Reliability Moving Forward:
Multi-Perspective View on Where We Go From Here
Reliability Moving Forward
Perspective View on Where We Go From Here

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Reliability Primer
April 28, 2010
NERC Standards

- It all starts with the standards
- Ambiguity in
  - What the standard requires
  - What is required to show compliance
- Interpretation Process
- Everyone agrees we need to eliminate ambiguity up front
NERC Standards - Ambiguity

- PRC-023-1, “Transmission Relay Loadability”
- Blackout Recommendation
- Blackout report used the term “operationally significant . . . lines” to mean “lines that are part of monitored flowgates or interfaces”
- NERC-approved standard uses the term “critical to the reliability of the Bulk Electric System”
- Change from “operationally significant” to “critical to the reliability” made early on with no explanation
Stakeholders argued that the two terms were meant to have the same meaning.

In Order No. 733, Transmission Relay Loadability Reliability Standard, 130 FERC ¶ 61,222 at PP 72-73 (2009), reh’g pending FERC agreed that the two terms “are intended to have the same meaning because PRC-023-1 was developed to implement Recommendation 21A [of the Blackout Report].” P 73.

Clarity in the record would have been preferable.
NERC Standards - Ambiguity

- Need to eliminate ambiguity up-front
- NERC standards are technical
- But need other skills for drafting enforceable standards
- Legislatures and agencies use lawyers to draft statutes and rules
- Stakeholders need to get lawyers involved in reviewing proposed standards for drafting ambiguity
- Also need to eliminate any ambiguity between standards – terms need to mean the same thing
NERC Standards - Who gets to write the standards?

- Industry has years of technical expertise
  - A number of technical areas are very specialized
- Concerns we hear
  - Takes too long
  - Standards will be ‘lowest common denominator’ and are influenced by compliance obligation
- Under §215, the ERO develops and files standards; the Commission approves or remands proposed standards to the ERO; and the Commission directs to the ERO to submit a proposed standard
  - FPA §215(d)(2) - Commission is supposed to give “due weight to the technical expertise” of the ERO
NERC Standards - Who gets to write the standards?

- March 18, 2010 Order
  - *North American Electric Reliability Corporation*, 130 FERC ¶ 61,203 (2009), *reh’g pending* (standards development process)
    - NERC requests rehearing, stay, reconsideration and public conference
    - FERC proposes to reject NERC interpretation
  - *Mandatory Reliability Standards for the Bulk Power System*, 130 FERC ¶ 61,200 (2009), *reh’g pending* (setting deadline to modify transmission planning standard)
    - NERC requests rehearing and stay
  - *Mandatory Reliability Standards for the Bulk Power System*, 130 FERC ¶ 61,218 (2009), *reh’g pending* (setting deadline to modify resource and demand balancing standard)
    - NERC requests rehearing and clarification
NERC Standards - Interpretations

- Formal Interpretation Process
- November 4, 2009 NERC Technical Conference on Interpretations
  - Choose the interpretation that provides greater reliability or the one that is in accordance with the wording of the standard?
- November 5, 2009 - Board of Trustees agrees on rule of strict interpretation of standards plus actions to modify standard if there is a reliability problem
- Will this decision apply in the context of compliance and enforcement?
Processing of Violations

- Lengthy Process
- Full Record
  - *North American Electric Reliability Corp.*, 127 FERC ¶ 61,198 (2009) (request for more data to review Notice of Penalty)
- Resulting backlog
- New orders
    - Record in Notice of Penalty “should be proportional to the complexity and relative importance of the violations it addresses.” P 9.
    - Merit to create an abbreviated for Notices of Penalty for less significant violations. P 10.
Need for Change in Process even with October “Omnibus Filing”
FERC Review of Violations

- NP10-18-000 (Turlock Irrigation District), 130 FERC ¶ 61,151 (2010) (review of Notice of Penalty)
- NP10-20-000 (Duke Energy Corp.), 130 FERC ¶ 61,177 (2010) (extending time period for consideration); 130 FERC ¶ 62,111 (2010) (extending time period for consideration and directing response to requests for data and documents)
Strict interpretation vs. Expansive interpretation

The question is whether the words “If a man has” can mean “If a man thinks he has.” I am of opinion that they cannot, and that the case should be decided accordingly. *Liversidge v. Anderson*, [1942] A.C. 206, 245 (H.L. 1941) (Atkin, L.J., dissenting)(quoting *Through the Looking Glass*).
It appears to industry that in the process of interpreting and enforcing those ambiguous standards, the bar is being raised as to what these standards mean.

Industry doesn’t always know what the interpretation is ahead of time.

This creates compliance risk but is reliability improved?

If what is required to comply with a standard is not known and/or is changing, how can you comply?
Notice of Interpretation

- Concern about “submarine interpretations” – interpretations that are not approved by the NERC Board but surface during an audit or enforcement actions and are not of record

- See Florida Blackout, 129 FERC ¶ 61,016 (2009) (Com. Moeller concurring)(“[t]hose who are subject to Commission penalties need to know, in advance, what they must do to avoid a penalty”)
Learnings - No Breaks in the Feedback Loop

- Violations
- Regional Entity/NERC CMEP
- Registered Entity Action
- NERC Analysis
- Registered Entity Feedback

No breaks in the feedback loop.
Closing the Feedback Loop

- Compliance Analysis Report
  - CIP-004-1 – Personnel and Training
  - PRC-005-1 – System Protection Maintenance and FAC-008, FAC-009 – Facilities Ratings

- Lessons Leaned
  - Timely publication of Events Analysis reports
Aurora

- June 21, 2007 - NERC, as ES-ISAC, issues original industry advisory, Industry begins response to advisory
- September 2007 - CNN breaks the Aurora vulnerability story
- October 2007 - Congress begins series of hearings about Aurora
- March 2010 - NERC publishes a new “Draft” Aurora vulnerability update with additional engineering information
- May 2010 - NERC expected to issue “Formal” Aurora vulnerability update
Reliability Moving Forward - Where Do We Go From Here?

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Vice President and Chief Strategic Officer
Chair of Midwest Reliability Organization Board*
April 28, 2010

*these observations and comments do not reflect the opinion of the MRO Board or MRO Management

Helping to keep the lights on, businesses running and communities strong
• Formed in 2001 as **first multi-state transmission-only utility**
• Owner and operator of **9,400 miles** of transmission line
• **510 substations**
• **Largest transmission owner** in MISO
• **$2.1 billion** in investment in nine years
• Approximately one million square miles
• Total net energy to load is nearly three hundred million megawatt hours (MWh)
• Board of Directors is all stakeholder representation by sector
• Strong Canadian representation
• Set up to have no non-statutory responsibilities
Context of remarks

• ATC strongly supports the SRO “model” which includes strong Regional Entity responsibility and accountability under the NERC framework;
• ATC itself has a Board that is partly stakeholder, partly independent
• MRO members and Board both strongly support a stakeholder driven model
• Regions should be structured to help the members improve reliability while also ensuring compliance and being the primary enforcement vehicle for the NERC standards
• ATC is an EEI member and is active in working with the IOU’s on reliability issues in general and NERC issues specifically
The SRO Model Works

• Self Regulatory Organization (SRO) model
  - recognition of importance of industry expertise in developing standards that are appropriate
  - balances those with “skin in the game” at the regional level with a strong, independent NERC Board
  - checks and balances work
• Notion of independence
• Are regions “under the thumb” of the stakeholders?
• Region’s should have a goal to eliminate any nonstatuatory responsibilities
• To ultimately be successful, requires trust between and among FERC, NERC, the Regions and stakeholders
Standards

• Standards development
  - Regional vs. NERC (NERC drives national standards, regional variations)
    – Application guidelines or results-based standards
    – Use of interpretations (not in enforcement actions)
• Impact of standards on compliance and enforcement
  - need to get beyond the literal words of the standard
  - focus on administrivia not productive and focuses on the wrong thing
  - “lawyering up” defeats improving reliability and makes it a documentation game;
  - clearer expectations of how compliance of a standard will be viewed by Regions
Compliance and Enforcement

- **Current issues**
  - **Consistency**: NERC needs to take a leadership role in providing ongoing training for regional auditors; NERC also should not leave to “voluntary” efforts of Regions to attain consistency.
  - **Backlog**: Regions’ should be given significant deference to identify and deal with minor administrative violations, with discretion to report but not prosecute all violations.
  - Minor violations that have been fixed and are administrative pose little risk and should not be prosecuted through the NOP process.
  - **Transparency**: NERC should establish a uniform step-by-step approach to enforcement. Region’s allow Registered Entities to demonstrate compliance in different ways.
Improving Reliability Through Lessons Learned

- Lessons learned from event analyses, compliance findings, etc need to be reported in a timely fashion to help others avoid similar situations and to improve reliability.
- Today’s approach of keeping information confidential (even black box settlements) does not help registered entities improve reliability.
- Regions can provide this service directly while NERC should coordinate and supplement.
- Today’s focus is on compliance/enforcement; this needs to be balanced by reliability improvement through lessons learned.
Canadian Considerations

• Canadian membership
  – NERC is an international organization
  – Canadian entities are subject to provincial regulation, not from FERC
  – In MRO, compliance and violation determination is done by the region, but for Canadian entities the potential enforcement information and action goes to the Province and does not go to FERC
  – Canadians participate in standards development along with other NERC stakeholders; FERC override of a NERC developed standard threatens Canadian support for the standard
Additional Concerns

• FERC actions
  – Potential penalty guidelines threaten regional discretion and flexibility
  – Standards development through stakeholders threatened
  – Potential cyber legislation
  – SRO model appears to be in jeopardy
  – Potential redefinition of BES reliability as it relates to loss of local load
  – FERC determination on NERC 3 year assessment
• Long term resource assessment
  – Move away from regions and NERC
  – RTO/ISO/PA role – ultimately EIPC
  – Use resources for event/disturbance analyses results
    - need clear guidelines for what disturbances are investigated
Conclusion

- Use 3 year assessment and renegotiated Regional Delegation Agreements to clarify and improve role of Regions and NERC
- Support NERC in its strategic priorities
  - Productivity
  - Transparency of Information
  - Trust among NERC, regions, stakeholders, and regulatory authorities
  - Incent compliance - encourage compliance excellence and reliability improvement
Resources

www.atcllc.com
www.atc10yearplan.com
www.atc-projects.com
Reliability Moving Forward: Multi-Perspective View on Where We Go From Here
Independent Power Producer Perspectives

Bruce L. Richardson
King & Spalding LLP

Energy Bar Association
The Reliability Primer for Lawyers and Energy Professionals
April 28, 2010
History

- 1962-1963 - Electric industry creates informal, voluntary organization of operating personnel to facilitate coordination of the bulk power system in the US and Canada
- 1960s - Industry followed (1) certain criteria and guidelines for reliable operations and (2) in certain regions, reliability planning guidelines
- 1968 - National Electric Reliability Council established by industry in response to 1965 black out (NE US and SE Ontario Canada)
- As a result of the 2003 large-scale blackout, however, the Federal Energy Regulatory Commission’s (FERC) oversight over reliability was expanded in the Energy Policy Act of 2005 (EPAct 2005)
- Prior to EPAct 2005, compliance with criteria/policies/standards voluntary
- Historically, vertically integrated electric utilities involved in the voluntary compliance program
EPAct 2005

- FERC oversight over reliability
- Authorized creation of a self-regulatory Electric Reliability Organization (ERO)
- Mandatory Reliability Standards subject to FERC’s review and oversight
- Section 316A of the Federal Power Act amended to include penalties of up to $1,000,000 for each day a violation continues
Implementation of EPAct 2005 Reliability Mandate

- July 20, 2006 - North American Electric Reliability Corporation (NERC) certified as the ERO (Order No. 672)
- March 16, 2007 - Of the 107 proposed Reliability Standards, FERC approved 83; voluntary compliance with the additional standards should continue as good utility practice (Order No. 693)
- April 19, 2007 - FERC approved 8 delegation agreements with Regional Entities; NERC retains oversight role
Implementation of EPAct 2005 Reliability Mandate (cont.)

- The Commission is, however, also cognizant of commenters’ concerns. In the NOPR, the Commission proposed that the ERO and Regional Entities use their enforcement discretion in imposing penalties on entities that historically had not participated in the pre-existing voluntary reliability regime, although authority to impose a penalty on such an entity would be retained “if warranted by the circumstances.” In light of commenters’ concerns, including the fact that there are new aspects to the Reliability Standards and the proposed compliance program that will apply to all users, owners and operators of the Bulk-Power System, the Commission directs the ERO and Regional Entities to focus their resources on the most serious violations during an initial period through December 31, 2007. This thoughtful use of enforcement discretion should apply to all users, owners and operators of the Bulk-Power System, and not just those new to the program as originally proposed in the NOPR. This approach will allow the ERO, Regional Entities and other entities time to ensure that the compliance monitoring and enforcement processes work as intended and that all entities have time to implement new processes. (Order No. 693 at P 222 (footnote omitted)).

- By directing the ERO and Regional Entities to focus their resources on the most serious violations through the end of 2007, the ERO and Regional Entities will have the discretion necessary to assess penalties for such violations, while also having discretion to calculate a penalty without collecting the penalty if circumstances warrant. Further, even if the ERO or a Regional Entity declines to assess a monetary penalty during the initial period, they are authorized to require remedial actions where a Reliability Standard has been violated. Furthermore, where the ERO uses its discretion and does not assess a penalty for a Reliability Standard violation, we encourage the ERO to establish a process to inform the user, owner or operator of the Bulk-Power System of the violation and the potential penalty that could have been assessed to such entity and how that penalty was calculated. We leave to the ERO’s discretion the parameters of the notification process and the amount of resources to dedicate to this effort. Moreover, the Commission retains its power under section 215(e)(3) of the FPA to bring an enforcement action against a user, owner or operator of the Bulk-Power System. (Order No. 693 at P 223).
Implementation of EPAct 2005 Reliability Mandate (cont.)

- Regional Entities
  - Florida Reliability Coordinating Council (FRCC)
  - Midwest Reliability Organization (MRO)
  - Northeast Power Coordinating Council (NPCC)
  - ReliabilityFirst Corporation (RFC)
  - SERC Reliability Corporation (SERC)
  - Southwest Power Pool, RE (SPP)
  - Texas Regional Entity (TRE)
  - Western Electricity Coordinating Council (WECC)
Implementation of EPAct 2005 Reliability Mandate (cont.)

- NERC has identified 15 specific functions that are subject to registration on the NERC Compliance Registry:
  - Balancing Authority (BA)
  - Distribution Provider (DP)
  - Generator Operator (GOP)
  - Generator Owner (GO)
  - Interchange Authority (IA)
  - Load-Serving Entity (LSE)
  - Planning Authority (PA)
  - Purchasing-Selling Entity (PSE)
  - Reliability Coordinator (RC)
  - Reserve Sharing Group (RSG)
  - Resource Planner (RP)
  - Transmission Owner (TO)
  - Transmission Operator (TOP)
  - Transmission Planner (TP)
  - Transmission Service Provider (TSP)

- Independent power producer (IPP) functions: typically GO and GOP; related functions include BA and PSE
- Treatment of interconnection facilities as TO and TOP in WECC
Catch-all for additional entities that affect the bulk power system:

“The [regional compliance entity] considering registration of an organization not meeting (e.g., smaller in size than) the criteria may propose registration of that organization if the [regional compliance entity] believes and can reasonably demonstrate that the organization is a bulk power system owner, or operates, or uses bulk power system assets, and is material to the reliability of the bulk power system.”

-Statement of Compliance Registry Criteria, n. 1
Currently, there are over 100 Reliability Standards applicable to registered entities exclusive of region-specific standards.

The Reliability Standards are grouped into 14 categories:

- Resource and Demand Balancing (BAL)
- Communications (COM)
- Critical Infrastructure Protection (CIP)
- Emergency Preparedness and Operations (EOP)
- Facilities Design, Connections, and Maintenance (FAC)
- Interchange Scheduling and Coordination (INT)
- Interconnection Reliability Operations and Coordination (IRO)
- Modeling, Data, and Analysis (MOD)
- Nuclear (NUC)
- Personnel Performance, Training, and Qualifications (PER)
- Protection and Control (PRC)
- Transmission Operations (TOP)
- Transmission Planning (TPL)
- Voltage and Reactive (VAR)

Each standard under a category will include requirements and may include sub-requirements.

In some cases there are as many as 60 requirements and sub-requirements under a given standard.

Overall, there are over 1,400 reliability requirements applicable to all registered entities and additional region-specific requirements.
Old World Order to New World Order For IPPs

- **Pre-ERO**
  - Interconnection agreements governed, among other things, technical requirements for interconnection, operations, and communication
  - Interconnection agreements addressed defaults
  - Unlike FERC-jurisdictional Transmission Providers, no experience with a FERC-mandated compliance program

- **Post-ERO**
  - Mandatory Reliability Standards
  - Compliance Enforcement
  - Penalties of $1,000 to $1,000,000 per day per violation
  - Development of compliance programs
  - Vertically integrated electric utility-like treatment
IPP Implementation Issues

- Many IPP plants are project financed
  - NERC Compliance Registry issues
  - Compliance program issues
- Joint registration issues
- Single IPP could have plants in more than one reliability region
- Standards not self-implementing
  - Development of procedures, training programs, monitoring systems, documentation control, etc.
- Deployment of resources
  - Implementation, monitoring, participation in standards development, etc.
- Cost incurrence/cost recovery
Reliability Standards

- Moving targets (resource intensive)
  - New standards
  - Revisions to standards
  - Interpretations of standards
  - Evidence of compliance
- Cost-benefit issues
- Cost recovery issues
- Need for a reasonable set of standards that work for the industry - balance of reliability and costs
  - Micro example: NERC Project 2010-07 - Transmission Requirements at the Generator Interface
IPP Experiences With Compliance/Audits

- Inconsistencies between Regions
  - Interpretations
  - Evidence of compliance
- No standard audit guidelines
- Inconsistency within Region
- Emphasis on enforcement, not education
- Pre-12/31/07 possible violations
- Lack of guidance, lack of lessons learned
Change in Emphasis On Initial Compliance and Audits

- Phase-in should focus on education with emphasis on reliability, not enforcement.
- Lessons learned = closing the barn door after the horse has bolted.
- For each standard there could be model procedures by function and/or the results of “beta audits” that identify what it takes to be in compliance.
- For each standard there could be guidance on organizing material to demonstrate compliance.
- Regions should perform pre-compliance audit of procedures.
- Creation of a one-stop database organized by Reliability Standard with e-mail notification of updates.
Due Process Concerns

- Rules of Procedure not always followed by Regions
- Cost of due process – Regions, NERC, FERC
- Scope of audit
  - Compliance with Reliability Standard
  - Compliance with procedure that goes beyond requirements of the Reliability Standard
- Applicability of Reliability Standard
Submitted question and answer from a 2009 Regional Entity’s Compliance Workshop:

**Q10** - What is the Responsible Entity’s obligation to meet a standard approved by the NERC BOT [Board of Trustees] not yet approved by FERC approved [sic] (Standards awaiting Regulatory approval)?

**Response** - Standards approved by the NERC BOT are to be addressed by Registered Entities and can be monitored for these standards during an audit. However, if the Registered Entity is found to be in violation of the standard no penalties or sanctions can be imposed upon the entity.
Guidance

- Lessons learned
- FERC - Representative guidance
  - April 17, 2008 - Statement of Administrative Policy on Processing on Processing Reliability Notices of Penalty and Order Revising Statement in Order No. 672
    - (1) determining monetary penalties, (2) non-monetary sanctions and remedial actions, (3) review upon application of entity, (4) review upon FERC motion, (5) FERC review of settlements
  - May 15, 2008 - Enforcement of Statutes, Regulations, and Orders
    - (1) FERC audits and (2) FERC investigations
  - July 3, 2008 - Guidance on Filing Reliability Notices of Penalty
    - (1) settlements, (2) completeness of the record, (3) documentation issues, (4) self-reports and self-certifications, (5) linkage between facts and penalties, (6) mitigation plans, and (7) multiple violations
  - October 16, 2008 – Compliance with Statutes, Regulations, and Orders
    - Factors for vigorous compliance programs: (1) actions by senior management, (2) effective preventive measures, (3) prompt detection, cessation, and reporting of the offense, and (4) remediation
    - Penalty credit
  - January 28, 2009 - Guidance Order on Compliance Audits Conducted by the Electric Reliability Organization and Regional Entities
    - (1) pre-audit procedures, (2) procedures during the compliance audit (including assessment of the compliance program), and (3) guidance on audit team leadership and training
  - October 16, 2009 - Florida Blackout
    - Spitzer and Moeller concurrences raise transparency concerns
  - October 26, 2009 - Guidance on Reliability Notices of Penalty
    - Abbreviated Notices of Penalty where violations did not pose a significant risk
  - February 26, 2010 - North American Electric Reliability Corporation (Turlock Irrigation District settlement)
    - Factors for FERC initiating review: (1) seriousness of violation (violation risk factor and violation severity level considered), (2) potential risk and actual harm to the bulk power system, and (3) consistency in applying penalties and the ability of the penalty to improve compliance
  - March 18, 2010 – Enforcement of Statutes, Orders, Rules, and Regulations
    - Five-step process for determining civil penalties: (1) base violation level, (2) adjustments to base violation level, (3) base penalty, (4) culpability score, and (5) calculation of penalty range
    - Can be applied to notices of penalty “for an out-of-ordinary notice of penalty describing a serious violation”
    - Suspended application of policy statement pending comment period and final order

KING & SPALDING
Slide 4

Slide 17
- Enforcement of Statutes, Regulations, and Orders, 123 FERC ¶ 61,156 (2008)
- Compliance with Statutes, Regulations, and Orders, 125 FERC ¶ 61,058 (2008)
- Guidance Order on Compliance Audits Conducted by the Elec. Reliability Org. and Reg’l Entities, 126 FERC ¶ 61,038 (2009)
- Enforcement of Statutes, Orders, Rules, and Regulations, 130 FERC ¶ 61,220; see also, Order Regarding Policy Statement On Penalty Guidelines, 131 FERC ¶ 61,040 (2010)
Reliability and Variable Generation
Accommodating High Levels of Variable Generation
Agenda

- About NERC
- About the Integration of Variable Generation Task Force (IVGTF)
- “Variable” Resources
- Recommendations
- Next Steps
About NERC

International regulatory authority for electric reliability in North America

- Develop & enforce reliability standards
- Analyze system outages and near-misses & recommend improved practices
- Assess current and future reliability
Integration of Variable Generation Task Force

- Formed by NERC’s Planning & Operating Committees in December 2007
- 100 participants
  - Utilities, ISO / RTO’s, wind and solar manufacturers, associations, government
  - Strong cross-border collaboration (U.S. & Canada)
- Focus on reliability
Keeping Reliability in the Balance

- Bulk power system reliability must be maintained, regardless of the generation mix;
- All generation must contribute to system reliability within their physical capabilities; and
- Industry standards and criteria must be fair, transparent and performance-based.
Variable resources are types of electric power generation that rely on an uncontrolled, “variable” fuel (e.g. wind, sunlight, waves, tidal forces, and some types of rivers) to generate electricity. Most renewables fall into this category.

