and non-market areas on Flowgates. Too many times unknown flows are generically classified as loop-flows and have become accepted as a part of doing business. All of the unknown loop flows are coming from somewhere and without properly identifying the cause of the flows, it is very difficult to understand, predict, and model the impact of neighboring registered entities for planning and operational planning studies.

- Suggest that modeling and state estimator accuracy metrics be shared between parties for each party's visibility of their neighboring areas. Also, enhanced detail in first and perhaps second tier BAs.
- The biggest evolving impediment is the recent emphasis by some registered entities requiring bilateral corporate-level Non-Disclosure Agreements and even individual operator execution of critical energy infrastructure information (CEII) agreements before conversations about system changes and study results can take place rather than relying on the historically used multi-party agreements such as the SERC Confidentiality Agreement or the NERC operating reliability data (ORD). This bilateral environment is further complicated by the fact that each registered entity has their own CEII definition which further limits the free flow of information between real-time reliability registered entities.
- Several respondents indicated the current processes are sufficient.
    - Real-time data sharing seems to be adequately handled with current processes utilizing ICCP data exchange.
    - Continue to utilize and improve existing systems, tools, and models, and collaborate and communicate to mitigate potential issues.
    - The respondent believes there are adequate measures in place for visibility and situational awareness.

11.0 Next Steps

This report is a compilation of 2015 SERC Operational Practices survey responses and represents completion of Project Deliverable 1. This report also represents completion of Project Deliverable 2, analysis of survey responses and identification of recommendations to minimize reliability risks to the SERC Region. Project Deliverable 2 is represented in Appendix A.

Appendix A System-to-System Coordination Project Report – Findings and Recommendations

A.1 Introduction

The SERC System-to-System Coordination Project is a 2015 corporate initiative to assure continued reliability of the Bulk Electric System (BES) through coordinated operations in a fully studied state. The project's primary purpose is to assess coordination and visibility and develop a plan to address any identified gaps. In April 2015, SERC distributed a survey to the Balancing Authorities (BA), Transmission Operators (TOP), Reliability Coordinators (RC), Transmission Planners (TP), and Planning Coordinators (PC) registered functions in the SERC Region to identify the current state of the SERC Region's processes and to obtain suggestions for improvement. The survey asked stakeholders to answer questions regarding practices in the following areas:

1. Operations to account for the status of facilities outside stakeholder individual systems
2. The effect of external operations on the stakeholders' own systems
3. Real-time contingency analysis modeling validity
4. Data information and sharing
5. Communications – seasonal coordination
6. Transmission system use
7. Reliability threats
8. Visibility

This report recommends actions based on the survey results. SERC encourages stakeholders to incorporate best practices and improve existing practices to enhance reliability even with changing operating structures.

The responses were further categorized into the following four subject areas:

1. Modeling
2. Next-Day Studies
3. Situation Awareness
4. Transmission Usage

Each section distills survey results into actionable steps summarized in a comprehensive recommendations section.

A.2 Executive Summary

SERC seeks to ensure that the BES is planned and operated reliably. The survey's purpose is to help SERC assess the current state of operational coordination and neighboring system visibility, and to address any identified gaps. The goal is to sustain and reinforce the SERC Region's strong reliability culture.

The 2015 survey consists of 41 questions spanning eight overlapping categories. Feedback received from stakeholders precipitated 14 recommendations across four main areas of concern:

1. Modeling
2. Next-Day Studies
3. Situation Awareness
4. Transmission System Usage

The survey assessed approximately 80 percent of identified functions in the SERC Region. Thus, the survey responses adequately depict the current state of coordination and visibility of the SERC Region representing a large portion of the Eastern Interconnection (EI). Overall, survey responses support a strong reliability culture among stakeholders.

SERC recognizes ongoing stakeholder development and implementation of modeling enhancements across the EI. Consistent with these efforts, the survey results encourage additional enhancement of modeling functions. SERC recommends that its Technical Committees develop associated guidelines and training.

