NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

G&T RPM Task Force Final Report on Methodology and Metrics

Prepared by the Generation & Transmission Reliability Planning Models Task Force for the NERC Planning Committee

Presented to the Planning Committee (PC) on September 15, 2010, including Planning Committee Approvals and Revisions from the September 15, 2010 and December 8, 2010 PC Meetings

to ensure the reliability of the bulk power system

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Table of Contents

1. Recommendations

Pursuant to its scope, the G&T Reliability Models Task Force (TF) recommends that the Planning Committee:

1. Approve the *Methodology and Metrics* document (in Appendix 3).
2. Approve the implementation plan (in Section 4).

The Planning Committee approved these recommendations on September 15, 2010. The Methodology and Metrics document was subsequently revised to incorporate a report outline as well as to make minor changes that add clarity and consistency. The revised Methodology and Metrics document was approved on December 8, 2010 and is included in Appendix 3, which has a clean and redline versions against the September 15 approved document.

2. Background

At the December 2008 NERC Planning Committee (PC) meeting, the PC approved the formation of the task force with these two main deliverables in the scope:

- To evaluate approaches and models for composite generation and transmission (G&T) reliability assessment. (The term "generation" was taken to include all resources including demand-side management.)
- To provide a common set of probabilistic reliability indices and recommend probabilistic-based work products that could be used to supplement the NERC's long-term reliability assessments.

At the June 2009 PC meeting, the TF delivered a report with four recommendations, two of which addressed a revised work plan and a revised scope. The PC revised the work plan and the scope. [1] (The current GTRPMTF scope, including its work plan, is in Appendix 1.) The scope was revised, with the first deliverable above changed to "develop a common composite generation and transmission reliability modeling methodology for the purpose of assessing system resource adequacy, which considers the ability of load to receive power supplied by aggregate resources."

Since then, the TF had numerous conference calls and six face-to-face meeting. At the June 2010 meeting, the PC approved posting draft *Methodology and Metrics* document for comments and conducting a Web meeting on July 15 to address any questions. Written comments were received by August 6. All written comments are included in Appendix 2, including answers to questions posed by commenters. As a result of the comments received, the *Methodology and Metrics* document was revised and approved on September 15, 2010. *As noted above, the Methodology and Metrics document was subsequently revised again to incorporate a report outline as well as to make minor changes that add clarity and consistency. The revised Methodology and Metrics document was approved on December 8, 2010 and is included in Appendix 3, which has a clean and redline versions against the September 15 approved document.*

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[1] The report with the PC's revisions is available at http://www.nerc.com/docs/pc/gtrpmtf/Final_GTRPMTF_Rpt_to_PC-06-09-09.pdf.

3. Review of Issues Addressed by the TF

The TF had to define a framework for developing probabilistic metrics for inclusion into the LTRA. The path that was taken is described below. *Only those issues which proved difficult to address are discussed below*.

1. The term "metrics reporting area" (MRA) for reporting probabilistic metrics is synonymous with the reporting subregions of the LTRA. Based upon the proposed 2011 LTRA's 26 subregions approved at the December 8, 2010 PC meeting, 26 identical MRAs are defined.

2. Initially, the TF believed its assignment was to develop a methodology that would produce metrics that could be comparable between all MRAs; for example, all 16 MRAs in the Eastern Interconnection would have comparable metrics to supplement the reserve margin calculation in the LTRA. In its June 2009 report, the TF had concluded the following:

   The TF does not believe that a common approach necessarily requires a single model – different models could be used that perform computations in a consistent manner defined by a common methodology.

   However, allowing different models complicates implementation. That is because each MRA's metrics would rely in part upon the assumptions and modeling approaches used by its neighboring MRAs since an MRA's metrics are dependent upon the availability of capacity from its neighbors. A neighboring MRAs available capacity is, in turn, partially dependent upon *its* neighbors' situation as well. The TF recognized that practical limitations might require partial modeling of neighboring systems; however, it also believed that if each MRA within an Interconnection used different models, especially with regard to their modeling of transmission constraints, comparability would unlikely be achieved. Differences between the metrics of different MRAs would be partially due to modeling differences. One solution to avoiding these complications would be to require a common model to be used within an Interconnection. The interim decision to use a common model raised concerns within the Eastern Interconnection regarding how a common model would be agreed upon by 16 MRAs in six Regional Entities.

3. A common Interconnection model also turned into a challenge from an unexpected technical area – the development of an Interconnection-wide load model that is comprised as the sum of the individual MRA load models. In the reliability modeling done by some entities, a single load shape is used that is determined by the entity as appropriate for their area. They use those same load shape assumptions for the neighbors that they model. However, a single load shape for an Interconnection would not produce comparable metrics for the MRAs within the Interconnection. The reason is that while such a load shape may be typical for some MRAs, it may be atypical (i.e., loads are higher or lower than normal) for other MRAs, resulting in metrics that are not comparable due to load level differences. Ways to overcome this issue were considered by members, but they were deemed cumbersome and untried on the scale that would be required for an Interconnection-wide calculation.

