Historical Documents Relating to CREZ and PREZ[1]

Table of Contents

1. CREZ Order on Rehearing (Oct. 7, 2008)

This is the seminal order that designated the CREZ zones pursuant to PURA § 39.904(g)(1) and adopted a CREZ "transmission capacity" plan to serve those CREZs pursuant to PURA § 39.904(g)(2). As indicated on page 11, the Commission approved "Scenario 2" to accommodate an estimated 18,456 MW total of which 11,553 MW was new CREZ "transfer capability" including 5,584 MW for the two Panhandle zones. See Table 1. (At the time, the Panhandle zones were named Zone 2A and 4. They were later renamed Panhandle A and B. As Table 1 shows, the approved Scenario 2 capacity was 3,191 MW for Zone 2A and 2,393 MW for Zone 4, a total of 5,584 MW for the Panhandle.)

As you will see, the Commission adopted Scenario 2 based on findings that the Scenario 2 upgrades would provide the most beneficial and cost effective level of transmission capacity (*e.g.*, FOF 117), and that ERCOT is capable of integrating 18,456 MW without sacrificing system stability and reliability (*e.g.*, FOF 156). At the same time, the Commission gave ERCOT flexibility to implement the capacity plan, recognizing that integrating increasing levels of wind energy while ensuring reliability would be a learning process (pp. 19-20).

2. Amended PUC Rule 25.174 (Oct. 15, 2009)

See specifically Rule 25.174(d)(4), (d)(6), and (d)(7). The Commission amended its rule to require Panhandle CREZ wind developers to post financial commitments in amounts specifically tied to the level of CREZ capacity for the Panhandle A and B zones approved the CREZ Order on Rehearing. This rule amendment implemented PURA §39.904(g)(3), which required the Commission to consider financial commitments not only when designating CREZs but again at the CREZ CCN stage. A copy of the order adopting the rule amendment is available on the Interchange as Item No. 266 in Project No. 34577.

[1] Note: We provide this information as it relates to ongoing CREZ-related planning activities at ERCOT, general issues that came up in the course of workshop discussions in Project No. 42647, *ERCOT Planning and System Costs Associated With Renewable Resources and New Large DC Ties*, and possible legislative bills that might be filed relating to CREZ and the Commission's legislative recommendations. EDF RE understands that any approval of a PREZ Stage 1 or other upgrade would require the filing of an CCN application by a TSP at some future point, presumably to be followed by a rate application to recover the costs. EDF RE cannot speak to whether or when a TSP might file such an application or applications.

3. Order on Panhandle CREZ financial commitments (July 30, 2010)

In this order the Commission found that wind developers had posted sufficient financial commitments for both the Panhandle A and B CREZs in compliance with amended Rule 25.174.[2]

4. ERCOT Panhandle Renewable Energy Zone (PREZ) Study Report (April 2014)

This report describes the steps that ERCOT has taken and plans to take in the Panhandle CREZs. After the Commission approved the Scenario 2 transmission capacity plan giving ERCOT flexibility, ERCOT commissioned a CREZ Reactive Power Study to help identify the equipment needed to control and route the power over the Panhandle CREZ lines. (Report p. 2) Based the study's recommendations, ERCOT proceeded with an "Initial Build" of reactive equipment for the Panhandle. (p. 3) This Initial Build supported the export of only 2,400 MW "even though the transmission lines were constructed to accommodate a much larger capacity." (p. 3) (As you'll note, 2,400 MW represents less than half of the 5,584 MW capacity specified in Scenario 2, and is more in line with the Scenario 1 level that the Commission rejected.)[3]

The PREZ Report also includes a "Roadmap" with four sequential upgrades or "Stages" that will reliably integrate increasing levels of Panhandle generation. (pp. ii-iii, Figure E-2 and Table E-1) Stage 1 will increase the export capacity from 2,400 MW to 3,500 MW. (*Id.*) Stage 1 involves adding a second circuit on existing double-circuit-capable towers and installing shunt reactors and synchronous condensors. (*Id.*) The estimated cost is $115 million. (*Id.*) That translates to $104,545/MW for the additional 1,100 MW. By comparison, the cost of the original CREZ build-out was $6.92 billion to provide an intended 11,553 MW that so far is only about 8,400 MW because of the shortfall in the Panhandle. That translates to approximately $821,000/MW.

Stage 2 would raise the Panhandle export capability to 5,200 MW at a more substantial estimated cost of $560 million. (*Id.*) Stage 2 would also require a new 345 double circuit and new right-of-way. (*Id.*) Stages 3 and 4 are longer term, more expensive, and would exceed the 5,584 MW Panhandle CREZ capacity specified in the CREZ order. (pp. 31-33)

5. ERCOT Panhandle Wind Project Status Update (Jan. 15, 2015)

This update shows that ERCOT is expecting 3,454 MW of Panhandle generation to be in commercial operation by year-end.

---

[2] EDF RE acquired Panhandle wind projects from two developers that made CREZ financial commitments. EDF RE followed through on those commitments by replacing them with financial commitments pursuant to ERCOT interconnection agreements. These projects are now fully operational or will be shortly. They represent part of EDF RE's investment in Texas of over $1 billion.

[3] ERCOT later updated the expected export limit to 2,441 MW applying a 90% factor based on system strength criteria. Placing the west Texas series capacitors in service would increase the export capability by approximately 250 MW.

DOCKET NO. 33672

COMMISSION STAFF'S PETITION FOR DESIGNATION OF COMPETITIVE RENEWABLE-ENERGY ZONES	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER ON REHEARING

I. Introduction

This Order addresses Commission Staff's petition for designation of competitive renewable-energy zones (CREZs), including conclusions regarding which zones should be designated as CREZs, the identification of the major transmission improvements necessary to deliver, in a manner that is most beneficial and cost-effective to customers, the energy generated by renewable resources in the CREZs, and updates of the Commission's estimate of the maximum generating capacity of renewable resources in the CREZs that the Commission expects the transmission ordered for the CREZs to accommodate.

Based on the evidence and testimony presented during hearing, the Commission concludes that the following areas from the AWS Truewind Study contained in Figure 3 of the *ERCOT Analysis of Transmission Alternatives for Competitive Renewable-energy Zones*[1] (ERCOT Study), with certain modifications as described in this order, should be designated as CREZs: zone 2A,[2] zone 4, zones 5 and 6, zone 9A,[3] and zone 19. The Commission finds that the major transmission improvements identified in the CREZ Transmission Optimization Study[4] (CTO Study) for Scenario 2 are necessary to deliver the energy generated by renewable

---

[1] ERCOT Analysis of Transmission Alternatives for Competitive Renewable-energy Zones, ERCOT Ex. 1 at Ex. DW-1 at 10.

[2] Zone 2A is comprised of that area enclosed by the perimeter boundaries of zones 1 and 2, plus an additional area that includes all of Briscoe County.

[3] Zone 9A is comprised of zones 9 and 10, plus additional areas between and near the zones as requested by AES SeaWest, BNB Renewable Energy LLC, FPL Energy LLC, and RES America Developments, Inc.

[4] ERCOT's Competitive Renewable-energy Zones Transmission Optimization Study, ERCOT Ex. 4 at Ex. DW-1.

resources in the CREZs, in a manner that is most beneficial and cost-effective to the customers. Additionally, the Commission's estimate of the maximum generating capacity of renewable resources in the CREZs that the Commission expects the transmission ordered for the CREZs to accommodate is 18,456 MW.

It is also noted, regarding the renewable-energy goals set for the state in PURA[5] § 39.904(a), that as of December 2006 there were 2,508 MW of wind generation in service in ERCOT and at least 4,850 MW of wind resources were likely to be in service by the end of 2007.[6] As of April 2007, the amount of wind generation in service in ERCOT had reportedly increased to 2,981 MW, with an additional 1,605 MW of wind generation having executed interconnection agreements with ERCOT.[7] The testimony at the hearing on the merits on June 12, 2008 credibly established that the amount of wind generation expected to be on the grid by the end of 2008 is approximately 10,000 MW.[8] The renewable-energy potential being developed thus far has allowed the State of Texas to meet and surpass the statutory renewable-energy goals.

II. Procedural History

P.U.C. SUBST. R. 25.174(a)(1) requires Commission Staff to initiate a contested case proceeding to designate CREZs upon receiving ERCOT's study of the wind energy production potential statewide and the transmission constraints that are most likely to limit the delivery of electricity from wind energy resources. ERCOT filed the ERCOT Study in Project No. 33577 on December 7, 2006, and Commission Staff filed a petition for the designation of CREZs on January 4, 2007.

The Commission's approach in the CREZ proceeding is two-phased. In the first phase, the Commission conducted a hearing from June 11 – 14, 2007, and designated areas of the state as CREZs in an interim order on reconsideration issued on November 6, 2007. The scope of the

---

[5] Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. §§ 11.001-66.017 (Vernon 2007).

[6] ERCOT Study. ERCOT Ex.1 at Ex. DW-1 at ES-1.

[7] Direct Testimony of Jeffry Pollock, TIEC Exhibit 1 at 9-10 *citing to* ERCOT, *Wind Impact/Integration Analysis,* Regional Planning Group Meeting April 13, 2007.

[8] Tr. at p. 1865 (June 12, 2008).

interim order was limited to designating areas as CREZs and providing initial estimates of the maximum generating capacity that the Commission expected the transmission ordered for the CREZs to accommodate. Regarding transmission solutions, the Commission determined that it would be necessary for ERCOT to conduct studies on the four aggregate tiers of megawatt transfer capability identified by the Commission for the designated CREZs, and directed ERCOT to conduct the CTO study. The purpose of the study was to identify transmission proposals that would produce the most beneficial and cost-effective transmission solutions to deliver each scenario's estimated generating capacity from the designated CREZs. ERCOT conducted workgroups over a 6-month period with stakeholders to consider and test multiple alternative transmission solutions.

On April 2, 2008, ERCOT filed the CTO study, which presented 5 alternative plans that represent the least expensive transmission alternatives that will support each of the four scenarios on a $/kWh basis. Also on the same day, ERCOT filed the "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements" study prepared by General Electric International, Inc. (the GE Ancillary Services study). The purpose of this study was to determine the level, type, and cost of additional ancillary services to maintain the reliability of the grid with increasing levels of wind generation. The GE Ancillary Services study began before the Commission's interim order in the CREZ proceeding, therefore the levels and geographic location of the wind generation studied are similar to, but do not exactly mirror, the four scenarios addressed in the CTO study. The GE Ancillary Services study covers four scenarios also: a 5,000 MW, two 10,000 MW, and a 15,000 MW scenario of wind generation.

After these filings by ERCOT, the second phase of the proceeding commenced, and a second hearing on the merits was held on June 11-12, 2008. In the second phase, the Commission identified the major transmission improvements necessary to deliver, in a manner that is most beneficial and cost-effective to customers, the energy generated by renewable resources in the CREZs designated in the first phase. This identification of improvements includes the new and upgraded lines, identified by voltage level; a general description of where any new lines will interconnect to the existing grid;[9] as well as the necessary improvements other

[9] P.U.C. SUBST. R. 25.174(a)(5)(B).

than transmission lines. The Commission also updates the estimate of the maximum generating capacity that the Commission expects the transmission ordered for the CREZs to accommodate.

III. Discussion

PURA § 39.904(g) directs the Commission to designate competitive CREZs throughout Texas in areas in which renewable-energy resources and suitable land areas are sufficient to develop generating capacity from renewable-energy technologies. In determining whether to designate an area as a CREZ, the Commission must consider the level of financial commitment by generators for each CREZ[10] and may consider any other factors considered appropriate by the Commission, as provided by PURA.[11]

P.U.C. SUBST. R. 25.174(a)(5) provides that the Commission's final order in this proceeding shall specify: (1) the geographic extent of the CREZ; (2) major transmission improvements necessary to deliver to customers the energy generated by renewable resources in the CREZ, in a manner that is most beneficial and cost-effective to the customers, including new and upgraded lines identified by voltage level and a general description of where any new lines will interconnect with the existing grid; (3) an estimate of the maximum generating capacity that the Commission expects the transmission ordered for the CREZ to accommodate; and (4) any other requirement considered appropriate by the Commission as provided by PURA.

IV. CREZ Designations

A. Suitable Land Area and Renewable-energy Resources

The Commission finds that the methodology utilized in the AWS Truewind Study, as described in the ERCOT Study, in addition to the relevant testimony and evidence submitted by the parties, establishes that the statutory criteria related to suitable land areas and renewable-energy resources has been met for each of the zones designated by the Commission as a CREZ. As discussed in the ERCOT Study, AWS Truewind conducted its analysis of wind generation

---

[10] PURA § 39.904(g)(3), P.U.C. SUBST. R. 25.174(a)(4)(B).

[11] P.U.C. SUBST. R. 25.174(a)(4)(C).

potential by using a proprietary model called MesoMap, which is an integrated set of atmospheric models, computer systems, and meteorological and geophysical databases.[12] AWS Truewind also analyzed land use patterns to determine the amount of land available for wind development.[13] After reviewing the information contained in the ERCOT Study and testimony by the parties regarding the analysis conducted by AWS Truewind, the Commission finds that the methodology used by AWS Truewind is an adequate method for determining those areas within the state where sufficient renewable-energy resources and suitable land areas exist for wind-power development.

Using its modeling tools in addition to certain other data, AWS Truewind identified the 100-MW sites within Texas with the highest annual capacity factors[14] and clustered those sites into 25 areas.[15] A generation supply curve was developed for each of the 25 zones, based on "the amount of developable land in each zone, the existing wind resources, and the output power curve of a large generic wind turbine."[16] Figure 3 of the ERCOT Study shows the location of the areas with the best 4,000 MW with the highest annual capacity factors within each of the 25 areas studied by AWS Truewind.[17] AWS Truewind's modeling results were released to ERCOT stakeholders, who were given an opportunity to provide additional data to AWS Truewind that, in some instances, resulted in modifications to certain findings reached by AWS Truewind.[18]

Each of the zones designated by the Commission as a CREZ is shown within Figure 3 of the ERCOT Study, or an expansion of a zone or zones shown within Figure 3. The Commission finds that the methodology utilized by AWS Truewind was thorough and serves as an adequate method for identifying those areas of the state in which renewable-energy resources and suitable land areas are sufficient for wind-generation development. The Commission finds that

---

[12] ERCOT Study, ERCOT Ex. 1 at Ex. DW-1 at 7.

[13] *Id.*

[14] "The term capacity factor means the amount of energy produced by a generator over the period of a year, as a percentage of the product of the generator's nameplate capacity multiplied by the number of hours in a year (8,760)." *Id.* at 8.

[15] *See* ERCOT Study, ERCOT Ex. 1 at Ex. DW-1 at 8.

[16] *Id.*

[17] *See* ERCOT Study, ERCOT Ex. 1 at Ex. DW-1 at 10.

[18] *Id.* at 12.

expanding certain zones, as described in this order, is warranted based upon the evidence in the record regarding parties' commitment to develop renewable-energy resources within the expanded areas, as well as the presence of renewable-energy resources and suitable land area within the expanded area. Accordingly, each of the Commission's designated CREZs fulfill the requirements of PURA § 39.904(g) and P.U.C. SUBST. R. 25.174(a)(4).

B. Evidence of Financial Commitment

PURA § 39.904(g)(3) and P.U.C. Subst. R. 25.174(a)(4)(B) require the Commission to consider the level of financial commitment by generators for each zone in determining whether to designate an area as a CREZ. Thus, aside from the presence of sufficient renewable-energy resources and suitable land areas, a zone must have a certain level of financial commitment by developers for the Commission to determine that the zone should be designated as a CREZ. P.U.C. SUBST. R. 25.174(b) sets forth examples of financial commitment by developers, including: (1) existing renewable-energy resources; (2) pending or signed interconnection agreements; (3) leasing agreements; (4) letters of credit; (5) interconnection studies by a TSP, ERCOT, or other ISO; (6) "any other factors;" (7) a non-utility entity's commitment to build and own transmission facilities; and (8) a deposit or payment to secure or fund the construction of such transmission facilities by an electric utility or a transmission facility.

In evaluating the level of financial commitment for the nominated zones, the Commission considered the number of developers, total resources committed by those developers, and the nature of the resources committed. Accordingly, because the record reflects that no financial commitment evidence was received for zones 3, 8, 15, 16, 17, 21, 22, 23, and 24, the Commission excluded these zones from further evaluation for CREZ designation. Further, the Commission did not select for CREZ designation those zones for which the record reflected relatively limited developer interest. Accordingly, zones 7, 11, 12, 13, 14, 18, 20, and 25 did not receive CREZ designation because those zones were supported by only one or two interested developers with relatively less significant financial commitment.

While both zones 1 and 19 reflect financial commitment filed by three developers, the Commission finds that the weight of this commitment is significant. Zone 1 possesses

superlative wind resources, and the level of financial commitment for zone 2A (which combines zone 1 and 2) is sufficient for CREZ designation. The financial commitment for zone 19 reflects significant resources and the potential for upwards of 1,500 MW of wind development.[19] Thus, the zones chosen by the Commission for CREZ designation – zones 2A, 4, 5, 6, 9A, and 19 – were supported by testimony and evidence demonstrating significant levels of financial commitment. It should be noted that zones that did not receive CREZ designation in this docket are not precluded from receiving CREZ designation in a future CREZ proceeding.

C. Geographic Extent of the Designated CREZs

P.U.C. SUBST. R. 25.174(a)(5) requires the Commission to specify the geographic extent of the CREZs in its final order in this proceeding. Consistent with Commission Staff's recommendation, the Commission finds that, except as specifically modified by this order, the CREZ boundaries should be based on the lines drawn by AWS Truewind in Figure 3 of the ERCOT Study, which represent the areas with the best 4,000 MW in each of the wind resource zones.[20] For ease of reference, a copy of Figure 3 from the ERCOT Study has been attached to this order as Attachment A. Certain modifications to the boundaries set forth in Figure 3 of the ERCOT Study are warranted based upon the evidence of renewable-energy resources, suitable land areas, and financial commitment relating to the requested expanded areas. For those zones that have been expanded from the original boundaries in Figure 3 of the ERCOT Study for which a written description of the expanded area is not sufficiently precise, attached to this order as Attachments B, C, and D are copies of the maps submitted by the parties depicting those expansions. For all zones for which the Commission has not made a specific statement regarding the granting of an expansion, the Commission finds that expansion of such zones was not sufficiently supported by the record evidence.

The boundaries for the CREZs designated by the Commission are as follows:

---

[19] Although Wind Tex Energy prefiled the direct testimony of Steven DeWolf, which described Wind Tex Energy's financial commitment to zone 9A and 19, the Commission did not consider this testimony as it was not offered into evidence pursuant to the requirements of P.U.C. PROC. R. 22.225(b).

[20] The brown-line boundaries on ERCOT Exhibit – 3A also set forth the boundaries of the CREZs; however, because Exhibit – 3A was filed under seal, citation to Figure 3 from the ERCOT Study is made for ease of reference.

zone 2A: Comprised of that area enclosed by the perimeter boundaries of zones 1 and 2, plus an additional area that includes all of Briscoe County.

zone 4: Comprised of that area designated as zone 4 in Figure 3 of the ERCOT Study without modification.

zones 5 and 6: Expanded to include an extension of the eastern boundary of zone 5 ten miles further east into Tom Green and Schliecher counties, as depicted in Exhibit NRG-3 at Exhibit 1. (Attachment B)

zone 9A: Comprised of zones 9 and 10, plus an additional area between the zones as requested by FPL Energy and BNB Renewable Energy as set forth in Exhibit BNB-10. (Attachment C) Additionally, to the extent that this area differs from the expansion requested by AES Seawest, as set forth in AES SeaWest Exh. No. 2 at Exhibit RS-1, the differing area is also included in zone 9A. (Attachment D) Further, RES's projects located in Callahan and Shackelford counties in zone 12, as those projects were described in the record and depicted in RES EX. 2A at Exhibit C (filed under seal), are also included in zone 9A.

zone 19: Comprised of that area designated as zone 19 in Figure 3 of the ERCOT Study without modification.

Consistent with open access principles, developers are not deemed automatically ineligible to interconnect with a transmission line built to serve a CREZ simply because the location of their wind project may fall outside a delineated CREZ boundary. However, in any subsequent dispatch priority proceeding, developers within a CREZ that submitted evidence of financial commitment in this proceeding will likely fare better than other developers.

D. Transmission Solutions

P.U.C. SUBST. R. 25.174(a)(5)(B) requires the final order in this proceeding to specify the major transmission improvements necessary to deliver to customers the energy generated by renewable resources in the CREZ, in a manner that is most beneficial and cost-effective to customers, including new and upgraded lines identified by voltage level and a general description of where any new lines will interconnect to the existing grid. There appeared to be

general consensus from ERCOT and the transmission service providers who participated in the hearing on the merits in the first phase that certain transmission lines, such as those involving the movement of power in the Texas Hill Country, should be built from a reliability standpoint. However, the Commission finds that it was difficult, and possibly counterproductive, to direct with detailed specificity at that phase all the transmission lines that should be built to serve a given CREZ. As testified to by ERCOT witness Dan Woodfin at the first phase hearing on the merits, in order for ERCOT to conduct the necessary studies to determine the transmission needed to serve the CREZs, ERCOT would need to know which CREZs will be served and how many megawatts are expected to be served.[21] Therefore, the Commission specified in the interim order those components to provide parameters for the necessary studies.

Pursuant to P.U.C. SUBST. R. 25.174(a)(5)(C), the Commission's final order should specify the estimated maximum generating capacity that the Commission expects the transmission ordered for the CREZ to accommodate. The Commission's directives to ERCOT, as set forth below, provided an initial estimate after the first phase hearing on the merits. The Commission requested that ERCOT study four aggregate tiers of megawatt transfer capability, based upon the number of megawatts parties in this proceeding have stated they intend to develop. Because the Commission had determined which zones should receive CREZ designation, ERCOT could estimate costs with greater precision than had been achievable during the ERCOT Study. ERCOT's CTO Study, along with stakeholder input, allowed ERCOT to present to the Commission transmission proposals that provide transfer capability for the estimated maximum generating capacity per CREZ in the most beneficial and cost-effective way to customers. In its CTO Study, ERCOT delineated which portions of the CREZ transmission lines would likely be required as part of ERCOT's long term system assessment absent the need to serve the additional renewable generation.[22]

The Commission found that it would be beneficial for ERCOT to consider, as part of its CTO Study, more than one interconnection point within certain CREZs, because certain CREZs, such as zones 2A and 9A, cover expansive territory where the cost of interconnection by

[21] Tr. at 1358-1359 (June 14, 2007).

