White Paper Addressing Differences between the CDR Report and Transmission Planning Models

**Revision History**

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| --- | --- | --- | --- |
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| 7/9/2015 | 0 | Endorsed by ROS | PLWG |
| MM/DD/YYYY | Draft | Updates on modeling DC tie flows in Transmission Planning Models | PLWG |

**Overview**

During the July 10, 2014, meeting of the ERCOT Reliability and Operations Subcommittee (ROS), the Planning Working Group (PLWG) was asked to create a white paper describing the load and generation assumption methodologies utilized in the Report on the Capacity, Demand and Reserves in the ERCOT Region (CDR Report) and the various ERCOT transmission planning models (Transmission Planning Models). This white paper seeks to satisfy that request by:

* describing the purposes of the CDR Report and the Transmission Planning Models;
* identifying the assumption methodologies used in the CDR Report and Transmission Planning Models;
* explaining the reasons why different assumption methodologies may be appropriate for certain assumptions; and
* identifying the assumptions for which it may be appropriate to eliminate the differences.

## Purpose of the CDR Report

The CDR Report provides an estimate of the planning reserve margin in the summer and winter peak load seasons for the next ten years. At a high level, the planning reserve margin is calculated as the difference between generation capacity and firm peak load. [[1]](#footnote-1) This calculation does not itself provide information about expected reliability in future years because it does not fully account for forced generation outages, extreme temperatures, and the variability of wind and other renewable resources. To address those issues, a separate loss-of-load expectation study (LOLE Study) is performed to determine the expected level of reliability provided by a given planning reserve margin. Stakeholders may then compare the expected planning reserve margins in the CDR Report with the results of the LOLE Study to inform their respective activities related to the ERCOT Region.

## Purpose of the Transmission Planning Models

The Transmission Planning Models provide the starting point for power flow analysis that determines whether electric grid infrastructure will be adequate to move electric power from generation resources to customers under a variety of possible future conditions. The Transmission Planning Models include expectations about three categories of electric grid components: the location and capacity of future resources (i.e. generation), a forecast of the customer demand by substation that will need to be served (i.e. load), and the specifications of the expected individual components that make up the transmission grid (i.e. system topology). The processes used to develop the Transmission Planning Models are defined in the Steady-State Working Group Procedure Manual, the ERCOT Protocols, and the ERCOT Planning Guide. The Transmission Planning Models are also developed in compliance with the reliability standards issued by the North American Electric Reliability Corporation (NERC). These models do not themselves provide information about expected future transmission reliability but rather are a starting point for transmission reliability studies performed by ERCOT and stakeholders using specialized power flow software.

## Assumptions Methods Used

Because the CDR Report and the Transmission Planning Models both include assumptions about future resources and loads, it is expected that the assumptions should be generally consistent, and to the extent they are different, the reasons for those differences should be known. The following table describes the generation and load assumption used in the CDR Report and Transmission Planning Models.

