###### ERCOT STEADY STATE WORKING GROUP

###### PROCEDURE MANUAL

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# 1 INTRODUCTION

1.1 ERCOT Steady-State Working Group Scope

The ERCOT Steady-State Working Group (SSWG) operates under the direction of the Reliability and Operations Subcommittee (ROS). The SSWG is a non-voting working group whose members include representatives from ERCOT Transmission Service Providers (TSPs) and ERCOT staff. The SSWG’s main objectives are to produce seasonal and future steady-state base cases. The SSWG meets twice a year to accomplish these tasks, and at other times during the year as needed to resolve any impending power-flow modeling issues or to provide technical support to the ROS. The SSWG responsibilities are further described as follows:

* Develop and maintain steady-state base cases for the spring, summer, fall, and winter seasons of the upcoming year, six future year summer on-peak cases, one High Wind/Low Load (HWLL) case, and one minimum load case. The seasonal base cases consist of both an on-peak and an off-peak case for each of the four seasons. The cases, collectively known as the Steady-State Cases (SS), are produced by the SSWG on an annual basis.
* Update Steady-State Cases on a triannual basis
* Maintain and update the Transmission Project Information Tracking (TPIT) report to reflect data used in base case development and update.
* Maintain and update the Planning Data Dictionary to reflect current and future year bus and county information.
* Review and update, as necessary (at least every five years), the SSWG Procedural Manual toreflect current planning practices and the latest steady-state base case modeling methodologies.
* Prepare data for and review seasonal transmission loss factor calculation on an annual basis. This task is to be completed by January 1st.
* Assist in development of SSWG processes for compliance with NERC Reliability Standards for Transmission Planner and Planning Authority/Coordinator.
* Coordinate tie-line modeling data with adjacent companies via the case-building process.
* Review and update the contingency definition files used for planning.
* Address issues as directed by the ROS.
* Annually review status of the NMMS and Topology Processor software regarding new planning data needs.

1.2 Introduction to Case Building Procedures and Methodologies

The principal function of the SSWG is to provide steady-state power flow models, or base cases, which contain appropriate equipment characteristics, system data, and shall represent projected system conditions. This procedure manual is intended to demonstrate compliance with NERC Reliability Standards applicable to steady-state modeling. The ERCOT Protocols require the base cases developed for annual planning purposes to contain, as much as practicable, information consistent with the Network Operations Model.

Planning models are bus-branch representations of the transmission system (60 kV and above), which includes buses, branches, impedances, facility ratings, loads, reactive devices, transformers, generators, and DC lines.

The ROS directs the SSWG as to which base cases are to be created. Currently, the SSWG builds a set of steady-state base cases on an annual basis, collectively called the Steady State Cases (SS). The SS cases consist of seasonal cases for the following year, future summer peak planning cases, future HWLL case, and a future minimum load planning case. The summer peak base cases will be known collectively as the Annual Planning Models and will be subject to the requirements defined in the ERCOT Protocols. Each set of SS cases are to be built or updated during the triannual update cycle.

Various groups utilize the SSWG steady-state base cases for a variety of tasks. ERCOT and Transmission Service Providers (TSPs) test the interconnected systems modeled in the cases against the ERCOT Planning Criteria and their individual TSP planning criteria to assess system reliability into the future. 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

# 2 Definitions and Acronyms

In the event of a conflict between any definitions or acronyms included in this manual and any definitions or acronyms established in the ERCOT Protocols, the definitions and acronyms established in the ERCOT Protocols take precedence.

* + 1. **Definitions**

Model On Demand (MOD) Model On Demand application is a Siemens program that serves as a database and case building tool that SSWG uses to create and maintain the SSWG base cases

Planning Model Design Guidelines A manual that describes (MOD), MOD File Builder, and naming

& Expectations conventions for cases.

IDEV A script file recognized by PSS/E used for transporting and applying network model changes.

MOD File Builder An application which converts planning model changes made in the PSS/E application (IDEV) into a PMCR-ready format (PRJ) which can be uploaded to MOD.

Network Operations Model The NMMS database containing the model of the ERCOT

System interconnection which is the basis for all applications used in reliability and market analysis and system planning.

Profile A method for specifying non-topology modeling parameters in the steady-state base cases which are not typically constant over the various seasons and years. This includes load, generation, and device control information. Profiles are described more fully in the ERCOT MOD Manual.

Planning Model Change Request A Planning Model Change Request modifies MOD to model future transmission projects in the steady-state base cases.

ROS ERCOT Reliability and Operating Subcommittee. SSWG is a working group created by ROS to create the steady-state planning models for ERCOT. SSWG reports to ROS and takes direction from ROS.

Standard PMCR A PMCR for adding planning model elements or modifying planning model attributes in the Network Operations Model in MOD for steady-state base cases that either are not available in the NMMS database or are not properly converted by the Topology Processor.

Topology The arrangement of buses and lines in a network model.

Topology Processer (TP) Siemens software application that converts the ERCOT Network Operations network model to a planning bus/branch model.

TP Case A bus/branch model created from the Network Operations Model using the Topology Processor application for a specific date.

MOD Base Case The TP Case loaded into MOD that is incrementally updated by ERCOT to maintain consistency between NMMS and MOD and is used as a starting point for building/updating steady-state base cases.

Transmission Project Info Tracking A report (Excel spreadsheet) that is created upon completion of the triannual case build/update cycle to reflect data used in the base cases.

Transmission In-Service Date: The equipment energization date used in the creation of the TP case and used in MOD to incorporate Project PMCRs that will be included in the MOD case build.

* 1. **Acronyms**

ALDR Annual Load Data Request

SS Steady State Cases

DSP Distribution Service Provider

EPS ERCOT Polled Settlement (metering)

ERCOT Electric Reliability Council of Texas

FERC Federal Energy Regulatory Commission

GINR Generation Interconnection Request number

HWLL High Wind/Low Load

IMM Information Model Manager

LSE Load Serving Entity

MLSE Most Limiting Series Element

MOD Model on Demand

NDCRC Net Dependable Capability and Reactive Capability

NERC North American Electric Reliability Corporation

NMMS Network Model Management System

NOIE Non Opt In Entity

NOMCR Network Operations Model Change Request

PLWG Planning Working Group

PMCR Planning Model Change Request

PPL Project Priority List

PSS/E Power System Simulator for Engineering

PUN Private Use Network

RARF Resource Asset Registration Form

RAWD PSS/E Raw Data format

RE Resource Entity

ROS Reliability and Operating Subcommittee

SCADA Supervisory Control And Data Acquisition

SCR System Change Request

SSWG Steady-State Working Group

TPIT Transmission Project Information Tracking

TSP Transmission Service Provider

TO Transmission Owner

WGR Wind Generation Resource

# 3 Steady-State Base Case Procedures and Schedules

3.1 General

The SSWG and ERCOT build steady-state base cases and perform triannual updates on these cases at fixed intervals on an annual basis. The processes and schedules for building the SSWG steady-state base cases and performing triannual updates are described in this section.

3.2 Steady-State Base Case Definitions and Build Schedules

A set of cases are created by SSWG each year to be known as the Steady State Cases (SS). The SS Cases consist of eight seasonal cases which model expected on-peak and off-peak conditions for the following year’s four seasons, expected peak conditions for each year over a six-year planning horizon beginning the year after the following year, a HWLL case, and a minimum load case for one of the years in the six-year planning horizon. Each set of SSWG cases consist of 16 base cases.

The Steady State Cases are defined as follows:

SPG March, April, May

SUM June, July, August, September

FAL October, November

WIN December, January, February

**SSWG**

**(YR) = CURRENT YEAR**

|  |  |  |
| --- | --- | --- |
| BASE CASE | NOTES | **TRANSMISSION IN-SERVICE DATE** |
| (YR+1) SPG1 | 2 | April 1, (YR+1) |
| (YR+1) SPG2 | 3 | April 1, (YR+1) |
| (YR+1) SUM1 | 1 | July 1, (YR+1) |
| (YR+1) SUM2 | 3 | July 1, (YR+1) |
| (YR+1) FAL1 | 2 | October 1, (YR+1) |
| (YR+1) FAL2 | 3 | October 1, (YR+1) |
| (YR+2) WIN1 | 1 | January 1, (YR+2) |
| (YR+2) WIN2 | 3 | January 1, (YR+2) |
| (YR+2) SUM1 | 1 | July 1, (YR+2) |
| (YR+3) SUM1 | 1 | July 1, (YR+3) |
| (YR+4) MIN | 4 | January 1, (YR+4) |
| (YR+4) HWLL | 5 | January 1, (YR+4) |
| (YR+4) SUM1 | 1 | July 1, (YR+4) |
| (YR+5) SUM1 | 1 | July 1, (YR+5) |
| (YR+6) SUM1 | 1 | July 1, (YR+6) |
| (YR+7) SUM1 | 1 | July 1, (YR+7) |

Notes:

1. Cases to represent the maximum expected load during the season.
2. Cases to represent maximum expected load during month of transmission in-service date.
3. Cases to represent lowest load on same day as the corresponding seasonal case (not a minimum case). For example, (YR) FAL2 case represents the lowest load on the same day as the (YR) FAL1 case.
4. Cases to represent the absolute minimum load expected for the year
5. Case to represent a high wind generation dispatch and corresponding load level that is greater than the minimum case, but lower the summer peak case.

***3.2.3 Triannual Updates***

The SSWG base cases are updated triannually. All triannual updates will be made in the MOD environment by changing an existing PMCR or creating a new PMCR. It should be recognized that impedance or ratings updates made to the Network Operations Model after the TP case was created will have to be submitted as a ‘NOMCR Pending’ or ‘NOMCR Submitted’ PMCR to maintain consistency with the Network Operations Model. See Planning Guide Section 6.4 for additional information about the TPIT process.

|  |
| --- |
| YR (YR=Current Year) |
| Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
| YR-1 SSWG Update 2  |   | YR SSWG Build(Apply YR ALDR) |   | YR SSWG Update 1  |   |   |
|  | Update YR-1 SSWG Fall and Win cases |  | Update YR-1 SSWG Win cases |  |  |
|   | March 1 - Post Base Cases and TPIT |   |  |   | July 1 - Post Base Cases and TPIT |   |  |   |  Oct 15 - Post Base Cases and TPIT |   |   |
|   | Update Con Files and Planning Data Dictionary |   |   | Update Con Files and Planning Data Dictionary |   |   | Update Con Files and Planning Data Dictionary |   |

3.3 Steady-State Base Case Build Processes

***3.3.1 Overview***

The Steady State Cases are based upon the ERCOT Network Operations Model. Network model data from the ERCOT NMMS system is used to create the TP case. The TP case, or an incremental update to the previously uploaded TP case, is then imported into MOD and becomes the MOD base case. ERCOT and the TSPs submit Standard PMCRs and PMCRs into MOD. Other PMCRs (i.e. ‘NOMCR\_PENDING’ and ‘NOMCR\_SUBMITTED’ PMCRs), aim at maintaining consistency between NMMS and MOD, are also submitted into MOD. Additionally, ERCOT and the TSPs submit Load, Generation, and Device Control Profiles into MOD. After being submitted, approved, and accepted, the combination of PMCRs and Profiles are applied to the MOD seed case to create the SSWG Steady State Cases.

The primary software tools utilized for these processes are MOD, MOD File Builder and PSS/E. MOD is a web based application maintained by ERCOT. TSPs and ERCOT use MOD to submit projects and profiles for Steady State Cases. ERCOT will compile these projects and profiles to build the Steady State Cases. Case modifications can be accomplished in MOD by either uploading PMCRs in MOD, or by manual entry using the MOD interface. SSWG members will need to consult the Planning Model Design Guidelines & Expectations manual for specific instructions on MOD.

***3.3.2 Incremental Update***

Upon commencement of each new Steady State Case build and each update, the SSWG will implement an incremental update to the MOD base case in order to include the latest Network Operations Model data in the Steady State Cases. This is accomplished by using MOD File Builder to compare the RAW files of topology processed NMMS data with selected data currently existing in MOD. MOD File Builder is used to create a comparison PMCR that updates the corresponding Planning Model data in MOD to be consistent with the Network Operations Model data. The comparison PMCR is subsequently submitted into MOD and committed to the MOD base case to perform the incremental MOD base case update.

The sample flowchart below identifies the general process:



***3.3.3 Transmission In-Service Date for the TP Case***

The TP case will be generated by ERCOT staff using an NMMS Transmission In-Service Date agreed upon by SSWG. The TP case will contain all existing NOMCRs with a Transmission In-Service Date on or before the agreed upon Transmission In-Service Date. Any NOMCR submitted after the TP case download which happens to have a Transmission In-Service Date prior to the agreed upon Transmission In-Service Date will not be included in the TP case. For that situation, the TSP who owns the NOMCR must submit a PMCR to appropriately include the network model change in the steady-state base cases.

***3.3.4 Entity Responsibilities***

The Steady State Cases are assembled and produced as a collaborative effort by the SSWG. The responsibilities for providing this data are divided among the various market participants and ERCOT. These data provision responsibilities may overlap among the various market participants because participants may designate their representative or a participant may be a member of more than one market participant group. The market participants can generally be divided into four groups: TSPs, LSEs, REs, and Market Entities. ERCOT staff is included as a fifth entity with data provision responsibilities. The data responsibilities of each group are as follows:

**3.3.4.1 TSPs**

It is the responsibility of each TSP to provide accurate modeling information for all ERCOT Transmission Facilities owned or planned by the TSP. Submission requirements and naming conventions described in the ERCOT Planning Model Design & Expectations manual shall be followed.

* Future transmission facility changes will be submitted as PMCRs. A PMCR phase date should correspond to the transmission in-service date. PMCRs should be submitted as far out into the future as possible. This technique will make the case building process more efficient when transitioning to new case builds.
* TSPs shall model all load data, and associated topology, of load entities they are the designated representatives of. Loads for the cases are submitted through Profiles.
* TSPs will provide all loads that it has accepted responsibility for modeling. TSPs shall change the ID of the load to ‘ER’ or ‘E1’, ‘E2’, etc. for loads for which it historically has submitted data but no longer accepts responsibility. ERCOT will determine the owner of the load and ensure they are part of the ALDR or SSWG process.
* PUN loads will be provided by TSPs.
* NOIEs have the option of submitting generation dispatch or deferring to ERCOT staff.
* Proper transmission system voltages will be maintained by submitting Profiles. This will include accurate data for static and dynamic reactive resources and transformer settings in a Device Control Profile for each case. Scheduled bus voltages are maintained by the TSPs and submitted via Device Control Profiles as well. TSPs can suggest different generator reactive limits Qmax and Qmin for ERCOT to submit in the Load Generation Profiles and should submit data to collaborate the need for the change such as historical unit operation and biennial reactive tests. ERCOT will submit the change and follow-up with the RE and TSP to determine any RARF modifications.
* If the TSPs identify errors with generator data or RE topology, the TSPs will notify ERCOT staff in accordance with the identified NMMS process. This process entails email notification to the TSP of a RARF change in their footprint and posting of updated RARF data on the Citrix NMMS\_POSTINGS area of the ERCOT Market Information System.
* Review and resolve all inconsistencies identified from the incremental update process for their respective Transmission Facilities.
* TPIT numbers will be submitted by the TSPs and will be the “MOD Project ID”. When editing an accepted project, click the “Edit” button from the project list to put project into “Preliminary” state, then “View” the project from project list and use the “Replace” button to upload edited project. This will preserve the MOD Project ID for TPIT.
* TSPs are responsible for updating TPIT project and phase information in MOD during each tri-annual case build/update.

**3.3.4.2 LSEs**

* Entities not having representation on SSWG shall submit their data to ERCOT staff or to the directly connected TSP, if the TSP has agreed to be the agent on SSWG for that entity.
* See Section 6.5, Annual Load Date Request of the ERCOT Planning Guide.

**3.3.4.3 Resource and Interconnecting Entities**

* It is the responsibility of REs to provide all data required to accurately model their generators, step-up transformers, associated transmission facilities and reactive devices in the steady-state base cases in accordance with Section 6.8, Resource Registration Procedures of the ERCOT Planning Guide.
* Interconnecting Entities are required to submit data for SSWG base cases in accordance with Section 6.9 of the ERCOT Planning Guide.
* It is the responsibility of REs to supply any applicable load and/or generation data if they are the designated representatives for either a load or generating entity or both.

