###### ERCOT STEADY STATE WORKING GROUP

###### PROCEDURE MANUAL

**February 16, 2012**

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###### SECTION 1.0 – INTRODUCTION

* 1. **ERCOT STEADY-STATE WORKING GROUP’S 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. The cases, collectively known as Data Set A, are produced by the SSWG by approximately August 1st on an annual basis. These seasonal cases consist of both an on peak and an off-peak case for each of the four seasons.
* Develop and maintain steady-state base cases for the five future years following the upcoming year. The cases, collectively known as Data Set B, are produced by the SSWG by approximately October 15th on an annual basis. These future cases consist of five summer on-peak cases, and one minimum case.
* Maintain and update the Planning Data Dictionary to reflect current and future year bus and county information and link a planning bus to its corresponding ERCOT Network Operations Model bus name. This task is performed upon completion of the Data Set B work.
* 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 done by approximately 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.
* Provide Data Set A and Data Set B base case updates to correspond with the quarterly Transmission Project Information Tracking (TPIT) report.
* Review and update the contingency definition database used for planning.
* Address issues as directed by the ROS or the ERCOT Regional Planning Group (RPG).
* Annually review status of the NMMS and Topology Processor software regarding new planning data needs.

1. **INTRODUCTION TO CASE BUILDING PROCEDURES AND METHODOLOGIES**

The principal function of the SSWG is to provide steady-state seasonal and future 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 models 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 high voltage 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 two sets of steady-state base cases on an annual basis; Data Set A and Data Set B. Data Set A consists of seasonal cases for the following year. Data Set B is used for planning purposes and consists of future summer peak planning cases and a future minimum load planning case. The Annual Planning Model required by the ERCOT Protocols is defined as a model of the ERCOT power system for each of the next five years as it is expected to operate during peak load conditions for the corresponding future year. The five future summer peak planning cases of Data Set B will satisfy the Annual Planning Model requirement. Each Data Set A and Data Set B case is updated quarterly during the quarterly update process.

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 System Operations use SSWG 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

###### SECTION 2.0 – Definitions and Acronyms

* + 1. **Definitions**

Annual Planning Model Models of the ERCOT power system for each of the next five years (created, approved, posted, and updated regularly by ERCOT) as it is expected to operate during peak Load conditions for the corresponding future year.

ERCOT MOD Manual: Also known as the Planning Model Design Guidelines & Expectations. Manual that describes Model on Demand (MOD), MOD File Builder and naming conventions for cases.

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

Model On Demand Model On Demand software. Siemens program that serves as a database and case building tool that SSWG now uses to create and maintain the SSWG base cases

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 database from the NMMS system containing ERCOT transmission system modeling which is used for real-time operations and market based tools.

Profile: A PMCR 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.

Project PMCR: A PMCR for modeling 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 planning models for ERCOT. SSWG reports to ROS and takes direction from ROS.

Seed Case The TP Case loaded into MOD by ERCOT and used as a starting point for building steady-state base cases.

Standard PMCR: A PMCR for adding planning model elements or modify planning model attributes in the steady-state base cases that either are not available in the NMMS database or are not properly converted by the TP.

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

Topology Processer: Siemens software application that converts the ERCOT Operations network model in NMMS to a planning model.

TP Case: A planning case created from the Topology Processor. A bus/branch representation of ERCOT system based on the NMMS database that models equipment energization states for a designated point in time.

TPIT Transmission Project Information Tracking process. This includes a report (Excel spreadsheet) that TSPs update quarterly to report transmission project information, such as expected in-service date and whether the project is included in base cases. The second part of the TPIT process is the quarterly update of the base cases to reflect the new TPIT information.

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

DSA Data Set A

DSB Data Set B

DSP Distribution Service Provider

EPS ERCOT Polled Settlement (metering)

LSE Load Serving Entity

MLSE Most Limiting Series Element

MOD Model on Demand

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 Raw Data format

RE Resource Entity

ROS Reliability and Operating Subcommittee

SCR System Change Request

SSWG Steady-State Working Group

TP Topology Processor

TPIT Transmission Project Information Tracking

TSP Transmission Service Provider

WGR Wind Generation Resource

###### SECTION 4.0 MODELING METHODOLOGIES

1. **BUS, AREA, ZONE, AND OWNER DATA**
   * 1. **Bus Data Records**

All existing and planned transmission (60kV and above) and generator 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.

* + 1. **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.

* + 1. **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.

* + 1. **Area Numbers**

Each TSP is assigned a unique area name and number. Area number assignments are listed in the Bus/Zone Range Table in Appendix A.

* + 1. **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.

* + 1. **Owner IDs**

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

* + 1. 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 PROFILES | MOD PMCR & PROFILES |

* 1. **LOAD DATA**

Loads within the DSA and DSB are populated with data consistent with, but not necessarily identical to, load data submitted in the ALDR process. In general, the ALDR contains non-coincident load data while the DSA and DSB 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 DSA and DSB 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. All loads (MW and MVAR) should be modeled on the high side of transformers serving load at less than 60 kV.