4. The desire for a common methodology to develop comparable metrics for an Interconnection seemed an unachievable goal, given the state of the industry's use of

probabilistic resource adequacy models. Some Resource Planners have a long history of using such models. Other Resource Planners may not use probabilistic models for resource adequacy planning. Therefore, the TF decided to develop a common methodology that could be interpreted as liberal on the use of the term "common." In the draft *Methodology and Metrics* document, the TF allows each MRA to choose its own model for computing a common set of probabilistic metrics. However, for consistency, the *Methodology and Metrics* document does require adherence to these minimum requirements:

a. An hourly chronological load model that includes load forecast uncertainty.
b. A limitation on what generation is to be included in modeling. Future generation to be included must have associated transmission.
c. For modeling dispatchable capacity, random outages for all units are to be modeled as random variables as opposed to derating the unit's capacity.
d. While no common transmission approach is prescribed, each MRA must use a transmission modeling method to incorporate major transmission constraints and limitations, consistent with their planning processes. The transmission modeling method the MRA selects is at its discretion. Each MRA must document its transmission modeling approach – how that approach takes in to account transmission constraints within and outside of the MRA, and how it developed the data needed for modeling.
e. Three metric results: (i) annual Loss-of Load Hours (LOLH), (ii) Expected Unserved Energy (EUE), and (iii) Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE) for two common forecasted years – year 2 and year 5.[2]
    i. The TF did not recommend the computation of Loss-of-Load Expectation (LOLE). This metric is generally defined as the summation of the Loss of Load Probability (LOLP) for each daily peak hour. Therefore, the metric calculation is based on 365 hourly load values.[3] Since LOLE only evaluates resource reliability across the daily peak hour, the reliability of energy-limited systems or systems with significant variable resources may not be accurately modeled.
f. Documentation of all modeling assumptions.
g. A common report format.

The TF has opted for a methodology that has many common elements. While this may not lead to the direct comparability of metrics between MRAs, the *Methodology and Metrics* document will allow for consistency of the inputs to the metrics. Not all comparability, however, is lost by the TF's recommendations. By requiring each MRA to forecast metrics for two common years, the trend for an MRA's reliability over time is displayed. In addition, an MRA's metrics from one LTRA to another LTRA would be comparable, assuming an MRA's methodology does not change. More importantly, the

[2] 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] Some entities use only the weekday peak loads, or 260 hourly values. These entities generally assume that the LOLP for the weekend peak loads are expected to sum to zero and not contribute to the LOLE for the year.

approach proposed will allow each MRA to maximize the use of any on-going probabilistic modeling efforts and hence the usefulness of the analysis to the MRAs themselves. Finally, over time, the reports produced by the MRAs will describe their modeling methods used and allow the possibility of more common modeling and therefore more comparability.

4. Implementation Plan

The following outlines the major tasks to be completed in the implementation plan.

4.1. Immediate – by year end 2010

1. The TF will draft, for PC approval at the December 2010 PC meeting, the report format for the MRAs to use to report the metrics and the detailed documentation of their model assumptions and approaches to implementing the methodology. *The TF incorporated the report outline in an updated Methodology and Metrics document, which the PC approved on December 8, 2010. See Table 3 in the Methodology and Metrics document (clean version)) in Appendix 3.*
2. The PC will assign the Resource Issues Subcommittee (RIS) the task of coordinating this implementation plan at the September 2010 meeting.
3. Each MRA will, through the RIS, determine what it needs to do to be able to conduct the probability analysis required in the *Methodology and Metrics* document, and report the information at the December 2010 PC meeting. RIS will identify those MRAs with the modeling capability to participate in the 2011 field test.
4. The PC will disband the G&T Reliability Planning Models TF upon approval of the report format prepared for the MRAs (at the December 2010 meeting). *The PC approved disbanding the TF once it had updated this report.*

4.2. Near term – in 2011

1. The MRAs that have the modeling capability will conduct a probability analysis based on the 2010 LTRA data, and provide the results to be used as a field test. The RIS will review the field test results to determine what changes need to be included prior to conducting the analysis for the 2012 LTRA.
2. The MRAs that do not currently have the modeling capability will acquire or access a model to be used for their probability analysis.

4.3. Long term – 2012 and later

1. All MRAs will conduct a probability analysis and report the metric results to the RIS. Results will be due to the RIS six months after the LTRA is finalized. The initial LTRA referenced for this analysis is expected to be completed in October 2012.
2. The RIS will include the metric results in a separate summary report issued for review at the June 2013 PC meetings.
3. The RIS will make a recommendation to the PC whether or not to continue this effort moving forward, and if it is recommended to be continued, what changes should be considered for future LTRAs.

Appendix 1. G&T RPM Task Force Scope & Work Plan

Please see the next two pages.

G&T Reliability Planning Models Task Force

Purpose and Deliverables

This task force will develop a common composite generation and transmission reliability modeling methodology for the purpose of assessing system resource adequacy, which considers the ability of load to receive power supplied by aggregate resources. The task force will provide a common set of probabilistic reliability indices and recommend probabilistic-based work products that could be used to supplement the NERC's long-term reliability assessments. The task force's milestones are described in the attached work plan.

Membership

The PC Chair will appoint a chair and PC members and PC subgroup members with resource planning and transmission planning expertise for the task force. Industry experts may be appointed as well. The PC Secretary will be the secretary of the task force.

Members are expected to participate in the task force's discussion, including the development of the work plan and the final report.

Governance

The task force reports to the Planning Committee and its work products will be subject to PC review and approval.

Meeting

Meeting and conference calls will be scheduled as needed.

Approved by the Planning Committee: June 10, 2009

Planning Committee Approved G&T Reliability Planning Models Task Force Work Plan
June 2009-June 2010

Note: In this work plan, sometimes several tasks are being done at the same time. Therefore the cumulative number of weeks is not equal to the sum of the number of weeks of the current task plus all prior tasks. All weeks are rounded to the nearest ½ week.

Task No.	Task description	Start date	End date	Weeks	Cum. Weeks
1	Develop consensus on process and method: a. Assessment procedures – which entity does it? What is the level of reporting (regions, zones, etc.)? Address data confidentiality. b. Assessment parameters - time frames (e.g., daily peaks vs. hourly loads), definitions (e.g., what constitutes a loss-of-load), and general generation and load data requirements c. Transmission model representation (AC or DC power flow versus transportation model), modeling of transmission availability, and transmission data requirements d. Other modeling issues per the "parking lot" list e. Determine if we need to calibrate NERC results with existing methods used by others f. Uniqueness issues with regard to modeling a region or Interconnection. Is the method a minimum or can the method be enhanced or modified to account for specific differences?	6/15/09	11/15/09	22	22
2	**Major progress report to the PC: December 2009 meeting** to report on Task 1.	9/15/09	11/19/09	9.5	22.5
3	Identify potential metrics that could be used in the LTRA for assessments and identifying reliability trends but not for resource requirements. Clarify possible metrics overlap responsibility with the Reliability Metrics Working Group.	11/20/09	2/15/10	12.5	35
4	Hold several **WebEx sessions** on the task forces' work to date with all NERC PC subgroups and the regions invited. Seek their input on the task force's recommendations to date. If appropriate, modify those recommendations.	2/1/10	3/15/10	6	39
5	**Major progress report to the PC: June 2010 meeting** on Tasks 3 and 4,	3/16/10	5/19/10	9	48.5

Appendix 2. Comments – Methodology and Metrics Document

The comments received and the TF responses follow.

