ERCOT System Planning

2014 Regional Transmission Plan Report

Executive Summary

The 2014 Regional Transmission Plan (RTP) is the 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 region-wide reliability and economic transmission needs for years 2015 through 2020. This report documents the results of the assessment in part to comply with the requirements from NERC Reliability Standards, ERCOT Protocol Section 3.11 and ERCOT Planning Guide Sections 3 and 4.

In addition to the N-1 and G-1+N-1 analysis conducted in the prior year's RTP, the 2014 RTP also performed analysis of X-1+N-1 post contingency conditions per ERCOT Planning Guide Section 4.1.1.2. Furthermore, the 2014 RTP studied one additional year (year six – 2020) whereas prior RTPs only analyzed up to year five of the planning horizon. Planned improvements identified in the 2014 RTP include several 69-kV, 138-kV and 345-kV line upgrades, and mutiple 138/69-kV and 345/138-kV autotransformer upgrades.

The 2014 Regional Transmission Plan identified the following new noteworthy reliability projects:

- New 345/138-kV autotransformers added at Fisher Road Switch, Hicks Switch, Jewett, Jordan and Rothwood substations.
- Upgraded 345/138-kV autotransformers at Odessa and Renner substations.

These projects were identified in addition to upgrades identified in the 2013 RTP. The 2014 RTP retained the following noteworthy reliability projects from the 2013 RTP:

- Upgrade of Trinidad – Watermill, Lake Creek – Tradinghouse – Sam Switch and Big Brown – Navarro 345-kV transmission lines.
- Addition of 345/138-kV autotransformers at Fowlerton, Lobo, South McAllen and Twin Buttes substations.

Years 2017 and 2020 were evaluated for transmission projects that may result in production cost savings in the economic analysis phase of the 2014 RTP. Five projects were evaluated using the economic criteria, and only one project, namely, the Eagle Mountain – Rosen Heights 138-kV double circuit line upgrade, showed enough savings to justify an in-service date of 2020.

The project completion years stated in this 2014 RTP Report were chosen to address reliability and economic needs in a timely manner. The TOs will attempt 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 designated to complete these projects 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. Assumptions and Process

This report documents the 2014 Regional Transmission Plan (RTP) performed by ERCOT System Planning in accordance with the ERCOT Planning Guide Section 3. 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 2014 RTP analyzed the reliability and efficiency of the ERCOT transmission system for the years 2015, 2017, 2019 and 2020.

1.1 Stakeholder Involvement

The input assumptions and technical studies being conducted as a part of the 2014 RTP were described in the RTP Scope and Process document and presented to the stakeholder community at the Regional Planning Group (RPG) meetings. The RPG is responsible for reviewing and providing comments on new transmission projects in the ERCOT region. Per ERCOT Protocol section 3.11.3, participation in the RPG is required of all TSPs and is open to all Market Participants, consumers, other stakeholders and PUCT Staff. The RTP Scope and Process document can be found in Appendix A.

ERCOT worked with NERC registered Transmission Planners (TP)s, Transmission Owners (TO)s 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 2014 RTP study in the monthly RPG meetings held from February to May of 2014. Feedback and comments from the RPG were incorporated into the RTP Scope and Process document.

1.2 Assumptions

The RTP study is dependent upon data calculated and compiled by numerous parties both inside and outside of ERCOT. The required data includes: a forecast of system demand, generation supply and starting network topology. This data 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 used for the 2014 RTP.