**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 North American Electric Reliability Corporation (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 Data Set A and Data Set B 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.
    6. **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 |

* 1. **GENERATOR DATA**
     1. **Acquisition of Generator Data**

ERCOT will utilize generator data provided by REs in the Resource Asset Registration Form (RARF) 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 60kV 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 REs. This data should reflect the most recent generator reactive unit test data provided to ERCOT. If the test does not meet these requirements, reference the ERCOT Operating Guides for further explanation or actions. Note that the Corrected Unit Reactive Limit (CURL) MVAr values are gross values at the generator terminals. Limited ERCOT Resource Asset Registration Form (RARF) 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 CURL value by subtracting any auxiliary MVAr loads and any Load Host MVAr (Self Serve) load served from the low side of the generator step up transformer.

Example:

Lagging CURL value is 85 MVAr

Lagging test value is 80 MVAr

Auxiliary Load is 5 MVAr [[1]](#footnote-1)

In this example, Qmax is 85 – 5 = 80 MVAr (Use the CURL value here if the test value is equal to or greater than 90% of the CURL. Use the test value here if the test value is less than 90% of the CURL.)

**Qmin**

Qmin is the maximum 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 CURL value by adding any auxiliary MVAr loads and any Load Host MVAr (Self Serve) load served from the low side of the generator step up transformer.

Example:

Leading CURL value is -55 MVAr

Auxiliary Load is 5 MVAr

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

* + - 1. **Self-Serve Generation**

Self-serve generators serve local load that does not flow through the ERCOT transmission system. Generation data should be submitted for self-serve facilities serving self-serve load modeled in the base case. Total self serve generation MWs shall match total self-serve load MWs.

* + - 1. **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
  + 1. **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.

* + 1. **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 Data Set A and Data Set B cases. 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 for DSA and DSB cases; unless a NOIE requests that their units are to be dispatched according to the order that is described below.

Private network generation is also dispatched independently. The plants are dispatched to meet their load modeled in the case. DC Ties are modeled as load levels or at generation levels based on historical data. Likewise, wind plants are modeled at generation levels based on historical data.

See Appendix I on Method for Calculating Wind Generation Levels in SSWG Cases.

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:

Data Set A will be Security Constrained Economically Dispatched (SCED) using NERC Category B contingencies and identified double circuit contingencies applicable to Transmission Planning 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. The system load will be simulated for the two weeks leading up to the peak hour for each season.

Data Set B cases will be economically dispatched for a given load level with no contingencies but while monitoring Rate A for all transmission lines greater than 60 kV and transformers with the low side greater than 60 kV. The system load will be simulated for the two weeks leading up to the peak hour for each summer peak case and the two weeks leading up to the minimum load hour for the minimum case.

In all cases spinning reserve is maintained according to ERCOT Operating Guides. Specifically, spinning reserve is maintained such that 1150 MW of the Responsive Reserve Service obligation is made up of generation resources. The dispatch may be modified for Data Set A cases if necessary to maintain voltages at acceptable levels.

New Generation Resources will be included in the base cases once (1) ERCOT receives an executed interconnection agreement or a public, financially-binding agreement between the generator and the TSP under which the generation interconnection facilities would be constructed; or (2) ERCOT receives a commitment letter from a Municipally Owned Utility (MOU) or an Electric Cooperative (EC) building a generation resource.

*Extraordinary Dispatch Conditions*

On occasion, the total load plus the spinning reserve indicated above in later year cases can exceed the amount of available generation due to load forecasts in later year cases. 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. DC ties dispatched to increase transfers into ERCOT to the full capacity of the DC ties.
2. Mothballed units that have not announced their return to service. The methodology for this procedure is detailed below.
3. Ignore spinning reserve.
4. Add publicly announced plants without interconnect agreements.
5. Black start Units
6. Add generation resources at the sites of retired units.

**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 installed 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.

* + 1. **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.

* + 1. 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 PMCR |
| 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 PMCR |
| PMin (MW) | RARF - NMMS | RARF - MOD PMCR |
| QMax (Mvar)**[[2]](#footnote-2)** | RARF - NMMS | RARF - MOD PMCR |
| QMin (Mvar)**2** | RARF - NMMS | RARF - MOD PMCR |
| 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 |

* 1. **Branch Data**
     1. **Use of Branch Record Data Fields**

All existing and planned transmission lines shall be modeled in the SSWG steady-state base cases.

* + - 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 1.5.3, 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 1.5.2.). 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.

* + - 1. **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.

* + - 1. **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.

* + - * 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:



* + - * 1. **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:



* + - * 1. **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:





* + - 1. **Facility Ratings**

SSWG Steady-state 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 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 | 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.

