G&T Reliability Planning Models Task Force (GTRPMTF) Methodology and Metrics

A. Methodology

1. Areas for probabilistic resource adequacy metrics computations

a. Table 1 shows the geographic areas that will be used in the 2010 LTRA for self-assessment reporting (second column) with one exception – Southwest Power Pool (SPP), the Regional Transmission Organization (RTO), not the Regional Entity (RE), added RTO members from the MRO region in 2010. For the first time in 2010, PJM and MISO will report a self-assessment for their respective RTOs. The addition of the SPP RTO to this list reflects the same trend.

b. The last column in Table 1 shows the areas for reporting probabilistic metrics under the methodology. These will be identified as Metric Reporting Areas (MRAs). The differences with the annual Long-Term Reliability Assessment (LTRA) are bolded. The areas for probabilistic metrics reporting were adjusted to eliminate overlap areas that are included in PJM, MISO, and SPP (the RTO, not the Regional Entity). There are a total of 25 reporting MRAs: 16 in the Eastern Interconnection (EI), one in ERCOT, and eight in the Western Interconnection (WI). Three MRA's have no reporting requirements because they are included in either PJM or MISO – these are RFC-PJM, RFC-MISO, and Gateway in SERC. Required metrics are discussed in Section B.

2. Single MRA Simulation Software Model

a. Each MRA will utilize a single load-generation-transmission simulation software model for computing forward-looking probabilistic metrics.

b. Common load and generation model requirements that apply to every MRA are described in Sections A.3 and A.4. Many requirements allow flexibility at the MRA level, provided that what is being done is documented. This flexibility recognizes that several different, but equally valid, methods may be used by different MRAs. Allowing flexibility at this stage of the probabilistic assessment effort permits each MRA to make modeling decisions that are most meaningful to its Resource Planners and Transmission Planners. At a future time, disparate methods can be evaluated to determine whether common modeling approaches are warranted.

c. While no common transmission approach is proposed, each MRA must use a transmission modeling method to incorporate major transmission constraints and limitations. The transmission modeling method the MRA selects is at its discretion. The utilization of transportation models in one area while another uses a dc power flow model will permit a future evaluation of the benefits and limitations of each transmission modeling approach. Section 5 describes required transmission information.

d. Each MRA will explain how it models different entities that comprise the MRA, such as different Planning Authorities or Load Serving Entities. For example, are the different entities considered as one entity for the calculation of metrics? Or are the individual entities modeled separately?

Table 1
NERC LTRA Reporting Areas and Metrics Reporting Areas

Region	LTRA Reporting Areas		Metrics Reporting Areas and Interconnection (MRAs)
Multi-region RTOs	1	PJM	PJM / EI
	2	MISO	MISO / EI
	3	SPP (the RTO, not the RE)	SPP RTO / EI
ERCOT	4	ERCOT	ERCOT / ERCOT
FRCC	5	FRCC	FRCC / EI
MRO	6	MRO (US)	MRO (US) **less MISO and SPP areas in MRO (US)**/ EI
	7	MRO (CN)	MRO (CN) / EI
NPCC	8	New England	New England / EI
	9	New York	New York / EI
	10	Maritimes	Maritimes / EI
	11	Ontario	Ontario / EI
	12	Quebec	Quebec / EI
RFC	13	RFC-PJM	**Not reported – included in PJM area**
	14	RFC-MISO	**Not reported – included in MISO area**
SERC	15	Central	Central / EI
	16	Delta	Delta / EI
	17	Gateway	**Not reported – included in MISO area**
	18	Southeastern	Southeastern / EI
	19	VACAR	VACAR **less PJM areas in VACAR** / EI
SPP	20	SPP (the RE)	SPP RE **less SPP (RTO) areas in SPP RE** / EI
WECC	21	WECC-Canada	WECC-Canada /WI
	22	Northwest	Northwest /WI
	23	Basin	Basin /WI
	24	Desert Southwest	Desert Southwest /WI
	25	Rockies	Rockies /WI
	26	California-North	California-North /WI
	27	California-South	California-South /WI
	28	WECC-Mexico	WECC-Mexico / WI