**3.3.4.4 ERCOT**

* It is the responsibility of ERCOT staff to maintain the ERCOT MOD production environment that allows SSWG members to provide appropriate equipment characteristics and system data as stated in this procedure.
* ERCOT staff shall be responsible for creating each MOD incremental update base case.
* ERCOT staff shall be responsible for the review and inclusion of all latest available generator models with each triannual case update, including generator step-up transformers and associated RE-owned transmission facilities, RE-owned reactive devices, in the steady-state base cases. ERCOT staff will use a Bus Number range assigned to it and assign equipment IDs per ERCOT’s methodology. Future units will be modeled in accordance with data provided by REs as required in the Generation Interconnection or Change Request Procedure.
* ERCOT staff shall provide and review all RE topology, ratings, and impedances.
* It is the responsibility of ERCOT staff to provide an initial generation dispatch for Pass 0 during the Planning Case creation, but this dispatch does not have to be economic or security constrained.
* It is the responsibility of ERCOT staff to provide the revised generation dispatch based on the latest topology and loads by submitting the Generation Profile with each triannual case update. This dispatch will be in accordance with Section 4.3.3 of this document and will be provided at the next Pass after the case reaches an acceptable AC solution and no islands exist not related to an asynchronous tie or normally open equipment.
* ERCOT staff shall revise the generation dispatch as needed throughout the Planning Case building processes.
* ERCOT staff shall review submitted PMCRs and notify TSPs of any PMCRs which appear to modify topology, ratings, or impedances from the Network Operations Model which do not have a corresponding future project.
* Based on the TSPs NERC responsibilities of providing appropriate equipment characteristics and system data, ERCOT staff shall not reject any PMCR that TSPs ultimately determine should be applied to a steady-state base case after appropriate reviews have occurred.
* ERCOT staff shall provide case checking files after each pass of the case building processes.
* ERCOT staff shall provide a MOD change request report following posting of finalized cases.
* Review and resolve all inconsistencies identified from the incremental update process for RE data.
* ERCOT staff shall provide TPIT spreadsheet from MOD with each case build pass.
* ERCOT staff shall be responsible for posting the final TPIT spreadsheet with the posting of each triannual case update.
* ERCOT staff shall provide all updated Steady State Cases with every pass.

***3.3.5 Process Overview for Building the Steady State Cases***

* Base Case Preparation
	+ Export the TP Case from NMMS.
	+ Zero out TP Case load MW/MVAR quantities.
	+ Convert the TP Case to the current PSS/E version.

Incremental update process:

* + ERCOT produces a comparison file with inconsistencies between the newly produced MOD case with an effective date of the TP pull date and the new TP case.
	+ ERCOT shall upload and commit the comparison file to MOD which synchronizes MOD with NMMS.
* Pass 0
	+ TSPs review existing PMCRs.
	+ Submit Standard PMCRs.
	+ Submit PMCRs.
	+ Submit Profiles.
	+ Load initial generation dispatch.
	+ Review generation voltage schedules and suggest changes.
	+ Review generation reactive curves and suggest changes.
	+ Output Pass 1 cases.
* Pass 1 – Pass N
	+ Continue submitting Standard PMCRs.
	+ Continue submitting PMCRs.
	+ Update Profiles.
	+ Load revised generation dispatch.
	+ Output Pass 2 – Pass N+1 cases.
* Final Pass
	+ SSWG approves cases.
	+ Cases finalized by SSWG, the generation dispatch spreadsheet, and the change request report are posted on the ERCOT MIS. website.

Any changes required after the Steady State Cases are posted will be made in the MOD environment. Off-Cycle updates will be made by posting change files on the ERCOT M.I.S. website per section 6.1 of the ERCOT Planning Guide.

***3.3.6 Transition from Completed Build to Next Case Build***

* Implement the incremental update process triannual to include the latest Network Operation Modeling data.
* Project files representing planned projects and profiles will be retained from the previous case update.
* This process will continue not only for the Planning Case builds, but for each triannual update.

# 4 MODELING METHODOLOGIES

4.1 Bus, Area, Zone and Owner Data

4.1.1 Bus Data Records

All existing and planned transmission (60kV and above) and generator (greater than 10 MW) terminal buses shall be modeled in the steady-state base cases. Each bus record has a bus number, name, base kV, bus type code, area number, zone number, per-unit bus nominal voltage magnitude, bus voltage phase angle, and owner number. Reactive resources shall be modeled in either the fixed shunt table or the switched shunt table and shall not be modeled in any bus record.

4.1.2 Bus Number Ranges

The ERCOT transmission system is modeled within the full PSSE bus number range (1 through 999,997). The Chairman of the SSWG allocates bus ranges, new or amended, with confirmation from the SSWG members. Each TSP represents their network in the base cases within the TSP’s designated bus number range. ERCOT represents Resource Entities (REs) and Private Use Networks (PUNs) in the base cases within ERCOT’s designated bus number range. Bus number range assignments are listed in the Bus/Zone Range Table in Appendix A.

4.1.3 Bus Names

Bus names shall not identify the customers or owners of loads or generation at new buses unless requested by customers. The twelve character bus name in the planning model shall follow certain technical criteria as stated in the ERCOT Nodal Protocol Section 3.10 and Other Binding Documents.

4.1.4 Area Numbers

TSPs and ERCOT are assigned area names and numbers for modeling purposes. Area names and number assignments are listed in the Bus/Zone Range Table in Appendix A. The area number does not refer to a geographic area.

***4.1.5 Zone Number Ranges***

In PSSE, each zone data record has a zone number and a zone name identifier. The Chairman of the SSWG allocates zone number ranges, new or amended, with confirmation from SSWG members. Each TSP represents their network in the base cases using allocated zone number ranges. Zone numbers from within the TSP’s designated zone range are assigned by the TSP. ERCOT represents Resource Entities (REs) and Private Use Networks (PUNs) in the base cases using zone ranges allocated to ERCOT. Zone numbers from within ERCOT’s designated zone range are assigned by ERCOT. Zone number range assignments are listed in the Bus/Zone Range Table in Appendix A.

4.1.6 Owner IDs

In PSSE, each owner data record has an owner number and an owner name identifier. Owner IDs are assigned by ERCOT.

4.1.7 Bus Voltage Limits

Normal and Emergency Bus Voltage Minimum and Maximum Limits shall reflect voltage limits set forth by the “System Operating Limit Methodology for Planning and Operations Horizon” document, however, Emergency Bus Voltage Limits for generator buses shall reflect minimum generator or high-side of GSU steady-state or ride-through voltage limitations.

4.1.8 Bus Data Source

|  |  |  |
| --- | --- | --- |
| **Data Element** | **Source For Existing Elements** | **Source For Planned Elements** |
| Bus Number | NMMS | MOD PMCR |
| Bus Name | NMMS  | MOD PMCR  |
| Area Number/Name | NMMS | MOD PMCR |
| Owner Number/Name | NMMS | MOD PMCR |
| Bus Code | NMMS & MOD STD PMCR | MOD PMCR |
| Bus Voltage & angle | NMMS & MOD PMCR | MOD PMCR |
| Bus Voltage Limits | NMMS & MOD PMCR | MOD PMCR |

4.2 Load Data

Real and reactive load forecasts within the Steady State Cases are populated with data consistent with, but not necessarily identical to, load data submitted through the ALDR process. In general, the ALDR contains non-coincident load data while the Steady State Cases contain load data coincident with either the individual TSP projected load levels or the ERCOT system projected load level. Furthermore, some of the loads defined in the Steady State Cases are not contained within the ALDR (e.g. No off-peak, no Spring, and no Fall loads are defined in the ALDR). See Planning Guides Section 6.5 for further information about the ALDR process.

Each load data record contains a bus number, load identifier, load status, area, zone, real and reactive power components of constant MVA load, real and reactive power components of constant current load, and real and reactive power components of constant admittance load. In general, loads (MW and MVAR) should be modeled on the high side of transformers serving load at less than 60 kV. However, special conditions may require more modeling detail such as parallel operation of power transformers from different sources.

Load Resources are not modeled in the Steady State Cases but are considered a Responsive Reserve.

4.2.1 Guidelines

(1) The bus number in the load data record must be a bus that exists in the base case. The load identifier is a two-character alphanumeric identifier used to differentiate between loads at a bus. All self-serve loads must be identified by “SS”. If there are multiple self-serve loads at the same bus, then the self-serve loads will be identified by S1, S2, S3, etc. See Section 4.3.1.1. Partial self-serve load should be modeled as a multiple load with “SS” identifying the self-serve portion. Distributed Generation must be identified by “DG” and modeled as negative load.

(2) The load data record zone number must be in the zone range of the TSP submitting the load, or in the zone range of ERCOT for loads associated with PUNs. Zone numbers for loads do not have to be the same as the bus to which the load is connected.

(3) Generator auxiliary load should not be modeled at generating station buses. Refer to section 4.3.1.

(4) In conformance with NERC Reliability Standards and the Planning Guide Section 6.5, entities not having representation on SSWG shall submit their load data to ERCOT or, if the directly connected TDSP has agreed to be the agent on SSWG for that entity, to that TSP. If load data is not timely submitted on the schedule and in the format defined by the TSP, then ERCOT shall calculate loads based on historical data and insert these loads into the steady-state base cases during annual updates.

(5) Multiple loads from different TSPs at a bus may be used. At this time, each TSP can define a load with a load ID of its choice. Careful coordination, however, is required between TSP representatives to ensure that the multiple loads modeled at the same bus are modeled correctly with unique load IDs.

4.2.2 Load Data Source

NMMS determines the bus where the load is connected. TSPs and ERCOT will assign MW and MVAR values by submitting Load/Generation Profiles through MOD. New loads or corrections to the location of existing loads will be submitted by PMCR through MOD.

|  |  |  |
| --- | --- | --- |
| **Data Element** | **Source For Existing Elements** | **Source For Planned Elements** |
| Bus Number | NMMS | MOD PMCR |
| Bus Name | NMMS  | MOD PMCR  |
| Area Number/Name | NMMS | MOD PMCR |
| Owner Number/Name | NMMS | MOD PMCR |
| Bus Code | NMMS  | MOD PMCR |
| Load ID | NMMS | MOD PMCR |
| Load Zone | NMMS  | MOD PMCR  |
| P load (MW) | MOD PROFILES | MOD PROFILES |
| Q load (Mvar) | MOD PROFILES | MOD PROFILES |
| Scalable Flag | NMMSMOD PMCR | MOD PMCR |
| Interruptible Flag | NMMSMOD PMCR | MOD PMCR |

4.3 Generator Data

4.3.1 Acquisition of Generator Data

ERCOT will utilize Resource Registration data provided by REs in accordance with ERCOT Protocols and the Generation Interconnection Process. Only net real and reactive generator outputs and ratings should be modeled in steady-state base cases. Net generation is equal to the gross generation minus station auxiliaries and other internal power requirements. All non-self-serve generation connected at 60 kV and above with at least 10 MW aggregated at the point of interconnect must be explicitly modeled. A generator explicitly modeled must include generator step-up transformer and actual no-load tap position. Generation of less than 10 MW is still required to be modeled, but not explicitly.

Unit Reactive Limits (leading and lagging) for existing units are obtained from the Resource Registration data. The Resource Registration data should reflect the most recent generator reactive unit test data conducted by the RE. Limited Resource Registration data shall be made available to SSWG upon request.

Generator reactive limits should be modeled with one value for Qmax and one value for Qmin as described below:

**Qmax**

Qmax is the maximum net lagging MVAr observed at the low side of the generator step up transformer when the unit is operating at its maximum net dependable MW capability. Qmax is calculated from the lagging Resource Registration data MW4 MVar value by subtracting Resource Registration data auxiliary load MVAr.

Example:

Resource Registration data lagging MW4 value is 85 MVAr

Resource Registration data auxiliary Load is 5 MVAr [[1]](#footnote-2)

In this example, Qmax is 85 – 5 = 80 MVAr

**Qmin**

Qmin is the maximum net leading MVAr observed at the low side of the generator step up transformer when the unit is operating at its maximum net dependable MW capability. Qmin is calculated from the leading Resource Registration data MW4 MVar value by subtracting Resource Registration data auxiliary load MVAr.

Example:

Resource Registration data leading MW4 value is -55 MVAr

Resource Registration data auxiliary Load is 5 MVAr

In this example, Qmin is -55 – 5 = -60 MVAr

4.3.1.1 Self-Serve Generation

Self-serve generators serve local load that does not flow through the ERCOT transmission system. Generation dispatch may be submitted by TSPs on a triannual basis for self-serve facilities serving self-serve load modeled in the base case. If no generation dispatch is submitted by the TSPs, ERCOT will dispatch the units accordingly to meet the self-serve load. Total self-serve generation MWs shall match total self-serve load MWs.

4.3.1.2 Coordination with other ERCOT Working Groups

All generator data should be coordinated with the Dynamics Working Group, Operations Working Group, Network Data Support Working Group and System Protection Working Group members to assure that it is correct before submitting the cases. This will insure that all of the cases have the most current steady state and dynamics information. The following items should be provided to these working groups for data coordination:

* Unit bus number
* Unit ID
* Unit maximum and minimum real power capabilities
* Unit maximum and minimum reactive power capabilities
* Unit MVA base
* Resistive and reactive machine impedances
* Resistive and reactive generator step-up transformer impedances
* Reactive devices modeled on the Generator side

4.3.2 Load and Generation Balance

Before the generation schedule can be determined, the expected ERCOT load and losses (demand) must be determined. Each MW of demand needs to be accounted for by a MW of generation.

4.3.3 Generation Dispatch Methodology for Planning Purposes

In order to simulate the future market, the following methodology for generation dispatch has been adopted for building the Steady State Cases, with the exception of the HWLL case. The HWLL case build process is described separately below. Generation dispatch as described below is for planning and may not necessarily reflect the actual real-time dispatch.

Existing and planned units owned by the Non-Opt-In Entities (NOIE) are dispatched according to the NOIE dispatch spreadsheets submitted to ERCOT on a triannual basis; unless a NOIE requests that their units are to be dispatched according to the order that is described below or do not submit a NOIE dispatch.

Private network generation is also dispatched independently. The plants are dispatched to meet their load modeled in the case. The import/export contributions of the DC Ties will be set based on historical data to the extent that the contributions are consistent with those indicated in the most recent Capacity, Demand and Reserves (CDR) Report. Likewise, wind plants are dispatched in accordance with Appendix B on Method for Calculating Wind Generation Levels in SSWG Cases to extent that the dispatch is consistent with the regional contributions indicated in the CDR Report.

Units that are solely for black start purposes are to be modeled in the base cases; however, these units should not be dispatched. Black Start units are designated with a unit ID that begins with the letter ‘B’ which can be followed by an alphanumeric character (for example, ‘B1’, ‘B2’, etc.).