[22] CTO study, ERCOT Ex. 4 at Ex. DW-1 at 35-36.

developer could vary greatly based upon the location of the ERCOT interconnection point. ERCOT retained discretion to determine the number and location of interconnection points within each CREZ to be studied as part of the CTO Study.

The transfer capability scenarios set forth below begin at a low for Scenario 1 of 5,150 MW, which is the shortfall between the 2007 ERCOT base case of 4,850 MW[23] and the 10,000 MW statutory target for renewable energy provided in PURA § 39.904(a), and a high for Scenario 3 of 17,956 MW, which is determined by adding the total megawatt capacity of development proposed for each designated CREZ.[24] Scenario 4 divides the sum of the total megawatt capacity proposed for the zones desired by Commissioner Parsley among all the zones designated by the Commission, with the exception of zone 4 and that portion of zone 2A that encompasses zone 1. Such a division reflects Commissioner Parsley's desire to have zones 1 and 4 deliver power to the Southwest Power Pool (SPP) and goal to maintain potential transmission infrastructure costs at close to $1.3 billion. Accordingly, the Commission requested that ERCOT study the following scenarios in its CTO Study:[25]

---

[23] According to ERCOT, at least 4,850 MW of wind resources are likely to be in service by the end of 2007. *See* ERCOT Study, ERCOT Ex. 1 at Ex. DW-1 at 10.

[24] Each proposed project in excess of 1,000 MW was capped at 1,000 MW for purposes of Scenarios 1, 2, and 3 in the ERCOT CREZ Transmission Optimization Study.

[25] These MW transfer capability numbers are provided with the understanding that ERCOT may exercise discretion in determining the number of MW that could safely and reliably be served based upon limitations such as voltage control. Additionally, while the Commission used a base case figure of 4,850 MW in determining the scenarios above, ERCOT is to use best available data in determining the base case figure.

Table 1: MW Tiers for ERCOT CREZ Transmission Optimization Study

	Scenario 1 (MW)	**Scenario 2 (MW)**	**Scenario 3 (MW)**	**Scenario 4 (MW)**
Zone 2A	1422	3191	4960	6660
Zone 4	1067	2393	3720	0
Zones 5/6	829	1859	2890	3190+[26]
Zone 9A	1358	3047	4735	5615
Zone 19	474	1063	1651	2051
CREZ transfer capability	5150	11,553	17,956	17,516
Total transfer capability[27]	10,000	16,403	22,806	22,366

ERCOT was directed to pursue the completion of the CTO Study in the most expeditious manner possible, which could involve studying the lower tiers of megawatt transfer capability (*i.e.*, Scenarios 1, 2, and 4) before evaluating the higher tier (*i.e.*, Scenario 3). As directed, ERCOT filed the results of its CTO Study in this docket on April 2, 2008, along with the GE Ancillary Services study.

E. CREZ Transmission Capacity Plan

The Commission finds that the major transmission improvements identified in the CTO study for Scenario 2 are necessary to deliver the energy generated by renewable resources in the CREZs, in a manner that is most beneficial and cost-effective to the customers. A copy of ERCOT's Figure 5: Scenario 2 of the CTO Study, ERCOT Exhibit 8, which is a map depicting the major transmission improvements to deliver energy generated in the CREZs, is attached to this order as Attachment E. The Commission's updated estimate of the maximum generating capacity of renewable resources in the CREZs that the Commission expects the transmission ordered for the CREZs to accommodate is 18,456 MW.

[26] ERCOT may increase the 3190 MW figure to include any additional MWs that are currently being curtailed from operating wind facilities in zones 5/6.

[27] CREZ transfer capability plus 4,850 MW (ERCOT base case wind generation figure). *See* ERCOT Study, ERCOT Ex. 1 at Ex. DW-1 at 10.

In addition, the Commission finds that certain line segments of the transmission plan identified as part of the CREZ transmission solution Scenario 2 are critical to relieve current congestion that is hampering the delivery of existing wind-powered energy to the grid.[28] These projects are of utmost priority, and will take precedence in the CREZ transmission implementation process, including planning, certification, and construction. The Commission designates these lines as part of the selected CREZ transmission solution, but directs that if it is more expedient to complete these projects by the incumbent transmission service providers or others through ERCOT's customary Resource Planning Group (RPG) process, that process may be utilized to achieve the stated goal of ensuring these facilities are in service as quickly as possible. The following projects[29] are identified as having first priority: the Central B to Central A double-circuit 345-kV line, the Central A to Central Bluff double-circuit 345-kV line, the Central Bluff to Bluff Creek double-circuit 345-kV line, the Bluff Creek to Brown double-circuit 345-kV line, the Brown to Newton/Salado double-circuit 345-kV line, the Newton to Killeen double-circuit 345-kV line, the Twin Butte to Brown additional 345-kV line on existing structures, the Twin Butte to McCamey D single-circuit, double-circuit-capable 345-kV line, the McCamey D to Kendall double-circuit 345-kV line, the Kendall to Gillespie single-circuit, double-circuit-capable 345-kV line, the Gillespie to Newton single-circuit, double-circuit-capable 345-kV line, and the Oklaunion to Bowman double-circuit 345-kV line.

In developing the capacity plan to construct the necessary transmission improvements, the Commission considered several factors pursuant to PURA § 39.904(g) and P.U.C. SUBST. R. 25.174(c)(3), including: 1) the cost-effectiveness and benefits to customers of each proposed scenario; 2) the estimated cost of constructing transmission capacity necessary to deliver to electric customers the electric output from renewable-energy resources in the CREZs; 3) the

---

[28] Tr. at 1633-34 (June 11, 2008); Direct Testimony of Sergio Garza, LCRA TSC Ex. 2 at 13-14.

[29] The projects were identified in shorthand terms in prefiled testimony as the Clear Crossing switch station, the Red Creek to Killeen line, the Twin Butte to Kendall line, the Panhandle south zone to Central zone line, and the Oklaunion to Bowman line. However, for purposes of the order, they are identified more specifically to reflect the lines' identification in the CTO study and the ERCOT 2007 Transmission Constraints Needs Report (Five-Year Transmission Plan). *See,* Direct Testimony of Brian Almon, Staff Ex. 6 at 7 and Direct Testimony of Bradley C. Jones, Luminant Ex. 1 at 34. It is noted that the Clear Crossing 345-KV switching station was in Scenario 1A, but not in Scenario 1B or 2. The PanOakMid to Center C line passes the location identified for the siting of the Clear Crossing station, which is where that line criss-crosses with the line from Central B to Willow Creek. Accordingly, the Commission is not including it in the prioritized projects. If this project continues to be, or later becomes necessary, it can be addressed through the usual RPG process.

estimated cost of additional ancillary services; and 4) other appropriate factors such as the integration of each scenario's wind generation in a reliable manner, the intent of the Legislature in directing the Commission to construct transmission capacity to deliver electricity from the CREZs, the environmental benefits, and the future expansion capability and other benefits of the plan.

1. Identification of Major Transmission Improvements

Appendix B to the CTO study provides sufficient detail in the cost calculations of the major transmission improvements in Scenario 2 to identify the lines to be constructed, by voltage level and a general description of where new lines will interconnect to the existing grid. In addition to the voltage levels and general descriptions of where new lines will interconnect, the cost breakdown for Scenario 2 also identifies other major transmission improvements necessary for the plan.

2. General Description of New Lines by Voltage Level and Interconnection Points

The new lines identified for Scenario 2 are visually depicted on the map in Attachment E to this order. The lines are identified by voltage levels and general descriptions of where new lines will interconnect in the CTO study cost breakdown for Scenario 2, and include the following:

McCamey, Central, and Central West: Gillespie to Newton single-circuit, double-circuit - capable 345-kV line; Kendall to Gillespie single-circuit, double-circuit-capable 345-kV line; West C to Odessa single-circuit, double-circuit-capable 345-kV line; West B to Moss single-circuit 138-kV line; West A to West C single-circuit, double-circuit-capable 345-kV line; West A to Central D single-circuit, double-circuit-capable 345-kV line; Twin Butte to Brown new 345-kV line on existing structures; Tonkawas to Sweetwater double-circuit 345-kV line; Sweetwater to Central Bluff double-circuit 345-kV line; McCamey D to Twin Butte single-circuit, double- circuit-capable 345-kV line; McCamey D to Kendall double-circuit 345-kV line; McCamey C to McCamey A single-circuit, double-circuit-capable 345-kV line; McCamey B to North McCamey 138-kV line on existing structures; McCamey A to Odessa single-circuit, double-circuit-capable 345-kV line; McCamey C to McCamey D single-circuit, double-circuit-

capable 345-kV line; Mason to Pittsburgh 138-kV line; Divide to Twin Butte adding a second circuit to existing structures; Central E to Central D single-circuit, double-circuit-capable 345-kV line; Central D to Divide single-circuit, double-circuit-capable 345-kV line; Central C to Navarro/Sam Switch double-circuit 345-kV line; Central B to Willow Creek double-circuit 345-kV line; Central B to Central A double-circuit 345-kV line; Central A to West A double-circuit 345-kV line; Central A to Tonkawas double-circuit 345-kV line; Central A to Central C double-circuit 345-kV line; Newton to Killeen 345-kV line; Brown to Newton/Salado double-circuit 345-kV line; Bluff Creek to Brown double-circuit 345-kV line; and Central Bluff to Bluff Creek double-circuit 345-kV line.

Panhandle: West Krum to Anna double-circuit 345-kV line; Willow Creek to Hicks double-circuit 345-kV line; West Krum to Carrolton NW adding a new 345-kV line to existing structures; PanOakMid to Central C double-circuit 345-kV line; Panhandle AC to PanOakMid (with one circuit looping into Tesla 345-kV bus); Panhandle BB to Panhandle BA double-circuit 345-kV line; Panhandle BB to Oklaunion (with one circuit looping into Tesla 345-kV bus) double- circuit 345-kV line; Panhandle BA to Panhandle AC double-circuit 345-kV line; Panhandle AD to PanOakMid double-circuit 345-kV line; Panhandle AD to Central B double-circuit 345-kV line, Panhandle AC to Panhandle AD double-circuit 345-kV line; Panhandle AB to Panhandle BA single-circuit, double-circuit-capable 345-kV line; Panhandle AA to Panhandle AB single-circuit, double-circuit-capable 345-kV line; Panhandle AA to Panhandle AC single-circuit, double-circuit-capable 345-kV line; Parker to Everman new 345-kV line on existing structures; Oklaunion to West Krum double-circuit 345-kV line; Oklaunion to PanOakMid double-circuit 345-kV line; and Bowman to Oklaunion double-circuit 345-kV line.

3. Major Transmission Improvements Other Than New Lines

Transmission improvements other than new lines are also identified in the CTO study cost breakdown for Scenario 2, and include the following:

Stations: new 345-kV stations at Sam Switch, Gillespie, Newton, Brown, Navarro, Tesla, Hicks, West Krum, and PanOakMid;

Auto Transformers: addition of a 345-kV auto at Whitney, a 138-kV auto at Bandera, a 345-kV auto at Gillespie, two 345-kV autos at North McCamey, a 345-kV auto at Eagle Mountain, and the replacement of a 345-kV auto at Kendall;

50% Series Compensation: on McCamey D to Kendall; on Central C to Navarro/Sam Switch, on PanOakMid to Central C, on Panhandle AC to Tesla, and on Central B to Willow Creek;

Mega volt-ampere-reactive (MVAR) reactive compensation: 200 MVAR on PanOakMid; 150 MVAR on Central C, Central B, and Brown, 100 MVAR on Tesla, Gillespie, Central A, and McCamey D, 50 MVAR on Panhandle AC, Panhandle AD, Panhandle BB, and Panhandle AB;

MVAR capacitor bank: 300-MVAR bank on Oklaunion, 200-MVAR bank on PanOakMid, 150-MVAR bank on Tesla, 100-MVAR bank on Panhandle AC, and 50-MVAR bank on Panhandle AD;

Open and close lines: open Seymour to Bomarton 69-kV line, open Saps to Yellowjacket 138-kV line, open Rocksprings to Friess Ranch 69-kV line, open Fort Stockton to Barilla 69-kV line, open Bradshaw to Winters 69-kV line, and close bus ties at North McCamey bus;

Rebuilds: Sonora to Hamilton 138-kV line, Goldthwaite to Evant 138-kV line, Raymond Barker to Verde Creek 138-kV line, Kendct to Kendal 138-kV line, Verde Creek to Bandera, Willow Creek to Parker 345-kV as double circuit, and Jacksboro to Willow Creek 345-kV as double circuit;

Upgrade terminal equipment: on Eagle Mountain-Hicks-Alliance-Roanoke 345-kV line, on Abilene to Mulberry 138-kV line, on Abilene South to Leon 138-kV line, on Bowman to Graham 345-kV line, on Bowman to Fisher Road 345-kV line, on both Singleton to Gibbons Creek 345-kV lines, on Roanoke to Alliance 345-kV line, and on Morgan Creek to Twin Butte 345-kV line; and

Reconductor: on Bowman to Jacksboro 345-kV line.

4. Estimated Construction Costs of Transmission Capacity

P.U.C. SUBST. R. 25.174(c)(3)(A) allows the Commission to consider the estimated cost of constructing transmission capacity necessary to deliver to electric customers the electric output from renewable-energy resources in the CREZs in developing the transmission capacity plan. Because of the increases in materials costs, the cost estimates provided in the CTO study were significantly higher than those used in the initial ERCOT CREZ report referenced in the interim order on reconsideration.[30] The CTO study also contains general assumptions regarding costs per mile for new transmission, understanding that the lines would cross varying terrain, would likely not be routed as straight lines, and would have variations in right-of-way costs.[31] Additionally, the cost estimates include the equipment to connect the wind generation to the new transmission, assuming 10 miles as the average length of transmission lines from the wind facilities to the collection substation, an average of 400-500 MW of wind generation on each new circuit, and 138-kV or 345-kV voltage level for lines connecting the wind farms to the collection substations.[32] Scenario 2 contains 2,334 miles of new 345-kV right-of-way, and 42 miles of new 138-kV right-of-way.[33] The estimated collection costs for Scenario 2 range from $580 to $820 million.[34] The estimated cost of the transmission improvements identified in Scenario 2 is $4.93 billion.[35]

Scenario 2 will prove less expensive than Scenario 1 (plans A or B) over the long term, because the transmission cost will be less per unit of capacity with higher levels of wind generation.[36] Additional wind generation will provide lower production costs.[37] While Scenario 1B has a lower overall cost than Scenario 2, its cost per MW of capacity is actually greater.[38]

---

[30] CTO Study, ERCOT Ex. 4 at Ex. DW-1 at 4.

[31] *Id.*

[32] CTO Study, ERCOT Ex. 4 at Ex. DW-1 at 19.

[33] *Id.* at 24.

[34] *Id.*

[35] CTO Study, ERCOT Ex. 4 at Ex. DW-1 at Appendix B.

[36] Direct Testimony of Jan Bagnall, FPLE Ex. 15 at 711-13.

[37] Direct Testimony of Jess Totten, Staff Ex. 5 at 6.

[38] CTO Study, ERCOT Ex. 4 at Ex. DW-1 at 24; Direct Testimony of Jan Bagnall, FPLE Ex. 15 at 6-7.

This leaves Scenario 1B less cost-effective than Scenario 2, which is counter to the requirement in PURA § 39.904(g)(2) calling for the most cost-effective and beneficial plan. Additionally, although Scenario 1B is less expensive, it leaves little (if any) room for expansion of wind generation after 2008. While Scenario 1B has cost estimates of $733,981 per MW of new capacity and barely catches up with current development, Scenario 2 has cost estimates of $426,729 per MW of new capacity and leaves room for expansion.[39] ERCOT did not evaluate production cost savings for Scenarios 3 or 4, so there is no basis for making a determination on their cost-effectiveness. ERCOT did conclude that it was unlikely that the higher level of wind generation in those two scenarios could be placed in service by 2012. Because information on ERCOT generation levels, loads, and transmission additions needed to make accurate forecasts of ERCOT operation and production costs after 2012, it would be risky and premature for the Commission to implement Scenario 3 or 4.[40] In order to calculate fuel cost savings for 3 or 4, ERCOT would need to develop a transmission plan for the transmission overloads that result from the load growth between 2012 and 2018, or would need to develop a different modeling approach.[41]

5. Estimated Costs of Additional Ancillary Services

P.U.C. SUBST. R. 25.174(c)(3)(B) allows the Commission to consider the estimated cost of additional ancillary services in developing the transmission capacity plan. The analysis of cost-effectiveness of the plan includes consideration of the costs of reliably integrating the additional energy. The Commission acknowledges the GE study's finding that increased wind capacity requires traditional thermal units to provide ancillary services more frequently, and that ramping thermal units up and down will have cost impacts on the maintenance and operations of the units. However, the Commission finds compelling the GE study's conclusion that this displacement of thermal units with wind generation reduces the overall spot price of energy.[42]

---

[39] CTO Study, ERCOT Ex. 4 at Ex. DW-1 at 22-23.

[40] Direct Testimony of Scott Norwood, Cities Ex. 1 at 19-20.

[41] Direct Testimony of Brian Almon, Staff Ex. 6 at 14.

[42] GE's Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements, ERCOT Resource 3 at RW-2, Executive Summary at 8, and at 5-9.

The Commission also notes the GE study's finding that although the total regulation service procured in a year will increase with increased wind generation capacity, increased wind capacity tends to reduce the per-MWh price, resulting in a small cost of regulation per MWh of wind generation, with the high end of the range at $0.27/MWh.[43] In addition, the study addressed responsive and non-spinning reserves service and replacement reserves, and made the analogy that fast drops in wind generation output are much like a fast load rise. Responsive reserve service would only need to be procured to the degree that they are not covered by non-spinning reserve service. The study suggested ways to influence and manage the relative costs of increased wind penetration on these services, such as the development of an additional "quick-start non-spinning reserve" (15 minute start-up time rather than 30 minutes), more certain wind forecasting, and higher confidence levels for commitment schedules.[44] Also, as a point related to ancillary services costs, the Commission notes that ERCOT estimated that Scenario 2 brings lower congestion costs ($2,926,117) compared to those costs of Scenario 1B ($3,271,508).[45] Another factor of the costs of ancillary services is balancing the potential increase in ancillary services and costs against the average system fuel savings of wind energy. ERCOT estimated that Scenario 2 provides an average savings of $38/MWh for each MWh of wind.[46]

It is understood that the costs of maintaining reliability and stability will vary depending on market structure and system conditions. The Commission is confident in ERCOT's assurances that system reliability can be maintained at Scenario 2 levels of wind generation by the lowest-cost alternatives, and can rely on scheduling additional thermal units and curtailing wind generation when there is no lower-cost alternative. Although there were benefits regarding ancillary services costs being lower and more predictable with lower levels of wind-energy integration at Scenario 1B, and the potential for greater fuel savings with higher levels of wind-energy at Scenario 3 or 4, the trade-offs for getting the best value for the transmission dollars while limiting the risks associated with maintaining reliability lead the Commission to the selection of Scenario 2.

---

[43] GE Ancillary Services study, ERCOT Resource 3 at RW-2 at 9-7 to 9-8.

[44] *Id.* at Executive Summary at 15.

[45] Work Papers of Jess Totten, Staff Exhibit 7 at 15.

[46] CTO study, ERCOT Ex. 4 at Ex. DW- 1 at 24; Direct Testimony of Brendan Kirby, Wind Coalition Ex. 1 – Phase 2 at 7-8.

6. Other Factors Regarding Benefits and Cost-effectiveness of the Plan

P.U.C. Subst. R. 25.174(c)(3)(C) allows any other factors the Commission finds appropriate to be considered as provided by PURA. The Commission considered factors such as the integration of each scenario's wind generation in a reliable manner, the intent of the Legislature in directing the Commission to construct transmission capacity to deliver electricity from the CREZs, the environmental benefits, and the future expansion capability and other benefits of the plans.

i. Reliable Integration

The implementation of Scenario 2, with the specific lines prioritized as described, will provide ERCOT the benefit of experience in the process of integrating increasingly more wind energy. Reliability issues that were discussed at length in the direct testimony and evidence presented and during cross examination of witnesses at the hearing should be resolved through this experience.

The record is replete with examples of the efforts currently underway at ERCOT to address maintaining reliability with higher levels of wind generation.[47] There have been recent operational rule changes and there are several revisions under consideration, specifically in the Wind Operations Task Force. One notable example is the replacement of unit-specific energy schedules with schedules based on an objective wind forecast. Another example is ERCOT's use of an 80% confidence factor to mitigate the risk that wind will not deliver scheduled energy in real time. There are rule changes addressing wind generation interconnection standards, performance measures, and ancillary service requirements, such as voltage control, training, and grid maintenance and congestion. ERCOT is considering ramp rate limitations on wind resources, to mitigate impacts to system frequency (system frequency requires balancing supply and load on an instantaneous basis and is negatively impacted by rapid ramp rates). Also, requirements are being implemented that wind generation provide real-time hourly production

[47] *See e.g.* Rebuttal Testimony of Mark Bruce, FPLE Ex. 15 at 3-7; Tr. at 1922-24 (June 12, 2008).

updates, and the implementation of nodal operations will provide more transparency than QSE portfolio-based dispatch and will better enable ERCOT to manage wind generation.[48]

A more conservative approach would be to select Scenario 1B, which would bring into ERCOT 12,053 MW of wind-generated electricity, once the transmission facilities can be constructed and placed into service. This amount is well within the actual tiers of MW analyzed, as applied to 2008 peak system load, in the GE Ancillary Services study. However, the Commission is confident that ERCOT is capable of integrating 18,456 MW of wind-generated electricity without sacrificing system stability and reliability. The Commission notes that the GE Ancillary Services study pointed out that the 15,000 actual MW analyzed is the equivalent in terms of wind penetration to 18,456 MW of wind generation applied to the forecast 2017 peak system load.[49] In other words, 15,000 MW is 23% wind penetration as applied to the 2008 peak system load, which is equivalent to the wind penetration of 18,456 MW as applied to the 2017 forecasted peak system load. The GE study found that, although the impacts of wind generation will become a significant focus in ERCOT system operation, this percentage of wind penetration could be reliably integrated with existing technology and operational attention, without any radical alteration of operations.[50] The aforementioned efforts being undertaken at ERCOT further buttress the decision to proceed directly to Scenario 2. It is also clear that from a reliability standpoint, the selection of Scenario 3, with almost 25,000 MW of wind generation, is not supported by the record evidence. Gaining experience in reliably integrating wind, at levels of penetration as related to system load projections that have been vetted by the GE Ancillary Services study, is the most reasonable approach.

ii. Legislative Intent

The intent of the Legislature in passing the amendments to PURA §§ 36.053, 39.203, and 39.904 in 2005 was to further encourage the development of renewable-energy resources by establishing a process to provide reliable and economical transmission resources ahead of renewable generation. In addition to raising the bar on renewable-energy goals and requiring the

---

[48] Tr. at 1860-62 (June 12, 2008).

