Status

• Outline for the white paper presented at the January SAMS meeting

• No progress has been made on writing a draft

• The target is to have a draft written by the end of the year for SAMS to review
Outline

• Introduction

• Background
  – The need for three-phase representation

• Development of three-phase model
  – Modeling of network elements
    • Generators, lines, transformers, loads
  – Modeling of unbalanced conditions
    • Mutual coupling from lines in the same ROW, untransposed transmission lines, unbalanced loads
  – Model validation

• Studies
  – Unbalanced power flow
Outline (cont.)

• Example

• Analysis of results
  – Impact on protective relaying
  – Thermal capability of generators
    • Standards applicable
  – Percent unbalance (zero sequence and negative sequence)
  – Mitigation options

• Software packages
  – Readily available EMTP type tools, other tools

• Conclusions

• References
IEEE P1547 – Status update on latest efforts and past WG meeting

Jens Boemer, Aminul Huque, Brian Seal, Matt Rylander, Jeff Smith Eknath Vittal, Daniel Brooks, Tom Key
EPRI

NERC SAMS Meeting
Austin, May 3, 2016
The Challenge: Rapid DER Deployment
Development and forecast of Solar PV in the United States.

Data Source: GTM/SEIA's U.S. Solar Market Insight Report Q1 2015

Number of PV installations increases dramatically.

Cumulative Capacity in U.S. (MWdc)

Year (2015-2020 are forecasts)

- Residential PV
- Non-Residential PV
- Utility PV

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Bulk and distribution system needs

...are quite different but can only be approached in an integrated way.

<table>
<thead>
<tr>
<th>Transmission</th>
<th>Distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage/Reactive Power</td>
<td>Power quality: voltage limits/power factor</td>
</tr>
<tr>
<td>...</td>
<td>...</td>
</tr>
<tr>
<td>Frequency</td>
<td>Health &amp; Safety: protection coordination/anti-islanding</td>
</tr>
<tr>
<td>Stability</td>
<td></td>
</tr>
</tbody>
</table>
Bulk and distribution system needs

...are quite different but can only be approached in an integrated way.

**Transmission**
- Voltage/Reactive Power
- Frequency
- Stability

**Distribution**
- Power quality: voltage limits/power factor
- Health & Safety: protection coordination/anti-islanding

**Future Technical Guidelines Must Equally Address Bulk and Distribution System Needs**
Content

- High-level IEEE P1547 Timeline
- Applicability of Requirements
- Technology-neutral Requirements and ‘Performance Categories’
- Ride-Through Requirements
- Frequency-Droop Capability Requirements
- Dynamic Voltage Support
- Other Advances in Proposed Requirements
- Conclusions & Outlook
- Q&A
High-level IEEE P1547 Timeline

- June, WG meeting in Portland, OR.

- Fall/Winter 2016, WG final draft to IEEE for ballot…

- 1 year balloting of IEEE P1547?

- In Parallel: drafting of IEEE P1547.1 (testing standard) over 1-2 years.

- 2017-2019 time frame: Implementation of 1547 and 1547.1 by Authorities Having Jurisdiction?
  - assignment of performance categories, etc.
Applicability of Requirements
Point of Common Coupling or Point of DER Connection?

DER rating ≥ 500 kW?

No

% of average load demand ≤ 10%?

No

Point of DER Connection (DER terminals, ECP)

Yes

Point of DER Connection (DER terminals)

Yes

Point of Common Coupling (PCC)

Implications for IEEE P1547.1:

- Testing of requirements
- Conformance / Certification
Technology-neutral Requirements
Performance-Based category approach – will need implementation by AHJs

IEEE Std. 1547rev

Category I
Category II
Category III
Category A
Category B
Ride-Through
Voltage Regulation

DER Vendors

Authority Having Jurisdiction

Market Analysis
• Costs
• Market segment
• Etc.

Impact Assessment
• Technical conditions: type & capacity & future penetration of DER, type of grid configuration, etc.
• Non-technical issues: DER use case, impacts on environment, emissions, and sustainability, etc.

1 State Regulator, Area EPS or bulk system operator, etc.
## Ride-Through Requirements
### Foundations and Justifications

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Category</th>
<th>Foundation</th>
<th>Justification</th>
</tr>
</thead>
</table>
| Voltage Ride-Through      | Category I        | German grid code for medium voltage-connected synchronous generator-based DER | • Essential bulk system needs.  
• Attainable by all state-of-the-art DER technologies.                                      |
|                           | Category II       | NERC PRC-024-2 but w/o stability exception, extended LVRT duration for 65-88% $V_{nom}$ | • All bulk system needs.  
• Coordinated with existing reliability standards.  
• Considering fault-induced delayed voltage recovery. |
|                           | Category III      | CA Rule 21 and Hawaii, minor modifications                                  | • All bulk system needs.  
• Considering fault-induced delayed voltage recovery.  
• Distribution system operation.                                                                     |
| Frequency Ride-Through    | All Categories (harmonized) | CA Rule 21 and Hawaii, exceeds PRC-024-2  
➢ based on EPRI White Paper (May 2015) | • All bulk system needs.  
• Low inertia grids.                                                                                   |
Frequency Trip Requirements

IEEE Std 1547-2003

Frequency Ride-Through Requirements
IEEE P1547 Draft 3 (January 2016)

Frequency-Droop Capability Requirements

DER shall have the capability to provide a frequency-droop response for abnormal frequency values outside a 36 mHz deadband (if headroom is available).