3. **Load-shape modeling and documentation**
   a. Each MRA will utilize appropriate hourly chronological load model or models, depending upon 2.d. MRA's will describe how the coincident chronological load forecast was developed.
   b. All loads within a MRA's geographic boundary that are accounted for elsewhere must be documented.
   c. Load forecast uncertainty will be modeled and each MRA or MRA entity as appropriate (see 2.d) will document its method, describing the uncertainty components used (weather, economic, etc.), how their probability is incorporated, and how the MRA considered the uncertainty of different entities within the MRA.
   d. Each MRA will document how behind-the-meter (BTM) generation and any associated load are modeled. Explain whether netting (subtracting generation

from load) is used or explicit modeling of BTM generation and associated load is used.

e. Each MRA will document how the utilization of Direct Control Load Management, the curtailment of contracted Interruptible Demand[1], and any other controllable demand response is modeled. Controllable demand response can be modeled either as a load modifier or a resource~~.~~. However, it must be included in capacity resources for reporting purposes. [2]The documentation will explain the following:
   i. How seasonal demand response variations were considered (e.g., such as weather that might increase or reduce demand response from controlled appliances in different seasons).
   ii. For Interruptible Demands, how actual loads at the time of an interruption versus tariff contractual requirements are considered.
   iii. How demand response unavailability (forced and planned outages) is considered.
   iv. Is energy payback accounted for after demand response is deactivated?

4. Generation modeling and documentation

a. See Table 2 that contains four categories identified for generation resources in the LTRA. The "Conceptual" generation category is specifically excluded.[3] At a minimum, each MRA will explain how all four categories are addressed.

b. Model "Future, Planned" generation that has identified planned or existing transmission facilities for it to be deliverable and firm.

c. Each MRA will document all forecasted generation retirements and capacity re-ratings.

d. Each MRA will document all jointly-owned units, including temporary unit power sales or purchases, and how they are modeled when such units are shared by entities in different MRAs.

e. Each MRA will document all capacity sales or purchases.

f. For intermittent and energy-limited variable resources such as wind, solar, ~~cogeneration~~ and hydroelectric units, document how each these resources are modeled and what data is used.

g. For traditional dispatchable capacity, document how it is modeled and what data is used. The following needs to be documented by each MRA:
   i. Ratings: Document how monthly or seasonal on-peak capacity ratings were developed.
   ii. Forced outage modeling: Document exceptions to the following approach.

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[1] Include any load that has contracted to the interrupted or curtailed, including those that require pre-notification. Also includes utility load that is committed to be interrupted.

[2] See the report prepared by the Resource Issues Subcommittee and posted at: http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf.

[3] The "Conceptual" category is defined in the LTRA.

1. For existing unit forced outage modeling, use historic resource EFORd[4] along with those changes projected by the Generation Owner. If unit-specific EFORd is unavailable, use historic GADS or Canadian Electricity Association (CEA) class averages. For "new" generation without an EFORd history, utilize historic generation GADS or CEA class averages.
2. Model random outages for all units as random variables as opposed to derating the unit's capacity.

iii. Planned outage modeling: Document how planned outages are modeled.

5. Transmission

a. The modeling of existing and future transmission must be consistent with the modeling of existing and future resources. Therefore, each MRA will document transmission additions and retirements for each study year.

b. Each MRA will describe its transmission modeling approach, how that approach takes in to account transmission constraints and outages within and outside of the MRA, and how it developed the data needed for modeling, consistent with their planning processes. By modeling transmission, the MRA can take appropriate credit for external available deliverable capacity during shortage periods. On the other hand, internal constraints within an MRA can reduce MRA reliability.

6. Assistance from External Resources

Each MRA will explain its assumptions and methodology for quantifying non-firm assistance from resources outside the MRA's footprint.

[4] EFORd is defined in IEEE Standard 762 IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity. It is computed in NERC's voluntary Generating Availability Data System (GADS).