Reliably integrating these resources into the bulk power system will require significant changes to traditional methods used for system planning and operation.

Integration has the potential to fundamentally change how the system is planned, operated, and used – from the grid operator to the average customer.
New policies & environmental priorities driving growth

220GW of wind proposed in coming 10 years

Increases seen in solar (i.e. 30,000 MW in California ISO queue)
New Renewable Capacity

2018 Variable Generation Capacity
(Includes Existing, Future, and Conceptual Generation Resources)

- 49,039 MW
- 18,125 MW
- 12,392 MW
- 46,268 MW
- 45,700 MW
- 62,041 MW
Variable Fuels Must Be Used Where Available

- Variable generation often located in areas remote from demand centers and existing transmission infrastructure.

Legend:
- **Demand Centers**
- **High Wind Availability**

Horizontal resolution of 5 km
Resolution horizontale de 5 km

Source: EPRI & NREL
- 229 GW of additional installed wind capacity
- 38 GW expected on-peak capacity
- Expected on-peak capacity range from 0-37% of total installed capacity across different subregions
1.2 Consistent and accurate methods are needed to calculate capacity values attributable to variable generation.

1.4 Resource adequacy and transmission planning approaches must consider needed system flexibility to accommodate the characteristics of variable resources as part of bulk power system design.

1.6 Probabilistic planning techniques and approaches are needed to ensure that system designs maintain bulk power system reliability.
1.1 Standard, valid, generic, non-confidential, and public power flow and stability models (variable generation) are needed and must be developed, enabling planners to maintain bulk power system reliability.

1.5 Integration of large amounts of plug-in hybrid electric vehicles, storage and demand response programs may provide additional resource flexibility and influence bulk power system reliability and should be considered in planning studies.

1.8 Variable distributed resources can have a significant impact on system operation and must be considered and included in power system planning studies (2011).
1.3 Interconnection procedures and standards should be enhanced to address voltage and frequency ride-through, reactive and real power control, frequency and inertial response and must be applied in a consistent manner to all generation technologies.

1.7 Existing bulk power system voltage ride-through performance requirements and distribution system anti-islanding voltage drop-out requirements of IEEE Standard 1547 must be reconciled.

2.2 Balancing Areas must have sufficient communications for monitoring and sending dispatch instructions to variable resources.
Question & Answer

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Helping our members work together to keep the lights on... today & in the future
Reliability and Variable Generation

EBA Reliability Primer

Washington, DC

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3 Interconnections / 8 NERC Regions

NERC INTERCONNECTIONS

WESTERN INTERCONNECTION

SPP

TRE

ERCOT INTERCONNECTION

WECC

MRO

NPCC

RFCC

SERC

FRCC

EASTERN INTERCONNECTION

QUÉBEC INTERCONNECTION

SPP.org
Independent System Operator (ISO) / Regional Transmission Organization (RTO) Map
SPP Wind Developments

- 4 gigawatts (GW) in-service / being built – additional 6+ GW with approved Interconnection Agreements

- SPP EHV Overlay Studies investigated 20% scenarios with modest exports west and east

- Stakeholders expect 11 GW of wind in SPP to meet current respective goals/targets – but not necessarily the wind with approved Interconnection Agreements

- 2008 Southwestern Public Service Company (SPS) Wind Penetration Study investigated reliability margins

- 2009 SPP Wind Integration Study in 2009 focused on operational impacts of 10 – 20% scenarios
Renewables are BIG in SPP

- U.S. states with top potential wind are in SPP *
  - 1. Texas, 2. Kansas, 3. Nebraska

- In 2009, SPP Generation Interconnection queue included more wind than our peak load of ~50 GW
  - Current queue: Over 25 GW, with significantly more expected due to recent activity, e.g., NM Renewable Electricity Transmission Authority, LR1048 is law in NE, etc.
  - Eastern Wind Integration and Transmission Study projects 60-95 GW of wind development in SPP
    - Economic benefits that exceed costs even with $150 billion in transmission expansion despite significant curtailments of wind and 5 GW+ of additional reserve requirements in SPP

- Solar is hardly on our radar screen, but there…

* Department of Energy National Renewable Energy Laboratory
SPS Wind Penetration Study

- SPS primarily serves load in TX and NM – but has Extra High Voltage (EHV) transmission lines in KS and OK – and has integrated network of primarily 115 and 230 kV

  - Very good load factor, lots of efficient thermal generation, and relatively weak ties to neighbors

- Tremendous renewable potential with 900 MW of wind plants in service and 2,000 MW more with approved Interconnection Agreements

- AMEC contracted to investigate reliability margins
SPS Wind Penetration Study Findings

- Surprisingly homogeneous wind resources across SPS territory
- Operating margin limits will be approached with 1,100-1,200 MW of wind plants, absent curtailments or changes to existing system
- New operating procedures and changes to tariff / interconnection agreements may be required.
- Wind curtailment / management policies and procedures in development. Wind forecasting is becoming more critical each day.
SPP Wind Integration Study

- Wind Integration Task Force investigated operational and reliability impacts of 10-20% scenarios, without consideration of economics.

- Lots of new EHV transmission required to effectively integrate wind plants, with multiple 345 and 765 kV lines in all corridors between EHV substations in the plains to support 20% scenario:
  
  - 10% Case: 1,260 miles of 345 kV and 40 miles of 230 kV
  - 20% Case: 485 miles of 765 kV, 766 miles of 345 kV and 205 miles of 230 kV
Other Wind Integration Study Findings

• Increased operational flexibility is required
  - Increased regulation needs
  - Separate regulation up/down
  - Load following reserves

• SPP needs to continue to work toward Consolidated Balancing Authority, which reduces overall needs for reserves and flexible resources
  - Reduce forecast errors and implement intra-day unit commitment
Transmission Expansion
(345kV +)

- Single Circuit PP
- Double Circuit PP
- Committed to be Built (345kV+)
- 230 kV
- 345 kV
- 500 kV
- 765 kV
- Southwest Power Pool
- Entergy ICT
MAJOR TRANSMISSION EXPANSION IN AND AROUND SPP
CREZ/HPX/SPS Conceptual Plans
w/ HVDC Proposals
Reliability Implications of Variable Energy Resources

• Based on experience in other markets, technical challenges with large integration of renewable resources can be addressed without significant issues

• Major changes in planning/operations, markets, and tariffs needed to accommodate major renewable transfers within and beyond existing interconnections

• Coordination and collaboration in planning and operations - as well as effective seams agreements - will be key
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Variable Energy Resources

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Who are the co-ops?

- Consumer-owned, consumer-governed, not-for-profit electric utilities
- 12% of the consumers, 75% of the land mass, over 80% of the counties in the US
- Leaders in renewable resources, demand response, smart grid
Co-op Concerns

- Co-ops serve renewable energy rich regions with few consumers and less infrastructure.
- Co-ops serve “fly-over” states with few resources, few consumers, and insufficient infrastructure.
- Rural consumers are already struggling to pay for power: some co-ops face 30% delinquency rates.
We can integrate VERs reliably if:

- We recognize the real costs, challenges, and required time
- The costs are treated transparently and allocated to cost causers
- We don’t pretend there are “easy” answers
- We give the industry time to find the right regionally appropriate answers
- We think long-term
Reliably integrating VERs will be challenging

DOE/NREL studies agree high penetration cannot be accomplished with business-as-usual
Why are VERs Different?

VERs are location constrained.
Why are VERs Different?
VERs Output is Variable

- Limited capacity value
- Uncertain output
- Poorly correlated with load
- Subject to significant ramping
A good illustration of variability
What’s needed for reliable integration?

- Transmission
- Flexible resources
- Other resources to provide capacity
- Time & extensive and objective analyses
Integration will require transmission

Figure 8. Conceptual EHV transmission overlays for each study scenario
Transmission for VERs will be expensive

- EWITS EHV transmission costs estimates of up to $158 billion:
  - Doesn’t include the West and ERCOT
  - Doesn’t include necessary lower voltage upgrades
Transmission for VERs will take time to build

- J CSP, EWITS, Navigant agree even 5-6% integration is impossible without a huge transmission build-out

- It could take 16 years to build the transmission, and that’s only if we solve:
  - Planning
  - Siting
  - Cost Allocation
### Estimated Timeline: Reference Scenario (5% Wind)

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<tr>
<th>Infrastructure Project</th>
<th>Duration Range (Months)</th>
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<td>765 kV AC Transmission Lines (31 lines)</td>
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The 500 kV regulatory process is not started until the 765 kV regulatory process is successfully completed.

The 345/500 kV regulatory process is not started until the 500 kV regulatory process is successfully completed.
# Timeline Development

## Estimated Timeline: 20% Wind Scenario

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The 800 kV regulatory process is not started until the 765 kV regulatory process is successfully completed.

The 345/500 kV regulatory process is not started until the 800 kV regulatory process is successfully completed.
Flexibility for VERs will be expensive

EWITS estimates ~ $5/MW

- EWITS integration cost assumes interconnection-wide:
  - Reserve sharing
  - Trading of ancillary services
  - Intra-hour security constrained economic dispatch

- Doesn’t address the cost if those changes are politically unacceptable

- Doesn’t address the cost of making those changes if they are politically feasible
Reliably integrating VERs will be expensive

EWITS and other integration costs estimates don’t include costs of addressing:

- Loop flow and parallel flow
- Reactive power
- Stability limits
- The capital cost of capacity resources needed for reliability
The scale is extraordinary

- Today’s VG penetration < 3%
  - We are already bumping into operational challenges
- Today’s RPSs call for ~ 6%
- Federal RPS proposals call for 15-25%
- EWITS, WWSIS look at 20-35%
The scale is beyond any existing plans

- SPP currently planning huge transmission build-out to reach 20% wind in SPP
- EWITS assumes 120% penetration in SPP
VERs should pay the costs of integration to:

- Minimize cost shifting
- Create incentives to minimize integration costs
- Create appropriate incentives for efficient investment in:
  - Transmission
  - Flexible generation, Demand Response, Storage
  - Non-variable environmentally sustainable generation
There are no silver-bullets for reducing integration cost

- Proposed solutions all have limits
  - Improved forecasting
  - Intra-hour security-constrained economic dispatch and ancillary services markets
  - VER-only Balancing Areas
  - Balancing Area Consolidation
Example: BA consolidation/coordination

Wind In Service

17 BAs today

Wind
Load
Flexible reserves
Example: BA consolidation/coordination

- Assumes:
  - Firm transmission capacity between and within BAs
  - Diversity of resources between BAs
  - Adequate flexible resources between BAs
  - No local reliability issues (voltage, reactive power)
  - No operational cost of combining BAs
  - No cost to small BAs of lost control

- How would the combination or coordination be promoted?
The industry is on the job

- Industry groups: NERC IVGTF, UWIG, PSERC
- NREL: EWITS, WWSIS
- DOE: EI PC, EI SPC, ERCOT, WECC, WGA
- RTOs: MI SO, SPP & WECC studies; PJ M Intermittent Resources Working Group
We need to think long-term

- Avoid the cliff – don’t look for a soft landing after we jump
- Most “solutions” aimed at operational time-frames
- Not thinking long-term costs us:
  - Build infrastructure before interconnecting VERs we can’t yet handle?
  - Build infrastructure before consolidating BAs or altering scheduling and dispatch?
  - Central station storage v. curtailment?
  - Non-VER sustainable resources?
We haven’t jumped yet
Pursuant to the Notice of Inquiry on Integration of Variable Energy Resources issued by the Federal Energy Regulatory Commission (“Commission” or “FERC”) on January 21, 2010 (“NOI”), and the Notice Extending Comment Period, the National Rural Electric Cooperative Association (“NRECA”) respectfully submits its comments regarding the Commission’s inquiry regarding whether reforms are needed to encourage the reliable and efficient integration of variable energy resources (“VERs”) into the electric grid.

I. INTRODUCTION

NRECA is the not-for-profit national service organization representing approximately 930 not-for-profit, member-owned rural electric cooperatives. The great majority of these cooperatives are distribution cooperatives that provide retail electric service to over 42 million consumer-owners in 47 states. Kilowatt-hour sales by rural electric cooperatives account for approximately 10% of total electricity sales in the United States. In addition, NRECA members include approximately 66 generation and transmission (“G&T”) cooperatives that supply wholesale power to their distribution cooperative owner-members. Both distribution and G&T cooperatives were formed to provide electric service to their owner-members at the lowest reasonable cost consistent with adequate and reliable service.
Precisely because cooperatives’ sole purpose is to deliver electricity to consumers at the least cost consistent with reliable service, cooperatives have embraced eagerly the promise of power developed from renewable resources, including VERs. In 2007, rural electric cooperatives received eleven percent of their power from renewable sources, as compared with nine percent for the industry as a whole. At the same time, cooperatives are particularly sensitive to the challenges that integration of large increments of VERs pose for the industry. Many desirable locations for siting VERs—especially wind and solar—are within cooperatives’ sparsely populated service areas. Delivery of electricity from these locations to distant high-consumption urban load centers will not only require expansion of long-distance, high-voltage transmission facilities (and the ancillary generation services needed to support them) but also will tax the local transmission grids that host these resources. Cooperatives’ deep interest in the opportunities and challenges posed by VERs has resulted in their active participation in the Commission’s earlier proceedings addressing the integration of these resources.¹

Participation in these proceedings, and in a welter of industry meetings, conferences and workshops, has sharpened NRECA’s appreciation of the large number, scope and scale of the challenges that will have to be overcome to integrate large amounts of VERs into an affordable, reliable power supply for the nation’s consumers. A thorough, fact-based understanding of these challenges, and of the array of potential solutions under consideration and development by industry participants, is needed before the Commission can effectively sort those practices that may be unjust, unreasonable or discriminatory from measures required to facilitate VERs’ integration in a manner that preserves reliability and allocates costs fairly. Serious study of these

challenges is well underway. These efforts include the work of North American Electric Reliability Corporation’s (“NERC”) Integration of Variable Generation Task Force (“IVGTF”), the National Renewable Energy Laboratory’s Eastern Wind Integration and Transmission Study (“EWITS”)\(^2\) and Western Wind and Solar Integration Study (“WWSIS”\(^3\)), the work of the Department of Energy’s (“DOE”) Wind and Water Program, studies by the Midwest ISO (“MISO”), Southwest Power Pool (“SPP”) and Western Electric Coordinating Council (“WECC”), and PJM Interconnection’s (“PJM”) recently formed Intermittent Resources Working Group. NRECA believes that these industry efforts aimed at better understanding the challenges associated with integration of VERs and at developing a range of potential solutions to those challenges are extremely valuable, and these efforts are moving as quickly as possible consistent with good engineering and sound economics. Industry efforts such as these are the best means of developing reliability standards, new market rules, and tariff amendments that reliably integrate high levels of VERs into the grid in the most efficient and appropriate manner in different areas of the country.

While these efforts are well underway and making good progress, NRECA believes it is still too early for the Commission to consider one-size-fits-all policy prescriptions to prevent discrimination in the integration of VERs. The industry must still reach a more thorough understanding of the technical, physical and economic issues raised by integration of VERs before the associated regulatory issues can be well-framed, and the regulatory issues must be


\(^3\) See West Connect, [http://westconnect.com/init_wwis.php](http://westconnect.com/init_wwis.php); National Renewable Energy Laboratory, [http://www.nrel.gov/wind/systemsintegration/wwsis.html](http://www.nrel.gov/wind/systemsintegration/wwsis.html) and [http://wind.nrel.gov/public/WWIS/](http://wind.nrel.gov/public/WWIS/) (Western Wind and Solar Integration Study Draft). It is noteworthy that the WWSIS, one of the substantial studies in an advanced stage of development, is still in draft form, and thus, National Renewable Energy Laboratory states that it is not yet ready for distribution or citation. This is eloquent evidence of the incompleteness of the industry’s understanding of the problems posed by VER integration.
properly framed before solutions, in the form of proposed regulations, can properly be devised. Excessive haste could undermine reliability, lead to cost-shifting among industry stakeholders and/or regions of the country, and prevent the industry from developing creative cost-effective solutions to the integration of VERs. Meanwhile, the development of VER projects continues apace, and transmission providers are integrating VERs into their systems based on existing policy. According to the American Wind Energy Association (“AWEA”), U.S. wind power capacity has grown by an average of 32% each year from 2004 through 2008, with total U.S. installed wind capacity at the end of 2008 of 25,170 MW. 4 And as of the end of 2009, the total capacity of U.S. wind energy projects exceeded 35,000 MW. 5 Moreover, the Commission’s recent handling of Westar’s effort to accommodate the rapid growth of VER capacity on its system illustrates that existing policy still enables the Commission to distinguish nondiscriminatory solutions to the reliability problems posed by VER integration from those that would impede VER integration on non-preferential terms.

II. GENERAL COMMENTS

NRECA offers the following general comments.

First, NRECA urges the Commission, before considering any industry-wide changes, to ensure that costs of such changes are estimated accurately and made fully transparent. In evaluating the costs, it is important to include all costs. Some studies analyzing the integration of VERs into the transmission grid have focused on the costs of additional regulation, load following, and contingency reserves, as well as additional unit commitment and gas supply costs that would be required with greater levels of penetration by VERs. 6 Some of these studies have

6 See EWITS at pp. 156-57.
also looked at the cost of extra-high voltage transmission overlays needed to reach high levels of wind penetration. Indeed, the Joint Coordinated System Plan (“JCSP”), released in February 2008, suggests that 15,000 miles of new transmission lines at a cost of $80 billion will be needed to meet a 20% wind energy scenario in the Eastern Interconnection, and there is reason to be concerned that this estimate is substantially understated. Just a year later, the EWITS studied various scenarios that included more 765-kV lines than the JCSP “to ensure easy access to the high-quality wind resources in the Great Plains and Upper Midwest,” concluding that those transmission costs could exceed $158 billion.

Yet, these studies do not reflect all of the costs of integrating wind. For example, neither the JCSP nor the EWITS evaluated in any detail the cost of upgrades that would be required on the existing lower voltage transmission system in order to maintain reliability and deliverability in light of changes in power flows caused by a new extra-high voltage (“EHV”) transmission overlay. Those studies did not look in detail at the impacts that parallel flows could have on those existing facilities. As the EWITS explained, “[t]he transition over time from the current state of the bulk power system to any one of the scenarios” studied in the report “would require much more technical and economic evaluation, including detailed modeling of power flows and a study of the effects on the underlying transmission systems.” Nor did those studies tackle the enormous challenge of evaluating the stability, reactive power, or loop flow impacts of integrating wind into an AC grid. Instead, the power flow models they used were simplified to assume a DC grid. NRECA’s members are concerned that the cost of the local upgrades

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8 EWITS at pp. 114-115. NRECA acknowledges that the NOI proposes to exclude discussion of cost allocation issues raised by integration of VERs from this proceeding, and mention of costs and cost allocation in these comments is not intended to address those issues, as such. However, the magnitude and variety of the costs involved in the VER integration process are such that discussion of particular measures without any reference to how they might affect different market participants—and, ultimately, consumers—would be a hollow exercise.
9 EWITS at p. 226.
required to address parallel flows and other impacts of new infrastructure on the AC grid could equal or exceed the cost of the overlay system.

EWITS also assumed that low-cost integration of VERs would require: consolidation of numerous balancing authorities (“BAs’’); development of ancillary services markets throughout the country; the implementation of security constrained economic dispatch throughout the country;\(^\text{10}\) significantly improved wind forecasting;\(^\text{11}\) and, increased communication of forecast and telemetry data to System Operators. Yet, EWITS did not evaluate the costs of making those significant changes in the operation of the grid. Nor did EWITS evaluate the cost of integrating VERs if these changes are not made.

EWITS recognized (although it did not discuss the matter in detail) that the low marginal cost of VERs would reduce the cost of energy in spot markets during many hours of the year, potentially making it harder for capacity resources required to preserve reliability to recover their costs adequately through the energy markets.\(^\text{12}\) Power Systems Engineering Research Center (“PSERC”) has reached the same conclusion.\(^\text{13}\) Yet, neither EWITS nor PSERC has made it clear what it would cost consumers to make up that “missing money” or what it would cost to make the changes to existing market structures to ensure that capacity resources receive adequate compensation to continue operating. EWITS and PSERC also failed to evaluate the costs consumers would bear for the changes in the operation of these baseload plants, including the

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\(^\text{10}\) EWITS at pp. 33-34.