Table 15 – Requirements of a frequency-droop (frequency/power) operation for Low-Frequency Ride-Through and High-Frequency Ride-Through for DER of Category I, Category II, and Category III

<table>
<thead>
<tr>
<th>Category</th>
<th>Operation for Low-Frequency Ride-Through</th>
<th>Operation for High-Frequency Ride-Through</th>
</tr>
</thead>
<tbody>
<tr>
<td>Category I</td>
<td>optional</td>
<td>mandatory</td>
</tr>
<tr>
<td>Category II</td>
<td>mandatory</td>
<td>mandatory</td>
</tr>
<tr>
<td>Category III</td>
<td>mandatory</td>
<td>mandatory</td>
</tr>
</tbody>
</table>

Default value of frequency deadband was reduced from 100 mHz to 36 mHz.
Voltage Trip Requirements
IEEE Std 1547-2003

Voltage Ride-Through Requirements
IEEE P1547 Draft 3 (January 2016) – Category II

Category II
(based on NERC PRC-024-2 and considering FIDVR issues to a certain extent)

Legend
- range of adjustability
- default value
- shall trip zones
- may ride-through or may trip zones
- shall ride-through zones and operating regions describing performance

Voltage Ride-Through Requirements

IEEE P1547 Draft 3 (January 2016) – Category III

Voltage Ride-Through Requirements
Dynamic Voltage Support

What about this region?

Category III
(based on CA Rule 21 and Hawaii)

Region of interest

A/C stalling
Load trip
Voltage (p.u.)
Time (s)

Dynamic Voltage Support
Considerations for ‘Dynamic Voltage Support’ from DER

Support *during* disturbances?
- short-circuit contribution
- dynamic reactive current injection (DRC)
- fast voltage control / fast-responding closed-loop voltage regulation
- control loops typically operate in the sub-second time frame, often within a few cycles.

Support *after* disturbances?
- dynamic reactive support
- control loops typically operate in the 1 s … 10 s time frame

Further research required to adequately justify and specify requirements.
Other Advances in Proposed Requirements

- 4.2.2 Area EPS Reclosing Coordination
- 4.2.3.3.5 Dynamic Voltage Support
- 4.4.1 Anti-Islanding

- 4.3.2 Limitation of flicker induced by the DER
- 4.3.2 Harmonics
- 4.3.4 Avoidance of temporary overvoltage

- 4.X Prioritization of DER Responses
- X.X.X Minimum Requirements for Manufacturers Stated Measurement Accuracy
Conclusions & Outlook

- IEEE Std. 1547rev is an opportunity to harmonize advanced DER requirements to maintain bulk system reliability in the long-term. EPRI has and continues to facilitate drafting of IEEE Std. 1547rev’s through technology transfer funds.

- A technology-agnostic, performance-based requirements approach in IEEE Std. 1547rev would lead technological development and innovation of DER performance while giving sufficient flexibility to State Regulators et al. to account for regional system characteristics and societal benefits.

- Proposed ride-through requirements are solid. Further discussion of advanced requirements such as Dynamic Voltage Support is required.

Success in balloting depends on stakeholder involvement! Get involved…!
Conclusions & Outlook

Published EPRI Work

- White Paper ID# 3002006203 (publicly available)
- Published on May 8th, 2015

*Recommended Settings for Voltage and Frequency Ride-Through of Distributed Energy Resources*

- Technical Update ID# 3002007496 (members)
- Published on February 22th, 2016

*Analysis of Voltage and Frequency Performance of the Bulk System with High Levels of Variable Generation and Distributed Energy Resources*

- Facilitation of IEEE P1547 SubGroup III) on Clause 4.2 “abnormal conditions”

*Draft Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*

- Contact jboemer@epri.com for latest infos.
Conclusions & Outlook

Ongoing EPRI Work

Load Model Uncertainties and Aggregation (P40 Supplemental)
- PSCAD modeling of a feeder
- A/C induction motor models
- Point on wave fault studies
- Validation of CMPLDW model
- No DERs

Voltage & Frequency Performance (P173.011)
- DlgSILENT PowerFactory modeling with stability models
- Validation of PVD1 model against detailed positive-sequence models
- Further development of distributed PV model (PVD1)

California Solar Initiative – Phase 4: Task 4 (Bulk System Aspects)
- GE PSLF modeling of WECC, to date with CMPLDWG model, in future with PVD1 model
- Focused on California with ~11% DER PV penetration
- Test CA Rule 21 requirements
- VRT, FRT, P or Q priority, etc.
- Fast voltage control