**Comparisons of CDR Report and Transmission Planning Models**

|  | **CDR Report** | **Transmission Planning Models** | | |
| --- | --- | --- | --- | --- |
| **SSWG Models** | **RTP Reliability Models** | **RTP Economic Models** |
| **Purpose** | Provide an estimate of the planning reserve margin during summer and winter peak load seasons | Provide a range of power flow cases with a common reference point for ERCOT and Market Participants | Provide power flow cases for use in developing the reliability portion of the ERCOT Regional Transmission Plan (RTP) | Provide a power flow case for use in developing the economic assessment portion of the ERCOT Regional Transmission Plan (RTP) |
| **Load Forecast Inputs** |  |  |  |  |
| **Preparer** | ERCOT | TSPs | ERCOT and TSPs | ERCOT |
| **Season** | Summer and Winter | * Four seasons for current year * Summer peak for next 6 years * Minimum load and high wind for a future year | Summer peak for future Years 1, 3, 5, and 6 | Full year hourly analysis for Future Years 3 and 6 |
| **Weather Assumptions** | Average weather  (expect actual load to exceed forecast one out of two years) | Varies by TSP, see Appendix A | Higher of:   * Summed TSP SSWG case loads in each weather zone; or * ERCOT 90th percentile forecast by weather zone (expect actual load to exceed forecast one out of ten years) | “Average” weather in each weather zone  (expect actual load to exceed forecast one out of two years) |
| **Load Coincidence** | Coincident  (single peak load hour for ERCOT Region) | Based on ALDR forecast, TSPs use varied methods for populating loads by individual substation (see Appendix A for description by TSP) | Peak load by individual substation for each weather zone (non-coincident), with exceptions made depending on the case | Non-Coincident by weather zone |
| **Load Resource and other Demand Response Programs** | Included  (shown as separate line item) | Not Included | Not included | Not Included |
| **Self-Serve Load** | Net to the grid  (self-serve load minus self-serve generation) | Gross  (no reduction for self-serve generation) | Gross  (no reduction for self-serve generation) | Gross  (no reduction for self-serve generation) |
| **Load Adjustments** | None | No adjustments from TSP provided loads are made | Within a region of study the higher of: SSWG load in each weather zone or ERCOT 90th percentile load forecast by weather zone  Adjustments may be made outside of study region | None |
| **Generation Inputs** |  |  |  |  |
| **Extraordinary Dispatch Methods – a method of adding capacity to a model** | Not applicable | As needed, see Appendix B of SSWG manual. Has been used for years 4, 5, and 6 in recent years | Yes, a combination of extraordinary dispatch and load scaling outside of the region being studied may occur | Not applicable |
| **Thermal Generation** | Seasonal Net Maximum Sustainable MW Rating from RARF | Seasonal Net Maximum Sustainable MW Rating from RARF and Reactive curve gross MVAR less auxiliary Load MVAR Ratings from RARF | Seasonal Net Maximum Sustainable MW Rating from RARF and Reactive curve gross MVAR less auxiliary Load MVAR Ratings from RARF | Seasonal Net Maximum Sustainable MW Rating from RARF |
| **Wind Generation** | Capacity contribution based on average of recent peak-season output (top 20 load hours) | 100% of capacity modeled. Units dispatched according to CDR Report unless needed in extraordinary dispatch | 100% of capacity modeled. Units dispatched at varying levels, depending on the case | Units dispatched based on representative hourly patterns appropriate for weather assumptions |
| **Solar Generation** | 100% of capacity reported | 100% of capacity modeled. Units dispatched based on review of historic seasonal output | 100% of capacity modeled. Units dispatched at 70% of capacity | Units dispatched based on representative hourly patterns appropriate for weather assumptions; using vendor profiles |
| **DC-Ties** | Output levels based on average of recent peak-season output (top 20 load hours) | 100% of capacity modeled. Units dispatched based on review of historic seasonal operating levels | 100% of capacity modeled. Units dispatched based on review of historic seasonal operating levels | Units dispatched based on historical hourly patterns |
| **Hydro Generation** | Average of high sustainable limits (HSL) reported in the Current Operating Plan for the last 3 years during the peak-season (top 20 load hours) | 100% of capacity modeled. Units modeled offline | 100% of capacity modeled. Units modeled offline | Units dispatched based on historical hourly patterns |
| **Requirements for Including Planned Generation** | * Signed interconnection agreement; * Air permits (if needed); and * Cooling water attestation | Planning Guide 6.9.   * Signed interconnection agreement; * Air permits (if needed); * Cooling water attestation; and * Full financial commitment and notice to proceed given to TSP | Planning Guide 6.9.   * Signed interconnection agreement; * Air permits (if needed); * Cooling water attestation; and * Full financial commitment and notice to proceed given to TSP | Planning Guide 6.9.   * Signed interconnection agreement; * Air permits (if needed); * Cooling water attestation; and * Full financial commitment and notice to proceed given to TSP |
| **Self-Serve Generation** | Net to grid during peak hours of recent peak season | Full capacity available | Full capacity available | Full capacity available |
| **Switchable Units** | Capacity contracted to other region is not included | Capacity contracted to other region is considered unavailable | Capacity contracted to other region is considered unavailable | Capacity contracted to other region is considered unavailable |
| **Mothball Generation** | Capacity is included if unit owner states likelihood of return is greater than 50% | Designated as a mothball unit and status set to “out-of-service” unless needed for extraordinary dispatch | Mothball units not available (new for 2015 as a result of TPL-001-4) | Mothball units not available |