All other units are dispatched using an economic-simulation software package. Units will be dispatched to minimize production costs taking into account unit start-up times and cost and heat rates while adhering to the following guidelines for each set of cases:

**SSWG**

**(YR) = CURRENT YEAR**

|  |  |  |
| --- | --- | --- |
| BASE CASE | NOTES | **TRANSMISSION IN-SERVICE DATE** |
| (YR+1) SPG1 | 1 | April 1, (YR+1) |
| (YR+1) SPG2 | 1 | April 1, (YR+1) |
| (YR+1) SUM1 | 1 | July 1, (YR+1) |
| (YR+1) SUM2 | 1 | July 1, (YR+1) |
| (YR+1) FAL1 | 1 | October 1, (YR+1) |
| (YR+1) FAL2 | 1 | October 1, (YR+1) |
| (YR+2) WIN1 | 1 | January 1, (YR+2) |
| (YR+2) WIN2 | 1 | January 1, (YR+2) |
| (YR+2) SUM1 | 2 | July 1, (YR+2) |
| (YR+3) SUM1 | 2 | July 1, (YR+3) |
| (YR+4) MIN | 3 | January 1, (YR+4) |
| (YR+4) HWLL | 4 | January 1, (YR+4) |
| (YR+4) SUM1 | 2 | July 1, (YR+4) |
| (YR+5) SUM1 | 2 | July 1, (YR+5) |
| (YR+6) SUM1 | 2 | July 1, (YR+6) |
| (YR+7) SUM1 | 2 | July 1, (YR+7) |

Notes:

1. Steady State Cases that are Security Constrained Economically Dispatched (SCED) using NERC and ERCOT contingencies for which non-consequential load loss is generally not allowed while monitoring Rate A (pre-contingency) and Rate B (post-contingency) for all transmission lines greater than 60 kV and transformers with the low side greater than 60 kV.
2. The Steady State Cases that are economically dispatched with an attempt to prevent Rate A overloads for all transmission lines greater than 60 kV and transformers with the low side greater than 60 kV.
3. Not Economically Dispatched
4. The HWLL case build process is as follows:
	1. Find historic peak wind from latest Wind Integration Reports posted on <http://www.ercot.com/gridinfo/generation/windintegration/>.
		1. Record date and MW value of the Wind Record.
		2. Find Wind Integration Report for Wind Record date from above.
			1. Record Wind Peak Time
			2. Record Wind Integration %
			3. Record maximum Actual Wind Output as a Percentage of the Total Installed Wind Capacity
	2. Use MIN case topology.
	3. Determine generation and load level for HWLL case.
		1. Determine total wind capacity available in HWLL case and apply percentage from 1.b.iii. above to determine wind generation level to be dispatched in HWLL case. Please note the wind generation level may require additional adjustments in order to produce a stable base case.
		2. If the HWLL wind integration level is assumed to be 30%, divide HWLL wind level by 0.3 to get total generation for HWLL case, which is an approximation from 1.b.ii. above.
		3. Set HWLL total load level to total generation determined in 4.c.ii. above. Apply ratio from solved MIN case to determine the load level and losses for each area in the case. Each entity will provide load profiles to match their portion of the total load level for HWLL case. These load levels will remain constant and will only be updated during the case building process.

SSWG members shall be able to review and suggest changes to the generation dispatch based on historical information.

In all cases spinning reserve is maintained according to ERCOT Nodal Operating Guides, Section 2.3.1.1, to the extent that the extraordinary dispatch conditions in Section 4.3.3.1 Item 3 of this guide are not deployed. Specifically, spinning reserve is maintained such that 50% of the Responsive Reserve Service obligation is made up of generation resources with the other 50% of Responsive Reserve Service obligation coming from Load Resources. The dispatch may be modified in the seasonal Steady State Cases if necessary to maintain voltages at acceptable levels.

New Generation Resources will be included in the base cases on a triannual basis according to the procedures defined in Planning Guide, Section 6.9, addition of Proposed Generation Resources to the Planning Models.

4.3.3.1 Extraordinary Dispatch Conditions

On occasion, the total load plus the spinning reserve indicated above can exceed the amount of available generation due to load forecasts. SSWG base cases typically model load at individual coincident TSP peaks instead of at the ERCOT coincident system peak. When such a condition is encountered in future cases, ERCOT may increase generation resources by taking the indicated action, or adding generation, in the following order:

1. Increase NOIE generation with prior NOIE consent.
2. DC ties dispatched to increase transfers into ERCOT to the full capacity of the DC ties.
3. Ignore spinning reserve.
4. Mothballed units that have not announced their return to service. The methodology for this procedure is detailed below.
5. Scale wind generation dispatch up to 50% of capability
6. Add units with interconnection agreements, but do not meet all of the requirements for inclusion defined in the Planning Guide.
7. Add publicly announced plants without interconnection agreements.
8. Dispatch units that are solely for black start.
9. Scale wind generation dispatch up to 100% of capability
10. Add generation resources to the 345 kV transmission system near the sites of existing or retired units.

ERCOT shall post the extraordinary dispatch details used in each case to the MIS website.

***4.3.4 Generation Guidelines***

1. ERCOT will model registered resources and resource equipment.
2. ERCOT will model future resources and resource equipment in the interconnection process using the “Generation\_Interconnection” project type in MOD. The project name shall contain the ERCOT GINR.
3. TSPs may model resource and resource equipment not requiring ERCOT registration and not required by the Generation Interconnection process if they desire the resource to be in the base case.
4. ERCOT shall update the PMAX and PMIN values based upon the RARF net seasonal sustainable ratings. The generator identifier is a two-character alphanumeric identifier used to differentiate between generators at a bus. All self-serve generators must be identified by P1. If there are multiple self-serve generators at the same bus, then self-serve generators must be identified by P1, P2, P3, etc. Self-serve economic generators must be identified by “PE”.
5. Refer to Appendix D for the generator identifiers used in the base cases.
6. In extraordinary dispatch scenarios, the following generator zones should be assigned by ERCOT:

|  |  |  |
| --- | --- | --- |
| ***Extraordinary Dispatch Step*** | ***Zone Number*** | ***Zone Name*** |
| 4. Mothballed units that have not announced their return to service. | ***1195*** | ***EX\_MB*** |
| 6. For units with interconnection agreements, but do not meet all of the requirements for inclusion defined in the Planning Guide | ***1196*** | ***EX\_IA\_NOFC*** |
| *7.* For publicly announced plants without interconnect agreements. | ***1197*** | ***EX\_PUB\_NOIA*** |
| 10. For generation resources added to the 345 kV transmission system near the sites of existing or retired units. | ***1198*** | ***EX\_FAKEGEN*** |

**Methodology for Dispatching Mothballed Units**

In order to minimize the effect on transmission plans of the decision to use mothballed units to meet the load requirement, the generation that is needed from mothballed units as a group will be allocated over all the mothballed units on a capacity ratio share basis. If this technique results in some of the mothballed units being dispatched at a level below their minimum load, an economic ranking will be used to remove the least economic units from consideration for that particular case so that the allocation of the load requirement among the remaining mothballed units will result in all of those units being loaded above their minimum loads.

For example, assume that, in some future year, ERCOT has a projected peak demand of 80,000MW and a total installed resource capacity of 82,000MW, with 3000MW of that installed capacity being units that are mothballed and have not indicated they will return. For this simple example, assume that the mothballed capacity is 20 generating units of equal 150MW size. Ignoring losses and spinning reserve requirement, the steady-state case would need to include 1000MW of the 3000MW mothballed capacity in order to match the load. Thus, each of the 20 mothballed units would be set to an output of 50MW in the steady-state case (assuming their minimum load is less than 50MW).

**Consideration of Alternative Dispatch for Studies**

While this treatment of mothballed units attempts to generally minimize the effect of the assumption that mothballed units will be used to meet the load requirement in the steady-state base cases (rather than assumed new generation), the planning process should also consider alternative generation dispatches in instances where this treatment of mothballed units could have a direct effect on transmission plans. Specifically, in instances where having a mothballed unit available would alleviate the need for a transmission project that would be required to meet reliability criteria if the mothballed unit were not to return, the transmission project should not be deferred based on the assumption that the mothballed unit will return to service.

***4.3.4 Voltage Profile Adjustments***

After the generation dispatch has been determined, the expected voltage profile for the system can be applied. The scheduled voltages should reflect actual voltage set points used by the generator operators.

TSPs should check the voltages at several key locations within the system when modifying generation control voltages and reactive devices. Voltage profile changes can be accomplished by turning on/turning off capacitors or reactors, and by changing the operations of generators (turning on/turning off/redispatching for VAR control). The cases should ultimately model system voltages that could be reasonably expected to occur.

***4.3.5 Generator Data Source***

|  |  |  |
| --- | --- | --- |
| **Data Element** | **Source For Existing Elements** | **Source For Planned Elements** |
| Bus Number | NMMS | MOD PMCR |
| Bus Name | NMMS  | MOD PMCR  |
| Machine ID | NMMS | MOD PMCR |
| Bus Code | NMMS  | MOD PMCR |
| V Schedule | MOD PROFILES | MOD PROFILES |
| Remote Bus (Voltage Control) | MOD PMCR | MOD PROFILES |
| RMPCT | MOD PROFILES | MOD PROFILES |
| PGen (MW) | DISPATCH - MOD PROFILES | DISPATCH - MOD PROFILES |
| QGen (Mvar) | DISPATCH - MOD PROFILES | DISPATCH - MOD PROFILES |
| PMax (MW) | RARF - NMMS | RARF - MOD PROFILES |
| PMin (MW) | RARF - NMMS | RARF - MOD PROFILES |
| QMax (Mvar)**[[2]](#footnote-3)** | RARF - NMMS | RARF - MOD PROFILES |
| QMin (Mvar)**2**  | RARF - NMMS | RARF - MOD PROFILES |
| Mbase (MVA)**2**  | RARF - NMMS | RARF - MOD PMCR |
| R Source (pu)**2** | RARF - NMMS | RARF - MOD PMCR |
| X Source (pu)**2** | RARF - NMMS | RARF - MOD PMCR |
| Owner | RARF - NMMS | RARF - MOD PMCR |
| Generator Step-up Unit (GSU) ID | NMMS | MOD PMCR |
| GSU Tap positions**2** | RARF - NMMS | RARF - MOD PMCR |
| GSU Tap Controls**2** | RARF - NMMS | RARF - MOD PMCR |
| GSU Specified R **2** | RARF - NMMS | RARF - MOD PMCR |
| GSU Specified X **2** | RARF - NMMS | RARF - MOD PMCR |
| Rate A/Rate B/ Rate C  | RARF - NMMS | RARF - MOD PMCR |
| Generator Reactive Devices Control Mode**2** | RARF - NMMS | RARF - MOD PMCR |
| Generator Reactive Devices Vhi (pu)**2** | RARF - MOD PROFILES | RARF - MOD PROFILES |
| Generator Reactive Devices Vlo (pu)**2** | RARF - MOD PROFILES | RARF - MOD PROFILES |
| Generator Reactive Devices Binit (Mvar) | MOD PROFILES | MOD PROFILES |
| Generator Reactive Devices Bsteps (Mvar)**2** | RARF - NMMS | RARF - MOD PMCR |
| Wind Machine Control Mode | NMMS- / MOD PMCR | MOD PMCR |
| Wind Machine Power Factor | NMMS/MOD PMCR | MOD PMCR |

4.4 Branch Data

***4.4.1 Use of Branch Record Data Fields***

All existing and planned transmission lines (60 kV and above) shall be modeled in the SSWG steady-state base cases.

**4.4.1.1 Bus Specifications**

The end points of each branch in the SSWG steady-state base cases are specified by “from” and “to” bus numbers. In most cases the end point buses are in the same TSP area. However, when the “from” and “to” buses used to specify a branch are in different TSP areas, the branch is considered to be a tie line (See Section 4.4.3, Coordination of Tie Lines). Branch data includes exactly two buses. The end points of Multi-Section Lines (MSL) are defined by two buses specified in a branch data record (See Section 4.4.2). There are other components that are modeled with more than two buses, such as transformers with tertiary that may be represented by three-bus models.

**4.4.1.2 Branch Circuit Identifier**

Circuit identifiers are limited to two alphanumeric characters. Each TSP will determine its own naming convention for circuit identifiers. ERCOT will determine its own naming convention for branches owned by REs and PUNs with careful coordination with connected TSPs. These identifiers are typically numeric values (e.g. 1 or 2) that indicate the number of branches between two common buses, but many exceptions exist.

**4.4.1.3 Branch Impedance and Admittance Data**

The branch resistance, reactance, and admittance data contained in the steady-state base cases are expressed in per-unit quantities that are calculated from a base impedance. The base impedance for transmission lines is calculated from the system base MVA and the base voltage of the transmission branch of interest. The system base MVA used in the steady-state base cases is 100 MVA (S = 100 MVA). The base voltage for a transmission line branch is the nominal line-to-line voltage of that particular transmission branch (See Transformer Data for Calculation of Transformer Impedances). Therefore the base impedance used for calculating transmission branch impedances is:

 Ohms

This base impedance is then used to convert the physical quantities of the transmission line into per-unit values to be used in the steady-state base cases.

4.4.1.3.1 Resistance

Once the total transmission line resistance is known and expressed in ohms, then this value is divided by the base impedance to obtain the per-unit resistance to be used in the steady-state base cases. This calculation is as follows:



4.4.1.3.2 Reactance

Once the total transmission line reactance is known and expressed in ohms, then this value is divided by the base impedance to obtain the per-unit reactance to be used in the steady-state base cases. This calculation is as follows:



4.4.1.3.3 Admittance

Branch admittance is expressed as total branch charging susceptance in per unit on the 100 MVA system base. The total branch charging is expressed in MVARs and divided by the system base MVA to get per unit charging. The equation used to accomplish this depends on the starting point. Typically the charging of a transmission line is known in KVARs. Given the total transmission line charging expressed in KVARs, the equation to calculate the total branch charging susceptance in per unit on the system base is as follows:



Or, given the total capacitive reactance to neutral expressed in ohms , the equation to calculate the total branch charging susceptance in per unit on the system base is as follows:



4.4.1.4 Facility Ratings

SSWG base cases contain fields for three ratings for each branch record, including zero impedance branches. The ratings associated with these three fields are commonly referred to as Rate A, Rate B and Rate C. Each TO has their own methodology for calculating these ratings and shall be made available to others within ERCOT upon request. Following are the steady-state base case facility ratings corresponding to the ratings defined in Nodal Protocol 2.1:

|  |  |
| --- | --- |
| Planning Case Rating Definitions | Corresponding Nodal Protocol Section 2.1 Definitions |
| Rate A | Normal Rating |
| Rate B | Emergency Rating |
| Rate C | Conductor/Transformer 2-Hour Rating |

By definition, Rate C ≥ Rate B ≥ Rate A

When performing security studies, ERCOT will default to Rate B, unless the TSP has previously indicated in writing that other ratings (e.g., Rate A) should be used. If problems exist using Rate B and Rate B is significantly different from Rate C, then ERCOT will contact the TSP.

***Upon implementation of PSS/E v34 or prior to 2016***

SSWG base cases contain fields for four ratings for each branch record, including zero impedance branches. The ratings associated with these three fields are commonly referred to as Rate 1, Rate 2, Rate 3, and Rate 4. Each TSP has their own methodology for calculating these ratings and shall be made available to others within ERCOT upon request. Following are the steady-state base case facility ratings corresponding to the ratings defined in Nodal Protocol 2.1:

|  |  |
| --- | --- |
| Planning Case Rating Definitions | Corresponding Nodal Protocol Section 2.1 Definitions |
| Rate 1 | Normal Rating |
| Rate 2 | Emergency Rating |
| Rate 3 | Conductor/Transformer 2-Hour Rating |
| Rate 4 | Relay Loadability Limit  |

By definition, Rate 3 ≥ Rate 2 ≥ Rate 1

4.4.1.4.1 Most Limiting Series Element

Facility ratings shall not exceed the most limiting applicable equipment rating of the individual equipment that comprises the facility. If the continuous or two (2) hour ratings of any series elements at the station terminals is less than the associated transmission line’s continuous or two (2) hour rating, then the most limiting elements’ rating data will be used as the Rate A and/or Rate B rating for the transmission line. The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

4.4.1.5 Shunt Admittance

Branch Data records include four fields for complex admittance for line shunts. These records are rarely used in the SSWG steady-state base cases.

4.4.1.6 Status

Branch data records include a field for branch status. Entities are allowed to submit branch data with an out-of-service status for equipment normally out of service.

4.4.1.7 Line Length and Ownership

4.4.1.7.1 Line Length

This data will be provided in miles.

4.4.1.7.2 Ownership

Owner IDs are assigned by ERCOT. The PSSE line data record allows the specification of up to four owners for each branch including percent ownership. The percent ownership of each line should sum up to 100%.

Facilities owned by Generators will be assigned non-TSP ownership id in the cases.

4.4.1.7.3 Practices for Verification

Transmission line length for existing lines should be verified from field data and actual values entered into the power flow model.

A simple check can be utilized to verify certain modeling parameters for overhead lines. The following equation is an approximation that applies to transmission lines that are completely overhead:

or assuming  MVA then



4.4.2 Multi-Section Line Grouping

A multi-section line is defined as a grouping of several previously defined branches into one long circuit having several sub-sections or segments.