Survey respondents provided numerous suggestions for improving the next-day study process. Timeliness, transparency, and accuracy of information are required to enable operators to anticipate potential issues and plan accordingly. The SERC Region is not unique in its need to improve the next-day study process. The Western Electricity Coordinating Council (WECC), in its 2015 Operational Practices Survey Report, identified next-day studies as an ongoing focus.[1] WECC had previously identified the next-day study process as discussed in the 2011 Arizona-Southern California outage, noting improvements. WECC's next-day study information correlates with the 2015 SERC Operational Practices Survey. SERC recommends that its Technical Committees lead an initiative to improve the next-day study process to enhance Situation Awareness and minimize operating risk.

Situation Awareness covers a wide range of operational activities. According to the Real-Time Tools Best Practices Task Force, Situation Awareness is defined as "ensuring that accurate information on current system conditions is continuously available to operators." The SERC survey yielded recommendations for improving Situation Awareness through enhanced operational tools and processes, including (1) improved communication, (2) timely model update information, and (3) common guidelines governing the impact of external operations.

A high percentage of survey respondents indicated that nearly 50 percent of flows on their systems are associated with tagged schedules or coordinated market flows (e.g., loop flows). The inability to quantify and qualify loop flows represents a significant reliability concern requiring better characterization tools. Improving loop flow assessment will require SERC

[1] WECC 2015 Operational Practices Survey Report July 17, 2015

executive management's support of NERC's Parallel Flow Visualization Project and SERC's involvement in the Electric Reliability Organization (ERO) Executive Management Group (EMG) and/or ERO Reliability Assessments and Performance Analysis (RAPA).

Survey recommendations follow each of the four topic areas. A summary of recommendations is located at the end of this document.

A.3 Modeling

Modeling that represents the BES and, as necessary, critical lower-level (sub-100 kV) systems, is essential to adequate Situation Awareness. Representative models allow operators to anticipate issues and address them proactively. Real-time contingency analysis relies on representative models to be effective. Historically, modeling software and hardware limitations have required equivalizing portions of the system, resulting in an over-simplification of the power system. While modeling advancements have reduced or even eliminated the need for equivalizing, the practice is still in use.

A.3.1 Discussion of Questions

The questions directly related to modeling are 3.1, 3.2, 3.3, and 4.6.

In general, the Eastern Interconnection's (EI) power system modeling and model management have shown continuous improvement using model management practices defined by the Eastern Interconnection Reliability Assessment Group (ERAG) and its Multi-Regional Model Working Group (MMWG).[2]

The MMWG procedures are being modified to improve governor response modeling to address degradation of frequency response in the EI following major disturbances. The MMWG has held governor response workshops, reviewed survey data, and updated models. With these improvements, MMWG models will more closely simulate the frequency response of the EI. Also, MMWG process improvements have addressed recurring errors in the models.

ERAG tool and process improvements include:

- A power flow check program, used by the data submitter, is available to validate data prior to submission to the MMWG.
- MMWG requires all data check errors to be corrected before the models are posted as final.
- The MMWG manual includes documented checks and established acceptance criteria for the development of dynamics cases.
- ERAG has developed a power flow audit program to compare and list changes from one model series to the next to validate proposed changes.

[2] For more information on ERAG and the multiregional modeling working group (MMWG) see: https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/pages/default.aspx

- ERAG has completed a web-based dynamics database to facilitate the dynamic base case building process.
- An MMWG subgroup has developed an improved methodology for EI frequency response base cases.

Questions 3.1 and 3.2

SERC asked respondents to characterize the inclusion of line or bus details of external systems in their next-day study models and Real-Time Contingency Analysis (RTCA). They were also asked to provide the rationale for this external inclusion and any associated equivalizing.

In general, most entities appear to perform equivalizing of their models more for convenience and model simplification, instead of using the improved model accurately allowed by current power-flow modeling software.

Consideration should be placed on the following two points:

- Oversight and analysis of the system via the EI model-building process has improved in recent years.
- There is inconsistency regarding the level in which external systems are modeled/equivalized. Consideration should be given to a regional modeling criteria addressing equivalizing of external systems (e.g., addressing sub-100 kV lines, specifying the number of buses out to include, etc.).