Table 1.1: 2014 RTP starting cases

RTP Case	Steady State Working Group (SSWG) Case	SSWG Update
2015 Summer Peak	14DSB_2015_SUM1_TPIT_Final_03032014.raw	March 3 2014
2017 Summer Peak	14DSB_2017_SUM1_TPIT_Final_03032014.raw	March 3 2014
2019 Summer Peak	14DSB_2019_SUM1_TPIT_Final_03032014.raw	March 3 2014
2020 Summer Peak	14DSB_2020_SUM1_TPIT_Final_03032014.raw	March 3 2014
2017 Minimum Load	14DSB_2017_SPG1MIN_TPIT_Final_03032014.raw	March 3 2014

Each start case is built per the SSWG Procedure Manual and represents the most updated system topology and demand forecast as provided by the TSPs. The SSWG start cases are modified based on the guidelines provided in the RTP Scope and Process document to meet the needs of this study. Following is a summary of such model updates.

1.2.1 Study Regions

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 weather zones: 1. North and North Central; 2. West and Far West; 3. South and South Central; and 4. East and Coast.

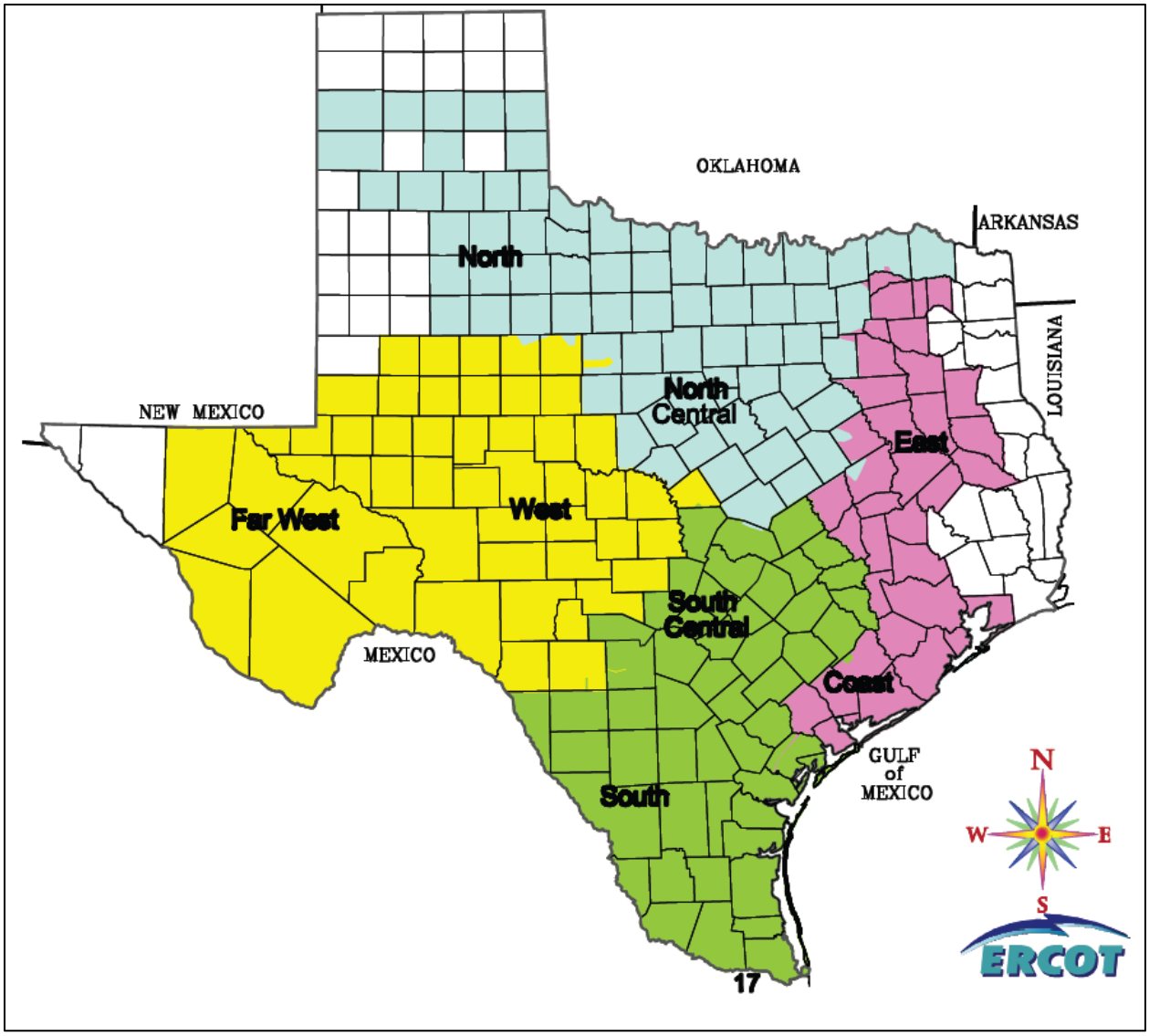

Figure 1.1: 2014 RTP Study Regions

1.2.2 Transmission Model

The SSWG 2014 Data Set B 2015, 2017, 2019 and 2020 summer peak cases, as well as the SSWG 2014 Data Set B minimum load case for 2017 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 all Tier 1, 2 and 3 projects that have not undergone RPG Project Review from the most recent SSWG summer peak base cases.

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 cases are further updated based on the following.

Transmission Outages

Appendix C contains the ERCOT Outage Scheduler listing of transmission outages in the 2015 through 2020 timeframe as of June 2014.

Base Case Updates and Corrections

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

Special Protection Systems

The initial analysis of the base cases did not include the effects of any protection offered by Special Protection Systems (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 E.

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 material impact on the analysis. A list of these projects can be found in Appendix F.

1.2.3 Contingency Definitions and Performance Requirements

Contingency Definitions

The 2014 RTP assessed the ERCOT System for pre-contingency (NERC Category A) performance and post-contingency (NERC Categories B and some C and D) performance.

Category A conditions are defined as having all transmission elements in their normal state with no contingencies. The software tools used in the 2014 RTP inherently test for Category A conditions.