\(^\text{11}\) EWITS at p. 31.

\(^\text{12}\) EWITS at p. 43. NRECA uses System Operator in the way that the Commission does in the NOI, i.e., to refer to the individual at a control center—balancing authority, transmission operator, generator operator (VERs as well as conventional resources), or reliability coordinator—whose responsibility it is to monitor and control the electric system in real time. NOI at n. 5.

higher O&M and environmental costs caused by the increased number and rapidity of ramping events.

Finally, while EWITS examined the costs of adding flexibility to the grid to integrate VERs, the cost estimates depended on the studies’ assumptions concerning transmission construction and changes in system operations. The study did not evaluate what the costs of reserves, regulation and load following and other sources of flexibility might be, given the existing constrained grid.

To the extent that the Commission adopts policies to promote integration of VERs, all of these costs must be acknowledged and addressed in a transparent manner. Only by making those costs transparent can they be properly understood, allocated, and taken into account by utilities, policy makers and other stakeholders as they make resource and policy decisions in the future. The costs must also be transparent if the Commission is to properly exercise its obligation to ensure that the rates, terms, and conditions of jurisdictional transactions are just and reasonable and not unduly discriminatory.

**Second,** once the costs are made transparent, the Commission must ensure that they are appropriately allocated, consistent with cost causation precedent. Proper allocation of the costs will encourage the development of the most efficient generation resources, encourage the construction of the most efficient transmission upgrades, and allow for the most efficient solutions to the challenges of VER integration to be developed. Hiding those costs will only increase them. For example, wrong signals to the market could well suppress such measures as building: (1) additional pumped storage, (2) quick-start, natural gas units with improved minimum load requirements, (3) additional natural gas storage, non-variable renewable resources
such as biomass or geothermal, (4) photo-voltaic or concentrating solar power with storage, (5) hybrid VER and dispatchable generation plants, or (6) other innovative energy storage devices.

Hiding the true costs of VER integration and failing to allocate these costs appropriately could also lead to inappropriate cross-subsidization, causing undue discrimination against customers in certain regions of the country and/or against owners of traditional dispatchable generation resources. The Commission’s long-standing policy is informed by cost causation principles, and there is no reason to deviate from those principles in pricing the integration of VERs. If the costs of new operational practices that facilitate VER integration are socialized, then development of effective, market-based solutions to real problems caused by VERs will be suppressed.

Third, the Commission should not assume away problems. For example, some have suggested that “BA consolidation might facilitate integration of greater VER penetration.” This suggestion implies several key assumptions that may not be correct. One assumption is that there is sufficient transmission infrastructure between and within existing BAs to support such additional integration; however, in many—if not most—cases, there is not. A second key assumption is that the BAs targeted for integration have sufficient diversity of loads and sufficient flexible generating sources to reliably support the operation of the combined BAs with increased VER penetration. This is also highly unlikely in similarly-situated BAs in a contiguous region. The third key assumption is that the BA consolidation would make business sense for the affected BAs. Clearly, this is not universally true, and would have to be examined on a case-by-case basis. As this discussion illustrates, several of the policy ideas raised by the NOI, like BA consolidation, are intuitively attractive but not, in fact, amenable to simple, one-

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See e.g., The Town of Norwood v. FERC, 962 F.2d 20, 25 (D.C. Cir. 1992); Union Electric Co. v. FERC, 890 F.2d 1193, 1198 (D.C. Cir. 1989) (rates should fairly track the costs for which the ratepayers are responsible).
size-fits-all implementation. The Commission should not adopt measures that “promote” those policies by penalizing those entities that do not embrace them because real infrastructure, operational, or economic barriers make them untenable in reality.

**Fourth**, many of the questions that the Commission poses in the NOI are certainly useful ones to ask, but the industry does not yet know enough to provide reliable, actionable answers. The industry’s knowledge base regarding integration of VERs is developing rapidly, but it is still incomplete. As discussed in response to various specific questions below, the industry is grappling with many of these questions already, and the Commission should allow this technical discussion to continue. NERC’s IVGTF has published a report examining myriad questions associated with integration of VERs and is currently delving in much greater detail into many of the issues raised in that report in order to be able to provide further guidance to the industry.15 Among these are many of the issues raised in the NOI, including, among other things, the impacts of consolidating BA areas and implementing shorter scheduling intervals.16

The issues being raised in the NOI are also being reviewed at this time by MISO, PJM, SPP, and other markets, as well as in regions and sub-regions that are located outside of organized markets, such as in portions of the WECC. In each of these “laboratories,” the industry is addressing both the economic and the reliability issues posed by integrating larger numbers of VERs. The Commission should not adopt a single untested approach before the industry has had a reasonable opportunity to test different options and develop best practices. The issues involved are too complicated, the potential solutions too expensive to implement on a


nationwide basis and then undo if ineffective, and the risks of unintended consequences too great for the Commission to rush to develop solutions to problems that are not yet fully understood.

The industry is working on the economic as well as the reliability issues raised by VER integration. At these early stages of research, multiple laboratories are more likely to reach better answers than a single laboratory.

**Fifth**, most of the issues raised by the NOI are not appropriate for generic rules or tariff provisions that would be applicable industry-wide. Many critical differences exist in different regions of the country. For one, regions with Regional Transmission Organizations (“RTOs”) and organized markets are in a different position than regions without, such as the Southeast and the West. Some regions of the country, such as the Southwest and portions of the upper Midwest, are rich in wind resources, while others have an abundance of hydro-electric power, such as the Pacific Northwest, and others are developing solar technology, biomass and other renewable resources. NRECA urges the Commission to allow each region—with the input of all interested stakeholders—to develop solutions that are appropriate to it. Most of the questions posed in the NOI do not lend themselves to a one-size-fits-all solution.

**Finally**, many of the policy proposals in the NOI assume high levels of VER penetration and then seek to (1) find solutions to the resulting reliability challenges in the operational time frames and (2) maximize efficient dispatch in the spot markets. In order to provide those solutions, the NOI then proposes for discussion rather dramatic changes to the operation of the grid.

NRECA takes a more long-term view. NRECA’s members’ goal is to provide their consumers safe and reliable power at the lowest cost over time consistent with good business practices. That requires building and contracting for a portfolio of resources, some of which
have an economic lifespan of 30-75 years. NRECA does not believe that an excessive focus on the most efficient dispatch at five-minute intervals will necessarily provide the incentives required for efficient investment in that long-term portfolio. Nor does an excessive focus on reliability only at the operational time frame provide the best means of preserving the reliability of the grid. The goal should be to avoid the cliff in the first instance – not to attempt to find a soft landing after having already jumped off.

Before asking consumers to bear the large cost and uncertainty imposed by significant changes to grid operations, NRECA believes the Commission should look at longer-term VER integration policies that could provide the appropriate incentives for development of the right amount of VERs in the right places with the right accompanying resources or contracts in order to minimize reliability and cost issues in the long term. With such policies in place, it might be more cost-effective and socially beneficial, for example, to build central station storage (a longer-term investment) than it is to curtail central station generation during minimum generation periods or to curtail industrial load during low-wind periods (short-term reliability/economic dispatch decisions). With such policies in place, it might also be more cost effective and socially beneficial to make the long-term investment in more non-VER renewable options such as hydro, biomass, geothermal, and landfill gas generation in a particular location or at a particular level of VER penetration than it is to invest in more VERs with all of the concomitant reliability and economic challenges. It could be that the costs of ever increasing VER penetration could result in consumer pushback due to increases in electric rates. In the long term, this could cause policymakers to rethink the acceptable level of VER penetration. This could conceivably cause the emphasis on new generation to switch to other means, including nuclear generation. Such a scenario could result in substantial stranded transmission
investments. Accordingly, NRECA urges the Commission to exercise caution in proposing industry-wide modifications to the overall operating rules of markets and the interconnected transmission system in order to integrate wind resources in real-time, without having looked at the broader and longer-term policy decisions that could lead to efficient and socially beneficial investment decisions that make such modifications unnecessary and undesirable.

III. COMMENTS ON SPECIFIC QUESTIONS

A. Data and Forecasting

In approaching the subject of forecasting, the Commission should remember that the electric industry depends on long-term plans and investments to operate in short-term environments. Today, forecasts of loads and the resources needed to serve those loads reliably and economically are made in numerous time frames: hourly, daily, seasonally, yearly and for ten or more years in the future. These forecasts are used to plan for resource adequacy in the short- and long-term. Generation capacity must be planned and scheduled to match load all the way from the next dispatch cycle, to the full operating day and out to the next ten or more years to assure reliability of supply and to produce the most economic solution to the fundamental problem, i.e., balancing supply and demand instantaneously.

Shorter term meteorological forecasts are generally more accurate than longer term forecasts simply because much of the uncertainty has been reduced or removed. Forecasting knowledge and methodologies are continuing to evolve. New methods and technologies for gathering data important to forecasting are being developed and researched. In exploring this area, the Commission must keep in mind that the primary purpose of a forecast is to produce the most reliable and economic result for serving load on the grid in multiple time frames—not just in the next fifteen minutes.
**Question A.1:** What are the current practices used to forecast generation from VERs?

Will current practices in forecasting VERs’ electricity production be adequate as the number of VERs increases? If so, why?

**Response:**

Accurate forecasts are important because, among other things, they enable the BA to plan and schedule resources needed to serve expected loads both reliably and economically throughout the operating day and beyond, and to determine the level of reserves needed to maintain reliability in the event of contingencies on the grid. Forecast accuracy is examined historically to help quantify the amount of uncertainty that is inherent in the forecast. This uncertainty is factored into the determination of the reserve levels needed to ensure continued reliable service.

Forecasting for wind resources and other VERs, is a relatively new challenge presented to System Operators as they plan for the hourly and daily resources needed to operate the grid. Even in the relatively short time that this challenge has existed, wind forecasting appears to have improved, but it is still clearly an evolving science. The present adequacy of forecasting to support increased penetration of VERs varies greatly from region to region, as well as from one form of VER to another. Regions with few wind resources may not have had the need to devote substantial resources to developing advanced forecasting technologies. In some regions, notably the Electric Reliability Council of Texas (“ERCOT”), wind forecasting has developed to the point where it can be quite accurate up to two hours out, although day-ahead forecasts still remain unreliable. Notwithstanding this progress, it seems unlikely that the uncertainty of forecasting VERs’ output over periods greater than 24 hours is likely to be reduced much in the near future, and it will never fully be eliminated.
It is important to bear in mind that only one aspect of VERs’ variability is reduced by improved forecasting. Even though improved forecasting may reduce the uncertainty of VERs’ output somewhat, it cannot reduce the variability inherent in the physical nature of those resources. Consequently, while improved forecasting may reduce somewhat the need for greater reserve levels and more frequent unit commitment and de-commitment caused by VERs in a particular dispatch period, it cannot eliminate that need. More accurate forecasts of wind will not eliminate the fluctuations in wind output that will occur, and the spikes and troughs that result will have to be filled by “some resource,” regardless of whether they were predicted five minutes or two hours in advance. Regions where VERs are already interconnecting to the grid are already evaluating the potential need for additional reserves due to the uncertainty in forecasting VERs output. They should be encouraged to continue these processes and to attempt to identify the costs associated with any increased reserve requirements due to uncertainty in forecasts.

Indeed, the question of whether current practices in forecasting VERs’ electricity production is adequate with increased numbers of VERs is one that can best be answered by the individual regions. Hence, to accommodate different regions’ different valuations of the costs and benefits of VERs, NRECA believes that the best way to approach this issue is to allow each region to continue down its path of determining the best means of incorporating forecasts in system operations, as well as the best means of ensuring adequate reserves.

**Question A.2:** What is necessary to transition from the existing power generation forecasting systems for wind and solar generation resources to a state-of-the-art forecasting system? What type of data (e.g., meteorological, outage, etc.), sampling frequency, and
sampling location requirements are necessary to develop and integrate state-of-the-art forecasts, and what technical or market barriers impede such development?

Response:

NRECA is not certain what data and techniques are required to advance state-of-the-art forecasting, but it is clear that much more and better of each will be required if greater levels of VER penetration are to be sustained and reliability preserved. To some extent, the need may be supplied by the National Oceanic and Atmospheric Administration (“NOAA”) and other public sources, but the Commission should expect and require the primary burden of advancing the science to be borne by the VER industry working in conjunction with other segments of the industry. It would not be appropriate to require load or other forms of generation to shoulder the burden of or bear the costs of developing highly advanced forecasting techniques.

To provide the VER industry appropriate incentives to carry this burden, the Commission must make certain that VER operators bear the operational consequences of the quality of their forecasts. As the science advances, BAs should be free to develop—with stakeholder input—region-specific market rules that would address required characteristics of forecasts. Such market rules could address both the variability of the generation and the time frame in which the forecast must be provided. For example, market rules could impose penalties on generators for inaccurate forecasts, and the revenues collected from such penalties could offset the costs of any additional reserves. ERCOT, for instance, has developed scheduling penalties for wind.

Question A.3: What data, forecasting tools and processes do System Operators need to more effectively address ramping events and other variations in VER output, and to validate enhanced forecasting tools and procedures?
Response:

Answers to this question will vary significantly from one region to the next based on, among other things, the amount and quality of the VERs located in it. What forecasting tools System Operators need will depend upon the type and amounts of VERs being integrated, the meteorology of the geographic area, the characteristics of conventional generation on the system, types and levels of reserves, and so on. This is another reason why, as noted above, each region should be given the latitude to continue its present efforts to address this issue without the imposition of a one-size-fits all approach.

Question A.4: What operational, outage and meteorological data should the Commission require VERs to provide to non-VER System Operators? To what size resources, in MWs, should any such data requirements apply, and what revisions to the pro forma OATT would be necessary to accommodate these requirements?

Response:

NERC’s IVGTF and the Utility Wind Integration Group (“UWIG”) are now studying these matters with an eye toward reforming interconnection requirements. They may also be able to make recommendations regarding additional operational requirements, but it is too soon to tell whether pro forma OATT changes will be required, much less to predict what any such changes should be. In principle, though, operational data, maintenance schedules and unit status of VERs should be communicated to the System Operator on the same basis as all generating units are required to communicate, and subject to similar consequences. Meteorological data from individual wind towers would also provide System Operators with the information they may need in order to perform their own forecasts of wind output. Because it is the System
Operators who are ultimately responsible for maintaining reliability, they should have access to all the information that they need to perform that function. Since VERs are reliant on meteorological conditions for generation output, the System Operators should be permitted to require VERs to share meteorological data from their local sites, and to communicate to the System Operator any and all meteorological data they have onsite or from meteorological towers. Wind turbines, for example, are equipped with anemometers (which measure wind speed). Knowing local meteorological conditions (e.g., temperature, humidity, barometric pressure, etc.) at the VER site, which covers thousands of acres, will be beneficial to the System Operator. The more granular the meteorological data, the better the forecasting models will become. Local temperature, relative humidity and barometric pressure are additional meteorological data which the VER operator should be required to provide to the System Operator. System Operators will be best positioned to know what communications they may need from VERs to operate their systems reliably, and they should be permitted to develop proposed requirements, in conjunction with interested stakeholders.

The VER operator typically has performed a year or more of meteorological data collection to determine viable sites. Through this collection of meteorological data, the VER operator knows where the prevailing winds originate. It would be beneficial if System Operators could require VERs to install, own and maintain meteorological towers “upwind” of the VER site to help anticipate changes.

**Question A.5:** *State-of-the-art forecasts may necessitate the sharing of meteorological data across regions to assure that the movement of weather patterns can be accurately predicted and analyzed. To what extent should meteorological data be made publicly available to aid in*
the development of state-of-the-art forecasts? Should the Commission require public utilities to maintain a meteorological data reporting system? If so, should such a system be akin to or in collaboration with Open Access Same Time Information System (OASIS) postings? In order to retain the confidentiality of commercially sensitive data reported by VERs for the purpose of developing state-of-the-art forecasts, what limits and/or safeguards should be established to protect operational data and generator outage reports?

Response:

Regarding the extent to which meteorological data should be made publicly available to aid in the development of state-of-the-art forecasts, as noted above, the full range of needs for sharing of meteorological data is not yet known, so it would be premature to speculate about forms or requirements for such communications, much less attempt to impose a generic approach to them. This is a matter, first, for the VER industry, working with the System Operators in their respective regions, to develop as a matter of good science; then for each region to propose to incorporate in a manner appropriate for itself; and only then for the Commission to evaluate for justness and reasonableness.

The Commission should not require public utilities to maintain a meteorological data reporting system; there is no reason for such a requirement. NERC reliability standard TOP-005-2 allows BAs and Transmission Owners (“TOs”) to share information on a confidential basis. NERC may conclude that this reliability standard could be modified to include meteorological data from VERs and then shared among the BAs and TOs on a confidential basis.

Question A.6: **Should the Commission encourage both decentralized and centralized meteorological and VER energy production forecasting?** For example, should transmission
providers have independent forecasting obligations as part of their reliability commitment processes similar to what is done today for demand forecasting?

Response:

The answer to this question is essentially the same as to A.5, with the additional observation that if a centralized approach to forecasting for VERs is implemented, the attendant costs should be assigned to the beneficiaries, i.e., VER operators. As discussed above, the Commission should allow individual regions to formulate mechanisms that they believe are appropriate for them.

Question A.7: To what extent is a lack of data regarding the operational status and forecasted output of distributed, or behind-the-meter, VERs leading to a need for additional reserves? To what extent would the provision of such data reduce the need for System Operators to rely on reserves?

Response:

Generally, insufficient data regarding the operational status and forecasted output of VERs makes calculating reserve requirements more difficult. In the absence of an accurate forecast of expected generation and accurate data regarding the operational status of VERs, reliability will require System Operators to make conservative assumptions relative to VER performance, so as to have sufficient reserves on hand.

Specifically, insufficient data regarding behind-the-meter VER generation would lead to the same kinds of operational difficulties, with the degree of those difficulties depending on the level of penetration of such behind-the-meter generation. For example, if a behind-the-meter generator builds multiple 19 MW generators in order to avoid compliance with the requirements
of the Large Generator Interconnection Agreement, that generation collectively can very quickly pose significant operational and reliability challenges. Cooperatives in Kansas have already seen small generators attempting to circumvent a law limiting additions to distribution circuits by placing multiple small turbines along the same distribution circuits.

For the sake of simplicity, until the penetration of residential-sized turbines becomes significant, the Commission should distinguish between self-generation—which is sized to serve behind-the-meter load at retail—and wholesale generation, which is sized and intended to export power onto the grid to sell to third parties. Commercial entities entering the generation business to earn a profit should be expected to act as such and to contribute to the reliability of the grid in the same manner as any other public utility.

**B. Scheduling Flexibility and Scheduling Incentives**

In this section, the Commission questions whether longstanding scheduling practices are causing rates for reserves to become unjust and unreasonable by inhibiting VERs from “establishing operationally-viable schedules” and preventing System Operators from using fully the flexibility of their systems. The Commission seeks to explore whether greater scheduling flexibility could provide system benefits and promote reliable and efficient use of all resources. The Commission’s concerns seem to embrace scheduling both the use of transmission within a single system, energy transactions between balancing areas, and in the latter case, transactions between systems in bilateral contract markets and Independent System Operators (“ISO”)/RTO Day 2 markets.

An assumption underlying the Commission’s inquiry is that System Operators in general have access to significantly more dispatch flexibility from the resources available on their systems than is currently being utilized. NRECA knows of no reason to believe that this is the case anywhere, much less everywhere. The operating characteristics of the generating resources
available to the System Operator have dictated scheduling (and dispatching) practices, not the other way around.

Scheduling transmission service within a single system or balancing area requires the System Operator to incorporate any changes in expected resource outputs into his overall dispatch plan and schedule. How simple or difficult this process is in any particular interval of time involves several factors, including the characteristics of the entire resource portfolio within the System Operator’s control, where those resources are currently positioned in their dispatch operating range, overall system load levels, any transmission constraints that would be affected by the change in flows, and others. Assuming that all those variables and conditions do not limit the desired change, then it is implemented by redispatching the other resources currently operating on the system in order to stay within NERC reliability criteria. The total level of VER output and quantity of the desired schedule change directly affect the difficulty of implementing such a change and the cost impacts of doing so.

In order to schedule a transfer of energy from one transmission system to another, the dispatch of both affected systems must be adjusted to accommodate the change. In order to keep each system in balance, one system must increase total generation output to execute an energy export, and the other must decrease in total generation output to import the energy, and they both must do so in tight coordination. The resulting “transmission schedules” then represent the net system re-dispatch efforts of two distinct balancing areas needed to execute the interchange transaction.

The ability of a single system, or of multiple systems, to accommodate any changes in scheduling procedures and timing will depend greatly on the availability of flexible resources to redispatch the system(s) in shorter intervals, and the costs incurred in implementing such a
change. Also, the system with the least available generation flexibility will be the limiting factor in transactions between two systems. In some cases, new unit commitment plans may need to be developed in order to have sufficient flexible resources available to support these transactions. Therefore, intra-hour scheduling could only be accomplished if transacting systems have the right economic incentives and the right kinds and amounts of flexible resources available to implement such a change. Whether the benefits of implementing shorter scheduling intervals within or between systems will outweigh the costs of doing so will vary from BA to BA, and region to region.