[49] GE Ancillary Services study, ERCOT Resource 3 at RW-2, Executive Summary at 2.

[50] *Id.* at 9-4.

Commission to develop a CREZ transmission plan, the amendments waive requirements and shorten timeframes applicable to other CCN applications and deem CREZ transmission facilities used, useful, and prudent for rate-setting purposes. The statements made by Texas legislators in the house and senate also support the conclusion that the Legislature's intent is clear.[51] Scenario 2 best satisfies this intent. Selection of a smaller plan than Scenario 2 would not only leave little room for expansion, thereby not providing transmission resources *ahead* of renewable generation, it would also have a chilling effect on capital investment in the Texas renewable energy industry, most notably wind. Although Scenario 3 arguably would go further in satisfying the intent of the Legislature, the noted discussions and filed statements of the legislators make it clear that maintaining reliability of the system is paramount. Because there was insufficient assurance that levels of wind energy associated with Scenario 3 could be reliably integrated, the Commission does not consider it the best plan from the standpoint of satisfying the Legislature's intent.

iii. Environmental Benefits

Environmental benefits were not specifically quantified in the CTO study, but the Commission notes that, logically, transmission plans providing for greater amounts of wind-generated energy also bring greater air quality and water conservation benefits as they reduce the reliance on other generation sources. FPL witness Jan Bagnall testified regarding the modeling of energy projects that credibly confirmed water savings of electricity produced through wind generation compared to combined cycle gas-fired and coal generation plants. It was estimated that 350 gallons of water are consumed per MWh from a gas plant and 800 gallons of water per MWh from a coal plant.[52] After construction of wind facilities, there is very little water consumed in the process of generating electricity.[53] Similar analysis was conducted regarding

---

[51] Senator Fraser, author of SB 20, described the increase in the goals for renewable energy as being conservative in a discussion on July 12, 2005 with Senator Lucio on the floor during the passage of the bill. He stated that the expectation was to get to a higher number as quickly as reliability issues can be addressed in ERCOT, and mentioned cost of transmission development as a secondary factor. In the House, Representatives Swinford and Baxter filed a statement of legislative intent regarding SB 20. The statement provided that the new goals were set in a measured step while instructing the Commission and ERCOT to carefully study transmission and capacity adequacy. It also stated that they want Texas to reach its renewable-energy goals ahead of time.

[52] Direct Testimony of Jan Bagnall, FPLE Ex. 15 at JB-2 at 10.

[53] United States Department of Energy's 20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply, Commissioners Ex. 7 at 1.3.2.

the reduction of emissions of NO_x, SO_2, and CO_2 that result from increased levels of wind-generated electricity. Thus, each transmission plan that brings increasing amounts of wind-generated electricity also brings increasing environmental benefits. Although Scenario 3 was even more attractive than Scenario 2 in this regard, the reliability concerns associated with Scenario 3 outweighed these benefits.

iv. Future Expansion Capability and Other Benefits

The ability to cost-effectively expand the transmission capacity is a very important consideration. Scenarios 1B, 2, and 3 were designed by ERCOT with expandability in mind.[54] Each of these plans is essentially a subset of the next larger plan. Scenario 1A was designed by ERCOT to be the least expensive way to reach the minimum tier of wind generation identified by the Commission at the first phase of the case, without any focus on expansion capability. Scenario 1A was dismissed as a non-viable option primarily for this reason. Expansion capability was a very attractive component of Scenario 1B, but because wind generation has already outgrown Scenario 1B's capacity, it too was rejected in favor of Scenario 2.

In addition to Scenario 2 leaving room for growth while still maintaining expansion capability to Scenario 3 if necessary, Scenario 2 also provides non-CREZ benefits that Scenario 1A or 1B do not. These were noted by LCRA TSC witness, Sergio Garza, who points out that Scenario 2 also benefits the system by meeting critical needs of non-CREZ wind development, economic long-term system solutions, and Hill Country load growth.[55]

Finally, Scenario 2 provides transmission capacity for 18,456 MW of wind-generated energy from the CREZs, which serves to better diversify Texas's energy mix by making renewable energy a larger slice of the Texas energy pie. Greater energy diversification is important to the goal of energy security. Wind as a cost-free fuel is not subject to price volatility like natural gas, or the regulatory uncertainties associated with the emission of greenhouse gases. Scenario 2 provides for the integration of levels of renewable energy that contribute to a robust and diverse portfolio of energy sources without sacrificing reliability. Similarly to the

---

[54] CTO Study, ERCOT Ex. 4 at Ex. DW-1 at 6, 16.

[55] Direct Testimony of Sergio Garza, LCRA TSC Ex. 2 at 17-18.

environmental benefits discussed previously, Scenario 3 was an even more attractive plan for bringing diversity to the state's energy mix, but this gain was outweighed by reliability concerns.

F. Future Actions

After the issuance of a final order in this docket, the Commission will proceed, pursuant in part to P.U.C. SUBST. R. 25.174(c), to select the entity or entities responsible for constructing the transmission improvements to the CREZs. The Commission anticipates that the selection of the entity or entities responsible for constructing the transmission improvements to the CREZs will be completed by the end of 2008, and that those selected entities will move diligently towards the development and submission of applications for certificates of convenience and necessity (CCN) by the end of 2009. The Commission intends to address the applications by mid-2010 and expects the selected entities to expeditiously begin and complete construction of their transmission projects following approval of their respective applications for CCNs.

Also as discussed in more detail above, the Commission has the expectation that the lines identified as having the utmost priority will be addressed, planned, certificated, constructed, and placed into service first. This prioritization may be accomplished in the manner determined to be the most expedient, either in the CREZ transmission process or via the RPG process.

Although the Commission determines that the designated CREZs be interconnected with ERCOT via the major transmission improvements identified in this order, the parties have raised concerns regarding jurisdictional issues attendant to the interconnection of generation in the northern area of the Panhandle. Should generators located in Zones 2A and 4 desire to pursue interconnection with the Southwest Power Pool (SPP), the Commission would not discourage such interconnection provided those generators do not interconnect simultaneously with ERCOT. For those generators located in zones 4 and the northern portion of zone 2A[56] who desire to interconnect with ERCOT, the Commission strongly suggests a determination by the Federal Energy Regulatory Commission (FERC) disclaiming jurisdiction. Accordingly, either the generator wishing to be served or the transmission service provider that would provide such

[56] Defined as the portion of zone 2A that is included in zone 1 in Figure 3 of the ERCOT Study.

interconnection should first obtain FERC statement disclaiming jurisdiction before the Commission will approve a CCN application. Similar to the approval granted in the *Cottonwood*[57] case, such FERC approval should be in the form of an Order Granting Petition for Declaratory Order or any other mechanism by which the FERC disclaims jurisdiction over the proposed transmission lines to ERCOT, transmission service over the proposed transmission lines, and the utilities in ERCOT that are not currently public utilities under the Federal Power Act.[58]

Although the Commission is not addressing curtailments and dispatch priority issues in this docket, the Commission does state that, as a matter of policy, there is an expectation that no nuclear facilities will be curtailed during periods of high wind generation. The GE study included the determination that increased wind energy production is primarily offset by a decrease in the production of combined-cycle gas turbine plants.[59] However, during periods of light load and high wind levels, plants utilizing other sources of generation may see significant turndowns, as well.[60] Given the unique characteristics of nuclear energy production, during periods of light load and high wind levels, it is sound policy to prohibit the back-down of nuclear power plants. The Commission also has the expectation that staff, ERCOT, and system participants will address the effects of light load and high wind levels on other forms of generation, in particular, recognizing the future critical role that coal generators utilizing "clean" coal and carbon capture and sequestration technologies may occupy in ERCOT. This issue is most appropriately resolved in a currently ongoing Commission project addressing dispatch prioritization in the CREZ zones.[61]

Finally, the Commission expects that reliability issues will be further explored through either an implementation docket or the Wind Operations Task Force, or some combination of

---

[57] *Cottonwood Energy Company, L.P.*, Order Granting Petition for Declaratory Order, 118 FERC ¶ 61,198 (2007).

[58] *See id.*

[59] GE Ancillary Services study, ERCOT Resource 3 at RW-2 at 5-2.

[60] *Id.*

[61] *See Proceeding to Establish Policy Relating to Excess Development in Competitive Renewable-energy Zones*, Project No. 34577 (pending).

both. It is necessary that the Commission maintain a strong feedback loop with a centralized process to assure that necessary reporting needs are met and that various reliability issues are being worked in a unified, not fragmented, manner. Toward that goal, the Commission directs ERCOT, through any committee or task force as designated by ERCOT, to report to the Commission on a quarterly basis regarding reliability issues being studied. Unless staff designates a different project, Project No. 34577 can also be utilized for this purpose.

V. Findings of Fact

Procedural History

1. On December 15, 2006, in Project No. 31852, the Commission adopted P.U.C. SUBST. R. 25.174 to effectuate the requirements of PURA § 39.904(g).

2. P.U.C. SUBST. R. 25.174(a)(1) required Commission Staff to initiate a contested-case proceeding to designate competitive renewable-energy zones (CREZs) upon receiving the Electric Reliability Council of Texas's (ERCOT's) study of the statewide wind-energy-production potential and the transmission constraints that are most likely to limit the deliverability of electricity from wind-energy resources.

3. On December 7, 2006, ERCOT filed its study, entitled "Analysis of Transmission Alternatives for Competitive Renewable-energy Zones in Texas," (ERCOT Study) in *Reports to the Legislature on Renewable Energy and the Need for Generation and Transmission Facilities*, Project No. 33577.

4. On January 4, 2007, Commission Staff filed its petition in this docket for CREZ designation.

5. On January 8, 2007, the Commission issued Order No. 2, setting the intervention deadline as January 22, 2007.

6. On January 25, 2007, the Commission issued Order No. 3, granting the following parties' motions to intervene: AEP Texas Companies (AEP Texas Central Company, AEP Texas North Company, and Southwestern Electric Power Company); AES SeaWest Inc.; Airtricity Inc.; Babcock & Brown Renewable Holdings Inc.; BNB Renewable Energy LLC; Briscoe County; Celanese Ltd.; CenterPoint Energy Houston Electric LLC; City

of Abilene; City of Austin d/b/a Austin Energy; City of Garland; CMS Enterprises Company; CPS Energy; Denton Municipal Electric; Direct Energy LP, CPL Retail Energy LP, and WTU Retail Energy (the Direct Companies); East Texas Cooperatives (Sam Rayburn G&T Electric Cooperative Inc, Tex-La Electric Cooperative Inc., and East Texas Electric Cooperative Inc.); Electric Transmission Texas LLC (ETT); ERCOT; Eurus Energy America Corporation; Floyd County; Floydada Economic Development Corporation; FPL Energy LLC; Fremantle Energy LLC; Golden Spread Electric Cooperative Inc.; Great Plains Windpower LLC; Guadalupe Valley Electric Cooperative Inc.; Homestead Wind LLC.; Horizon Wind Energy LLC; Invenergy Wind North America LLC; ITC Grid Development; LCRA Transmission Services Corporation; Lockney Economic Development Corporation d/b/a Opportunity Lockney; Mesa Water Inc. (subsequently identified as Mesa Power LLC); Noble Environmental Power LLC; NRG Texas LLC; Occidental Energy Ventures Corp.; Penn Real Estate Group Ltd.; PPM Energy Inc.; Public Werks Inc.; Reliant Energy Retail Services LLC; RES America Developments Inc.; Sharyland Utilities LP; Shell WindEnergy Inc.; South Texas Electric Cooperative Inc.; Southwest Power Pool Inc. (SPP); Southwestern Public Service Company (SPS); Steering Committee of Cities Served by TXU (Cities); Texas Industrial Energy Consumers (TIEC); Texas-New Mexico Power Company; The Wind Coalition; Tierra Energy LLC; TXU Electric Delivery Company; TXU Energy, Wholesale, and Power Companies; West Texas Wind Energy Consortium; and White-Wind Power Co.

7. On February 14, 2007, the Commission issued Order No. 6, granting the following parties' late-filed motions to intervene: BPWENA; Chermac Energy Corporation; Clipper Windpower Development Company Inc.; King Ranch Minerals Inc. (subsequently identified as King Ranch Inc.); and Office of Public Utility Counsel (OPC).

8. On February 15, 2007, the Commission issued an order requesting each interested party to file a list of issues to be addressed by the Commission in this docket.

9. On February 15, 2007, the following parties timely filed CREZ nominations: AES Seawest Inc.; BPWENA; Eurus Energy America Corporation, Clipper Windpower

Development Company Inc., and Floydada Economic Development Corp.; FPL Energy LLC; Fremantle Energy LLC; Horizon Wind Energy LLC; Invenergy; ITC Grid Development LLC; LCRA Transmission Services Corp.; Mesa Power LLC; NRG Texas LLC; Panhandle Loop Intervenors (Airtricity Inc., Babcock & Brown Renewable Holdings Inc., Celanese Ltd., Occidental Energy Ventures Corp., and Sharyland Utilities LP); Penn Real Estate Group Ltd.; PPM Energy Inc.; RES America Developments Inc.; and Shell WindEnergy Inc. BNB Renewable Energy LLC and Chermac Energy Corporation submitted nominations on February 16, 2007. McDowell Ranch submitted a motion to intervene that also indicated a CREZ nomination on March 8, 2007.

10. On February 26, 2007, each of the following entities filed a list of issues: AES SeaWest Inc.; BPWENA; Commission Staff; Electric Transmission Texas LLC, AEP Texas Central Company, AEP Texas North Company, and Southwestern Electric Power Company; ERCOT; FPL Energy LLC; Fremantle Energy LLC; Golden Spread Electric Cooperative Inc.; Horizon Wind Energy LLC; ITC Grid Development; King Ranch Inc.; Panhandle Loop Intervenors (Airtricity Inc., Babcock & Brown Renewable Holdings Inc., Celanese Ltd., Occidental Energy Ventures Corp. and Sharyland Utilities LP); PPM Energy Inc.; Public Werks Partners; RES America Developments Inc.; Shell WindEnergy Inc.; SPP; the Steering Committee of Cities Served by TXU; TIEC; and TXU Electric Delivery Company.

11. On March 8, 2007, King Ranch Inc. and ITC Grid Development LLC filed motions to sever, which were both subsequently denied.

12. On March 21, 2007, parties filed testimony regarding their financial commitment for CREZs.

13. On March 23, 2007, the Commission filed its preliminary order, identifying issues to be addressed and an issue not to be addressed in this case.

14. On March 26, 2007, the Commission issued Order No. 11, granting the following parties' late filed motions to intervene: McDowell Ranch and Wagner & Brown Ltd., and on March 27, 2007, the Commission issued Order No. 12 correcting the names of the intervenors listed in Order. No. 11.

15. On March 30, 2007, the Commission issued Order No. 13, granting the following parties' late filed motions to intervene: Salt Fork Wind LP & Cielo Wind Power LLC, Noelke Hill GP LLC & Cielo Wind Power LLC (subsequently corrected to Cielo Noelke GP, LLC & Cielo Wind Power, LLC), and Tenaska Transmission Development Partners LLC.

16. On April 24, 2007, parties filed direct testimony on issues other than financial commitment.

17. On April 26, 2007, the Commission issued Order No. 21, granting Wind Tex Energy LP's late-filed motion to intervene.

18. On May 4, 2007, the Commission issued Order No. 22, granting the following parties' motions to withdraw from this docket: Public Werks Inc. on behalf of Public Werks Partners and Homestead Wind LLC; and Tenaska Transmission Development Partners LLC.

19. On May 21, 2007, parties filed rebuttal testimony.

20. The Commission conducted a hearing on the merits for this docket on June 11-14, 2007.

21. On June 15, 2007, the Commission issued an order extending time for issuance of the final order and requesting briefing on certain threshold legal and policy issues.

22. Post-hearing briefs filed by the parties by June 29, 2007 were timely received.

23. At its July 20, 2007 open meeting, the Commission discussed and rendered its decision in this docket, as set forth in the Interim Order.

24. On August 6, 2007, the Commission issued Order No. 34, seeking clarification from Wind Tex Energy, L.P. regarding that entity's participation in the hearing. On August 13, 2007, Wind Tex Energy responded requesting that its prefiled testimony be considered part of the record.

25. At its August 16, 2007 open meeting, the Commission clarified certain determinations made at its July 20, 2007 open meeting, which were incorporated into the Interim Order issued on October 2, 2007.

26. Motions for reconsideration, responses and other pleadings regarding the interim order were filed by FPL Energy, Airtricity, Penn Real Estate Group, Commission Staff, Cielo Noelke, BP Wind Energy North America, Chermac Energy Corporation, LCRA TSC, AES Seawest, and Shell Windenergy.

27. On November 6, 2007, the Commission issued the Interim Order on Reconsideration.

28. On February 21, 2008, the Commission issued Order No. 35, granting the following parties' motions to intervene: CPV Renewable Energy Company, LLC and CPV Rattlesnake Den Renewable Energy Company, LLC.

29. On March 18, 2008, the Commission issued the Order Requiring Settlement Conference regarding the selection of transmission providers in Project No. 34560.

30. On April 2, 2008, ERCOT filed the GE Ancillary Services study and the CREZ Transmission Optimization study.

31. On April 9, 2008, the Commission issued Order No. 36, granting the following parties' motions to intervene: Lone Star Transmission, LLC, Trans-Elect Texas, LLC, and Tejas Transmission, LLC.

32. On April 15, 2008, the Commission issued Order No. 38, setting the prehearing and hearing schedule.

33. Appeals, responses to appeals, and other pleadings regarding Order No. 38 were filed by FPL Energy, Lone Star Transmission, CPS Energy, STEC, Golden Spread Electric Cooperative, Inc., the City of Garland, Denton Municipal Electric, Trans-Elect Texas, Luminant Energy and Luminant Generation, E.On Climate and Renewables, AES Seawest, Horizon Wind Energy, Sharyland Utilities, Invenergy, and Oncor.

34. On April 28, 2008, the Commission issued Order No. 39, approving ERCOT's proposal to utilize Mr. Reigh Walling of GE and Mr. Michael Brower of AWS as sponsoring witnesses for the GE study.

35. On May 2, 2008, the Commission issued Order No. 40, granting the following parties' motions to intervene: Cross Texas Transmission, LLC, Brazos Electric Power Cooperative, Inc., Longfellow Ranch Partners, Edison Mission Energy, Public Citizen of Texas, Texas Impact, Environment Texas, and the Sustainable Energy and Environmental

Development Coalition, Environmental Defense Fund, AEP Energy Partners, Inc., Desert Sky Wind Farm, LP, and Trent Wind Farm, LP.

36. On May 5, 2008, the Commission issued Order on Appeal of Order No. 38, granting in part and denying in part the relief requested in the appeals. The Commission determined that it is appropriate to include the GE Ancillary Services study in the record of this proceeding, and that the parties would be allowed the opportunity in this docket to present relevant, non-cumulative evidence and rebut evidence presented, regarding issues in dispute arising from the CREZ Transmission Optimization Study and the GE Ancillary Services study.

37. On May 7, 2008, the Commission issued Order No. 41 to set a revised procedural schedule, and issued Order No. 42 to provide additional clarification regarding the hearing and prehearing procedures.

38. On May 23, 2008, direct testimony was filed by the parties, and on June 3, 2008, rebuttal testimony was filed by the parties.

39. The Commission conducted a hearing on the merits in this second phase of this docket on June 11-12, 2008.

40. On June 26, 2008, post-hearing briefs from the parties were timely filed.

41. The Commission issued its initial order in this docket on August 15, 2008.

42. Motions for rehearing, responses, and other pleadings regarding the order were filed by Cities, City of Austin, TIEC, LCRA TSC, Commission Staff, FPL Energy, several wind developers, and the Direct Companies.

CREZ Designations

Renewable-energy Resources and Suitable Land Areas

43. The ERCOT Study was completed to support the Commission's evaluation of potential areas to be designated as CREZs.

44. The ERCOT Study represents ERCOT's independent evaluation, with input from ERCOT stakeholders and the SPP, of the potential for wind-generation development in Texas.

45. ERCOT solicited information from stakeholders regarding areas in which there was market interest in developing wind resources; these areas, as depicted in Figure 1 in the ERCOT Study, were considered in ERCOT's analysis of the potential for wind-generation development in the state.

46. ERCOT solicited proposals from outside consultants who specialized in meteorological modeling and wind generation analysis to conduct an independent analysis of wind resources throughout the state.

47. ERCOT selected AWS Truewind as its outside consultant to identify areas throughout the state with the best wind-resource potential.

48. AWS Truewind used a complex meteorological and geophysical model, called MesoMap, to provide localized prediction of wind patterns and resulting wind power output across the state to identify those areas with the best wind resources.

49. AWS Truewind identified areas where sufficient land was available to support 100 MW of installed wind generation with the highest annual capacity factors and clustered those sites into 25 areas based on similarity of wind resources.