Category B contingencies studied in the 2014 RTP include the loss of single elements, such as generation units, transmission lines and transformers 60 kV and above. All Category B contingencies that involve multiple elements being simultaneously removed from service were obtained from SSWG; circuit protection systems and any backup or redundant systems that remove multiple elements for a single fault are examples of such contingency definitions. The automatic selection of all single elements in the software tools were also used to study all Category B contingencies.

Category C contingencies studied in the 2014 RTP are maintained by TPs through the contingency update process facilitated by SSWG. As required per ERCOT Planning Guide 4.1.1.2, the Category C contingencies included in the RTP are as follow:

- All Category C5 contingencies that are defined as two circuits sharing a common tower for 0.5 miles or more,
- All Category C3 contingencies involving a generating unit outage followed by a single transmission facility outage,
- All Category C3 contingencies involving a 345/138-kV transformer outage followed by a single transmission facility.

A small subset of category D contingencies was also studied in the 2014 RTP. These include those multiple element contingencies that have a generator or a 345/138-kV transformer as the first level contingency and a double circuit transmission line as the second level contingency.

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. The file is maintained by TPs and is provided in addition to the contingency definitions.

All other Category C and D contingencies (submitted by the TPs as part of the SSWG contingency database) will be included in a separate contingency study that will be performed outside of the analysis documented in this report. A list of all contingencies for years 2015, 2017, 2020 and 2021 and their corresponding Powerflow basecases used in the 2014 RTP are attached to the report as Appendix G.

Performance Requirements

All System Operating Limits (SOLs) are respected in accordance with the latest ERCOT System Operating Limit Methodology. All transmission lines and transformers (excluding generator step-up transformers) above 60 kV were monitored for thermal overloads to ensure that they did not exceed their pre-contingency or post-contingency ratings. For voltage analysis all buses above 100 kV were monitored to ensure that they did not exceed their pre-contingency and post-contingency limits. A Panhandle export interface limit of 2669 MW[1] was enforced on the 345-kV double circuit interface defined by the Gray to Tesla, Tule Canyon to Tesla, Cottonwood to Edith Clarke and Cottonwood to Dermott substations.

