



ERCOT System Planning:

2016 Regional Transmission Plan Report

Document Revisions

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Executive Summary

The 2016 Regional Transmission Plan (RTP) is a result of a coordinated planning process performed by ERCOT with extensive review and input by NERC-registered Transmission Planners (TPs), Transmission Owners (TOs) and other stakeholders. The RTP addresses ERCOT System reliability and economic transmission needs for years 2018 through 2022. This report documents the results of the assessment in part to comply with the requirements from NERC Reliability Standards, ERCOT Protocols and ERCOT Planning Guide.

The analysis was performed over a six-year planning horizon, years one through five representing the near-term horizon and year six representing the long-term horizon. The 2016 RTP assessed ERCOT's steady-state transmission needs under summer peak and off-peak conditions. In addition to the seasonal variations, the RTP also included various sensitivities to address uncertainty involved in the transmission planning process. The reliability analysis in the 2016 RTP included:

- Steady-state contingency analysis to identify criteria violations based on NERC Reliability Standards and ERCOT planning criteria
- Short-circuit analysis to identify over-dutied circuit breakers in the near-term planning horizon
- Cascading analysis to identify potential system cascading conditions

Following the reliability assessment, ERCOT planners in collaboration with Transmission Planners developed Corrective Action Plans to address reliability concerns identified in this assessment. These plans included, but were not limited to, upgrades or addition of new transmission facilities and new constraint management plans.

The majority of planned improvements identified in the 2016 RTP are 138-kV and 69-kV upgrades. Most of the projects identified as 345-kV upgrades consist of either the addition of a new 345/138-kV transformer or the upgrade of an existing 345/138-kV transformer. Many of these transformer projects were identified in previous RTP studies.

The 2016 Regional Transmission Plan identified the following noteworthy reliability projects:

- New 345/138-kV transformer (third transformer) near the Zenith substation in Harris County
- Upgrade of existing 345/138-kV transformers at the San Miguel substation in Atascosa County
- A new 144-MVAr reactor at the Kiamichi 345-kV substation in Pittsburg County in Oklahoma
- A minimum of two 50-MVAr reactors at the Bakersfield 345-kV substation in Pecos County
- New 345/138-kV transformer at Salado in Bell County
- Two new 345/138-kV transformers at Stewart Rd and two new 345-kV transmission lines in Hidalgo and Starr Counties
- New 345/138-kV transformer (second transformer) at the Twin Buttes substation in Tom Green County
- New 345/138-kV transformer at Hicks Switch substation in Tarrant County

In addition to the reliability analysis, the 2016 RTP included an economic assessment of the ERCOT transmission system for years 2019 and 2022. Through this assessment, ERCOT planners identified transmission congestion and test various transmission upgrades to address the congestion in a cost-effective manner (as defined by ERCOT's economic planning criteria). Thirteen projects were evaluated using the economic criteria, and only one project, namely, the addition of two 175-MVAr synchronous condensers at the Windmill Substation in the Deaf Smith County showed enough savings to justify the project.

The project completion years stated in this 2016 RTP Report were chosen to address reliability and economic needs in a timely manner. The TOs are expected to meet these project completion dates, but lead times necessary to implement projects based on factors such as availability of construction clearances, time required to receive regulatory or governmental approvals, equipment availability, land acquisition and resource constraints may result in different project completion dates. The scope of projects

identified in the RTP may change if further analyses by ERCOT or the TPs find better alternatives or a need for modifying the projects due to changes in expected generation, load forecasts, or other system conditions. Projects requiring Regional Planning Group (RPG) approval will be reviewed in future assessments (where sufficient lead-time exists), such as future Regional Transmission Plans, to ensure the identified system facilities are still needed.

The TOs will provide ERCOT additional details on project scope, project cost and an implementation schedule with completion date(s). This information from the TOs may be provided through further RPG review and/or Transmission Project Information Tracking (TPIT) updates in accordance with ERCOT Planning Guide Section 6.4.1.

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1. RTP Process

This report documents the 2016 Regional Transmission Plan (RTP) performed by ERCOT System Planning. It is intended, in part, to satisfy ERCOT's requirements under NERC Reliability Standards, ERCOT Protocol Section 3.11 and ERCOT Planning Guide Sections 3 and 4.

The Regional Transmission Plan study is conducted annually for the entire ERCOT System. The 2016 RTP analyzed the reliability needs of the ERCOT transmission system for the years 2018, 2019, 2021 and 2022. The 2016 RTP performed steady-state analyses and short-circuit analysis as required by NERC Standard TPL-001-4 for the Summer Peak conditions of years 2018 (year 2), 2019 and 2021 (year 5) for the near-term planning horizon and Off-Peak conditions for 2019 (year 3). The 2016 RTP also included steady-state analyses for 2022 (year 6), representing the long-term planning horizon. The year six, or 2022, was selected based on the rationale that most of ERCOT transmission upgrades can be completed within five to six years from the date when the need is identified. In addition to the reliability needs, the 2016 RTP also evaluated economic/efficiency needs of the ERCOT system for 2019 and 2022.

1.1 Standards and Regulations

The RTP assessment was conducted based on the NERC Standards, ERCOT Protocols, and ERCOT Planning Guide.

NERC Standard

The RTP performed its steady-state reliability assessment in accordance with NERC Reliability Standard TPL-001-4 "Transmission System Planning Performance Requirements."

ERCOT Protocols

ERCOT Protocols Section 3.10.8.4 (3) requires ERCOT to identify additional Transmission Elements that have a high probability of providing significant added economic efficiency to the ERCOT market through the use of Dynamic Ratings and request such Dynamic Ratings from the associated ERCOT Transmission Service Provider (TSP). This report identifies such Transmission Elements as part of its economic analysis. ERCOT Protocols Section 3.11.5 specifies the economic planning criteria used to evaluate cost-effectiveness of projects in the RTP.

ERCOT Planning Guide

The RTP assessment adheres to ERCOT Planning Guide Section 3.1.1.2, which provides guidelines regarding completion of the RTP. This section also requires that ERCOT complete and publish the final RTP report no later than December 31 each year. Additionally, ERCOT Planning Guide Section 4 and ERCOT Protocol Sections 3.11.2 specify the transmission planning criteria to be used in the RTP assessment.

1.2 Stakeholder Involvement

The RTP is a collaborative process. ERCOT worked with NERC-registered Transmission Planners (TP)s, Transmission Owners (TO)s and other stakeholders to develop input assumptions and scope for technical studies that define the RTP. These assumptions are described in the RTP Scope and Process document and were presented to the stakeholder community at Regional Planning Group (RPG) meetings. The RPG is responsible for reviewing and providing comments on new transmission projects in the ERCOT Region. Per ERCOT Protocols Section 3.11.3, participation in the RPG is required of all TSPs and is open to all Market Participants, consumers, other stakeholders and Public Utility Commission of Texas (PUCT) Staff. The RTP Scope and Process document can be found in Appendix A.

ERCOT worked with TPs, TOs, and other stakeholders to study the existing system, identify system upgrades and new transmission projects to ensure continued system reliability, and address projected system congestion. Stakeholders and the RPG community were provided routine updates on the input assumptions and supporting analysis performed for the 2016 RTP study in the monthly RPG meetings held from January to April of 2016. Feedback and comments from the RPG were incorporated into the RTP Scope and Process document.

1.3 Assumptions and Criteria

The RTP study is dependent upon data compiled and provided by numerous parties both inside and outside of ERCOT. The required data include: a forecast of system demand, generation supply and starting network topology. This information is collected and updated each year before ERCOT begins the RTP study per the guidelines from the ERCOT Planning Guide and the RTP Scope and Process document. The following table shows the starting cases from the Steady-State Working Group (SSWG) used for the 2016 RTP.