50. Using the results of the MesoMap model, AWS Truewind selected the 40 best 100-MW sites in each of the 25 zones, for a total of 4,000 MW in each zone.

51. AWS Truewind provided one year of typical hourly wind output for each of the 100-MW sites within the 25 zones.

52. Figure 3 from the ERCOT Study shows the location of the areas, identified by AWS Truewind, with the best 4,000 MW with the highest annual capacity factors within each of the 25 zones.

53. The zones in Figure 3 of the ERCOT Study generally are ordered by the quality and quantity of wind generation, with zone 1 having the strongest and zone 25 the weakest overall wind resources.

54. The methodology utilized by AWS Truewind is adequate for identifying those areas in the state with renewable-energy resources, in the form of wind-energy potential, and land areas suitable for the development of those resources.

55. The AWS Truewind Study, as incorporated into the ERCOT Study, in addition to the relevant testimony and evidence submitted by the parties, establishes that the criteria relating to suitable land areas and renewable-energy resources has been met for each of the zones designated by the Commission as CREZs.

Financial Commitment by Generators

56. In evaluating the level of financial commitment for the nominated zones, among other factors, the Commission considered the number of developers and total resources committed by those developers.

57. No financial commitment evidence was received for zones 3, 8, 15, 16, 17, 21, 22, 23, and 24; thus, these zones were excluded from further evaluation for CREZ designation.

58. Zones 7, 11, 12, 13, 14, 18, 20, and 25 were supported by only one or two interested developers with relatively less financial commitment than those zones chosen by the Commission for CREZ designation.

59. The following developers presented financial commitment evidence and testimony with respect to zone 2A: BPWENA; Chermac Energy Corporation; Clipper Windpower Development Company Inc.; Eurus Energy America Corporation; Horizon Wind Energy LLC; Invenergy Wind North America LLC; PPM Energy Inc.; RES America Developments Inc.; and Shell WindEnergy Inc.

60. BPWENA's financial commitment to zone 2A is comprised of, but not limited to: approximately 50,000 acres either in final negotiations or under agreement; millions of dollars expended for development; and possession of a multi-year turbine supply agreement.

61. Chermac Energy Corporation's financial commitment to zone 2A is comprised of, but not limited to: approximately 20,000 acres leased; filed requests for interconnection studies with SPP; and upward of $1.5 million spent and projected to be spent for development.

62. Clipper Windpower Development Company Inc.'s financial commitment to zone 2A is comprised of, but not limited to: filed requests for interconnection studies with SPP; approximately 16,980 acres leased; and a projection of $750,000,000 to be spent for development.

63. Eurus Energy America Corporation's financial commitment to zone 2A is comprised of, but not limited to: financing facility letter for $400,000,000 from Mizuho Corporate Bank, Ltd.; 24,311 acres leased; and completed interconnection screening study and feasibility study.

64. Horizon Wind Energy LLC's financial commitment to zone 2A is comprised of, but not limited to: 45,816.93 acres under lease agreements; millions of dollars expended for development; and existing long-term wind turbine supply contracts.

65. Invenergy Wind North America LLC's financial commitment to zone 2A is comprised of, but not limited to: over $500,000 expended for development with over $1 billion projected to be expended; approximately 51,000 acres leased; and two initiated interconnection requests with ERCOT.

66. PPM Energy Inc.'s financial commitment to zone 2A is comprised of, but not limited to, approximately 10,000 acres leased for which over $50,000 has been expended.

67. RES America Developments Inc.'s financial commitment to zone 2A, which was filed under seal, represents a significant commitment to development in the form of funds expended, funds projected to be expended, and acres under lease.

68. Shell WindEnergy Inc.'s financial commitment to zone 2A, which was filed under seal, represents a significant commitment to development in the form of funds expended and acres under lease.

69. The following developers presented financial commitment evidence and testimony with respect to zone 4: Airtricity Inc.; Babcock & Brown Renewable Holdings Inc.; Chermac Energy Corporation; Mesa Power LLC; and PPM Energy Inc.

70. Airtricity Inc.'s financial commitment to zone 4 is comprised of, but not limited to: upwards of $8 million expended for development; over $2 billion projected to be expended under certain conditions; approximately 70,000 acres leased; filed interconnection request with ERCOT; and completed interconnection agreement with SPP.

71. Babcock & Brown Renewable Holdings Inc.'s financial commitment to zone 4, which was filed under seal, represents a significant commitment to development in the form of credit secured for development, funds projected to be expended, and acres under lease.

72. Chermac Energy Corporation's financial commitment to zone 4 is comprised of $20,000 expended for wind development prospect evaluation with $1,200,000-$1,500,000 allocated for development costs.

73. Mesa Power LLC's financial commitment to zone 4 is comprised of, but not limited to: in excess of $200,000 expended for development; $4-6 million projected to be spent; and negotiations with landowners regarding leasing rights to 200,000 acres.

74. PPM Energy Inc.'s commitment to zone 4 is comprised of, but not limited to: interconnection requests filed with both ERCOT and SPP; approximately $40,000 invested to install and operate 2 meteorological towers onsite; and commitments to obtain options to lease acreage sufficient to support a 300 MW project.

75. The following developers presented financial commitment evidence and testimony with respect to zones 5 and 6: BPWENA; Fremantle Energy LLC; Horizon Wind Energy LLC; NRG Texas LLC, and RES America Developments Inc.

76. BPWENA's financial commitment to zones 5 and 6 is comprised of, but not limited to: millions of dollars expended for development; approximately 60,000 acres either in final negotiations or under agreement; and possession of a multi-year turbine supply agreement.

77. Fremantle Energy LLC's financial commitment to zones 5 and 6 is comprised of, but not limited to: approximately 10,000 acres in final lease negotiations; $5.2 million projected to be spent; and funded ERCOT interconnection study.

78. Horizon Wind Energy LLC's financial commitment to zones 5 and 6 is comprised of, but not limited to: more than $110,000 spent for development; commitments for a minimum of 15,600 acres; and existing long-term wind turbine supply contracts.

79. NRG Texas LLC's financial commitment to zones 5 and 6, which was filed under seal, represents a substantial commitment to development in the form of funds expended and projected to be expended.

80. RES America Developments Inc.'s financial commitment to zones 5 and 6, which was filed under seal, represents a substantial commitment to development in the form of funds expended and acres under lease.

81. The following developers presented financial commitment evidence and testimony with respect to zone 9A: AES SeaWest Inc.; BNB Renewable Energy LLC; BPWENA; FPL Energy LLC; Invenergy Wind North America LLC; NRG Texas LLC; RES America Developments Inc.; and Tierra Energy LLC.

82. AES SeaWest Inc.'s financial commitment to zone 9A is comprised of, but not limited to: upwards of $1 billion dollars expended for existing and planned projects; tens of thousands of acres under lease for existing and planned projects; multiple interconnection studies in progress; and commitments to wind turbine vendors for future delivery.

83. BNB Renewable Energy LLC's financial commitment to zone 9A is comprised of, but not limited to: approximately $859,000 spent for development; approximately 60,000 acres leased and optioned; and an interconnection application filed with ERCOT.

84. BPWENA's financial commitment to zone 9A is comprised of, but not limited to: millions of dollars expended for development; approximately 20,000 acres either in final negotiations or under agreement; and possession of a multi-year turbine supply agreement.

85. FPL Energy LLC's financial commitment to zone 9A is comprised of, but not limited to: $1.05 billion expended for existing renewable facilities, with nearly $500 million projected to be spent for a new project; leasing agreements; and completed screening and interconnection studies.

86. Invenergy Wind North America LLC's financial commitment to zone 9A is comprised of, but not limited to: over $165 million expended for development; approximately 85,000 acres of surface rights obtained; interconnection requests initiated; and one signed interconnection agreement.

87. NRG Texas LLC's financial commitment to financial commitment to zone 9A, which was filed under seal, represents a significant commitment to development in the form of funds expended, funds projected to be expended, and acres under lease.

88. RES America Developments Inc.'s financial commitment to zone 9A, which was filed under seal, represents a substantial commitment to development in the form of funds expended, funds projected to be expended, and acres under lease.

89. Tierra Energy LLC's financial commitment to zone 9A, which was filed under seal, represents a significant commitment to development in the form of funds expended, funds projected to be expended, and acres under lease.

90. The following developers presented financial commitment evidence and testimony with respect to zone 19: Invenergy Wind North America LLC; Penn Real Estate Group Ltd.; and Tierra Energy LLC.

91. Invenergy Wind North America LLC's financial commitment to zone 19 is comprised of, but not limited to: approximately $322,000 expended for development; $1.8 billion projected to be spent; approximately 70,000 acres of surface rights obtained; interconnection requests initiated; and one signed interconnection agreement.

92. Penn Real Estate Group Ltd.'s financial commitment to zone 19 is comprised of, but not limited to: approximately $2,650,000 expended for development; approximately 9,000 acres purchased; and an interconnection screening study prepared by ERCOT.

93. Tierra Energy LLC's financial commitment to zone 19, which was filed under seal, represents a significant commitment to development in the form of funds expended, funds projected to be expended, and acres under lease.

94. Those zones chosen by the Commission for CREZ designation – zones 2A, 4, 5, 6, 9A, and 19 – were supported by testimony and evidence demonstrating significant levels of financial commitment.

Geographic Extent of CREZs

95. Based on the sufficiency of suitable land areas and renewable-energy resources, as well as the relatively significant level of financial commitment, zones 2A, 4, 5, 6, 9A, and 19 should receive CREZ designation.

96. Except as specifically modified by this Interim Order, the CREZ boundaries should be based on the lines drawn by AWS Truewind in Figure 3 of the ERCOT Study, which

represent the areas with the best 4,000 MW in each of the wind resource zones. (Attachment A).

97. The boundary of zone 4 is identical to the boundary of zone 4 as set forth in Figure 3 of the ERCOT Study.

98. The boundary of zone 19 is identical to the boundary of zone 19 as set forth in Figure 3 of the ERCOT Study.

99. The boundary of zone 2A is comprised of that area enclosed by the perimeter boundaries of zones 1 and 2 from Figure 3 of the ERCOT Study, plus an additional area that includes all of Briscoe County.

100. The evidence presented by Shell WindEnergy Inc.'s witness Chris Ziesler justifies the inclusion of the entirety of Briscoe County in zone 2A because of the presence of high capacity factors throughout the county and Shell WindEnergy Inc.'s financial commitment to develop resources in Briscoe County.

101. Zone 1's ranking in the ERCOT Study as the area possessing the best overall wind resource in Texas warrants combining this zone in zone 2A because the combined area would possess sufficient renewable-energy resources, suitable land areas, and an adequate level of financial commitment by developers.

102. The boundary of zones 5 and 6 is expanded to include an extension of the eastern boundary of zone 5 from Figure 3 of the ERCOT Study ten miles further east into Tom Green and Schliecher counties, as depicted in Exhibit NRG-3 at Exhibit 1. (Attachment B).

103. As proposed by NRG Texas LLC, zone 5 is also expanded to include an area that falls completely within zone 11, as zone 11 is depicted in Figure 3 of the ERCOT Study; thus, the expanded area contains sufficient suitable land areas and renewable-energy resources, as well as the financial commitment by NRG Texas LLC for development.

104. The boundary of zone 9A is comprised of zones 9 and 10 from Figure 3 of the ERCOT Study, plus an additional area between the zones as requested by FPL Energy LLC and BNB Renewable Energy LLC, as set forth in Exhibit BNB-10 (Attachment C), and as requested by AES SeaWest Inc., as set forth in AES SeaWest Exh. No. 2 at Exhibit RS-1.

(Attachment D). Zone 9A also includes RES America Developments Inc.'s projects located in Callahan and Shackelford County in zone 12, as those projects were described in the record and depicted in RES EX. 2A at Exhibit C (filed under seal).

105. The area advocated for CREZ designation by FPL Energy LLC and BNB Renewable Energy LLC, as set forth in BNB-10, contains Horse Hollow (the world's largest operational wind farm, which FPL Energy LLC has expressed plans to expand) as well as Bull Creek (BNB Renewable Energy LLC's planned wind project); thus, the expanded area possesses significant financial commitment. Such financial commitment is indicative of the presence of the sufficiency of suitable land areas and renewable-energy resources.

106. The expansion to zone 9A advocated by AES SeaWest Inc. to include the areas just east of zone 9 located in Coke and Tom Green counties captures the financial commitment advanced by AES SeaWest Inc. for wind-resource development in the expanded area. Such financial commitment is indicative of the presence of the sufficiency of suitable land areas and renewable-energy resources.

107. The area for which RES America Developments Inc. proposes to expand zone 9A to include falls completely within zone 12, as zone 12 is depicted in Figure 3 of the ERCOT Study; thus, the expanded area contains sufficient suitable land areas and renewable-energy resources, as well as the financial commitment by RES America Developments Inc. for development.

108. For all zones for which the Commission has not made a specific statement regarding the granting of an expansion, the Commission finds that expansion of such zones was not sufficiently supported by the record evidence.

Transmission Solutions

109. Although several transmission proposals were presented in phase 1 of this docket, further study was needed to evaluate the major transmission improvements needed to serve the CREZs to determine which improvements have the potential to be the most beneficial and cost-effective to customers.

110. ERCOT conducted the necessary studies to determine the transmission needed to serve the CREZs designated by the Commission in this proceeding and produced the "CREZ Transmission Optimization Study" (the CTO study).

111. The CTO study represents ERCOT's independent evaluation, with input from ERCOT stakeholders, of optimized transmission plans to provide transfer capacity for wind generation as specified in the four scenarios previously identified by the Commission.

112. In providing megawatt tiers of transfer capability for ERCOT to study during its CTO study, the Commission provided an estimate of the maximum generating capacity that the Commission expected the transmission ordered for each CREZ to accommodate.

113. ERCOT selected General Electric International, Inc. (GE) as its outside consultant to analyze and prepare a study regarding the level, type, and cost of additional ancillary services that might be required to maintain the reliability of the ERCOT system with increasing levels of wind generation.

114. GE produced the "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements" study (the GE Ancillary Services study) to support the Commission's evaluation of which transmission scenario is most cost-effective and beneficial to the customers.

115. In the GE Ancillary Services study, GE concluded that it is possible to integrate any of the levels of wind studied in the report without compromising reliability.

116. Through completion of the CTO study and the GE Ancillary Services study, ERCOT provided the Commission with a means to select the major transmission improvements necessary to deliver to customers the energy generated by renewable resources in the CREZs, in a manner that is most beneficial and cost-effective to customers.

Selection of Scenario 2 Transmission Solution

117. Transmission improvements and upgrades identified in Scenario 2 of the CTO study have capacity to deliver to customers the electric output from renewable-energy technologies in the CREZ in the most beneficial and cost-effective manner.

118. Scenario 2 consists of the following new and upgraded lines, identified by voltage level and a general description of where the new lines interconnect to the existing grid:

McCamey, Central, and Central West: Gillespie to Newton single-circuit, double-circuit capable 345-kV line; Kendall to Gillespie single-circuit, double-circuit-capable 345-kV line; West C to Odessa single-circuit, double-circuit-capable 345-kV line; West B to Moss single circuit 138-kV line; West A to West C single-circuit, double-circuit-capable 345-kV line; West A to Central D single-circuit, double-circuit-capable 345-kV line; Twin Butte to Brown new 345-kV line on existing structures; Tonkawas to Sweetwater double-circuit 345-kV line; Sweetwater to Central Bluff double-circuit 345-kV line; McCamey D to Twin Butte single-circuit, double-circuit-capable 345-kV line; McCamey D to Kendall double-circuit 345-kV line; McCamey C to McCamey A single-circuit, double-circuit-capable 345-kV line; McCamey B to North McCamey 138-kV line on existing structures; McCamey A to Odessa single-circuit, double-circuit-capable 345-kV line; McCamey C to McCamey D single-circuit, double-circuit-capable 345-kV line; Mason to Pittsburgh138-kV line; Divide to Twin Butte adding a second circuit to existing structures; Central E to Central D single-circuit, double-circuit-capable 345-kV line; Central D to Divide single-circuit, double-circuit-capable 345-kV line; Central C to Navarro/Sam Switch double-circuit 345-kV line; Central B to Willow Creek double-circuit 345-kV line; Central B to Central A double-circuit 345-kV line; Central A to West A double-circuit 345-kV line; Central A to Tonkawas double-circuit 345-kV line; Central A to Central C double-circuit 345-kV line; Newton to Killeen 345-kV line; Brown to Newton/Salado double-circuit 345-kV line; Bluff Creek to Brown double-circuit 345-kV line; and Central Bluff to Bluff Creek double-circuit 345-kV line.

Panhandle: West Krum to Anna double-circuit 345-kV line; Willow Creek to Hicks double-circuit 345-kV line; West Krum to Carrolton NW adding a new 345-kV line to existing structures; PanOakMid to Central C double-circuit 345-kV line; Panhandle AC to PanOakMid (with one circuit looping into Tesla 345-kV bus); Panhandle BB to Panhandle BA double-circuit 345-kV line; Panhandle BB to Oklaunion (with one circuit looping into Tesla 345-kV bus) double-circuit 345-kV line; Panhandle BA to Panhandle AC double-circuit 345-kV line; Panhandle AD to PanOakMid double-circuit 345-kV line; Panhandle AD to Central B double-circuit 345-kV line, Panhandle AC to Panhandle AD double-circuit 345-kV line; Panhandle AB to Panhandle BA single-circuit, double-circuit- capable 345-kV line; Panhandle AA to Panhandle AB single-circuit, double-

circuit-capable 345-kV line; Panhandle AA to Panhandle AC single-circuit, double-circuit-capable 345-kV line; Parker to Everman new 345-kV line on existing structures; Oklaunion to West Krum double-circuit 345-kV line; Oklaunion to PanOakMid double-circuit 345-kV line; and Bowman to Oklaunion double-circuit 345-kV line.

119. Scenario 2 also includes transmission improvements other than new lines, as identified in the CTO study cost breakdown for Scenario 2 as follows:

A. *Stations:* new 345-kV stations at Sam Switch, Gillespie, Newton, Brown, Navarro, Tesla, Hicks, West Krum, and PanOakMid;

B. *Auto transformers:* addition of a 345-kV auto at Whitney, a 138-kV auto at Bandera, a 345-kV auto at Gillespie, two 345-kV autos at North McCamey, a 345-kV auto at Eagle Mountain, and the replacement of a 345-kV auto at Kendall;

C. *50% series compensation:* 50% compensation on McCamey D to Kendall; on Central C to Navarro/Sam Switch, on PanOakMid to Central C, on Panhandle AC to Tesla, and on Central B to Willow Creek;

D. *Mega volt-ampere reactive (MVAR) Reactive Compensation:* 200 MVAR on PanOakMid; 150 MVAR on Central C, Central B, and Brown, 100 MVAR on Tesla, Gillespie, Central A, and McCamey D, 50 MVAR on Panhandle AC, Panhandle AD, Panhandle BB, and Panhandle AB;

E. *MVAR Capacitor bank:* 300-MVAR bank on Oklaunion, 200-MVAR bank on PanOakMid, 150-MVAR bank on Tesla, 100-MVAR bank on Panhandle AC, and 50-MVAR bank on Panhandle AD;

F. *Open and close lines:* open Seymour to Bomarton 69-kV line, open Saps to Yellowjacket 138-kV line, open Rocksprings to Friess Ranch 69-kV line, open Fort Stockton to Barilla 69-kV line, open Bradshaw to Winters 69-kV line, and close bus ties at North McCamey bus;

G. *Rebuilds:* Sonora to Hamilton 138-kV line, Goldthwaite to Evant 138-kV line, Raymond Barker to Verde Creek 138-kV line, Kendct to Kendal 138-kV line, Verde Creek to Bandera, Willow Creek to Parker 345-kV as double circuit, and Jacksboro to Willow Creek 345-kV as double circuit;

H. *Upgrade terminal equipment:* on Eagle Mountain-Hicks-Alliance-Roanoke 345-kV line, on Abilene to Mulberry 138-kV line, on Abilene South to Leon 138-kV line, on Bowman to Graham 345-kV line, on Bowman to Fisher Road 345-kV line, on both Singleton to Gibbons Creek 345-kV lines, on Roanoke to Alliance 345-kV line, and on Morgan Creek to Twin Butte 345-kV line; and

I. *Reconductor:* on Bowman to Jacksboro 345-kV line.

120. Scenario 2 contains 2,334 miles of new 345-kV right-of-way, and 42 miles of new 138-kV right-of-way.

121. ERCOT estimates that Scenario 2 provides an average savings of $38/MWh for each MWh of wind.

122. These improvements identified as Scenario 2 are necessary to deliver to customers the energy generated by renewable resources in the CREZs.

123. The estimated cost of the plan for Scenario 2 at the time of the CTO study was $4.93 billion.

124. Based on production-costs modeling, the expected average annual wind curtailment is 2.31%, with a total annual wind generation of 64,031 GWh.

125. The updated estimate of the maximum generating capacity that the Commission expects this transmission to accommodate is 18,456 MW.

126. Scenarios 3 and 4 were significantly more expensive than Scenario 2.

127. Average system fuel cost savings was not analyzed for Scenarios 3 or 4, and the GE Ancillary Services study addressed an amount of wind energy significantly less than what Scenarios 3 or 4 would support.

128. Scenario 1B has significant limitations compared to Scenario 2 in that the amount of wind generation expected to be on the grid by the end of 2008 is approximately 10,000 MW, which would leave very little room for further wind expansion.

129. The lack of expansion capability for Scenario 1B would have a dampening effect on wind related capital investment in ERCOT.

130. Scenario 2 is less expensive than Scenario 1B on an incremental per MW of wind generation basis.

131. Scenario 2 has more environmental benefits than scenario 1B.

132. Scenario 2 addresses current chronic and severe congestion issues.

133. Scenario 2 addresses present and future needs for transmission development.

134. There is a need for more transmission generally from West Texas to the east and southeast, rather than northeast towards Fort Worth.

135. The central objective of the statutory change contemplated by SB 20 was to plan ahead of transmission capacity needs.