Question 3.3

SERC asked respondents the extent to which neighboring systems are reporting from their State Estimator or planning model in their next-day studies, e.g., one or two buses outside their systems.

Based on the responses, the respondents' approaches appear to be inconsistent. Some entities rely heavily on Near Term Study Group (NTSG) models, others on ERAG/MMWG models directly. SERC recommends considering development of Regional Criteria that provides guidance on equivalizing external systems (below 100 kV and the number of external buses out from the entity system), or whether more complete modeling detail is appropriate.

Utilities in the SERC Region should consider the ERAG/MMWG's data validation tool and other efforts to benchmark the models for completeness.

Question 4.6

SERC asked respondents for suggestions to improve the assessment of the impact of neighboring operations on their own systems. Some respondents pointed to the current NERC/NAESB (North American Energy Standards Board) Parallel Flow Visualization project that is scheduled for completion within 18 months. Multiple respondents indicated the need to enhance information sharing (generation dispatch and interchange). As further discussed in Section 4, Next-Day Studies, respondents call for timely, transparent, and complete sharing of information necessary to develop a robust next-day study.

Utilities rely on neighboring operators to determine whether their operating conditions (e.g., outages or dispatch) will affect the neighboring systems. The assumption is that neighboring system operators usually know their own systems best and model their systems comprehensively, which is in generally true.

Modeling Recommendations

1. Arrange for overview training to SERC members on the EI modeling process.
   - Communicate to all SERC members (through Technical Committees and SERC conferences) the process improvements that the ERAG/MMWG has completed. Encourage SERC members to implement these improvements.
2. SERC staff should develop specific questions on modeling for a follow-up survey to be undertaken in 2016.
3. Identify the appropriate operations modeling technical committee to address the following reliability risk mitigation steps:

   A. Develop best practices and/or Regional Criteria that will provide guidance on equivalizing external systems (below 100 kV and the number of external buses out from the entity system).

   B. Establish a review process to ensure SERC members are incorporating modeling best practices in their daily operations. For example:

1.1.1 Data validation to benchmark models for completeness, incorporating data checks to confirm that non-firm market flows are entered into the models.

A.4 Next-Day Studies

Next-day studies are an essential component of Situation Awareness, allowing operators to identify potential issues and plan accordingly. Next-day studies are necessary to promote and maintain the Reliable Operation of the BES. Per the *Glossary of Terms Used in NERC Reliability Standards*, Reliable Operation is defined as:

> Operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

Next-day studies vary in type depending on targeted assessment of the system. For example, next-day studies may include but are not limited to thermal and system voltage limits, contingency analysis, and steady state analysis.

SERC posed several questions regarding the effectiveness, trustworthiness, and transparency of next-day studies within the SERC Region. Survey responses were contrasted with information from multiple blackout reports as well as other NERC and Regional Entity surveys and sources. Survey respondents noted numerous suggestions to improve planning for next-day operations.

WECC, in its 2015 Operational Practices Survey Report, identified next-day studies as one of five topics analyzed in its report.[1] WECC noted the next-day study process as a major focus of the 2011 Arizona-Southern California outage and recognized improvement within its Region over the last several years.

The questions directly related to Situation Awareness relevant to Next-Day Studies are: 4.1, 4.2, 4.3, 4.4, 5.5, and 7.4.

A.4.1 Discussion of Questions

Question 4.1

SERC asked respondents if their next-day studies consider generation dispatch, System Operating Limits/Interconnection Reliability Limits, and load external to their areas.

The respondents overwhelmingly indicated they include the aforementioned parameters in their next-day studies. This is a notable positive observation. However, multiple respondents indicated that the timeliness of information and completeness of generation dispatch supporting the next-day study is an issue requiring resolution. Survey recommendation includes adoption of this issue by the SERC Technical Committees.

Question 4.2

SERC asked respondents if they believed their next-day studies include external generation dispatch that represents actual system conditions.

Thirty-nine percent of survey respondents believe their next-day studies do not represent actual system conditions. Improved modeling is needed. Representative flows can be forecast if the models have enough detail to represent the system. Unit-level generator modeling is feasible, even in the Eastern Interconnection.