Joint P40/P174 project
- PSCAD modeling of a feeder
- A/C induction motor models
- With DERs
- Verification of distributed PV model (PVD1)
- Verification and justification of fast voltage control
Questions & Answers
Together...Shaping the Future of Electricity

EPRI’s IEEE P1547 Contacts:

• Ride-Through: Jens Boemer – 206.471.1180, jboemer@epri.com
• Voltage Regulation: Aminul Huque – 865.218.8051, mhuque@epri.com
• Information & Interoperability: Brian Seal – 8065.218.8181, bseal@epri.com
Proposed Retirement of FAC-010-3
• FAC-010-3 requires the Planning Coordinator (PC) to have an SOL Methodology for establishing SOLs used in the planning horizon
• FAC-014-2 requires the PC and the Transmission Planner (TP) to establish SOLs consistent with its PC’s SOL Methodology
• FAC-010-3 is almost word-for-word the same as FAC-011-3. The difference is that FAC-010-3 is applicable to the PC and the planning horizon, while FAC-011-3 is applicable to the RC and the operations horizon
FAC-010/-011/-014 Periodic Review Team (PRT) Conclusions:

- SOLs and the SOL Methodology for Planning Horizon are **not necessary inputs** to the BES (reliability) planning process because:
  - BES (reliability) planning is comprehensively covered by TPL-001-4;
  - FAC-010-3 Requirements are redundant with TPL-001-4 (demonstrated with mapping tables for R2 and R3)

- Paragraph 81 Criteria B7 applies to FAC-010-3 Requirements – therefore unnecessary and eligible for retirement

- FAC-010 Regional Difference applicable to Western Interconnection has been approved for retirement by WECC/NERC; petition pending at FERC

“Therefore, the PRT recommends ... ... to retire FAC-010-3.”

*SDT concurs with the PRT recommendation*
System Operating Limits (Proposed Definition by SDT)

Reliability limits *used for operations*, to include Facility Ratings, System voltage limits, any (identified) stability limitations, and any (identified) equipment limitations.

Proposed definition makes it explicitly clear that the concept of SOLs is used (i.e. needed) for BES operations – that is, for real-time and/or operations planning horizons, *not* for long-term planning horizon

Further reinforces SDT’s concurrence with, and acceptance of, PRT recommendation to retire FAC-010-3
The PRT concluded that if FAC-010-3 is retired, requirements may need to be written to facilitate the identification and communication of necessary reliability information from planning to operations. What reliability information should be identified in the planning horizon and communicated to the appropriate entities in the operations horizon?

What results/outputs from the Planning Assessment Studies (i.e. reliability risks/limits) would be desirable (or essential?) inputs to:

- Reliability Coordinator’s SOL/IROL Methodology?
- Performing OPA and/or RTA?
- Establishing the SOLs and IROLs?
• Do you agree with the SDT’s position regarding the retirement of FAC-010-3 and related requirements in FAC-014-2? Why or why not?

• Does the absence of PC/TP-defined SOLs and IROLs create a reliability gap for the operations horizon?

• Does the industry believe that there is a reliability need for instability risks to be identified in the planning horizon and communicated to operating entities?

• If so, whose methodology should the planning entities use for identifying these instability risks? Should the planning entities use their own methodology/criteria per TPL-001-4 R6, or should they use the RC’s methodology? If the planning entities use a methodology other than the RC’s methodology, does this create a potential reliability gap?
Reactive Power Planning and Operations Guideline

SAMS 5-03-2016 Meeting
Guideline Process

• Asking SAMS for approval to forward the “final draft” guideline to the PC for posting
  – 45 days for industry comment
    • You will all have the opportunity provide additional comments during that period
• Drafting team will reconvene to consider industry comments
  – This will be an industry developed NERC document
• Different than the Previous TIS Reactive white paper
  – TIS forwarded a final document to the PC for PC approval
    • Action items were incorporated in VAR-001, Var-002 and TPL-001
Guideline Development

- Sub team has had several conference call meetings
  - provided ongoing status reports to SAMS
    - SAMS encouraged to reach out to sub team with comments
- Forwarded draft for Comments to Sams on 4/1/2016
  - All comments and wording suggestions have been incorporated in this final draft
- Drafting team includes significant SAMS penetration
Sub team Members

- Sub team members are
  - Bill Harm
  - John Mills
  - Jose Conto
  - Harry Singh
  - Kent Bolton
  - Andrew Arana
  - Gary Brownfield
  - Tom Mielnik