136. The rapid completion of certain lines identified in Scenario 2 is imperative to resolve existing congestion and address current voltage issues. These projects are designated as part of the CREZ transmission solution and are the first priority for planning and construction: the Central B to Central A double-circuit 345-kV line, the Central A to Central Bluff double-circuit 345-kV line, the Central Bluff to Bluff Creek double-circuit 345-kV line, the Bluff Creek to Brown double-circuit 345-kV line, the Brown to Newton/Salado double-circuit 345-kV line, the Newton to Killeen double-circuit 345-kV line, the Twin Butte to Brown additional 345-kV line on existing structures, the Twin Butte to McCamey D single-circuit, double-circuit-capable 345-kV line, the McCamey D to Kendall double-circuit 345-kV line, the Kendall to Gillespie single-circuit, double-circuit-capable 345-kV line, the Gillespie to Newton single-circuit, double-circuit-capable 345-kV line, and the Oklaunion to Bowman double-circuit 345-kV line.

137. Without storage capacity at scale, increased wind capacity requires traditional thermal units to provide ancillary services more frequently, and ramping thermal units up and down will have cost impacts on the maintenance and operations of the units.

138. Displacement of thermal units with wind generation will reduce the overall spot price of energy.

139. The total regulation service procured in a year will increase with increased wind generation capacity. However, increased wind capacity tends to reduce the per-MWh

price, resulting in a small cost of regulation per MWh of wind generation, with the high end of the range at $0.27/MWh.

140. Fast drops in wind generation output are much like a fast load rise. Responsive reserve service would only need to be procured to the degree that fast drops in wind generation are not covered by non-spinning reserve service.

141. ERCOT estimates that Scenario 2 brings lower congestion costs (estimated to be $2,926,117) compared to those costs of Scenario 1B (estimated to be $3,271,508).

142. Maintaining reliability and stability will vary depending on market structure and system conditions.

143. The GE Ancillary Services study was limited to a maximum integration of 15,000 MW of wind generation, which equals 23% wind penetration as applied to 2008 peak system load.

144. As applied to the forecast 2017 peak system load, 23% wind penetration equals 18,456 MW.

145. ERCOT reports that system reliability can be maintained at Scenario 2 levels of wind generation.

146. Scheduling additional thermal units and curtailing wind generation could occur when there is no lower-cost alternative.

147. P.U.C. SUBST. R. 25.174(c)(3)(C) allows the Commission to consider any other factors the Commission considers appropriate as provided by PURA.

148. Although there were benefits regarding ancillary services costs being lower and more predicable with lower levels of wind-energy at Scenario 1B, and the potential for greater fuel savings with higher levels of wind-energy at Scenario 3 or 4, the trade-offs for getting the best value for the transmission dollars while limiting the risks associated with maintaining reliability renders Scenario 2 the best CREZ transmission plan.

149. The implementation of Scenario 2, with the specific lines prioritized as described, will provide ERCOT the benefit of experience in the process of integrating more and more wind energy. Reliability issues that were discussed at length in the direct testimony and

evidence presented and during cross examination of witnesses at the hearing will be resolved through this experience.

150. The Commission considered factors such as the integration of each scenario's wind generation in a reliable manner, the intent of the Legislature in directing the Commission to construct transmission capacity to deliver electricity from the CREZs, the environmental benefits, and the future expansion capability and other benefits of the plans.

151. Efforts are underway at ERCOT to address maintaining reliability with higher levels of wind generation. These include operational rule changes and revisions under consideration such as the replacement of unit-specific energy schedules with schedules based on an objective wind forecast and the use of an 80% confidence factor to mitigate the risk that wind will not deliver scheduled energy in real time.

152. Wind generation interconnection standards, performance measures, and ancillary service requirements such as voltage control, training, and grid maintenance and congestion are being addressed.

153. ERCOT is considering ramp rate limitations on wind resources, to mitigate impacts to system frequency (system frequency requires balancing supply and load on an instantaneous basis and is negatively impacted by rapid ramp rates).

154. Requirements are being implemented that wind generation provide real-time hourly production updates.

155. The implementation of nodal operations will provide more transparency than QSE portfolio-based dispatch and will better enable ERCOT to manage wind generation.

156. ERCOT is capable of integrating 18,456 MW of wind-generated electricity without sacrificing system stability and reliability.

157. Gaining experience in reliably integrating wind energy by integrating the lines prioritized in this order first is the most reasonable approach to establishing CREZ transmission.

158. The integration of almost 25,000 MW of wind generation contemplated in Scenario 3 or 4 is not supported by the evidentiary record from a reliability standpoint.

159. The intent of the Legislature in passing the amendments to PURA §§ 36.053, 39.203, and 39.904 in 2005 was to further encourage the development of renewable-energy resources by establishing a process to provide reliable and economical transmission resources ahead of renewable generation.

160. The amendments raised the state's renewable-energy goals, required the Commission to develop a CREZ transmission plan, waived requirements and shortened timeframes applicable to CCN applications, and deemed CREZ transmission facilities used, useful, and prudent for rate-setting purposes.

161. Scenario 2 best satisfies the Legislative intent.

162. Transmission plans with lesser transfer capacity than Scenario 2 would leave little room for expansion, thereby not providing transmission resources ahead of renewable generation as directed by the legislation.

163. There was insufficient evidence to assure that levels of wind energy that would be associated with Scenario 3 or 4 could be reliably integrated, therefore the Commission finds that the larger plans do not satisfy the Legislature's intent.

164. Because of Scenario 2's greater wind-energy capacity, it provides more environmental benefits than Scenario 1B, because Scenario 2 displaces more gas-fired and coal-fired electricity.

165. It is estimated that 350 gallons of water are consumed per MWh from a gas plant and 800 gallons of water per MWh from a coal plant. After construction of wind facilities, there is very little water consumed in the process of generating electricity.

166. Because wind-generated electricity burns no fuel with resulting air emissions, each MWh of electricity generated by wind that displaces electricity generated by burning coal or gas results in a reduction of emissions of NO_x, SO_2, and CO_2.

167. Although Scenario 3 was more attractive than Scenario 2 regarding environmental factors, the reliability concerns associated with Scenario 3 outweighed these benefits.

168. The ability to cost-effectively expand the transmission capacity is a very important consideration.

169. Scenarios 1B, 2, and 3 were designed by ERCOT to be essentially a subset of the next larger plan.

170. The selection of a plan smaller than Scenario 2 would leave little room for expansion, thereby not providing transmission resources *ahead* of renewable generation.

171. Scenario 1A was dismissed as a non-viable option primarily because it lacked expansion capability.

172. Expansion capability was a very attractive component of Scenario 1B, but because wind generation has already outgrown Scenario 1B's capacity, it was rejected in favor of Scenario 2.

173. Scenario 2 provides many non-CREZ benefits, such as meeting critical needs of non-CREZ wind development, economic long-term system solutions, and Hill Country load growth, that Scenario 1A and 1B do not.

174. Scenario 2 better diversifies Texas's energy mix by increasing the share of renewable energy as related to other energy resources.

175. Greater energy diversification leads to other benefits, such as energy security.

176. Wind is not subject to fuel-cost volatility like natural gas, or the uncertainties of the costs of future regulations on greenhouse gases.

177. Although Scenario 3 was attractive from the standpoint of enhancing a robust and diverse portfolio of energy sources, this aspect was outweighed by reliability concerns.

178. Scenario 2 provides for the integration of levels of renewable energy that contribute to a robust and diverse portfolio of energy sources necessary to meet the state's projected increasing load, without sacrificing reliability.

VI. Conclusions of Law

1. The Commission has jurisdiction over the parties and the subject matter of the application pursuant to PURA §§ 14.001 and 39.904(g).

2. PURA § 39.904(g) sets forth the following criteria for the Commission to evaluate in designating a CREZ: (1) sufficient renewable-energy resources; (2) suitable land areas; and (3) level of financial commitment by generators.

3. P.U.C. SUBST. R. 25.174(a)(4) mirrors the requirements of PURA § 39.904(g) but adds that the Commission shall consider any other factors considered appropriate by the Commission as provided by PURA.

4. P.U.C. SUBST. R. 25.174(a)(5) provides that the Commission's final order in this proceeding shall specify: (1) the geographic extent of the CREZ; (2) major transmission improvements necessary to deliver to customers the energy generated by renewable resources in the CREZ, in a manner that is most beneficial and cost-effective to the customers, including new and upgraded lines identified by voltage level and a general description of where any new lines will interconnect with the existing grid; (3) an estimate of the maximum generating capacity that the Commission expects the transmission ordered for the CREZ to accommodate; and (4) any other requirement considered appropriate by the Commission as provided by PURA.

5. Zones 2A, 4, 5, 6, 9A, and 19, as described in this order and the interim order on reconsideration, best meet the criteria set forth in PURA § 39.904(g) and P.U.C. SUBST. R. 25.174(a)(4).

6. The transmission improvements as described in this order are necessary to deliver to customers the energy generated by renewable resources in the CREZ, in a manner that is most beneficial and cost-effective to the customers.

7. Certain transmission improvements identified in this order as being most critical to be constructed and placed in service first to address current congestion are properly prioritized in this order.

8. Consistent with open-access principles, developers are not deemed automatically ineligible to interconnect with a transmission line built to serve a CREZ designated by the Commission in this proceeding due to the fact that the location of their wind project may fall outside a CREZ boundary.

9. Pursuant to P.U.C. SUBST. R. 25.174(e), the Commission may consider evidence of financial commitment shown in this docket in any subsequent proceeding to limit interconnection and/or establish dispatch priorities regarding the transmission system in the CREZ.

10. The Federal Power Act provides jurisdiction to the Federal Energy Regulatory Commission (FERC) over the "transmission of electric energy in interstate commerce and the sale of such energy in interstate commerce." 16 U.S.C. § 824(a).

11. Electricity is held to be in interstate commerce if it is "transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States." 16 U.S.C. § 824(c).

12. No interstate commerce issues are implicated by the Commission's designation of CREZ in this proceeding because each CREZ designated by the Commission is located wholly within the State of Texas, transmission improvements built to serve the CREZs will be interconnected solely with ERCOT facilities, and generation within the CREZs will not be authorized to interconnect simultaneously with ERCOT and electrical grids outside of ERCOT.

VII. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following order:

1. The Commission designates zones 2A, 4, 5, 6, 9A, and 19, as those zones are described in Figure 3 of the ERCOT Study, the interim order on reconsideration, and this order, as CREZs.

2. The Commission specifies the major transmission improvements identified in this order as necessary to deliver to customers the energy generated by renewable resources in the CREZ, in a manner that is most beneficial and cost-effective to the customers, including new and upgraded lines identified by voltage level and a general description of where any new lines will interconnect with the existing grid.

3. The Commission estimates that the maximum generating capacity that the Commission expects the transmission ordered for the CREZ to accommodate is 18,456 MW.

4. The lines identified in this order as having the utmost priority will be addressed, planned, certificated, constructed, and placed into service first. This may be accomplished in the manner determined to be the most expedient, either in the CREZ transmission process or via the RPG process.

5. After issuance of its final order, the Commission will proceed, pursuant in part to P.U.C. SUBST. R. 25.174(c), to select the entity or entities responsible for constructing the transmission improvements to the CREZs.

6. For those generators located in zones 4 and the northern portion of zone 2A who desire to interconnect with ERCOT, the Commission strongly suggests a determination by the Federal Energy Regulatory Commission (FERC) disclaiming jurisdiction. Accordingly, either the generator wishing to be served or the transmission service provider that would provide such interconnection should first obtain FERC statement disclaiming jurisdiction before the Commission will approve a CCN application. Similar to the approval granted in the *Cottonwood* case, such FERC approval should be in the form of an Order Granting Petition for Declaratory Order or any other mechanism by which the FERC disclaims jurisdiction over the proposed transmission lines to ERCOT, transmission service over the proposed transmission lines, and the utilities in ERCOT that are not currently public utilities under the Federal Power Act.

7. ERCOT is directed to study, in association with market participants, the system reliability and stability issues implicated by increased wind generation, particularly wind generation that is geographically concentrated, and report the status of these studies to the Commission at least quarterly through a committee or task force as designated by ERCOT. Unless staff designates a different project, Project No. 34577 can also be utilized for this purpose.

8. ERCOT is directed to file periodic updates on the progress of the CREZ transmission development, the estimated costs, the effects on system reliability, the need for additional transmission and generation capacity throughout the state, and the status of the generation

market, in order to facilitate the process for complying with PURA § 39.904(j) and (k), which require reports to the Legislature by December 1 of each even-numbered year.

9. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

SIGNED AT AUSTIN, TEXAS the 6th day of ~~September~~ October 2008.

PUBLIC UTILITY COMMISSION OF TEXAS

BARRY T. SMITHERMAN, CHAIRMAN

KENNETH W. ANDERSON, JR. COMMISSIONER

Commissioner Nelson recused herself and did not participate in this decision.

q:\cadm\orders\final\33000\33672order on rehearing.docx

DOCKET NO. 33672

ATTACHMENT A

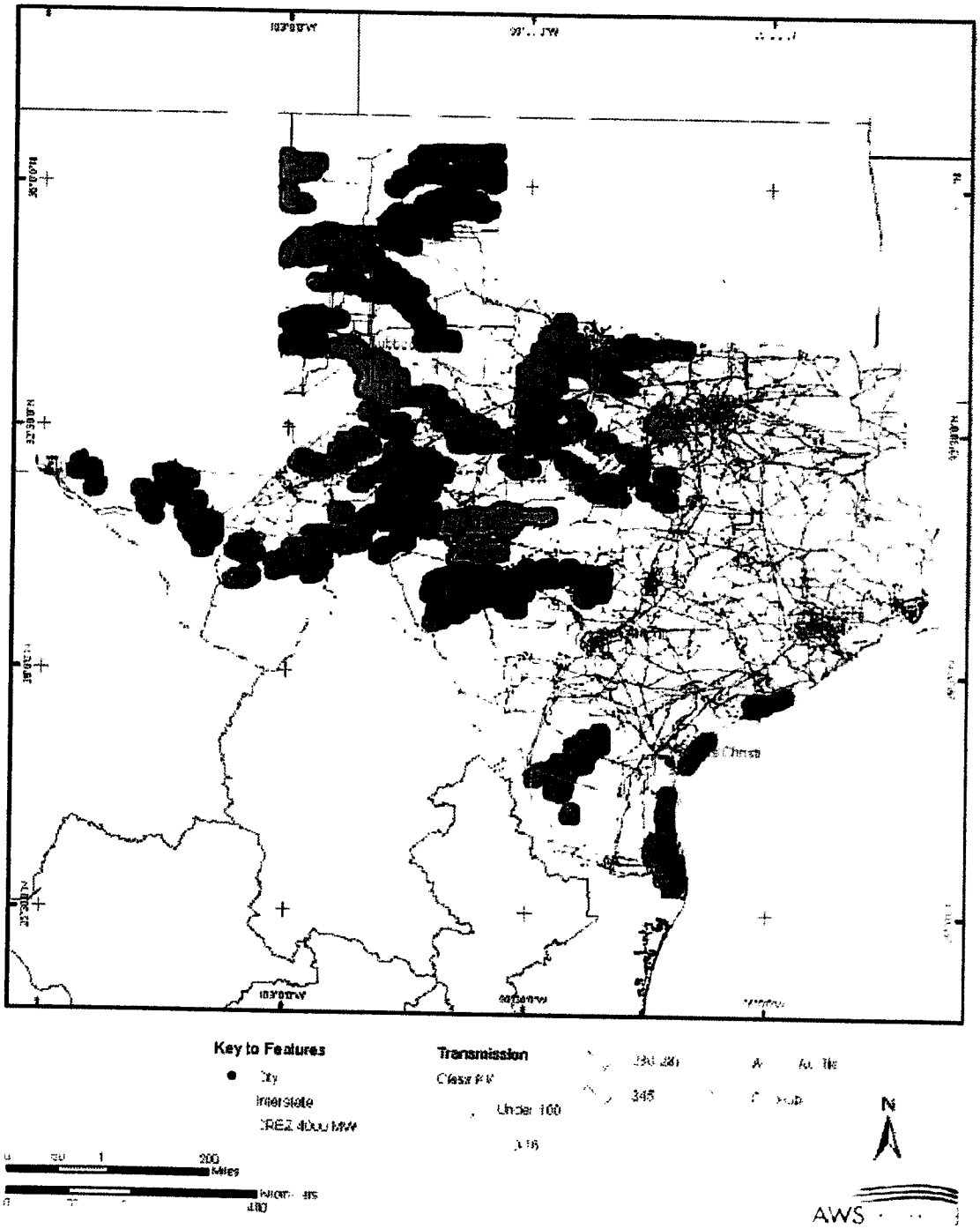
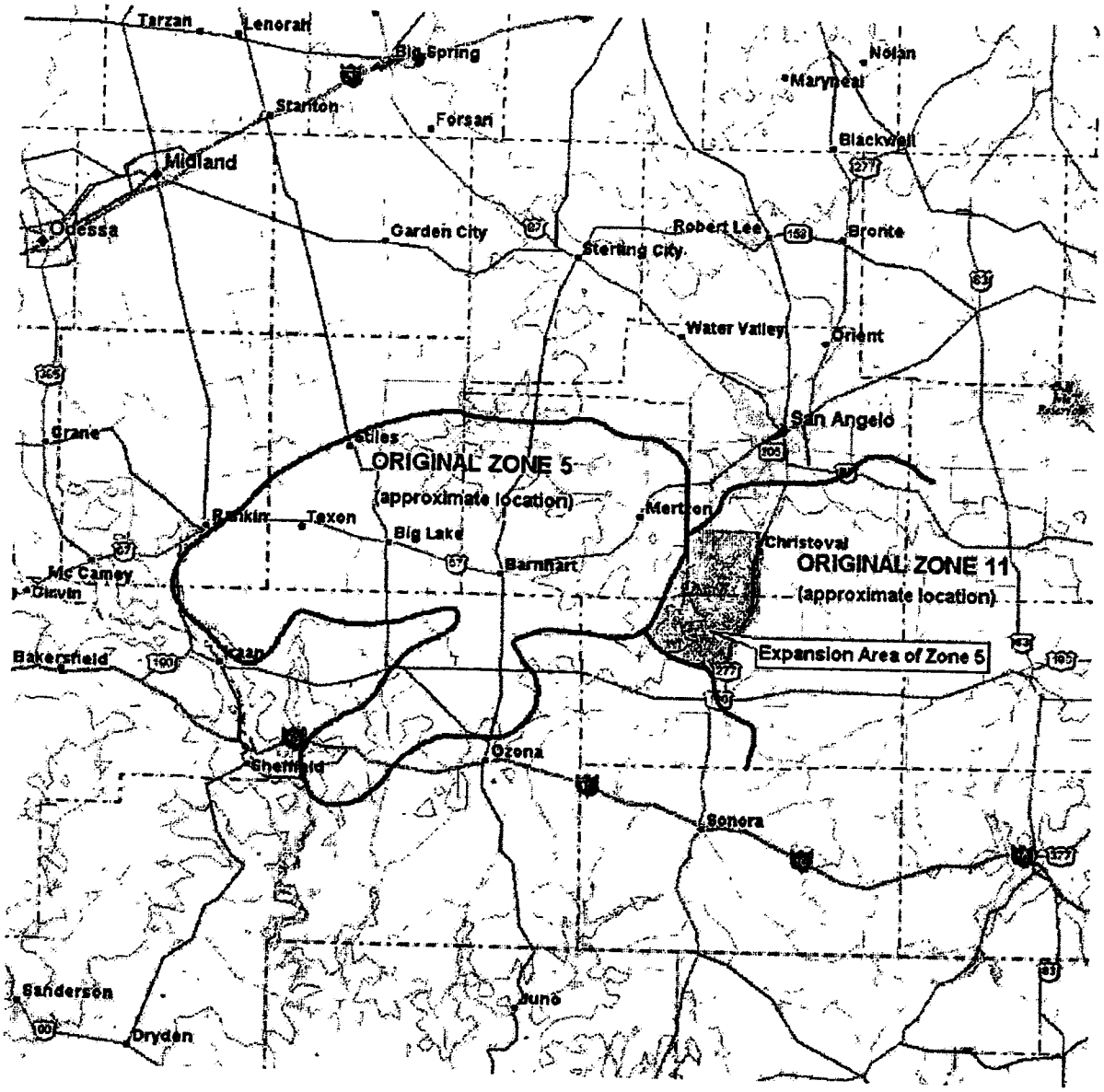