The need to continuously balance generation with load, and interchange transactions with dispatch schedules of affected systems is a reliability issue; whereas the desire to accommodate shorter scheduling intervals for certain resources is an economic issue for all affected systems involved in such transactions. Allowing VERs the ability to adjust their scheduled output levels over shorter periods may reduce their exposure to any penalties that may arise from deviations in schedules, but it will not eliminate the need to dispatch conventional resources “up” or “down” to deal with the actual variations in output to maintain reliability. That is, improved forecasting coupled with shorter scheduling intervals could enable VERs to reduce somewhat the uncertainty of their output over the scheduled interval. However, these changes would do nothing to change the variability of VERs’ output within the scheduled interval. Depending on the overall level of VER variability, shorter term schedule adjustments could change the types of resources the operator commits to meet schedule changes on some systems. However, if the amount of variability in VER output is significant, most operators will still have to rely on their fast ramp resources, i.e., regulation and spin resources, to accommodate the deviations of significant numbers of VERs. Therefore, implementing shorter scheduling intervals between systems may
result in very little change in the resources needed to accommodate VER variability. System Operators’ flexibility to change the unit commitments and dispatch schedule on the system in response to new scheduling procedures will also be hampered by natural gas pipeline rules, since natural gas scheduling is typically a day-ahead activity with limited opportunities for schedule changes during the day of scheduled delivery.

Because some systems may not be able to change unit commitments and dispatch in response to shorter scheduling periods, those systems could be exposed to higher costs and risks solely to help reduce the VERs’ exposure to penalties and ancillary services costs, and without actually reducing the need for regulation or other reserve resources. In other words, in many cases these changes would reduce costs for VERs at the expense of other users of the system. NRECA urges the Commission to be mindful of the danger for cross-subsidization as it considers whether to propose tariff changes to facilitate integration of VERs.

In an ISO/RTO with Day 2 markets, VERs have the option to bid into the day-ahead financial market, but are not required to do so unless compensated as a “capacity resource” in those regions with capacity markets. If they do bid in day-ahead and are selected in the auction, VERs must honor any commitments resulting from day-ahead compensation just like other resources. In that case, the VER would be responsible for delivering on its day-ahead commitment in real-time, or be subject to any market penalties, as all resource owners are. If VERs do not bid day-ahead, then the VERs are simply compensated at the real-time price for their actual output; without a binding day-ahead schedule, there should not be any market penalties.

VERs’ output is much more predictable the closer the forecast is made to the time for which the forecast applies. Consequently, shorter transmission scheduling intervals could
reasonably be expected to reduce VERs’ exposure to deviation penalties for scheduled interchange. However, the shorter scheduling period would necessarily increase operations center and administrative costs and could well do so without actually altering the units that the market operator must commit to provide ancillary services. That is, shortening the scheduling interval would certainly increase labor and information technology costs. However, it might equally well not change appreciably the dispatch required to support the system because of unit minimum run, start time and ramping constraints. The consequence could be increased costs without offsetting benefits.

The Commission’s treatment of scheduling practices as essentially economic phenomena ignores the extent to which they are affected by reliability concerns. Regardless of whether a System Operator is within a centralized market or not, and regardless of what scheduling practices the System Operator follows, reliability standards require the BA to maintain the reliable operation of the grid. The System Operator will do so with the resources it has available to it, whether those resources are spinning reserves, fast-start reserves, demand response or other tools. If VERs on the system at any point exceed the flexible resources available to the BA to preserve reliability, the System Operator must and will curtail some of the VERs. That is both a necessary and the appropriate response, as it is the VERs that would have imposed the need for flexibility on the system and because it would provide the VERs the incentive either to reduce the variability that they impose on the system or to bring to the system some of the flexibility required for them to be integrated reliably.

Understanding the relationship between scheduling practices and reliability imperatives should help the Commission evaluate which stakeholders will be advantaged or disadvantaged by proposed changes to the scheduling practices. If, on a particular system, a change to the
procedures would give the System Operator the ability to de-commit more expensive resources and to operate less expensive resources without diminishing reliability, then presumably the change would reduce the cost of operating the system. If those savings are sufficient not only to recover the significant cost of making the procedural changes but also to allow all users of the system to see a reduction in their ancillary services costs or at least to be held harmless, then the change could be considered just and reasonable. If, on the other hand, the change in scheduling procedures does not permit the System Operator to actually change the resource mix on a particular system, then the Commission should recognize that the change not only increases procedural and operational costs for all stakeholders, but also shifts ancillary service and operational costs from the VERs, whose need for flexibility caused them, to other users of the grid. That would not be just and reasonable. In fact, it would be unduly preferential in favor of the VERs. It would also undermine the price signals that VERs need to see in order to encourage optimum long run investments in technology and resources required to reduce the variability of their resources.

Because the situations of different BAs vary widely, such that new scheduling rules would be cost effective in some areas and not cost effective in others, the Commission should eschew one-size-fits all rules and should permit each System Operator, with input from its stakeholders, to determine the rules that best fit the resources and needs on its individual system. In fact, those regions of the country that are already seeing significant VER penetration, and thus have a significant need to look at this issue, already are doing so. To a large degree, those System Operators that have not yet begun to look at this issue operate in areas of the country where there has been little VER penetration, and where there may be little potential for
significant VER penetration, and thus little need to incur the expense required to conduct an exhaustive review of scheduling procedures to meet the needs of VERs.

1. Scheduling Flexibility

**Question B1.1:** Would shorter scheduling intervals allow System Operators to more efficiently manage the ramps of VERs and/or demand? To what extent would the availability of intra-hour scheduling decrease the overall reliance on regulation reserves to manage the variability of VERs?

**Response:**

To the extent that shorter scheduling intervals provide System Operators more timely notice of ramps, System Operators may be better able to manage the consequences of the ramps. However, changes to the scheduling rules to accomplish this goal are unnecessary if the Commission requires VERs to provide System Operators with improved forecasts and operating condition information. That data should give System Operators as good or better warning of ramps than changes to the scheduling rules.

In any event, whether shorter scheduling intervals would enhance the efficiency with which System Operators manage ramps—assuming that by “more efficiently” the NOI means with less cost and with less impact on reliability—is open to question. For instance, when evaluating whether shorter scheduling intervals would enhance efficiency, the Commission should consider the fact that large fossil units that otherwise would not need to run to provide energy in some dispatch periods may need to stay on-line to provide regulation if there are not enough other flexible resources on the system to provide this needed service. Moreover, the addition of intra-hour scheduling flexibility could actually increase the burden on System Operators by increasing the complexity and decreasing the efficiency of their internal operations.
As to the question of whether intra-hour scheduling would decrease the amount of regulation reserves needed to manage VER variability, there is no answer that would apply in all cases and to all regions. Many different variables go into the selection and commitment of resources that are available to the System Operator to match load throughout a given operating day. While certain types of resources may not be needed in all dispatch periods as discussed elsewhere in these comments, these units may have flexibility characteristics to provide regulation, spinning or other reserves in crucial ramping periods and to cover for contingencies.

When it comes to selecting reserves from different categories, it is a fairly common practice for System Operators to substitute “higher quality reserves (such as regulation, 10-minute spin)” for “lower quality reserves (30-minute spin, supplemental).” This is done because System Operators do not typically have a large portfolio of generating units available with the ideal operating characteristics to build the most “economically efficient” reserve portfolio.

There has been and still is a well-known lack of sufficient quick-start resources throughout the industry for many different reasons. This problem is particularly present in RTO markets, due to well-known issues with regard to cost recovery for quick-start resources. Because reliability is paramount, it is not unusual for a system to have more regulation and/or spinning reserves on line to manage load and contingencies than would be economically ideal, due to a lack of flexible options. Allowing VERs to implement intra-hour scheduling would have little impact on this situation and could likely increase short-term operating costs if sufficient variability is introduced with significant VER penetration.

As explained above, NRECA believes that the question of whether it would be appropriate to require or “encourage” intra-hour scheduling of VERs is one that must be
determined on a regional basis, by the BA(s) and stakeholders in each region working with the
VERs.

Another consideration is that if the Commission were to consider proposals to move
electric operational practices to sub-hourly scheduling, the benefits would be minimal unless
natural gas pipeline rules were similarly modified. Natural gas scheduling is typically a day-
ahead activity with limited opportunities for schedule changes during the day of scheduled
delivery.

If the Commission chooses to encourage intra-hour scheduling, it is essential that the
Commission permit all loads and resources to take advantage of the new procedures. It would be
discriminatory to allow VERs the ability to conduct intra-hour scheduling but not allow other
types of generation or load to make the same types of changes. NRECA urges the Commission
to ensure that any proposals to facilitate integration of VERs not discriminate against other types
of resources or load.

**Question B1.2:** What are the benefits and costs of allowing resources and transactions
to schedule on an intra-hour basis, and what tariff and/or technical barriers exist to
implementing intra-hour scheduling? Are there best practices that could be implemented to
facilitate greater intra-hour scheduling?

**Response:**

For those smaller systems that currently do not have intra-hour scheduling,
implementation of intra-hour scheduling would be a significant additional burden for their
System Operators because the entry and check-out mechanisms employed on such systems are
manual processes. The costs of automating these processes, including implementation of the
software systems to implement sub-hourly interval scheduling, could be substantial, although the precise level of costs would likely vary by system. These changes would inevitably be very costly for smaller market participants like many of NRECA’s cooperative members. While changes to infrastructure required for trading may be absorbed by large entities, smaller cooperatives would be affected disproportionately because of their inability to spread the costs over the large volume of trade. Thus, in any cost-benefit analysis, it is less likely that smaller entities will benefit, even over time, especially where they lack a large customer base, which is the case for many rural electric cooperatives. Consequently, some of NRECA’s members have expressed the view that intra-hour scheduling is simply infeasible for them at this time.

Although intra-hour scheduling could result in decreased imbalance charges for generators and load, it is important to recognize that allowing intra-hour scheduling changes could cause increased scheduling and dispatch charges, to recover the increased costs of providing the enhanced service. As noted in response to Question B1.1, above, NRECA believes the question of whether there is a need for intra-hour scheduling is one that is best left to regions to decide. To the extent a region decides to do so, NRECA urges the Commission to require BAs to make the costs of implementing these changes transparent, perhaps by implementing a new schedule under the tariff, with costs to implement the service allocated to the users of the service. Regions that do choose to adopt intra-hour scheduling will need to address, among other things, how to synchronize whatever intra-hour interval is adopted with the one hour minimum for transmission service and with the calculation of Available Transfer Capability (“ATC”)/Capacity Benefit Margin (“CBM”)/Transmission Reliability Margin (“TRM”) for neighboring utilities that use flowgate-based analyses.
**Question B1.3:** Are there an optimum number of intervals within the hour for scheduling? What time increments would be necessary and/or desirable in order to achieve optimum flexibility while still meeting the relevant reliability requirements?

**Response:**

The answers to these questions depend importantly on the characteristics of generation on the system, which varies widely from region to region. Accordingly, these issues are best determined by the industry and stakeholders on a regional basis.

**Question B1.4:** Identify any reliability issues that may result from changes to the scheduling rules. What changes, if any, to NERC Reliability Standards would be needed to fully implement additional scheduling flexibility while still ensuring reliability?

**Response:**

At a minimum, the BAL, INT, IRO standards, plus MOD-001 through -008, would need to be reviewed to determine the impact of any changes on the scheduling interval. The changes to the standards needed would have to be determined in the first instance through the stakeholder processes of the Regional Entities and NERC.

**Question B1.5:** How would intra-hour scheduling affect the operation of other processes such as available transfer capability (ATC), the E-Tag system, issuance of dispatch instructions for generation and/or demand resources, transmission loading relief procedures, and/or dynamic schedules? What costs would be incurred as a result?

**Response:**

See response to Question B1.4, above. It is difficult to enumerate the types of costs that
would be incurred since systems differ so significantly in how they handle these processes today. It is certain, however, that substantial additional labor, data processing equipment, control equipment and software would be required.

**Question B1.6:** If intra-hour scheduling is implemented in non-RTO/ISO regions, how would RTO/ISO scheduling practices at interties be affected? Would intra-hour scheduling at interties present problems for RTO/ISO markets? If so, describe the problems and feasible solutions for intra-hour scheduling at interties.

**Response:**

This issue has been addressed to some degree in previous responses. The key analysis of the feasibility of changes to scheduling practices is the availability of transmission capacity and/or system interface capability. If that available capacity is determined to exist and has been procured, then the scheduling issue can be addressed. If, as may frequently be the case, there is no available firm capacity at the interface, then the scheduling procedures are effectively irrelevant. In that case, the Commission must focus first on facilitating the building of necessary transmission infrastructure rather than on perfecting scheduling procedures.

Where transmission capacity is available to permit interchange transactions, Day 2 RTO market operators may be better situated to accommodate shorter scheduling intervals than non-market regions. That does not mean that it could not be done outside of RTO regions, but it would require coordinated analyses to determine the net costs and benefits to the affected systems for implementing shorter scheduling procedures. Coordination is critical between RTOs and non-RTO BAs as well; an RTO can import or export energy no faster than the transacting system can accommodate the schedule.
Because they are so deeply affected by local conditions, coordination at the interties and cost allocation responsibilities should be addressed in seams agreements between the individual RTO/ISO regions and non-RTO/ISO regions. No one-size-fits-all rule can provide adequate guidance in every instance.

2. Scheduling Incentives

**Question B2.1:** Has the exemption from third-tier penalty imbalances worked as a targeted exemption that recognizes operational limitations of VERs, or has it encouraged inefficient scheduling behaviors to develop? If the latter, what reforms to this exemption would encourage more accurate scheduling practices?

**Response:**

NRECA has not studied whether the exemption from third-tier penalty imbalances has worked as a targeted exemption; however, as discussed in more detail below in response to Question B2.3, NRECA believes that this exemption is discriminatory and should be eliminated.

**Question B2.2:** Assuming that efficient forecasting and scheduling practices help minimize deviations between scheduled and actual energy output of VERs, are additional incentives needed to encourage VERs to submit schedules that are informed by state-of-the-art forecasting? What would be the proper incentives?

**Response:**

NRECA does not believe that VERs should be provided “incentives” in the form of “rewards” to submit schedules that are informed by state-of-the-art forecasting. Rather, VERs should be required to comply with the BAs’ scheduling requirements, and these scheduling requirements should serve as “incentive” to schedule as accurately as possible. Individual BAs
should be permitted to develop and file with the Commission those imbalance provisions, and any other tariff or market rules they believe necessary to provide those incentives for accurate scheduling.

**Question B2.3:** Under an RTO/ISO market design, are there sufficient incentives to encourage VERs to submit accurate schedules? What costs and/or penalties should be assigned to VERs when their real-time output is not accurately scheduled on a forward basis? Should VERs be treated the same as conventional resources with respect to deviations from their production schedules?

**Response:**

NRECA believes that VERs should be treated the same as conventional resources with respect to deviations from their schedules. NRECA previously objected to the Commission’s proposal in 2005 to use preferential imbalance provisions for wind and other intermittent resources.¹⁷ NRECA continues to believe that this is discriminatory, and the principles NRECA advocated then are equally applicable to the Commission’s inquiry today:

- Any balancing provisions adopted should conform to NERC reliability standards and good utility practice.
- Imbalance provisions should recognize that load and even thermal generation, as well as wind, hydro-electric and solar generation, involve varying degrees of

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¹⁷ *Imbalance Provisions for Intermittent Resources,* Docket No. RM05-10-000; *Assessing the State of Wind Energy in Wholesale Electricity Markets,* Docket No. AD04-13-000, Comments of the National Rural Electric Cooperative Association (May 26, 2005), at pp. 1-2 (“NRECA does not support the NOPR’s proposal to use preferential imbalance provisions for wind and other intermittent resources to accomplish those goals. A number of NRECA members believe the Commission should address more broadly all forms of undue discrimination that the Commission has already acknowledged exist in Order 888’s imbalance provisions. Such an approach would protect wind – and all other transmission customers – from unreasonably punitive imbalance charges while also ensuring that wind generators pay the reasonable costs of imbalance service….”).
intermittency, or deviation in real time from scheduled flows that is difficult to accurately forecast in advance.

- Imbalance provisions should allow for full cost recovery that does not result in undue cost shifts or cross-subsidies or windfall profits for imbalance service providers.
- All entities causing imbalances should face comparable consequences.\(^{[18]}\)

As with many of these inquiries, NRECA believes it is premature for the Commission to impose an across-the-board rule. Instead, NRECA urges the Commission to allow the industry to continue to develop market rules as needed on a region-by-region basis. When the Commission evaluates these proposals, it should bear in mind cost causation principles.\(^{19}\) If costs are not imposed on the cost causers, then there is no incentive for those cost causers to develop economic solutions to the problems integration of their resources create.

C. Day-Ahead Market Participation and Reliability Commitments

As a general matter, day-ahead markets are financial markets and are voluntary. VERs cannot be required to participate under current tariffs unless they choose to be compensated as a capacity resource (in those RTOs with capacity markets). Requiring VERs to participate in the day-ahead market for any other reason is not likely to offer any substantial benefits to the operator or the markets. RTO System Operators start their unit commitment plans with the results of bidding and selection of “real generators” that are selected in the day-ahead market and supplement those selected resources with additional resources needed to match forecast load requirements in a reliability assessment commitment. It is in the reliability assessment

\(^{18}\) Id., at p. 3.

\(^{19}\) See, e.g., Westar Energy, Inc., 130 FERC ¶ 61,215 at P 36 (2010) (“Westar Energy”) (“Westar’s analysis submitted in response to the deficiency letter provides data showing, among other things, that intermittent generators’ deviations from the deployment signal are more than three times greater than those of dispatchable generators. Accordingly, the Commission finds that Westar’s proposal reasonably assesses intermittent generation a higher regulation requirement consistent with cost causation principles.”) (emphasis supplied).
commitment that expected VER output would be given the most consideration in determining what additional resources may be needed to meet the next day’s load. Regardless of whether VERs participate in the day-ahead market or not, RTO System Operators will have to be provided the same operational data and forecasted output from VERs as non-RTO operators would need in order to balance load and resources reliably. If VERs do not commit to the day-ahead market, they will simply be price takers in the real-time market, paid for their output at the market price without offsets for penalties for deviations from day-ahead commitments.

1. Day-ahead Market Participation

**Question C1.1:** Does the lack of day-ahead market participation by VERs present operational challenges or reduce market transparency as the number of VERs increases? Will out-of-market commitments increase as the number of VERs increases? If so, why?

**Response:**

VERs’ non-participation in day-ahead markets results in greater uncertainty about the next day’s system output. The lack of information, however, can be met by requiring VERs to provide System Operators with the best possible forecasts and information on their units’ status, without requiring participation in day-ahead markets. If VERs provide those improved forecasts and unit status information, day-ahead market participation would not provide System Operators additional value, but would, instead, only heighten the consequences of forecast errors. After all, the best day-ahead bids VERs can make are only as good as the best forecast and unit status information they have available to them. Any errors in the day-ahead forecast will be directly reflected in the day-ahead bids. The problem is not caused by the lack of bids but by the variability and uncertainty inherent in the resource.
**Question C1.2:** How can new or existing market design features assure that the day-ahead market will accurately represent real-time system conditions and that day-ahead and real-time energy prices will converge under the scenario of increasing numbers of VERs?

**Response:**

RTO markets already exhibit differences between day-ahead and real-time market outcomes. Since the day-ahead market is a financial market only, load is not required to bid into this market, but can do so on a voluntary basis in order to attain some price certainty over real-time events. At present, generators are required to bid into the day-ahead market only if they have made some other commitment that requires it, such as committing a unit to a “capacity resource” market and being compensated accordingly. Myriad possible changes in market rules have been investigated and implemented since the inception of these markets. This analysis is a work in progress that needs to continue in each RTO stakeholder process. There is no magic solution here for the Commission to implement in order to address VER integration. Improved forecasting can help achieve these goals, but only imperfectly. Market design and rule changes are properly the province of stakeholder processes within the RTOs, and those processes should be allowed to continue to work in order to avoid unintended consequences.

**Question C1.3:** Do current RTO/ISO market designs place undue barriers to participation in forward markets by VERs? Could the timing of certain RTO/ISO market design elements, such as the day-ahead market, be modified in a manner that would facilitate VERs to participate more in the day-ahead market rather than primarily in the real time market? If so, how?
Response:

Current RTO/ISO market designs do not place undue barriers to participation in forward markets by VERs. Any existing barriers result from the inherent variability and uncertainty inherent in the intermittent resource, not from the market itself. Current scheduling requirements cannot be blamed because they cannot diminish the consequences of VERs’ variability.

Question C1.4: Would the use of more accurate forecasting tools facilitate participation of VERs in the day-ahead market rather than primarily in the real time market? If so, how?

Response:

This seems a plausible hypothesis. Better forecasting could decrease the risk VERs now face that their real-time performance will differ considerably from their day-ahead schedules (if they choose to take that risk). As noted above, VERs’ schedules in the day-ahead market are only as good as their forecasts.

The Commission should recognize, however, that improved day-ahead forecasting will be inadequate to give VERs one of the largest benefits of day-ahead market participation: the ability to participate in capacity markets. Just because a VER operator can more accurately predict its short-term output, does not necessarily mean that the VER operator would have sufficiently increased confidence in its long-term forecasts to be willing to increase its capacity commitment over a longer period. At present, capacity commitments are made for a year at a time in RTO capacity markets. The VER operator that knows better what its unit may be doing two hours from now will most likely have no better idea of what its unit will be doing on that hot August day when its capacity is most needed for peak load conditions. Therefore, the desire of the VER to participate in the day-ahead market is unlikely to be significantly affected by
improvements in short-term forecasting. The Commission should give the industry more time for inquiry to better distinguish changes that could make a difference from those that would matter very little.