- Also contributions from
  - Rich Kowalski
  - John Simonelli
• 5/3/2016 Final Draft Approved for forwarding to PC (OC coordination)
• 6/8/2016 PC Approval for Posting (PC Meeting) (OC coordination)
• 8/1/2015 45 Day Comment Period Complete (6/15 Posting)
• 8/__/2016 Sub team Review Comments
• 9/__/2016 Sub team Finalize Response to Comments
• 10/27/2016 Final Draft based on comments - Ready for PC Approval (SAMS Meeting)
• 12/1/2016 PC Approval (PC Meeting) (OC coordination)
Eastern Interconnection
Frequency Response Assessment

Scenario Analysis of Changing Resource Mix

Olushola J. Lutalo, MS, P.E., PMP, Senior Engineer of System Analysis
SAMS Update
May 3-5, 2016
Objective:

- Study effects on interconnection primary frequency response for high penetrations of Variable Energy Resources (VERs)
- Examine scenarios of VER plant additions and Clean Power Plan (CPP) retirements impacts on the Eastern Interconnection frequency response
Purpose:

- Understand reliability implications of high penetration of VERs on primary frequency response
- Incorporate policy issues such as CPP ruling with sensitivities such as penetration level, control strategies, and other assumptions
- Use the ERSTF Measure 4 metrics to assess FR performance
Frequency Response Study

Frequency Response (FR) Study

• Evaluate base case FR using Event data
• Evaluate base case FR plant modeling
• Evaluate base case FR load modeling
• Modify plant and load controller models to obtain valid FR
• Build and validate frequency response scenario cases
• Perform Eastern Interconnection (EI) frequency response assessment
• Perform Eastern Interconnection frequency response sensitivity Analysis
• Report results to industry
<table>
<thead>
<tr>
<th>VER Study Scenarios for 2021 Light Load</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td><strong>VER Penetration % of Total Additions for CPP Phase II Study Retirements (Coal/Oil/Gas Retirement)</strong></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td><strong>VER Mix (Wind/Solar)</strong></td>
</tr>
<tr>
<td><strong>Dispatch % of Max Output</strong></td>
</tr>
<tr>
<td><strong>VER Type 3/ Type 4 %</strong></td>
</tr>
<tr>
<td><strong>VER Frequency Control On/Off</strong></td>
</tr>
<tr>
<td><strong>VER Inertia Control On/Off</strong></td>
</tr>
</tbody>
</table>
• Classify Frequency Response for Eastern Interconnect Machines
  ▪ About 7800 machines in the EI case
  ▪ Fully Responsive
  ▪ Squelched
  ▪ Non-Responsive

• Classify Governor Response On Regional Basis
  ▪ Where available, use recorded observations of frequency response
  ▪ Adjust turbine-governor models to simulate squelched and non-responsive governors
• Hydro: Responsive

• Steam Turbine
  ▪ Squelched (based on prime mover controller and boiler operation)
  ▪ Non-responsive (based on prime mover controller and boiler operation)

• Simple Combustion Turbines: Non-Responsive (Due to nature of CTs and how they are operated to protect the turbines)

• Combined Cycle
  ▪ CT: Non-responsive (due to nature of CTs and how they are operated to protect the turbines)
  ▪ ST: Non-responsive (based on boiler operation)

• Wind: Non-Responsive
Perform Base Case Model Validation with FNET & PMU Data
Questions and Answers
NATF Modeling Practices Group Update

April 27, 2016
NERC SAMS Meeting
Ed Ernst- NATF Program Manager

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Outline

• NATF Modeling Practices Group Activities
• Coordination between NATF and NERC
NATF Practice Groups

- Compliance
- Human Performance
- Modeling
- Operator Training
- Security
- System Operations
- System Protection
- Transmission-Nuclear Interface
- Vegetation Management
- Equipment Performance and Maintenance
NATF Modeling Practices Group Current Activities

• June 21-22 Modeling Practices Group Meeting at MISO in Carmel, IN

• On-going monthly calls of Modeling Practices Group and its various working groups
June 21-22 Modeling Practices Group Meeting
at MISO in Carmel, IN

- Open to NATF Members and invited non-NATF Guests
- Planned Agenda Topics
  - Dynamic Load Modeling Panel
  - Transmission Planning Panel on Model Validation- MOD-033
  - EMS Modeling Panel
  - Distributed Energy Resources Modeling, Planning and Studies Panel
  - NERC standards/FERC update
  - Grid Resiliency Modeling
  - GMD Modeling and planning studies for new TPL-007
  - Brainstorming/emerging issues/priority topics for 2016/2017
On-going monthly calls of Modeling Practices Group and its various working groups

• Dynamic Load Modeling Working Group
  – Sharing experiences
  – Following work of other groups: NERC Load Modeling Task Force, etc.
  – No documents under development

• Transmission Planning Working Group
  – Sharing experiences on TPL-001-4, TPL-007, MOD-033 model validation and transmission/sub-transmission connected renewables
  – Following work of other groups: NERC GMD Task Force, etc.
  – No documents under development

• Distributed Energy Resources Working Group
  – Sharing experiences
  – Following work of other groups: NERC Distributed Energy Resources Task Force, etc.
  – Plan to develop a Distributed Energy Resources Reference Document

• EMS Modeling Working Group
  – Current focus is on the building of external models
  – Plan to develop an EMS External Model Reference Document
Public Documents

To further benefit reliability, the NATF makes select products available to the entire industry. The resources below are available for download.