Figure 3: Areas Enclosing the Best 4,000 MW in Each of the Wind Resource Zones

DOCKET NO. 33672

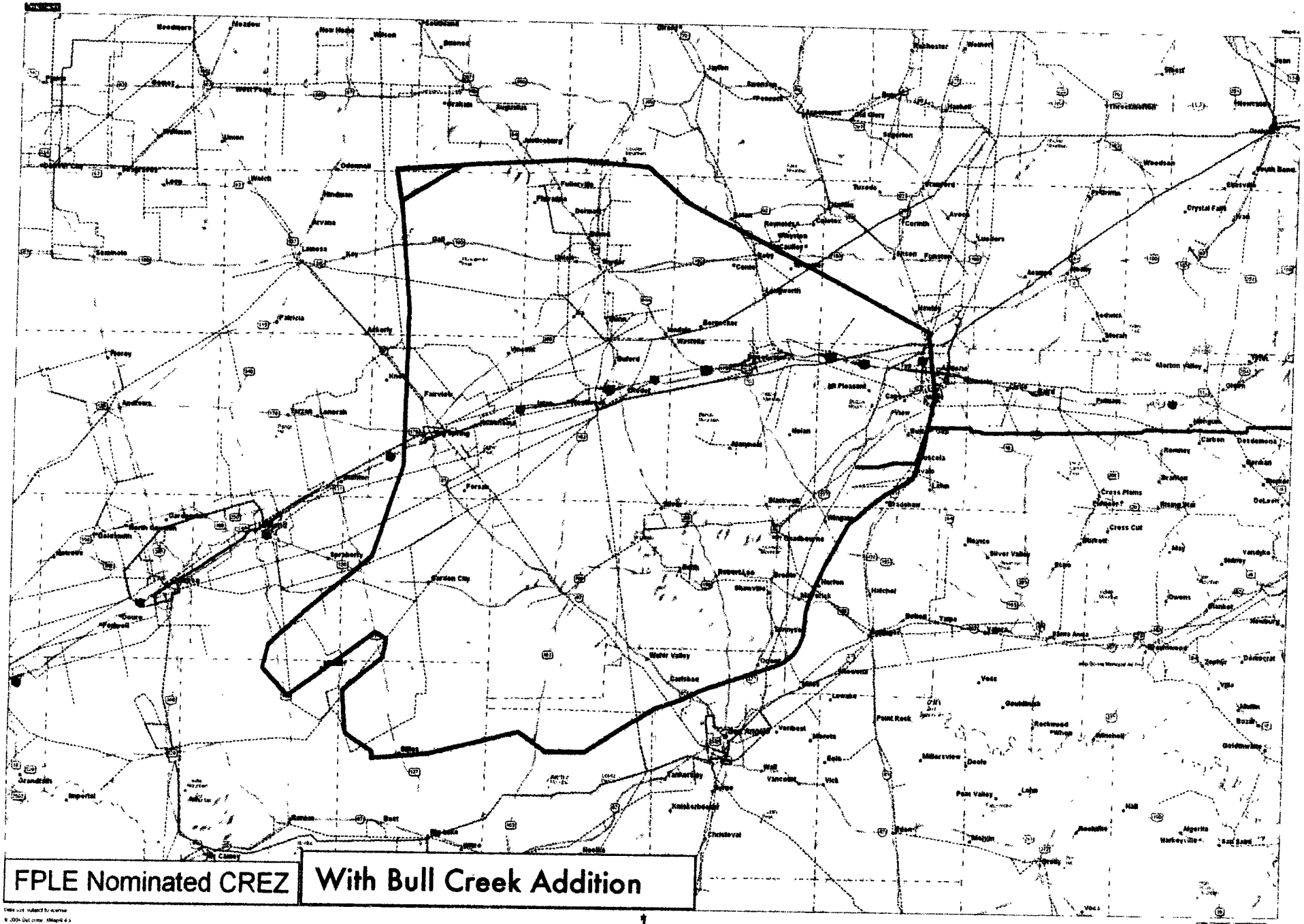
ATTACHMENT B

Exhibit 1 – Map of Modified Zone 5



DOCKET NO. 33672

ATTACHMENT C



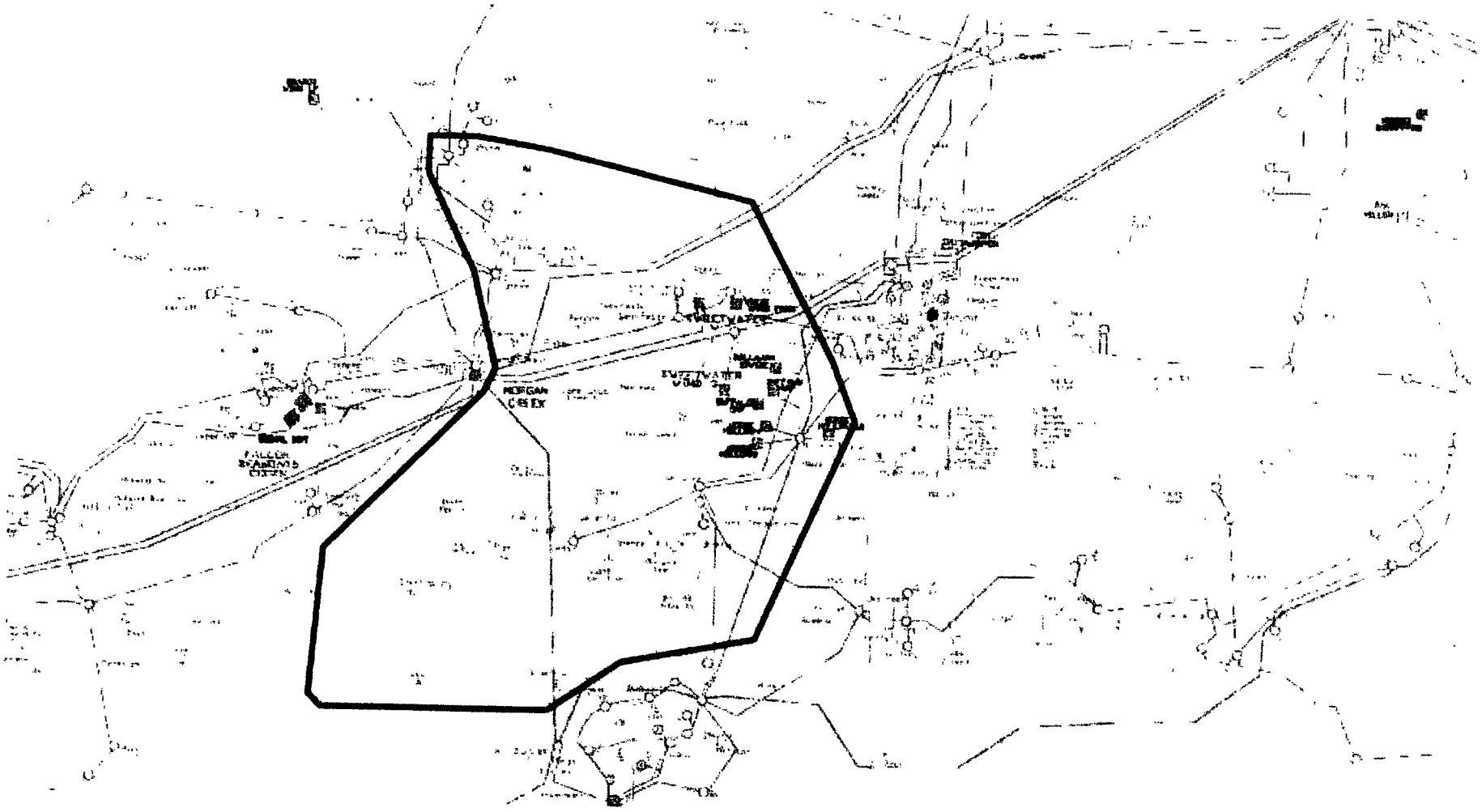
BNB -10

000000058

DOCKET NO. 33672

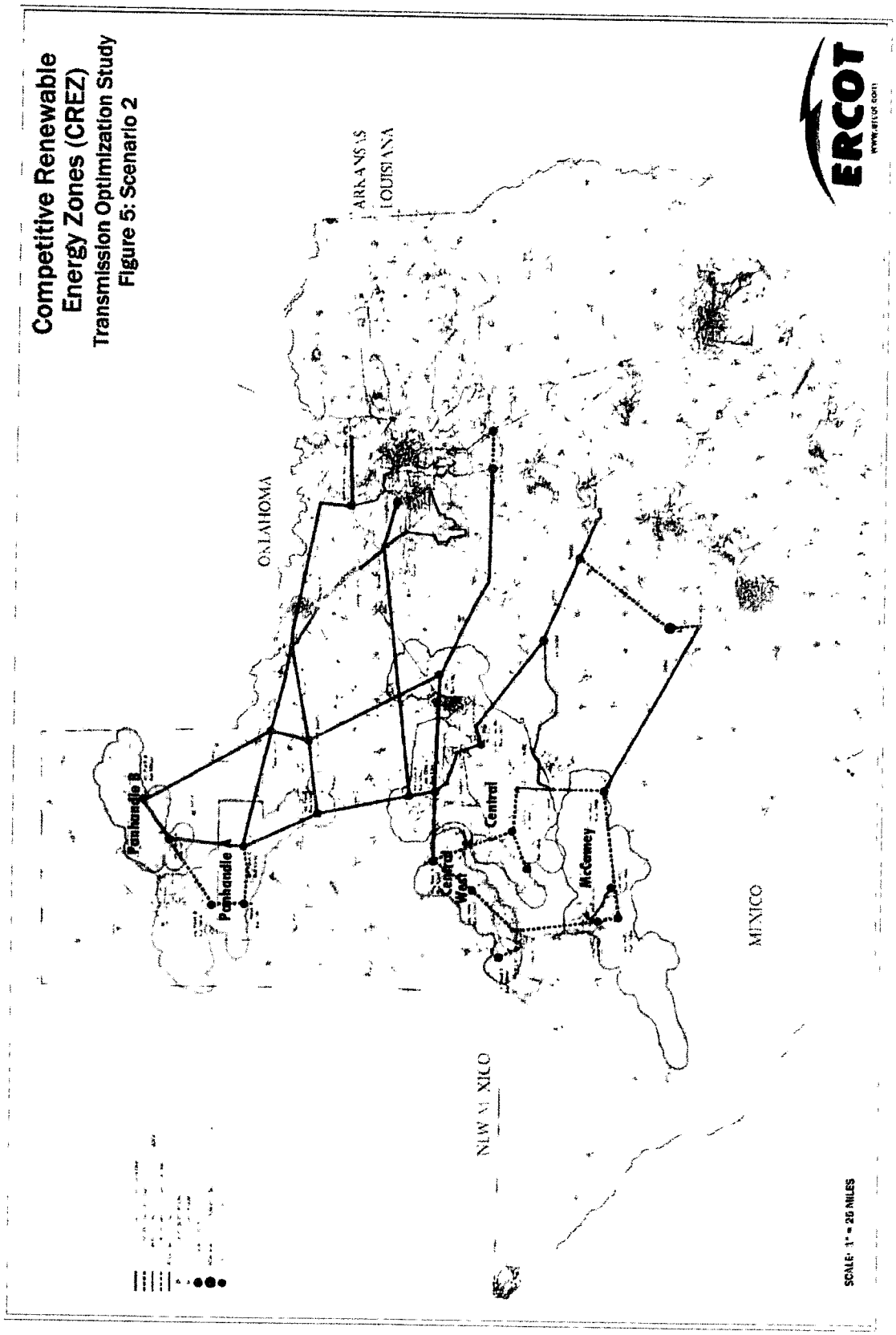
ATTACHMENT D

Exhibit RS-1: The Central CREZ



DOCKET NO. 33672

ATTACHMENT E


Competitive Renewable Energy Zones (CREZ)
Transmission Optimization Study
Figure 5: Scenario 2
ERCOT
OKLAHOMA
ARKANSAS
LOUISIANA
NEW MEXICO
MEXICO
Panhandle B
Panhandle
Central West
Central
McCamey
SCALE: 1" = 20 MILES

CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS.

Subchapter H. ELECTRICAL PLANNING.

DIVISION 1: RENEWABLE ENERGY RESOURCES AND USE OF NATURAL GAS

§25.174. Competitive Renewable Energy Zones.

(a) **Designation of competitive renewable energy zones.** The designation of Competitive Renewable Energy Zones (CREZs) pursuant to Public Utility Regulatory Act (PURA) §39.904(g) shall be made through one or more contested-case proceedings initiated by commission staff, for which the commission shall establish a procedural schedule. The commission shall consider the need for proceedings to determine CREZs in 2007 and in subsequent years as deemed necessary by the commission.

(1) Commission staff shall initiate a contested case proceeding upon receiving the information required by paragraph (2) of this subsection. Any interested entity that participates in the contested case may nominate a region for CREZ designation. An entity may submit any evidence it deems appropriate in support of its nomination, but it shall include information prescribed in paragraph (2)(A) - (C) of this subsection.

(2) By December 1, 2006, the Electric Reliability Council of Texas (ERCOT) shall provide to the commission a study of the wind energy production potential statewide, and of the transmission constraints that are most likely to limit the deliverability of electricity from wind energy resources. ERCOT shall consult with other regional transmission organizations, independent organizations, independent system operators, or utilities in its analysis of regions of Texas outside the ERCOT power region. At a minimum, the study submitted by ERCOT shall include:

(A) a map and geographic descriptions of regions that can reasonably accommodate at least 1,000 megawatts (MW) of new wind-powered generation resources;

(B) an estimate of the maximum generating capacity in MW that each zone can reasonably accommodate and an estimate of the zone's annual production potential;

(C) a description of the improvements necessary to provide transmission service to the region, a preliminary estimate of the cost, and identification of the transmission service provider (TSP) or TSPs whose existing transmission facilities would be directly affected;

(D) an analysis of any potential combinations of zones that, in ERCOT's estimation, would result in significantly greater efficiency if developed together; and

(E) the amount of generating capacity already in service in the zone, the amount not in service but for which interconnection agreements (IAs) have been executed, and the amount under study for.

(3) The Texas Department of Parks and Wildlife may provide an analysis of wildlife habitat that may be affected by renewable energy development in any candidate zone, and may submit recommendations for mitigating harmful impacts on wildlife and habitat.

(4) In determining whether to designate an area as a CREZ and the number of CREZs to designate, the commission shall consider:

(A) whether renewable energy resources and suitable land areas are sufficient to develop generating capacity from renewable energy technologies;

(B) the level of financial commitment by generators; and

(C) any other factors considered appropriate by the commission as provided by PURA, including, but not limited to, the estimated cost of constructing transmission capacity necessary to deliver to electric customers the electric output from renewable energy resources in the candidate zone, and the estimated benefits of renewable energy produced in the candidate zone.

(5) The commission shall issue a final order within six months of the initiation by commission staff of a CREZ proceeding, unless it finds good cause to extend the deadline. For each new CREZ it orders, the commission shall specify:

(A) the geographic extent of the CREZ;

(B) major transmission improvements necessary to deliver to customers the energy generated by renewable resources in the CREZ, in a manner that is most beneficial and cost-effective to the customers, including new and upgraded lines identified by voltage level and a general description of where any new lines will interconnect to the existing grid;

(C) an estimate of the maximum generating capacity that the commission expects the transmission ordered for the CREZ to accommodate; and

(D) any other requirement considered appropriate by the commission as provided by PURA.

(6) The commission may direct a utility outside of ERCOT to file a plan for the development of a CREZ in or adjacent to its service area. The plan shall include the maximum generating capacity that each potential CREZ can reasonably accommodate; identify the transmission improvements needed to provide service to each CREZ; and include the cost of the improvements and a timetable for complying with all applicable federal transmission tariff requirements.

(b) **Level of financial commitment by generators for designating a CREZ.**

(1) A renewable energy developer's existing renewable energy resources, and pending or signed IAs for planned renewable energy resources, leasing agreements with landowners in a proposed CREZ, and letters of credit representing dollars per MW of proposed renewable generation resources, posted with ERCOT, that the developer intends to install and the area of interest are examples of financial commitment by developers to a CREZ. The commission may also consider projects for which a TSP, ERCOT, or another independent system operator is conducting an interconnection study; and any other factors for which parties have provided evidence as indications of financial commitment.

(2) A non-utility entity's commitment to build and own transmission facilities dedicated to delivering the output of renewable energy resources in a proposed CREZ to the transmission system of a TSP in Texas or a deposit or payment to secure or fund the construction of such transmission facilities by an electric utility or a transmission utility to deliver the output of a renewable generation project in Texas is an indication of the entity's financial commitment to a CREZ.

(c) **Plan to develop transmission capacity.**

(1) After the issuance of a final order in accordance with subsection (a)(5) of this section, entities interested in constructing the transmission improvements shall submit expressions of interest to the commission. The commission shall select the entity or entities responsible for constructing the transmission improvements, establish a schedule by which the improvements shall be completed, and specify any additional reporting requirements or other measures deemed appropriate by the commission to ensure that entities complete the ordered improvements in a timely manner.

(2) The commission shall develop a plan to construct transmission capacity necessary to deliver to electric customers, in a manner that is most beneficial and cost-effective to the customers, the electric output from renewable energy technologies in the CREZ.

(3) In developing the transmission capacity plan, the commission may consider:

(A) the estimated cost of constructing transmission capacity necessary to deliver to electric customers the electric output from renewable energy resources in the candidate zone;

(B) the estimated cost of additional ancillary services; and

(C) any other factors considered appropriate by the commission as provided by PURA.

(d) **Certificates of convenience and necessity.**

(1) Not later than one year after a commission final order designating a CREZ, each TSP selected to build and own transmission facilities for that CREZ shall file all required CREZ Certificate of Convenience and Necessity (CCN) applications. The commission may grant an extension to this deadline for good cause. The commission may establish a filing schedule for the CCN applications.

(2) A CCN application for a transmission project intended to serve a CREZ need not address the criteria in PURA §37.056(c)(1) and (2).

(3) In determining whether financial commitment for a CREZ is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities for the CREZ, the commission shall consider the following evidence of financial commitment by renewable generators:

(A) capacity represented by installed generation located in one or more of the counties that lie in whole or in part within the CREZ;

(B) capacity represented by generation projects under construction that are located in one or more of the counties that lie in whole or in part within the CREZ and that will be operational within six months of the final order in a financial commitment proceeding initiated pursuant to paragraph (6) of this subsection. Evidence that the project will be operational within six months may include documentation showing that a construction contractor has been hired, that preliminary site work has begun, that the project financing has closed, or similar indicators of the status of the project.

(C) capacity represented by planned generation projects that are located in one or more of the counties that lie in whole or in part within the CREZ and that have a signed IA with a TSP that has been defined in subsection (a)(2)(E) of this section designated to build and own transmission facilities for that CREZ; and

(D) capacity represented by collateral posted by generators for the CREZ that complies with paragraph (7) of this subsection.

(4) Financial commitment for a CREZ is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities for the CREZ if the sum of the renewable generating capacity under any combination of paragraph (3)(A), (B), (C), and (D) of this subsection is at least 50% of the designated generating capacity for the CREZ. Fifty percent of the designated generating capacity for the Panhandle A CREZ approved by the commission in Docket Number 33672 shall be considered to be 1,595.5 MW. Fifty percent of the designated generating capacity for the Panhandle B CREZ approved by the commission in Docket Number 33672 shall be considered to be 1,196.5 MW.

(5) Installed renewable generation, renewable generation projects under construction, and planned renewable generation projects with signed IAs in the McCamey, Central, and Central West CREZs approved by the commission in Docket Number 33672 satisfy the financial commitment test set forth in paragraph (4) of this subsection for those CREZs and therefore financial commitment by renewable generators for those CREZs is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities for those CREZs. This finding of sufficient financial commitment shall be recognized in the CCN proceedings for transmission facilities for those CREZs and shall not be addressed further in those proceedings.

(6) Commission staff shall initiate a single proceeding for the commission to determine whether there is sufficient financial commitment under PURA §39.904(g)(3) by renewable generators for the Panhandle A and Panhandle B CREZs approved by the commission in Docket Number 33672 to grant CCNs for transmission facilities for those CREZs. If the commission determines that there is sufficient financial commitment for one of those CREZs, that finding shall be recognized in the CCN proceedings for transmission facilities for that CREZ, as

identified in the commission's order in the proceeding initiated pursuant to this paragraph, and shall not be addressed further in the CCN proceedings. If the commission determines that the Panhandle A or Panhandle B CREZ does not satisfy the financial commitment test in paragraph (4) of this subsection, the commission may:

(A) consider other evidence of financial commitment that the commission finds relevant under PURA §39.904(g)(3);

(B) find that the financial commitment requirement for that CREZ has been met if the commission determines that significant financial commitment exists in that CREZ and that the CREZ is sufficiently interrelated with a CREZ that has satisfied the financial commitment test;

(C) delay the filing of CREZ CCN applications for that CREZ until the commission conducts a subsequent proceeding in which it finds sufficient financial commitment for that CREZ in accordance with the financial commitment provisions of this subsection; or

(D) take other appropriate action.

(7) A renewable generator that elects to post collateral pursuant to paragraph (3)(D) of this subsection shall comply with the following requirements:

(A) The renewable generator shall provide a letter of intent to post collateral in a proceeding conducted pursuant to paragraph (6) of this subsection. The renewable generator shall then post the collateral no later than 30 days after the commission issues an interim order finding sufficient financial commitment by renewable generators for the CREZ. If the renewable generators post sufficient collateral, the commission may enter a final order with findings that reflect the adequacy of the financial commitment for the CREZ. If the renewable generators do not post sufficient collateral, the commission may enter a final order with findings that reflect the inadequacy of the financial commitments for the CREZ.

(B) A renewable generator shall post collateral equal to $15,350 per MW of its planned project capacity, or $10,000 per MW if the capacity is supported by leasing agreements with landowners that convey a right or option for a period of at least 20 years to develop and operate a renewable energy project based on a conversion factor of 60 acres per MW for a wind energy project.

(C) A renewable generator planning to build a project in a CREZ shall post collateral with the TSP with which it will interconnect in the CREZ or, if the TSP with which it will interconnect has not been determined, with any TSP that has been designated to build and own transmission facilities for that CREZ.

(D) A renewable generator may post collateral by providing a cash deposit, letter of credit, or guaranty agreement from an entity with an investment-grade credit rating. A TSP shall require a renewable generator that posts a guaranty agreement to provide another form of collateral if the guarantor loses its investment-grade credit rating or declares bankruptcy. If the renewable generator does not provide another form of collateral, the commission may take appropriate action including seeking administrative penalties.

(8) A TSP that receives collateral from a renewable generator pursuant to paragraph (7) of this subsection shall handle that collateral in accordance with the following provisions.

(A) If a renewable generator signs an IA with the TSP and posts any collateral required by the TSP to secure the construction of collection facilities, the TSP shall return to the generator all collateral received from that generator.

(B) If a renewable generator does not sign an IA with the TSP and post any collateral required by the TSP to secure the construction of collection facilities within 90 days after the TSP notifies it that the transmission system is capable of accommodating

the renewable generator's renewable energy facility, the TSP shall retain the collateral received from the generator as an offset to the cost of the transmission facilities the TSP constructs for the CREZ and shall take all reasonable measures to execute any non-cash collateral.

(9) In a CREZ CCN application, a TSP may propose modifications to the transmission facilities described in a CREZ order if such improvements would reduce the cost of transmission or increase the amount of generating capacity that transmission improvements for the CREZ can accommodate. The commission may direct ERCOT to review modifications proposed by the TSP.

(10) Findings in Docket Numbers 33672, 35665, and 36146 and the commission's finding in paragraph (5) of this subsection establish that the level of financial commitment is sufficient under PURA §39.904(g)(3) to grant CCNs for transmission facilities designated as a Default Project in ordering paragraph 1 of the Order in Docket Number 36146 and for transmission facilities designated as a Priority Project in finding of fact 136 in the Order on Rehearing in Docket Number 33672. This finding of sufficient financial commitment shall be recognized in all pending and future CCN proceedings for Default and Priority Projects and shall not be addressed further in those proceedings.