Table 2

Generation Resource Categories

1. Existing, Certain: Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following: • Contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment. • Where organized markets exist, designated market resource that is eligible to bid into a market or has been designated as a firm network resource. • Network Resource, as that term is used for FERC *pro forma* or other regulatory approved tariffs. • Energy-only resources confirmed able to serve load during the period of analysis in the assessment and that will not be curtailed. Energy-only resources with transmission service constraints are to be considered in the "Existing, Other" category. • Capacity resources that cannot be sold elsewhere. • Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed during the period of analysis in the assessment. Other resources with transmission service constraints are to be considered in the "Existing, Other" category.
2. Existing, Other: Existing generation resources that may be available to operate and deliver power within or into the Region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in the Existing, Certain category. This Existing, Other category includes, but is not limited to the following: • A resource with non-firm or other similar transmission arrangements. • Energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason. • Mothballed generation (that may be returned to service for the period of the assessment). • Portions of variable generation not counted in the Existing, Certain category (e.g., wind, solar, etc. that may not be available or derated during the assessment period). • Hydro generation not counted in the Existing, Certain category, or derated. • Generation resources constrained for other reasons.
3. Future, Planned: Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. This category includes, but is not limited to, the following: • Contracted (or firm) or other similar resource. • Where organized markets exist, designated market resource that is eligible to bid into a market or has been designated as a firm network resource. • Network Resource, as that term is used for FERC pro forma or other regulatory approved tariffs.
4. Future, Other: This category includes future generating resources that do not qualify in Future, Planned and are not included in the Conceptual category.[5] This category includes, but is not limited to, generation resources during the period of analysis in the assessment that may: • Be curtailed or interrupted at any time for any reason. • Energy-only resources that may not be able to serve load during the period of analysis in the assessment. • Variable generation not counted in the Future, Planned category or may not be available or is derated during the assessment period. • Hydro generation not counted in category Future, Planned category or derated. • Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

[5] The Conceptual category is defined in the LTRA.

B. Probabilistic Resource Adequacy Metrics

1. Definition of loss-of-load event

Each MRA will document how it defines a loss-of-load event. For example:

a. Are voltage reductions or public appeals considered a loss-of-load event?

b. Are reducing the Spinning Reserve portion of Operating Reserves below the minimum requirement of the Balancing Authority considered a loss-of-load event?

2. Study periods

The metrics below will be calculated annually for each MRA for the year two and year five of the LTRA. Although the LTRA spans a 10-year period, the selection of these two years provides the greatest value while reducing the reporting burden of calculating metrics for each year of the LTRA.

3. Metrics calculation

The following metrics will be calculated for the each MRA[6] for each calendar year study period:

a. Annual loss-of-load hours (LOLH) – Evaluated for all hours per year.[7] Note that if individual entities are modeled within an MRA, the LOLH for the MRA is not the sum of the LOLH values of each entity. The sum must be reduced by any common hours of load loss.

b. Annual expected unserved energy (EUE) – Evaluated for all hours per year (GWH).[7] Note that if individual entities are modeled within an MRA, the EUE of entities within an MRA is the sum of the EUE values for each entity.

c. Normalized EUE = [EUE/(Net Energy for Load)] x 1,000,000. Compare the simulated ~~EUE to the simulated~~ Net Energy for Load used in this calculation to the Net Energy for Load in the LTRA.[8]

Reserve margins will be already calculated in the LTRA; however, three MRAs will need to recalculate their reserve margins because they will have portions of their footprint included in MISO, PJM, or SPP. These are MRO (US) without the MISO area, VACAR without the PJM area, and the SPP RE without the SPP RTO area.

[6] The modeling of a MRA may involve the modeling of several different Planning Coordinators (PCs) or Load-Serving Entities (LSEs) within a MRA. The metrics specified in Section B are only required for the metrics reporting area as a whole and not for the PCs or LSEs within that area. In addition, because each MRA will be developing metrics using different modeling approaches, MRA-to-MRA metrics may not be comparable. However, different study year metrics for an MRA are comparable. In addition, an MRA's metrics from one LTRA to another LTRA would be comparable, assuming an MRA's methodology does not change.

[7] Document hours which are not evaluated because they have no material contribution to the metric.

[8] The sum of the chronological loads for an MRA (simulated NEL) may differ from the Net Energy for Load reported in the LTRA. The development of a chronological MRA load model from the chronological load forecasts of the MRA entities may require adjustments.

C. Confidentiality Agreement

Each MRA may need to develop and require a confidentiality agreement that permits "confidential information" as defined by Section 1500 of NERC's *Rules of Procedure* to be provided by those who supply confidential data to those who will be performing the analysis using that confidential data. In addition, MRAs may need to develop and require confidentiality agreements for sharing MRA-to-MRA data.[9]

D. Reporting

A common MRA report format will be provided for metric reporting and the documentation and explanation of each MRA's modeling method.[10]

[9] Existing confidentiality agreements may not be sufficient to cover the data collection needed to satisfy the metric calculations required under this document.

[10] The report format will be developed by the GTRPMTF at a later date, taking into consideration input on the methodology and metrics from the NERC Planning Committee and several of its subgroups – for example, the Reliability Assessment Subcommittee, Resource Issues Subcommittee, and the Reliability Metrics Working Group. The report format will be subject to Planning Committee approval.