Resources

- NATF CIP-014-1 R1 Guideline V1
- NATF Practices Document – NERC Reliability Standard CIP-014-1 Requirement R4
- NATF Reference Document – Generator Specifications
- NATF Reference Document – Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines

Presentations/Updates

- 2015-05 NATF Periodic Update – NERC BOT
- 2015-02 NATF Periodic Update – NERC BOT
- 2014-11 NATF Periodic Update – NERC BOT
Coordination between NATF and NERC

• Ryan Quint of NERC staff has standing slot on Monthly NATF MPG calls to cover topics as needed
• Ed Ernst has standing slots on SAMS and MWG calls to cover topics as needed
Questions?
PCPMTF UPDATE TO SAMS

Mohamed Osman, Senior Engineer of System Analysis
Systems Analysis and Modeling Working Group
May 04, 2016
• **PCPMTF**: Plant-Level Controls and Protection Modeling Task Force
  - Studying effects of plant-level, turbine, and boiler control and protection systems
  - Comprehensive look at the short- and mid-term post-disturbance behavior of plant control and protection systems
  - Outlining impacts plant control and protection systems have on unit reliability and system stability during grid disturbances

• PCPMTF Stakeholders:
  - Turbine Manufacturers; Generators Owners/Operators; North American Generator Forum (NAGF); experts in power system dynamics and control; stability simulation software vendors
Considerations for Quantities

- It is not practical or necessary to model the entire set of turbine or boiler controls.
- Task Force focused on defining the functions and behaviors that should be modeled for transient and mid-term dynamics.
- Variables to be monitored in simulation tools:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$V_t$</td>
<td>Stator Terminal Voltage</td>
</tr>
<tr>
<td>$P_e$</td>
<td>Electric Real Power</td>
</tr>
<tr>
<td>$Q_e$</td>
<td>Electrical Reactive Power</td>
</tr>
<tr>
<td>$I_f$</td>
<td>Field current, or in the case of a brushless unit the field of the pilot exciter</td>
</tr>
<tr>
<td>Speed</td>
<td>Mechanical Speed</td>
</tr>
<tr>
<td>$V_x$</td>
<td>Station level voltage – Aux bus voltage</td>
</tr>
<tr>
<td>$P_m$</td>
<td>Total Mechanical Power</td>
</tr>
</tbody>
</table>

- Protection systems and Limiters:

<table>
<thead>
<tr>
<th>Protection and Limiters</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>V/Hz</td>
<td>Volts per Hertz limiter and protection – per unit frequency and per unit generator terminal voltage</td>
</tr>
<tr>
<td>Overspeed protection</td>
<td>Shaft speed</td>
</tr>
<tr>
<td>Power/Load Balance</td>
<td>Electrical real power and mechanical power</td>
</tr>
<tr>
<td>Overvoltage/Undervoltage</td>
<td>Generator terminal voltage</td>
</tr>
<tr>
<td>Overfrequency/Underfrequency</td>
<td>Frequency</td>
</tr>
<tr>
<td>Turbine valve rate of change limiters</td>
<td>How fast the unit is able to respond to a frequency deviation</td>
</tr>
</tbody>
</table>
Models with Representation of Plant-level DCS Controls

- Turbine Load Controllers:
  - GGOV1
  - GGOV3
  - LCFB1

- Turbine Control Modes: ability to represent boiler dynamics
  - ccbt1 & ccbt3 (PSLF)
  - TGOV4 & TGOV5 (PSS/E)

- Power-Load Unbalance: ability to model fast valving scheme
  - TGOV3 and TGOV5 (PSS/E)
Models with Representation of Plant-level Protection

- Models gp1 and gp2 (PSLF)
  - generic models include protection models for a generator
  - monitors certain variables and make an assessment of whether the generator is reaching the protection systems trip criteria (e.g. V/Hz)
PCPMTF Deliverables

- Assess possible improvements to Plant-Level Control and Protection models
- Prioritizing turbine-governor model developments and modeling practices
- Technical report on plant-level controls and protection modeling gaps
- Potential models or software updates to be developed through this process
Questions and Answers
NERC LMTF: Current Activities