* + - * 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.

* + - 1. **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.

* + - 1. **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.

* + - 1. **Line Length and Ownership**
         1. **Line Length**

This data will be provided in miles.

* + - * 1. **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.

* + - * 1. **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



* + 1. **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.

* + 1. **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 ~~a~~ spring cases and added to ~~a~~ 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 Data Set A and Data Set B 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

hasmay

* + 1. 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-3)** | NMMS | MOD PMCR |
| Reactance X (pu)**3** | NMMS | MOD PMCR |
| Charging Susceptance (pu)**[[4]](#footnote-4)** | 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 |

* 1. **Transformer Data**
     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.

* + - 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 1.5.3, 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.

* + - 1. **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.

* + - 1. **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.

* + - * 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.

* + - * 1. **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.

* + - * 1. **Susceptance**

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

* + - 1. **Transformer Ratings**

The ratings used for transformer are defined the same as the ratings used for branches described in Section 1.5.1.4.

* + - 1. **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.

* + - 1. **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.

* + - 1. **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.

* + - 1. **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.

* + - * 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.

* + - * 1. **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.

* + - * 1. **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.

* + - * 1. **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.

* + - * 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.

* + - * 1. **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.

* + - * 1. **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.

* + - * 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.

* + - * 1. **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.

* + - * 1. **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.

* + - * 1. **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.

* + - 1. **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.

* + - 1. **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.

* + - * 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.

* + - * 1. **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.

* + 1. 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-5)** | 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 |
|  |  |  |

* 1. **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.

* + 1. **Shunt Devices**
       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.

* + - 1. **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.

* + - 1. **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.

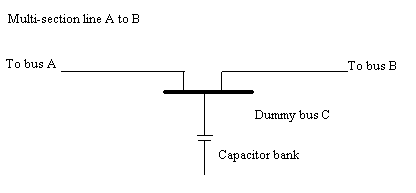


Figure 3. Example one-line of line connected capacitor bank

* + 1. **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.

* + 1. Static Reactive Device Data Source

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

* 1. 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. | | |

* 1. **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.

* + 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, thyristers, 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.



* + 1. **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.



* + 1. 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 |

###### SECTION 3.0 – Steady-State Base Case Procedures and Schedules

* 1. **General**

The SSWG and ERCOT build steady-state base cases and perform quarterly 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 quarterly updates are described in this section.

* 1. **Steady-State Base Case Definitions and Build Schedules**

Two sets of cases are created by SSWG each year, DSA and DSB. The DSA cases consist of eight seasonal cases which model expected on-peak and off-peak conditions for the following year’s four seasons. The DSB cases model expected peak conditions for each year over a five-year planning horizon beginning the year after the following year. The DSB cases also include a minimum load case for one of the years in the five-year planning horizon, bringing the total of number of DSB cases to six.

* + 1. **DSA Definition**

The seasons for the DSA cases are defined as follows:

SPG March, April, May

SUM June, July, August, September

FAL October, November

WIN December, January, February

**SSWG DSA CASES**

**(YR) = FOLLOWING YEAR**

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

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.
   * + 1. **DSA Uses**

The DSA cases are generally used for short-term planning studies, systems operational studies, transmission loss calculations and are posted on ERCOT web site for general use.

* + 1. **DSB Definition**

**SSWG DATA SET B BASE CASES**

**(YR) = FOLLOWING YEAR**

|  |  |  |
| --- | --- | --- |
| **BASE CASE** | NOTES | **TRANSMISSION IN-SERVICE DATE** |
| (YR+1) SUM1 | 1 | JULY 1, (YR+1) |
| (YR+2) SUM1 | 1 | JULY 1, (YR+2) |
| (YR+3) MIN | 2 | JANUARY 1, (YR+3) |
| (YR+3) SUM1 | 1 | JULY 1, (YR+3) |
| (YR+4) SUM1 | 1 | JULY 1, (YR+4) |
| (YR+5) SUM1 | 1 | JULY 1, (YR+5) |

Notes:

1. Cases to represent the maximum expected load during the season.
2. Cases to represent the absolute minimum load expected for (YR+3).
   * + 1. **DSB Uses**

Data Set B cases are generally used by the TSPs and ERCOT to perform planning studies over the near-term and longer-term planning horizon.

* + 1. **Build Schedules**

The SSWG and ERCOT formulate the DSA and DSB schedules on an annual basis. The DSA cases are typically completed by early August and the DSB cases are typically completed by mid-October.

* 1. **Steady-State Base Case Build Processes**
     1. **Overview**

The DSA and DSB 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 is then imported into MOD and becomes the seed case, which may also be referred to as the MOD base case. ERCOT and the TSPs apply Standard PMCRs, Project PMCRs, and Profiles to the seed case to create the SSWG base 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 DSA and DSB cases. ERCOT will compile these projects and profiles to build the DSA and DSB cases. Case modifications can be accomplished in MOD by either uploading files in the MOD project file format, which can be created by the MOD File Builder or any text editor, or by manual entry using the MOD interface. SSWG members will need to consult the ERCOT Planning Model Design Guidelines & Expectations manual for specific instructions on MOD usage.