Table 1.1: 2016 RTP starting cases

RTP Case	Steady-State Working Group (SSWG) Case	SSWG Update
2018 Summer Peak	15SSWG_2018_SUM1_U1_Final_10122015.raw	October 12 2015
2019 Summer Peak	15SSWG_2019_SUM1_U1_Final_10122015.raw	October 12 2015
2021 Summer Peak	15SSWG_2021_SUM1_U1_Final_10122015.raw	October 12 2015
2022 Summer Peak	15SSWG_2022_SUM1_U1_Final_10122015.raw	October 12 2015
2019 Off-peak	15SSWG_2019_MIN_U1_Final_10122015.raw	October 12 2015

Each starting case was built per the SSWG Procedure Manual and represented the most updated system topology and demand forecast as provided by the TSPs. ERCOT's transmission system is divided into eight different weather zones to represent the different climate-related weather patterns observed in the ERCOT Region. These weather zones were grouped into study regions, as shown in Figure 1.1, to facilitate transmission planning. For all study years the analysis of the system was grouped into four study regions, defined by the following weather zones: 1. North and North Central; 2. West and Far West; 3. South and South Central; and 4. East and Coast.

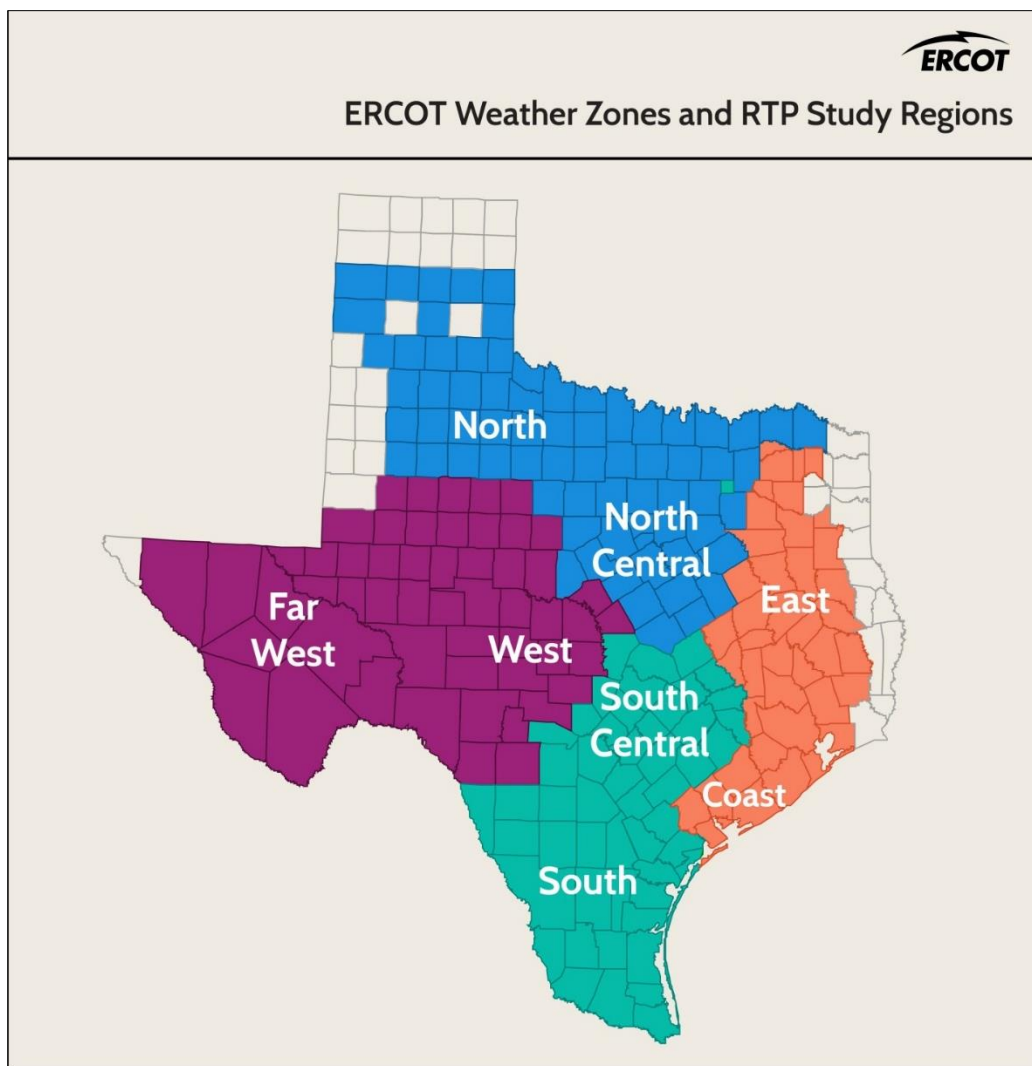


Figure 1.1: 2015 RTP Study Regions

1.3.1 Transmission Model

The October 2015 SSWG summer peak cases for 2018, 2019, 2021 and 2022, as well as the minimum load case for 2019 were used as the starting point models for the transmission topology. These cases contain all existing and planned facilities, including reactive power resources and control devices, except as noted below. Additionally, per Section 3.1.4.1 of the ERCOT Planning Guide, the starting base cases for the RTP are created by removing from the most recent SSWG cases all Tier 1, 2 and 3 projects that have not undergone RPG Project Review.

The list of Tier 1, 2 and 3 projects that have not yet received ERCOT review and endorsement and were removed from the base cases is included in Appendix B.

The SSWG start cases were modified based on the guidelines provided in the RTP Scope and Process document to meet the needs of this study. Following is the summary of these model updates.

Transmission and Generation Outages

The ERCOT Outage Scheduler was queried to extract a list of planned transmission and generation outages¹ from 2018 through 2022. During this timeframe, there were no planned outages available for modeling as of March 2016.

Base Case Updates and Corrections

Appendix C contains the corrections and updates that were applied to the base cases throughout the RTP analysis.

Protection Systems

A Special Protection System (SPS) refers to a protective relay system specially designed to detect abnormal system conditions and perform a pre-planned corrective action (other than the isolation of faulted elements) to provide acceptable system performance. The initial analysis of the base cases did not include the effects of any protection offered by SPSs. This test determines the feasibility of exit strategies for any existing and proposed SPSs. SPSs were added to the base cases as problems were identified if no feasible exit strategy could be found. The list of SPSs modeled during the analysis is included in Appendix D.

Base Case Updates for Recently Approved RPG Projects

Projects that received RPG acceptance after the RTP analysis had commenced were included in the cases if they were determined to have a material impact on the analysis. A list of these projects can be found in Appendix E.

1.3.2 Contingency Definitions and Performance Requirements

Contingency Definitions

The RTP includes an assessment of the ERCOT system for pre-contingency (NERC P0) performance and post-contingency (NERC Categories P1 through P7 and extreme events) steady-state performance.

Table 1 of NERC Standard TPL-001-4 provides the description of each contingency event (P0 through P7 and Extreme Event Contingencies). Each ERCOT TP, via SSWG, provides a database of P1, P2, P4, P5, P7 and Extreme Event (EE2 and EE3) contingencies. In addition to

¹ The generation outages queried in this step are in addition to those modeled based on Mothballed or retired status.

the TP-provided contingency definitions, ERCOT adds multiple element contingency definitions to model P3, P6 planning events and EE1 extreme events. Additionally, a “load throw over” file that models the switching of load from one bus to another following a contingency was used in the reliability analysis. This file is maintained by TPs and is provided in addition to the contingency definitions.

A list of all contingencies for years 2018, 2019, 2021 and 2022 and their corresponding power-flow base cases used in the 2016 RTP are posted on the ERCOT MIS Secure website.