One survey respondent suggested another way to accurately model generation dispatch for external systems using day-ahead, unit-specific generator dispatch. This data would allow the respondent to model each generator at its expected generation. However, obtaining this data from the neighboring registered entities (market and non-market) has been difficult. Neighboring registered entities struggle to provide timely, accurate data for the next-day analysis. Certain interchange transactions are also unknown beforehand and require assumptions. The survey recommendation is to enhance the next-day study process using unit-specific generation dispatch. Again, a SERC Technical Committee should undertake enhancement of the next-day study process.

Question 4.3

SERC asked respondents if they include external networked sub-100 kV systems in their next-day study models.

Five out of 29 respondents (17 percent) indicated that they do not include external sub-100 kV systems in their next-day study models. Recommendation number 3 of the Arizona-Southern California Outages on September 8, 2011 report dated April 2012 states that TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact bulk power system (BPS) reliability.

On May 13, 2014, SERC compiled a response to the Southwest Outage Recommendations. Based on responses to a 2014 survey conducted by the SERC Operations Planning Subcommittee, few entities monitored and performed contingency analysis on neighboring networked sub-100 kV facilities. The improvement is clear: In the 2014 survey, only a few entities monitored and performed contingency analysis on neighboring systems; in the 2015 survey, only five respondents fail to do so.

Question 4.4

SERC asked respondents if they review next-day studies compiled by neighboring registered entities. The survey respondent population was 29, including 21 TOPs and five RCs (TOPs and RCs are the only functions applicable to this question) with anonymous replies from other registered functions.

Of the 29 respondents, 13 routinely review their neighbors' next-day studies. Recommendation 1 of the report of the Arizona Southwest Outage states that all TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that impact the BPS are studied. SERC's response to the Southwest Outage Recommendations dated May 13, 2014 states, "…the SERC TOPs are performing next-day studies, or having them performed; and, are sharing the study results, as necessary to ensure reliability. No further action required or best practices recommended."

From the survey, several TOPs exchange results of next-day studies, but others exchange information infrequently, such as identification of a contingency only. SERC recommends an enhanced process to include review of next-day studies among TOPs (and perhaps RCs) to align activity among TOPs and RCs in the SERC Region with the expectation outlined in Arizona-Southern California Outage Recommendation number 1. This item is proposed for resolution in SERC Technical Committees.

Question 5.5

SERC asked survey respondents to suggest ways to improve the quality and effectiveness of next-day studies.

Feedback indicated that next-day models should be enhanced so they reflect real-time flows. Challenges include:

- Some entities' models represent blocks of generation to approximate generation dispatch on the system. By equivalizing generation on the system, models lack sufficient granularity that unit-specific generation dispatch provides. These models may not represent day-ahead firm and non-firm commitments.

- Generation unit names must align with the IDC model names.
- Data must be available before noon to enable neighboring entities to conduct timely next-day studies.
- Near-term study group type cases capture an insufficient number of transfers and market flows.

Respondents gave these recommendations to improve next-day studies, many of which require improved modeling:

- Develop a better way to capture non-firm interchange schedules that are usually unavailable when conducting a next-day study.
- Provide the ability to accurately model transfers through a system.
- Improve load modeling accuracy to improve next-day study accuracy.
- Provide a way for the larger BAs to create accurate next-day dispatches. This would improve the quality and effectiveness of next-day studies significantly.
- Improve the granularity of study models based on impact assessments of the complete system model analysis.
- Develop mapping between study application and SDX, and maintain SDX accuracy for both active and future outages.
- Improve dialogue among outage coordination, maintenance, and engineering organizations to maintain schedule accuracy.

One respondent noted that the pro-rata scaling of system load can lead to unrealistic load values. (Although this is not a significant issue, it represents an area for improvement.)