Ryan Quint, Ph.D., P.E.
Staff Coordinator, NERC Load Modeling Task Force
NERC SAMS Meeting
May 04, 2016
• Upcoming Meeting – Washington DC, May 2016
• Coordination with Regional load modeling groups
• Broad group of expertise involved
  - Utility planners
  - Software vendors
  - Modeling experts
  - Load modeling SMEs
• Looking for full industry coverage/participation
  - “Consolidate” load modeling practices across industry
<table>
<thead>
<tr>
<th>Task #</th>
<th>Task</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Technical Reference Document</td>
</tr>
<tr>
<td></td>
<td>• Current state of dynamic load modeling</td>
</tr>
<tr>
<td></td>
<td>• Follow-up to FIDVR Workshop in Alexandria, VA in 9/2015</td>
</tr>
<tr>
<td>2</td>
<td>Common Initialization Procedures</td>
</tr>
<tr>
<td></td>
<td>• Standardized procedures for software initialization – overcome “crashing” issues</td>
</tr>
<tr>
<td>3</td>
<td>Network Boundary Equations</td>
</tr>
<tr>
<td></td>
<td>• Common practices for dealing with current source in dynamics – motor model numerical issues resulting in “crashing”</td>
</tr>
<tr>
<td>4</td>
<td>Load Model (Software) Benchmarking</td>
</tr>
<tr>
<td></td>
<td>• Ongoing benchmarking of PSS®E, PSLF, PowerWorld, etc., composite load models</td>
</tr>
<tr>
<td></td>
<td>• Uncovering and fixing software issues – standardize platforms</td>
</tr>
<tr>
<td>5</td>
<td>Improved Protection System Modeling</td>
</tr>
<tr>
<td></td>
<td>• Discrete protection system operations is not sufficient – addressing this issue</td>
</tr>
<tr>
<td>6</td>
<td>Improved Single-Phase Motor Model</td>
</tr>
<tr>
<td></td>
<td>• Performance model replacement</td>
</tr>
</tbody>
</table>
## LMTF Tasks

<table>
<thead>
<tr>
<th>Task #</th>
<th>Task</th>
</tr>
</thead>
<tbody>
<tr>
<td>7</td>
<td><strong>Improved Three-Phase Motor Model</strong>&lt;br&gt;• Improved motor modeling for 3-phase motors – not a major issue</td>
</tr>
<tr>
<td>8</td>
<td><strong>Robust (Default) Data Sets</strong>&lt;br&gt;• Develop robust data sets for use across regions&lt;br&gt;• Develop regionally (load type) reasonable starting points</td>
</tr>
<tr>
<td>9</td>
<td><strong>Reliability Guideline: Load Composition</strong>&lt;br&gt;• Developing a Reliability Guideline on developing load composition data</td>
</tr>
<tr>
<td>10</td>
<td><strong>Educational Materials &amp; Industry Webinar</strong>&lt;br&gt;• Ongoing industry education – webinar/workshop in the works</td>
</tr>
<tr>
<td>11</td>
<td><strong>System Impact Studies</strong>&lt;br&gt;• Hearing from entities on findings/experiences</td>
</tr>
<tr>
<td>12</td>
<td><strong>Efficient Data Format &amp; Model Management</strong>&lt;br&gt;• Exploring new composite load model structure and model management concepts</td>
</tr>
<tr>
<td>13</td>
<td><strong>Distributed Generation Modeling Guidance</strong>&lt;br&gt;• Best practices on how to handle DG in simulations</td>
</tr>
<tr>
<td>14</td>
<td><strong>Dynamic Load Modeling in Real-Time Stability Analysis</strong>&lt;br&gt;• Surveying what dynamic load models are being used in real-time studies</td>
</tr>
</tbody>
</table>
Questions?
<table>
<thead>
<tr>
<th>Date</th>
<th>Action Item</th>
</tr>
</thead>
<tbody>
<tr>
<td>January 22</td>
<td>Data and Narrative Request sent to Regional Executives and RAS</td>
</tr>
<tr>
<td><strong>June 10</strong></td>
<td>Data due to NERC</td>
</tr>
<tr>
<td><strong>June 24</strong></td>
<td>Draft Narratives due to NERC and RAS, initiating the peer reviews</td>
</tr>
<tr>
<td>June 29-30</td>
<td>RAS Conference Call: Assessment Area representatives present Methods &amp; Assumptions (Part 2)</td>
</tr>
<tr>
<td>July 01</td>
<td>Peer Reviewer comments due to RAS</td>
</tr>
<tr>
<td>July 1-11</td>
<td>Respond to peer reviewer comments and modify narratives as needed</td>
</tr>
<tr>
<td>July 11</td>
<td>Send updated narratives to RAS</td>
</tr>
<tr>
<td>July 12-13</td>
<td>RAS Meeting; SERC – Charlotte NC; LTRA Peer Review</td>
</tr>
<tr>
<td>July 22</td>
<td>Corrections to Data and Final Narratives due to NERC</td>
</tr>
<tr>
<td>July 22-September 2</td>
<td>Ongoing report development by NERC Staff</td>
</tr>
<tr>
<td>August 23-24</td>
<td>ERO RAPA Meeting: review of Regional responses to narrative questions</td>
</tr>
<tr>
<td><strong>September 2</strong></td>
<td><strong>Draft report sent to RAS (ProbA dashboards NOT included)</strong></td>
</tr>
<tr>
<td>September 23</td>
<td>RAS comments due to NERC</td>
</tr>
<tr>
<td>September 26-30</td>
<td>NERC responds to RAS comments</td>
</tr>
<tr>
<td>October 4</td>
<td>RAS Meeting; Conference Call; ProbA Team presents to RAS</td>
</tr>
<tr>
<td>October 14</td>
<td>ProbA dashboards/narratives due to NERC</td>
</tr>
<tr>
<td><strong>October 17-21</strong></td>
<td><strong>NERC incorporates ProbA dashboards and addresses ERS Measure 6 in the report</strong></td>
</tr>
<tr>
<td><strong>October 21</strong></td>
<td><strong>LTRA sent to PC for review</strong></td>
</tr>
<tr>
<td>October 21-November 4</td>
<td>PC review period</td>
</tr>
<tr>
<td>November 4-8</td>
<td>NERC responds to PC feedback</td>
</tr>
<tr>
<td>November 8</td>
<td>PC webinar for report endorsement</td>
</tr>
<tr>
<td>November 8-18</td>
<td>NERC Editorial Review</td>
</tr>
<tr>
<td>November 14-16</td>
<td>RAS Meeting; FRCC - Tampa FL; WRA/STSA/LTRA</td>
</tr>
<tr>
<td>November 21</td>
<td>LTRA sent to NERC Executive Management, MRC, and ERO RAPA</td>
</tr>
<tr>
<td>November 21-25</td>
<td>NERC Executive Management, MRC, and ERO RAPA review period</td>
</tr>
<tr>
<td>November 25-28</td>
<td>NERC responds to feedback from NERC Executive Management and MRC</td>
</tr>
<tr>
<td>November 28</td>
<td>LTRA sent to NERC Board of Trustees</td>
</tr>
<tr>
<td>November 28-December 5-6 (awaiting confirmation)</td>
<td>NERC Board of Trustees review period</td>
</tr>
<tr>
<td>December 5-8 (awaiting confirmation)</td>
<td>NERC Board of Trustees conference call to vote on report approval</td>
</tr>
<tr>
<td>December 8-13</td>
<td>NERC responds to feedback from Board of Trustees</td>
</tr>
<tr>
<td><strong>December 13 (awaiting confirmation)</strong></td>
<td>Target Release</td>
</tr>
</tbody>
</table>
Gas-Electric Interdependency
Short-Term Special Assessment