**CDR Report**

The CDR Report is an accounting of expected loads and resources that provides a forecast of future year planning reserve margins. Resource information in the CDR Report is derived from the Resource Asset Registration forms (RARFs) submitted by resource owners. Additional information regarding the expected output or available capacity of renewable generation, the net output of self-serve generation (behind the fence), and the net import from DC-ties is calculated from operational data. The composition of the CDR Report is prescribed in the ERCOT Nodal Protocols 3.2.6.2., ERCOT Planning Reserve Margin Calculation Methodology. A primary benefit of the CDR Report is the calculation of the Planning Reserve Margin (PRM) for future years. The minimum PRM required for ERCOT is determined by the ERCOT Board of Directors in accordance with Nodal Protocol Section 3.2.6.1., Minimum ERCOT Planning Reserve Margin Criterion. ERCOT staff performs a study called the Loss of Load Expectation (LOLE) study to provide a measure of the reliability that can be anticipated at various PRM. In order for the CDR Report to be meaningful in the context of a stated minimum PRM requirement, the assumptions about capacity and load used to perform the LOLE Study must be consistent with those used to develop the CDR Report. These assumptions include the assumed capacity contribution of variable resources such as wind and solar generation and the specific weather conditions used to develop the load forecast. While ERCOT currently uses average weather conditions to develop the load forecast in the CDR Report, this and other input assumptions can be varied without reducing the validity of the CDR Report as long as similar changes are made to the input assumptions included in the corresponding LOLE Study. Similarly, the impact of resource outages, both planned and unplanned, on system reliability is included in the development of the LOLE Study and the CDR Report does not include deration of available resources to reflect possible outages.

A LOLE Study includes multiple scenarios based on a range of possible weather conditions. Derived from historical weather patterns, these load scenarios are consistent with weather expectations ranging from mild to extreme, with appropriate probabilities of occurrence assigned to each weather scenario. Similarly, resource outages are included in the study based on historical operational data reflecting by unit maintenance schedules and forced outage probabilities. Variable generation units, such as wind, solar and hydro generation, are included in the study as hourly output based on weather patterns that are consistent with the load used for each specific scenario. In this way the net impact of weather on both load and variable generation is consistent with actual historical data.

The CDR Report and LOLE Study both assume unlimited transmission capacity and, therefore, do not account for transmission constraints that exist in actual grid operations. This assumption provides a system-wide perspective of resource adequacy and not a locational assessment of the reliability of electric service. In other words, constraints in the transfer of power caused by insufficient transmission serving locations in ERCOT where loads exceed resources will create locations in which outage expectations are higher than for the system as a whole.

**Transmission Planning Models**

There are numerous future year Transmission Planning Models used by ERCOT and the Transmission Service Providers (TSPs) to assess transmission adequacy and reliability. ERCOT, the TSPs, along with many other involved stakeholders who submit model data representing their grid-connected equipment, develop sixteen steady-state planning models representing the current and future years, three transient stability cases and a short-circuit case. The intent of all of these models is to allow planners to assess the capability of the transmission infrastructure to move power reliably from existing and planned resources to every load-serving substation in the system under a range of reasonably likely future system conditions. Each of these models includes input assumptions, such as the customer demand levels assigned by bus (e.g., a load forecast), that have been selected to allow planners an opportunity to assess any system weaknesses.

The Steady-State Working Group (SSWG) develops the base Transmission Planning Models to analyze future system capability. The SSWG models are designed to provide transmission planners with a set of base case models containing the possible future infrastructure and capabilities and limitations required for planners to develop study-specific planning cases. These studies begin with an engineering assessment of the model components and adjustments needed to reflect the appropriate assumptions for the specific study. For example, ERCOT planners adjust components in the SSWG models to develop the models for the Regional Transmission Plan (RTP) assessment. Some of these adjustments are stipulated in ERCOT binding documents, while others are communicated to stakeholders through the annual RTP scope document. ERCOT develops RTP transmission models for both a reliability assessment and for an economic assessment of transmission projects.