**Question C1.5:** *Should the financial risk of VERs participating in the day-ahead market be different than the risk imposed on other resources in that market in recognition of their unique characteristics? Are there settlement practices, such as netting deviations, which could be employed to address VERs participating in the day-ahead market? If so, what are they?*

**Response:**

No. In general, it is difficult to imagine that the benefits of VER participation in day-ahead markets would justify subsidizing such participation by shifting costs resulting from VERs’ variability to other market participants. As noted above, VER participation in the day-ahead market, and settlement practices such as netting deviations, provide System Operators no greater benefit than would improved VER forecasts and unit status information. VERs, therefore, should not receive preferential mitigation of the financial risks of participating in the day-ahead market. Special preferences for VERs that provide other industry participants no benefit would be unduly discriminatory. If the Commission decides to change the rules to afford VERs risk mitigation measures to induce them to participate in day-ahead markets, those risk mitigation opportunities should also be afforded to other resources and, in some cases, such as energy imbalance, to load as well.
Question C1.6: Will changes to the financial risk of participating in the day-ahead market encourage VERs to participate in day-ahead markets, and will this participation result in day-ahead market schedules that accurately reflect real-time market activity?

Response:

While affording VERs preferential risk mitigation might induce them to enter the day-ahead market, as discussed above, VER participation or non-participation in the day-ahead market would likely make very little difference in overall market efficiency. Capacity commitments are currently required on a much longer-term basis than a few hours, and would be little affected by the inclusion of VERs in the day-ahead market. Moreover, those capacity commitments would be based, not on the VERs’ day-ahead schedules but rather on the System Operators’ estimations of the generation resources required to meet load reliably. Those evaluations would be based on the System Operators’ forecast of wind output and understanding of VER unit status, rather than on the VERs’ schedules, if the two differ. System Operators understand that VERs’ real-time market activity will be based on atmospheric conditions and unit status, not on the day-ahead schedule, and that they are responsible for maintaining reliability given real-time conditions regardless of what the VER operators may have scheduled in the day-ahead. This is not unusual. As already discussed, there are many reasons day-ahead market outcomes do not reflect real-time market outcomes. VER participation on a day-ahead basis is only one of many variables to be considered.

2. Reliability Commitments

Question C2.1: Would the implementation of a formalized and transparent intra-day reliability assessment and commitment process prior to each operating hour reduce the amount
of reserves needed and/or reduce system uplift costs? What would be the optimal time (e.g., 4 to 6 hours ahead of the operating hour) for such a process?

Response:

The first question seems applicable only to RTOs, and NRECA believes that each RTO should answer it with the input of its market participants. Similarly, the details regarding the optimal time for such a process are best left to individual regions to determine for themselves, through the appropriate stakeholder process and subsequent proposed modification to market rules, if necessary, by the RTO. The RTOs would need to consider, among other things, coordination with gas scheduling practices, as just one example. NRECA notes that, as a general matter, it is by no means clear shortening intervals for real-time operation in order to accommodate a new intra-day market would result in increased consumer benefits. On the contrary, it could well increase operating costs and lead to economically efficient dispatch for the rest of the day, the month, or the year. Even in the short run, shortening scheduling and commitment intervals won’t change units’ minimum run and ramping times, so the degree to which System Operators might be able to shut down non-VER units to accommodate VER output will vary greatly and will nowhere be assured.

**Question C2.2:** Would an additional market that coincides with the timing of an intra-day reliability commitment process be beneficial in the forward scheduling of VERs? If such a market is implemented, would an intra-day reliability commitment process be necessary? Should the frequency of scheduling intervals resulting from such a market coincide with intra-hour schedules discussed above?

Response:
Organized markets today already have a financially binding forward market for multiple products. For example, MISO has a day-ahead market, a real-time energy market and forward-looking reliability assessment commitment process.\textsuperscript{20} VERs that wish to participate in these markets make a business decision to do so and, if they do, knowingly take on the financial risk of doing so. It is unclear what additional market is intended by the question, and the question seems to blur the distinction between market issues and reliability issues.

Additionally, it is important to bear in mind the distinction between RTO and non-RTO regions. Whatever the Commission hopes to achieve through markets, it is likely that the goal can be achieved through bilateral agreements among BAs, or multilateral/regional agreements, as has been done in the West. The Commission should not revive standard-market design in this context and seek to mandate market solutions in regions where those approaches have been soundly rejected by the industry and policymakers.

**Question C2.3:** *What role should centralized forecasting of VERs’ output play in reliability assessment and commitment processes?*

**Response:**

Centralized forecasting plays a significant role in ERCOT and in the SPP, because of the geographic diversity of wind and other resources on those systems. However, it is by no means clear that the potential benefits of centralized forecasting would outweigh the substantial costs of providing this service in all BAs. In any event, any obligation to forecast VER output will necessarily depend on highly localized data that only the VER operator can provide. Existing NERC Reliability Standards, which require generator owners and operators to provide data

needed to forecast reserve requirements, may need to be amended to take into account the increased amount and quality of data required to manage the consequences of the variability and uncertainty of VERs’ output.

D. BA Coordination

Although it has become common wisdom, simply increasing the geographic or electric scope of a BA does not necessarily mean that a larger percentage of VERs can be integrated reliably or at a lower cost.

MISO is the second largest BA and transmission operator in North America. MISO is also directly interconnected with and is tightly coordinating its operations with PJM, which is the largest BA in North America. Yet, with a VER penetration of only three percent in 2008, MISO is already beginning to face significant challenges in integrating VERs. MISO’s transmission interconnection queue has long been jammed with wind interconnection requests it cannot accommodate because of transmission congestion. MISO has already had to curtail VERs during some minimum generation periods in order to preserve reliability because it lacks the flexibility on the system it would need to permit the VERs to operate during those hours. Some capacity resources in MISO are beginning to have trouble recovering their capital costs in the energy markets because VERs have artificially driven down the cost of energy in spot markets (because of the nature of government incentives for VERs). Clearly, increased size and


22 See id. at iii (“Although wind provides substantial environmental benefits, its intermittent nature limits its contribution to reliability and resource adequacy and creates significant operational challenges that the Midwest ISO is working to address.”).
tight coordination do not automatically eliminate the challenges associated with integrating VERs.

   Even where BA consolidation is a part of the solution for integrating VERs, it cannot be accomplished with the wave of a regulatory wand. SPP has been operating as an RTO for six years and has been studying the consolidation of all the BAs in the region into one large BA for SPP for much of that time. It has not yet moved forward, despite the desire of many within SPP to do so, illustrating that BA consolidation, even within a centralized market, is not a simple task technically or financially.

   One factor that both undermines the value of the MISO’s giant BA and slows the process of consolidating the BAs within the SPP is transmission congestion. Those who support BA consolidation insist that a larger BA benefits from: reduced uncertainty and variability caused by geographic dispersion of VERs; reduced uncertainty and variability caused by load diversity; the ability to share a larger and more diverse pool of reserves and flexible resources across the BA; and an increased load base to absorb the VERs. Where the transmission exists to permit the free flow of power across the large BA, and where the large BA in fact includes diverse loads, resources, and widely dispersed VERs, this is certainly true. In many instances, however, there is only limited interchange capacity between neighboring BAs. Consolidation of the BAs does not eliminate the transmission bottleneck, it only internalizes it. The VERs within a congested area on the grid are still incapable of reaching loads when their output exceeds local demand. The congested area cannot benefit from reserves on the other side of a bottleneck, and thus cannot rely on them when VER output is inadequate to meet local demand. The congested area gains no benefit from either load or VER diversity. In these areas, the Commission must focus on encouraging the necessary long-term infrastructure investment needed to serve load reliably
before it can focus effectively on improving efficiency in real-time through BA consolidation. To reverse that order would be to “assume a can-opener;” \textit{i.e.}, to make an unrealistic assumption for economic convenience that is unreflective of reality. Until the infrastructure issues are addressed, BA consolidation cannot bring the promised benefits in many parts of the country.

Dynamic scheduling and pseudo ties have also gained favor as more limited solutions to the problems posed by VER integration. These and other efforts to coordinate efforts between BAs can have tremendous value and many cooperatives and other BAs are already taking advantage of them across the country to a large degree. Many entities continue to work together to find additional opportunities to do so. Those in the West, for example, participate in WestConnect, a voluntary organization with the goal of “developing cost-effective enhancements to the western wholesale electricity market.” Two of WestConnect’s successes are the multi-utility OASIS called WesTTrans and the adoption of a FERC approved experimental, non-pancaked, multi-utility non-firm transmission tariff. WestConnect is collaborating with the Northern Tier Transmission Group and the Columbia Grid to develop WECC-wide processes for BA coordination. A Dynamic Scheduling System will be implemented in 2010 that will allow generators to dynamically schedule generation into a BA on an hourly basis. The groups are also developing business practices that will accommodate intra-hour scheduling and a new bulletin board—I-TAP hub software and hardware, that will enable high-speed real-time transactions via a single port of entry. Implementation of I-TAP is scheduled for late 2010. The Virtual Control Area project, referred to as ACE Diversity Interchange, includes more than fifteen BAs. This project presents an example of why it is important to approach BA coordination or consolidation carefully. The Virtual Control Area functioned for a short time, but is currently on hold as some
bugs are worked out of the system. The participants expect it to be operational again later this year.

Despite their advantages, however, these measures, too, are dependent on the underlying transmission needed to deliver the output to load. Dynamic scheduling between two adjacent BAs may involve fewer potential restrictions than pseudo ties across a third transmission system. But neither of these measures can overcome the deficiencies of many regions’ transmission systems. A VER that is pseudo-tied into another BA still has real reliability impacts on the home BA’s system. Without firm transmission capacity between the home BA and the host BA, the home BA could find itself without the resources it needs to avoid violating NERC reliability standards. Moreover, pseudo-ties do not resolve localized reliability challenges such as maintaining volt/VAR balance. The need for reactive power is localized and cannot be met by a host BA.

Finally, operating as a BA entails certain responsibilities, as detailed in NERC requirements, that should not and cannot be waived for any System Operator, whether small, large, VER or some other resource only. The System Operator, regardless of size and makeup, still has to balance load and generation in real time, and account for interchange transactions.

**Question D.1:** *Will smaller BAs, when operated individually, have higher VER integration costs than geographically or electrically larger BAs? If so, why?*

**Response:**

The absolute size of the BA is not as important a factor in determining VER integration costs as is the level of VER penetration as a percentage of the installed capacity in the BA. A small BA with very few installed VERs may be better positioned to integrate a new VER than a
larger BA that has already reached saturation levels of VER penetration. Another factor that will affect the integration costs is the composition of installed conventional capacity (e.g., fossil, nuclear, hydro, etc.) in the region. A small BA with a high percentage of combustion turbines and newer combined cycle gas plants may be better positioned to integrate VERs than a larger BA that is highly dependent on coal or nuclear generation.

Also, differences in geographic scope and electrical scale of BAs affect the costs of integrating VERs differently. For instance, the geographic extent of a geographically large, but electrically small, BA may diminish the variability of VERs in the aggregate (on account of geographic diversity) but require installation of additional facilities in order to maintain voltage on a sprawling transmission system thinly populated with generation (and/or load). Similarly, the density of generation on an electrically large, but geographically small, system may provide the regulation and reserves needed to integrate VERs but lack the geographic scope required to benefit from increased variability of aggregate VER output.

Finally, the question presumes adequate transmission within the BA, be it large or small. As the consolidation of BAs in MISO has demonstrated, consolidating BAs that lack adequate transmission between and within them only creates a large BA riddled with load pockets. BA consolidation is not a substitute for adequate transmission, which is lacking in many areas of the country, perhaps most notably in the Southwest.

**Question D.2:** Should the Commission encourage the consolidation of BAs? If so, indicate the potential for and impediments to consolidation among BAs and the means by which the Commission should encourage consolidation.
Response:

No. Whether BA consolidation is a good idea depends on a number of factors, including the adequacy of the transmission infrastructure, the level of wind penetration, and the overall generation mix in the region. Those regions that see value for them in consolidation, such as SPP, are already pursuing it and do not need “encouragement.” Those that cannot benefit today from full consolidation are pursuing those coordination efforts that make sense for them in light of their local conditions. Those regions that cannot benefit today from coordination or consolidation due to prevailing conditions should not be penalized or treated differently for declining to act against the interests of their consumers.

For this last category, the Commission needs to understand that consolidation is simply not a realistic option where existing transmission infrastructure is inadequate. MISO, for example, consolidated multiple BAs into one for the region, but did so without ensuring adequate transmission. Transmission Loading Relief (“TLRs”) have continued within and outside of MISO. As a result, NRECA’s members have found that they cannot move power from the Western Area Power Administration (“WAPA”) to MISO on a firm basis. While transmission service is firm on the WAPA system to deliver power to the MISO border, it is treated as non-firm inside MISO for the same transaction.

As another example, the inter-mountain West and Southwest are characterized by relatively large (for the West) load centers connected by long transmission lines through sparsely populated rural areas. The high cost of constructing these interconnected lines has resulted in a relatively thin, frequently constrained transmission system. WECC has identified “qualified paths” which, when constrained, are subject to unscheduled flow mitigation procedures (these procedures are comparable to TLR activation in the East). However there are even more
constrained paths than those designated as the WECC qualified paths. Within the WECC, the challenges of a large regional BA can be seen in the state of Colorado. Although the primary BAs within the state are adequately interconnected, there are still constraints and access to other BAs is problematic. Colorado connects to the east only through back-to-back DC ties. Flows into Colorado from Wyoming are constrained; flows from western Colorado to eastern Colorado are constrained and flows between Colorado and New Mexico/Arizona are constrained in both directions. The ties between Public Service Company of Colorado and Public Service Company of New Mexico are extremely limited. There is simply not enough transmission to support large transfers of power to and from adjoining states necessary to support the reserve, regulation and load following requirements of a large BA.

In the 1980s and 1990s the utilities in this region operated the Inland Power Pool reserve sharing group. Most utilities from Wyoming to Arizona were members. Eventually after extensive studies, the group was disbanded because there was inadequate transmission to reliably provide reserve services. For example, it was not feasible for the Laramie River Station in Wyoming to respond to an outage at Palo Verde in Arizona. Adequate transmission did not and does not exist to facilitate this energy transfer and the energy could not flow. There are now two reserve sharing groups, but even within the northern group, the reserve responses are tailored to avoid constrained paths.

These examples all demonstrate that BA consolidation does nothing to address the underlying problem of an insufficient transmission grid. Transmission constraints do not disappear simply because BAs have been consolidated.

Aside from transmission issues, many cooperatives are concerned that mandating BA consolidation, would deprive existing BAs of control over the dispatch of their generation. For
many cooperatives, this control is important for them to be able to protect themselves from
discriminatory treatment by other, larger System Operators and to operate and maintain their
generation in a least-cost manner, which is critical to cooperatives’ core mission. Consumers
served by those smaller BAs should not be penalized or otherwise “encouraged” to bear higher
costs merely to facilitate third-party generators’ ability to wheel their power to distant customers
across the transmission systems paid for by local consumers. If the Commission were to pursue
consolidation, the costs of that to consumers in small BAs should be made transparent and
allocated to the VERs that benefit from the consolidation.

Another concern is that while BA consolidation is being touted as an “easy” way to
permit integration of more intermittent resources into the grid, an unintended (or perhaps
intended) consequence is that the full panoply of costs associated with such resource integration
are being shifted away from the generators and onto the transmission customers—albeit a larger
set of transmission customers, but still not the cost causers.

Those of NRECA’s members that are not in RTOs are concerned that BA consolidation
for the benefit of VERs not be used to require RTO membership/participation in Day 2 markets.
A number of NRECA’s members are on the seams between RTOs and non-RTO areas and have
not joined the neighboring RTO or RTOs for solid business reasons. A one-size fits all approach
to BA consolidation that forces those cooperatives into the RTO could dramatically increase
their costs and the costs borne by their consumers. If the Commission pursues that course, it
should make those costs transparent and allocate them to the VERs that benefit from the
consolidation.

NRECA notes that there are other ways to address the challenges of incorporating VERs
that can and should be initiated before ordering or “encouraging” BAs to consolidate.
Implementation of a regional approach to ancillary services and reserves required to respond to the intermittent nature of VERs, including imbalance, regulation and operating reserves, may be sufficient to address the intermittent nature of VERs and may provide significant benefits without BA consolidation. However, this regional approach requires recognition that the addition of VERs will require an incremental increase in the specific resources required to provide these services as well as sufficient transmission infrastructure to allow for the regional ancillary services and reserve sharing to operate effectively.

Many BAs are already coordinating activities to achieve many of the same benefits of BA consolidation without shifting costs. As discussed above, Tri-State, Southwest Transmission, and other BAs within WECC have taken aggressive steps in this direction. Similarly, another one of NRECA’s members, Associated Electric Cooperative, Inc., has an agreement with MISO which provides for Emergency Energy Assistance, Coordination of Outages, Communication and Coordination of Normal and Emergency Operating Procedure, and Data Exchange.

No matter how great the degree of coordination, however, if there is insufficient transmission across seams, the benefits of coordination will be greatly diminished. As discussed above with respect to full consolidation of BAs, coordination can only be accomplished effectively and without undermining reliability if the transmission infrastructure is sufficient to permit VER generation and reserves to flow across the system without constraints. Where there is insufficient transmission to permit firm paths to be reserved between BAs, coordination efforts will be severely limited.

Because the potential benefits and costs of BA consolidation and coordination differ widely depending on local circumstances, NRECA urges the Commission not to mandate or
“encourage” BA consolidation or coordination but to allow regions to develop solutions that work for them. Regions are already undertaking efforts in this regard.

**Question D.3:** *What tools or arrangements (e.g., dynamic schedules, pseudo-ties, and virtual BAs) are available and/or could be enhanced or created to reduce barriers to greater operational coordination among BAs? What role should the Commission play in facilitating inter-BA coordination?*

**Response:**

As discussed above in response to Question D.2., dynamic scheduling, pseudo-ties, and other efforts to coordinate among BAs are tools that are available to and being used by System Operators and their transmission customers today. Enhancements that improve reliability without increasing costs substantially may have merit, but whether such enhancements are cost effective will vary on a regional basis. To a large degree, they are dependent on the availability of firm transmission capacity, which is not available in all cases. They also do not resolve local reliability issues, such as reactive power support. Just because a generator is moved into another BA on paper does not mean that it has no electrical impacts on the local grid where it is physically located.

If the Commission wants to expand BA coordination, one step it could take would be to encourage reserve sharing arrangements to be opened up to broader participation. However, reserve sharing arrangements typically cover emergency situations, and therefore involve more limited amounts of capacity than the reserves that would be required to support VERs.
Question D.4: What are the costs and benefits, if any, associated with the proliferation of small generation-only BAs? How do NERC Certification and Reliability Standards encourage or discourage the creation of small generation-only BAs?

Response:

Creating small, generation-only BAs is no more a “magic fix” than requiring BA consolidation and creating more giant BAs. Creating small, generation-only BAs might hold some advantages for existing smaller System Operators because it would place more responsibility on the new System Operators. However, none of the challenges posed by VER integration are eliminated. This approach would only reshuffle the identities of the System Operators who still would face the challenges of VER integration.

Question D.5: The Commission is interested in receiving comments on whether the integration of VERs with small host BAs may limit the benefits derived from geographical diversity and increase integration costs. Should the Commission encourage and/or facilitate the creation of a VER BA, essentially a large area virtual BA primarily designed to accommodate VERs across a broad geographic region? What would be the benefits and costs of creating such a large area entity?

Response:

The creation of a VER BA across a broad geographic region introduces several technical challenges, including, among others:

- Increased complexity of operations planning;
- Ensuring deployment of reserves in regions where there is insufficient transmission across broad region;
• Ramping limitations across seams (e.g., PJM-New York ISO);

• Reactive supply limitations across a wider region (i.e., VARs do not “travel” well).

Additionally, the creation of a large VER BA would not solve any of the underlying problems of the inadequacy of the transmission grid.

If there were a large VER BA, it would be critical to maintain scheduling obligations and generator imbalance obligations so that the burden is not shifted entirely or disproportionately onto load.

**Question D.6:** Would a large area VER BA be capable of capturing the reduced variability of VERs located across a broad and geographically diverse region? What tariff or technical limitations would prevent and/or inhibit the development of a large area VER BA?

**Response:**

As discussed above, a large area VER BA will not be beneficial if there is insufficient transmission. There is nothing preventing VERs from currently integrating into existing BAs if they are willing to fund the transmission to make their generation deliverable. Neither balancing area consolidation/coordination nor VER BA creation is an adequate substitute for needed new transmission infrastructure. Each is intended to reduce the cost to VERs of addressing their inherent variability in short-term operational time frames without looking long-term, across the planning horizon, at the most efficient ways of meeting consumers’ need for affordable, sustainable reliable power. Accordingly, they may mask necessary incentives for VERs or other stakeholders to develop better solutions.
**Question D.7:** What reliability impacts may be associated with the creation of a large area VER BA?

**Response:**

Proponents’ arguments for VER-only BAs appear to assume away real transmission, reactive power, and other operational challenges. In fact, such VER-only BAs would make the integration challenges less transparent and more difficult to address. As discussed above in response to Question D.2, if there is insufficient transmission, the limited deliverability of energy and reserves across the wider footprint can create a serious reliability problem. Moreover, regardless of who was responsible for balancing, the VERs would still have real reactive power, stability, and other reliability impacts in the part of the grid where they are located. They just wouldn’t be as visible to the System Operator required to prevent those problems.

Thus, if a VER BA is formed, the Commission must ensure that local System Operators where the VER is physically located have access to the information they need about the VERs and retain the legal authority to impose and enforce conditions on the interconnection and operation of the VER required to preserve reliability.