Comments Received on draft *Methodology and Metrics* Document (5/27/10 version) and GTRPMTF responses

Each person's comments and the draft document are posted at http://www.nerc.com/filez/gtrpmtf.html under the "Related Files" heading.

Commenter	Section Reference	Comment	GTRPMTF Response
Pakeltis	A.4.g (p. 3)	As NERC moves forward with metrics that are related to TADS Elements, it would be good to recommend common use of outage terms from the TADS definitions. In that case, I recommend that the following be revised to use "Automatic Outage" and Non-Automatic Outage" instead of the following: [an insert that duplicates Section A.4.g which references forced outage modeling and planned outage modeling for dispatchable generation.]	The TF believes that it is not practical to adopt a common terminology for this effort. The terminology used is well known by resource planners. However, your suggestion will be sent to the Generating Availability Data System Task Force.
Cox	None	I think it would be helpful to understand how these (new) models align with (or not) other models / studies.	Since the methodology is proposed to evaluate trends within an MRA, the TF doesn't believe that comparisons with existing methods are necessary. We would leave any comparison to the individual MRA entities.
Cox	B.1 (p. 5) and C (p.6)	You provide discretion for each MRA to develop its own "loss of load event" and its own confidentiality agreement. It may be better to have a proposed NERC model for both and for each MRA to indicate how (if at all) they intend to differ from it.	The TF did not define a common loss-of load event so that the definition used locally could be adopted, with an explanation required. We believe that is sufficient. Likewise, we did not propose a common confidentiality agreement, allowing each MRA to adopt its own to suit its needs.
Chowdhury	None	I went through the methodology and it looks good to me. I look forward to contributing to the task force.	No response required.
Mazur	None	As there is no standard requiring reporting of metrics, what mechanism will be used to ensure that the metric calculations are done?	Once approved by the PC, a request for the metrics, calculated per the methodology and following a prescribed report format, will be a "data request" similar to other data requested for the LTRA. The LTRA uses NERC's *Rules of Procedure*, Section 804 – Reliability Assessment Data and Information Requirements to request LTRA data.
Mazur	Table 1 (p. 1)	Metric reporting area (MRA): The document indicates that MH and Saskatchewan shall be combined to be the MRO Canada and probabilistic indices will be calculated and reported to NERC as one MRA. The MRA should be tied to a functional entity such as the Planning Authority, or MRO which would include MH, Saskatchewan and MRO US. An entity such as MRO Canada does not exist, so who would conduct the studies to develop the metric for MRO Canada?	The Regional Entity will coordinate with MRA's within its region to ensure that all entities are included in a metrics calculation. The MRAs could coordinate among themselves to perform the studies; alternatively, a third party could be contracted with to do the analysis on behalf of the entities. If future LTRA reporting is done on a Planning Authority basis, then Manitoba Hydro and Saskatchewan could report separately.

Comments Received on draft *Methodology and Metrics* Document (5/27/10 version) and GTRPMTF responses

Commenter	Section Reference	Comment	GTRPMTF Response
Mazur	A.2.c (p. 2)	The original task was to develop a common composite generation and transmission reliability modeling methodology. However, no common transmission model requirements are proposed. Can the GTRPMTF provide some reason for not using a common methodology?	The TF added language in the September 2010 report to the Planning Committee to explain did not prescribe a common methodology. Several valid methodologies to appropriately model transmission constraints and limitations currently exist. Transmission constraints, however, must be considered in the analysis.
Mazur	A.3.d (p.2)	Each MRA will document the modeling of behind-the-meter demand and associated BTM generation? Does this preclude modeling net demand of such customers?	No. We have modified the document to make that clear.
Mazur	A.4.b (p.3)	Requires one to only model "Future, Planned" generation that has identified planned or existing transmission facilities for it to be deliverable and firm. How is firm defined, or is it left to the entity?	All "Future, Planned" generation is firm. See the description of "Future, Planned" in Table 2 of the document. This definition is used by entities for LTRA reporting. Only Future, Planned generation that has planned or existing transmission to make it deliverable and firm should be modeled. In other words, we do not want generation to be modeled without the corresponding transmission needed to make it deliverable.
Mazur	A.4.e (p.3)	What does "all full requirements" mean?	The TF changed the document and eliminated the term "full requirements" from A. 4.e.
Mazur	Table 2 (p. 4)	4. Future, Other refers to a Conceptual Category – it does not exist in the table.	The TF added a footnote that the Conceptual Category is a separately defined category within the LTRA that we are not using.
Mazur	B.3 (p.5)	The traditional index of LOLE (expressed in days/year) is not included as a probabilistic metric instead the Task Force recommends LOLH (expressed in hours/year). Many entities are more comfortable with the LOLE index. Is there a reason for choosing LOLH? Should both indices be calculated for each MRA?	The TF added language in the TF's September 2010 report to the Planning Committee to explain why it did not chose to calculate this index. Additional metrics, such as LOLE, may be included by any MRA if desired, so long as the calculation is explained.
Hohlbaugh	Table 1 (p.1)	Table 1 highlights differences with the annual Long-Term Reliability Assessment (LTRA) sub-area groupings. FE applauds the TF's efficiency of excluding groups 12 (RFC-PJM) and 13 (RFC-MISO). FE concurs that Metric Reporting Areas (MRA) 1 (PJM) and 2 (MISO) sufficiently cover the RFC footprint. The change is an improvement and provides reporting efficiencies that should carry over to the LTRA.	No response required.