Example: Two circuits exist (Figure 1) which originate at the same substation (4001) and terminate at the same substation (4742). Each circuit has a tap to Substation A and a tap to Substation B. If a fault occurs or maintenance requires an outage of Circuit 09, the circuit would be out-of-service between bus 4001 and bus 4742 including the taps to buses 4099 and 4672. The loads normally served by these taps would be served by means of low-side rollover to buses 4100 and 4671 on Circuit 21. This is the type of situation for which multi-section lines are used to accurately model load flows.



**Figure 1. Example of circuits needing to use multi-section line modeling.**

Figure 2 represents a power-flow data model of the circuits in Figure 1. Branch data record would have included the following:

4001,4099,09,…

4099,4672,09,…

4672,4742,09,…

4001,4100,21,…

4100,4671,21,…

4671,4742,21,…

along with the necessary bus, load, and shunt data. To identify these two circuits as multi-section lines, entries must be made in the raw data input file. The multi-section line data record format is as follows:

I,J,ID,DUM1,DUM2, … DUM9 where :

I “From bus” number.

J “To bus” number.

ID Two characters multi-section line grouping identifier. The first character must be an ampersand (“&”). ID = ‘&1’ by default.

DUMi Bus numbers, or extended bus name enclosed in single quotes, of the “dummy buses” connected by the branches that comprise this multi-section line grouping. No defaults allowed.

Up to 10 line sections (and 9 dummy buses) may be defined in each multi-section line grouping. A branch may be a line section of at most one multi-section line grouping.

Each dummy bus must have exactly two branches connected to it, both of which must be members of the same multi-section line grouping.

The status of line sections and type codes of dummy buses are set such that the multi-section line is treated as a single element.



**Figure 2. Power-flow model of example circuits.**

For our example, the following would be entered as multi-section line data records:

4001, 4742, &1, 4099, 4672

4001, 4742, &2, 4100, 4671

Multi-section lines give a great amount of flexibility in performing contingency studies on steady-state base cases. When set up correctly, hundreds of contingencies where the automatic low-side load rollover occurs can be analyzed and reported within minutes

.

4.4.3 Coordination of Tie Lines

A tie line is defined as any transmission circuit with multiple owners represented within the context of the transmission circuit’s associated facility.  As used here, a transmission circuit’s associated facility includes all terminal buses as well as the transmission branch, transformer, bus section, or another electrical component connecting systems together.  For a tie line, each of the interconnected entities (TSP/TSP or TSP/RE) owns one or more elements of the tie line’s associated facility.

Careful coordination and discussion is required among SSWG members to verify all modeled tie line data.  Even in situations where no new tie lines are added to a network model, there could be many tie line changes.  Construction timing for future points of interconnection or modified existing points of interconnection can change.  As a result, a tie line may need to be deleted from some cases and added to others (e.g. deleted from spring cases and added to summer cases).  Additionally, a new substation installed in the middle of an existing tie line can redefine the tie line’s bus numbers, mileages, impedances, ratings, or ownership.

Tie line models also affect a number of important ERCOT calculations and therefore must accurately reflect real-world conditions.  Missing, redundant, or erroneous tie line models can produce unrealistic indications of stability and/or voltage limits.  Inaccurate impedances, ratings, transformer adjustment data, status information, mileages, or ownership data can all have a profound effect on system studies.  Therefore, it is imperative that neighboring entities exercise care in coordinating tie line data.

Ratings for tie lines should be mutually agreed upon by all involved entities and should comply with NERC Reliability Standards.

It is imperative for neighboring entities to coordinate tie data in order to allow Planning Case work activities to proceed unimpeded. Entities should exchange tie-line data at least two weeks before the data is due to ERCOT. Coordination of tie data includes timely agreement between entities on the following for each tie line:

* In-service/ out-service dates for ties
* From bus number
* To bus number
* Circuit identifier
* Impedance and charging data
* Ratings
* Transformer adjustment (LTC) data
* Status of branch
* Circuit miles
* Ownership (up to four owners)
* Entity responsible for submitting data

4.4.4 Metering Point

Each tie line or branch has a designated metering point and this designation may also be coordinated between neighboring TSP areas. The location of the metering point determines which TSP area will account for losses on the tie branch. The PSS/e load-flow program allocates branch losses to the TSP area of the un-metered bus. For example, if the metering point is located at the “to” bus then branch losses will be allocated to the TSP area of the “from” bus.

The first bus specified in the branch record is the default location of the metering point unless the second bus is entered as a negative number. These are the first and second data fields in the branch record.

4.4.5 Branch Data Source

|  |  |  |
| --- | --- | --- |
| **Data Element** | **Source For Existing Elements** | **Source For Planned Elements** |
| From Bus Number | NMMS | MOD PMCR |
| From Bus Name | NMMS  | MOD PMCR  |
| To Bus Number | NMMS | MOD PMCR |
| To Bus Name | NMMS  | MOD PMCR  |
| ID | NMMS | MOD PMCR |
| Resistance R (pu)**[[3]](#footnote-4)** | NMMS | MOD PMCR |
| Reactance X (pu)**3** | NMMS | MOD PMCR |
| Charging Susceptance (pu)**[[4]](#footnote-5)** | NMMS | MOD PMCR |
| Branch Status | NMMS | MOD PMCR |
| Rate A/Rate B/ Rate C (MVA) | NMMS | MOD PMCR |
| Line Length (Miles) | NMMS | MOD PMCR |
| Owner  | NMMS | MOD PMCR |
| RE or PUN Owned Branch data | RARF - NMMS | RARF - MOD PMCR |
| Multi-Section Line | NMMS | MOD PMCR |

4.5 Transformer Data

***4.5.1 Use of Transformer Record Data Fields***

All existing and planned transformers are to be represented in the steady-state base cases. Transformer data records specify all the data necessary to model transformers in power flow calculations. Both two winding transformers and three winding transformers can be specified in the steady-state base cases.

**4.5.1.1 Bus Specifications**

The end points of each transformer in the SSWG steady-state base cases are specified by “winding 1” and “winding 2” bus numbers. In some cases, the “winding 1” and “winding 2” buses used to specify a transformer are in two different TSP areas, making the transformer a tie line (See Section 4.4.3, Coordination of Tie Lines). Three winding transformers (transformers with a tertiary winding) can be represented by specifying a “winding 3” bus number in the data to represent the tertiary winding.

**4.5.1.2 Transformer Circuit Identifier**

Circuit identifiers are limited to two alphanumeric characters. Each TSP will determine its own naming convention for circuit identifiers. Actual transformer identifiers may be used for circuit identifiers for transformers, however, typically, circuit identifiers are used to indicate which transformer is being defined when more than one transformer is modeled between two common buses. TSP’s can identify autotransformers with the letter A as the first character of the ID field. Generator Step-Up transformers can be identified with the letter G. Phase-shifting transformers can be identified with the letter P.

**4.5.1.3 Impedance and Admittance Data**

The resistance and reactance data for transformers in the steady-state base cases can be specified in one of three ways: (1) in per-unit on 100 MVA system base (default), (2) in per-unit on winding base MVA and winding bus base voltage, (3) in transformer load loss in watts and impedance magnitude in per-unit on winding base MVA and winding bus base voltage. Transformer resistance and reactance data supplied from the Topology Processor are specified in per-unit on 100 MVA system base.

4.5.1.3.1 Resistance

Transformer test records should be used to calculate the resistance associated with a transformer record. Where transformer test records are unavailable, the resistance should be entered as either a value similar to a comparable transformer or zero.

4.5.1.3.2 Reactance

Transformer test records or transformer nameplate impedance should be used to calculate the reactance associated with a transformer record. Where the transformer resistance component is known, the transformer reactance is calculated on the same base using the known data and the reactance component is determined using the Pythagorean Theorem. Where the transformer resistance is assumed to be zero, the calculated transformer reactance can be assumed to be equal to the transformer impedance.

4.5.1.3.3 Susceptance

For power-flow modeling purposes, the transformer susceptance is always assumed to be zero.

**4.5.1.4 Transformer Ratings**

The ratings used for transformer are defined the same as the ratings used for branches described in Section 4.4.1.4.

**4.5.1.5 Status**

Transformer data records include a field for status. Entities are allowed to submit transformer data with an out-of-service status for equipment normally out of service.

**4.5.1.6 Ownership**

Up to four owners and corresponding percent ownership can be specified for each transformer in the base cases. Owner IDs and corresponding percent ownership should be included for all transformers. The sum of all percent ownerships should equal 100% for every transformer.

**4.5.1.7 Angle**

In PSSE, the phase shift across a two-winding transformer is specified by an angle referenced to the winding defined as “winding 1” by the combined logic of the “From Bus Number”, “To Bus Number” and “Winding 1 Side” (From or To logic) fields. The phase shift angle is positive when the voltage of the bus corresponding to the referenced winding leads the voltage of the bus connected to the opposite winding.

The phase shift(s) associated with a three-winding transformer is(are) accounted for by the specification of an angle for each of the three windings. The phase shift angle across a winding is positive when the voltage of the corresponding bus leads the voltage of the star point bus.

The transformer phase shift angle is measured in degrees for both two-winding and three-winding transformers.

**4.5.1.8 Tap Data**

All transformer tap characteristics should be appropriately modeled. Such tap characteristics include no-load tap settings and load tap changing (LTC) properties and associated control settings.

4.5.1.8.1 Ratio

The ratio is defined as the transformer off nominal turns ratio and is entered as a non-zero value, typically in per unit. Where the base kV contained in the bus data records for the buses connected to transformer terminals are equal to the rated voltage of the transformer windings connected to those terminals, the transformer off-nominal ratio is equal to 1.00. When the transformer has no-load taps, the transformer off-nominal ratio can be something other than 1, but is usually in the range of 0.95 to 1.05. The effects of load tap changing (LTC) transformer taps are also handled in the transformer data record.

4.5.1.8.2 Control Mode

This field enables or disables automatic transformer tap adjustment. Setting this field to a value other than zero (“None” within PSSE) enables automatic adjustment of the LTC or phase shifter as specified by the adjustment data values during power-flow solution activities. Setting this field to zero prohibits automatic adjustment of this transformer during the power-flow solution activities.

4.5.1.8.3 Controlled Bus

The bus number of the bus whose voltage is controlled by the transformer LTC and the transformer turns ratio adjustment option of the power-flow solution activities. This record should be non-zero only for voltage controlling transformers.

4.5.1.8.4 Transformer Adjustment Limits

These two fields specify the upper and lower limits of the transformer’s turns ratio adjustment or phase shifter’s angle adjustment. For transformers with automatic tap changer adjustments, these fields are typically populated with values in the range of 0.80 to 1.20 per-unit. For phase-shifting transformers, these fields may be populated with phase angle adjustment ranges up to +/- 180 degrees, but are typically modeled with values in the range of +30 to -30 degrees.

4.5.1.8.4.1 Upper Limit (Rmax)

This field defines the maximum upper limit of the off-nominal ratio for voltage or reactive controlling transformers and is typically entered as a per-unit value. The limit should take into account the no-load tap setting of the transformer, if applicable. For a phase shifting transformer, the value is entered in degrees.

4.5.1.8.4.2 Lower Limit (Rmin)

Similar to the upper limit, this field defines the lower limit of the off-nominal ratio or phase shift angle for the transformer defined.

4.5.1.8.5 Voltage or Power-Flow Limits

These two fields specify the upper and lower voltage limits at the controlled bus or for the real or reactive load flow through the transformer at the tapped side bus before automatic LTC adjustment will be initiated by the power-flow program. As long as bus voltage, or real power flow for phase shifting transformers, is between the two limits, no LTC adjustment will take place during the power-flow solution activities.

4.5.1.8.5.1 Upper Limit (Vmax)

This field specifies the upper limit for bus voltage in per unit at the controlled bus or for the reactive load flow in MVAR at the tapped side bus. For a phase shifting transformer, this field specifies the upper limit for the real power load flow in MW. Direction for power flow across the phase shifting transformer is referenced from the bus side defined as the “Winding 1” bus. Negative upper (and lower) limit values for phase shifting transformers imply power flow from the “Winding 2” bus to the “Winding 1” bus.

4.5.1.8.5.2 Lower Limit (Vmin)

Similar to the upper limit, this field specifies the lower limit for the bus voltage or the real or reactive load flow for the transformer defined.

4.5.1.8.6 Tap Positions Step

Transformer test records or nameplate data should be used to identify the number of tap positions available for a transformer’s LTC, along with the corresponding maximum and minimum turns ratio adjustment capabilities (i.e. Rmax and Rmin). The transformer’s turns ratio step increment for a LTC can be calculated based upon data present in the “Tap Positions”, “Rmax”, and “Rmin” fields of the transformer’s PSSE model. A common range for a LTC turns ratio step increment is +/- 10 % over 33 tap positions (32 steps), which corresponds to 5/8% or 0.00625 per unit voltage increment per tap step.

4.5.1.8.7 Table

The number of a transformer impedance correction table is specified by this field if the transformer's impedance is to be a function of either the off-nominal turns ratio or phase shift angle. SSWG steady-state base cases normally don’t use these tables and this field is set to zero by default.

4.5.1.9 Magnetizing Admittance

Magnetizing admittance data is not required for SSWG steady-state base cases and the values for each of these two fields should be zero.

4.5.1.10 Load Drop Compensation

These two fields define the real and reactive impedance compensation components for voltage controlling transformers. They are ignored for MW and MVAR flow controlling transformers. SSWG steady-state base cases normally don’t use these fields and they are set to zero by default.

4.5.1.10.1 Resistive Component

The resistive component of load drop compensation entered in per unit is based on the resistance between the location of the LTC and the point in the system at which voltage is to be regulated.

4.5.1.10.2 Reactive Component

Similar to the resistive component of load drop compensation, this value is entered in per unit and is based on the reactance between the location of the LTC and the point in the system at which voltage is to be regulated.

4.5.2 Transformer Data Source

|  |  |  |
| --- | --- | --- |
| **Data Element** | **Source For Existing Elements** | **Source For Planned Elements** |
| From Bus Number | NMMS | MOD PMCR |
| From Bus Name | NMMS  | MOD PMCR  |
| To Bus Number | NMMS | MOD PMCR |
| To Bus Name | NMMS  | MOD PMCR  |
| Last Bus Number | NMMS | MOD PMCR |
| Last Bus Name | NMMS  | MOD PMCR  |
| ID | NMMS | MOD PMCR |
| Transformer Name | NMMS | MOD PMCR |
| Resistance R (pu)**[[5]](#footnote-6)** | NMMS | MOD PMCR |
| Reactance X (pu)**5** | NMMS  | MOD PMCR  |
| Susceptance | NMMS or N/A | MOD PMCR or N/A |
| Rate A/Rate B/ Rate C | NMMS  | MOD PMCR  |
| Status | NMMS/ MOD STD PMCR | MOD PMCR |
| Owner | NMMS | MOD PMCR |
| Angle (phase-shift) | NMMS | MOD PMCR |
| Tap Ratio | MOD PROFILES | MOD PROFILES |
| Control Mode | NMMS | MOD PMCR |
| Controlled Bus | NMMS | MOD PMCR |
| Transformer Adjustment Limits | NMMS | MOD PMCR |
| Voltage or Power-flow Limits | MOD PROFILES | MOD PROFILES |
| Transformer Tap Step | NMMS | MOD PMCR |

4.6 Static Reactive Devices

All existing and planned static reactors and capacitors that are used to control voltage at the transmission level are to be modeled in the SSWG steady-state base cases to simulate actual transmission operation. There are two distinct static reactive devices currently represented in the SSWG steady-state base cases: shunt devices and series devices.

***4.6.1 Shunt Devices***

**4.6.1.1 Switched Shunt Devices**

A shunt capacitor or reactor located in a station for the purpose of controlling the transmission voltage can be represented in the SSWG steady-state base cases as a switched shunt device to accurately simulate operating conditions. Care should be exercised when specifying the size of cap banks. Be sure that the rated size of the bank is for 1.0 per unit voltage. Care should be taken to ensure that distribution level capacitors are not modeled in such a way as to be counted twice.