The following quotes are from the *Arizona-Southern California Outages on September 8, 2011 – Causes and Recommendations – April 2012*:

> The September 8th event illustrates that conducting next-day studies and sharing the results of such studies are critical to allow TOPs to identify and plan for potential contingencies. – p. 68
>
> Finding 2 - Lack of Updated External Networks in Next-Day Study Models:
>
> When conducting next-day studies, some affected TOPs use models for external networks that are not updated to reflect next-day operating conditions external to their systems, such as generation schedules and transmission outages. As a result, these TOPs' next-day studies do not adequately predict the impact of external contingencies on their systems or internal contingencies on external systems.

> Arizona-Southern California Outage Recommendation 2: TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.
>
> Leading into September 8th, the affected TOPs had limited knowledge of the current status of transmission facilities, expected generation output, and load predictions outside their footprints. Consequently, their next-day studies could not adequately predict the impact of external contingencies on their systems or of internal contingencies on external systems.

WECC worked with registered entities located within its regional boundaries and coordinated several annual operational practices surveys subsequent to the 2011 Arizona-Southern California Blackout. The surveys gathered information regarding the performance, coordination, quality, and utilization of next-day studies conducted by registered entities. In 2015, WECC developed a Next-day Studies Guideline to better prepare operators for real-time conditions. SERC should leverage WECC's work. An educational initiative to work with WECC's Operating Committee and WECC's Next-day Study Task Force should be undertaken through SERC Technical Committees. A recommendation from the 2015 SERC Operational Practices Survey is that SERC Technical Committees should develop Regional Criteria specific to next-day studies, similar to WECC's Next-day Studies Guideline.

Question 7.4

SERC asked respondents to provide suggestions to improve transparency between systems for the purpose of reliability coordination of next-day studies.

Again, SERC received good feedback from its members to promote and sustain reliability in the SERC Region. One commenter noted that entities should participate in the SERC Near-Term Study Group (NTSG) to the degree possible. Most SERC members have good processes in place for sharing generation and transmission outage information, as well as model topology and impedances. The commenter noted two areas that need improvement: sharing of planned generation dispatch and planned interchange. Another commenter noted that improving modeling of neighboring systems and sharing day-ahead unit commitment will help improve reliability coordination of next-day studies.

An Arizona-Southern California Outage finding included a flawed process for estimating scheduled interchanges. According to the report, "WECC RC's process for estimating scheduled interchanges is not adequate to ensure that such values are accurately reflected in its next-day studies. As a result, its next-day studies may not accurately predict actual power flows and contingency overloads." SERC's response to the finding indicated that RCs in the SERC Region have identified a process to perform post analysis of each day using some portion of actual conditions or all the actual conditions in next-day analysis. However, on ongoing issue is the limited ability to accurately predict all non-firm transactions in the day-ahead time frame.

Another commenter suggested there is a need for consistency among BAs, TOPs, and RCs in defining a reliability impact. For example, one entity might deny an outage if it caused an n-1 exceedance even if firm generation dispatch could be used to mitigate the exceedance. Another entity might allow mitigations, including firm generation dispatch, and not consider this a reliability impact. This scenario may cause problems when an entity approves an outage on its system, which would most likely place the neighboring system in a TLR5 condition. This is a reliability concern. The same commenter noted that some firm generation redispatch is inevitable to accommodate outages on certain parts of the transmission system due to existing system topology and configuration. However, the commenter believes that firm generation redispatch to accommodate transmission outages should be the exception, not the norm.

The need for transparency will become even more critical as entities begin including non-firm transactions and non-firm market flows in their next-day analysis. The commenter indicated the current process also lacks a defined responsibility. If an entity has a significant impact on a neighboring entity and causes an overload, no mechanism exists that would require the entity to help mitigate the overload caused on a neighboring system. Clearly, this is an opportunity to improve transparency of information and mutual operations among BAs, TOPs, and RCs to promote and sustain reliability of the Eastern Interconnection.

Other commenters recommended more accurate reporting of outages in NERC's SDX. As outage windows change, entities must assure that the SDX information is updated to reflect those changes. Several commenters noted continued emphasis on updating NERC SDX information and sharing best available dispatch and interchange information, even if the information is approximate. For example, if an entity anticipates that an interchange will be scheduled, the entity should share that knowledge to those affected by loop flows, even if non-firm tags have not been submitted for the next day.