* + 1. **Incremental Update**

In lieu of reseeding MOD with a new TP Case upon commencement of a DSA build, DSB build, or quarterly update, the SSWG may implement an incremental update in order to include the latest Network Operations Model data in the planning models. This is accomplished by comparison of topology processed NMMS data with selected data currently existing in MOD. All inconsistencies between NMMS data and MOD data identified from the comparison are passed on to the appropriate TSP or ERCOT for correction. A correction could be accomplished by either a NOMCR or PMCR.

* + 1. **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 this situation, the TSP who owns the NOMCR must submit a PMCR to appropriately include the network model change in the steady-state base cases.

* + 1. **DSA Generation Dispatch**

The DSA cases will contain a security constrained (N-1) economic dispatch as described in Section 4.3.3.

* + 1. **DSB Generation Dispatch**

The DSB cases will contain economically dispatched generation (ECO) as described in Section 4.3.3.

* + 1. **Entity Responsibilities**

The DSA and DSB 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:

* + - 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 document shall be followed.

* Future transmission facility changes will be submitted as Project PMCRs. A Project PMCRs phase date should correspond to the transmission in-service date. Project 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.
  + - 1. **LSEs**
* Each DSP directly interconnected with the ERCOT transmission system (or its agent so designated to ERCOT) shall provide annual load forecasts to ERCOT staff as outlined in the ERCOT ALDR Procedures.
* For each substation not owned by either a TSP or a DSP, the owner shall provide a substation load forecast to the directly connected TSP sufficient to allow it to adequately include that substation in its ALDR response.
* 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 of the Planning Guide.
  + - 1. **REs**
* 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. This data should be coordinated with ERCOT staff and should include, but is not limited to unit capabilities.
* It is the responsibility of Resource Entities to supply any applicable load and/or generation data if they are the designated representatives for either a load or generating entity or both.
  + - 1. **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 seed case.
* ERCOT staff shall be responsible for the review and inclusion of all latest available generator models, 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 DSA and DSB 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 by Pass 2 in the DSA and DSB case building process. This dispatch will be security constrained (N-1) for DSA and economically dispatched for DSB and will be provided at 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 DSA and DSB 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 DSA and DSB 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.
  + 1. **Process Overview for Building the DSA and DSB Cases**
* Seed 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.

If the SSWG chooses to seed MOD with a new TP case:

* + Import the Seed Case into MOD.

If the SSWG chooses to use the incremental update process:

* + ERCOT produces a comparison file with inconsistencies between the seed case and the new TP case.
  + TSPs and ERCOT submit NOMCRs and/or PMCRs to resolve inconsistencies.
* Pass 0
  + TSPs review existing PMCRs and delete those that are represented in the TP case.
  + Submit Standard PMCRs.
  + Submit Project 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 Project PMCRs.
  + Update Profiles.
  + Load revised generation dispatch.
  + Output Pass 2 – Pass N+1 cases.
* Final Pass
  + SSWG approves cases.
  + Cases and generation dispatch spreadsheet finalized by SSWG and posted on the ERCOT POI website.

Any changes required after the DSA and DSB cases are posted will be made in the MOD environment. Change files for modified PMCRs will be posted on the ERCOT POI website.

* + 1. **Transition from Completed Build to Next Case Build**
* Either reseed MOD or implement the incremental update process quarterly 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 DSA and DSB case builds, but for each quarterly update.
  + 1. **Quarterly Updates**

The SSWG base cases are updated quarterly throughout the year. All quarterly 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 Standard PMCR to maintain consistency with the Network Operations Model. See Planning Guide Section 6.4 for additional information about the TPIT process.











###### SECTION 5.0 – 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 SSWG DSA base 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 Data Set A 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. An annual review of the contingency database will be conducted shortly after the release of the DSB steady state base cases. 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 |
| ERCOTID |  |  |  | May be null |
| 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 |
| ElementIdentifier |  |  |  | Must be either a bus, transformer, branch 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 B, C, D, or C/D |
| ERCOTCategory |  |  |  | Must be N/A or ERCOT\_1 |
| TDSPComments |  |  |  | May be null |
| ERCOTComment |  |  |  | May be null |
| ContingencyName |  |  |  | Must be consistent within a contingency definition |

The procedure for the annual review and update of the contingency database is as follows:

1. ERCOT will send out the current contingency list to SSWG members with invalid entries highlighted.
2. 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.
3. Upon import, ERCOT will overwrite the previous list of definitions submitted by the TSP.
4. 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.
5. Steps 1 to 4 will be repeated for each pass of the contingency update process.
6. When the contingency list is finalized, ERCOT will post the list on the POI 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.