There is also a risk that a VER BA could lock up firm transmission needed to serve local load. As noted above, a VER BA could not function without sufficient firm transmission service. If the VER BA were empowered to obtain that transmission service in the thinly served regions where much of the VERs will be built, it could raise questions whether the load-serving entities in the region would be able to retain the transmission they need to meet the long-term needs of their loads as required by Section 217(b)(4) of the Federal Power Act and the NERC standards.
Finally, to the extent such a large area VER BA was created, it is critical that the costs of addressing reliability issues arising from the VERs not be shifted to local load-serving entities.

**Question D.8:** Should a large area VER BA be limited only to VERs? Why or why not?

**Response:**

Limiting a large area VER BA to only VERs would be disastrous. Unless pseudo-ties were established with adjacent BAs containing conventional generating resources with defined ramping capability, the VER-only BA would not be able to comply with NERC Reliability Standards and would impose an unmitigated reliability risk to the interconnection. Frequency and voltage could not be easily controlled in either steady-state or post-disturbance operation.

**Question D.9:** Should the Commission consider establishing specific policies that support the creation of a large area VER BA? If so, why?

**Response:**

NRECA urges the Commission not to do so. The creation of a VER BA is subject to the same network physics as any other resource, and failing to address the physical flows to accommodate a virtual BA could potentially have large reliability impacts. Utilization of the transmission grid to accommodate a large area VER BA could also result in other generation being constrained due to firm transmission commitments for delivery of power from the pool of VERs in the larger BA.

If a region, with the support of its stakeholders, decides to consider such an approach, the Commission should require the BA/region to ensure that there are cost savings to the customers
in the form of reduced ancillary services rates or power costs. Any evaluation of such a proposal must include the costs of necessary transmission infrastructure in the equation.

E. Reserve Products and Ancillary Services

It is possible—even likely—that experience will teach that there is a need for new reserve or other ancillary services to support integration of VERs. Some form of ramping response service, for example, that allows quick-start units and demand response to respond to multi-hour ramping events, could prove to be valuable in some regions at some point in time. However, that need has not yet been demonstrated and certainly has not proven to be universally or generically required. The problems posed by VER integration need to be much better understood, and some solutions experimented with, before generic tariff provisions can be adopted. Proposing generic services before it is even known what types of VERs can be expected to be developed, where they will be located and at what levels of penetration, to serve what loads, would be premature.

The Commission should take counsel from its recent experience in creating conditional firm transmission service, largely at the behest of wind generators. The Commission created the service (denying a comparable service to network service users) but so far there has been little, if any, demand for it. Until it is clear that VER operators will use and pay for new ancillary services needed to integrate their units, it would be a waste of the Commission’s resources to invent and impose them on transmission providers and a waste of consumers’ resources to pay for their implementation.

If the Commission insists on prescribing new reserve or other ancillary services to support VER integration, it is imperative that the costs follow the benefits. It would be manifestly unjust, unreasonable and unduly preferential and discriminatory to visit the costs of
increased regulation and reserves required to support VER integration on all load unless the load thus taxed receives whatever benefit the VER output confers.

**Question E.1:** To what extent do existing reserve products provide System Operators with the most cost-effective means of maintaining reliability during VER ramping events? To what extent would the other reforms discussed herein, if implemented, mitigate the need for additional reforms to existing reserve products without adversely impacting system reliability?

**Response:**

The answer will be very situation specific. As discussed above, the problem of integrating VERs cost effectively often is not a result of the lack of appropriate reserve products, but the lack of appropriate flexible resources or transmission. The system was not planned or designed for the integration of VERs and the long-term investments required to integrate VERs most cost-effectively have not been made. Nor will they be made if the Commission focuses exclusively on spot markets and ancillary services markets. Only if the Commission can effectively address long-range planning and investment issues will the infrastructure be in place that will then allow the Commission to improve system efficiency in the operational time-frames. One cannot give consumers a choice between white bread and wheat bread if no one has planted the wheat field or built a mill.

**Question E.2:** How could System Operators, managing the variability of VER resources, more fully utilize forecasting information and knowledge about existing system conditions to optimize reserve requirement levels?

**Response:**
As already discussed, more accurate forecasting knowledge may allow System Operators to schedule resources more efficiently than otherwise would be the case. However, accurate forecasting will not eliminate the need for system generation output to continue to match load and accommodate the variability of VER generators. Whether or not there is an economic benefit would have to be examined case-by-case, but in any event, more accurate information for System Operators on VER outputs and unit status is most likely to be of benefit to reliability across the board.

**Question E.3:** *Would a following or similar reserve product facilitate the reduction of costs associated with ensuring that sufficient reserve capacity is available to address the uncertainty and variability associated with VERs? If so, what are the ideal characteristics of such a product?*

**Response:**

NRECA is aware that a study was done for ERCOT suggesting a 30-minute ancillary service product. New York ISO and New England ISO have 30-minute products. It is possible that this type of product might achieve certain benefits addressing the uncertainty and variability associated with VERs in some parts of the country; however, such a product may not be valuable in other parts of the country. For this reason, NRECA believes this question is best left to each region to determine with input from all interested stakeholders.

**Question E.4:** *Existing contingency reserve products were designed to be utilized by System Operators to respond to disturbances (i.e., contingency events) due to a loss of supply and to assure system reliability. Does or should the definition of a contingency event include*
extreme VER ramping events? If so, would an additional level of contingency reserves be needed to achieve the same level of system reliability? In responding to this question, please include a proposed definition of “extreme ramping event.”

Response:

The definition of a contingency event should not include extreme VER ramping events. Doing so for purposes of determining the appropriate level of contingency reserves could more than double or triple the amount of contingency reserves that would need to be maintained by a BA, or by an individual transmission provider that is participating in part of a contingency-sharing pool. Thus, without modification of the market rules, those participating in the contingency reserve sharing pool would end up bearing the additional costs of reserves—costs that were caused by the addition of VERs to the system. To the extent that the addition of VERs to the transmission system will cause additional contingency reserves to be needed, it would be appropriate to require the VERs to bear those incremental costs, rather than force others to subsidize them.

The NERC Glossary of Terms defines “contingency” as the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element. NRECA recommends that any additional definitions of “contingency” or “contingency event” should be left to the NERC Standards Authorization request process.

At the same time, an “extreme ramping event” is best defined by the regions, in particular, by reserve sharing groups, which typically define contingency events. For example, the SPP Reserve Sharing Group provides several examples of what constitutes a “contingency operation” (complete loss of a generator rated at 50 MW or greater, partial loss of generating output of 50 MW or more, etc.) in the SPP Criteria. However, these definitions may not be
adequate for other regions. Reserve sharing groups should be encouraged to develop appropriate
definitions for contingency events for extreme ramps, while working with the NERC Standards
Authorization request process.

**Question E.5:** *Should a new category of reserves, that would be similar to contingency reserves, be developed to maintain reliability during VER ramping events in a cost effective manner? If so, what benefit would such reserves provide to System Operators and customers?*

**Response:**

Such a service would at least identify the increased costs caused by VERs’ extreme ramping with the cost of VERs’ output, providing a more accurate price signal than would the inclusion of the incremental reserve costs caused by VERs in the price of all contingency reserves, which would effectively socialize the cost. However, as discussed above in response to E.3, it is unclear that yet another reserve “product” in addition to regulating, spinning and supplemental would enhance reliability or result in customer savings in all parts of the country. As mentioned above, some regions have studied and/or adopted a 30-minute ancillary service product; however, the final decision on whether such a product is appropriate is one that should be made on a regional basis with the input of stakeholders. To the extent a region adopts a new product, the costs of that product must be made transparent and should be assigned appropriately to the cost causers.

**Question E.6:** *Could the expanded use of reserve-sharing programs between BAs contribute to lowering the costs associated with integrating VERs? If so, how?*
Response:

There could be merit to expanded reserve-sharing pools, but the transmission upgrades needed to make the reserves deliverable via firm transmission could be very expensive. The only way expanded use of reserve-sharing programs between BAs could work successfully would be if there was sufficient transmission between the two areas and within them. The Western U.S., for example, has four reserve sharing groups, rather than one, because of existing transmission limits. Otherwise, constraints would prevent reserves from being deliverable across the larger region. This illustrates the need to permit different regions to find their regions’ appropriate solutions to VER integration issues.

The response to this question also depends on whether extreme VER ramping events are considered contingencies. If VER curtailment is included as an extreme ramping event to be covered by reserves, additional reserve requirements may be needed.

Question E.7: Should the ancillary services provisions of the pro forma OATT be revised or new provisions added to expressly address the added reserve capacity necessitated by increased number of VERs? If so, how?

Response:

NRECA believes that the pro forma OATT should not be modified generically to incorporate new ancillary service provisions at this time. Where transmission providers with input from their stakeholders conclude that a new ancillary service provision is necessary, the transmission provider can—and should—file the proposed provision as a deviation that is consistent with or superior to the pro forma OATT.\textsuperscript{23} The Commission then has the opportunity

to evaluate such proposals on a case-by-case basis to ensure that they are just and reasonable
given the circumstances of the specific transmission provider. Where transmission providers do
not expect to experience a significant penetration of VERs, if any, or where they and their
stakeholders conclude that the additional ancillary service does not provide a net benefit, the
transmission provider should not be required to file an OATT amendment.

As discussed above, Westar Energy recently justified a new provision in its OATT to
address the added reserve capacity necessitated by an increased number of off-system VERs.
Specifically, Westar adopted a new Schedule 3A, requiring generators that were seeking to
become part of Westar’s BA, but who serve load outside of the Westar BA or into the SPP
energy imbalance market, to purchase or self-provide an appropriate amount of additional
regulating capacity.24 The Commission then applied existing policy to modify the proposal to
assure that it would not discriminate against generators required to purchase the new service.
The case shows that transmission providers are best situated, in the first instance, to propose
solutions to the problems of integrating VERs and that the Commission, taking into account the
input of stakeholders, is fully competent to adjust such proposals to the extent necessary to
obtain a just and reasonable result.

**Question E.8:** *Are there new sources and/or providers for reserve products (such as
inter-BA pooling arrangements, demand response aggregators and/or storage devices) that can
be used to maintain reliability and lower reserve costs during VER ramping events? Based on
experience, are there characteristics of these new sources of reserves that would positively or

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Reg. 2983 (Jan. 16, 2008), *order on reh’g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), *order on
reh’g*, Order No. 890-C, 74 Fed. Reg. 12,540 (March 19, 2009), *order on clarification*, Order No. 890-D, 74

24 *See Westar Energy*, at PP 3-6.
negatively impact their ability to match the reserve product needs presented by the variability of VERs?

Response:
There certainly may be new sources and/or providers for reserve products in the future. If the Commission makes the costs of VER integration more transparent and assigns them based on cost causation, then VERs will have the incentive to find and develop those resources so they can bring a less costly or more easily integrated bundled product to market.

Question E.9: To what extent are VERs capable of providing reserve services? Should VERs be expected to provide reserve services? What are the tariff and technical barriers that may impede VERs from providing these reserve products?

Response:
At a minimum, all VERs can provide a “regulation down” service. VERs have the opportunity to bid into the marketplace and make a strategic decision based on the value of that service to itself and to the market. However, failure of VERs to meet commitments into which they have entered should be handled on the same basis as failures of other generators to meet like commitments.

Question E.10: To what extent should all resources, and VERs in particular, be required to provide Frequency Response? How would such a requirement be implemented?

Response:
VERs have the opportunity to bid into the marketplace and make a strategic decision based on the value of that service to itself and to the market. However, failure of VERs to meet
commitments into which they have entered should be handled on the same basis as failures of other generators to meet like commitments.

**Question E.11:** Should the Commission revisit the reactive power requirements set forth in Order No. 661? What other requirements, if any, should apply to VERs to ensure that all resources contribute to grid reliability in a manner that is not unduly discriminatory?

**Response:**

The Commission should revisit these reactive power requirements. NRECA opposed the reactive power provisions in Order No. 661, arguing that the Order No. 661 Final Rule imposed unreasonable risks on the reliability of the transmission system and unduly discriminated in favor of wind resources by arbitrarily and capriciously adopting a “necessity” requirement for application of the power factor design criteria. NRECA also argued that Order No. 661 imposed unreasonable risks on the reliability of the system and unduly discriminated in favor of wind investors by arbitrarily and capriciously permitting wind investors to avoid meeting power factor design criteria outside the +/- 95% level to which all other generators are subject.

There is no evident reason why VERs should not have to bear the same responsibility as other generators.

**F. Capacity Markets**

The Commission should take counsel from its own difficult experiences with RTOs’ capacity construct designs. Capacity constructs are very complicated and need to begin with a

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*Id.* at pp. 13-14.
needs analysis. RTOs have experimented with different approaches to capacity construct design. No single size has so far fit all; nor is one that does likely to materialize soon.

**Question F.1:** Should the Commission examine whether capacity rating rules as applied to VERs are unduly discriminatory and investigate whether standard rules may be appropriate?

**Response:**

Capacity is generally rated according to a unit’s ability to meet peak load requirements. This should be the same for all generators including VERs. The Commission should make no change to capacity rating requirements at this time. Both the IVGTF and the UWIG are currently reviewing this issue. There will be time enough for the Commission to address it, if necessary, after the industry has completed its analysis.

**Question F.2:** Do obligations for capacity resources to offer into the day-ahead market unfairly discriminate against VERs? If so, how?

**Response:**

Not all RTOs have capacity constructs in place, so this issue will have to be addressed on a regional basis, with local knowledge and needs in mind. However, in principle, if VERs participate in a capacity market, they should be required to provide the service that they have committed to provide and for which they are being compensated, including, if required of other energy resources, and if deemed appropriate by the RTO, requiring VERs to have a “must offer” requirement in the day-ahead energy market. This will help ensure that load is obtaining the capacity for which they are paying.
**Question F.3:** As more VERs choose to become capacity resources, will existing processes for compensating capacity services adequately compensate all generating resources that may be needed for reliability services? If not, what reforms may be necessary? For instance, should the Commission examine formation of forward ancillary services capacity markets?

**Response:**

It is likely that existing processes for compensating capacity services may not capture the costs of all the generation needed to add additional reserves or back-down capability needed to preserve reliability while accommodating VERs. Mechanisms for capturing—and distributing—such costs should be developed on a regional basis with the input of interested stakeholders.

**Question F.4:** Should capacity markets incorporate a goal of ensuring sufficient generation flexibility to accommodate ramping events in addition to the goal of ensuring sufficient generation to meet peak demand?

**Response:**

NRECA interprets the question to refer to capacity markets or some other form of capacity construct in “organized” markets. Of course, such markets do not exist in some areas of the country where VERs are likely to have a significant impact on system planning and operation. Even where such markets do exist, NRECA does not believe that accommodating ramping events is a goal that should be imposed on capacity constructs. Such an approach would inappropriately put the burden of ensuring adequate generation flexibility on all load-serving entities and not on the VERs whose inherent variability makes the additional flexibility
necessary. The obligation to ensure sufficient flexibility and the burden to pay for it should be allocated according to cost causation principles.

G. Real-time Adjustments;

Question G.1: How have redispatch and curtailment practices changed with increased numbers of VERs? Are there any shortcomings of current redispatch and curtailment practices?

Response:

Some of NRECA’s members are concerned that the current redispatch and curtailment protocols will not result in economic solutions when VERs—particularly wind—are introduced into the equation. The predictability and sustainability of wind energy is not at the point or level which allows for smooth and manageable changes in dispatching without supplemental (and mostly out-of-merit dispatch) resources. Until either energy storage on a mass scale is available or there is another way to “smooth out” the wind energy, the industry should consider the impact of using supplemental resources, including identifying the additional costs associated with them, so they can be incorporated into the “economic” dispatch.

Some of NRECA’s members in the West believe that redispatch and curtailments within the inter-mountain West are generally functioning well, notwithstanding the advent of VERs. The current system in the West of contract path transmission commitment coupled with effective use of phase shifting transformers, including compensation of the transformer owners, has reduced the need for frequent curtailments. The Unscheduled Flow Mitigation procedures complement this approach well. However, VER penetration levels could reach a “tipping point” where these techniques are no longer sufficient.
Question G.2: Do existing redispatch and curtailment processes unduly discriminate against VERs? If so, how should they be modified?

Response:

NRECA does not believe that existing redispatch and curtailment processes unduly discriminate against VERs. The purpose of these processes is to provide an assurance of relief across an element or set of elements in the transmission system that may be in danger of violating a system operating limit or interconnected reliability operating limit while at the same time preserving system reliability—which needs to remain paramount. Some VERs, because of their intermittency, cannot provide relief across a necessary element with any degree of certainty. If the redispatch and curtailment protocols were modified to permit the use of VERs, then other generation sources would likely be called upon to an even greater extent to provide congestion relief, diminishing their participation in the market. It may appear that VERs are discriminated against in minimum generation events if only the hours in which VERs are curtailed are taken into account. However, when the entire operating day is taken into account, it becomes apparent that VER curtailment may have been the only option available to the operator to preserve reliability over several dispatch periods (or the whole day) due to the lack of flexibility available in the generation portfolio as a whole. This is because other generators contributing to the minimum generation event in one dispatch cycle were forecasted to be needed later in the dispatch cycle, when load picked up (usually in the morning). This is typically when VERS are unavailable. In these circumstances, VER curtailment is necessary in order to assure reliability throughout the day. More flexibility in the overall system would help alleviate this problem, as would the addition of some type of storage in concert with the operation and dispatch of VERs.
**Question G.3:** Some RTOs/ISOs will redisplay VERs based on required economic bids. Should all RTOs/ISOs implement similar practices? Why or why not?

**Response:**

VERs must remain subject to the same N-1 security constraints that cause other generators to be redisplayed. Doing otherwise will simply provide preference to VERs. Reliability should be paramount and economics should not take priority when assessing the reliability of the system.

As more VERs are integrated into the transmission grid, System Operators will begin to learn more about reliability issues that wind creates (e.g., frequency response, voltage control and minimum issues) and the challenges they present. The Commission should be responsive to proposals that allow the Reliability Coordinator to simply redisplay/curtail transactions on the system, not make it more complex with the addition of an “economic” consideration. Any benefit from “economic curtailment/redisplay” would be easily lost if a blackout were to occur due to a more complex redisplay/curtailment process.

As discussed above, the Commission should not undermine long-run economic efficiency or reliability in an overly myopic effort to maximize efficiency in the spot markets or in short-term dispatch decisions. There will be many instances in which the most economic efficient decision for the next 5 minutes will undermine the efficiency and reliability of the system five minutes, one hour, eight hours, or even years later. The grid is a highly complex machine that has to be run in the most efficient manner possible over the long-term. A chess player who looks at only the next move will lose the game, but if the Commission looks only at the next move in this industry, it is the consumers and the economy as a whole that lose.
Question G.4: Should transmission loading relief protocols be altered to allow reliability coordinators in non-RTO/ISO regions to consider economic merit when considering curtailing VERs? If so, how? Similarly, should redispatch and curtailment protocols in non-RTOs/ISOs be revised to consider economic merit for all resources? If so, how?

Response:

In one respect, economics is already considered in the TLR protocols. Firmness of transmission service is a characteristic of transmission service that is paid for. TLR protocols generally cut transactions from the least firm to the most firm. It is the responsibility of the Reliability Coordinator to make sure that the load is reliably served without violating Interconnection Reliability Operating Limits (“IROLs”) and System Operating Limits (“SOLs”) in real-time operations. This is not, and should not be, a decision based on economic factors beyond those already built into the transmission service protocols.

Economy should never be valued on par with reliability. Curtailments should only be allowed for reliability purposes. A worst-case scenario could occur if reliability becomes secondary to economic dispatch: for instance, if an intermediate generator that would otherwise have been online at less than full output were taken offline due to an economic curtailment. The curtailment inherently degrades the overall reliability of the power system, especially when that curtailment was in lieu of a variable resource. Additionally, the owner of the generator that is subject to curtailment may have to put another unit online to maintain its reserve requirements.

As noted in response to question G.3., the Commission should not focus excessively on maximizing short-run efficiency. The Commission must look at the long-term operation of the system over minutes, hours, days, and years, to ensure that its decisions create the right long-term operational and investment decisions to meet consumers’ energy needs. The Commission’s
goal should not be just the lowest cost energy in the next five minutes; it should also be the lowest cost power over the planning horizon.

**Question G.5**: *Is the increasing number of VERs affecting operational issues that arise during minimum generation events? Are there ways to minimize curtailments during a minimum generation event? Should conventional base-load resources be offered incentives to lower their minimum operating levels or even shut down during minimum generation events to reflect an economically efficient dispatch of resources? If so, what would be the benefits and costs of doing so?*

**Response:**

The penetration of VERs has a large impact on minimum generation events. Base-loaded facilities such as coal and nuclear plants are forced to reduce their output to minimum output levels to accommodate VERs in the off-peak hours. These assets are also the same units that have Automatic Generation Control (“AGC”) to respond to the variations in frequency that can be caused by the high concentration of VERs. If these units are forced offline due to minimum generation events, they will not have the ability to provide low-cost power and needed ancillary services during upcoming peak periods, because of the relatively long start and ramp periods that characterize base load generation. This will ultimately result in increased costs for the majority of the hours in which minimum generation events do not occur.

Encouraging or requiring conventional base-load resources to shut down or reduce output to reflect a purported economically efficient dispatch of resources also could have the potential to unnecessarily increase wear and tear on intermediate and peaking units. It is very difficult to quantify the cost of such incremental stresses on generating units; however, the costs of these
dispatch decisions need to be taken into consideration. As discussed in response to the prior two questions, the Commission’s goal should not be just the lowest cost energy in the next five minutes, it should also be the lowest cost power over the planning horizon.