System data should be available to any BA, TOP, or RC with a reliability need for the information. Entity-specific confidentiality provisions applied to operator-level agreements may create legal barriers to performing certain reliability-related activities. Any employee who is performing reliability tasks under an entity registered as a BA, TOP, or RC should be able to exchange reliability information freely and as necessary to perform reliability-related tasks.

The following is a finding from the Arizona-Southern California Blackout report:

> TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs…. Leading into September 8th, the affected TOPs had limited knowledge of the current status of transmission facilities, expected generation output, and load predictions outside their footprints. Consequently,

their next-day studies could not adequately predict the impact of external contingencies on their systems or of internal contingencies on external systems.

SERC recommends that SERC staff address the issue concerning individual specific confidentiality provisions.

A.4.2 Next-Day Studies Recommendations

SERC recommends a SERC Technical Committee initiative to improve next-day studies. The initiative should have the following objectives:

1. Improve timeliness of information and completeness of generation dispatch supporting the next-day study.
2. Ensure that TOPs' and RCs' next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.
3. Enhance the next-day study process to include review of next-day studies among TOPs and RCs.
4. Improve quality and effectiveness of next-day studies. The studies must capture all interchange schedules and improve model transfers across systems.
5. Optimize system operations. Identify and implement a common application of the term “reliability impact” as it relates to outage requests and firm generation dispatch consideration in next-day models.
6. Develop specific questions on next-day studies for a SERC follow-up survey to be undertaken in 2016.
7. Recommend that the SERC Legal department addresses entity-specific confidentiality provisions applied to individual-level agreements. This issue may create a barrier to performing certain reliability-related activities. Address the following needs:
    - Establish guidelines and nondisclosures to regulate access to modeling information.
    - Establish protocols and timing release of information to the appropriate parties because generation dispatch is considered market-sensitive.

A.5 Situation Awareness

Situation Awareness is the result of many processes within a utility, ranging from modeling to EMS design. One focus of this survey is the intersection of modeling and RTCA and communication of critical results with neighboring systems.

The questions directly related to Situation Awareness were 3.4, 4.7, 4.11, 4.12, 5.2, 10.1, and 10.2.

A.5.1 Discussion of Questions

Question 3.4

SERC asked respondents if they specifically alarm points in their EMS systems for n-1 contingencies on their own systems that they know cause transmission constraints in a neighboring operating area.

The responses show that 25 percent do not have any such alarms, which implies that 75 percent have the alarms. This is a positive outcome but not comprehensive. Minimizing impacts on neighboring systems is a key principle of good utility operations. Respondents require a common process to help them operate reliably within new operating paradigms. Based on the responses to this question, a proactive, risk-mitigating strategy is required to address the identified gap (the 25 percent that do not have the alarms). SERC Technical Committees could implement an educational and outreach initiative through the SERC System Operator Conferences.

Question 4.7

SERC asked respondents if they use RTCA.

Eight responded that they do not use RTCA; seven responses were "not applicable" (N/A). If eight out of 29 do not use RTCA, this will require deeper investigation. The seven N/A respondents perform functions that do not require RTCA.

This item is inconclusive. SERC recommends investigating further, perhaps through a more detailed survey with specific questions.

Question 4.11

SERC asked respondents if they notify neighboring BA/TOP/RCs when their own RTCA is unavailable.

The responses show that 14 of 29 (48 percent) may not be notifying neighbors when their RTCA is unavailable. Of the 14, three responses were "No" and 11 "N/A." This is a key reliability risk that requires operational risk mitigation, even if the 11 "N/As" are not counted. SERC Technical Committees could implement an educational and outreach initiative through the SERC System Operator Conferences.

Question 4.12

SERC asked respondents for ideas to improve awareness concerning effects of external operations to their systems.

Numerous good suggestions warrant consideration in the SERC Technical Committees. Perhaps special topic-specific project teams should be formed across technical committees if the subject is within SERC Technical Committee scopes. Highlights of these suggestions include:

- Openly communicate the cause and effect of identified issues to neighbors. Share more data, including better generation dispatch and interchange information.