Performance Requirements

All System Operating Limits (SOLs), including Stability SOLs, were respected in accordance with the latest ERCOT System Operating Limit Methodology. All transmission lines and transformers (excluding generator step-up transformers) 60-kV and above were monitored for thermal overloads to ensure that they do not exceed their pre-contingency or post-contingency ratings. Dynamic ratings were used for both the reliability and economic portions of the analysis. The summer peak case ratings were based on the 90th percentile temperature² as determined for the weather zone associated with the transmission element. The table below shows the 90th percentile temperatures used to derive the dynamic reliability rating.

Table 1.2: 90th percentile temperatures used in the dynamic reliability ratings calculation

Weather Zone	90 th -percentile temperature (°F)
Coast	102.4
East	106.2
Far West	110.4
North Central	108.4
North	109.0
South Central	105.5
South	104.0
West	107.3

For voltage analysis, all buses 100-kV and above were monitored to ensure that they do not exceed their pre-contingency and post-contingency limits. In addition to the voltage limits, the 2016 RTP also included an analysis of the post-contingency voltage deviations for all buses 100-kV and above. These criteria are defined in Planning Guide Section 4.1.1.4.

² Calculated based on the most recent 30-year historical data of annual peak temperatures for each weather zone.

Requirement 3.3.1 of TPL-001-4 requires automatic tripping of elements where relay loadability limits are exceeded. For this analysis, TP-provided relay loadability limits were used when available. In the absence of such ratings, a default limit of the higher of either 115% of the emergency rating or 150% of the normal rating was used. Additionally, cascading outage analysis was conducted if transmission elements were overloaded beyond their relay loadability limits following a contingency event where load shed is allowed per Table 1 of TPL-001-4.

A Panhandle export interface limit of 3611 MW in 2019 and 2022 was enforced on the 345-kV double circuit interface defined by the circuits connecting the Gray to Tesla, Tule Canyon to Tesla, Cottonwood to Edith Clarke and Cottonwood to Dermott substations while conducting economic analysis. This limit was included in order to represent the stability limit for exporting power from the Panhandle region based on the location and characteristics of the 5271 MW of wind generation installed in the panhandle region³.

1.3.3 Generation

Generation in the 2016 RTP reliability cases was modeled as per the guidelines given in the RTP scope and process document. The initial generation dispatch information of all existing conventional generation (including natural gas, coal and nuclear) was based on the SSWG start cases. However, these generators were re-dispatched to relieve transmission overloads. Wind, solar and hydro units were dispatched according to the guidelines specified in the RTP scope and process document. Future generation units which meet Planning Guide Section 6.9 requirements were added to the start cases and dispatched according to their resource type. A list of future generation included in the RTP start cases is attached in Appendix F.

Wind, Solar and Hydro in economic analysis

In the economic analysis, 8760-hour unit output profiles were used to model the wind, solar and hydro generators' dispatch. ERCOT performed a weather-year analysis using twelve different sets of load forecasts each representing a weather year from 2002-2013. Based on this analysis it was determined that the year 2006 was best-suited to be the representative weather year for the 8760-hour profiles in the economic analysis. Based on the above analysis, vendor-provided wind and solar profiles for year 2006 were used to model wind and solar dispatch in the economic analysis. Hydro dispatch was also based on historical hydro output levels from the year 2006.

Mothballed Generation

³ This limit is based on an update at the September Regional Planning Group Meeting (http://www.ercot.com/content/wcm/key_documents_lists/77742/Panhandle_Interface_Limit-Update_RPG_09202016.pptx)

In accordance with the requirements from the NERC TPL-001-4 standard and the 2016 RTP Scope and Process document, mothballed and seasonally mothballed generation was modeled as out of service when not available for the period under study.

DC Ties

DC tie flows were modeled to match prevailing historical flows during summer peak hours in the reliability analysis. The prevailing historical flows during summer peak hours were full import for the North and East DC ties and full export for the Eagle Pass, Laredo and Railroad DC ties. In economic analysis, profiles to model DC tie flows were created based on historic patterns.

Switchable Generation

Switchable Generation Resource parameters used in the RTP cases were updated to appropriately reflect the amount of switchable generation available to ERCOT for the study cases per ERCOT Protocol Section 16.5.4, upon receipt of a written notice.

Firm Transfers

The ERCOT market does not have firm transfers and none were modeled in this study.

Natural Gas Price

Appendix G contains the natural gas price assumption used in the economic analysis.

1.3.4 Demand Forecast

The 2016 RTP utilized two demand forecast sources for the summer peak reliability portion of the study. The first was the bus-level load forecast derived from the Annual Load Data Request (ALDR) and implemented in the SSWG base cases by the TPs. This load forecast included the load represented by the TPs and self-served load of customers and was included in the SSWG summer peak start cases. The other demand forecast source was the ERCOT-developed 90th percentile weather zone load forecast. Tables 1.3 and 1.4 show the two sets of load forecasts considered in the 2016 RTP.

Table 1.3: 2016 ERCOT 90th percentile summer peak weather zone load forecast (MW)⁴

Year	Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non Coincidental Peak Total
2018	21,168	2,715	3,117	1,554	27,754	12,615	6,199	2,178	77,300
2019	21,994	2,740	3,207	1,556	28,016	12,659	6,298	2,247	78,717
2021	22,313	2,794	3,393	1,563	28,468	12,731	6,482	2,391	80,135
2022	22,476	2,822	3,489	1,565	28,694	12,770	6,579	2,465	80,860

Table 1.4: 2016 SSWG summer peak weather zone load forecast (MW)⁵

Year	Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non Coincidental Peak Total
2018	27,156	2,930	3,521	1,764	25,473	13,276	6,518	2,349	82,986
2019	27,464	2,967	3,672	1,799	25,829	13,595	6,629	2,386	84,339
2021	27,963	3,011	3,925	1,852	26,398	14,208	6,847	2,468	86,672
2022	28,178	3,030	4,043	1,875	26,712	14,478	6,972	2,505	87,794

The 90th percentile ERCOT load forecast for North Central weather zones was greater than the corresponding SSWG weather zone forecast. This difference is highlighted in the shaded cells in Table 1.4. ERCOT used the higher of the ERCOT or SSWG load forecast for each weather zone as specified in the 2016 RTP Scope document. Using the highest non-coincident load forecast for each weather zone resulted in a simultaneous system demand greater than the amount of generation available to serve the load plus reserves for all of the summer peak base cases. ERCOT does not expect that all zones will reach their non-coincident peak loads at the same time so this system-wide load value is assumed to be higher than what would occur in real-time operations.

Table 1.5: 2016 RTP summer peak weather zone load forecast (MW)⁶

Year	Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non-Coincidental Peak
2018	27,156	2,930	3,521	1,764	27,754	13,276	6,518	2,349	85,268
2019	27,464	2,967	3,672	1,799	28,016	13,595	6,629	2,386	86,528
2021	27,963	3,011	3,925	1,852	28,468	14,208	6,847	2,468	88,742
2022	28,178	3,030	4,043	1,875	28,694	14,478	6,972	2,505	89,775

⁴ This load forecast includes losses but does not include self-served load.

⁵ These numbers include self-served loads but do not include losses.

⁶ This the final weather zone load modeled in RTP cases. These include self-served load MWs and do not include losses.

The non-conforming flag from ERCOT's operational models was used to identify loads that do not follow typical weather-related variability. Each bus in the ERCOT System was assigned an appropriate weather zone profile based on its physical location. The North Central weather zone load from Table 1.5 was redistributed to the individual load-serving bus level for all conforming loads in the North Central weather zone using distribution factors from the SSWG cases. For the conforming loads in the weather zones outside the region being studied the demand was scaled down to achieve a balance of system-wide load plus responsive reserves and generation.

In addition to the summer peak conditions, the 2016 RTP included an assessment of the off-peak conditions for 2018. The 2018 SSWG minimum load case was used to represent the off-peak conditions (as noted in Table 1.1). Table 1.6 shows the load forecast in MWs for the 2018 off-peak case.