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 DSA and DSB 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 Category B 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 Category B, C, and D contingencies must either be submitted in entirety by each TSP or as a minimum, those Category B, C, and D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

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, please 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. |
| NERC Category Missing | The NERC Category is missing. The only acceptable values are B, C, D, or C/D. |
| ERCOT Category Missing | The ERCOT Category is missing. The only acceptable values ERCOT\_1 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. |

**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**

Each SSWG member will submit a data file listing all buses that exist in any case from either Data Set A or B. This file is called the Planning Data Dictionary. The Planning Data Dictionary is used by ERCOT to show correlation between base case bus numbers and TSP area SCADA names. Also, the Planning Data Dictionary without the SCADA names is included as part of ERCOT’s FERC 715 filing. The format will be as follows:

| **Column Heading** | **Description** | **Who's Responsible** |
| --- | --- | --- |
| **TSP** | Should be verified by SSWG member | SSWG member |
| **Planning Bus Date In** | Should be added by a member of SSWG. This is a required field for all the buses which are going in service in the future. | SSWG member |
| **Planning Bus Date Out** | Should be added by a member of SSWG. This is a required field for all the buses which are going out of service either in current year or in the future. | SSWG member |
| **Planning Bus No** | Planning - Up to 6 digit number used in planning models. Will be added by a member of the SSWG. Is required by FERC for FERC 715 pt. 2 report. | SSWG member |
| **Planning Base kV** | Planning Base kV - Will be added or corrected by a member of SSWG. Is required by FERC for FERC 715 pt. 2 report. | SSWG member |
| **Planning Bus Name** | Planning - 12 character name used in planning models. Will be added by a member of the SSWG. Is required by FERC for FERC 715 pt. 2 report. | SSWG member |
| **Planning Full Bus Name** | Planning Full Bus Name that has been used in planning. Will be added by a member of the SSWG. Is required by FERC for FERC 715 pt. 2 report. | SSWG member |
| **TSP Comments** | This Field is optional and should be used by SSWG members to input some comments like bus name changed, bus number changed etc... | SSWG member |
| **County of Bus** | Planning - Self explanatory - geography. Is required by FERC for FERC 715 pt. 2 report. | SSWG member |

6 APPENDICES

Appendix A

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

| **BUS RANGE** | **DSP, OTHER ENTITY,**  **or SUBSYSTEM** | **ACRONYM** | **TSP or**  **OTHER**  **ENTITY** | **PSSE AREA NO** | **ZONE RANGE** | | **NERC TP**  **Yes/No** | **NERC DP**  **Yes/No** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  |  |  |  |  |
| 1 - 799 | **BRAZOS ELECTRIC POWER COOP.** | TBREC | TBREC | 11 | 11 | 11 | Yes |  |
| 33000 - 36999 |  |  |
| 32050 - 32999 | **BRYAN, CITY OF** | TBTU | TBTU | 22 | 2 | 2 | Yes |  |
| 900 - 934 | **DENTON MUNICIPAL UTILITIES, CITY OF** | TDME | TDME | 19 | 3 | 3 | No | Yes |
| 800 - 899 | **GARLAND, CITY OF** | TGAR | TGAR | 20 | 4 | 4 | Yes |  |
| 935 - 955 | **GREENVILLE ELECTRIC UTILITY SYSTEM** | TGEUS | TGEUS | 21 | 5 | 5 | No | Yes |
| 956 - 999 | **TEXAS MUNICIPAL POWER AGENCY** | TTMPA | TTMPA | 12 | 6 | 6 | Yes |  |
| 9500 - 9699 |
| 1000 - 4999 | **ONCOR** | TONCOR | TONCOR | 1 | 100 | 175 | Yes |  |
| 10000 - 31999 |  |  |
| 32000 - 32049 | **COLLEGE STATION, CITY OF** | TCOLGS | TCOLGS | 23 | 199 | 199 | Yes |  |
| 37000 - 39999 | **TEXAS NEW MEXICO POWER CO.** | TTNMP | TTNMP | 17 | 220 | 240 | Yes |  |
| 40000 - 49999 | **CENTERPOINT** | TCNPE | TCNPE | 4 | 260 | 320 | Yes |  |
| 5000 - 5499 | **CPS ENERGY** | TCPSE | TCPSE | 5 | 350 | 351 | Yes |  |
| 50000 - 54999 |  |  |
| 5500 - 5899 | **SOUTH TEXAS ELECTRIC COOP.** | TSTEC | TSTEC | 13 | 870 | 890 | Yes |  |
| 55000 - 58999 |  |  |
| 5910 - 5919 | **SOUTH TEXAS POWER PLANT** | TCNPE | TCNPE | 10 | 310 | 310 | No  TCNPE |  |