1.2.4 Generation

Generation in the 2014 RTP cases is modeled as per the guidelines given in the RTP scope and process document. The initial generation dispatch information of all existing conventional generation (natural gas, coal and nuclear) is retained from the SSWG start cases initially but may be re-dispatched to relieve transmission overloads. Wind, solar and hydro units are dispatched according to the guidelines specified in the RTP scope and process document. Future generation units which meet Planning Guide Section 6.9 requirements are 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 H.

Wind, Solar and Hydro

In economic analysis, 8760-hour profiles are 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 year 2006 can be used as the representative weather year for the 8760 profiles in the economic analysis. Based on the above analysis, wind profiles from AWS Truepower and solar profiles from URS for year 2006 were used to model wind and solar dispatch in economic analysis. Hydro dispatch was based on historical hydro output levels from the year 2006.

[1] http://www.ercot.com/content/meetings/rpg/keydocs/2014/0819/DATC_ERCOT_assessment_update_RPG_08192014.pdf

Mothballed Generation

Mothballed generation was modeled in the start cases as indicated in the RTP scope and process document. Mothballed generation units were placed in-service in the reliability analysis per the SSWG Procedure Manual Section 4.3.3.1. Per the guidelines from the RTP scope and process document, the mothballed plants inside a study region were not placed in-service when that region was being analyzed.

DC Ties

DC tie flows are modeled to match prevailing historical flows during summer peak hours. The prevailing historical flows during summer peak hours are 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 are created based on historic patterns.

Switchable Generation

The available capacity of switchable units is left unchanged from SSWG cases unless notice is received from the resource owner to change the available capacity for one or more study years.

Firm Transfers

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

Natural Gas Price

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

1.2.5 Demand Forecast

The 2014 RTP utilized two demand forecast sources for the reliability portion of the study. The first was the bus load forecast derived from the Annual Load Data Request (ALDR) and implemented in the Steady State Working Group (SSWG) Data Set B (future year) base cases by the TPs. This load forecast includes the load represented by the TPs and self-served load of customers and is found in the SSWG summer peak start cases. The other demand forecast source was the ERCOT-developed 90th percentile weather zone load forecast. Both forecasts assumed that summer peak is deemed to be the critical system condition of interest in ERCOT due to the high air conditioner load that exists during summer afternoons in Texas. Tables 1.2 and 1.3 show the two sets of load forecasts considered in the 2014 RTP.

Table 1.2: 2014 ERCOT 90th percentile weather zone load forecast (MW)

Year	Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non-Coincidental Peak
2015	23048	2343	2589	1589	25917	11882	6346	1945	75659
2017	23419	2356	2824	1570	26629	12049	6721	1983	77553
2019	23853	2369	3056	1551	27322	12210	7087	2022	79470
2020	24054	2376	3172	1541	27664	12289	7271	2041	80408

Table 1.3: 2014 Steady State Working Group DSB weather zone load forecast (MW)

Year	Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non-Coincidental Peak
2015	25279	2642	3014	1667	24106	13124	6102	2336	78,257
2017	25999	2682	3356	1752	24703	13837	6391	2407	81,108
2019	26667	2702	3604	1802	25312	14547	6676	2470	83,774
2020	26953	2726	3708	1827	25649	14869	6805	2479	85,013

Upon further analysis of these two sources, it was observed that for two weather zones, the 90th percentile ERCOT load forecast was greater than the corresponding SSWG weather zone forecast. This difference is highlighted in the shaded cells in Table 1.3. ERCOT used the higher of the ERCOT or SSWG load forecast for each weather zone. 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 base cases. ERCOT does not expect that all zones will reach their non-coincident peaks at the same time so this system-wide load value is assumed to be higher than what would be expected to occur in real-time operations.