Table 1.6: 2016 RTP weather zone load forecast for 2018 Off-peak conditions (MW)

Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non Coincidental
13,019	1,055	1,893	623	7,465	4,215	3,087	1,005	32,363

For the economic analysis, the ERCOT developed 50th-percentile 8760-hour weather zone load forecast was utilized for the years 2019 and 2022 based on year 2006 weather assumptions. Additionally, a separate load-specific demand profile was used to model the non-conforming loads. The hourly forecast and demand profile can be found in Appendix H. Table 1.7 shows the peak load (in megawatts) seen in the 50th percentile load forecast. These numbers include self-serve and non-conforming loads.

Table 1.7: Peak load from 50th percentile load forecast (MW)

Year	Coast	East	Far West	North	North Central	South Central	South	West
2018	22,700	2,304	2,887	1,552	26,056	11,358	6,609	1,994
2021	23,266	2,323	3,240	1,523	27,081	11,601	7,151	2,053

1.3.5 Transmission Planning Criteria

The 2016 RTP reliability analysis was conducted to evaluate the performance requirements as established in Table 1 of NERC TPL-001-4. In addition to the TPL requirements the reliability analysis also followed the ERCOT transmission planning criteria as documented in the section 4.1.1.2 of ERCOT Planning Guides.

1.4 Regional Transmission Plan Process

The RTP study process is described in Figure 1.2. Initial start cases to be used in the reliability analysis were prepared in the case-conditioning stage. Following case conditioning, reliability analysis was conducted on the base case to determine the transmission upgrades and additions needed to meet ERCOT and NERC reliability requirements. In addition to the base case, the 2016 RTP also included sensitivity cases, short circuit analysis, cascade analysis and multiple element outage analysis as required by the NERC Standard TPL-001-4. Economic analysis was then conducted to identify transmission projects that allow reliability criteria to be met at a lower total cost.

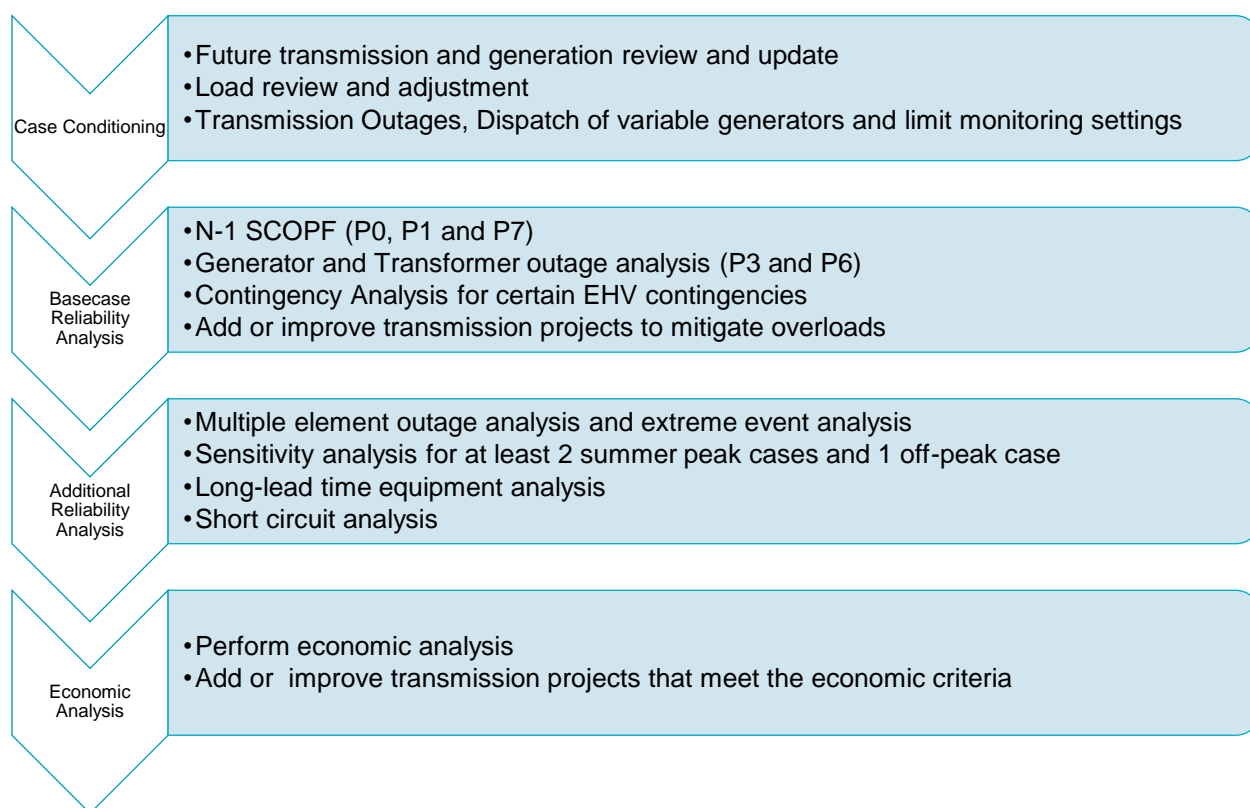


Figure 1.2: 2016 Regional Transmission Plan Process

ERCOT utilized the following software tools while performing the 2016 RTP:

- PSS/E version 33 was used to develop the conditioned cases and the AC reliability cases
- PowerWorld versions 17 and 18 with Security Constrained Optimal Power Flow (SCOPF) and its SIMAUTO functionality were used to perform AC SCOPF analysis and to run generator and transformer outage analysis.
- TARA version 800 was used to screen critical contingencies while evaluating P3 (Generator outage) and P6-2 (Transformer outage) planning events.

- POM application suite including Physical and Operations Margin (POM) – Optimal Mitigation Measures (OPM) and Predicting Cascading Modes (PCM) were used to perform load shed analysis, multiple element outage analysis and cascade analysis.
- UPLAN version 9.04 was used to perform security-constrained economic analysis.

2. Reliability Analysis

Reliability analysis in the 2016 RTP focused on the steady-state portion of the NERC TPL standards and the ERCOT Planning Guide. The purpose of reliability analysis is to identify potential criteria violations and Corrective Action Plans that may be used to resolve them. Per the ERCOT Planning Guide, reliability projects are those system improvements (projects) that are needed to meet NERC Reliability Standards or ERCOT planning criteria which could not otherwise be met by any re-dispatch of existing or planned generation.

The RTP analysis included Security Constrained Optimal Power Flow (SCOPF) to identify unresolvable constraints. Loading and voltage levels at BES elements were monitored for all contingency events, including Extreme Events. ERCOT developed Corrective Action Plans in collaboration with TPs to mitigate criteria violations following a contingency where non-consequential load shed was not allowed. These plans were created in accordance with the NERC and ERCOT reliability criteria in collaboration with the TPs. The above analysis started with the final year case (2022) and concluded with the analysis of the initial year case (2018).

A list of potential projects along with the corresponding limiting elements and contingencies was communicated to the appropriate TP and/or TO. TPs and TOs reviewed the initial list of reliability-driven projects for their technical feasibility and estimated year of completion (taking into account necessary lead times). In some cases, the TOs also provided project alternatives. Intermediate and final results were posted on the ERCOT website and presented to stakeholders at regularly scheduled RPG meetings in order to solicit comments and suggestions.

Once feedback was received, the refined set of improvements was implemented in the base cases. Since many of the upgrades were developed independent of other upgrades, it was necessary to check for redundancies, i.e., any project that could be removed from the project set without creating a resulting system deficiency. The remaining projects formed the final set of the reliability-driven projects. An AC contingency analysis was performed for each of the final reliability cases in order to demonstrate that the reliability criteria were met. The 2016 RTP

transmission system upgrades will need to be further reviewed by the appropriate TPs to determine the need for an earlier in-service year.