<u>Comments Received on draft *Methodology and Metrics* Document (5/27/10 version) and GTRPMTF responses</u>

Commenter	Section Reference	Comment	GTRPMTF Response
Hohlbaugh	A.2.c (p. 2)	This item states " … no common transmission model requirements are proposed …". This appears to deviate from the scope set forth by the PC that indicated the TF should "develop a <u>common</u> composite generation and <u>transmission</u> reliability modeling <u>methodology</u> for the purpose of assessing system resource adequacy." The document should further explain this apparent deviation from the PC's goal.	The TF added language in the TF's September 2010 report to the Planning Committee to explain why it did not prescribe a common methodology. Several valid methodologies to appropriately model transmission constraints and limitations currently exist. Transmission constraints, however, must be considered in the analysis.
Hohlbaugh	A.3.b (p.2)	It is indicated that "All loads within a MRA that are excluded must be documented." The ability to exclude load appears to conflict with the RFC reliability standard BAL-502-RFC-02 requirement R1.7 that indicates the Planning Coordinator must account for all load within its Resource Adequacy Assessment. By 'excluded' does that TF envision significant load retirements? If so, the TF may also want to consider reporting of significant load additions (step change) from prior years.	The TF does not mean load associated with BTM generation, since that is addressed in 3.d. The TF clarified this sentence in the document to read "All loads within a MRA's geographic boundary that are accounted for elsewhere must be documented."
Hohlbaugh	A.4.g (p.4)	On-peak capacity ratings. Shouldn't be expected that the on-peak generation capacity ratings simply be consistent with the values obtained and reported through the NERC reliability standards (MOD-024)?	They should be consistent with what is reported in the LTRA. MOD-024 addresses ratings for steady-state (i.e. power flow) models, and only addresses generation covered by NERC's registration criteria. There is no requirement within the LTRA that the rating be the same at this time as MOD-024; however, in practical terms the ratings should be close.
Gibson	None	WECC LRS also is concerned that there appears to be no clear goal for this process. If NERC intend to use the results of these studies to compare reliability across regions, then differences in data treatment, characterization of uncertainty in the major variables and modeling approaches required by data availability and computational limits will render the results across NERC less comparable than the task force would perhaps like.	While it was the TF's original intent to provide comparability among different MRAs, the flexibility that the method permits still allows for trending within an MRA.

Comments Received on draft *Methodology and Metrics* Document (5/27/10 version) and GTRPMTF responses

Commenter	Section Reference	Comment	GTRPMTF Response
Gibson	None	In addition, WECC LRS suggests that following the first submittal, the G&T Reliability Planning Models Task Force (GTRPMTF) evaluate the responses to determine the value added in this process. The results of this evaluation should be used to determine if this process should continue. WECC LRS is concerned that this study requirement will become permanent even though there may be no clear value added.	The TF agrees that the value of these results should be reviewed by the Planning Committee after initial submittal to determine whether value was added to resource adequacy assessments. The requirement for and evaluation has been added to the implementation plan contained in the TF's September 2010 report to the Planning Committee.
Gibson	A.2.a (p.2)	WECC does the overall analysis for the region but will report by MRA. All requirements for MRAs are taken to be requirements for WECC as a whole in these comments.	No response required.
Gibson	A.2.b (p.2)	WECC LRS agrees that flexibility in modeling approaches is necessary. We do not support the notion that in the future, a common modeling approach might be warranted.	The TF does not know whether a common modeling approach would be warranted; it only suggested it be evaluated.
Gibson	A.2.d (p.2)	For WECC, behind-the-meter generation is a minor issue, with line 1d amounts in the LTRA amounting to ~0.7% of net internal demand. WECC does not have sufficient data to treat this question probabilistically and the LTRA does not ask for such data (basically, FORs for BTM generation). WECC LRS suggests this question be dropped.	Netting can be used, and we have clarified the document in this regard. We just ask that the treatment of BTM generation and load treatment be documented.
Gibson	A.3.e (p.2)	Demand response is an important issue and the magnitude, while relatively small in WECC currently, is likely to grow in the future. However, the variations around expected values for implementable amounts are largely unknown at this time. Until the size of the demand response resource gets bigger, the detail about the uncertainties of individual programs and their implementation required for a probabilistic analysis would likely not be worth the effort to pursue and model, particularly in the context of the larger load and generation availability uncertainties. WECC would not be in a position to provide the level of detail proposed to be required and suggests that the detailed requirements in parts 3.e.i-iv be dropped.	The method does not require a probabilistic analysis of DR. It may be modeled deterministically as a load modifier or a resource. The questions in 3.e.i-iv are intended to document how DR is accounted for. Those entities that sponsor DR programs should be able to address them.

Comments Received on draft *Methodology and Metrics* Document (5/27/10 version) and GTRPMTF responses