When a switched capacitor or reactor is submitted as the switched shunt data record, there are three modes that it can operate in: fixed, discrete, or continuous. Switched capacitors are to be modeled in the mode in which they are operated.

A switched shunt can be represented as up to eight blocks of admittance, each one consisting of up to nine steps of the specified block admittance. The switched shunt device can be a mixture of reactors and capacitors. The reactor blocks are specified first in the data record (in the order in which they are switched on), followed by the capacitor blocks (in the order in which they are switched on). The complex admittance (p.u.), the desired upper limit voltage (p.u.), desired lower limit voltage (p.u.), and the bus number of the bus whose voltage is regulated must be defined to accurately simulate the switched shunt device. A positive reactive component of admittance represents a shunt capacitor and a negative reactive component represents a shunt reactor.

**4.6.1.2 Fixed Shunt Devices**

A shunt capacitor or reactor located in a station for the purpose of controlling the transmission voltage can be represented in the SSWG steady-state base cases as a fixed shunt device to accurately simulate operating conditions. Care should be exercised when specifying the size of cap banks. Be sure that the rated size of the bank is for 1.0 per unit voltage. Care should be taken to ensure that distribution level capacitors are not modeled in such a way as to be counted twice.

Multiple fixed shunts can be modeled at a bus, each with a unique ID. These fixed shunts have a status that can be set to on or off.

A positive reactive component of admittance represents a shunt capacitor and a negative reactive component represents a shunt reactor.

**4.6.1.3 Dummy Bus Shunt**

If a switchable or fixed capacitor or reactor were connected to a transmission line instead of a station bus, an outage of the transmission line would also cause the capacitor or reactor to be taken out of service (see Figure 3). For these instances, the most accurate model is the switched shunt modeled at a dummy bus connected by a zero impedance branch to the real station bus. This dummy bus must have exactly two branches connected to it, both of which must be members of the same multi-section line grouping. The status of the line section is that the multi-section line is treated as a single element. A shunt capacitor or reactor connected to a line but modeled as a shunt within a station will result in power-flow calculations for contingencies that differ from real operating conditions.



 **Figure 3. Example one-line of line connected capacitor bank**

***4.6.2 Series Devices***

Series capacitors and reactors will be modeled as a series branch with the appropriate impedance. If a parallel bypass exists, it should be modeled as a zero impedance branch with the appropriate branch status indicating whether it is normally open or normally closed.

***4.6.3 Static Reactive Device Data Source***

|  |  |  |
| --- | --- | --- |
| **Data Element** | **Source For Existing Elements** | **Source For Planned Elements** |
| Switched Shunt: Control Mode | NMMS | MOD PMCR/PROFILES |
| Switched Shunt: Voltage Limits | MOD PROFILES/NMMS | MOD PMCR/PROFILES |
| Switched Shunt: Controlled Bus | NMMS | MOD PMCR/PROFILES |
| Switched Shunt: B init | MOD PROFILES/NMMS | MOD PROFILES |
| Switched Shunt: B steps | NMMS | MOD PMCR |
| Fixed Shunt: ID | NMMS | MOD PMCR |
| Fixed Shunt: Status | NMMS | MOD PMCR |
| Fixed Shunt: B-Shunt | NMMS | MOD PMCR |
| Series Device | NMMS | MOD PMCR |

4.7 Dynamic Control Devices

All existing and planned FACTS devices shall be modeled in the SSWG steady-state base cases. There are a multitude of FACTS (Flexible AC Transmission System) devices currently available, comprising shunt devices, such as Static VAR Compensator (SVC), Static Compensator (STATCOM), series devices such as the Static Synchronous Series Compensator (SSSC), combined devices such as the Unified Power Flow Controller (UPFC) and the Interline Power Flow Controllers (IPFC). These devices are being studied and installed for their fast and accurate control of the transmission system voltages, currents, impedance and power flow. They are intended to improve power system performance without the need for generator rescheduling or topology changes. These devices are available because of the fast development of power electronic devices.

PSS/E has the capability to model several different FACTS devices and their documentation is the best source for specific applications.

|  |  |  |
| --- | --- | --- |
| **FACT Device – Data SourceData Element** | **Source For Existing Elements** | **Source For Planned Elements** |
| Device Number | MOD STD PMCR  | MOD PMCR  |
| Sending Bus Number | MOD STD PMCR  | MOD PMCR  |
| Terminal End Bus Number | MOD STD PMCR  | MOD PMCR  |
| Control Mode | MOD PROFILES | MOD PROFILES |
| P Setpoint (MW) | MOD PROFILES | MOD PROFILES |
| Q Setpoint (Mvar) | MOD PROFILES | MOD PROFILES |
| V Send Setpoint | MOD PROFILES | MOD PROFILES |
| Shunt Max (MVA) | MOD STD PMCR  | MOD PMCR  |
| RMPCT (%) | MOD STD PMCR  | MOD PMCR  |
| V Term Max (pu) | MOD STD PMCR  | MOD PMCR  |
| V Term Min (pu) | MOD STD PMCR  | MOD PMCR  |
| V Series Max (pu) | MOD STD PMCR  | MOD PMCR  |
| I Series Max (MVA) | MOD STD PMCR  | MOD PMCR  |
| Owner | MOD STD PMCR  | MOD PMCR  |
| **NOTE:** The above list is an example of typical FACTs device parameters and does not include all possible types of FACTs devices. |

4.8 HVDC Devices

HVDC Devices allow a specified real power flow to be imposed on the DC link. For base case operation, this should be set to the desired interchange across the DC tie. Capacitors, filter banks and reactors should be modeled explicitly and switched in or out of service based on normal DC tie operation. The HVDC model itself normally calculates reactive power consumption.

HVDC ties with external interconnections may be modeled by the use of either the Two Terminal DC Transmission Line Data or Voltage Source Converter DC Line Data.

***4.8.1 Two Terminal DC Transmission Line Data***

Conventional HVDC ties should be modeled using Two Terminal DC Transmission Line Data. The Two Terminal DC Transmission Line Data model represents the HVDC terminal equipment, including any converter transformers, thyristors, and the DC link. The model will calculate voltages, converter transformer taps, losses, and VA requirements, based upon the power transfer over the HVDC facility, and the terminal AC bus voltages. See PSS/E Manual for more information.

***4.8.2 Voltage Source Converter (VSC) DC Line Data***

Voltage Source Converter DC line data can be used to model DC ties that use the voltage source converter technology. See PSS/E Manual for more information.

***4.8.3 HVDC Two Terminal Data Source***

|  |  |  |
| --- | --- | --- |
| **Data Element** | **Source For Existing Elements** | **Source For Planned Elements** |
| Line number | MOD STD PMCR & PROFILES | MOD PMCR & PROFILES |
| Controlled Mode | MOD STD PMCR & PROFILES | MOD PMCR & PROFILES |
| Line Resistance (Ohms) | MOD STD PMCR | MOD PMCR |
| Demand Setting (MW or Amps) | MOD PROFILES | MOD PROFILES |
| V schedule (kV) | MOD PROFILES | MOD PROFILES |
| Vcmod (kV) | MOD PROFILES | MOD PROFILES |
| Delti (pu) | MOD PROFILES | MOD PROFILES |
| Dcvmin (kV) | MOD PROFILES | MOD PROFILES |
| Metered (Rect/Invr) | MOD STD PMCR | MOD PMCR |

***4.9 Modeling of Resource and Transmission Outages***

TSPs are responsible for entering known outages of equipment for which they are the modeling entity with duration of at least six months as normally open equipment in the applicable steady-state base case(s). ERCOT is responsible for submitting outages for resource and resource owned equipment using the Outage Scheduler to determine outages with duration of at least six months and will model the status in the applicable steady-state base case(s) in accordance with its transmission in-service date.

5 Other SSWG Activities

5.1 Transmission Loss Factor Calculations

The transmission loss factors must be calculated according to Protocol Section 13. The loss factors are calculated using the seasonal Steady State Cases. The values are entered in the ERCOT settlements system to account for losses on the transmission system. Separate calculations are performed for the eight seasonal Steady State Cases: spring, summer, fall, and winter with an on and off peak for each season.

The Non Opt In Entities (NOIE) that provide metering of their system load to the ERCOT settlement system by a set of ERCOT Polled Settlements Meters (EPS) that ‘ring’ their transmission system as defined in Protocol 13.4.1 have additional calculations performed for their transmission loss factors.

The NOIE that send extra data to ERCOT for the loss calculations have EPS settlement meters on all of their transmission lines that connect or “tie” their system to the rest of the ERCOT transmission network. For the ERCOT settlement process ERCOT calculates their load as the net of inflows minus the outflows from these EPS meters. However calculations must be performed to subtract out the losses on the transmission lines that are ‘inside’ their EPS meters. If this was not done then these NOIE loads would be too high relative to the other loads where EPS meters are at each delivery point. Other NOIE send EPS metering data from each delivery point so their load can be calculated by summing the individual points. Therefore the extra calculations are not necessary.

The process for creating the loss factors is outlined below.

1. Send out a request to SSWG for any case updates, changes to NOIE bus ranges, and latest self serve data. NOIE’s that have a ‘ring’ of EPS meters must validate the PSS/E Metered End data in each of the cases. The PSS/E Metered End for a transmission facility that is not inside the ‘ring’ of EPS meters should be Metered ‘to’ the remote bus, and not Metered ‘to’ bus where the EPS meter is located.
2. ERCOT updates the transmission loss factor spreadsheet.
3. Send to SSWG for review and approval
4. Send to ERCOT settlements (Settlement Metering Manager) to be put into the ERCOT settlement system and post at <http://www.ercot.com/mktinfo/data_agg/index.html>[.](https://portal.ercot.com/ercotPublicWeb/MarketInformation/Transmission.htm)

5.2 Contingency Database

The ERCOT contingency database is a compilation of contingency definitions as submitted by the TSPs. The exchange of information for the contingency database will only be communicated using an Excel spreadsheet with the columns as listed in the table below. The table identifies the columns which the TSPs and ERCOT are responsible for populating. ERCOT does not create or manually update the information submitted by the TSPs. In an effort to produce a contingency list with complete and accurate data, ERCOT will run topology and data entry checks on submitted information to highlight submission errors that the TSPs will need to correct within a given timeline. A review of the contingency database will be conducted with each TPIT case update and case build. ERCOT will accept updates to the contingency list outside of this review process as requested by the TSPs. This section covers the approved format for submitting contingency definitions, the review process, and the validation rules ERCOT will implement to verify submissions.

**ERCOT Contingency Database Columns**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Column Name** | **TSP Responsibility** | **ERCOT Responsibility** | **Default Value** | **Validation Rule** |
| Item |  |  |  | Must be a numeric value |
| DatabaseID |  |  |  | Must be an alphanumeric with a 12 character maximum |
| TOContingencyID |  |  |  | May not be null |
| ContingencyAction |  |  | Open | Must be either open or close |
| FromBusNumber\_i |  |  | 0 | Must be a numeric value |
| ToBusNumber\_j |  |  | 0 | Must be a numeric value |
| ToBusNumber\_k |  |  | 0 | Must be a numeric value |
| CircuitID |  |  |  | Must be an alphanumeric with a two character maximum, and must be null if the element identifier for the outage is a bus or switched\_shunt |
| ElementIdentifier |  |  |  | Must be either a bus, transformer, branch, fixed\_bus\_shunt, switched\_shunt or gen |
| Submitter |  |  |  | Must match current submitter name in database |
| StartDate |  |  | 1/1/2000 | Must be a valid date |
| StopDate |  |  | 12/31/2099 | Must be a valid date |
| DateCreated |  |  |  | Must be a valid date |
| UpdatedDate |  |  |  | Must be a valid date |
| Multi-SectionLine |  |  | No | Must be either yes or no |
| NERCCategory |  |  |  | Must be NERC Category, ‘.’, and the type of Event; example P4.3\*  |
| ERCOTCategory |  |  |  | Must be N/A, ERCOT\_1, ERCOT\_NonBES, ERCOT\_CCT |
| BES Level |  |  |  | Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. |
| TDSPComments |  |  |  | May be null |
| ERCOTComment |  |  |  | May be null |
| ContingencyName |  |  |  | Must be consistent within a contingency definition |

\* In addition, the steady state contingencies as described by the NERC TPL-001-4 Table 1, consist of definitions which may have multiple category classifications. In this case, each category must be separated by a ‘/’.The procedure for the annual update of the contingency database is as follows: ERCOT will send out the current contingency list to SSWG members with invalid entries highlighted.

1. TSPs will submit a complete list of contingency definitions with the necessary changes and additions within an agreed upon timeline and format for ERCOT to import into the existing database.
2. Upon import, ERCOT will overwrite the previous list of definitions submitted by the TSP.
3. ERCOT will verify that the changes were imported into the database and provide the TSPs with a change log which will list the contingency definitions that were updated, deleted or created.
4. Steps 1 to 4 will be repeated for each pass of the contingency update process.
5. When the contingency list is finalized, ERCOT will post the list on the MIS website along with the contingency files created for use with MUST, PSS/E, PowerWorld, UPLAN and VSAT. Definitions which are flagged as being invalid will NOT be included in the contingency file.
6. The planning or extreme event rationale will be provided in supporting documentation from TSPs upon request.

A TSP may only submit changes for their company and rows with null values in either the *Submitter* or *TOContingencyID* columns will be ignored. The default value listed in the table will be used upon import if the provided value is either invalid or missing. Topology and data entry checks will be completed on the imported rows to highlight invalid contingency definitions.

ERCOT will utilize the latest available SSWG cases to verify that the devices listed in the contingency definition exist in the base case. Additional columns will be added to the spreadsheet which will correspond to the filename of the base case used to validate the submissions. The start and stop dates of the contingency definitions will be used to determine which base cases they need to be compared against. Any inconsistencies between the case and contingency definition will be communicated in these columns. A contingency definition will be highlighted as invalid and an error message will be printed if it fails any of the following data entry or topology checks.

NERC contingencies not covered by automatic contingency processing capabilities of the various power-flow applications, which the TSP deems to have an impact on the power-flow solution, shall be submitted.

NERC contingencies must either be submitted in entirety by each TSP or as a minimum, those planning event and extreme event NERC contingency categories that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information upon request.

In addition to the aforementioned NERC defined contingencies, TSPs shall also submit:

* All combinations of double circuit contingencies for all multiple circuit transmission lines, 60 kV and above, that share the same structures for 0.5 miles or longer. These contingency scenarios will be categorized in the ERCOT contingency database as ERCOT\_1.
* Single and multiple element contingencies, not covered by automatic contingency processing capabilities of the various power-flow applications and not fitting the definition of ERCOT\_1, for transmission facilities between 60 kV and 100 kV that produce the most severe system results or impacts. These will be categorized in the ERCOT contingency database as ERCOT\_NonBES.

ERCOT shall submit:

* Loss of an entire combine cycle plant are to be categorized as ERCOT\_CCT.

Contingency definitions shall take into account the effects of existing and planned protection systems, including any backup or redundant systems.