Pooja Shah
SAMS Meeting
May 5, 2016
What is the new “Short-Term Special Assessment”? 

- Topic-oriented reliability evaluations 
- Identify potential reliability risks over the next 18-24 months 
- Provide an independent review of potential reliability issues, studies, policies, and initiatives 
- NERC and the Regions select assessment topics 
- ERO-RAPA approves the topics
First Short-Term Assessment – Gas-Electric Interdependency

- Generation Availability Risk Assessment
- Short-term challenges related to natural gas infrastructure
- Leverage existing studies from industry and Regions

Areas Highly-Dependent on Natural Gas-Fired Capacity

- ISO-NE
- NYISO
- ERCOT
- CAISO

Gas-fired  Other
Key Findings

- Single-fuel dependency increases risk of BPS-impairing common-mode failures
- Risks to natural gas generation during summer season
- Expand gas-electric planning and coordination
  - A planning-based Reliability Standard should be considered
- Operational coordination between gas and electric industries decrease likelihood of wide-spread outage
Gas Availability Risk Assessment

Overview

Based on GADS Performance Data

- Firm Import Capability
- Average Forced Non-Gas Outages
- Average Forced Gas Outages
- Maximum Forced Gas Outages (in excess of average)

- Separate Area-Specific NG Scenario
  Refers to loss of a major pipelines during the peak

- Extreme (90/10) Peak Load Forecast
- Normal (50/50) Peak Load Forecast

- Gas-Fired Capacity
- Dual-Fuel Capacity
- Non-Gas-Fired Capacity

- Anticipated Capacity
- Net Imports (Firm)
- At-Risk Capacity
- Extreme Scenario

Based on GADS Performance Data
# 2016 CA/MX Gas Operational Risk

## Load Projections

<table>
<thead>
<tr>
<th></th>
<th>2016 Summer</th>
<th>2016/17 Winter</th>
<th>2017 Summer</th>
<th>2017/18 Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td>50/50 Peak Load Forecast (Reduced by Available DR)</td>
<td>52,669</td>
<td>38,213</td>
<td>52,919</td>
<td>38,245</td>
</tr>
<tr>
<td>90/10 Peak Load Forecast (Reduced by Available DR)</td>
<td>57,936</td>
<td>42,034</td>
<td>58,211</td>
<td>42,070</td>
</tr>
</tbody>
</table>