| **BUS RANGE** | **DSP, OTHER ENTITY,**  **or SUBSYSTEM** | **ACRONYM** | **TSP or**  **OTHER**  **ENTITY** | **PSSE AREA NO** | **ZONE RANGE** | | **NERC TP**  **Yes/No** | **NERC DP**  **Yes/No** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  |  |  |  |  |  |  |  |
| In TRAYBN | **GRAYSON COUNTY ELECTRIC COOP.** | TGEC | TRAYBN | 2 | 178 | 178 | No | No  TRAYBN |
| In TRAYBN | **LAMAR ELECTRIC COOP.** | TLAHOU | TRAYBN | 2 | 178 | 178 | No | No  TRAYBN |
| In TRAYBN | **FARMERS ELECTRIC COOP.** | TFECE | TRAYBN | 2 | 178 | 178 | No | No  TRAYBN |
| In TRAYBN | **TRINITY VALLEY ELECTRIC COOP.** | TTRINY | TRAYBN | 2 | 178 | 178 | No | No  TRAYBN |
| In TRAYBN | **FANNIN COUNTY ELECTRIC COOPERATIVE** | TFCEC | TRAYBN | 2 | 178 | 178 | No | No  TRAYBN |
| 68000 - 69999 | ***LONE STAR TRANSMISSION*** | TLSTR | TLSTR | 27 | 670 | 689 | Yes |  |

**Bus/Zone Range Table (continue)**

| **BUS RANGE** | **DSP, OTHER ENTITY,**  **or SUBSYSTEM** | **ACRONYM** | **TSP or**  **OTHER**  **ENTITY** | **PSSE AREA NO** | **ZONE RANGE** | | **NERC TP**  **Yes/No** | **NERC DP**  **Yes/No** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| 5920 - 5929 | **EAST HIGH VOLTAGE DC TIE** |  | TAEPTC | 16 | 200 | 200 | No  AEPSC | n/a |
| 5930 - 5989 | **PUBLIC UTILITY BOARD OF BROWNSVILLE** | TBPUB | TBPUB | 15 | 800 | 800 | Yes |  |
| 59300 - 59899 |  |  |
| 59900 - 59999 | **WIND ENERGY TRANSMISSION TEXAS** | WETT | WETT | 29 | 590 | 609 | Yes |  |
| 6000 - 6699 | **AMERICAN ELECTRIC POWER- TNC** | TAEPTN | TAEPTN | 6 | 402 | 479 | No | n/a |
| 60000 - 67999 | AEPSC |  |
| 69000 - 69999 |  |  |
| In TAEPTN | **COLEMAN COUNTY ELECTRIC COOP.** | TCOLMN | AEPTN |  |  |  | No  AEPSC | n/a |
| In TAEPTN | **CONCHO VALLEY ELECTRIC COOP.** | TCVEC2 | AEPTN |  |  |  | No  AEPSC | n/a |
| In TAEPTN | **MIDWEST ELECTRIC COOP.** | RBECWR | AEPTN |  |  |  | No  AEPSC | n/a |
| In TAEPTN | **RIO GRANDE ELECTRIC COOP.** | TRGEC1 | AEPTN |  |  |  | No  AEPSC | n/a |
| In TAEPTN | **SOUTHWEST TEXAS ELECTRIC COOP.** | TSWEC1 | AEPTN |  |  |  | No  AEPSC | n/a |
| In TAEPTN | **STAMFORD ELECTRIC COOP.** |  | AEPTN |  |  |  | No  AEPSC | n/a |
| In TAEPTN | **TAYLOR ELECTRIC COOP.** | TECX | AEPTN |  |  |  | No  AEPSC | n/a |
| 6096 - 6096 | **NORTH HIGH VOLTAGE DC** |  | AEPTN | 14 | 394 | 394 | No  AEPSC | n/a |
| 6700 - 6749 | **TEX-LA ELECTRIC COOP.** | XTEXLA | TONCOR | 3 | 177 | 177 | No | Yes |
| 6800 - 6949 | **RAYBURN COUNTRY ELECTRIC COOP.** | TRAYBN | TRAYBN | 2 | 178 | 178 | No | Yes |