**General Data Entry Checks**

|  |  |
| --- | --- |
| **Error Message** | **Reason for Failing Data Validation** |
| Duplicate | The device is listed more than once in the contingency definition. |
| Needs Consistent Name | For each unique *TOContingencyID*, only one *ContingencyName* can be used.  |
| Invalid Date Selection | Either the start and/or stop dates for a single contingency definition are inconsistent or the start date occurs after the stop date.  In the case where a single contingency definition has inconsistent start dates, use the one that occurs furthest in the future since the contingency definition will not be valid until all devices listed in the contingency are present in the base case.  The start date is used to determine when the contingency definition becomes valid—it is not the energization date for the device listed on that row. |
| Invalid Bus Selection | The same bus number is used twice in the same row, or a needed bus number is missing. |
| Invalid Element Identifier | Element Identifier is invalid. The only acceptable values are Bus, Branch, Gen, Transformer, Fixed\_Bus\_Shunt, or Switched\_Shunt |
| NERC Category Missing | The new NERC Category is missing. The only acceptable values are ‘NERC Category’‘.’‘Event’ defined in TPL-001-4 Table 1. Multiple Category contingencies are must be separated by ‘/’. For example: P2.2/P4.3/P5.2 |
| ERCOT Category Missing | The ERCOT Category is missing. The only acceptable values are ERCOT\_1, ERCOT\_NonBES, ERCOT\_CCT, or N/A. |

**Topology Checks**

|  |  |
| --- | --- |
| **Error Message** | **Reason for Failing Data Validation** |
| FromBus\_i Missing, ToBus\_j Missing, ToBus\_k Missing | A bus with the corresponding bus number cannot be found in the base case. |
| Branch Missing | A branch with the submitted combination of bus numbers and circuit ID cannot be found in the base case. |
| Transformer Missing | A transformer with the submitted combination of bus numbers and circuit ID cannot be found in the base case. |
| Generator Missing | A generator with the submitted combination of bus numbers and circuit ID cannot be found in the base case. |
| Shunt Missing | A shunt with the submitted combination of bus numbers and circuit ID cannot be found in the base case. |

5.3 Review of NMMS and Topology Processor Compatibility with PSS/E

From time to time, updated versions of PSS/E may require modifications to the methods of extracting necessary power-flow data from NMMS. For every PSS/E version change, the following evaluation process shall be followed:

1. Use PSS/E documentation such as release notes and compatibility references to identify new fields and record formats added to a new version of PSS/E.
2. SSWG determines which, if any, of the new fields or records need to be implemented in NMMS and Topology Processor.
	1. Determine how to use MOD to implement most needed fields immediately
3. ERCOT determines approximate implementation method, initial impact analysis and cost of implementation for each new field and/or record determined by the SSWG to be necessary for implementation.
	1. Determine method to arbitrate disagreement on proposed recommendation
4. Present to ROS new fields and/or records that have been jointly determined to be needed, with approximate implementation method, initial impact analysis and cost of implementation.
5. Upon ROS approval, prepare Project initiation to create and add projects to PPL.
6. Upon addition to PPL above cut line, prepare requirements documents to describe data type addition/changes to NMMS and Topology Processor output desired for example input.

5.4 Planning Data Dictionary

The Planning Data Dictionary is used by ERCOT to show correlation between base case bus numbers and TSP area SCADA names. Additionally, the Planning Data Dictionary without the SCADA names is included as part of ERCOT’s FERC 715 filing.

The exchange of information for the Planning Data Dictionary will only be communicated using an Excel spreadsheet with the columns as listed in the table below. The table identifies the columns which the TSPs and ERCOT are responsible for populating. ERCOT does not create or manually update the information submitted by the TSPs. The Planning Data Dictionary will be updated with each TPIT case update and Planning Case build.

The format will be as follows (see next page):

|  |  |  |  |
| --- | --- | --- | --- |
| **Column Name** | **TSP Responsibility** | **ERCOT Responsibility** | **Description** |
| TSP |  |  | Shortened version of SSWG Area |
| SSWG BUS NUMBER |  |  | Extracted from the SSWG Steady State Cases |
| SSWG BUS DATE IN |  |  | From the SSWG Steady State Cases, this is populated by searching for the earliest SSWG Steady State Case that the bus exists. If the bus exists throughout all of the existing Steady State Cases, the field is left blank under the assumption that it already exists in the NMMS. |
| SSWG BUS DATE OUT |  |  | From the SSWG Steady State Cases, this is populated by searching for the latest SSWG Steady State Case that the bus exists. If the bus exists throughout all of the existing SSWG Steady State Cases, the field is left blank under the assumption that it exists beyond the current planning scope. |
| SSWG BUS NAME |  |  | This is required by FERC for FERC 715 pt. 2 report and is extracted from the SSWG Steady State Cases.  |
| SSWG BASE KV |  |  | This is required by FERC for FERC 715 pt. 2 report and is extracted from the SSWG Steady State Cases |
| SSWG BUS TYPE |  |  | Extracted from the SSWG Steady State Cases |
| SSWG AREA |  |  | Extracted from the SSWG Steady State Cases |
| NMMS BUS NUMBER |  |  | Extracted from NMMS |
| NMMS BUS NAME |  |  | Extracted from NMMS |
| NMMS STATION CODE |  |  | Extracted from NMMS |
| NMMS STATION NAME |  |  | Extracted from NMMS |
| NMMS BASE KV |  |  | Extracted from NMMS |
| NMMS TSP |  |  | Extracted from NMMS |
| NMMS WEATHER ZONE |  |  | Extracted from NMMS. Field is populated via mapping sheet for future buses and are italicized. |
| NMMS SETTLEMENT ZONE |  |  | Extracted from NMMS. Field is populated via mapping sheet for future buses and are italicized. |
| EIA CODE |  |  | EIA Codes for bus within Stations associated with a generating unit. This is required for the FERC 715 pt. 2 report. |
| PLANNING BUS LONG NAME |  |  | The Planning Bus Long Name is provided by the TSP |
| PLANNING BUS COUNTY |  |  | The Planning Bus County is provided by the TSP |
| TSP COMMENTS |  |  | Section for TSP to provide comments on individual buses. |
| ERCOT COMMENTS |  |  | Information for changes of bus properties throughout all SSWG Steady State Cases. This information will point to changes in SSWG BUS NAME, SSWG BASE KV and SSWG BUS TYPE. |

# 6 APPENDICES

Appendix A

Bus/Zone Range, FACTS Device Range, and Zone Description Tables

| **BUS RANGE** | **DSP, OTHER ENTITY,****or SUBSYSTEM** | **ACRONYM** | **MODELING****ENTITY** | **PSSE AREA NO** | **ZONE RANGE** |
| --- | --- | --- | --- | --- | --- |
| 1 - 799 | **BRAZOS ELECTRIC POWER COOP.** | TBREC | TBREC | 11 | 11 |
| 33000 - 36999 |
| 32050 - 32999 | **BRYAN, CITY OF** | TBTU | TBTU | 22 | 2 |
| 900 - 934 | **DENTON MUNICIPAL UTILITIES, CITY OF** | TDME | TDME | 19 | 3 |
| 800 - 899 | **GARLAND, CITY OF** | TGAR | TGAR | 20 | 4 |
| 935 - 955 | **GREENVILLE ELECTRIC UTILITY SYSTEM** | TGEUS | TGEUS | 21 | 5 |
| 956 - 999 | **TEXAS MUNICIPAL POWER AGENCY** | TTMPA | TTMPA | 12 | 6 |
| 9500 - 9699 |
| 1000 - 4999 | **ONCOR** | TONCOR | TONCOR | 1 | 100 - 175 |
| 10000 - 31999 |
| 32000 - 32049 | **COLLEGE STATION, CITY OF** | TCOLGS | TCOLGS | 23 | 199 |
| 37000 - 39999 | **TEXAS NEW MEXICO POWER CO.** | TTNMP | TTNMP | 17 | 220 - 240 |
| 40000 - 49999 | **CENTERPOINT** | TCNPE | TCNPE | 4 | 260 - 320 |
| 5000 - 5499 | **CPS ENERGY**  | TCPSE | TCPSE | 5 | 350 - 370 |
| 50000 - 54999 |
| 5500 - 5899 | **SOUTH TEXAS ELECTRIC COOP** | TSTEC | TSTEC | 13 | 870 - 890 |
| 55000 - 58999 |
| 5910 - 5919 | **SOUTH TEXAS POWER PLANT** | TCNPE | TCNPE | 10 | 310 |
| 7000 – 789970000 - 78999 | **LCRA Transmission Services Corporation (TSC)** | TLCRA | TLCRA | 7 | 500 - 589 |
| In TLCRA | **BANDERA ELECTRIC COOP** | TBDEC | TLCRA |  |  |
| In TLCRA | **BLUEBONNET ELECTRIC COOP** | TBBEC | TLCRA |  |  |
| In TLCRA | **CENTRAL TEXAS ELECTRIC COOP** | TCTEC | TLCRA |  |  |
| In TLCRA | **GUADALUPE VALLEY ELECTRIC COOP** | TGVEC | TLCRA |  |  |
| In TLCRA | **NEW BRAUNFELS UTILITIES** | TNBRUT | TLCRA |  |  |
| In TLCRA | **PEDERNALES ELECTRIC COOP** | TPDEC0 | TLCRA |  |  |
| In TLCRA | **SAN BERNARD ELECTRIC COOP** | TSBEC | TLCRA |  |  |
| 79000-79499 | **CROSS TEXAS TRANSMISSION** | TCROS | TCROS | 30 | 790 - 799 |
| 8000 – 899980000 - 89999 | **AMERICAN ELECTRIC POWER - TCC** | TAEPTC | TAEPTC | 8 | 610 - 662 |
| 79500-79699 | **SHARYLAND** | TSLND1 | TSLND1 | 18 | 820 - 829 |
| 9000 – 939990000 - 93999 | **AUSTIN ENERGY** | TAEN | TAEN | 9 | 691 - 712 |
| 5920 - 5929 | **EAST HIGH VOLTAGE DC TIE** |  | TAEPTC | 16 | 200 |
| 5930 - 5989 | **PUBLIC UTILITY BOARD OF BROWNSVILLE** | TBPUB | TBPUB | 15 | 800 |
| 59300 - 59899 |
| 59900 - 59999 | **WIND ENERGY TRANSMISSION TEXAS** | WETT | WETT | 29 | 590 - 609 |
| 6000 - 6699 | **AMERICAN ELECTRIC POWER- TNC** | TAEPTN | TAEPTN | 6 | 402 - 479 |
| 60000 - 67999 |
| 69000 - 69999 |
| In TAEPTN | **COLEMAN COUNTY ELECTRIC COOP** | TCOLMN | TGSEC | 25 | 181 |
| In TAEPTN | **CONCHO VALLEY ELECTRIC COOP** | TCVEC2 | TGSEC | 25 | 182 |
| In TAEPTN | **RIO GRANDE ELECTRIC COOP** | TRGEC1 | AEPTN |  |  |
| In TAEPTN | **SOUTHWEST TEXAS ELECTRIC COOP** | TSWEC1 | TGSEC | 25 | 185 |
| In TAEPTN | **TAYLOR ELECTRIC COOP.** | TECX | TGSEC | 25 | 186 |
| 6096 - 6096 | **NORTH HIGH VOLTAGE DC** |  | AEPTN | 14 | 394 |
| 6700 - 6749 | **TEX-LA ELECTRIC COOP** | XTEXLA | TEXLATSP  | 3 | 177 |
| 6800 - 6949 | **RAYBURN COUNTRY ELECTRIC COOP** | TRAYBN | TRAYBN | 2 | 178 |
| In TRAYBN | **GRAYSON COUNTY ELECTRIC COOP** | TGEC | TRAYBN | 2 | 178 |
| In TRAYBN | **LAMAR ELECTRIC COOP** | TLAHOU | TRAYBN | 2 | 178 |
| In TRAYBN | **FARMERS ELECTRIC COOP** | TFECE | TRAYBN | 2 | 178 |
| In TRAYBN | **TRINITY VALLEY ELECTRIC COOP** | TTRINY | TRAYBN | 2 | 178 |
| In TRAYBN | **FANNIN COUNTY ELECTRIC COOPERATIVE** | TFCEC | TRAYBN | 2 | 178 |
| N/A | **GOLDENSPREAD ELECTRIC COOP** | TGSEC | TGSEC | 25 | 179 |
| IN TAEPTN | **LIGHTHOUSE ELECTRIC COOP** | TLHEC | TGSEC | 25 | 183 |
| 68000 - 68999 | **LONE STAR TRANSMISSION** | TLSTR | TLSTR | 27 | 670 - 689 |
| 9400-9450 | **LYNTEGAR ELECTRIC COOP**  | TLYEC | TGSEC | 25 | 183 |
| 9451-9470 | **TAYLOR ELECTRIC COOP** | TTAYLEC | TGSEC | 25 | 186 |
| 9471-9490 | **BIG COUNTRY ELECTRIC COOP** | TBCEC1 | TGSEC | 25 | 180 |
| 9491-9499 | **CITY OF GOLDSMITH** | TGOLDS | TGOLDS | 26 | 190 |
| 9700 – 9999 | **ERCOT** | TERCOT | TERCOT | 900 - 999 | 9001199 |
| 94000 – 99999 |
| 100000 - 199999 |
| In TAEPTC | **RIO GRANDE ELECTRIC COOP** | TRGEC2 | TRGEC2 |  |  |
| 600-601 | **BRIDGEPORT ELECTRIC** | TBRIDG | TBTU |  |  |

**FACTS Device ID Range Table**

|  |  |
| --- | --- |
| **FACTS Device ID#** |  **Ownership claimed by TSP** |
| 4 - 18  | American Electric Power |
| 1 - 3 | Austin Energy  |
| 19 |   |
| 20 - 30 | ONCOR |
| 30 - 34 |   |
| 35 - 39 | Texas New Mexico Power |
| 40 - 50 | Centerpoint Energy |

**Description of Zones in Base Cases**

The following table provides a description of the zones. Zone numbers and zone names are subject to change.