Commenter	Section Reference	Comment	GTRPMTF Response
Gibson	A.4.e (p.3)	Because WECC models the entire interconnection, which has a very robust power market, it is only concerned in its adequacy analyses with generation availability and physical transmission constraints on delivery, not with contracts. WECC does not collect contract data, which would be irrelevant in these circumstances, though relevant for some other regions.	This requirement may not apply since WECC is modeling the entire interconnection. However, WECC's modeling (or not modeling) of contracts needs to be documented.
Gibson	A.4.f (p.3)	This requirement offers another illustration of the need for flexibility in modeling and in treatments of uncertainty. The availability of wind generation data is limited: the WECC-wide synthetic hourly data set from NREL has only three year's worth of data. While longer data sets may exist for particular areas of WECC, their availability is often constrained by confidentiality limitations imposed by developers. There are three large hydro systems in WECC (Northern California, the US Northwest and BC), the modeling of which is extremely complicated. Incorporating the uncertainty of their output, particularly the hourly energy output, into a probabilistic analysis that incorporates all the other uncertainties across WECC would require realistic approximations and flexibility in interpretation.	This just requires that an MRA document how intermittent resources are modeled. The data used need not be provided.
Gibson	B.3.a, B.3.b (p. 5)	Both of these requirements call for evaluation of the metrics across all hours of the year. This is theoretically correct, but raises again the need for flexibility in approaches to the correct method, so that the data and computational burden become manageable. Analytical methods that provide approximations need to be allowed, such as analyses that provide prior information on the hours in which the metric are likely to be zero or approximately zero, allowing more detailed analysis of periods likely to have loss of load. Language such as "Appropriately evaluated for all hours per year" would convey the necessary flexibility.	We have added a footnote in both metrics that states "Document hours which are not evaluated because they have no material contribution to the metric."

Commenter	Section Reference	Comment	GTRPMTF Response
Gibson	D.1-2 (p.6)	WECC LRS supports a phased-in implementation period, with the first report due no earlier than 2012. WECC LRS also supports reporting results of the LTRA and the probabilistic analysis in two separate reports, separated in time by approximately six months to allow adequate time for the evaluation to be completed. This time gap could potentially be reduced in later years, as the process becomes more routine.	The TF removed this section and instead conveyed the same thought in its implementation plan included in the TF's September 2010 report to the Planning Committee.

Appendix 3. *Methodology and Metrics* Document – Clean and Redlined

Clean and redlined versions of the *Methodology and Metrics* document follow.

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 subregions that will be used in the 2011 LTRA for self-assessment reporting. RFC does not report separately (as was done in 2010) because it is entirely included in the PJM and MISO Regional Transmission Organizations (RTOs).

b. The identical LTRA subregions will be used for reporting probabilistic metrics under this methodology. These will be identified as Metric Reporting Areas (MRAs). There are a total of 26 reporting MRAs: 16 in the Eastern Interconnection (EI), one in ERCOT, and nine in the Western Interconnection (WI). Required metrics are discussed in Section B.

2. MRA Simulation Software

a. Each MRA will utilize load-generation-transmission simulation software 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; however, to improve transparency each MRA is required to document their input assumptions. 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 may 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, limitations, and issues such as deliverability of designated resources to load and imports of supplemental resources. 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 Subregions and Identical Metrics Reporting Areas

Region	LTRA Reporting Subregions and MRAs		Interconnection
Multi-region RTOs	1	PJM	Eastern
	2	MISO	Eastern
TRE	3	ERCOT	ERCOT
FRCC	4	FRCC	Eastern
MRO	5	MRO (US) excluding MISO and SPP RTO areas in MRO (US)	Eastern
	6	MRO (CN) Manitoba	Eastern
	7	MRO (CN) Saskatchewan	Eastern
NPCC	8	New England	Eastern
	9	New York	Eastern
	10	Maritimes	Eastern
	11	Ontario	Eastern
	12	Quebec	Eastern
SERC	13	TVA	Eastern
	14	SOCO	Eastern
	15	ICTE[1]	Eastern
	16	VACS excluding PJM areas is VACS	Eastern
SPP	17	SPP RTO plus the SPP RE	Eastern
WECC	18	NWPP (US)	Western
	19	Basin (US)	Western
	20	RMPA (US)	Western
	21	Desert SW (US)	Western
	22	CAISO (US)	Western
	23	CA (US) excluding CAISO	Western
	24	BC (CN)	Western
	25	AESO (CN)	Western
	26	Mexico (MX)	Western

3. Load-shape modeling and documentation

a. Each MRA will utilize appropriate hourly chronological load model or models, depending upon 2.d. MRAs 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.

[1] Includes SPP Reliability Coordinator entities registered in SERC.

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[2], and any other controllable demand response is modeled. Controllable demand response will be reported as capacity, consistent with the report prepared by the Resource Issues Subcommittee. [3] Controllable demand response can be modeled either as a load modifier or a resource. 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 forecast load interrupted differs from tariff contractual load subject to interruption.
   iii. If demand response is considered fixed and constant or subject to variability.
   iv. Is energy payback accounted for after demand response is deactivated?

4. Generation modeling and documentation

a. Table 2 contains four categories of generation resources which have been identified in the LTRA. The "Conceptual" generation category defined in the LTRA has specifically been excluded.[4] 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 consistent with the transmission criteria identified by the MRA.

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, 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:

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[2] 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.

[3] See http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf.

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

i. Ratings: Document how monthly or seasonal on-peak capacity ratings were developed.

ii. Forced outage modeling: Document exceptions to the following approach.

1. For existing unit forced outage modeling, use historic resource EFORd[5] 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 its planning processes. If transmission constraints (e.g. thermal, voltage, stability, or interface limits) are used in the MRA's process, the methodology should be described. The MRA should also describe how deliverability of internal and external resources and access to external supplemental resources is addressed.

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.

[5] 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.[6] 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.

[6] 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 the calculation of the metrics.

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[7] for each calendar year study period:

a. Annual loss-of-load hours (LOLH) – Evaluated for all hours per year.[8] 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 simulated)] x 1,000,000.

C. Confidentiality Agreements

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]

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[7] 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.

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

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

D. Reporting

The initial report outline is included on Table 3. This outline will be modified, as needed, with Planning Committee approval, by the Resource Issues Subcommittee or other group designated by the Planning Committee.

1. **General instructions:**
   a. The data used in the simulation models should be consistent with the data reported in the LTRA, or explained if different.
   b. No confidential data will be disclosed by an MRA in their report.
   c. The calculation years for the field test (pilot) calculation and report will be 2011 (year 2) and 2014 (year 5), based on the 2010 LTRA.