| **BUS RANGE** | **DSP, OTHER ENTITY,**  **or SUBSYSTEM** | **ACRONYM** | **TSP or**  **OTHER**  **ENTITY** | **PSSE AREA NO** | **ZONE RANGE** | | **NERC TP**  **Yes/No** | **NERC DP**  **Yes/No** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| 7000 – 7899  70000 - 78999 | **LOWER COLORADO RIVER AUTHORITY TSC** | TLCRA | TLCRA | 7 | 500 | 589 | Yes |  |
| In TLCRA | **BANDERA ELECTRIC COOP.** | TBDEC | TLCRA |  |  |  | Yes |  |
| In TLCRA | **BLUEBONNET ELECTRIC COOP.** | TBBEC | TLCRA |  |  |  | Yes |  |
| In TLCRA | **CENTRAL TEXAS ELECTRIC COOP.** | TCTEC | TLCRA |  |  |  | No | Yes  TLCRA |
| In TLCRA | **GUADALUPE VALLEY ELECTRIC COOP.** | TGVEC | TLCRA |  |  |  | Yes |  |
| In TLCRA | **NEW BRAUNFELS UTILITIES** | TNBRUT | TLCRA |  |  |  | Yes |  |
| In TLCRA | **PEDERNALES ELECTRIC COOP.** | TPDEC0 | TLCRA |  |  |  | Yes |  |
| In TLCRA | **SAN BERNARD ELECTRIC COOP.** | TSBEC | TLCRA |  |  |  | Yes |  |
| 79000-79499 | **CROSS TEXAS TRANSMISSION** | TCROS | TCROS | 30 | 790 | 799 | Yes | No |
| 8000 – 8999  80000 - 89999 | **AMERICAN ELECTRIC POWER - TCC** | TAEPTC | TAEPTC | 8 | 610 | 662 | Yes |  |
| 79500-79599 | **SHARYLAND** | TSLND1 | TSLND1 | 18 | 820 | 829 | Yes |  |
| 9000 – 9399  90000 - 93999 | **AUSTIN ENERGY** | TAEN | TAEN | 9 | 691 | 712 | Yes |  |

| **BUS RANGE** | **DSP, OTHER ENTITY,**  **or SUBSYSTEM** | **ACRONYM** | **TSP or**  **OTHER**  **ENTITY** | **PSSE AREA NO** | **ZONE RANGE** | | **NERC TP**  **Yes/No** | **NERC DP**  **Yes/No** |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| 9400-9450 | **LYNTEGAR ELECTRIC COOP (Goldenspread)** | TGSEC | TGSEC | 25 | 179 | 179 | No | Yes |
| 9451-9470 | **TAYLOR ELECTRIC COOP** | TTLEC2 | TTLEC2 | 25 | 179 | 179 | No | Yes |
| 9471-9490 | **BIG COUNTRY ELECTRIC COOP** | TBCEC1 | TBCEC1 | 25 | 179 | 179 | No | Yes |
| 9491-9499 | **CITY OF GOLDSMITH** | TGOLDS | TGOLDS | 26 | 180 | 180 | No | Yes |
| 9700 – 9999  94000 – 99999  100000 - 199999 | **ERCOT SYSTEM PLANNING** | TERCOT | TERCOT |  | 900 | 1199 | No  N/A |  |
| 5824,5864,  5870,5872 | **RIO GRANDE ELECTRIC COOP** | TRGEC2 | TRGEC2 |  |  |  | No  AEPSC |  |
| 600-601 | **BRIDGEPORT ELECTRIC** | TBRIDG | TBTU |  |  |  | No  BRYN |  |

**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 Bases**

The following table provides a description of the zones defined in NMMS as of January 2012. 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. |
| 120 | W FALLS | ONCOR |
| 121 | EASTLAND | ONCOR |
| 124 | COMANCHE | ONCOR |
| 125 | MINERL W | ONCOR |
| 130 | FT WORTH | ONCOR |
| 131 | DFW CENT | ONCOR |
| 132 | DALLAS | ONCOR |
| 133 | ROANOKE | ONCOR |
| 134 | VENUS | ONCOR |
| 135 | DAL SUBS | ONCOR |
| 140 | GAINESVL | ONCOR |
| 141 | PARIS | ONCOR |
| 142 | SULPHR S | ONCOR |
| 143 | WILLS PT | ONCOR |
| 144 | TYLER | ONCOR |
| 145 | ATHENS | ONCOR |
| 146 | LUFKIN | ONCOR |
| 147 | PALESTIN | ONCOR |
| 148 | CORSICAN | ONCOR |
| 149 | LIMESTON | ONCOR |
| 150 | RND ROCK | ONCOR |
| 151 | TEMPLE | ONCOR |
| 152 | KILLEEN | ONCOR |
| 153 | WACO | ONCOR |
| 154 | HILLSBOR | ONCOR |
| 160 | ODESSA | ONCOR |
| 161 | MIDLAND | ONCOR |
| 162 | BIG SPRG | ONCOR |
| 163 | SWEETWTR | ONCOR |
| 177 | TEX-LA | TEX-LA Electric Coop |
| 178 | RAYBURN | Rayburn Country Electric Coop |
| 179 | GOLDSPRD | Golden Spread Electric Cooperative |
| 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 |

|  |  |  |
| --- | --- | --- |
| **Zone #** | **Zone Name** | **Zone Description** |
| 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 |
| 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 |
| 318 | CNP TERTIARY | CenterPoint Energy- 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 |