- Continually obtain operator observations on abnormal/unexplained system conditions, analyze possible external causes, and then adjust models to reflect the observations in a study environment.

Question 5.2

SERC asked respondents how often they compare their RTCA results to their planning model results.

Answers varied widely. Only 17 percent perform this planning to real-time model benchmarking annually. About 58.6 percent perform this either annually or every two years, with 41 percent performing this benchmarking on longer intervals. This seems to be a common practice; however, establishing a common interval might benefit the SERC Region. A future survey with specific questions will help SERC form a recommendation.

Question 10.1

SERC asked respondents if they monitor transmission elements located in an adjacent system that are sensitive to changes in their own system operation.

Nineteen percent said they are not monitoring some elements in an adjacent system for this purpose. This result supports the need for a proactive effort to reduce the number of entities not monitoring adjacent systems. Monitoring adjacent systems for known influences, while not a direct requirement in NERC standards, is a good practice to avoid more drastic action (such as Transmission Loading Relief (TLR), or emergency declarations leading to public appeals). SERC Technical Committees could implement an educational and outreach initiative through the SERC System Operator Conferences.

Question 10.2

SERC asked respondents for suggestions to enhance real-time data sharing to increase visibility and Situation Awareness.

Some suggestions have been incorporated into the recommendations in this report. Others can be provided to the Technical Committee teams assigned as a result of the recommendations in this report.

A.5.2 Situation Awareness Recommendations

SERC recommends the following actions for SERC stakeholders to consider based on the Situation Awareness-related survey findings:

1. Establish common guidelines to aid each SERC TOP stakeholder to model its neighboring systems accurately to reveal potential reliability impacts.
2. Share timely model change information in the Real-time Modeling Working Group (RWMG) and improve its communication to stakeholders.
3. Establish common guidelines to aid SERC stakeholders regarding the effects of external operations on a respondent’s system. Expanding the list of external contingencies simulated in the RTCA could have a significant impact.

4. SERC staff should develop specific questions on Situation Awareness for a follow-up survey to be undertaken in 2016.

A.6 Transmission System Use

The Final Report on the August 14, 2003 Blackout in the United States and Canada - Recommendation 12 suggested an independent study of the relationships among industry restructuring, competition, and reliability. The report went further to state the DOE and Natural Resources Canada should commission an independent study of the relationships among industry restructuring, competition in power markets, and grid reliability, and how those relationships should be managed to best serve the public interest. The 2003 Blackout report states:

> Some of these commenters assert that the transmission system is now being used to transmit power over distances and at volumes that were not envisioned when the system was designed, and that this functional shift has created major risks that have not been adequately addressed.... The relationship between competition in power markets and reliability is both important and complex, and careful management and sound rules are required to achieve the public policy goals of reasonable electricity prices and high reliability. At the present stage in the evolution of these markets, it is worthwhile for DOE and Natural Resources Canada (in consultation with FERC and the Canadian Council of Energy Ministers) to commission an independent expert study to provide advice on how to achieve and sustain an appropriate balance in this important area.

Regardless of the independent study outcome, a reliability issue exists involving availability of granular generation and interchange information.

Additionally, in FERC Order 890-A, P100, the Commission stated, "Loop flow impact in ATC (and/or AFC) calculation should not be restricted to the transmission provider's control area. Loop flow that occur in the power system must be included in the load flow models that simulate power system conditions. Loop flows affecting ATC (and/or AFC) calculation should be taken into account consistently by using the same models and assumptions as used for the planning of the system." This is much easier said than done.

A.6.1 Discussion of Questions

Questions 6.4 and 6.5

Today, nearly 50 percent of SERC survey respondents cannot account for 51- to 75 percent of loop flow causes impacting their systems. Additionally, 87 percent of respondents indicate that only about 50 percent of loop flow situations on their system can be associated with tagged schedules and coordinated market flow. Uncoordinated market flow further complicates the matter. These are significant reliability concerns, and the industry must be provided the tools to better identify loop flow causes.