Table 1.4: 2014 Regional Transmission Plan weather zone load forecast (MW)

Year	Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non Coincidental Peak
2015	25279	2642	3014	1667	25917	13124	6346	2336	80327
2017	25999	2682	3356	1752	26629	13837	6721	2407	83383
2019	26667	2702	3604	1802	27322	14547	7087	2470	86201
2020	26953	2726	3708	1827	27664	14869	7271	2479	87497

The non-conforming flag from ERCOT's operational models was used to identify loads that do not conform to the load changes resulting from weather variations. Each bus in the ERCOT System was assigned an appropriate weather zone profile based on its physical location. The weather zone load from Table 1.4 was redistributed to the individual load level for all conforming loads 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.

For the economic analysis section, the ERCOT developed 50th-percentile 8760-hour weather zone load forecast was utilized for the years 2017 and 2020 based on year 2006 weather assumptions. The year 2006 was determined using the representative weather year analysis mentioned earlier in this report. Additionally, a separate load-specific demand profile is used to model the non-conforming loads. The hourly forecast and demand profile can be found attached in Appendix O. Table 1.5 shows the peak load megawatts seen in the 50th percentile load forecast. These numbers include self-served and non-conforming loads.

Table 1.5: Peak load from 50th percentile load forecast (MW)

Year	Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Coincidental Peak
2017	22,596	2,231	2,753	1,571	25,686	11,274	6,426	1,927	72,277
2020	23,219	2,231	3,105	1,542	2,6717	11,521	6,994	1,984	75,048

1.3 Regional Transmission Plan Process

The RTP is conducted in four distinct stages as 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 is conducted to determine the transmission upgrades and additions needed to meet ERCOT and NERC reliability requirements. Economic analysis is then conducted to identify transmission projects that allow reliability criteria to be met at a lower total cost.