In addition to the above analysis, per the Planning Guide Section 3.1.1.2 (3), the 2016 RTP analysis also included development of a list of transmission facilities that are loaded above 95% of their applicable ratings under normal and contingency events (loss of single generating unit, transmission circuit, transformer or common tower outage). This list is attached to the report as Appendix I.

Besides the SCOPF and contingency analyses, the 2016 RTP also included the analyses described in the following sections.

2.1 Multiple Element Outage Analysis

ERCOT planners investigated the need for a transmission improvement project if following a contingency where non-consequential load shed was acceptable, the total load shed required to reduce the loading on elements below their 100% emergency rating was greater than 300 MW. For an N-1-1 event, if the total load shed required after the first contingency, but prior to the second contingency, to prevent a cascading event was greater than 100 MW, ERCOT investigated the need for a transmission improvement project. The detailed scope, process, criteria and study methodology of the multiple element outage analysis are documented in a separate report found in Appendix J.

All contingency events where non-consequential load shed is allowed per TPL-001-4 Table 1 were screened to detect the potential for a cascade event. This screening was conducted by a simulation of events that could result in tripping of system elements based on the following criteria:

- transmission facilities (100-kV and above) overloaded beyond their relay loadability limits (defined in section 1.3.2)
- generator buses where voltage on the low or high side of the Generator Step Up (GSU) transformer is less than known or assumed minimum generator under-voltage trip limits
- generator buses where voltage on the low or high side of the GSU transformer exceeds known or assumed maximum generator over-voltage trip limits
- buses with known Under Voltage Load Shed (UVLS) protection schemes where voltages go below the under-voltage triggering level

Following the simulation, an event was categorized as a potential cascade condition if the following criteria were met:

- The total load loss as a result of system cascading was greater than 6% of the total initial system load⁷
- The power flow did not converge - which may be a result of a potential voltage collapse condition, subject to additional confirmation

The events identified as potential cascade conditions were studied further in co-ordination with associated TPs.

2.2 Sensitivity Analysis

Per the 2016 RTP Scope document, ERCOT selected the summer peak conditions of 2018 and 2021 and off-peak conditions of 2019 for sensitivity analyses as required by Requirement 2.1.4 of the NERC TPL-001-4 standard. The 2016 RTP prepared the sensitivity cases by varying the following set of input assumptions:

- Turn all wind and hydro units in the study region offline and unavailable in the 2018 and 2021 summer peak cases, and
- High-wind, low-load conditions for the off peak case

The sensitivity analyses was performed with all reliability solutions identified from the base case analysis to evaluate the effectiveness and robustness of the base case solutions under the stressed system conditions.

2.3 Short-Circuit Analysis

Per Requirement 2.3 and 2.8 of TPL-001-4, ERCOT conducted a short-circuit analysis based on simulation of three-phase to ground fault and single-line to ground fault conditions. The study was performed using the 2019 and 2021 summer peak reliability base cases with all reliability projects identified in the 2016 RTP. Appendix A contains the assumptions used in performing the short circuit analysis.

The results of short-circuit analysis included the magnitude of short-circuit current and source impedance associated with each fault; these results were communicated to NERC Registered TOs and GOs. TOs and GOs completed a review of study results, acknowledged the findings and provided a list of over-dutied circuit breakers and Corrective Action Plans. In addition, TOs and

⁷ Based on Section 3.7 of the SOL Methodology for Operating and Planning Horizon

GOs also confirmed the continued validity and implementation status of the facilities identified in the previous RTP.

2.4 Additional Analysis

In addition to the above analysis, the 2016 RTP included an analysis of the following conditions:

- Per Requirement 2.1.5 of TPL-001-4, the impact of the possible unavailability of major transmission equipment with a lead-time of one year or more was studied. The studies were performed with an initial condition of the identified long lead-time equipment modeled as out of service, followed by P0, P1 and P2 contingency events. The list of long lead-time equipment was developed based on TO feedback. The results of such analysis were communicated to the appropriate TPs.
- A scenario in which all Dallas-Fort Worth area generation without Selective Catalytic Reduction (SCR) equipment were removed from service.
- An environmental regulation scenario designed to reflect the potential impact of the Regional Haze Federal Implementation Plan. This scenario was studied using the 2021 RTP secure reliability cases along with certain generation retirements and additions. More detail on this scenario is provided in Section 4.2.5.

3. Economic Analysis

ERCOT Planning conducted economic analysis to identify system improvements that would allow ERCOT to meet NERC Reliability Standards and ERCOT Planning Criteria at a lower total cost (total system variable production cost plus carrying-cost of new projects) than the continued dispatch of higher cost generation.

To identify such economically driven projects, ERCOT prepared a production cost model for years 2019 and 2022. This model was based on the ERCOT-developed 50th percentile load forecast, existing and planned generation (meeting the requirements of Planning Guide Section 6.9), and the conditioned topology with the newly identified reliability projects. Following the production cost simulation, a list of all congested elements and binding contingencies was produced using UPLAN.

According to the economic planning criteria described in the ERCOT Protocol Section 3.11.2 (5), ERCOT recommends economic projects if the annual production cost savings exceed the first-year annual revenue requirement for the project. Based on the recent review of current market

conditions, the first-year annual revenue requirement for a project is assumed to be 15% of the total project cost⁸.

Improvements were evaluated in an iterative process, focusing on the most heavily congested areas in the system first. Due to the sequential nature of evaluation, projects developed later in the process could affect the economics of those justified earlier. ERCOT conducted a back-out analysis to ensure that all the economic benefits of the economically driven projects were sufficient following the inclusion of all other projects.

After the completion of the back-out analysis, projects that did not pass the economic criterion were removed from the model. Additionally, emissions from all Dallas-Fort Worth area generation units that do not have SCRs were monitored in the course of the economic analysis. The total NOx emissions from Dallas-Fort Worth area generation units that do not have SCRs did not exceed their environmental restrictions.

The final topology for each year, containing all of the identified reliability and economically driven projects, will serve as the base case for RPG project reviews performed by ERCOT over the next year.

4. Transmission Projects and Mitigation Plans

4.1 Reliability-Driven Projects

Following contingencies where non-consequential load shed is not allowed, Corrective Action Plans were developed per NERC and ERCOT reliability criteria in collaboration with the TPs. These plans often included upgrades or additions of new transmission facilities. The RTP reliability assessment identified transmission system upgrades for the years 2018, 2019, 2021 and 2022 under summer peak conditions and 2019 under off-peak conditions. Figure 4.1, Figure 4.2, and Figure 4.3 summarize the type of projects, their geographic locations and voltage levels. Figure 4.3 also summarizes a list of projects that were newly identified in the 2016 RTP that were not identified in previous ERCOT planning studies. Appendix T shows a geographic representation of the base case reliability projects identified in this study.

For reliability concerns identified for 2018 summer peak conditions, if a necessary transmission project was not feasible prior to the summer of 2018, ERCOT identified potential Constraint Management Plans (CMPs) in collaboration with TPs. These CMPs will be used as placeholder

⁸ http://www.ercot.com/content/wcm/key_documents_lists/77724/2016_ERCOT_Economic_Studies_Financial_Assumptions.pdf

mitigating actions until they are reviewed in the operations planning horizon by ERCOT and TOs. The list and details about the CMPs identified in the 2016 RTP can be found in Appendix K.

The list and details of the reliability-driven projects identified in the 2016 RTP can be found in Appendices L and M. The majority of planned improvements identified in the 2016 RTP are 138-kV and 69-kV upgrades. Of the few projects that involved 345-kV equipment, most consisted of either adding a new 345/138-kV transformer or upgrading an existing 345/138-kV transformer. All of these 345-kV projects were identified in previous ERCOT studies. The following table shows the breakdown of transmission upgrades.