One potential solution to help identify loop flow may be through support of NERC’s Parallel Flow Visualization Project. The project is intended to enhance the available information concerning generation-to-load impacts captured in the interchange distribution calculator in real-time. It will more accurately depict the flow across the system and define the relief responsibility of entities that contribute to congestion. The project involves participation from NERC and NAESB. Possible solutions are SERC executive management's support of NERC's Parallel Flow Visualization Project through involvement with ERO EMG and/or ERO RAPA.

A.6.2 Transmission System Use Recommendations

1. Enhance identification of loop flow situations across the Eastern Interconnection. Possible solutions are SERC executive management's support of NERC's Parallel Flow Visualization Project through involvement with ERO EMG and/or ERO RAPA.
2. SERC staff should develop specific questions regarding the Flow Visualization Project awareness for a follow-up survey to be undertaken in 2016.

SERC Reliability Corporation

Summary of Recommendations

I. Modeling

1. Arrange for overview training on the Eastern Interconnection modeling process. {SERC training in 2016}
2. Through technical committees and SERC conferences, communicate to all SERC members the extensive process improvements in modeling that the ERAG/MMWG has completed. Encourage SERC members to implement these modeling improvements. {SERC Training 2016}
3. Identify the appropriate operations modeling Technical Committee to address the following issues:
    - SERC member and regional collaborative efforts should establish best practices and/or Regional Criteria that will provide guidance on equivalizing external systems (below 100 kV and the number of external buses out from entity system) to provide consistency in entities' monitoring and analyzing the system. {SERC Technical Committee initiative concerning improvement of modeling practices}
    - The Region should establish an entity review process to ensure entities are incorporating the modeling best practices in their daily operations. {SERC Technical Committee initiative to review entities' modeling practices—implementation and improvement}

II. Next-Day Studies

1. Improve timeliness of information and completeness of generation dispatch supporting the next-day study {SERC Technical Committee initiative concerning improvement of next-day studies}
2. Ensure that TOPs' and RCs' next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability. {Discussion and review of topic with SERC Technical Committees}
3. Enhance the next-day study process to include review of next-day studies among TOPs and RCs. {SERC Technical Committee initiative concerning improvement of next-day studies}
4. Improve quality and effectiveness of next-day studies to address the need to capture all interchange schedules and improve model transfers across systems. {SERC Technical Committee initiative concerning improvement of next-day studies}
5. Optimize system operations. Identify and implement a common application of the term "reliability impact" as it relates to outage requests and firm generation dispatch consideration in next-day models. {SERC Technical Committee initiative concerning improvement of next-day studies}
6. Resolve the legal issue concerning entity-specific confidentiality provisions applied to individual-level agreements. This issue may create a barrier to performing certain reliability-related activities. {SERC staff to review}

III. Situation Awareness

1. Establish common guidelines to aid each SERC TOP stakeholder to model its neighboring systems accurately to reveal potential reliability impacts. {SERC Technical Committee initiative concerning improvement of operational modeling in EMS operations}
2. Improve communication and sharing of timely model change information in the Real-time Modeling Working Group (RMWG). {SERC Technical Committee (RMWG) initiative concerning improvement of model updates in EMS operations}
3. Establish common guidelines to aid SERC stakeholders regarding the effects of external operations on another respondent's system. Expand the list of external contingencies simulated in the RTCA that could have a significant impact. {SERC Technical Committee (RWMG) initiative concerning neighboring system impacts EMS operations}

IV. Transmission System Use

1. Enhance identification of loop flow situations across the Eastern Interconnection. {Possible solutions are SERC executive management's support of NERC's Parallel Flow Visualization Project through involvement with ERO EMG and/or ERO RAPA.}

V. General Recommendation

1. SERC staff should develop specific questions for a follow-up survey to be undertaken in 2016. The survey questions will focus on each of the four major areas above, provide more granularity in the information requested, and reach more functions under the NERC functional model. The survey will also be designed to permit SERC to understand trends in process improvement and reliability risk mitigation over time. {SERC Staff}