(e) **Excess development in a CREZ.** If the aggregate level of renewable energy capacity for which transmission service is requested for a CREZ exceeds the maximum level of renewable capacity specified in the CREZ order, and if the commission determines that the security constrained economic dispatch mechanism used in the power region to establish a priority in the dispatch of CREZ resources is insufficient to resolve the congestion caused by excess development, the commission may initiate a proceeding and may consider limiting interconnection to and/or establishing dispatch priorities regarding the transmission system in the CREZ, and identifying the developers whose projects may interconnect to the transmission system in the CREZ under special protection schemes.

DOCKET NO. 37567

COMMISSION STAFF'S PETITION FOR DETERMINATION OF FINANCIAL COMMITMENT FOR THE PANHANDLE A AND PANHANDLE B COMPETITIVE RENEWABLE ENERGY ZONES	§ § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the petition of the Public Utility Commission of Texas (Commission) Staff for determination of financial commitment for the Panhandle A and Panhandle B Competitive Renewable Energy Zones (CREZs). BP Wind Energy North America Inc.; Chermac Energy Corporation; Cielo Wind Services, Inc.; Clipper Windpower Development Company, Inc.; Cross Texas Transmission, LLC; Public Utility Commission of Texas (Commission) Staff, Duke Energy Corporation; E.ON Climate & Renewables North America, LLC; Electric Transmission Texas, LLC; Eurus Energy America Corporation; Fremantle Energy LLC; Higher Power Energy, LLC; Horizon Wind Energy LLC; Iberdrola Renewables, Inc.; Invenergy Wind North America LLC; Oncor Electric Delivery Company LLC; Pattern Renewables LP; RES America Developments, Inc.; Scandia Wind Southwest LLC; Sharyland Utilities, L.P.; Shell WindEnergy, Inc.; South Texas Electric Cooperative, Inc. (STEC); Third Planet Windpower, LLC; and Wind Energy Transmission Texas, LLC have entered into a Stipulation and Settlement Agreement (Agreement) resolving all issues in this docket.

The Agreement is unopposed by other parties to this docket.[1] Consistent with the Agreement, the Commission finds that there is sufficient financial commitment by renewable generators for the Panhandle A and Panhandle B CREZs.

[1] CPS Energy, City of Garland, Luminant Energy Company LLC, Luminant Generation Company LLC, Steering Committee of Cities Served by Oncor, Texas Industrial Energy Consumers, and ERCOT. The only other party to this case, AES Wind Generation, Inc. did not take a position.

The Commission adopts the following findings of fact and conclusions of law:

I. Findings of Fact

Procedural History

1. The Commission adopted P.U.C. SUBST. R. 25.174[2] in 2006 wherein it created the procedures and requirements for renewable generators to provide their financial commitment for the CREZs and amended the rule in 2009.[3]

2. On October 16, 2009, Commission Staff filed a petition to commence this proceeding. Commission Staff stated in the petition that it would serve the petition on each person that filed comments in the proposed rule published in the *Texas Register* in Project No. 34577. Staff also served a copy of the petition on each party in Docket No. 35665, *Commission Staff's Petition for Selection of Entities Responsible for Transmission Improvements Necessary to Delivery Renewable Energy from Competitive Renewable Energy Zones.*

3. Commission Staff also requested a shortened intervention deadline and the issuance of a protective order that conforms to the July 15, 2008 Revised Protective Order issued in Docket No. 35665.

4. Notice was published in the *Texas Register* on November 6, 2009.

5. On October 22, 2009, Order No. 1 was issued approving the notice, setting the deadline to intervene as November 6, 2009, entering the protective order, and scheduling a prehearing conference.

6. On November 12, 2009, ERCOT filed a motion for authorization to review the highly sensitive protected material filed in this proceeding. On November 23, 2009, Order No. 4

---

[2] *Rulemaking Relating to Renewable Energy Amendments,* Project No. 31852, (Dec. 5, 2006).

[3] *Proceeding to Establish Policy Relating to Excess Development in Competitive Renewable Energy Zones,* Project No. 34577 (Oct. 15, 2009).

was issued granting ERCOT's motion. ERCOT did not file testimony or a statement of position in this docket.

7. On November 18, 2009, Order No. 3 was issued setting the procedural schedule and adopting procedures regarding requests for information, service, and requiring each renewable generator that filed direct testimony to also complete the "Form for Renewable Generator Financial Commitment Evidence" (the financial commitment form).

8. The following entities were granted intervention in this proceeding: AES Wind Generation, Inc. (AES Wind) ; BP Wind Energy North America Inc. (BP Wind); Chermac Energy Corporation (Chermac); Cielo Wind Services, Inc. (Cielo); City of Garland (Garland); Clipper Windpower Development Company, Inc. (Clipper Windpower); CPS Energy (CPS); Cross Texas Transmission, LLC (CTT); Duke Energy Corporation (Duke); E.ON Climate & Renewables North America Inc. (E.ON);[4] Electric Transmission Texas, LLC (ETT); Electric Reliability Council of Texas (ERCOT); Eurus Energy America Corporation (Eurus); Fremantle Energy LLC (Freemantle); Higher Power Energy, LLC (Higher Power); Horizon Wind Energy LLC (Horizon); Iberdrola Renewables, Inc. (Iberdrola); Invenergy Wind North America LLC (Invenergy); Luminant Energy Company LLC (Luminant); Luminant Generation Company LLC (Luminant); Oncor Electric Delivery Company LLC (Oncor); Pattern Renewables LP (Pattern); RES America Developments, Inc. (RES America); Scandia Wind Southwest LLC (Scandia Wind); Sharyland Utilities, L.P. (Sharyland); Shell WindEnergy, Inc. (Shell); South Texas Electric Cooperative, Inc. (STEC); Steering Committee of Cities Served by Oncor (Cities); Texas Industrial Energy Consumers (TIEC); Third Planet Windpower, LLC (Third Planet); and Wind Energy Transmission Texas, LLC (WETT).

9. On December 4, 2009, the following parties filed direct testimony: Invenergy; Scandia; E.ON; Horizon; Higher Power; Clipper; Duke; RES America; Iberdrola; Pattern; and

[4] Now E.ON Climate & Renewables North America, LLC.

Cielo. Also on December 4, Third Planet filed a letter concerning its intent to post collateral.[5]

10. On January 8, 2010, Order No. 7 was issued establishing procedures and guidelines for the prehearing conference and hearing on the merits and setting the deadline for the filing of statements of position in lieu of testimony.

11. On January 14, 2010, Order No. 8 was issued ruling on several motions to compel responses to requests for information.

12. AES Wind, CPS Energy, CTT, ETT, City of Garland, Luminant, Oncor, Sharyland, Steering Committee of Cities Served by Oncor, TIEC, and WETT filed statements of position.

13. The Commission held the hearing on the merits on January 21, 2010.

14. On January 21, 2010, Order No. 9 was issued setting the briefing schedule for post-hearing briefs on the merits and for briefs regarding the treatment of information designated as confidential and the confidentiality of compilations of publicly available information as well as the procedures under the protective order in this docket.

15. On January 29, 2010, Iberdrola, STEC, Horizon, CPS, E.ON, Duke, Commission Staff, Luminant, Clipper, Pattern, the Joint TSPs (Cross Texas, Sharyland, Oncor, ETT, and WETT), TIEC, Higher Power, Scandia, and RES America filed post-hearing briefs.

16. On February 4, 2010, Commission Staff filed a brief in response to Order No. 9. On February 5, 2010, joint parties filed a settlement regarding the confidentiality issue. STEC withdrew its objection as a result of the settlement.

---

[5] Third Planet stated that at the time it filed its motion to intervene it intended to affirm its interest and commitment in posting collateral for the wind generation capacity it is currently planning to develop in the Panhandle A CREZ. Third Planet stated that it is actively working toward development of 500 MW of wind generation in the Panhandle A CREZ, of which approximately 334 MW is supported by leases at this time. Third Planet stated that it is not confident at this time that it can meet the rule's deadline to timely post collateral in support of the capacity it is proceeding to develop in the Panhandle A CREZ. Third Planet could not affirm its intent to increase its financial commitment by posting additional collateral in the near future for its Panhandle A project.

17. The Commission discussed its decision in this docket at the February 11, 2010 open meeting.

18. On March 23, 2010, Higher Power requested good cause to amend its testimony and offer an additional exhibit to change its form of collateral for Panhandle A from a letter of credit to a guaranty agreement from an entity with an investment-grade credit rating.

19. No party objected to the change proposed by Higher Power. Order No. 11 issued on April 2, 2010, admitted HPE Exhibit Nos. HPE 3, HPE4, and HPE 5 into the record. Order No. 12 issued on April 13, 2010, admitted HPE Exhibit Nos. HPE 6 and HPE 6A into the record.

20. The Commission considered its decision in this docket again at the April 15, 2010 open meeting.

21. The Commission issued its Interim Order on April 21, 2010, providing for the renewable energy generators to post collateral within a 30-day time period.

22. On May 21, 2010, Iberdrola filed a motion for good cause exception to file amended exhibits and a notice of highly sensitive protected material.

23. On May 21, 2010, E.ON filed a notice of posting collateral.

24. On May 28, 2010, CTT and Sharyland filed their respective affidavits attesting to the amount of collateral that had been posted with each by renewable energy generators.

25. On June 2, 2010, Commission Staff filed the affidavit of Danielle Jaussaud regarding financial commitment for the Panhandle A and Panhandle B CREZs.

26. On June 4, 2010, Order No. 13 granted Iberdrola's motion of May 21, 2010 for good cause exception to file amended exhibits admitting Iberdrola Exhibit 1B into the record.

27. On June 7, 2010, Order No. 14 was issued requiring Sharyland, CTT, and Commission Staff to clarify that their earlier affidavits were intended to be part of the evidentiary

record of the proceeding, and established dates for 1) comments and objections to same; and 2) the filing of a joint procedural schedule to bring the docket to a close.

28. On June 14, 2010, Sharyland, CTT, and Commission Staff filed the clarification requested by Order No. 14.

29. STEC requested clarification of Order No. 14 on June 17, 2010, to which Commission Staff filed a response the same day.

30. Order No. 15, clarifying Order No. 14, was issued on June 18, 2010.

31. The affidavits of Sharyland, CTT, and Commission Staff were admitted into the record by Order No. 16 on June 18, 2010.

32. Joint Parties filed a proposed procedural schedule in response to Order No. 14 on June 18, 2010.

33. On June 21, 2010, STEC, TIEC, and Cities filed responses to the Joint Parties' proposed procedural schedule.

34. Commission Staff responded to STEC, TIEC, and Cities on June 23, 2010.

35. Order No. 17, adopting a procedural schedule, was issued on June 24, 2010.

36. On June 29, 2010, Joint Parties, in an unopposed filing, stated that certain renewable energy developers had agreed to post sufficient additional collateral to allow Panhandle A CREZ to meet the financial commitment test and requested a modification of the procedural schedule as a result.

37. On June 30, 2010, Order No. 18 was issued adopting a new schedule and setting July 7, 2010, as the deadline for renewable energy generators to post additional collateral for Panhandle A CREZ.

38. On July 8, 2010, Sharyland filed an affidavit attesting to the additional collateral posted by certain renewable generators for Panhandle A CREZ pursuant to Order No. 18. On this same date, Chermac, one such renewable generator, filed evidence of leased acreage

to support the posting. Iberdrola filed a motion requesting authorization to transfer a limited amount of previously-posted collateral from Panhandle B CREZ to Panhandle A CREZ. Scandia filed a pleading identifying leased acreage in the record to support its posting of additional collateral.

39. On July 9, 2010, Chermac filed a correction to its July 8, 2010 filing.

40. On July 13, 2010, the parties filed a Unanimous Stipulation and Settlement Agreement resolving all issues in the case.

41. On July 19, 2010, Order No. 19 was issued admitting into evidence the documents described in Finding of Fact No. 38 filed by Sharyland, Chermac, and Iberdrola, and on July 20, 2010, Order No. 20 was issued granting Iberdrola's motion to transfer collateral. On July 22, 2010, Order No. 21 was issued to admit into evidence Chermac's July 8, 2010 correction letter, thus completing the record in this case.

Financial Commitment

42. Pursuant to § 39.904(g)(3) of the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 11.001-66.016 (Vernon 2007 & Supp. 2009) (PURA), the Commission is required to consider the level of financial commitment by generators for each CREZ in determining whether to grant a certificate of convenience and necessity.

43. Commission Staff initiated this proceeding for the Commission to determine whether there is sufficient financial commitment under PURA § 39.904(g)(3) by renewable generators for the Panhandle A and Panhandle B CREZs to grant CCNs for transmission facilities for those CREZs.

44. If the Commission determines that there is sufficient financial commitment for a CREZ, that finding will be recognized in the CCN proceedings for transmission facilities for that CREZ, and will not be addressed further in the CCN proceedings.

45. The sum of the renewable generating capacity represented by the financial commitment evidence is required to be at least 50% of the designated generating capacity for the CREZ.

46. Fifty percent of the designated generating capacity for the Panhandle A CREZ approved by the Commission in Docket No. 33672 is 1,595.5 MW.

47. Fifty percent of the designated generating capacity for the Panhandle B CREZ approved by the Commission in Docket No. 33672 is 1,196.5 MW.

48. In determining whether financial commitment for a CREZ is sufficient under PURA § 39.904(g)(3) to grant transmission facility CCNs for the CREZ, the Commission is required to consider the following evidence of financial commitment by generators: 1) capacity represented by installed generation located in one or more of the counties that lie in whole or in part within the CREZ; 2) capacity represented by generation projects under construction that are located in one or more of the counties that lie in whole or in part within the CREZ and that will be operational within six months of the final order in a financial commitment proceeding initiated pursuant to paragraph (6) of P.U.C. SUBST. R. 25.174(d); 3) capacity represented by planned generation projects that are located in one or more of the counties that lie in whole or in part within the CREZ and that have a signed interconnection agreement defined in P.U.C. SUBST. R. 25.174(a)(2)(E) with a TSP designated to build and own transmission facilities for that CREZ; and 4) capacity represented by collateral posted by generators for the CREZ that complies with paragraph (7) of P.U.C. SUBST. R. 25.174(d).

49. Cash deposits, letters of credit, or guaranty agreements from an entity with an investment-grade credit rating are acceptable forms of collateral under the rule. If a guarantor that is used in a guaranty agreement loses its investment-grade credit rating or declares bankruptcy, the TSP must require the renewable generator to provide another form of collateral. If the renewable generator does not provide another form of collateral, the Commission may take appropriate action including seeking administrative penalties.

50. The amount of collateral required by the rule is either $15,350 per MW of its planned project capacity, or $10,000 per MW if the capacity is supported by leasing agreements with landowners that convey a right or option for a period of at least 20 years to develop and operate a renewable energy project based on a conversion factor of 60 acres per MW for a wind energy project. All renewable generators that posted collateral did so at $10,000 per MW supported by such leasing agreements.

51. If a renewable generator signs an interconnection agreement with the TSP and posts any collateral required by the TSP to secure the construction of collection facilities, the TSP is required to return to the generator all collateral previously received pursuant to P.U.C. SUBST. R. 27.174(d)(7) from that generator. If a generator does not sign an interconnection agreement with the TSP and post any collateral required by the TSP to secure the construction of collection facilities within 90 days after the TSP notifies it that the transmission system is capable of accommodating the renewable generator's renewable energy facility, the TSP is permitted to retain the collateral received from the generator as an offset to the cost of the transmission facilities the TSP constructs for the CREZ and is required to take all reasonable measures to collect any non-cash collateral.

Panhandle A CREZ

52. The geographic boundaries for the area that has been identified as the Panhandle A CREZ are set forth in the Commission's Order on Rehearing in Docket No. 33672,[6] identified as Zone 2A in that order.

53. Seven renewable generators submitted letters of intent to post collateral with supporting evidence for the Panhandle A CREZ.

54. Pursuant to the Interim Order, six renewable generators posted collateral for the Panhandle A CREZ.

55. Pursuant to Order No. 18, six renewable generators, some of whom had previously posted collateral, posted additional collateral for the Panhandle A CREZ.

---

[6] *Commission Staff's Petition for Designation of Competitive Renewable Energy Zones*. Docket No. 33672 (Aug. 15, 2008).

The collateral posted for the Panhandle A CREZ, together with the amounts of installed generation capacity in that CREZ, are shown in the table below:

Renewable Generator	Form	Amount Posted	Representative Capacity (MW)
Cielo Wind Services, Inc.	Cash Deposit	$500,000	50
Clipper Windpower Development Company, Inc.	Letter of Credit	$1,050,000	105
Horizon Wind Energy LLC	Letter of Credit	$4,200,000	420
Iberdrola Renewables, Inc.	Guaranty	$3,319,500	331.95
RES America Developments, Inc.	Letter of Credit	$3,575,000	357.5
RES America Developments, Inc.	Installed Capacity	N/A	60
Scandia Wind Southwest LLC	Letter of Credit	$1,060,500	106.05
Chermac Energy Corporation	Cash Deposit	$150,000	15
Invenergy	Installed Capacity	N/A	150

56. The Commission finds that the aggregate MW represented by the collateral posted as reflected in the table above in addition to the installed generation of Invenergy and RES America totals 1,595.5 MW and meets the requirements of P.U.C. SUBST. R. 27.174(d)(4) and PURA § 39.904(g)(3) for the Panhandle A CREZ.

57. The Commission finds that there is sufficient financial commitment by the renewable generators for the Panhandle A CREZ.

Panhandle B CREZ

58. The geographic boundaries for the area that has been identified as the Panhandle B CREZ are set forth in the Commission's Order on Rehearing in Docket No. 33672, identified as Zone 4 in that order.

59. Five renewable generators submitted letters of intent to post collateral with supporting evidence for the Panhandle B CREZ.

60. Pursuant to the Interim Order, four renewable generators posted collateral for the Panhandle B CREZ. One such generator, Iberdrola Renewables, subsequently modified its posted amount.

61. The collateral posted for the Panhandle B CREZ is shown in the table below:

Renewable Generator	Form	Amount Posted	Representative Capacity (MW)
E.ON Climate & Renewable North America, LLC	Letter of Credit	$6,330,000	633
Iberdrola Renewables, Inc.	Guaranty	$2,375,500	237.55
Cielo Wind Services, Inc.	Cash	$500,000	50
Pattern Renewables LP	Letter of Credit	$3,190,000	319

62. The Commission finds that the aggregate MW represented by the collateral posted as reflected in the table above totals 1,239.55 MW and meets the requirements of P.U.C. SUBST. R. 27.174(d)(4) and PURA § 39.904(g)(3) for the Panhandle B CREZ.

63. The Commission finds that there is sufficient financial commitment by the renewable generators for the Panhandle B CREZ.

64. Pursuant to P.U.C. PROC. R. 22.5(b), good cause exists to waive the requirements of P.U.C. PROC. R. 22.35(b)(2), so that this proceeding may be considered at the Commission's Open Meeting scheduled for July 30, 2010, to avoid any undue delay in the processing of CREZ related matters.

II. Conclusions of Law

1. The Commission has jurisdiction and authority over this proceeding pursuant to PURA §§ 14.001 and 39.904(g), and P.U.C. SUBST. R. 25.174 applies to this proceeding.

2. PURA § 39.904(g)(3) requires the Commission to consider the level of financial commitment by generators for each CREZ in determining whether to grant a certificate of convenience and necessity.

3. Pursuant to P.U.C. SUBST. R. 25.174(d)(3), the Commission considered installed generation and capacity represented by posted collateral as evidence of financial commitment by renewable generators in the Panhandle A and Panhandle B CREZs in this proceeding.

4. The evidence of financial commitment provided by renewable generators in this docket complies with and meets the requirements in P.U.C. SUBST. R. 25.174(d)(3), (4), and (7).

5. Financial commitment for a CREZ is sufficient under PURA § 39.904(g)(3) to grant CCNs for transmission facilities for the CREZ if the sum of the renewable generating capacity is at least 50% of the designated generating capacity for the CREZ.

6. The level of financial commitment for the Panhandle A CREZ is sufficient under PURA § 39.904(g)(3).

7. The level of financial commitment for the Panhandle B CREZ is sufficient under PURA § 39.904(g)(3).

8. The Commission has fulfilled its obligation under PURA § 39.904(g)(3) and P.U.C. SUBST. R. 25.174(d)(3), (4), (6), and (7) to determine whether there is sufficient financial commitment for the Panhandle A and Panhandle B CREZs.

9. Pursuant to P.U.C. PROC. R. 22.5(b), good cause exists to waive the 20-day requirement of P.U.C. PROC. R. 22.35(b)(2).

III. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following order:

1. The Commission finds that the level of financial commitment for the Panhandle A CREZ is sufficient under PURA § 39.904(g)(3).

2. The Commission finds that the level of financial commitment for the Panhandle B CREZ is sufficient under PURA § 39.904(g)(3).

3. The Commission's determination that there is sufficient financial commitment for both the Panhandle A CREZ and the Panhandle B CREZ shall be recognized in the CCN proceedings for transmission facilities for those CREZs, and shall not be addressed further in the CCN proceedings.

4. Entry of this Order consistent with the Agreement does not indicate the Commission's endorsement or approval of any principle or methodology that may underlie the Agreement. Entry of this Order consistent with the Agreement should not be regarded as a binding holding or precedent as to the appropriateness of any principle or methodology that may underlie the Agreement.

5. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

SIGNED AT AUSTIN, TEXAS on the 30th day of July 2010.

PUBLIC UTILITY COMMISSION OF TEXAS

BARRY T. SMITHERMAN, CHAIRMAN

DONNA L. NELSON, COMMISSIONER

KENNETH W. ANDERSON, JR., COMMISSIONER

q:\cadm\docket management\electric\commission held hearings\37567 panhandle a & b crez\37567 po.docx

PANHANDLE RENEWABLE ENERGY ZONE (PREZ) STUDY REPORT

April 2014

Prepared by ERCOT System Planning

Disclaimer

The Electric Reliability Council of Texas (ERCOT) System Planning staff prepared this document. It is a report of the ERCOT transmission system, identifying the potential system constraints and transmission upgrade needs to accommodate wind generation projects in Texas Panhandle. Transmission system planning is a continuous process. Conclusions reached in this report can change with the addition (or elimination) of plans for new generation, transmission facilities, equipment, or loads.