| **Zone #** | **Zone Name** | **Zone Description** |
| --- | --- | --- |
| 1 | TEMPORARY | TEMPORARY |
| 2 | BRYAN | City of Bryan |
| 3 | DENTON | Denton Municipal Electric |
| 4 | GARLAND | Garland Power and Light |
| 5 | GRNVILLE | Greenville Electric Utility System |
| 6 | TMPA | Texas Municipal Power Agency |
| 11 | BEPC | Brazos Electric Power Coop. |
| 102 | O\_Rusk | ONCOR - Rusk County |
| 103 | O\_Nacogdoches | ONCOR - Nacogdoches County |
| 104 | O\_Angelina | ONCOR - Angelina County |
| 105 | O\_Smith | ONCOR - Smith County |
| 106 | O\_Cherokee | ONCOR - Cherokee County |
| 107 | O\_Houston | ONCOR - Houston County |
| 108 | O\_Anderson | ONCOR - Anderson County |
| 109 | O\_Henderson | ONCOR - Henderson County |
| 110 | O\_VanZandt | ONCOR - Rains and Van Zandt Counties |
| 113 | O\_Kaufman | ONCOR - Kaufman and Rockwall Counties |
| 114 | O\_Dallas | ONCOR - Dallas County |
| 115 | O\_Ellis | ONCOR - Ellis County |
| 118 | O\_Tarrant | ONCOR - Tarrant County |
| 119 | O\_Johnson | ONCOR - Johnson County |
| 120 | O\_Hood | ONCOR - Hood and Somervell Counties |
| 121 | O\_Parker | ONCOR - Palo Pinto and Parker Counties |
| 122 | O\_Young | ONCOR - Stephens and Young Counties |
| 125 | O\_Eastland | ONCOR - Eastland County |
| 126 | O\_Erath | ONCOR - Erath County |
| 127 | O\_Bosque | ONCOR - Bosque County |
| 128 | O\_Hill | ONCOR - Hill County |
| 129 | O\_Navarro | ONCOR - Navarro County |
| 130 | O\_Freestone | ONCOR - Freestone County |
| 131 | O\_Leon | ONCOR - Leon County |
| 132 | O\_Limestone | ONCOR - Limestone County |
| 133 | O\_Robertson | ONCOR - Robertson County |
| 134 | O\_Falls | ONCOR - Falls County |
| 135 | O\_McLennan | ONCOR - McLennan County |
| 136 | O\_Bell | ONCOR - Bell County |
| 137 | O\_Milam | ONCOR - Milam County |
| 138 | O\_Williamson | ONCOR - Bastrop, Lee, Travis, and Williamson Counties |
| 139 | O\_Coryell | ONCOR - Coryell County |
| 140 | O\_Hamilton | ONCOR - Hamilton and Mills Counties |
| 141 | O\_Comanche | ONCOR - Comanche County |
| 142 | O\_Brown | ONCOR - Brown County |
| 145 | O\_Titus | ONCOR - Franklin and Titus Counties |
| 146 | O\_Lamar | ONCOR - Lamar and Red River Counties |
| 147 | O\_Hopkins | ONCOR - Delta and Hopkins Counties |
| 148 | O\_Hunt | ONCOR - Hunt County |
| 149 | O\_Fannin | ONCOR - Fannin County |
| 150 | O\_Grayson | ONCOR - Grayson County |
| 151 | O\_Collin | ONCOR - Collin County |
| 152 | O\_Denton | ONCOR - Denton County |
| 153 | O\_Cooke | ONCOR - Cooke County |
| 154 | O\_Clay | ONCOR - Clay and Montague Counties |
| 155 | O\_Wise | ONCOR - Wise County |
| 156 | O\_Jack | ONCOR - Jack County |
| 157 | O\_Wichita | ONCOR - Wichita County |
| 158 | O\_Archer | ONCOR - Archer and Baylor Counties |
| 161 | O\_Shackelford | ONCOR - Shackelford and Throckmorton Counties |
| 162 | O\_Haskell | ONCOR - Haskell County |
| 163 | O\_Taylor | ONCOR - Jones and Taylor Counties |
| 164 | O\_Scurry | ONCOR - Fisher and Scurry Counties |
| 165 | O\_Nolan | ONCOR - Nolan County |
| 166 | O\_Mitchell | ONCOR - Mitchell County |
| 167 | O\_Howard | ONCOR - Borden, Dawson, Howard, and Martin Counties |
| 168 | O\_Midland | ONCOR - Glasscock, Midland, Reagan, and Upton Counties |
| 169 | O\_Andrews | ONCOR - Andrews County |
| 170 | O\_Ector | ONCOR - Ector County |
| 171 | O\_Ward | ONCOR - Crane, Pecos, and Ward Counties |
| 172 | O\_Winkler | ONCOR - Culberson, Loving, Reeves, and Winkler Counties |
| 177 | TEX-LA | TEX-LA Electric Coop |
| 178 | RAYBURN | Rayburn Country Electric Coop |
| 179 | GS\_GOLDENSPR | Golden Spread Electric Cooperative |
| 180 | GS\_BIGCOUTNR | Big Country Electric Cooperative |
| 181 | GS\_COLEMAN | Coleman County Electric Cooperative |
| 182 | GS\_CONCHOVAL | Concho Valley Electric Cooperative |
| 183 | GS\_LIGHTHOUS | Lighthouse Electric Cooperative |
| 184 | GS\_LYNTEGAR | Lyntegar Electric Cooperative |
| 185 | GS\_SWTEXAS | Southwest Texas Electric Cooperative |
| 186 | GS\_TAYLOR | Taylor Electric Cooperative |
| 190 | GOLDSMITH | City of Goldsmith |
| 199 | COCS | City of College Station |
| 200 | EHVDC | East High Voltage DC |
| 220 | TNP\_CLIF | TNMP – Clifton  |
| 221 | TNP\_WLSP | TNMP – Walnut Springs |
| 222 | TNP\_VROG | TNMP – Various Central TX buses |
| 224 | TNP\_LEW | TNMP - Lewisville |
| 225 | TNP\_KTRC | TNMP – Various North TX buses |
| 226 | TNP\_BELS | TNMP – Grayson & Fannin Counties |
| 227 | TNP\_CLMX | TNMP – Fannin & Collin Counties |
| 229 | TNP\_PMWK | TNMP – Wink, Pecos |
| 230 | TNP\_TC | TNMP – Galveston County |
| 233 | TNP\_COGN | TNMP |
| 234 | TNP\_WC | TNMP – Brazoria County |
| 235 | TNP\_HC-F | TNMP - Farmersville |
| 238 | TNP\_GEN | TNMP |
| 240 | TNP\_FS | TNMP – Pecos County |
| 260 | CNP\_DNTN | CenterPoint Energy - Dist Buses in Downtown |
| 261 | CNP\_INNR | CenterPoint Energy - Dist Buses in Inner Loop |
| 290 | CNP\_DG | CenterPoint Energy – Distributed Generation |
| 300 | CNPEXNSS | CenterPoint Energy - Exxon Facility self serve |
| 301 | CNP\_INDS | CenterPoint Energy - Industrial Customers |
| 302 | CNP\_COGN | CenterPoint Energy - Cogeneration |
| 303 | CNP\_SS | CenterPoint Energy - Self Serve |
| 304 | CNP\_DIST | CenterPoint Energy - Distribution |
| 305 | CNP\_TGN | CenterPoint Energy |
| 306 | CNP\_IPP | CenterPoint Energy |
| 308 | CNP\_GALV | CenterPoint Energy - Galveston area distribution buses |
| 310 | STP | South Texas Project |
| 317 | CNP\_TERT345 | CenterPoint Energy- 345kV AUTO TERTIARIES |
| 318 |  CNP TERTIARY | CenterPoint Energy- 138kV – 69kV AUTO TERTIARIES |
| 319 | CNP\_LCAP | CenterPoint Energy - In Line Capacitor Banks |
| 320 | CNPDOWSS | CenterPoint Energy  |
| 350 | CPS | CPS Energy |
| 351 | CPS\_GENS | CPS Energy |
| 391 | WEATHFRD | American Electric Power - TNC |
| 393 | TNC/LCRA | American Electric Power - TNC |
| 394 | NHVDC | North High Voltage DC Tie |
| 402 | WHEARNE | American Electric Power - TNC |
| 424 | TRENT | American Electric Power - TNC |
| 428 | PUTNAM | American Electric Power - TNC |
| 432 | ABILENE | American Electric Power - TNC |
| 434 | PECOS | American Electric Power - TNC |
| 438 | MCCAMEY | American Electric Power - TNC |
| 442 | W CHLDRS | American Electric Power - TNC |
| 444 | TUSCOLA | American Electric Power - TNC |
| 446 | PADUCAH | American Electric Power - TNC |
| 456 | ASPR MNT | American Electric Power - TNC |
| 458 | SOUTHERN | American Electric Power - TNC |
| 460 | E MUNDAY | American Electric Power - TNC |
| 462 | SONORA | American Electric Power - TNC |
| 466 | MASON | American Electric Power - TNC |
| 472 | PRESIDIO | American Electric Power - TNC |
| 474 | SAN ANG | American Electric Power - TNC |
| 477 | OKLUNION | American Electric Power - TNC |
| 478 | CEDR HIL | American Electric Power - TNC |
| 479 | BALLINGR | American Electric Power - TNC |
| 500 | AUSTIN | Lower Colorado River Authority |
| 502 | BANDERA | Lower Colorado River Authority |
| 504 | BASTROP | Lower Colorado River Authority |
| 505 | BREWSTER | Lower Colorado River Authority |
| 506 | BLANCO | Lower Colorado River Authority |
| 507 | BROWN | Lower Colorado River Authority |
| 508 | BURLESON | Lower Colorado River Authority |
| 510 | BURNET | Lower Colorado River Authority |
| 511 | COKE | Lower Colorado River Authority |
| 512 | CALDWELL | Lower Colorado River Authority |
| 514 | COLORADO | Lower Colorado River Authority |
| 516 | COMAL | Lower Colorado River Authority |
| 517 | CONCHO | Lower Colorado River Authority |
| 519 | CRANE | Lower Colorado River Authority |
| 520 | CROCKETT | Lower Colorado River Authority |
| 522 | CULBERSON | Lower Colorado River Authority |
| 525 | DEWITT | Lower Colorado River Authority |
| 526 | DIMMIT | Lower Colorado River Authority |
| 527 | ECTOR | Lower Colorado River Authority |
| 528 | FAYETTE | Lower Colorado River Authority |
| 531 | GILLESPIE | Lower Colorado River Authority |
| 534 | GOLIAD | Lower Colorado River Authority |
| 537 | GONZALES | Lower Colorado River Authority |
| 540 | GUADALUPE | Lower Colorado River Authority |
| 543 | HAYS | Lower Colorado River Authority |
| 542 | KARNES | Lower Colorado River Authority |
| 546 | KENDALL | Lower Colorado River Authority |
| 549 | KERR | Lower Colorado River Authority |
| 550 | PRESIDIO | Lower Colorado River Authority |
| 551 | UVALDE | Lower Colorado River Authority |
| 553 | KIMBLE | Lower Colorado River Authority |
| 554 | KINNEY | Lower Colorado River Authority |
| 555 | LAMPASAS | Lower Colorado River Authority |
| 558 | LAVACA | Lower Colorado River Authority |
| 561 | LEE | Lower Colorado River Authority |
| 562 | ZAVALA | Lower Colorado River Authority |
| 563 | REEVES | Lower Colorado River Authority |
| 564 | LLANO | Lower Colorado River Authority |
| 566 | SCHLEICHER | Lower Colorado River Authority |
| 567 | STERLING | Lower Colorado River Authority |
| 570 | MASON | Lower Colorado River Authority |
| 571 | MAVERICK | Lower Colorado River Authority |
| 572 | MCCULLOCH | Lower Colorado River Authority |
| 573 | MENARD | Lower Colorado River Authority |
| 574 | MIDLAND | Lower Colorado River Authority |
| 575 | MILLS | Lower Colorado River Authority |
| 576 | NOLAN | Lower Colorado River Authority |
| 577 | REAL | Lower Colorado River Authority |
| 578 | PECOS | Lower Colorado River Authority |
| 579 | SAN SABA | Lower Colorado River Authority |
| 580 | TAYLOR | Lower Colorado River Authority |
| 581 | TRAVIS | Lower Colorado River Authority |
| 582 | TOM GREEN | Lower Colorado River Authority |
| 583 | WALLER | Lower Colorado River Authority |
| 584 | UPTON | Lower Colorado River Authority |
| 585 | WASHNGTON | Lower Colorado River Authority |
| 586 | VAL VERDE | Lower Colorado River Authority |
| 587 | WILLIAMSON | Lower Colorado River Authority |
| 588 | WHARTON | Lower Colorado River Authority |
| 589 | WILSON | Lower Colorado River Authority |
| 590 | BORDEN | Wind Energy Transmission Texas |
| 591 | MARTIN | Wind Energy Transmission Texas |
| 592 | STERLING | Wind Energy Transmission Texas |
| 593 | GLASSCOCK | Wind Energy Transmission Texas |
| 594 | DICKENS | Wind Energy Transmission Texas |
| 610 | E VALLEY | American Electric Power - TCC |
| 611 | TCCSWIND | American Electric Power - TCC |
| 612 | CFE | CFE |
| 615 | W VALLEY | American Electric Power - TCC |
| 620 | N REGION | American Electric Power - TCC |
| 621 | TCCNWIND | American Electric Power - TCC |
| 625 | C REGION | American Electric Power - TCC |
| 626 | TCCCWIND | American Electric Power - TCC |
| 630 | W REGION | American Electric Power - TCC |
| 631 | TCCWWIND | American Electric Power - TCC |
| 635 | LAREDO | American Electric Power - TCC |
| 636 | TRIANGLE | American Electric Power - TCC |
| 640 | NORTH LI | American Electric Power - TCC |
| 645 | CENT LI | American Electric Power - TCC |
| 650 | NR COGEN | American Electric Power - TCC |
| 651 | CR COGEN | American Electric Power - TCC |
| 656 | TCC/RGEC | American Electric Power - TCC |
| 658 | TCC/LCRA | American Electric Power - TCC |
| 659 | TCC/MEC | American Electric Power - TCC |
| 660 | DAV\_1GEN | American Electric Power - TCC |
| 661 | ROBSTOWN | American Electric Power - TCC |
| 662 | KIMBLE | American Electric Power - TCC |
| 670 | SHACKFORD | Lone Star Transmission |
| 672 | EAST\_LAND | Lone Star Transmission |
| 673 | SAMSWTC | Lone Star Transmission |
| 674 | NAVARRO | Lone Star Transmission |
| 675 | BOSQUE | Lone Star Transmission |
| 688 | HILL | Lone Star Transmission |
| 691 | BAST-AEU | Austin Energy |
| 692 | CALD-AEU | Austin Energy |
| 695 | FAYE-AEU | Austin Energy |
| 709 | TRAV-AEU | Austin Energy |
| 712 | WILL-AEU | Austin Energy |
| 790 | GRAY | Cross Texas Transmission |
| 791 | SCOMP | Cross Texas Transmission |
| 800 | BPUB | Public Utility Board of Brownsville |
| 825 | SU CAPROCK | Sharyland Utilities |
| 829 | SHRY | Sharyland Utilities |
| 870 | MEC | South Texas Electric Coop - Medina Electric Coop |
| 872 | JEC | South Texas Electric Coop - Jackson Electric Coop |
| 874 | KEC | South Texas Electric Coop - Karnes Electric Coop |
| 875 | MVEC\_E | South Texas Electric Coop - Eastern Magic Valley |
| 876 | MVEC\_W | South Texas Electric Coop - Western Magic Valley |
| 878 | NEC | South Texas Electric Coop - Nueces Electric Coop |
| 880 | SPEC | South Texas Electric Coop - San Patricio Electric Coop |
| 882 | VEC | South Texas Electric Coop - Victoria Electric Coop |
| 884 | WCEC | South Texas Electric Coop - Wharton County Electric Coop |
| 890 | STEC | South Texas Electric Coop except member coops |
| 891 | LOAD-EX | American Electric Power - TCC |
| 900 | E\_BRAZORIA | ERCOT designated generation zone |
| 902 | E\_CHAMBERS | ERCOT designated generation zone |
| 903 | E\_FORT BEND | ERCOT designated generation zone |
| 904 | E\_GALVESTO | ERCOT designated generation zone |
| 906 | E\_HARRIS | ERCOT designated generation zone |
| 911 | E\_MATAGORD | ERCOT designated generation zone |
| 918 | E\_VICTORIA | ERCOT designated generation zone |
| 920 | E\_WHARTON | ERCOT designated generation zone |
| 931 | E\_ANGELINA | ERCOT designated generation zone |
| 932 | E\_BRAZOS | ERCOT designated generation zone |
| 935 | E\_CHEROKEE | ERCOT designated generation zone |
| 937 | E\_FREESTONE | ERCOT designated generation zone |
| 939 | E\_GRIMES | ERCOT designated generation zone |
| 941 | E\_HENDERSON | ERCOT designated generation zone |
| 948 | E\_NACOGDOC | ERCOT designated generation zone |
| 951 | E\_ROBERTSO | ERCOT designated generation zone |
| 952 | E\_RUSK | ERCOT designated generation zone |
| 957 | E\_TITUS | ERCOT designated generation zone |
| 971 | E\_BORDEN | ERCOT designated generation zone |
| 973 | E\_CRANE | ERCOT designated generation zone |
| 975 | E\_CULBERSON | ERCOT designated generation zone |
| 977 | E\_ECTOR | ERCOT designated generation zone |
| 979 | E\_GLASSCOCK | ERCOT designated generation zone |
| 980 | E\_HOWARD | ERCOT designated generation zone |
| 984 | E\_MARTIN | ERCOT designated generation zone |
| 986 | E\_PECOS | ERCOT designated generation zone |
| 987 | E\_PRESIDIO | ERCOT designated generation zone |
| 991 | E\_UPTON | ERCOT designated generation zone |
| 992 | E\_WARD | ERCOT designated generation zone |
| 993 | E\_WINKLER | ERCOT designated generation zone |
| 1000 | E\_ARCHER | ERCOT designated generation zone |
| 1001 | E\_BAYLOR | ERCOT designated generation zone |
| 1007 | E\_CLAY | ERCOT designated generation zone |
| 1009 | E\_COOKE | ERCOT designated generation zone |
| 1012 | E\_DEAF SMIT | ERCOT designated generation zone |
| 1013 | E\_DICKENS | ERCOT designated generation zone |
| 1015 | E\_FANNIN | ERCOT designated generation zone |
| 1020 | E\_GRAYSON | ERCOT designated generation zone |
| 1024 | E\_KENT | ERCOT designated generation zone |
| 1027 | E\_LAMAR | ERCOT designated generation zone |
| 1029 | E\_MOTLEY | ERCOT designated generation zone |
| 1033 | E\_WICHITA | ERCOT designated generation zone |
| 1034 | E\_WILBARGER | ERCOT designated generation zone |
| 1036 | E\_PITTSBURG- | ERCOT designated generation zone |
| 1037 | E\_OLDHAM | ERCOT designated generation zone |
| 1038 | E\_CARSON | ERCOT designated generation zone |
| 1047 | E\_BRISCOE | ERCOT designated generation zone |
| 1050 | E\_BELL | ERCOT designated generation zone |
| 1051 | E\_BOSQUE | ERCOT designated generation zone |
| 1054 | E\_COLLIN | ERCOT designated generation zone |
| 1057 | E\_DALLAS | ERCOT designated generation zone |
| 1059 | E\_DENTON | ERCOT designated generation zone |
| 1061 | E\_ELLIS | ERCOT designated generation zone |
| 1062 | E\_ERATH | ERCOT designated generation zone |
| 1066 | E\_HOOD | ERCOT designated generation zone |
| 1067 | E\_HUNT | ERCOT designated generation zone |
| 1068 | E\_JACK | ERCOT designated generation zone |
| 1069 | E\_JOHNSON | ERCOT designated generation zone |
| 1070 | E\_KAUFMAN | ERCOT designated generation zone |
| 1071 | E\_LIMESTONE | ERCOT designated generation zone |
| 1072 | E\_MCLENNAN | ERCOT designated generation zone |
| 1075 | E\_PALO PINTO | ERCOT designated generation zone |
| 1076 | E\_PARKER | ERCOT designated generation zone |
| 1078 | E\_SHACKELFO | ERCOT designated generation zone |
| 1079 | E\_SOMERVELL | ERCOT designated generation zone |
| 1081 | E\_TARRANT | ERCOT designated generation zone |
| 1083 | E\_WISE | ERCOT designated generation zone |
| 1084 | E\_YOUNG | ERCOT designated generation zone |
| 1091 | E\_ATASCOSA | ERCOT designated generation zone |
| 1094 | E\_CAMERON | ERCOT designated generation zone |
| 1097 | E\_FRIO | ERCOT designated generation zone |
| 1098 | E\_GOLIAD | ERCOT designated generation zone |
| 1099 | E\_HIDALGO | ERCOT designated generation zone |
| 1102 | E\_KENEDY | ERCOT designated generation zone |
| 1106 | E\_MAVERICK | ERCOT designated generation zone |
| 1108 | E\_NUECES | ERCOT designated generation zone |
| 1110 | E\_SANPATRICI | ERCOT designated generation zone |
| 1111 | E\_STARR | ERCOT designated generation zone |
| 1112 | E\_WEBB | ERCOT designated generation zone |
| 1113 | E\_WILLACY | ERCOT designated generation zone |
| 1122 | E\_BASTROP | ERCOT designated generation zone |
| 1123 | E\_BEXAR | ERCOT designated generation zone |
| 1126 | E\_BURNET | ERCOT designated generation zone |
| 1129 | E\_COMAL | ERCOT designated generation zone |
| 1131 | E\_FAYETTE | ERCOT designated generation zone |
| 1132 | E\_GONZALES | ERCOT designated generation zone |
| 1133 | E\_GUADALUPE | ERCOT designated generation zone |
| 1134 | E\_HAYS | ERCOT designated generation zone |
| 1136 | E\_KENDALL | ERCOT designated generation zone |
| 1137 | E\_LAVACA | ERCOT designated generation zone |
| 1140 | E\_MILAM | ERCOT designated generation zone |
| 1141 | E\_TRAVIS | ERCOT designated generation zone |
| 1150 | E\_COKE | ERCOT designated generation zone |
| 1160 | E\_KINNEY | ERCOT designated generation zone |
| 1162 | E\_LLANO | ERCOT designated generation zone |
| 1166 | E\_MITCHELL | ERCOT designated generation zone |
| 1167 | E\_NOLAN | ERCOT designated generation zone |
| 1171 | E\_SCHLEICHER | ERCOT designated generation zone |
| 1172 | E\_SCURRY | ERCOT designated generation zone |
| 1175 | E\_TAYLOR | ERCOT designated generation zone |
| 1178 | E\_VAL VERDE | ERCOT designated generation zone |
| 1180 | E\_ONCOR\_PU | ERCOT designated private use network |
| 1181 | E\_CNP\_PUN | ERCOT designated private use network |
| 1182 | E\_AEPTNC\_PUN | ERCOT designated private use network |
| 1183 | E\_AEPTCC\_PUN | ERCOT designated private use network |
| 1184 | E\_TNMP\_PUN | ERCOT designated private use network |
| 1190 | E\_MB | ERCOT designated zone for Mothballed units |
| 1192 | E\_RMRUNITS | ERCOT designated zone for Reliability Must Run (RMR) Units |
| 1193 | E\_SEASNL\_GEN | ERCOT designated zone for seasonal units |
| 1194 | E\_RETIREDGEN | ERCOT designated zone for retired units |
| 1195 | EX\_MB | ERCOT designated extraordinary dispatch zone for mothballed units |
| 1196 | EX\_IA\_NOFC | ERCOT designated extraordinary dispatch zone |
| 1197 | EX\_PUB\_NOIA | ERCOT designated extraordinary dispatch zone |
| 1198 | EX\_FAKEGEN | ERCOT designated extraordinary dispatch zone for Modeling Fake units |
| 1199 | E\_AUXLOAD | ERCOT designated auxiliary load zone |
| 1200 | UNASSIGNED | Planning zones that are not defined in NMMS are defaulted to this zone |