Table 3
Metrics Reporting Area Report Outline

General instructions per Section D.1 of the *Methodology and Metrics* document:

1. The data used in the simulation models should be consistent with the data reported in the LTRA, or explained if different.
2. No confidential data will be disclosed by an MRA in their report.
3. The calculation years for the field test (pilot) calculation and report will be 2011 (year 2) and 2014 (year 5), based on the 2010 LTRA.

Report Outline	Relevant sections in the *Methodology and Metrics* document
1. Summary	**NA**
a. Identify the entities included in the MRA and whether the individual entities were modeled or whether they were modeled as a single combined entity.	The entities need to those in the MRAs defined in Table 1. See Section A.2.d.
Items 1.b-1.e are to be put into a table b. Seasonal capacity totals (summer and winter) – year 2 and year 5 by subcategory, with a total provided: i. Controllable capacity demand response ii. Intermittent and energy-limited variable resources iii. Traditional dispatchable capacity iv. Sales v. Purchases	See Section A.3.e regarding reporting of controllable capacity demand response (CCDR) as capacity, section A.4.f for intermittent and energy-limited variable resources, section A.4.g for traditional dispatchable capacity, and section A4.e for capacity sales and purchases. Note that all capacity should account for retirements and re-ratings (Section A.4.c).
c. Coincident forecast 50/50 peak seasonal demands (summer and winter) as reported in the LTRA, and the comparable demands from the simulation, if different – year 2 and year 5.	See Section 3.a and 3.b.
d. Net Energy for Load as reported for the LTRA and the simulated NEL, if different – year 2 and year 5.[10]	See Section 3.a and 3.b.
e. MRA metrics results – year 2 and year 5	See section B.3.
2. Software model description	**NA**
a. Describe the basic computational approach – Monte Carlo or analytical method.	Not discussed in the *Methodology and Metrics* document. However, this was addressed in Section 2 of the GTRPMTF report posted at http://www.nerc.com/docs/pc/gtrpmtf/Final_GTRPMTF_Rpt_to_PC-06-09-09.pdf.
b. Does the model have an algorithm to reduce the number of hours included in the metric calculations when the hours have no material impact on the metrics? Was the algorithm used?	See Section B.3.a and footnote 7.

[10] 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.

Report Outline	Relevant sections in the *Methodology and Metrics* document
3. Demand Modeling	**NA**
a. For items 1.c and 1.d, explain any differences between the reported information and similar data reported in the LTRA.	For 1.c, explain any demand differences (the LTRA may report non-coincident load forecasts while the chronological load model will have coincident forecasts); for item 1.d, explain any differences between the simulated NEL and the LTRA reported NEL. See Section B.3.c. and footnote 8.
b. Explain the development of the chronological load model and any loads within the MRA's geographic boundary that are accounted for elsewhere.	See A.3.a and A.3.b.
c. Explain how load forecast uncertainty was modeled.	See A.3.c for a complete list of the topics to be addressed.
d. Explain the treatment of behind-the-meter generation and whether it was netted from load or explicitly modeled with associated load.	See A.3.d.
4. Controllable Capacity Demand Response Modeling	**NA**
a. Explain whether controllable capacity demand response is modeled resource is modeled as a load modifier or as a resource. In addition, describe how it is modeled. Either modeling approach is acceptable; however, note that NERC has agreed upon a convention for reporting it as a capacity resource that is includable in 1.b above.	Section A.3.e has a list of items that should be addressed at a minimum (to the extent they apply). The report should include any additional information that describes the modeling of controllable capacity demand response.
5. Capacity Modeling	**NA**
a. For the capacity in item 1.b above, explain any differences between the MRA capacity and the LTRA capacity for the four LTRA categories in Table 2 of the *Methodology and Metrics* document.	See Section A.4.a.
b. For "Future, Planned" generation that has identified planned and existing capacity for it to be firm and deliverable, explain the process for determining whether such generation is "firm and deliverable."	See Section A.4.b.
c. Document generation additions and capacity re-ratings.	See Section A.4.c.
d. 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.	See Section A.4.d.
e. Document capacity sales and purchases, indicating the selling and purchasing party.	See Section A.4.e.
f. For intermittent and energy-limited variable resources such as wind, solar, and hydroelectric units, document how each these resources are modeled and what data is used	See Section A.4.f.
g. For traditional dispatchable capacity, document how it is modeled and what data is used. Specifically, three topics should be addressed: i. Ratings ii. Forced outage modeling iii. Planned outage modeling	See Section A.4.g for details.

Report Outline		Relevant sections in the *Methodology and Metrics* document
6.	**Transmission**	
a.	Document transmission additions and retirements for years 2 and 5 that are included in the modeling and explain any differences between the modeled transmission additions and retirements and the transmission addition and retirement data provided for the LTRA.	See Section A.5.a.
b.	Describe the MRA's 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 its planning processes. If transmission constraints (e.g. thermal, voltage, stability, or interface limits) are used in the MRA's process, the methodology should be described. The MRA should also describe how deliverability of internal and external resources and access to external supplemental resources is addressed.	See Section A.5.b.
7.	**Assistance from External Resources**	
a.	Explain the MRA's assumptions and methodology for quantifying non-firm assistance from resources outside the MRA's footprint	See Section A.6.
8. a.	**Definition of Loss-of-Load Event** Explain the MRA's definition of a loss-of load event.	See Section B.1.

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~~subregions that will be used in the ~~2010~~2011 LTRA for self-assessment reporting ~~(second column) with one exception – Southwest Power Pool (SPP), the Regional Transmission Organization (RTO),~~. RFC does not ~~the Regional Entity (RE), added RTO members from the MRO region~~report separately (as was done in 2010~~. For the first time in 2010,~~) because it is entirely included in the PJM and MISO ~~will report a self-assessment for their respective~~ Regional Transmission Organizations (RTOs~~.~~).