Finally, a system that, in essence, dispatches VERs first could inadvertently lead to NERC sanctions against BAs and generation and transmission service providers for failing to respond promptly to rapidly changing generation output.

**Question G.6:** To what extent do VERs have the capability to respond to specific dispatch instructions? Are there any advanced technologies that could be adopted by VERs to control output to match system needs more effectively? Should incentives be put into place for VERs that can respond to dispatch instructions? If so, what types of incentives would be appropriate?

**Response:**

NRECA believes that the VER industry is working on ways to make VERs more responsive to dispatch instructions. NRECA believes additional incentives are unnecessary. Incentives already exist, and generators have the ability to offer bid-based ancillary services in RTO markets or to offer the ancillary services at market-based rates in non-RTO regions. VERs can develop technologies that create additional value in the ancillary services markets, and they will be rewarded under existing market and tariff structures. The addition of additional incentives would inject bias into this regime.

**IV. CONCLUSION**

There is no reason to believe that there is pervasive discrimination against VER operators, much less that generic remedies are required. NRECA urges the Commission to
permit the industry to develop the fact-based understanding of the challenges posed by the integration of VERs that is required to frame the attendant regulatory issues. The Commission should refrain from attempting to fashion rules of general applicability until it has gained experience with the issues raised by VER integration in the context of its review of concrete proposals by industry participants. The industry’s work to identify problems posed by VER integration and workable solutions to those problems is well underway, but there is much to do before a workable consensus about the technical issues involved emerges to form a basis for thoughtful analysis of any needed changes in the Commission’s regulation of interconnection of VERs and delivery of their output.

Respectfully submitted,

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

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April 12, 2010
Role of Lawyers in NERC Audits and Compliance Violation Investigations
EBA Reliability Primer for Lawyers and Energy Professionals

April 28, 2010

Role of Lawyers in NERC Audits and Compliance Violation Investigations
Panelists

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  - Moderator
- **Rebecca J. Michael**, Assistant General Counsel, NERC
- **Mark Bennett**, Vice President of Regulatory Compliance, Competitive Power Ventures, Inc.
- **Steve Huntoon**, Senior Attorney, Florida Power & Light Company
- **Craig W. Silverstein**, Principal, Miller, Balis & O’Neil, PC
Format
Overview of FERC Enforcement of Mandatory Reliability Standards

Reliability Enforcement Orders*
*Note: These are initial orders, so be sure to check dockets for any subsequent orders.

- **Enforcement at the Regional and National Levels**

- **Enforcement at the Federal Level**
  - Director Orders Staying Notices of Penalty in Docket Nos. NP10-18-000, NP10-20-000, NP10-25-000, and NP10-32 to 36-000 (Orders Staying Notices of Penalty).
Overview of FERC Enforcement of Mandatory Reliability Standards

General Enforcement Orders

- *Submissions to the Commission upon Staff Intention to Seek an Order to Show Cause*, Order No. 711, FERC Stats. & Regs. ¶ 31,279 (2008).
- *Order Authorizing Secretary to Issue Staff’s Preliminary Notice of Violations*, 129 FERC ¶ 61,247 (2009), rehearing pending.
FERC’s Enforcement Role

- Recognizes that REs and NERC are the first line of defense.
- Implicates original, concurrent, and appellate jurisdiction.
- Involves the close working relationship between FERC’s Office of Enforcement and Office of Electric Reliability – with the advice and counsel of the Office of General Counsel.
NERC Program Areas

• Compliance Enforcement
• Compliance Operations
• Critical Infrastructure Protection
• Operations and Engineering
• Reliability Assessment and Performance Analysis
• Standards
• Government Relations
• Human Resources
• Finance and Accounting
• Information Technology
• Legal and Regulatory
NERC 2010 Organizational Changes (1)

- **Compliance Operations**
  - Oversees the compliance activities of the eight Regional Entities
  - Conducts the Regional Entity Audit Program
  - Promotes transparency, consistency, auditor training and a culture of compliance among the regions and registered entities

- **Compliance Enforcement**
  - Oversees all enforcement actions processed by NERC and the Regional Entities
  - Oversees all mitigation actions processed by NERC and the Regional Entities
  - Analysis and tracking
NERC 2010 Organizational Changes (2)

- **Operations and Engineering**
  - Event analysis and Investigations
  - Situational awareness
  - Training and Educational Opportunities
  - Publication and tracking of reliability lessons learned
  - System Analysis and Reliability Initiatives

- **Critical Infrastructure Protection**
  - Infrastructure security
  - Critical infrastructure protection
  - High impact, low frequency risks to the bulk power system
Compliance Programs Must Address Technical, Operational and Legal Issues

- Fundamental Components for Collaboration—WHO is doing WHAT and WHEN—With OVERSIGHT

- Reliability compliance depends upon:
  - Interpreting and understanding standard requirements (Expertise: technical/legal)
  - Establishing roles and responsibilities for required actions/documentation (Expertise: facility operators/compliance manager)
  - Properly documenting adequate procedures and required actions/”triggering events” (Expertise: operational/compliance manager/legal)
  - Overseeing self-report obligation/audit prep (Expertise: operators/compliance manager/legal)
  - Addressing alleged violations, mitigation plans and settlements (Expertise: operators/compliance manager/legal)
Compliance Culture: Communication, Collaboration, and Engagement

  - Background and Overview
  - Roles and Responsibilities—link ongoing operational activities to reliability requirements
  - Designation of on-site compliance manager—responds to monitoring requests/lead audit prep (potential legal issues)
  - Identification of Subject Matter Experts/”Standards Owners”
  - Orientation and Training
  - Self-Assessments/Readiness Reviews—ongoing effort to improve (with technical support)
  - Oversight: reporting and documentation obligations (potential legal issues)
Before It Happens

• Compliance stakes are enormous.
• Hopefully your organization has had an effective compliance program and been in full compliance -- *before* receiving notice of an audit or investigation.
• Hopefully your organization has observed the *New York Times* front page rule.
• A reliability audit or investigation is the equivalent of a major rate case and should be organized and staffed accordingly with affected business units, compliance organization and counsel.
• Counsel should be familiar with all substantive and procedural aspects of the audit/investigation.
“Discovery”

- Counsel should be involved with all aspects of document retention and production.
- Reliability Standard Audit Worksheet (RSAWs) responses are akin to data responses in a Commission proceeding and should receive appropriate attention from counsel.
- Major investigation will involve intensive discovery, including depositions.
- Objections (including privilege assertions) risk losing penalty mitigation from full cooperation.
SME Preparation for the Audit

• SME preparation should be handled akin to witness testimony in a major rate case.
• Review of RSAW responses, data request responses, entity’s responses to the pre-audit survey questions, and illustrative auditor team opening slides from a prior audit.
• Ask SME to notify compliance organization/counsel of any concerns with any of these materials.
• Absent overriding considerations, SME should bring to the audit interview only copies of RSAW responses and data request responses.
Guidelines for SMEs at the Audit (1)

• Tell the truth.
• Answer the question.
• Answer only the question -- there is no need to fill pauses in the questioning.
• If you don’t understand the question ask for clarification.
• Be prepared to provide examples of what you describe.
• If you don’t know the answer say you don’t know – don’t guess or speculate.
• Minimize casual conversations with the auditors.
Guidelines for SMEs at the Audit (2)

• Don’t be distracted by a past answer – if you have a concern jot a note to yourself and raise at a break.
• Don’t worry.
• Don’t try to please the questioner.
• Don’t overstate our capabilities – we may be asked to substantiate all claims.
• Don’t leave your papers around.
• Don’t take any risks with your work
Role of Counsel at the Audit

- Present at all interviews.
- Our philosophy for counsel at interviews – largely passive.
- Review all written responses to requests.
- Assist in development of attestations.
- Identify potential weaknesses for business units to address as quickly as possible.
- Research alleged possible violations and review with audit team.
Post Audit Activities

• Review of Audit Report (Draft and Final)
• Participation in Risk Assessments
• Development of Mitigation Plans
• Settlement Negotiations
Don’t Let Your Guard Down If There Is No Audit!

• Lawyers can continue to push compliance – there is no window for an organization to exhale and be less diligent about full compliance at any time
• Review and distribute information about other violations (settlements, FERC orders, RE issuances, etc.)
• Make sure that your organization’s compliance plan touches every affected standard and that your organization is actually following its own ICP documentation
• Lawyers make great pests! Internal mock activities and spot checks should be used
Potential Legal Issues under New Regulatory Framework (1)

- FERC has authority over ERO, yet must give “due weight” to industry “technical expertise” in standards development.

- Consistency/due process
  - NERC to maintain a “single, uniform compliance monitoring and enforcement program…to ensure the consistency and fairness of the processes used to determine regional entity compliance and noncompliance, and the application of penalties and sanctions.” (Rules of Procedure 402.2.2)
  - “We intend the enforcement audit program to be a single program applicable to both the ERO and Regional Entities unless there is a compelling reason for a difference…Such programs must not vary significantly from region to region unless good cause is shown for such differences.” (FERC Order 672 at P 464)
Potential Legal Issues under New Regulatory Framework (2)

• “Repeat Offender” exposure for violations inherited by company merger or acquisition (Interpretation of Sanction Guidelines §4.3 “Adjustment Factors”)
• Registration decisions based on expansive views of “BES” and “Material Impact”
• Self-reporting “minor” violations—legal gray areas
• Legal issues arising from operational events:
  o Reporting obligations for “misoperations” (PRC-004), “disturbances” (EOP-004) and relay/equipment failures that “reduce system reliability” (PRC-001)
  o Obligation to comply with “reliability directives” (IRO-001/TOP-001)
  o Documentation format issues, e.g., “summary” of maintenance/testing procedures (PRC-005)
  o Auditor requests for pre-June 2007 documentation to establish compliance with interval testing period under PRC-005
Questions?

Discussion

Thank you!
Cyber Security Legislation for the Electric Utility Industry – What are the key issues?
ERO Compliance and Enforcement – Lessons Learned from the Enforcers
Consistency in the Electric Reliability Organization Compliance Program

Mike Moon
Director of Compliance Operations

Energy Bar Association
April 28, 2010
Revisions to:
- Delegation Agreements (RDAs),
- Rules of Procedure (RoP)
- Compliance Monitoring and Enforcement Program (CMEP)

New developments at NERC
Compliance Operations
Consistency Discussions
Revisions to RDAs, RoP & CMEP

- Numerous changes proposed or under consideration
- Current RDAs, RoP and CMEP extended until May 2011
- Changes coming from:
  - Internal review of CMEP and lessons learned to date
  - Stakeholder comments to NERC Three-Year Assessment
  - Crowe Horwath audit reports
Revisions to RDAs, RoP & CMEP

- Revisions are intended to define roles/responsibilities, drive consistency, and promote efficiency.

- Clear Roles and Responsibilities:
  - Define NERC oversight of Regional Entities
  - Directives Process
  - Dispute resolution
  - Clear roles in Certification, Registration, Reliability Assessments, Event Analysis, Education and Training, Situational Awareness
  - Clear roles for audit observers
Revisions to RDAs, RoP & CMEP

Consistency:
- Single CMEP
- Common intake point in enforcement process ("Possible Violations")
- Guidance, directives, lessons learned

Efficiency:
- Performance Metrics
- Reconcile differences in CMEP and Practice (e.g., risk based approach to setting audit scope)
- Clearer end point to enforcement process
New developments at NERC

Key Drivers

- Rebalance NERC
  - Compliance
  - Reliability improvement through learning and risk management

- Build ERO enterprise
  - NERC
  - Regions
  - Stakeholders
New developments at NERC

NERC Vision

- Leading expert organization in bulk power system reliability
- Reliability-learning industry
- Strong culture of compliance
- Strong enforcement
- Trusted leader and advocate for reliability
NERC Priorities

1) **Productivity.** Producing results by making sure NERC is aligned and organized correctly, and that its people know their own roles as well as see the ‘big picture.’

2) **Transparency** of Information. NERC will provide a better set of tools to provide the information stakeholders need to be reliable and compliant.

3) **Trust.** Enhance trust among NERC, regions, stakeholders, and regulatory authorities. All parties should work together to improve reliability.

4) **Incent compliance.** Set the right incentives to encourage compliance excellence and reliability improvement.
New developments at NERC

Risk-based CMEP approaches and actions

- Treatment and record proportional to seriousness
  - “Omnibus” Notice of Penalty filing October 2009
  - “Disposition document” based CME processing

- Risk drivers for monitoring (audits) and enforcement
Contributions Needed from Industry (G. Cauley; February 15, 2010)

- Bright-line criteria for CIP critical assets
- Performance-based standards
- Expedite development of priority standards
- Strive for compliance excellence ("lean in")
- Engage in event analysis and lessons learned
- Promote/support risk-based, learning approach
Compliance Operations

- **Primary Effort:**
  Help make the Regional Entities successful

- **Critical Documents:**
  - Annual CMEP Report
  - Annual CMEP Implementation Plan and Actively Monitored List
  - Reliability Standards Audit Worksheet
  - Audit Observation reports
  - Compliance Registry

- **Key initiatives:**
  - Publish lessons learned/best practices to support consistency
  - Develop Compliance Application Notices
  - Provided formal feedback loop to Standards Department
  - Assist the regions during audits
  - Leverage experts in the regions and industry to improve training
  - Draft an ERO culture of compliance white paper
Compliance Operations

- **Interfaces:** Process for outreach to gather, review, and publish Compliance Application Notices
  - Feedback mechanisms between Compliance and Standards Departments

- **Outreach:** Identify, develop, and publish relevant and timely compliance guidance, Compliance Applications Notices, to assist:
  - Regional Entities with the performance of audits
  - Registered Entities with compliance regarding NERC Reliability Standards

- **Compliance Application Notices:**
  - Best Practices (BP)
  - Lessons Learned (LL)
  - Compliance Applicability (CA)
Initial deliverables under review identified from priority or prior requests:

- LL, 3 under review, EOP-005; PRC-005; Audit Planning
- BP, 3 under review, on management; sampling, audit support
- CA, 4 under review, IRO-006; IRO-004; INT-004; TOP-003

Future deliverables from various sources; 2009 audit observation reports yielded 71 items so far, still undergoing analysis.

Publishing

- Compliance Application Notices, posted as approved
- Quarterly Compliance Reports will list LL, BP, CA

Incorporation into training, tools (e.g., RSAWs), feedback to standards program
Duplication not sifted from initial analysis. Other identified Compliance Applications from findings of 2009 audit observation reports include Sampling, Findings, Procedural, Training, Observers, Scope, and Registration.
Consistency Discussions

- Capture mechanisms for areas of inconsistency
- Is there a particular process that can be talked about and fast tracked for clean up
- Update on MRRE effort
- Training of auditors
- Specific examples of consistency issues
Consistency Discussion

Capture Mechanisms and Means

- NERC Audit Observation reports
- Regional Entity Audit Reports
- Registered Entity Feedback forms
- NERC Stakeholder Committees (MRC, SC, CCC)
- Industry Trade Associations and Forums
Standards and Compliance are intimately intertwined.

Consistency is a collaborative effort and we’ve come along way, but we still have far to go.

We need the industry to help identify consistency issues and participate in standards revisions on an accelerated scale.
For questions about the Compliance Monitoring and Enforcement Program and/or process, please contact:

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Achieving Fairness, Transparency, and Consistency in the Enforcement Process

Energy Bar Association
April 28, 2010

Sara E. Patrick
Regulatory Affairs, Counsel, and Enforcement Director
Midwest Reliability Organization
The focus and primary objective of NERC’s compliance program is to improve the reliability of the bulk power system in North America by fairly and consistently enforcing compliance with NERC standards.
Regional Responsibilities

• To enforce Reliability Standards on Owners, Operators, and Users of the Bulk Power System within Regional boundaries in order to ensure system reliability is maintained and corrective actions are taken when deficiencies are discovered.

• To provide an open and fair process in conducting its activities as described in the Uniform Compliance Monitoring and Enforcement Program (CMEP).

• To be independent and non discriminatory in carrying out responsibilities under the CMEP.
Don’t Confuse Enforcement with Compliance

- Compliance: the burden is on the Registered Entity to provide sufficient evidence to be reasonably assured of compliance
- Enforcement: the burden is on the Region to reach higher level of assurance—closer to “absolute assurance”
  - A second, independent review of “findings” by enforcement staff
  - Determine facts and circumstances to validate severity of violation(s)
  - Issue Notice of Alleged Violation and Proposed Penalty or Sanction
  - If contested:
    - Right to a hearing at the Regional-level
    - Right to an appeal at ERO-level
    - May contest at the Regulatory level and then court
Segregating Compliance from Enforcement

**Reaching Absolute Assurance = Enforcement Action**

**ENFORCEMENT**

- Absolute Assurance
  - Investigations and Findings
  - Notices [PNAVs, NAVAPS, NOCVs]
  - Settlements and Hearings
  - Key considerations: harm, compliance culture, intent, compliance history, sufficiency/quality of evidence

**COMPLIANCE**

- Reasonable Assurance
  - Findings (Potential Wrong Doing)
    - Sufficiency
    - Relevance
    - Appropriateness ("reliability")
    - Overall Assessment of Evidence
    - Key considerations: risk, materiality, strength of internal (compliance) controls, applicability, legal context of Section 215 and provincial agreements

**CMEP Due Process**

**GAO STANDARDS**

1. Planning
2. Field Work
3. Reporting

**No Presumption of Wrong Doing**
Importance of Mitigation Efforts

• Penalty imposed for a violation of a Reliability Standard
  • “shall bear a reasonable relation to the seriousness of the violation” AND
  • “shall take into consideration the efforts of the Registered Entity to remedy the violation in a timely manner.”
    • Excerpted from Federal Power Act, 16 U.S.C. § 824o(e)(6)
Mitigation Plan

- Mitigation Plan
  - Required for all items of non-compliance regardless of discovery method
  - Regional staff tracks all mitigation plans to completion
  - Registered Entity will certify Mitigation Plan completion
  - Supporting evidence is provided to Region to verify Mitigation Plan completion
  - Region provides notice of verification of Mitigation Plan completion
    - If Region cannot verify Mitigation Plan completion, there may be additional enforcement action
Settlement Process

- Available at any time prior to filing of Notice of Confirmed Violation
- Includes facts and statements by both parties
- Remedies are considered with respect to financial penalties
  - Regions look to Registered Entities to offer proposed remedy(ies)
  - Offset proposed financial penalty, not a dollar for dollar offset or “proxy”
  - Must be clearly above and beyond mitigation efforts
  - MRO may reject remedies as not being effective in improving reliability
- Requires approval by Regional BOD (in certain Regions), NERC and FERC
Differences in Regional Enforcement

• Each Region has its own governance, staff, and organization
• Regions separate compliance efforts from enforcement, to provide independence—some have separate departments, all conduct separate reviews of possible violations
• All follow CMEP (few Regional variances) and have established procedures to implement the CMEP
• Procedures may vary, but the outcomes are similar
  • Much like industry efforts to comply—what works for one entity may not work for another
Maintaining Fairness

- **Quantitative Factors**
  - Risk to the bulk power system
  - Entity size
  - Repeat infractions and prior warnings
  - Time horizon (real-time / planning etc.)