Appendix B

Methodology for Calculating Wind Generation levels in the SSWG Cases

Goal – Use available forecast data to set the dispatch for wind generation in the new SSWG base cases.

Section 3.2.6.2.2 of the Nodal Procotols

|  |  |  |
| --- | --- | --- |
| WINDPEAKPCT *s, r* | % | *Seasonal Peak Average Wind Capacity as a Percent of Installed Capacity*—The average wind capacity available for the summer and winter Peak Load Seasons *s* and region *r*, divided by the installed capacity for region *r*, expressed as a percentage. The Seasonal Peak Average, derived from Settlement data, is first calculated as the average capacity during the 20 highest system-wide peak Load hours for a given year’s summer and winter Peak Load Seasons. The final value is the average of the previous ten eligible years of Seasonal Peak Average values. Eligible years include 2009 through the most recent year for which COP data is available for the summer and winter Peak Load Seasons. If the number of eligible years is less than ten, the average shall be based on the number of eligible years available. This calculation is limited to WGRs that have been in operation as of January 1 for each year of the period used for the calculation. |
| WINDCAP *s, i, r* | MW | *Existing WGR Capacity*—The capacity available for all existing WGRs for the summer and winter Peak Load Seasons *s,* year *i*, and region *r*, multiplied by WINDPEAKPCT for summer and winter Peak Load Seasons *s* and region *r*. |

Appendix C

Mexico’s Transmission System in ERCOT SSWG Cases

This appendix provides an explanation of the modeling that represents Mexico’s Comisión Federal de Electridad (CFE) system in SSWG cases. A drawing of the system is at the end of this appendix. All AEP and CFE facilities (bus, lines, etc.) tied to the CFE grid will be assigned to area 24 and zone 612. The AEP facilities will retain the owner 9 and CFE will be assigned owner 300.

The following generation modeled in the power flow and short circuit cases are system equivalents of the CFE system and are located in Mexico. These units are not in ERCOT and should only be used for specialized studies. **These units should not be included when performing transfer studies in ERCOT unless one is studying a transfer to or from CFE.** The generation capability is not counted in ERCOT reports. These units are online in the cases to offset the real and reactive losses that are caused by the other CFE transmission facilities and reactive flow across the Laredo VFT, Railroad HVDC, and Eagle Pass HVDC that are modeled in the SSWG cases. Lines in CFE will not be included in the ERCOT contingency list.

|  |  |  |
| --- | --- | --- |
| **Generation Station Name** | **Bus Number** | **Bus Voltage** |
| CIDINDUS-138 (System Equivalent) | 86104 | 138kV |
| CIDINDUS-230 (Swing Bus/Equivalent) | 86105 | 230kV |
| CUF-230 (System Equivalent) | 86106 | 230kV |
| CUF-138 (System Equivalent) | 86107 | 138kV |

The following are the transmission lines between Mexico and the United States. All of the tie lines between CFE and ERCOT are operated normally open with the exception of the asynchronous ties at Eagle Pass, Laredo, and Railroad.

|  |  |
| --- | --- |
| **Mexico** | **United States** |
| **Bus Name** | **Bus Number** | **Bus Voltage** | **Bus Name** | **Bus Number** | **Bus Voltage** |
| Falcon | 86111 | 138 | Falcon | 8395 | 138 |
| Piedras Negras | 86110 | 138 | Eagle Pass | 86109 | 138 |
| Ciudad Industrial | 86105 | 230 | Laredo VFT | 80168 | 230 |
| Ciudad Industrial | 86104 | 138 | Laredo VFT | 80169 | 138 |
| Cumbres | 86107 | 138 | Railroad | 8395 | 138 |
| Cumbres | 86107 | 138 | Frontera | 86114 | 138 |
| Matamoras | 86112 | 138 | Military Highway | 8339 | 138 |
| Matamoras | 86113 | 69 | Brownsville Switching Station | 8332 | 69 |

**Asynchronous Ties**

**Laredo**

The Variable Frequency Transformer (VFT) in Laredo has a detailed model at busses 80170 (ERCOT Side), 80014 (ERCOT Side), 80169 (CFE Side), and 80165 (CFE Side). The VFT is tied to the CFE system by a 12.73 mile 230 kV transmission line and a 12.39 mile normally open 138 kV transmission line. Both lines terminate at the CFE Ciudad Industrial Substation (86103 and 86104) and are breakered at each end. There is also a normally open 138 kV transmission line between the Laredo Power Plant (8293) and the Laredo VFT (80169) that is utilized for emergency block load transfers between ERCOT and CFE. The Laredo Power Plant to Laredo VFT 138 kV transmission line is breakered at both ends.

**Railroad**

The HVDC tie in Mission has a detailed model at busses 8825 (ERCOT Side) and 8824 (CFE Side). The Railroad HVDC is tied to the CFE system at Cumbres (86107) by an 11.79 mile 138 kV transmission line and is breakered at each end. There is also a normally open bus tie that by-passes the HVDC that is utilized for emergency block load transfers between ERCOT and CFE. The by-pass is breakered at both ends.

**Eagle Pass**

The HVDC tie in Eagle Pass has a detailed model at busses 8270 (ERCOT Side), 80000 (ERCOT Side), 86108 (CFE Side), and 86109 (CFE Side). The HVDC is tied to the CFE system at Piedras Negras (86110) by a 4.23 mile 138 kV transmission line and is breakered at each end. There is also a normally open bus tie that by-passes the HVDC that is utilized for emergency block load transfers between ERCOT and CFE. The by-pass is breakered at both ends.

**Normally Open Block Load Ties**

**Brownsville Switching Station**

The Brownsville Switching Station (8332) is connected to the CFE Matamoras Substation (86113) by a 1.9 mile 69 kV transmission line and is breakered at each end. The transmission line is operated normally open and is utilized for emergency block load transfers between ERCOT and CFE.

**Military Highway**

The Military Highway Substation (8339) is connected to the CFE Matamoras Substation (86112) by a 1.44 mile 138 kV transmission line and is breakered at each end. The transmission line is operated normally open and is utilized for emergency block load transfers between ERCOT and CFE.

**Frontera**

The Frontera Power Plant (86114) is connected to the CFE Cumbres Substation (86107) by a 138 kV transmission line. This transmission line is privately owned and operated by the owners of the Frontera Power Plant and is utilized to move the generation at Frontera Power Plant between the ERCOT and CFE systems.

**Falcon**

The Falcon Substation (8395) is connected to the CFE Falcon Substation (86111) by a .3034 mile 138 kV transmission line and is breakered at each end. The transmission line is operated normally open and is utilized for emergency block load transfers between ERCOT and CFE.

**Normally Open Block Load Ties on Distribution**

There are three normally open ties with CFE that are on the 12.47 kV distribution systems. These ties are at Amistad, Presido and Redford. These ties are only used for emergency block load transfers. Since SSWG does not model radial distribution systems these points are not in the SSWG power flow cases.

**Map of Area**



Appendix D

Generation Unit ID Prefixes

This appendix provides an explanation of the Generator ID prefixes that correspond with modeling in the base case.

| **Types of Generation Plants** | **Unit ID Prefix** | **Unit ID** | **Comment** | **Explanation** |
| --- | --- | --- | --- | --- |
|  |  |  |  |  |
| Solar | **S** | S1 | Two units connected to same bus  |  Any type of solar technology |
|   |   | S2 |
|   |   |   |   |   |
| Coal and Lignite | **L** | L1 | Three units connected to same bus   | Any type of thermal power plant |
|   |   | L2 |
|   |   | L3 |
|   |   |   |   |   |
| Natural Gas except Combined Cycle | **N** | N1 | Two units connected to same bus & 1 unit connected to another bus  | Any type of gas unit |
|   |   | N2 |
|   |   | N1 |   |
|   |   |   |   |   |
| Combined Cycle | **C** | C1 |   | Any type of combined cycle plant. Self Serve and Self Serve Economic Units will not be represented by this Unit ID prefix |
|   |   | C2 |   |
|   |   | C3 |   |
|   |   | C0 | It’s always C0 for steam units |
|   |   |   |   |   |
| Wind | **W** | W1 |   | Any type of wind generation |
|   |   | W2 |   |
|   |   | W3 |   |
|   |   | W4 |   |
|   |   | W5 |   |
|   |   | W6 |   |
|   |   | W7 |   |
|   |   |   |   |   |
| Nuclear | **U** | U1 |   | All nuclear types |
|   |   | U2 |   |
|   |   | U3 |   |
|   |   |   |   |   |
| Renewables | **R** | R1 |   | All other renewable generation except solar, wind & hydro |
|   |   | R2 |   |
|   |   |   |   |   |
| Distributed Generation | **D** | D1 |   | All types of distributed generation |
|   |   | D2 |   |
|   |   | D3 |   |
|   |   |   |   |   |
|  |  |  |  |  |
| Hydro | **H** | H1 |   | Hydro |
|   |   | H2 |   |
|   |   | H3 |   |
|   |   | H4 |   |
|   |   | H5 |   |
|   |   | H6 |   |
|   |   |   |   |   |
| Oil Fired | **O** | O1 |   | Any type of oil generation |
|   |   | O2 |   |
|   |   | O3 |   |
|   |   | O4 |   |
|   |   | O5 |   |
|   |   | O6 |   |
|   |   | O7 |   |
|   |   |   |   |   |
| FACTS Device | **F** | F1 |   | All FACTS devices |
|   |   | F2 |   |
|  | **V** | V1 |  |  |
|  |  | V2 |  |  |
|   |   |   |   |   |
| Equivalents | **EQ** | EQ |   | Equivalent units in Mexico |
|   |   |   |   |   |
| Self Serve | **P1** | P1 | Two units connected to same bus  | Self Serve units |
|   |   | P2 |
|   |   | P1 | Only one unit |
|   |   |   |   |   |
| Self Serve Economic Units | PE | PE |   | Self Serve Economic Units |
|   |   |   |   |   |
| Black Start Units | BS | BS |   | Black Start Units |
|   |   |   |   |   |
| Battery Units | BT | BT |   | All battery units |
|   |   |   |   |   |
| Block Load Transfer Model | BL | BL |   | Modeling equivalent block load transfer |

1. If the auxiliary MVAr load is not supplied, it can be estimated from the auxiliary MW load by assuming a power factor. CenterPoint Energy reviewed test data for its units from the fall of 2005. By comparing generating unit net MVAr to the system (high side of GSU), gross MVAr at the generator terminals, and estimated generator step up transformer MVAr losses under test conditions, an estimated auxiliary load power factor of 0.87 was determined. [↑](#footnote-ref-2)
2. This parameter originates from the RARFs, but can be overridden by the interconnecting TSP upon confirmation with ERCOT. [↑](#footnote-ref-3)
3. These parameters are stored in units of Ohms within NMMS and are converted to per-unit quantities by the Topology Processor. [↑](#footnote-ref-4)
4. Branch charging susceptance is stored in units of Siemens within NMMS and is converted to a per-unit quantity by the Topology Processor. [↑](#footnote-ref-5)
5. These parameters are stored in units of Ohms within NMMS and are converted to per-unit quantities by the Topology Processor. [↑](#footnote-ref-6)