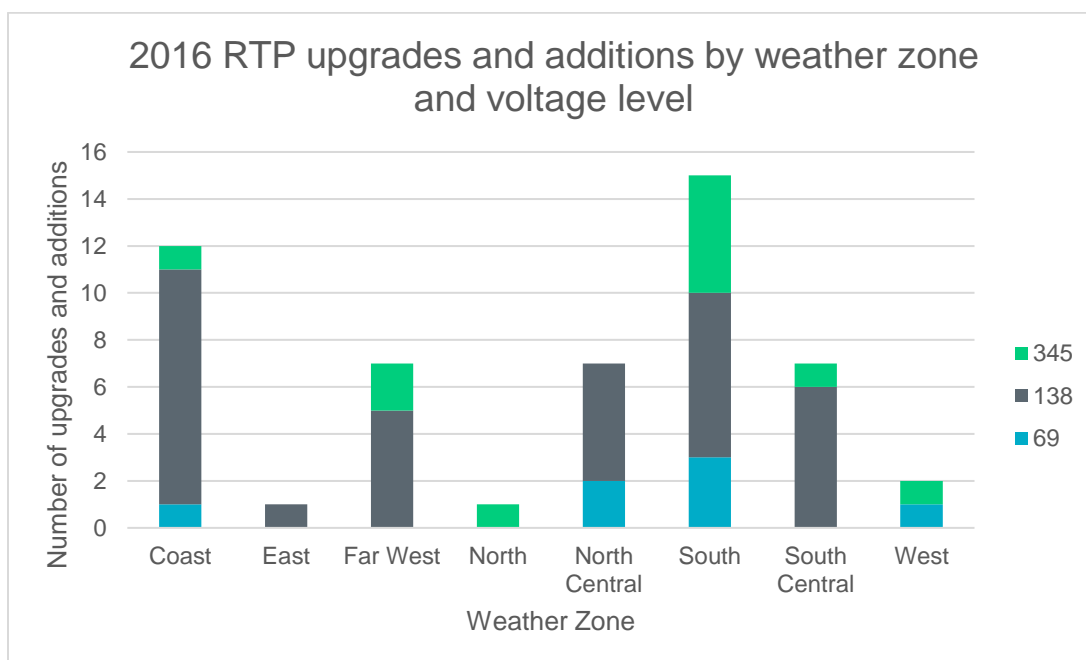


Figure 4.1: 2016 RTP upgrades and additions by weather zone and voltage level

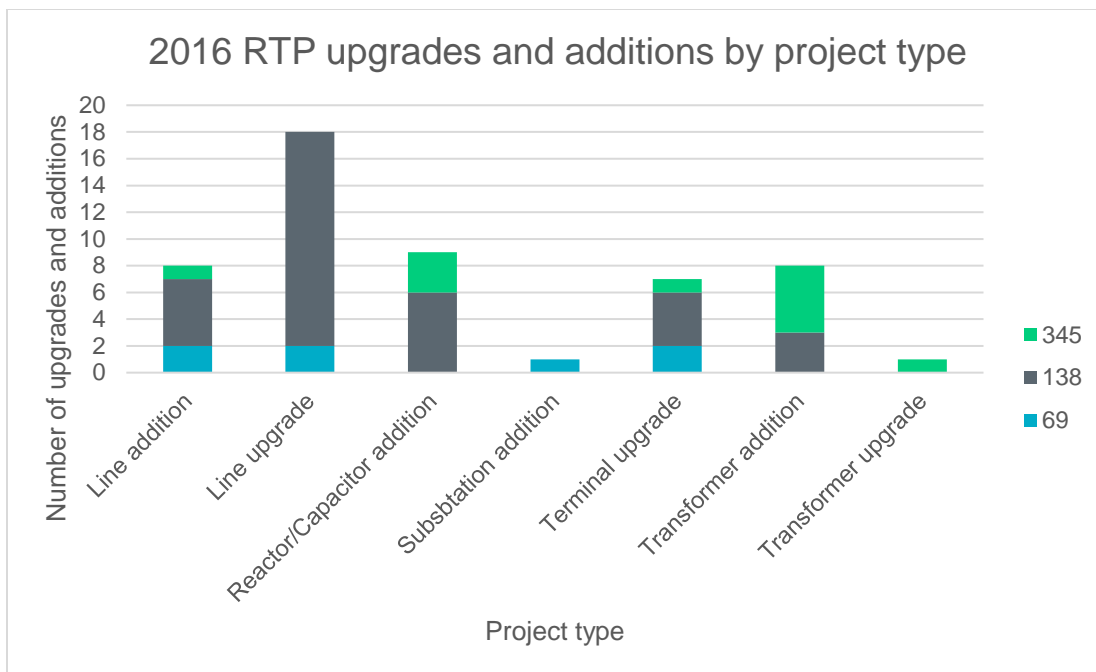


Figure 4.2: 2016 RTP upgrades and additions by project type

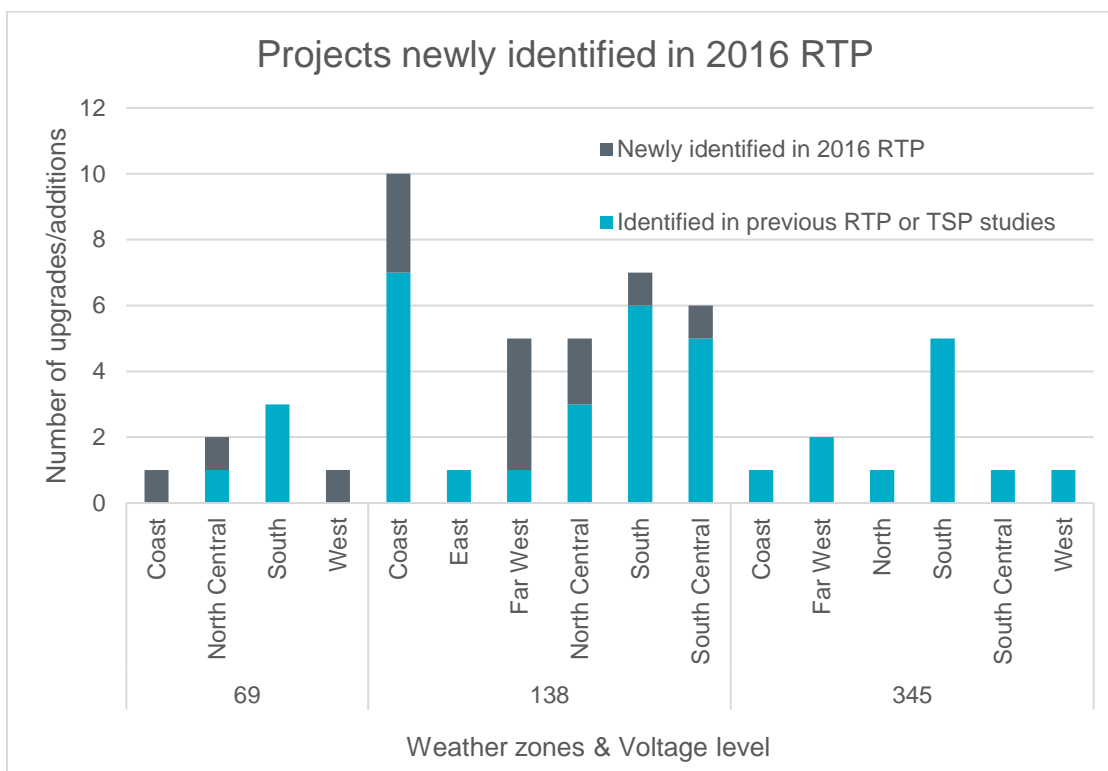


Figure 4.3: Projects newly identified in 2016 RTP

The 2016 Regional Transmission Plan continued need for the following reliability projects:

- New 345/138-kV transformer (third transformer) near the Zenith substation in Harris County
- Upgrade of existing 345/138-kV transformers at the San Miguel substation in Atascosa County
- A new 144-MVAr reactor at the Kiamichi 345-kV substation in Pittsburg County in Oklahoma
- A minimum of two 50-MVAr reactors at the Bakersfield 345-kV substation in Pecos County
- New 345/138-kV transformer at Salado in Bell County
- Two new 345/138-kV transformers at Stewart Rd and two new 345-kV transmission lines in Hidalgo and Starr Counties
- New 345/138-kV transformer (second transformer) at the Twin Buttes substation in Tom Green County
- New 345/138-kV transformer at Hicks Switch substation in Tarrant County

4.2 Results of Other Reliability Studies

4.2.1 Sensitivity analysis

As indicated in Section 2.2, the impact of unavailability of wind and hydro generating units under summer peak conditions was evaluated in the 2018 and 2021 summer peak cases. The following table shows the amount wind and hydro generation unavailable for summer peak conditions in respective study regions.

Table 4.1: Wind and hydro generation unavailable in study case for 2018 and 2022 (MW)

Generation type	South-South Central	West-Far West	North-North Central
Wind	491	226	167
Hydro	228	92	111
Total	719	318	278

For the 2019 off-peak conditions, ERCOT also analyzed the system impact of the high-wind, low-load conditions. Table 4.2 shows the percent of total generation output dispatched by fuel type in the off-peak cases, and Table 4.3 compares the total loads assumed in the two off-peak cases.

Table 4.2: Percent of total generation output by fuel type in the off-peak case

Fuel Type	Percent of Total Output	
	2019 MIN Base Case	2019 HWLL Sensitivity Case
Coal	31.69%	23.93%
Combined Cycle	6.49%	0.01%
Natural Gas (non-CC)	5.06%	2.33%
Nuclear	14.65%	12.72%
PUN	19.08%	15.72%
Solar	0.00%	0.00%
Wind	22.17%	44.43%
Other	0.00%	0.86%

Table 4.3: Total Load Assumed in the off-peak cases

Weather Zone	Load (MW)	
	2019 MIN Base Case	2019 HWLL Sensitivity Case
ERCOT	34,539	37,610

The purpose of this portion of the study was to evaluate the effectiveness and robustness of the base case reliability projects under stressed system conditions. The sensitivity analysis identified the need for four additional upgrades, in addition to other mitigation actions such as voltage schedule changes, tap setting changes, generation re-dispatch or controlled load shed and generation curtailment.

A detailed list of system deficiencies and transmission improvements identified in the 2016 sensitivity analysis is provided in Appendix N.

4.2.2 Short-circuit analysis

As indicated in Section 2.3, ERCOT conducted the short circuit analysis for the 2019 and 2021 summer peak base cases with all reliability projects identified in the 2016 RTP. ERCOT worked with Transmission Owners (TOs) and Generation Owners (GOs) to review the fault duty information and to identify substations with over-dutied breakers along with Corrective Action Plans.

Table 4.5 provides a summary of the results of the short-circuit analysis. This table indicates that short-circuit currents tend to increase as additional transmission elements are added or upgraded over the years. Based on the review and comment provided by Transmission Owners (TOs) and Generation Owners (GOs), twenty-three buses were identified as having over-dutied breakers. The buses with over-dutied breakers and the resulting Corrective Action Plans can be found in Appendix O, which also contains the study cases and details of the results.

Table 4.4: Summary of Short Circuit Analysis

Magnitude of Fault Current	Number of buses (3-phase to ground fault)		Number of buses (single-line to ground fault)	
	2019	2021	2019	2021
Below 40 kA	3882	3915	4117	4152
40 kA ~ 60 kA	420	423	199	199
More than 60 kA	22	21	8	8

4.2.3 Multiple element outage analysis

A multiple-element outage analysis was conducted for contingencies where non-consequential load shed was allowed as an acceptable Corrective Action Plan. This analysis consisted of 1) load shed analysis, which identified mitigation measures (such as transformer tap setting changes, switching actions, generator re-dispatch and load shed) to resolve any criteria violations resulting from such contingencies; and 2) cascade analysis, which identified any contingencies that could result in potential cascade events.

Contingency events which required more than 300 MW of load shed or resulted in a power flow convergence failure were identified as critical contingencies and studied in detail in collaboration with associated TSPs. The criteria used to determine potential Cascade events are defined in the RTP Scope and Process document.

No new planning system operating limits were identified as part of this analysis. Based on the Multiple Element Contingency Study performed by ERCOT and the feedback provided by the TPs it was determined that the criteria violations resulting from all the events could be effectively addressed by mitigation plans which included, but were not limited to, voltage schedule changes, tap setting changes, generation re-dispatch or controlled load shed and generation curtailment. Initially, some Extreme Events were noted causing power flow convergence issues. However, further investigation performed by ERCOT and affected TPs indicated no events resulting in system-wide cascading conditions. The results of the multiple element outage analysis are

documented in Appendix J. This appendix includes the list of critical contingencies identified as a result of this analysis and Corrective Action Plans or recommendations necessary to mitigate the impact of these contingencies.

4.2.4 Long lead time equipment analysis

Upon ERCOT's request the Transmission Owners provided a list of long lead-time equipment based on their spare equipment strategy. All TSP-provided, BES, long lead-time equipment outages were studied to determine the impact of unavailability of such equipment for an extended period of time. This analysis was conducted on 2018, 2019, 2021 and 2022 summer peak conditions, along with 2019 off-peak conditions. Overall, twenty-two 345/138-kV transformers and eleven 345-kV reactors were identified as long lead-time equipment. Criteria violations resulting from P0, P1 and P2 contingencies were shared with the respective TPs. The list of long lead-time equipment and criteria violations are attached in Appendix P.

4.2.5 Analysis of environmental regulation scenario

Several U.S. Environmental Protection Agency (EPA) regulations have been proposed or finalized which could have significant impacts on future electricity production in ERCOT. One of these regulations is the Regional Haze program, which requires specific units to retrofit or upgrade scrubbers to reduce sulfur dioxide (SO₂) emissions. Under this regulation, as shown in Figure 4.4, approximately 3,000 MW of coal-fired capacity is required to be retrofitted with new scrubbers by 2021, and 5,500 MW of coal-fired capacity is required to have their existing scrubbers upgraded by 2019. Even if this specific program, which is undergoing legal review, is not implemented, it can serve in this study as a surrogate for studying the potential impacts of any future regulatory change that would result in the retirement of a significant amount of legacy coal generation.

Given current market conditions, it is reasonable to assume that a significant number of the coal-fired power plants affected by the Regional Haze program would be retired rather than upgraded. This is especially true of the resource owners anticipate additional impacts under other regulations such as Clean Power Plan (CPP) and 2010 SO₂ US National Ambient Air Quality Standards (NAAQS). If these plants are expected to suspend operations, the owners of the generation company must notify ERCOT at least 90 days before retiring or suspending operations of the generation resources. Earlier notification is unlikely.

Multiple retirements occurring within a short timeframe can result in localized grid reliability issues. In the ERCOT region, it takes five years for a new major transmission project to be planned,

routed, approved and constructed. As such, in order for major transmission constraints to be addressed in a timely fashion, the need must be assessed at least five years in advance.