- **Qualitative Factors**
  - Self-reporting
  - Quality of compliance program
  - Deliberate violations
  - Level of Cooperation
  - Documentation vs Failure to Perform

- **Enforcement action should correspond to the severity of the violation, impact to BES, actual harm caused/risk posed**
Creating Transparency

- Omnibus Filing
  - FERC Order, November 13, 2009
  - 564 violations in one filing
- NERC posting Compliance Analysis Reports
  - Analysis of Top Violated Standards
  - PRC-005-1, CIP-004-1, FAC-008-1 and FAC-009-1
- Abbreviated Notice of Penalty
  - FERC Order, October 26, 2009
  - Scalable Record
  - Disposition Document for all violations
Achieving Consistency

- Facts and circumstances are almost always unique
  - Need to be careful not to confuse consistency with judgment required to make determinations
    - Example: Not all Registered Entities demonstrate compliance to Reliability Standards exactly the same; therefore, Region staff must exercise judgment in making a determination of a finding or not a finding

- Regions need to know if similar violations are being processed by another Region

- Regions rely on NERC Sanction Guidelines in calculating penalties

- Regional Working Group meets regularly with NERC staff to discuss challenges, concerns, and consistency
• Demonstrate a commitment to compliance and the implementation of a corporate “culture of compliance”
  • Conduct periodic self-assessments to determine compliance with Standards
  • Understand root cause of any identified instances of non-compliance
  • Promptly mitigate any risk and resolve non-compliance
  • Document the concern and resolution
  • Provide education and training to avoid future instances of non-compliance
Developing and Implementing Compliance Culture

- FERC Policy Statement On Compliance:
  (October 16, 2008)
  - It is in the public interest to encourage companies to develop a rigorous compliance program (this should help minimize potential violations, and if violation is discovered can give a significant weight when determining a penalty)

- Identified 4 Key Factors of Effective Compliance
  - Role of Senior Management in fostering compliance
  - Effective preventive measures to ensure compliance
  - Prompt detection, cessation, and reporting of violations
  - Remediation efforts
Compliance Controls
“Culture of Compliance”

- Significant mitigating factor for audit risk and enforcement actions
- How can you demonstrate it?
  - Examples:
    - Have a written program
    - Senior management engagement early and often [MRO likes to see a very senior executive engaged in the audit] and review of draft audit reports
    - Documentation readily available (ability to get information quickly)
    - Understanding of how to demonstrate compliance
    - Single points of contact
    - Ongoing compliance training, including the field staff
    - Cooperation [flexibility for change to schedule, provide additional information, etc.]
    - Continuous and tested [internal self assessments, self reporting, training]
    - Complete the internal compliance control survey
    - Bottom line: Effective compliance programs Detect, Report, and Correct [refer to Commission guidance, US sentencing guidelines, NERC sanction guidelines]
In other words, effective compliance programs systematically detect, report, correct and prevent violations and mitigate risks to reliability.
Questions

• For questions about the Compliance Monitoring and Enforcement Program and/or process, please contact:

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Implementation of the CMEP: Sharing A Regional Entity’s Experiences

Stanley E. Kopman
Assistant Vice President of Compliance
Northeast Power Coordinating Council
EBA Reliability Primer– April 28, 2010
Overview

- Overall Experiences
- Specific Examples
- Continuing Efforts
Overall Experiences

- Progress
- Adaptation
- Continued Outreach
Progress

- Establishment of Effective Relationships With Registered Entities
- Enhanced Documentation, Procedures, Processes and Recordkeeping
- Increased Interaction with NERC, FERC and Canadian Regulatory Authorities
- Distribution of Lessons Learned.
Adaptation

- Feedback from Registered Entities
- Exchange of Information Among Regional Entities
- NERC Directives and Bulletins
- FERC Orders and Policy Statements
Continued Outreach

- Continuous Interaction with Registered Entities
- Work Closely with NERC and Regulatory Authorities
- Strive for Consistency
Specific Examples

- Registration
- Compliance Audit Program
- Enforcement
- Procedures, Documentation and Tools
Registration

- Registered Entity Surveys
- Registered Entity Asset Listing
- MRRE Project and Increasing Use of JRO
Compliance Audit Program

- Experienced Audit Team Members
- Pre Audit Preparation
- Interaction with Audited Entity
- Presentation of Evidence
Enforcement

- Timely Distribution of Applicable Notices
- Thorough Enforcement Investigation
- Evolution of Settlement Process
- Comprehensive Mitigation Plans
Procedures, Documentation and Tools

- Comprehensive Set of Procedures
- Enhanced Recordkeeping and Document Retention
- Enhancement of On-line Applications
- Development of Performance Measures
Continuing Efforts

- Single ERO Enterprise
- Increasing Feedback of Lessons Learned
- Continuous Interaction with all CMEP Participants – Registered Entities, Regional Entities, NERC, Regulatory Authorities
BIOGRAPHIES
Steven T. Naumann

Steven T. Naumann is Vice President – Wholesale Market Development at Exelon Corporation. In addition to his responsibilities for development of markets nationwide and for reliability issues, he is one of a team of Exelon executives involved in development of RTO policy, including integration of ComEd into PJM. Mr. Naumann joined Commonwealth Edison Co. following service as an officer in the United States Air Force. During his over 35 years at Exelon and Commonwealth Edison, Mr. Naumann has held a number of engineering, managerial and executive positions responsible for the planning, operation, and security of the electric delivery system. Prior to assuming his current position, Mr. Naumann was Vice President – Transmission Services for ComEd. He has participated on a number of NERC and MAIN committees, work groups and task forces, including serving as Vice Chairman of MAIN from 2004-2005. Mr. Naumann has served on NERC Member Representatives Committee, including Vice Chairman and Chairman. He has testified before Congress, the Federal Energy Regulatory Commission, the Illinois Commerce Commission and the Public Service Commission of Wisconsin.

Mr. Naumann received a Bachelor of Science degree in Electric Power Engineering in 1971 and a Master of Engineering degree in Electric Power Engineering in 1972, both from Rensselaer Polytechnic Institute in Troy, New York. He later received a J.D. degree from Chicago-Kent College of Law in 1988. Mr. Naumann is a Registered Professional Engineer in the State of Illinois and is licensed to practice law in Illinois.
DALE A. LANDGREN
Vice President and Chief Strategic Officer
American Transmission Company

Dale Landgren joined American Transmission Co. in June 2000, as Vice President and Chief Strategic Officer, prior to that company’s startup on January 1, 2001. He is currently responsible for, federal and regional relations and policy, customer relations, interconnection services and system planning. He also serves on the ATC Reliability and Compliance Executive Steering Committee.

Landgren joined Wisconsin Electric in 1973. He was named director of the Business Planning Department in 1993 and became an officer of the company in 1997.

Landgren has been a member of the Board of Directors of the Midwest Reliability Organization (MRO) since 2006 and was elected chairman of that Board for 2009-2010. In that role he is a non-voting member of the NERC Member Representatives Committee (MRC). He serves on the EEI Energy Delivery Policy Executive Advisory Committee and EEI’s Reliability Executive Advisory Committee. Landgren also serves on the Eastern Interconnection Planning Collaborative (EIPC) Executive Committee.

Landgren was a significant player in the establishment of the Midwest ISO. He served on the Management Council of the Midwest ISO from 1996 to 1998 and from 1998 to 2002 on the Transmission Owners Group where he also served as chair of that group from 2001-2002. He was Vice Chair of the MISO Advisory Committee from 2001-2002.

Landgren received his bachelor of science - electric engineering degree (magna cum laude) from Marquette University in 1971 and was elected to TAU BETA PI in 1970. He received a master’s degree in economics from the University of Chicago in 1972 where he attended on a National Science Foundation fellowship.
Bruce L. Richardson

Bruce L. Richardson is a partner in the Global Transactions Practice Group at King & Spalding LLP. Mr. Richardson focuses his practice on energy law. He represents and advises independent power producers, merchant transmission developers, electric power marketers, energy asset managers, private equity firms involved in the energy sector, and generation-owning industrial companies in connection with a broad range of transactional issues, administrative litigation, regulatory matters, and project issues. Transactional matters include electric power contracts, interconnection, and mergers and acquisitions. Regulatory matters include issues arising under the Federal Power Act, the Public Utility Regulatory Policies Act of 1978, the Public Utility Holding Company Act of 2005, and the Energy Policy Act of 2005. Project experience includes support of development, operation, and management of generation projects in numerous states.

Representative Experience

Regulatory and Litigation Practice

- **Regulatory Compliance.** Advice to clients on regulatory compliance matters, including Federal Energy Regulatory Commission (“FERC”) exempt wholesale generator activities, electronic quarterly report compliance, separation of functions, and FERC Standards of Conduct requirements. Representation of clients before FERC on regulatory compliance, including Standards of Conduct and open-access transmission policies.

- **Regulatory Policy.** Draft comments in connection with federal and state policy statements and rulemakings. Appear on behalf of clients in connection with development of regulatory policy. Participate in litigated proceedings in the formation of regulatory policy.

- **Regulatory Representation.** Represent clients in connection with utility restructuring, affiliated utility issues, regional transmission organizations, reliability procedures, transmission access and pricing, ancillary services, market-based rate proposals, power supply purchases and sales, retail wheeling, independent power production, wholesale electric customer disputes, and interconnection matters.

- **Transaction Support.** Regularly assist clients in obtaining regulatory approvals in connection with power plants, mergers, asset sales, and asset acquisitions.

- **Electric Reliability.** Consult with clients on compliance with the North American Electric Reliability Corporation (“NERC”) electric reliability standards and requirements. Represent clients on registration issues at the NERC regional level, at NERC, and before FERC. Negotiate at the NERC regional level both the applicability of and compliance with reliability standards and requirements.

- **Rate Litigation.** Assist clients in the development of cost-based rate filings for services subject to FERC jurisdiction. Appear before FERC in reactive service proceedings and transmission rate proceedings. Advise and represent clients in all facets of regulatory hearing process, including settlement, discovery, depositions, testimony preparation, witness preparation, hearing strategy, cross-examination, and briefing.

- **Contract Termination.** Represent clients in challenges to existing wholesale electric service contract arrangements in litigated proceedings before FERC.

- **Merger Litigation.** Represent clients before FERC in complex merger proceedings.
Transactional Practice

- **Long-Term Power Agreements.** Negotiation and drafting of long-term power agreements, including a ten year tolling agreement for an independent power producer.
- **Master Agreements/Proprietary Agreements.** Negotiation and drafting of terms and conditions under power master agreements and propriety agreements, gas master agreements and propriety agreements, coal master agreements and propriety agreements, and derivative master agreements. Contract review of energy commodity contracts for pre-bankruptcy energy trading companies. Post-bankruptcy negotiations for liquidation of energy trading companies.
- **Security Arrangements.** Negotiation and drafting of security arrangements, including guaranties, letters of credit, prepayment, and lock-box arrangements for energy trading client and project development clients.
- **Retail Supply Arrangements.** Development of proprietary master agreement and supporting security arrangements for use by energy trading client with retail suppliers in retail electric market.
- **Interconnection Agreements.** Representation of utilities and independent power producers on interconnection matters, including negotiation of interconnection agreements.
- **Mergers and Acquisitions.** Representation of independent power, private equity, and industrial company acquisition and sale of electric generating assets. Representation of utilities in mergers, including the first three-way electric utility merger.

Project Experience

- **Project Development.** Support clients in the development of electric generation projects in numerous states. Advise on responses to requests for proposals. Negotiate project contracts, including real property acquisition and easements, equipment procurement, supply contracts, interconnection, and power sales.
- **Project Operation and Management.** Advise generating facilities on contract issues, including procurement, contract disputes, and operation and maintenance contracts. Support clients on asset management issues.

Education and Clerkship

- **J.D., with Honors, George Washington University Law School**
- **B.A., Economics, University of Chicago**
Mr. Morrison joined the National Rural Electric Cooperative Association as Regulatory Counsel in June 1998 in order to address the broad range of issues raised by the restructuring of the electric utility industry. Mr. Morrison has also focused extensively on issues relating to renewable energy, energy efficiency, Smart Grid, and distributed generation.

Prior to joining NRECA, Mr. Morrison spent 3 ½ years with the law firm of Paul, Hastings, Janofsky & Walker LLP. There, Mr. Morrison represented clients before the Federal Energy Regulatory Commission, the United States Court of Appeals for the D.C. Circuit, and Congress, on matters arising from electric restructuring, FERC Order Nos. 888 and 889, the Federal Power Act, the Energy Policy Act, the Public Utility Regulatory Policies Act, and the Public Utility Holding Company Act. Mr. Morrison also represented clients on a variety of environmental, antitrust, and complex litigation matters.

In 1993, Mr. Morrison earned his MPP, from the John F. Kennedy School of Government and his JD, magna cum laude, from Harvard Law School. Mr. Morrison earned his BA, summa cum laude and Phi Beta Kappa, from UCLA in 1989. Mr. Morrison has also clerked for the Honorable A. Raymond Randolph on the D.C. Circuit, and served as counsel to the U.S. Senate Committee on Labor and Human Resources.

Mr. Morrison and his wife Barbara Burgess live on a tiny farm in rural Virginia with their sons Abraham and Samuel and too many animals.
Biography of Susan J. Court

Susan J. Court is a partner at Hogan & Hartson, LLP, in Washington, D.C., where she concentrates on energy issues with a particular focus on enforcement of regulations promulgated by the Federal Energy Regulatory Commission (FERC). Prior to joining the law firm, Susan was a senior lawyer and executive at FERC, which she joined in 1982. Immediately prior to leaving FERC in 2009, Susan served as the first Director of Enforcement following the enactment of the Energy Policy Act of 2005. In this position, she helped develop the agency’s enforcement program generally and in particular as it implicates the mandatory standards governing the reliability of the electric bulk power system. Before heading the FERC Enforcement office, Susan served as the agency’s Chief of Staff, Associate General Counsel for General and Administrative Law, Designated Agency Ethics Official, Deputy Solicitor, and Associate General Counsel for Gas and Oil. In 2005, Susan worked at the Irish Commission for Energy Regulation, a European Union Regulatory Authority, on assignment from FERC.
Mark Bennett joined CPV in July, 2007 as Vice President of Regulatory Compliance. In addition to advising power plants CPV manages on reliability standards compliance, he also directs CPV’s internal compliance program covering its trading and market related activities. Before joining CPV, Mark was General Counsel and Director of Policy at the Electric Power Supply Association, the trade association for competitive power suppliers.

While at EPSA, Mark actively engaged in various NERC committee and board activities, and contributed to the ERO transition process. His background also includes experience as Associate General Counsel at the New York Mercantile Exchange, and as an enforcement attorney with the Securities and Exchange Commission. He is a founding Steering Committee member of the Generator Forum, and chairs the Forum’s Legal Subcommittee.

Mark is a graduate of Washington & Lee University, has a J.D. from The John Marshall Law School, an LL.M. in Corporate and Securities Law from New York University, and an Environmental Masters from Vermont Law School.
STEPHEN L. HUNTOON

Stephen L. Huntoon is a Senior Attorney with Florida Power & Light Company. Previously he was with the firm of Sullivan & Worcester, and prior to that held in-house positions with Dynegy, Conectiv Energy and PECO Energy. He began his legal career with the firm of Reid & Priest in 1982.

Steve is a past President of the Energy Bar Association, and has served the Association in a variety of other positions. He also has served as an officer and director of the Foundation of the Energy Law Journal, and as a director of the Charitable Foundation of the Association. He has published several articles on the energy industry and spoken many times at energy industry events.

Steve received his B.A. with honors from the University of Virginia in 1978, and his J.D., also from the University of Virginia, in 1982.
Laura M. Schepis is the Deputy Director of the Government Relations department at the National Rural Electric Cooperative Association (NRECA), headquartered in Arlington, Virginia. She represents NRECA before Congress on a variety of issues, including renewable energy, energy efficiency, telecommunications and homeland security. She also coordinates the association’s legislative efforts with national organizations of state elected officials. A graduate of the University of Georgia School of Law, she practiced law in a small-town setting for four years before re-locating to Washington, D.C. in 2000 to lobby on rural development issues. She lives in Alexandria, Virginia with her husband Chris and daughter Audrey Claire.
Jeff Baran is Counsel to the Energy and Commerce Committee of the U.S. House of Representatives. He advises Chairman Henry Waxman on a range of energy and environmental issues, including renewable energy, nuclear energy, clean energy financing, electric grid modernization, carbon markets, and Montreal Protocol gases. Prior to joining the Energy and Commerce Committee staff in January 2009, Mr. Baran was Counsel to the Oversight and Government Reform Committee from 2003 through 2008. He was a judicial clerk to Federal District Judge Lesley Wells from 2001 to 2003. Mr. Baran is a graduate of Ohio University (1998) and Harvard Law School (2001).
Conrad Lass is the Vice President of Legislative Affairs for the Electric Power Supply Association (EPSA), which represents competitive power suppliers including generators and marketers. EPSA member companies account for 40 percent of the installed generating capacity in the United States. Conrad is responsible for federal legislative policy development and advocacy and is the principle liaison between the association and Members of Congress and staff, the Executive Branch and federal agency officials.

Prior to joining EPSA, Conrad served as director of government affairs for Rio Tinto, a multi-national mining company headquartered in London, England. He has also served as the executive director of the Wyoming Rural Electric Association, was a former chief of staff of the U.S. Bureau of Land Management, was a manager of federal legislative affairs for Southern Company, and was director of the Office of Federal Land Policy for former Wyoming governor Jim Geringer. Conrad began his career in Washington in the office of former Senator Alan K. Simpson (WY) and also served on the staff of the late Senator Craig Thomas (WY) handling energy, agriculture and environmental issues.

Mr. Lass is a 1993 graduate of the University of Wyoming and received his B.S. degree in Communications. He is a member of the Congressional Award Foundation Board of Directors and also serves on the Board of the University of Wyoming National Ambassadors. Conrad and his wife Holly reside in Alexandria, Virginia with their daughter Anna Kate and son Conrad, III.
Linda L. Walsh

Practice focuses on regulatory matters affecting electric utilities, particularly in NERC reliability matters, industry restructuring, rates and administrative litigation.

Relevant Experience

→ Advises clients on matters involving all aspects of the newly mandatory NERC Reliability Standards, including NERC and Regional Entity audits and investigations, standards development and compliance, Compliance Registry issues, penalty liability, and hearing processes. Regularly analyzes implications of registry appeals, penalty notices, development of NERC and Regional Entity compliance and enforcement programs and other proceedings underway at FERC.

→ Provides general FERC-related advice regarding compliance issues in connection with utility reporting requirements, interlocking director applications, and standards of conduct issues. Obtained FERC "No-Action" letter regarding standards of conduct issues in connection with a regional reliability training program.

→ FERC counsel to a stand alone transmission company, providing ongoing representation in rulemakings, ADR proceedings, transmission rate proceedings, negotiating generator interconnection agreements and providing general regulatory advice on transmission and RTO formation issues; prepared initial FERC filings to establish a transmission tariff and rates for the newly formed transco; obtained FPA Section 204 authorizations for the issuance of debt, prepared Section 203 filings for the acquisition of facilities, and prepared Section 205 filings for approval of incentive rate treatments.

→ Advises a Northeastern ISO on FERC matters including inter-RTO coordination agreements, liability limitation, data confidentiality agreements, and NERC reliability matters.

→ Provides general FERC-related advice regarding merchant generation interconnection issues and operation and maintenance issues regarding restructuring of projects turned back to lenders. Prepared Section 203 filing for approval of transfer of leased generation facilities and declaratory order application for project owner to attain passive ownership status. Prepared market-based rate triennial update filings.

→ Prepared filing and supporting materials for approval of liability limitation provisions in RTO open access transmission tariff.

→ Provided advice to utilities in connection with FERC’s rulemaking regarding standardized policies on new large generator interconnections.
Involved in advising several utilities on obtaining FERC approval in the formation of independent transmission companies; provided advice on the operation of Northeast ISO ancillary services markets and control area issues.


Membership

- Chair, Committee on System Reliability, Planning and Compliance, Energy Bar Association, 2008-2009
- Charitable Foundation of the Energy Bar Association, President, 2007-2008; Vice President, 2006-2007; Director 2004-present; Secretary, 2004
- Member, Energy Bar Association, Board of Directors, 2001-2004
- Member, District of Columbia Bar
- Member, Connecticut Bar
- Member, New York State Bar

Speeches

- Panelist, "What to Do if You are Faced with a Compliance Audit or Investigation," Infocast's FERC Compliance Summit, Washington, DC, September 25, 2009
- Moderator, NERC and Regional Entity Hearing and Appeal Processes; Advice from the Field, Energy Bar Association, Washington, DC, October 2, 2008
- Speaker, Minimum Requirements in the NOPR for Creating and Operating an RTO, Update on FERC's RTO Initiative, Infocast conference, Washington, DC, November 1999

Publications

- Author, Client Alert: FERC Proposes to Reduce Regulatory Requirements for Small Power Production Qualifying Facilities, October 2009
Linda L. Walsh  
Partner  
Regulated Markets & Energy Infrastructure  

→ Author, Client Alert: FERC Revises Policies to Ease Financing of Merchant Transmission Projects, March 2009  

**Awards and Professional Recognition**  
→ Listed in *Chambers USA*, 2005-2009  
→ Listed in *DC Super Lawyers*, 2007-2009  
→ Listed in *Best Lawyers*, 2007-2009

**Education**  
→ J.D., Syracuse University College of Law, *cum laude*, 1987  
→ M.A., University of Hartford, Economics, 1984  
→ B.A., University of Connecticut, 1982
Michael Moon joined NERC in June 2009 and is currently serving as the Director of Compliance. He came to NERC after a 26 year career as an Army engineer; in the later part of his career he specialized in energy, environment and infrastructure. Significant positions include; Director of Electrical Sector Development in Baghdad, Iraq 2007-2008, managing the $4.3 Billion US reconstruction effort of the Iraqi grid; generation, transmission, distribution; operations, maintenance and sustainment; and capacity development; and the Command Infrastructure Engineer for the US European Command in Stuttgart, Germany, 2003-2005, managing new construction and sustainment, restoration and modernization of existing facilities for the command’s 500 plus installations across Europe. Mike earned a masters degree in National Security Studies from the US Army War College and a bachelor’s degree in Applied Mathematics from Longwood University.
SARA E. PATRICK

Sara E. Patrick is the Director of Regulatory Affairs and Enforcement for the Midwest Reliability Organization (MRO). Ms. Patrick is responsible for the enforcement of Reliability Standards as detailed in the NERC Compliance and Enforcement Monitoring Program (CMEP) within the MRO region.

Prior to joining MRO, Ms. Patrick served as the Director of Government Affairs for Explore Information Services, LLC, a leading service provider to the property and casualty insurance industry. Ms. Patrick also served as an Assistant Attorney General for the State of Arizona under both the administration of Janet Napolitano (D) and Grant Woods (R). Early in her career, she honed her legal research skills at Thomson West, a leading provider of legal reference materials.

Ms. Patrick was born and raised in Michigan. She is a graduate of the Lee Honor’s College of Western Michigan University in Kalamazoo, MI and received her doctor of jurisprudence (J.D.) from the Indiana University School of Law in Bloomington, IN. She currently resides in the Twin Cities Metro.

Ms. Patrick is licensed to practice law in Minnesota and Arizona. She is a Certified Information Privacy Professional and a member of the Energy Bar Association.
Stanley E. Kopman

Stanley E. Kopman is the Assistant Vice President of Compliance for the Northeast Coordinating Council (NPCC.) Mr. Kopman is responsible for overseeing the implementation of the NERC Compliance and Enforcement Monitoring Program (CMEP) within the NPCC Region.

Mr. Kopman has worked for NPCC for over 21 years including the last 12 years working in the Compliance Area and was responsible for developing and implementing the first Reliability Compliance and Enforcement Program in NPCC. Prior to joining NPCC, Mr. Kopman worked at the New York Power Authority and American Electric Power.

Mr. Kopman was born and raised in Brooklyn, New York. He is a graduate of Polytechnic University in Brooklyn, New York. He currently resides in Bridgewater, New Jersey.