|  |  |  |
| --- | --- | --- |
| **Zone #** | **Zone Name** | **Zone Description** |
| 500 | AUSTIN | Lower Colorado River Authority |
| 502 | BANDERA | Lower Colorado River Authority |
| 504 | BASTROP | 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 |
| 512 | CALDWELL | Lower Colorado River Authority |
| 514 | COLORADO | Lower Colorado River Authority |
| 516 | COMAL | Lower Colorado River Authority |
| 517 | CONCHO | Lower Colorado River Authority |
| 522 | CULBRSON | Lower Colorado River Authority |
| 525 | DEWITT | Lower Colorado River Authority |
| 528 | FAYETTE | Lower Colorado River Authority |
| 531 | GILESPIE | Lower Colorado River Authority |
| 534 | GOLIAD | Lower Colorado River Authority |
| 537 | GONZALES | Lower Colorado River Authority |
| 540 | GUADLUPE | Lower Colorado River Authority |
| 543 | HAYS | Lower Colorado River Authority |
| 546 | KENDALL | Lower Colorado River Authority |
| 549 | KERR | Lower Colorado River Authority |
| 552 | KIMBLE | Lower Colorado River Authority |
| 555 | LAMPASAS | Lower Colorado River Authority |
| 558 | LAVACA | Lower Colorado River Authority |
| 561 | LEE | Lower Colorado River Authority |
| 564 | LLANO | Lower Colorado River Authority |
| 570 | MASON | Lower Colorado River Authority |
| 572 | MCCULLOCH | Lower Colorado River Authority |
| 573 | MENARD | Lower Colorado River Authority |
| 575 | MILLS | Lower Colorado River Authority |
| 577 | REAL | Lower Colorado River Authority |
| 579 | SAN SABA | Lower Colorado River Authority |
| 581 | TRAVIS | Lower Colorado River Authority |
| 583 | WALLER | Lower Colorado River Authority |
| 585 | WSHNGTON | Lower Colorado River Authority |
| 587 | WILLMSON | 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 |

|  |  |  |
| --- | --- | --- |
| **Zone #** | **Zone Name** | **Zone Description** |
| 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 |  | 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 |
| 901 | E\_CALHOUN | ERCOT designated generation zone |
| 902 | E\_CHAMBERS | ERCOT designated generation zone |
| 903 | E\_FORT BEND | ERCOT designated generation zone |
| 904 | E\_GALVESTON | ERCOT designated generation zone |
| 906 | E\_HARRIS | ERCOT designated generation zone |
| 911 | E\_MATAGORDA | 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\_NACOGDOCHE | ERCOT designated generation zone |
| 951 | E\_ROBERTSON | 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 |
| 991 | E\_UPTON | ERCOT designated generation zone |
| 992 | E\_WARD | ERCOT designated generation zone |
| 993 | E\_WINKLER | ERCOT designated generation zone |
| 1009 | E\_COOKE | 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 |
| 1027 | E\_LAMAR | ERCOT designated generation zone |
| 1029 | E\_MOTLEY | ERCOT designated generation zone |
| 1033 | E\_WICHITA | ERCOT designated generation zone |
| 1036 | E\_PITTSBURG- | 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\_SHACKELFOR | 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 |
| 1133 | E\_GUADALUPE | ERCOT designated generation zone |
| 1134 | E\_HAYS | ERCOT designated generation zone |
| 1136 | E\_KENDALL | 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 |
| 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\_PUN | 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 |



















### 

Appendix B

**Methodology for Calculating Wind Generation levels in the SSWG Cases**

Goal – Use the available prior year’s operating data from the wind farms to set the dispatch in the new SSWG base cases.

Process

1. Retrieve MW forecast for the following time frames:
   1. May 3-5AM 4-6PM
   2. August 3-6AM 4-6PM
   3. September 3-6AM 4-6PM
   4. December 3-6AM 6-8PM
   5. January 3-6AM 7-8AM
2. Calculate the average capacity factor of each plant for each time frame. For the winter numbers, combine the data for December of one calendar year and January of the next calendar year (same winter). Winter peak typically occurs either immediately after the minimum in January, or early evening in December.
3. The default group is determined by taking the minimum of all identified areas with forecast data.
4. Calculate the average % capacity factor of each wind farm for each time frame. Round off to the closest 1%.



**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 605. The AEP facilities will retain the owner 8 and CFE will be assigned owner 150.

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**



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-1)
2. This parameter originates from the RARFs, but can be overridden by the interconnecting TSP upon confirmation with ERCOT. [↑](#footnote-ref-2)
3. These parameters are stored in units of Ohms within NMMS and are converted to per-unit quantities by the Topology Processor. [↑](#footnote-ref-3)
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-4)
5. These parameters are stored in units of Ohms within NMMS and are converted to per-unit quantities by the Topology Processor. [↑](#footnote-ref-5)