Steady-State Working Group Base Case Models

As stated in the SSWG Procedure Manual:

*“ROS Working Groups and ERCOT use SSWG base cases as the basis for other types of calculations and studies including, but not limited to:*

* *Internal planning studies and generation interconnection studies*
* *Voltage control and reactive planning studies*
* *Basis for Dynamics Working Group stability studies*
* *ERCOT transmission loss factor calculation*
* *Basis for ERCOT operating cases and FERC 715 filing”*

The sixteen models developed by SSWG provide a range of load and system conditions and establish a common point of reference for the analysis of the transmission system. Perhaps most importantly, these models represent the planned transmission topology and generation resources available for planning the transmission system in accordance with NERC Reliability Standards, the ERCOT Nodal Protocols and ERCOT Planning Guides. These models represent a range of system conditions but not all possible system conditions, therefore, adjustments to load and generation are needed depending on the scope of the transmission analysis being performed.

The three fundamental categories of data needed to construct these models are expected generation, load, and system topology.  TSPs are responsible for ensuring that load information and topology information are provided, except for the high wind-low load model, for which the load information is provided by ERCOT Staff. Generation information is added by ERCOT staff based on information provided to ERCOT by Resource Entities via the Resource Asset Registration Form. In general, the SSWG models are developed with all potential resources (including mothballed resources), allowing maximum flexibility to transmission planners to include or not include these units as appropriate for each study.

Each TSP provides load information according to anticipated load conditions as defined in the particular model being constructed. The TSP provides loads so that planners can meet their obligation to plan adequate transmission infrastructure in accordance with the performance requirements of the ERCOT Planning Guides and the NERC Reliability Standards. Consistent with this approach each TSP provides load data relevant to the peak load conditions for the transmission facilities they own. The approach leads to a condition in which the total load in the model is higher than a corresponding ERCOT-wide coincident load forecast. That is, the ERCOT system serves a broad area in which one portion of the system will often be under peak load conditions while other portions are not. Therefore, the sum of each TSP’s individual load will be higher than the ERCOT-wide coincident load.

In most instances, the total load in future year SSWG planning cases is greater than the total generation available for dispatch. The factors that contribute to this circumstance include:

* the use of non-coincident load forecasts that exceed system-wide coincident peak forecasts, as discussed above;
* an increased amount of variable generation on the system, which is typically derated to reflect expected generation output at the time of peak conditions;
* Planning Guide requirements that only allow a planned resource to be included in the models if the resource has a signed interconnection agreement, air permits (if needed), adequate cooling water, and full collateral for any necessary transmission improvements; and
* development time for planned generation that is typically less than that for transmission, which then reduces the number of planned resources that meet the requirements for inclusion in the models.

In order for the planning models to solve, the amount of generation dispatched by resources must be equal to the sum of all the loads plus transmission losses. Because one primary purpose of the SSWG base case models is to communicate bus-level load expectations, it would not be appropriate to reduce loads to achieve a balance with available resources. As a result, SSWG base case model developers use “extraordinary dispatch methods” for generation resources to balance load and generation. These methods include dispatching mothballed resources and increasing the dispatch of variable generation resources.

Because the loads in the SSWG models are not ERCOT-wide coincident loads, transmission planners may need to adjust load and generation as appropriate for a given transmission planning study. Adjustments to an SSWG model may not be necessary for highly localized studies, such as an analysis of radial lines serving loads or portions of the system with net power flow into, as opposed to through, the area being studied. In other instances, adjustments to the SSWG model may be necessary to eliminate impacts of model development decisions such as extraordinary dispatch methods needed to make the initial SSWG model solve.

Regional Transmission Plan Models

ERCOT develops two sets of models as part of its annual Reliability Transmission Plan analysis: models are developed to assess any transmission projects needed to meet the reliability criteria established in the NERC reliability standards, the ERCOT Protocols, and the ERCOT Planning Guide, and models are developed to assess the economic benefits from proposed transmission projects.