~~a.~~ The ~~addition of the SPP RTO to this list reflects the same trend.~~

b. ~~The last column in Table 1 shows the areas~~identical LTRA subregions will be used for reporting probabilistic metrics under ~~the~~this 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~~26 reporting MRAs: 16 in the Eastern Interconnection (EI), one in ERCOT, and ~~eight~~nine 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.~~; however, to improve transparency each MRA is required to document their input assumptions. 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~~may 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.~~, limitations, and issues such as deliverability of designated resources to load and imports of supplemental resources. 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~~Subregions and Identical Metrics Reporting Areas

Region	**LTRA Reporting ~~Areas~~Subregions and MRAs**		**~~Metrics Reporting Areas and~~ Interconnection ~~(MRAs)~~**
Multi-region RTOs	1	PJM	~~PJM / EI~~Eastern
	2	MISO	~~MISO / EI~~Eastern
	~~3~~	~~SPP (the RTO, not the RE)~~	~~SPP RTO / EI~~
~~ERCOT~~TRE	~~4~~3	ERCOT	~~ERCOT /~~ ERCOT
FRCC	~~5~~4	FRCC	~~FRCC / EI~~Eastern
MRO	~~6~~5	MRO (US) excluding MISO and SPP RTO areas in MRO (US)	**~~MRO (US) less MISO and SPP areas in MRO (US)~~**~~/ EI~~Eastern
	6	MRO (CN) Manitoba	Eastern
	7	MRO (CN) Saskatchewan	~~MRO (CN) / EI~~Eastern
NPCC	8	New England	~~New England / EI~~Eastern
	9	New York	~~New York / EI~~Eastern
	10	Maritimes	~~Maritimes / EI~~Eastern
	11	Ontario	~~Ontario / EI~~Eastern
	12	Quebec	~~Quebec / EI~~Eastern
~~RFC~~SERC	13	~~RFC-PJM~~TVA	**~~Not reported – included in PJM area~~**Eastern
	14	~~RFC-MISO~~SOCO	**~~Not reported – included in MISO area~~**Eastern
~~SERC~~	15	~~Central~~ICTE[1]	~~Central / EI~~Eastern
	~~16~~	~~Delta~~	~~Delta / EI~~
	~~17~~	~~Gateway~~	**~~Not reported – included in MISO area~~**
	~~18~~	~~Southeastern~~	~~Southeastern / EI~~

[1] Includes SPP Reliability Coordinator entities registered in SERC.

Region	LTRA Reporting ~~Areas~~**Subregions and MRAs**		~~Metrics Reporting Areas and~~ **Interconnection** ~~(MRAs)~~
	~~19~~16	~~VACAR~~VACS excluding PJM areas is VACS	~~**VACAR less PJM areas in VACAR / EI**~~Eastern
SPP	~~20~~17	SPP ~~(~~RTO plus the SPP RE~~)~~	~~**SPP RE less SPP (RTO) areas in SPP RE / EI**~~Eastern
WECC	~~21~~18	~~WECC-Canada~~NWPP (US)	~~WECC-Canada /WI~~Western
	~~22~~	~~Northwest~~	~~Northwest /WI~~
	~~23~~19	Basin (US)	~~Basin /WI~~Western
	20	RMPA (US)	Western
	~~24~~21	Desert ~~Southwest~~SW (US)	~~Desert Southwest /WI~~Western
	~~25~~22	~~Rockies~~CAISO (US)	~~Rockies /WI~~Western
	~~26~~23	~~California-North~~CA (US) excluding CAISO	~~California-North /WI~~Western
	~~27~~24	~~California-South~~BC (CN)	~~California-South /WI~~Western
	25	AESO (CN)	Western
	~~28~~26	~~WECC-~~Mexico (MX)	~~WECC-Mexico / WI~~Western

3. Load-shape modeling and documentation

a. Each MRA will utilize appropriate hourly chronological load model or models, depending upon 2.d. ~~MRA's~~MRAs 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[2], and any other controllable demand response is modeled. Controllable demand response will be reported as capacity, consistent with the report prepared by the Resource Issues Subcommittee. [3] Controllable demand response can be modeled either as a load modifier or a resource. 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~~forecast load interrupted differs from tariff contractual ~~requirements are considered~~load subject to interruption.

   iii. ~~How~~If demand response ~~unavailability (forced and planned outages)~~ is considered fixed and constant or subject to variability.

   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~~of generation resources which have been identified in the LTRA. The "Conceptual" generation category ~~is~~defined in the LTRA has specifically been excluded.[4] 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~~consistent with the transmission criteria identified by the MRA.

c. Each MRA will document all forecasted generation retirements and capacity re-~~rating~~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 ~~resource~~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.

[2] 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.

[3] See http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf.

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

1. For existing unit forced outage modeling, use historic resource EFORd[5] 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~~its planning processes. ~~By modeling~~ If transmission~~,~~ constraints (e.g. thermal, voltage, stability, or interface limits) are used in the ~~MRA can take appropriate credit for external available deliverable capacity during shortage periods. On~~MRA's process, the ~~other hand,~~methodology should be described. The MRA should also describe how deliverability of internal ~~constraints within an MRA can reduce MRA reliability.~~and external resources and access to external supplemental resources is addressed.

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.

[5] 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.[6] 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.

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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 the calculation of the metrics.

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[7] for each calendar year study period:

a. Annual loss-of-load hours (LOLH) – Evaluated for all hours per year.[8] 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 simulated)] x 1,000,000. ~~Compare the simulated EUE to the simulated Net Energy for Load in the LTRA.~~[9]

~~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~~

[7] 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.

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

~~[9] 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.~~

~~MISO area, VACAR without the PJM area, and the SPP RE without the SPP RTO area.~~

C. Confidentiality ~~Agreement~~Agreements

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.[10]

D. Reporting

~~A common MRA~~The initial report ~~format~~outline is included on Table 3. This outline will be ~~provided~~modified, as needed, with Planning Committee approval, by the Resource Issues Subcommittee or other group designated by the Planning Committee.