With these concerns in mind, ERCOT conducted a transmission analysis to evaluate the potential impacts of the loss of the generation units affected by the Regional Haze ruling. The transmission base case was developed using the 2021 reliability secure case and applying the following assumptions:

- 1) Generation requiring new scrubbers (Big Brown 1 and 2, Monticello 1 and 2, Coletto Creek) retire by the summer of 2021
- 2) Generation requiring upgrades of existing scrubbers and which are located in counties proposed for SO₂ non-attainment (Martin Lake 1, 2, and 3, and Monticello 3) retire by the summer of 2021

To balance power supply and demand, ERCOT added new generation based on the review of the ERCOT Generation Interconnection Status (GIS) report that met the following criteria:

- 1) New generation that has met all the Planning Guide Section 6.9 requirements but were not included in the RTP start cases
- 2) New thermal (with air permit) and solar units with a signed interconnection agreement (IA) that do not meet Planning Guide 6.9 requirements.

Table 4.5 lists the total MW capacity from the added generation by weather zone. Appendix M provides more detail on these generation resources.

Table 4.5: New generation assumed for the scenario analysis

MW Capacity for Grid	Coast	East	Far West	North	North Central	South	South Central	West
Gas	1073	1217	-	-	928	730	362	1598
Solar*	-	-	834	201	-	-	-	100
Wind*	-	-	-	1465	-	250	-	-
Total	1073	1217	834	1666	928	980	362	1698

* Based on these MW capacities, the maximum dispatch levels were determined consistent with the 2016 RTP methodology.

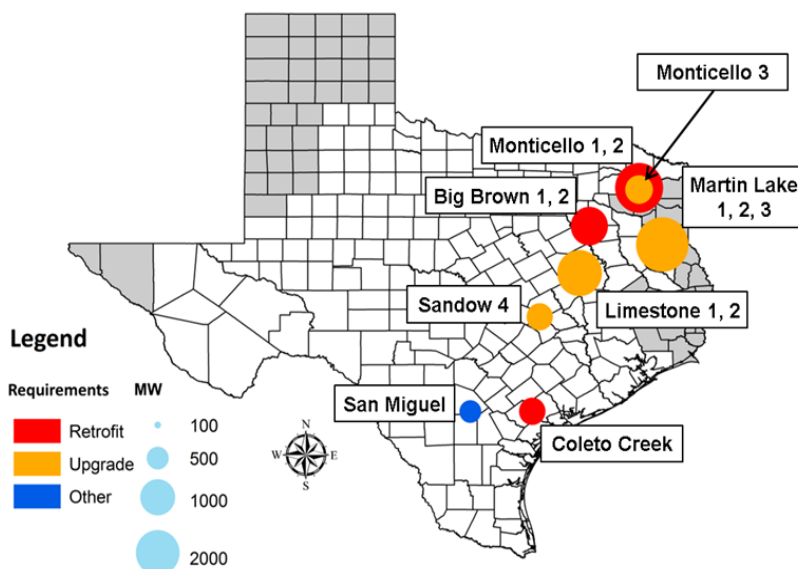


Figure 4.4: Units requiring to retrofit scrubbers or upgrade of existing scrubbers

As described in Appendix M, the results indicate the retirement of the resources would result in thermal overloads on transmission system serving the Dallas-Fort Worth area. This study identifies a list of transmission projects that would likely be required to ensure transmission system reliability criteria are met even if a moderate amount of new resources were to be displaced around the region. In summary, approximately 178 circuit-miles of 345-kV lines, 23 circuit-miles of 138-kV lines, and 15 circuit-miles of 69-kV lines need to be upgraded to address the thermal issues identified in the analysis.

As noted, the Regional Haze program is undergoing legal review. As this and/or other regulations are implemented, resource owners will make decisions about their generation units that could result in grid reliability issues. As new information becomes available, ERCOT will continue to analyze the impacts of regulatory developments that may affect the ability to provide reliable electricity to consumers in Texas.

4.3 Economic Projects

Economic analysis was conducted using production-cost simulation for years 2019 and 2022. The input information used in the start and final cases for economic analysis is provided as Appendix H. When applicable, pre-defined SPS's were modeled in the case to relieve congested portions of the network. The list of SPS's modeled in the economic analysis section is documented in Appendix E. After SPS modeling, when congestion persisted, transmission upgrades and

additions were tested by comparing the production-cost simulation results for models with and without potential projects. The annual constraint information after SPS modeling is documented in a spreadsheet attached to the report as Appendix Q.

The analysis indicated substantial congestion on the Panhandle interface. Several options to upgrade the transmission system in and around panhandle were tested. Given the current amount of wind generation interconnected in Panhandle, two 175 MVA synchronous condensers at Windmill substation were seen to provide enough benefit to meet the economic criteria. However, ERCOT notes that panhandle region is dynamic in nature and recommends addition of only one 175 MVA synchronous condenser instead of the two identified as meeting the criteria. Future upgrade paths for the Panhandle region should be studied as an independent project and at a minimum should include a detailed dynamic assessment.

In addition to the panhandle area project, thirteen other projects were evaluated. The list and details of the economic projects tested in the 2016 RTP can be found in Appendix R.

In addition to the evaluation of economic projects, the 2016 RTP, per the ERCOT Protocol Section 3.10.8.4 (3), identified additional Transmission Elements that have a high probability of providing significant added economic efficiency to the ERCOT market through the use of dynamic ratings. Dynamic ratings for the identified elements (listed in Appendix S) have been requested from the associated TPs.

5. Appendices

Appendix	Description	Document	Access
A	RTP Scope and Process Document	Appendix_A_2016RTP_Scope_Process_v1.3_clean.pdf	Public
B	Base case updates for projects removed from the SSWG basecases	Appendix_B-F_2016RTP_CaseInformationUpdates.xlsx (File is available on ERCOT MIS Secure Area)	MIS Secure
C	Base Case updates and Corrections		
D	Special protection schemes employed in RTP		
E	Base case updates for addition of recently approved RPG projects		
F	List of generators added and retired from the SSWG basecase		
G	Natural gas fuel cost forecast	Appendix G - Natural gas fuel cost forecast.xlsx	Public
H	Economic analysis input information	Appendix_H_2016_RTP_Econ_Input_Information.zip (File is available on ERCOT MIS Secure Area)	MIS Secure
I	Facilities loaded over 95%	Appendix_I_2016_RTP_95%_Overload_PG31123.xlsx (File is available on ERCOT MIS Secure Area)	MIS Secure
J	Multiple element outage analysis	Appendix_J_2016_RTP_MultipleElementContingencyStudyReport.docx (File is ERCOT-Confidential)	MIS Certified (CEII)
K	Constraint Management Plans	Appendix_K_2016RTP_ConstraintsManagementPlans.xlsx (File is available on ERCOT MIS Secure Area)	MIS Secure
L	Reliability Driven Projects	Appendix_L_2016RTP_Reliability_Projects_public.xlsx	MIS Secure
M	Environmental Regulation Scenario	Appendix_M_2016RTP_EnvironmentalRegulationScenario_public.xlsx	Public
N	Sensitivity Analysis Results	Appendix_N_2016RTP_Sensitivity_Projects.xlsx (File is available on ERCOT MIS Secure Area)	MIS Secure
O	Short Circuit Analysis	Appendix_O_2016RTP_ShortCircuitStudyCases_DetailedResult.docx (File is available on ERCOT MIS Secure Area)	MIS Secure
P	Long lead time equipment analysis	Appendix_P_2016RTP_LongLeadTimeEquipment.docx (File is ERCOT-Confidential)	ERCOT Confidential

Q	Annual Constraints from economic analysis	Appendix_Q_2016_RTP_Econ_AnnualConstraints.zip (File is available on ERCOT MIS Secure Area)	MIS Secure
R	Economic projects evaluated	Appendix_R_2016RTP_Economic_Projects_public.xlsx	Public
S	Transmission elements proposed to be dynamically rated	(File is available on ERCOT MIS Secure Area)	MIS Secure
T	Project locations	Appendix_T_2016RTP_Project_Locations.docx	Public