The RTP Reliability Models are created by ERCOT annually and are used to analyze steady-state system performance in regards to NERC and ERCOT reliability planning criteria. These models are also used to evaluate transmission system upgrades when performance deficiencies are found.

The RTP Reliability Models start from the SSWG base case models and are modified as specified in the Planning Guide and the annual RTP scope document. The RTP scope document is presented by ERCOT to the Regional Planning Group (RPG) each year to communicate any case-specific assumptions not stipulated in the Planning Guides and to solicit stakeholder comments on the process and assumptions to be used in the upcoming analysis.

The SSWG base case models are modified because some of the assumptions contained in the SSWG models are not appropriate for the RTP studies. Planning Guide Section 6.1(1) states, in part, “These case models…provide *a starting point* for each required season and year” [emphasis added]. For example, the following adjustments to the SSWG base case models are typically made to create the RTP Reliability Models:

* A transmission project is removed if it (1) is classified as a Tier 1, 2, or 3 project[[2]](#footnote-2), and (2) has not completed RPG Project Review.[[3]](#footnote-3)
* ERCOT compares its 90th percentile load forecast[[4]](#footnote-4) to the load forecast contained in the SSWG models by weather zone and uses the higher of the two.
* If there are not enough resources to meet the load, the model is split into two or more regions (i.e., groups of weather zones) and loads outside the region being studied are scaled down to achieve balance with resources.
* The set of generation units matches the SSWG models in accordance with Planning Guide Section 6.9. However, changes in generation dispatch assumptions are listed in the RTP scope document. These changes typically include modeling wind generation at a lower, more conservative output level, and turning off mothballed units in the area of study. Generation dispatch changes will be made during the course of the analysis in order to eliminate or minimize overloads on the system, similar to Security Constrained Economic Dispatch, which is performed in real-time.
* DC Ties are modeled according to their historical performance.
* Beginning in 2015, the RTP Reliability Models include dynamic ratings for transmission lines corresponding to a 90th percentile temperature by weather zone. This change only applies to existing transmission lines that have dynamic ratings specified by the appropriate TSP.

Following completion of studies to assess needed reliability projects, ERCOT uses the RTP Economic Models to evaluate expected future year transmission congestion and to plan any viable economic transmission upgrades. This economic analysis is conducted using hourly production cost simulation software, such as UPLAN. The economic analysis begins with the final transmission topology resulting from the RTP reliability analysis.

The generation set is the same as that of the RTP Reliability Models but may be updated to include any generation units that achieved Planning Guide Section 6.9 requirements after the RTP Reliability Models were created. The grid simulation software uses unit-specific cost and operational information, such as heat rates, startup costs, minimum up-times and down-times, to simulate Reliability Unit Commitment and Security Constrained Economic Dispatch. Wind, solar, and hydro-electric units are modeled with 8760-hour output profiles reflecting weather conditions consistent with modeled hourly loads.

The RTP Economic Models use the 8760-hour average weather (or 50/50) load forecast developed as part of the ERCOT Long-Term Hourly Peak Demand and Energy Forecast. Transmission projects evaluated as part of the economic analysis must achieve sufficient system cost savings to offset their cost of construction and operation in order to be endorsed. As such, it is important that the model output represent expected cost savings. Using a 90/10 forecast, similar to the RTP Reliability Models, would mean that indicated cost savings would likely only be achieved in one out of every ten years and thus would overstate the value of any future project. Separate from this effort, ERCOT and stakeholders are currently analyzing a possible future change in methodology that would employ multiple load forecasts with a probability weighting factor.**PLWG Review and Conclusions**

The PLWG reviewed the load and generation assumption methodologies used in the CDR Report and the ERCOT Transmission Planning Models and noted the following observations for different methodologies:

* The CDR Report, released every six months, is used to report the planning reserve margin calculation for the following 10 years. The planning reserve margin is calculated as the percent of generating capacity that exceeds the firm load forecast. The firm load forecast is based on normal weather (i.e.; 50th percentile load forecast). The planning reserve margin *target* is based upon ERCOT’s annual LOLE Study. The LOLE Study is a probabilistic analysis to determine the level of additional resources required to reliably serve load in more stressful conditions, such as higher than normal loads, generator forced outages, and wind output lower than the assumed Effective Load Carrying Capability (ELCC).
* The CDR Report is not used as the basis for recommending construction of new facilities but rather provides guidance to policy makers and the market regarding the need for additional resources in ERCOT. Transmission Planning Models, however, are used as the basis for recommending construction of new transmission projects to meet NERC and ERCOT requirements; subject to PUCT approval for inclusion into transmission cost of service.
* All of the assumptions used to develop the CDR Report are included in the protocols. To the extent that policy makers and market participants use the CDR Report in their decision making processes, they can perform their own analysis by adjusting the variables. For example, if a market participant does not think that a certain planned generation plant will get constructed, they can remove it from their reserve margin analysis and use that information in their decision making.
* The CDR reports firm peak load forecasts based on normal weather, system-peak demand conditions reduced by demand response programs that would be expected to activate under system-wide scarcity conditions. Conversely, the transmission planning processes assume demand response may not activate for transmission constraints and specific Load Resources are not assumed available throughout the planning horizon.
* The transmission planning models are a bus by bus representation of Loads and Resources and the transmission system that connects them, whereas the CDR Report is an aggregate accounting of Loads and Resources within ERCOT.
* SSWG base case Loads are based on ALDR filings of individual load serving transformers and metering points, provided by Load Serving Entities, whereas the CDR Report Load forecast is developed by ERCOT using employment, economic and other data necessary to develop a regional Load forecast.
* The SSWG base case models provide a starting point for transmission planners throughout the ERCOT Region to use in their analyses. It is important to have a common model that every entity can begin with, but the load and generation assumptions may be modified as appropriate for a given study.
* Transmission planners are required to develop sensitivity cases to meet reasonable variation requirements in the NERC reliability standards and therefore the Loads in the SSWG base case models may be modified in each planning case. Conversely, the CDR Report contains a single, normal weather Load forecast and relies on the reserve margin requirement developed from the LOLE study in order to account for the range of possible scenarios.
* The RTP Reliability Models are used by ERCOT to identify the need for reliability projects in a deterministic analysis. The ultimate outcome of this analysis is the continuing development of a transmission grid that will be used by operators to manage reliability. Planners apply reasonable variations of assumptions to help address uncertainties about future grid conditions that can lead to reliability problems. Variations of assumptions are specifically stated to allow vetting in the Regional Planning Group forum.
* The RTP Economic Models are full-year, hourly models based on the single-hour RTP Reliability Models, except using 50th percentile Weather Zone hourly load forecasts. ERCOT uses these models to forecast costs associated with transmission congestion on the ERCOT System in order to plan cost justified economic transmission projects.
* There are four categories of Loads listed in the CDR Report that are subtracted from the Total Summer Peak Demand(based on normal weather): Load Resources providing Responsive Reserve, Load Resource providing Non-Spinning Reserve, Emergency Response Service (10 and 30 minute ramp products) and TDSP Standard Offer Load Management Programs. These categories of load total 2,530 MW or 3.63% of the Total Summer Peak Demand according to the May, 2015 CDR Report. The values in these categories are used to calculate the reserve margin but are not associated with a specific facility, location, or entity and are not included in transmission planning models.

In light of these observations, the PLWG determined that some differences in the assumption methodologies between the CDR Report and Transmission Planning Models are appropriate. However, the PLWG also identified several assumptions that do not warrant different methodologies. While there may be no “right or wrong” methodology in many cases, the fact that differences exist may cause confusion. The PLWG concludes that changes to achieve consistency between the CDR Report and Transmission Planning Models may be appropriate for the following assumption methodologies:

1. The CDR Report methodology for inclusion of planned generation resources in the capacity calculation is different than the criteria used for the Transmission Planning Models. The criteria for the Transmission Planning Models can be found in Planning Guide Section 6.9., Addition of Proposed Generation Resources to the Planning Models, and was recently changed to include a requirement for planned generation resources to provide financial commitment to their interconnection TSP, along with a notice to proceed. This change was made to provide more certainty that planned generation resources included in the models will actually be constructed. The PLWG recommends that the CDR Report split the line “Planned Resources (not wind) with Signed IA, Air Permits and Water Rights” into two separate lines as follows:

“Planned Resources (not wind) that meet PG 6.9 requirements”, and

“Planned Resources (not wind) that do not meet PG 6.9 requirements, lacking financial commitment only”

This will not change the CDR Report reserve margin calculations, but will provide the user with the ability to reconcile the CDR with the planning case, as well as provide user insight into the amount of generation that nearly meets Planning Guide Section 6.9 requirements. This change would require a Protocol revision.

1. The RTP Reliability Models should adopt the methodology for hydro-electric unit dispatch that the CDR Report uses for calculating hydro-electric unit capacity. This change would have very little impact on the Transmission Planning Models and would result in more consistency between the processes. If a planner would like to study a scenario with zero output from hydro-electric units this can be run as a one-off scenario.
2. The SSWG base case models and the RTP Reliability Models should maintain the current methodology for DC tie import/ export levels that are used for the transmission planning models. The SSWG base models, RTP Reliability Models, and CDR Report all use historic information to determine DC tie import/ export levels, but the methodologies are not consistent. Using the same methodology may improve consistency and reduce confusion but may limit analysis of the range of credible conditions needed for transmission planning studies needed to comply the NERC Reliability Standards. The CDR Report methodology for determining the available DC tie capacity is based on the average of recent peak-season flows. This approach is not appropriate for Transmission Planning Models used to evaluate transmission system performance in the ERCOT Regional Transmission Plan because the average of the historical flows on DC ties does not necessarily represent a stressed system condition during summer peak, a requirement for compliance with NERC TPL Reliability Standards. In addition, since the CDR approach only relies on historical data, it may not capture recent or planned changes in the capacity of a DC tie. Therefore, PLWG does not recommend any change to the current methodology used for DC Ties in Transmission Planning Models (SSWG and RTP), which is based on review of historic seasonal operating levels and any changes in the capacity of a DC tie.
3. It is appropriate for the SSWG base case models and the RTP Reliability Models to model more conservative (lower) levels of wind generation output. However, when modeled wind generation output levels are increased as an extraordinary dispatch measure, the wind generation output level should be set consistent with the CDR Report methodology to the extent that Load and Resource balance can be achieved in the model. Using the same methodology will improve consistency and reduce confusion. This change would require modifications to the SSWG Procedure Manual and would be reflected in the annual RTP scope document.
4. As more solar is developed on the ERCOT System, PLWG recommends that the consistency between the CDR Report and the Planning Models be reviewed.

**Appendix A - Example Transmission Service Provider Load Forecasting Methodologies**

AEP

AEP tries to match our total load value to the value of the load during each operating company’s peak (TCC and TNC, individually). Our intent for the SSWG peak load (i.e. summer) cases is to represent a load scenario where the local transmission system is most stressed. We do this by taking the NCP loads, provided in the ALDR, and applying a factor that consists of the company’s CP load value divided by the total of the company’s NCPs. This factor is not applied to industrial loads which are kept constant throughout the cases. This factor is also not applied to “self-serve” loads, which are forecasted separately.  This philosophy results in the SSWG cases having a combined total AEP company load that is higher than AEP’s portion of the ERCOT CP load, but less than the combined total of the NCP at each load point.

CenterPoint

CenterPoint Energy’s SSWG load data is based on our ALDR submittal. Loads within the CenterPoint Energy system include distribution loads, transmission level customer loads, and self-serve loads.

The distribution load forecast is based on 102 degree F average temperature across all CenterPoint Energy distribution substations. All distributed generators above 1 MW are modeled explicitly as negative loads based on historical operation. CenterPoint Energy’s energy efficiency programs are also incorporated in the distribution load forecast. Any new loads are added to the previous actual summer peak loads to produce a substation level forecast. Load projections for each substation are adjusted based on historical trends or similarly-situated customer demands.