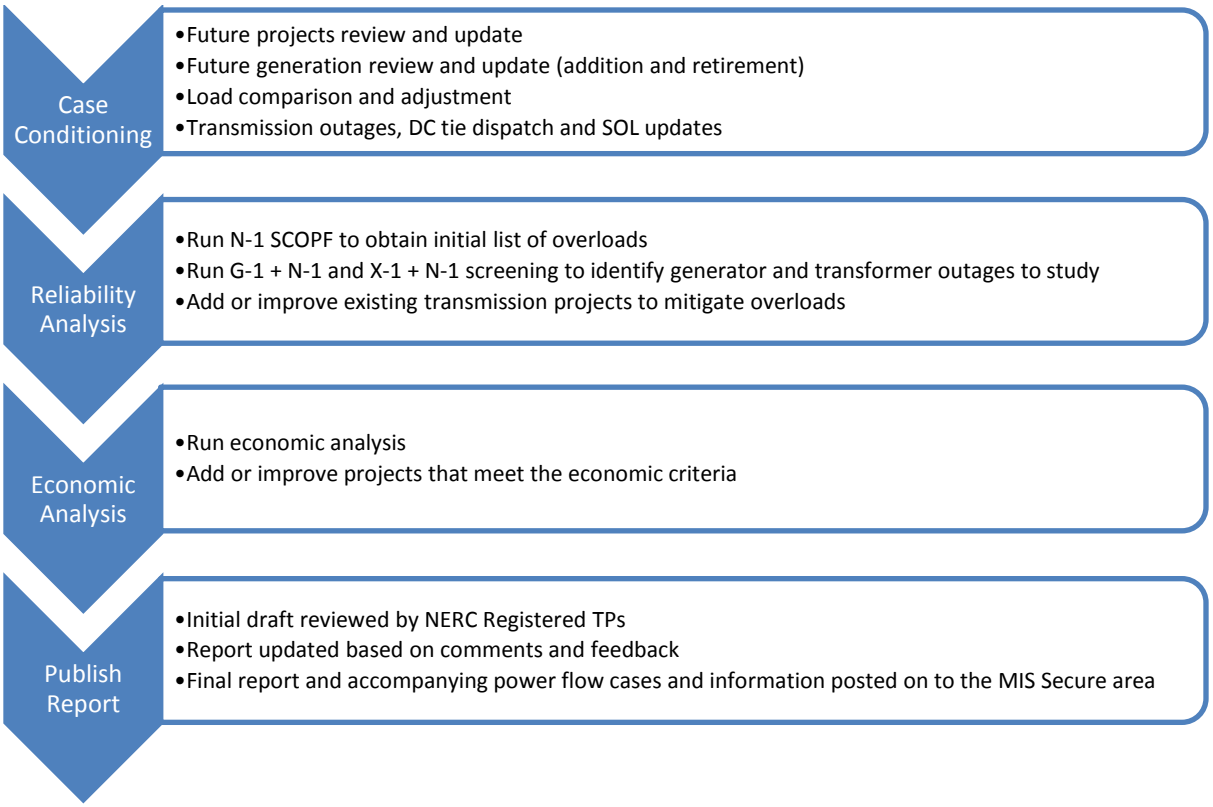

Figure 1.2: Regional Transmission Plan Process

ERCOT utilized the following software tools while performing the 2014 RTP:

- PSS/E version 33 was used to develop the conditioned cases and the AC reliability cases
- PowerWorld versions 17 and 18 with SCOPF and its SIMAUTO functionality were used to perform AC SCOPF analysis, and run generator and transformer outage analysis.
- TARA version 800 was used to perform the N-1-1 contingency analysis on the minimum case.
- UPLAN version 9.04 was used to perform security-constrained economic analysis.

2. Reliability Analysis

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.

PowerWorld SCOPF was run on the conditioned case for each year to determine if all the system generation could be dispatched to remove violations under pre-contingency and post-contingency conditions. If deficiencies were found under the pre-contingency or post-contingency conditions, system improvements were developed to address the deficiencies. The conditioned 2020 case served as the starting point for this analysis. Once projects were identified for 2020, similar analyses were performed for each of the previous years in the study. By starting the analysis with the base case for the farthest out year of the study, the optimal solution set of projects with the greatest long-term benefit could be determined and applied to prior years as necessary.

Some deficiencies were identified in near-term years for which system improvements could not be implemented in a timely manner. A Congestion Management Plan (CMP) was developed to address such cases.

In accordance with ERCOT Planning Guide Section 4.1.1.2, an analysis was performed for each year in the reliability portion of the assessment to determine if additional transmission upgrades are required in order to maintain N-1 reliability performance requirement when a single generating unit is unavailable for dispatch or a 345/138-kV transformer is taken out of service.

Additionally, the following scenarios were analyzed:

- A low load scenario to identify N-1-1 transmission reliability constraints was performed for the year 2017.
- A scenario with all the wind generation inside the study region out of service was performed for all summer peak cases. This analysis was repeated for all the four study regions.
- A scenario in which all Dallas-Fort Worth area generation with no Selective Catalytic Reduction (SCR) were removed from service.
- On July 29, 2014, a market notice was received indicating that certain generation resources from Frontera Generation LP will move to switchable status. As this notice was

received after ERCOT had concluded bulk of reliability analysis, the list of reliability and economic projects as proposed in the 2014 RTP are based on the assumption that the Frontera generation is available to ERCOT through summer of 2020. However, an additional sensitivity was performed to study the impact of this scenario under a loss of an additional generator in the region.

The list of projects along with the corresponding limiting elements and contingencies (SOL violations) 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 had been received, the refined set of improvements was implemented in the base cases. However, since many of the upgrades were developed independent of the other upgrades, some may not be necessary. If a project can be backed out and the system could be dispatched such that no deficiencies existed, the project was removed from the reliability-driven project list. The remaining projects formed the final set of the reliability-driven projects. The improved topology for 2017 and 2020 was used as the starting case for the economic analysis for 2017 and 2020. An AC contingency analysis was performed for each of the final reliability cases in order to demonstrate that the reliability criteria were met. The 2014 RTP transmission system upgrades identified for the years 2017 and 2019 need to be further reviewed by the appropriate TPs to determine the need for an earlier in-service year (2016 or 2018, respectively).