## Anticipated Capacity

<table>
<thead>
<tr>
<th>Capacity Type</th>
<th>2016 Summer</th>
<th>2016/17 Winter</th>
<th>2017 Summer</th>
<th>2017/18 Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Capacity</td>
<td>63,748</td>
<td>54,438</td>
<td>65,823</td>
<td>54,445</td>
</tr>
<tr>
<td>Non Gas-Fired Capacity (MW)</td>
<td>19,051</td>
<td>8,545</td>
<td>19,241</td>
<td>7,593</td>
</tr>
<tr>
<td>Gas-Fired Capacity (non-Dual-Fuel)</td>
<td>43,200</td>
<td>44,396</td>
<td>45,085</td>
<td>45,355</td>
</tr>
<tr>
<td>Dual-Fuel Capacity</td>
<td>1,497</td>
<td>1,497</td>
<td>1,497</td>
<td>1,497</td>
</tr>
<tr>
<td>Gas-Fired + Dual Fuel Capacity (MW)</td>
<td>44,697</td>
<td>45,893</td>
<td>46,582</td>
<td>46,852</td>
</tr>
<tr>
<td>Gas-Fired Capacity (% of Total On-Peak)</td>
<td>70%</td>
<td>84%</td>
<td>71%</td>
<td>86%</td>
</tr>
</tbody>
</table>

## At-Risk Capacity

<table>
<thead>
<tr>
<th>Capacity Type</th>
<th>2016 Summer</th>
<th>2016/17 Winter</th>
<th>2017 Summer</th>
<th>2017/18 Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Outages of Non Gas-Fired Generation</td>
<td>1,027</td>
<td>3,571</td>
<td>1,027</td>
<td>3,571</td>
</tr>
<tr>
<td>Average Outages of Gas-Fired Generation</td>
<td>337</td>
<td>484</td>
<td>337</td>
<td>484</td>
</tr>
<tr>
<td>Maximum Outages of Gas-Fired Generation</td>
<td>2,658</td>
<td>1,391</td>
<td>2,658</td>
<td>1,391</td>
</tr>
<tr>
<td>Extreme Scenario</td>
<td>9,800</td>
<td>9,800</td>
<td>9,800</td>
<td>5,000</td>
</tr>
</tbody>
</table>
Aliso Canyon: LA Basin Power Supply

Potential Impacted Generation
LA Basin:
- 9,800 MW natural gas generation
- ~95% of total local capacity

Rest of Southern California:
- >15,000 MW natural gas generation

Maximum Import Capacity
- 5,500 MW DC capacity
- 14,900 MW AC capacity
- 20,400 MW total* 

* Typically limited to 17,000 - 18,000 MW
• Electric import capacity (transmission)
  ▪ 20.4 GW gross import capacity on five major transmission paths to LA Basin
  ▪ Capacity is typically limited to 17-18 GW (stability limitation)

• Operational realities
  ▪ Gas system pressure during electric generation ramping without storage support
  ▪ Voltage support/stability if in-basin power plants curtailed below acceptable minimum load
  ▪ Local gas generation is relied on to manage pre- and post-contingency flows
<table>
<thead>
<tr>
<th>Date</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>May 6</td>
<td>Embargoed report to Board of Trustees (Board) and MRC</td>
</tr>
<tr>
<td>May 13</td>
<td>Board call to accept the report</td>
</tr>
<tr>
<td>May 17</td>
<td>Target release</td>
</tr>
</tbody>
</table>
Questions and Answers

Pooja Shah
Senior Engineer, Reliability Assessment
404-446-9621 office | 404-710-0502 cell
pooja.shah@nerc.net
RAS Standard Update

Bobby Jones
SAMS Meeting May 5, 2016
Status

• Standard posted for comment and ballot Feb. 3 – March 18

• Received 78.9% approval

• Drafting team met in April to respond to comments

• Most changes were made to the rationales and technical basis material in response to comments, no changes to requirements

• Standard posted for final ballot April 20 - 29
RAS Standard

• R1 – R3  Requirements for adding or modifying RAS to get approval by RC

• R4 – Requires PC to perform an evaluation of the RAS every five years

• R5 – Requires RAS entities to analyze any operation or failure to operate when expected

• R6 – requires the RAS entity to participate in developing a Corrective Action Plan (CAP) to correct any deficiencies found by the PC’s evaluation or operation analysis or through functional testing and submit CAP to RC
RAS Standard (cont.)

- R7 – Requires the RAS entity to implement the CAP from R6

- R8 – Requires the RAS entity to perform a functional test every 6 years (or 12 years) to verify proper operation on non-Protection System components

- R9 – Requires the RC to maintain a database of RAS in his area
Biggest Concern

- FERC staff and some others thought that the standard was exempting limited impact RAS from meeting the TPL standard.

4.1.4. Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

4.1.4.1. The BES shall remain stable.
4.1.4.2. Cascading shall not occur.
4.1.4.3. Applicable Facility Ratings shall not be exceeded.
4.1.4.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
4.1.4.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

- The drafting team spent one whole afternoon creating a write up that explains how PRC-012 and TPL-001-4 work together.
Next Steps

• If final ballot passes, the standard will be submitted to the NERC Board of Trustees

• If BOT approves, NERC will file with FERC