The transmission level customer load forecast is independent of the ambient temperature. Load forecasts for the large industrial customers are developed by reviewing billing data from the previous year’s peak load during summer weekday afternoon hours. Future load increases, based on customer provided data, are included in the models once construction of the new facilities has begun. The load forecast for future transmission level customers are developed using customer provided load estimates and included in the SSWG models once they sign a letter agreement with CenterPoint Energy, provide payment for service extension, and provide security for any associated upgrades.

Loads at self-serve facilities are explicitly modeled along with its self-serve generation. The self-serve load modeling in the SSWG models is based on actual net injection to the transmission grid and resource capability (i.e. self-serve load is off-set by self-serve generation). The net load forecast for self-serve customers are developed by reviewing billing data from the previous year’s peak load during summer weekday afternoon hours.

CPS Energy

The Annual Load Data Request (ALDR) serves as the starting point for determining the load profile to use in the SSWG base case models. The ALDR load forecast data contains the forecasted non-coincident summer peak load for each delivery point. A coincidence factor is calculated by dividing historical CPS Energy system peak load by the actual non-coincident load reported in the ALDR for the same year and season. The coincidence factor provides a basis for scaling the forecasted non-coincident peaks provided in the ALDR. Individual substation loads are scaled by the coincidence factor except those that primarily serve nonconforming load, which are not scaled. Distributed Generation is modeled separately in the SSWG Base Case Models as negative load.

LCRA

LCRA TSC receives load forecast information, consistent with loads reported in the ERCOT Annual Load Data Request (ALDR), from Load Serving Entities to use in developing a load profile for the SSWG power flow models. This load forecast data contains the forecasted non-coincident summer and winter peak load on the low side of the substation power transformer for each delivery point. LCRA TSC derives a factor, the coincidence factor, to apply to each load in order to establish a load profile that is coincident with LCRA TSC’s system peak then adds transformer losses so that the loads provided for the SSWG power flow models are representative of the load connected to the LCRA TSC transmission system.  The coincidence factor is derived from the previous year’s meter data for each delivery point.  LCRA TSC also analyzes the previous year’s meter data for each delivery point to determine an appropriate power factor to establish the real and reactive power component for each load modeled in the SSWG summer and winter peak power flow models.  LCRA TSC determines the load profile for the SSWG DSA seasonal peak and seasonal minimum power flow models by scaling the summer peak load forecast by load factor ratios based on an analysis of five years of historical meter data. The appropriate load factor ratio is then applied to the LCRA TSC system peak coincident load profile for each delivery point, transformer losses are added and an appropriate power factor applied to prepare the load profile for use in the SSWG seasonal peak and minimum power flow models.

Oncor

Oncor develops their ALDR based on substation bank peak load projections provided by their Distribution Planning Department and Industrial/Commercial load projections provided by the customer or customer representative. Oncor also develops load projections by weather zone. Load projections are considered an average (50/50 or 50th percentile). The Oncor weather zone load projections are adjusted to exclude system losses and then used to develop a “Target” for the SSWG base case loads. Non-conforming/non-scalable loads are determined and using an in-house program the remaining loads are adjusted based on the ALDR so that the target is met. If applicable, loads are also adjusted to include I2X transformer losses. Loads are applied to the appropriate PSS/E busses for use in the SSWG base case models. These loads are submitted during the SSWG model build process and adjusted if necessary during the SSWG model update process.

1. Protocol Section 3.2.6 contains additional detail about the calculation of the planning reserve margin. [↑](#footnote-ref-1)
2. The Tiers of RPG Project Review are defined in Protocol Section 3.11.4. [↑](#footnote-ref-2)
3. Planning Guide Section 3.1.4.1(1). [↑](#footnote-ref-3)
4. ERCOT uses a 90th percentile or 90/10 forecast (as opposed to a 50/50 forecast based on average weather conditions) in order to achieve a transmission system that is sufficient to meet future loads 9 out of 10 years. The ERCOT 90/10 load forecast is developed using the ERCOT Long-Term Hourly Peak Demand and Energy Forecast with a 90th percentile temperature assumption. [↑](#footnote-ref-4)