In addition to the above analysis, per the Planning Guide Section 3.1.1.2 (3), the 2014 RTP also reported 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 J.

3. Economic Analysis

Economically driven projects are those system improvements that allow NERC Reliability Standards and ERCOT Planning Criteria to be met 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 the economically driven projects, a UPLAN model was prepared based on the ERCOT developed econometric 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. A list of all congested elements and contingencies causing the congestion was produced by UPLAN. Using this information, a preliminary set of improvements was designed by ERCOT and TPs to solve or reduce the congestion. Projects were put into the model one by one and an annual production cost analysis was performed. Production cost results, before and after the project, were compared to determine the annual production cost savings associated with the project. According to the economic planning criteria described in the ERCOT Protocol Section 3.11.2 (5), economic projects are recommended if the annual production cost savings exceed the first-year annual revenue requirement for the project. Based on the recent review of the economic criteria, the first-year annual revenue requirement for a project is assumed to be 16% of the total project cost.

Improvements were evaluated in an iterative process, focusing on the most heavily congested areas in the system first. Projects developed later in the process may impact the economics of those developed earlier since they were developed independently. To ensure that all the potential economically driven projects were still economic with all the other projects in place, a back-out analysis was conducted similar to the back out analysis performed for the reliability-driven projects. In the back-out analysis, each potential project was individually backed out from the model and tested. Total system production cost before and after a backed out improvement were compared to determine if the upgrade still met the criterion.

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 SCR were monitored in the course of the economic analysis.

The total NO_x emissions of Dallas / Fort Worth area generation units that do not have SCR 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

ERCOT, in collaboration with TSPs, identified transmission system upgrades for the years 2017, 2019 and 2020. If TPs confirmed that there is not enough time to implement a construction project for overloads identified as early as 2015, then a CMP was put in place.

4.1 Reliability-Driven Projects

The list and details of the reliability-driven projects identified in the 2014 RTP can be found in Appendix K. In addition to the summer peak case, the following analysis was completed in the 2014 RTP.

An N-1-1 screening analysis was performed on the 2017 minimum load case (SSWG 2014 Data Set B case). Results of the screening analysis were communicated to the TPs and can be found in Appendix K.

A sensitivity analysis similar to the G-1 + N-1 analysis was performed with all Dallas / Fort Worth (DFW) area units without selective catalytic reduction (SCR) removed from service. The sensitivity analysis showed no additional reliability violations.

A sensitivity to study the impact of Frontera units switching out of ERCOT was performed to evaluate the reliability needs under the loss of Frontera units and a contingency loss of the largest unit in region. N-1 SCOPF analysis was conducted with Frontera and North Edinburg units unavailable. This study was performed for years 2017, 2019 and 2020. The resulting list of overloads and unsolved contingencies can be found in Appendix M. ERCOT is currently performing a separate analysis on the transmission system needs in the Lower Rio Grande Valley with the Frontera units assumed to be not available. This analysis is expected to be completed in 2015. Additionally, near term needs of years 2015 and 2016 were studied and documented by ERCOT in the Frontera Analysis Report issued in October 2014[2].

A scenario with all the wind generation inside the study region out of service was performed for all summer peak cases. The analysis was repeated for all the four study regions. The sensitivity

[2] Assessment of valley region considering the availability of the Frontera facility beginning 2015, October 20, 2014 (http://www.ercot.com/content/news/presentations/2014/FRONTERA_Analysis_Report_20141020_FINAL.pdf)

analysis while studying the North-North Central, South-South Central and Coast-East study regions showed no additional reliability violations. Voltage violations were seen in the West-Far West study regions when studies modeled the wind generation out of service. Transmission upgrades were identified in these instances and documented in this report as reliability projects on Appendix K.