1. General instructions:

a. The data used in the simulation models should be consistent with the data reported in the LTRA, or explained if different.

b. No confidential data will be disclosed by an MRA in their report.

c. The calculation years for ~~metric reporting~~the field test (pilot) calculation and ~~the documentation~~report will be 2011 (year 2) and ~~explanation~~2014 (year 5), based on the 2010 LTRA.

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

Table 3
Metrics Reporting Area Report Outline

General instructions per Section D.1 of ~~each MRA's modeling method.~~[11] the *Methodology and Metrics* document:

1. The data used in the simulation models should be consistent with the data reported in the LTRA, or explained if different.
2. No confidential data will be disclosed by an MRA in their report.
3. The calculation years for the field test (pilot) calculation and report will be 2011 (year 2) and 2014 (year 5), based on the 2010 LTRA.

Report Outline	Relevant sections in the *Methodology and Metrics* document
1. Summary	**NA**
a. Identify the entities included in the MRA and whether the individual entities were modeled or whether they were modeled as a single combined entity.	The entities need to those in the MRAs defined in Table 1. See Section A.2.d.
Items 1.b-1.e are to be put into a table b. Seasonal capacity totals (summer and winter) – year 2 and year 5 by subcategory, with a total provided: i. Controllable capacity demand response ii. Intermittent and energy-limited variable resources iii. Traditional dispatchable capacity iv. Sales v. Purchases	See Section A.3.e regarding reporting of controllable capacity demand response (CCDR) as capacity, section A.4.f for intermittent and energy-limited variable resources, section A.4.g for traditional dispatchable capacity, and section A4.e for capacity sales and purchases. Note that all capacity should account for retirements and re-ratings (Section A.4.c).
c. Coincident forecast 50/50 peak seasonal demands (summer and winter) as reported in the LTRA, and the comparable demands from the simulation, if different – year 2 and year 5.	See Section 3.a and 3.b.
d. Net Energy for Load as reported for the LTRA and the simulated NEL, if different – year 2 and year 5.[12]	See Section 3.a and 3.b.
e. MRA metrics results – year 2 and year 5	See section B.3.
2. Software model description	**NA**
a. Describe the basic computational approach – Monte Carlo or analytical method.	Not discussed in the *Methodology and Metrics* document. However, this was addressed in Section 2 of the GTRPMTF report posted at http://www.nerc.com/docs/pc/gtrpmtf/Final_GTRPMTF_Rpt_to_PC-06-09-

~~[11] 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.~~

[12] 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.

Report Outline	Relevant sections in the *Methodology and Metrics* document
	09.pdf.
b. Does the model have an algorithm to reduce the number of hours included in the metric calculations when the hours have no material impact on the metrics? Was the algorithm used?	See Section B.3.a and footnote 7.
3. Demand Modeling	**NA**
a. For items 1.c and 1.d, explain any differences between the reported information and similar data reported in the LTRA.	For 1.c, explain any demand differences (the LTRA may report non-coincident load forecasts while the chronological load model will have coincident forecasts); for item 1.d, explain any differences between the simulated NEL and the LTRA reported NEL. See Section B.3.c. and footnote 8.
b. Explain the development of the chronological load model and any loads within the MRA's geographic boundary that are accounted for elsewhere.	See A.3.a and A.3.b.
c. Explain how load forecast uncertainty was modeled.	See A.3.c for a complete list of the topics to be addressed.
d. Explain the treatment of behind-the-meter generation and whether it was netted from load or explicitly modeled with associated load.	See A.3.d.
4. Controllable Capacity Demand Response Modeling	**NA**
a. Explain whether controllable capacity demand response is modeled resource is modeled as a load modifier or as a resource. In addition, describe how it is modeled. Either modeling approach is acceptable; however, note that NERC has agreed upon a convention for reporting it as a capacity resource that is includable in 1.b above.	Section A.3.e has a list of items that should be addressed at a minimum (to the extent they apply). The report should include any additional information that describes the modeling of controllable capacity demand response.
5. Capacity Modeling	**NA**
a. For the capacity in item 1.b above, explain any differences between the MRA capacity and the LTRA capacity for the four LTRA categories in Table 2 of the *Methodology and Metrics* document.	See Section A.4.a.
b. For "Future, Planned" generation that has identified planned and existing capacity for it to be firm and deliverable, explain the process for determining whether such generation is "firm and deliverable."	See Section A.4.b.
c. Document generation additions and capacity re-ratings.	See Section A.4.c.
d. 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.	See Section A.4.d.
e. Document capacity sales and purchases, indicating the selling and purchasing party.	See Section A.4.e.
f. For intermittent and energy-limited variable resources such as wind, solar, and hydroelectric units, document how each these resources are modeled and what data is used	See Section A.4.f.
g. For traditional dispatchable capacity, document how it is modeled and what data is used. Specifically, three topics should be addressed:	See Section A.4.g for details.

Report Outline	Relevant sections in the *Methodology and Metrics* document
i. Ratings ii. Forced outage modeling iii. Planned outage modeling	

Report Outline	Relevant sections in the *Methodology and Metrics* document
6. Transmission	
a. Document transmission additions and retirements for years 2 and 5 that are included in the modeling and explain any differences between the modeled transmission additions and retirements and the transmission addition and retirement data provided for the LTRA.	See Section A.5.a.
b. Describe the MRA's 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 its planning processes. If transmission constraints (e.g. thermal, voltage, stability, or interface limits) are used in the MRA's process, the methodology should be described. The MRA should also describe how deliverability of internal and external resources and access to external supplemental resources is addressed.	See Section A.5.b.
7. Assistance from External Resources	
a. Explain the MRA's assumptions and methodology for quantifying non-firm assistance from resources outside the MRA's footprint	See Section A.6.
8. Definition of Loss-of-Load Event a. Explain the MRA's definition of a loss-of load event.	See Section B.1.

Appendix 4. G&T RPM TF Members

The TF roster follows.

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