4.2 Remaining Reliability Constraints

The list of remaining violations for the year 2015 was reviewed. ERCOT worked closely with respective TPs to develop mitigation plans. Similar plans were developed for 2017 overloads if the responsible transmission upgrade is not expected to be in-service by then. These CMPs will be reviewed further in the operations planning horizon by ERCOT and TOs. The list and details about the CMPs identified in the 2014 RTP can be found in Appendix N.

4.3 Economic Projects

For years 2017 and 2020 an economic analysis was conducted using production-cost simulation. The input information used in the start and final cases for economic analysis is attached to this report as Appendix O. When applicable, pre-defined SPS were modeled in the case to relieve congested portions of the network. The list of SPS 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 the projects. The annual constraint information after SPS modeling is documented in a spreadsheet attached to the report as Appendix P. The economic benefits of each project were measured against the economic planning criteria per the ERCOT Protocol. In this study, it was assumed that the first-year annual revenue requirement for the transmission project is approximately 16% of the total transmission project cost. The production cost savings and project costs were represented in 2017 dollars. A discount rate of 8%[3] was used to calculate the net present value (NPV). Oftentimes, the cost to implement a transmission project outweighs the production-cost benefits achieved by building that project. If a project did not meet the economic planning criteria the projected congestion will remain on the system.

[3] Reference of discount rate: www.puc.texas.gov/industry/electric/reports/31600/PUCT_CBA_Report_Final.pdf

ERCOT tested five projects to relieve congestion identified in the economic analysis. The transmission upgrades necessary to mitigate congestion met the economic criteria for only one of the five. The list and details of the economic projects tested in the 2014 RTP can be found in Appendix Q.

Appendices

Appendix	Description	Document
A	RTP Scope and Process Document	2014_Regional_Transmission_Plan_Scope_and_Process.doc
B	Base case updates for projects removed from the SSWG basecases	"Removed Projects" worksheet on CaseUpdate.xlsx
C	ERCOT Outage Schedule for 2015-2020	Appendix C - 2014_RTP_Scheduled_Outage_05052014.xlsx
D	Base Case updates and Corrections	"Model Corrections" spreadsheet on CaseUpdates.xlsx
E	Special protection schemes employed in 2014 RTP	"SPS" worksheet on CaseUpdates.xlsx
F	Base case updates for addition of recently approved RPG projects	"Recently Approved Projects" on CaseUpdate.xlsx
G	Final Powerflow basecase with contingency definitions with all reliability and economic projects included	Appendix G – Final_Powerflow_Basecases.zip
H	List of generators added and retired from the SSWG basecase	"Generation Changes" worksheet on CaseUpdate.xlsx
I	Natural gas fuel cost forecast	Appendix I - Natural gas fuel cost forecast.xlsx
J	Facilities overloaded over 95%	Appendix J – 2014_RTP_overloads_over_95%.xlsx
K	Reliability Driven Projects	Appendix K - 2014_RTP_Reliability_Projects.xlsx
L	N-1-1 Screening Analysis	Appendix L - 2014_RTP_N-1-1_Analysis_2017_MinCase.xlsx

	Results for the 2017 minimum load case	
M	Impact of Frontera market notice	Appendix M - 2014_RTP_Frontera_Sensitivity.xlsx
N	Congestion Management Plans	Appendix N - 2014_RTP_CongestionManagementPlan.xlsx
O	Economic analysis input information	Appendix O - 2014_RTP_EconomicAnalysisInput.zip
P	Annual Constraints from 2014 economic analysis	Appendix P - 2014_RTP_AnnualConstraints_EconomicAnalysis.zip
Q	Economic projects evaluated	Appendix Q – 2014_RTP_EconomicProjectsEvaluation.xlsx