ERCOT AND ITS CONTRIBUTING MEMBER COMPANIES DISCLAIM ANY WARRANTY, EXPRESSED OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE WHATSOEVER WITH RESPECT TO THE INFORMATION BEING PROVIDED IN THIS REPORT.

The use of this information in any manner constitutes an agreement to hold harmless and indemnify ERCOT, its Member Companies, employees, and/or representatives from all claims of any damages. In no event shall ERCOT, its Member Companies, employees, and/or representatives be liable for actual, indirect, special, or consequential damages in connection with the use of this data. Users are advised to verify the accuracy of this information with the original source of the data.

Acknowledgement

ERCOT acknowledges the support, cooperation, and contribution of the ERCOT Regional Planning Group and ERCOT Transmission Service Providers.

Document Revisions

Date	Version	Description	Author(s)
04/18/2014	1.0	Final	Shun-Hsien (Fred) Huang, John Schmall, Yang Zhang, Ying Li Reviewed by: Jeff Billo, Warren Lasher

EXECUTIVE SUMMARY

Background

The Competitive Renewable Energy Zone (CREZ) transmission improvements were endorsed by the Public Utility Commission of Texas (PUCT) in 2008 in order to accommodate an incremental 11,553 MW of wind generation capacity in West Texas. These projects include new transmission facilities in the Texas Panhandle. Prior to the CREZ project, there were no ERCOT transmission lines extending into the Texas Panhandle and therefore no load or generation in the area connected to ERCOT. Furthermore, at the time the PUCT ordered the CREZ transmission projects to be constructed, there were no generation plants with signed generation interconnection agreements (SGIA) for connection to the proposed Panhandle CREZ facilities. The reactive equipment necessary to support the export of power from the Panhandle was implemented for 2,400 MW of wind generation capacity (shown in Figure E-1), even though the transmission lines were constructed to accommodate a much larger capacity. This decision was made because the size and location of any additional equipment would be dependent upon the size and location of the wind generation that actually developed in the area.

The Panhandle region is currently experiencing significantly more interest from wind generation developers than what was initially planned for the area. The ERCOT 2012 Long-Term System Assessment (LTSA) report indicated that the northwestern-most portion of the Panhandle CREZ system could see a significant amount of wind generation development and resulting voltage stability limits would cause the constraining of wind power delivery to the rest of the ERCOT system. As of 2013, there was over 11 GW of wind generation in service on the ERCOT system. According to the Generation Interconnection Request list reviewed in December 2013, there was over 4 GW of wind generation capacity with a signed interconnection agreement (SGIA) in the Texas Panhandle and more than 10 GW wind generation capacity proposed to connect to the Texas Panhandle that was progressing through the interconnection process. This information indicates that the wind generation projects located in the Texas Panhandle are likely to exceed the 2,400 MW capacity for which reactive support was initially installed.

The ERCOT Panhandle grid is remote from synchronous generators and requires long distance power transfer to the load centers in ERCOT. All wind generation projects in the Panhandle are expected to be equipped with advanced power electronic devices that will further weaken the system strength due to limited short circuit current contributions. Dynamic response in the Panhandle will be dominated by power electronic devices (wind plants, SVC, etc.) such that voltage control becomes very difficult because of the high voltage sensitivity of dV/dQ. In other words, under weak grid conditions, a small variation of reactive support results in large voltage deviations. Stability challenges and weak system strength are expected to be significant constraints for Panhandle export.

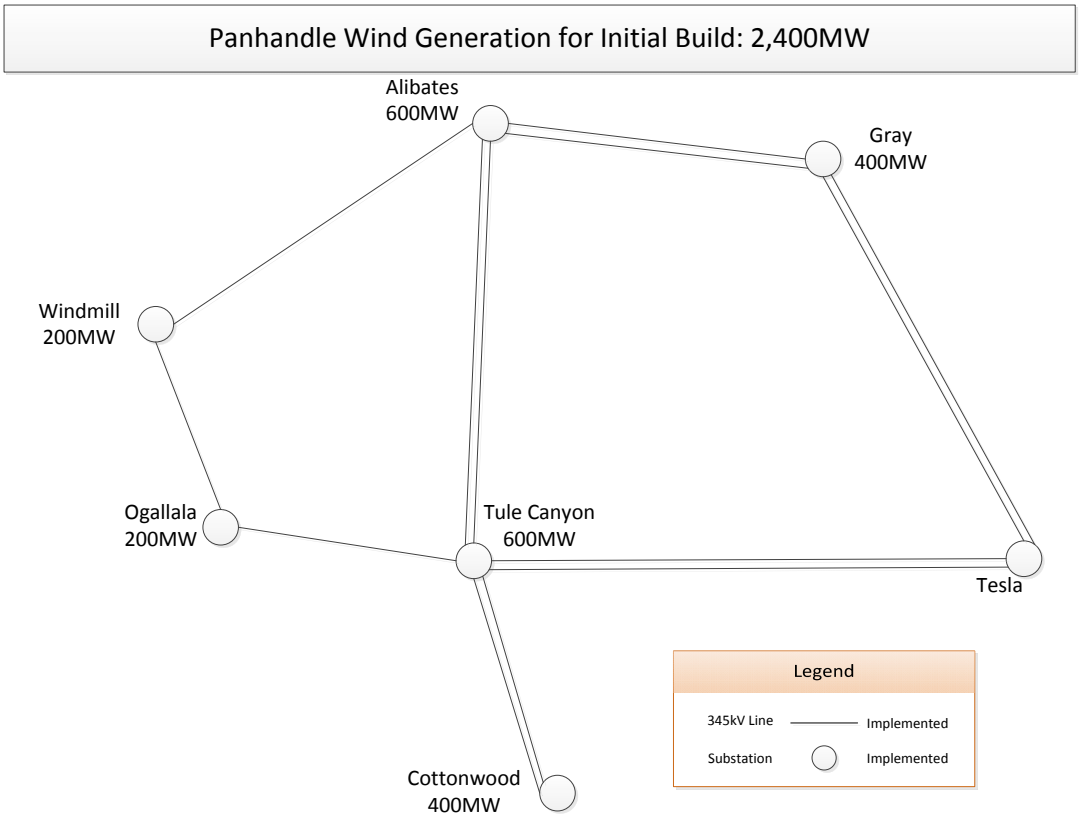


Figure E-1 Panhandle Transmission Topology

PREZ Study Results

Recognizing the challenges associated with connecting a large amount of wind generation in the Panhandle, ERCOT initiated the Panhandle Renewable Energy Zone (PREZ) study in early 2013. The purpose of the PREZ study was to identify the potential system constraints and transmission upgrade needs for the Texas Panhandle to accommodate wind generation projects that exceed the existing designed Panhandle export capability. The results provide a roadmap to both ERCOT and TSPs that includes the upgrade needs and the associated triggers in terms of wind generation capacity in the Panhandle.

There are four upgrade stages identified as a roadmap to ultimately accommodate 7.5 GW wind generation output in the Panhandle region. Figure E-2 shows the Panhandle export stability limit after each stage and Table E-1 lists the upgrade details associated with the first two stages.

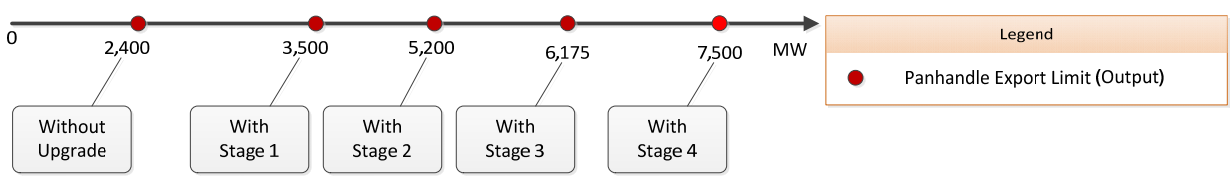


Figure E-2 Panhandle Export Stability Limit for Transmission Upgrade -- Roadmap

Table E-1 Panhandle Transmission Upgrade Roadmap -- Detailed Project List

Stage	Panhandle Export Stability Limit (MW)	Trigger for Upgrade (Panhandle Wind Capacity) (MW)*	Upgrade Element	Estimated Upgrade Cost ($M)
Existing grid	2,400	-	-	-
1	3,500	3,000 MW	• Add second circuit on the existing Panhandle grid • 200 MVA synchronous condensers • 150 MVAr reactors	115
2	5,200	6,500 MW	• Add one new 345 kV double circuit -- (Ogallala-Long Draw) • 750 MVA synchronous condensers • 350 MVAr reactors	560

*assuming the limit will be enforced at 90% of the stability limit

Several transmission improvements can be implemented at a relatively low cost and in a relatively short time frame to increase the Panhandle export capability. These include installing shunt reactors, synchronous condensers, and adding the second circuit on the existing towers that were constructed to be double-circuit capable with originally just one circuit in place. Additional improvements to increase export limits will include new transmission lines on new right of way (ROW). These improvements will require significant wind generation development commitment in order to be economically justified.

It should be noted that the identified improvements were based on the assumptions used in this study. Should these assumptions change, the results of this analysis will need to be updated which could yield a different set of transmission improvements or trigger points. Assumptions that could change the results of this analysis include the size and location of actual wind generation development in the Panhandle, a change to the assumed high voltage ride through requirement, connection of a proposed DC-tie in the Panhandle, transmission upgrade cost estimates, or natural gas price projections.

Although additional synchronous generators in the Panhandle region can improve the system strength and provide dynamic voltage support, it is unlikely that such synchronous generators will be on-line under high wind output conditions since synchronous generators typically have a higher marginal cost than wind plants. Therefore, the addition of new synchronous generators in the Panhandle region is not expected to change the study results.

Key Observations and Findings

- **Panhandle Weak Grid Characteristics**

The Panhandle grid is remote from synchronous generators and load centers and is considered a weak grid when integrating a large amount of wind generation. Several system characteristics and challenges that can occur in a weak grid are:

- In a highly compensated weak grid, voltage collapse can occur within the normal operating voltage range (0.95 to 1.05 pu) masking voltage stability risks in real time operations. Static capacitor and static var compensators contribute to this effect and have limited effectiveness for further increasing transfer capability.
- A grid with low short circuit ratios and high voltage sensitivity of dV/dQ requires special coordination of various complex control systems. Typical voltage control settings can result in aggressive voltage support in a weak system and lead to un-damped oscillations, overvoltage cascading or voltage collapse.
- Wind projects connected to the Panhandle region are effectively connected to a common point of interconnection (POI) such that each wind plant may interact with other Panhandle wind plants.

- **Weighted Short Circuit Ratio (WSCR)**

There is currently no industry-standard approach to calculate the proper short circuit ratio (SCR) index for a weak system with a high penetration of wind power plants. To take into account the effect of interactions between wind plants and give a better estimate of the system strength, a more appropriate quantity is the weighted short circuit ratio (WSCR), defined by:

$$WSCR = \frac{Weighted \quad S_{SCMVA}}{\sum_{i}^{N} P_{RMWi}} = \frac{(\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}) / \sum_{i}^{N} P_{RMWi}}{\sum_{i}^{N} P_{RMWi}} = \frac{\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}}{(\sum_{i}^{N} P_{RMWi})^2} \qquad \text{(E-1)}$$

Where S_{SCMVAi} is the short circuit capacity at bus i before the connection of wind plant i and P_{RMWi} is the MW rating of wind plant i to be connected. N is the number of wind plants fully interacting with each other and i is the wind plant index.

The proposed WSCR calculation method is based on the assumption of full interactions between wind plants. This is equivalent to assuming all wind plants are connected to a single virtual Point of Interconnection (POI). For a real power system, there is usually some electrical distance between each wind plant's POI and the wind plants will not fully interact with each other. The WSCR obtained with this method gives a conservative estimate of the system strength and is considered as a proper index to represent the system strength for the Panhandle region.

- **Voltage Ride Through Capability**

Based on the wind plant design information available at this time, it appears that some projects have less high voltage ride through (HVRT) capability compared to others. Actuation of wind plant overvoltage relays was observed in various simulation results and can potentially lead to overvoltage cascading as shown in Figure E-3.

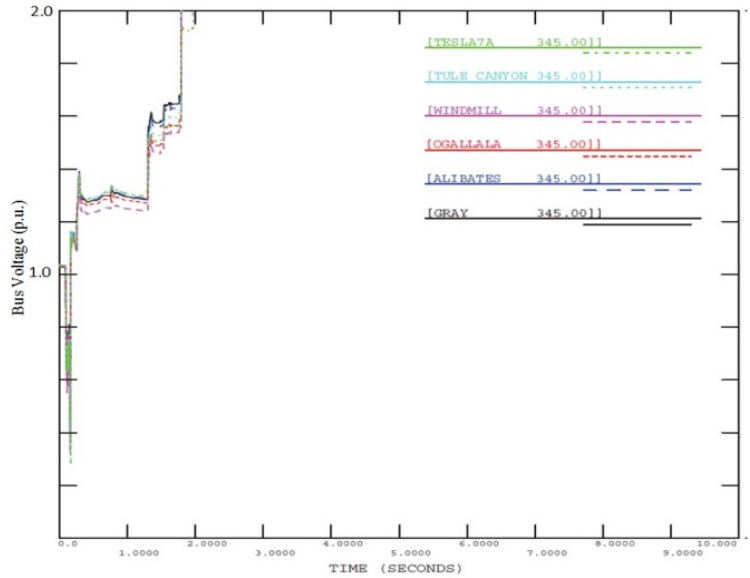


Figure E-3 Cascading High Voltage Collapse in the Panhandle

Post-disturbance overvoltage is more likely to occur under weak grid conditions. Overvoltage tripping can be minimized through a combination of system strength enhancements and better HVRT capability of wind generation projects. The collapse caused by overvoltage cascading presents a significant reliability risk and suggests a need for wind generation projects to comply with the HVRT requirement shown in Figure E-4. This standard is proposed in ERCOT NOGRR 124, and is consistent with the approved NERC PRC-024 standard. At the time of this report NOGRR 124 was still being reviewed in the stakeholder process. If the proposed HVRT requirements are not implemented in ERCOT then a higher system strength criterion will be required.

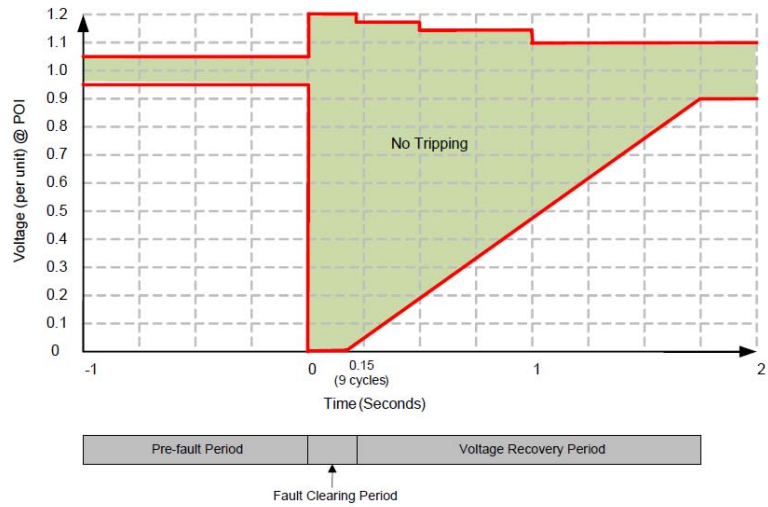


Figure E-4 Proposed Voltage Ride Through Capability for Wind Generation Resources

- **System Strength Enhancement**

An appropriately conservative system strength calculation, WSCR, was used to characterize Panhandle system strength. A WSCR of 1.5 was proposed as the minimum system strength need for the Panhandle. The need for system strength enhancement should be determined based on wind generation output instead of wind generation capacity when there is a constraint to limit wind plant output in real time operations.

Applicability of Study Results

The Panhandle wind generation resources modeled in the study case were based on each project's available generation interconnection information at the time the study was performed. As of 2013, there were no generation projects in-service in the Panhandle, and the proposed upgrades may need to be revised based on actual installed wind generation projects. The study results serve as a reference to both ERCOT and TSPs to identify the challenges, constraints, and upgrade needs in the Panhandle region. These identified projects are not approved transmission projects and may require additional Regional Planning Group (RPG) review prior to implementation.

Future Work

ERCOT staff will continue to work with TSPs to evaluate alternative upgrade options proposed by TSPs and/or stakeholders. ERCOT also will monitor the generation interconnection status for actual implementation of wind projects in the Panhandle region. The impact of a proposed DC-tie connection to the Panhandle may require further study.

Table of Contents

Table of Figures

Table of Tables

GLOSSARY

- HVRT – High Voltage Ride Through
- NERC - North American Electric Reliability Corporation
- PREZ – Panhandle Renewable Energy Zone
- PSS/E - Power System Simulator for Engineering, Version 32.0
- PV - Power versus Voltage relationship
- SSWG - Steady-State Working Group under the ERCOT Reliability and Operations Subcommittee
- SVC - Static VAR Compensator (a device for providing dynamic reactive support)
- STATCOM – Static Synchronous Compensator (a device for providing dynamic reactive support)
- VFT - Variable Frequency Transformer

1. INTRODUCTION

A Competitive Renewable Energy Zone (CREZ) is a geographic area with optimal conditions for the economic development of wind power generation facilities. The Public Utility Commission of Texas (PUCT) issued a final order in Docket No. 33672 in 2008, designating a number of transmission projects to be constructed to transmit wind power from the CREZs to the highly populated metropolitan areas of the state. The approved CREZ projects were largely completed in 2013 and Figure 1-1 shows the overall projects by Transmission Service Provider (TSP) [1].

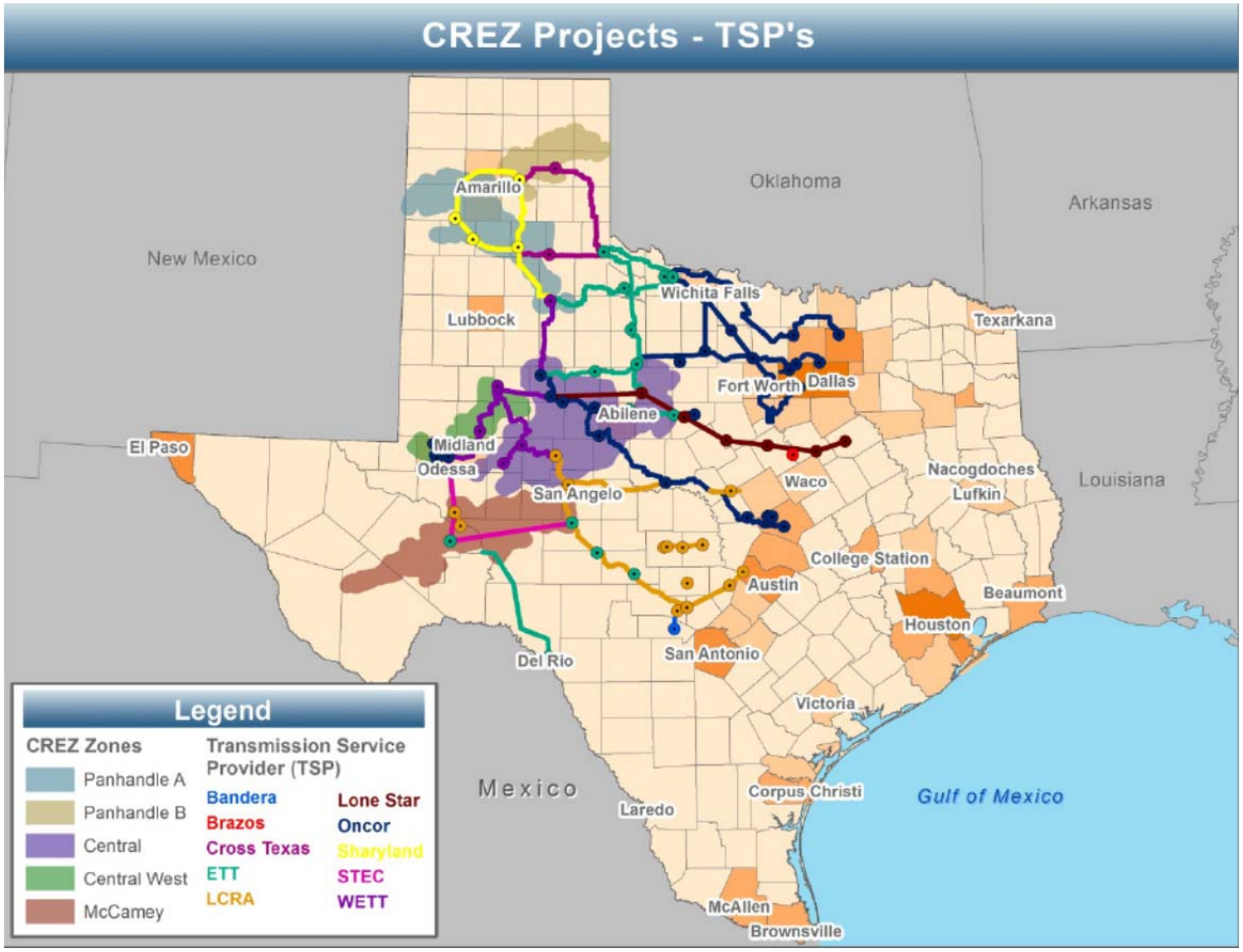


Figure 1-1 CREZ Projects - TSP's

The designated CREZ transmission improvements include over 2,300 miles of new 345 kV right-of-way and were planned to accommodate an incremental 11,553 MW of wind generation capacity in West Texas. ERCOT, in conjunction with the CREZ TSPs, commissioned the CREZ Reactive Power Study to identify the size, type, and location of equipment needed to control, condition, and route the power flowing through the CREZ transmission projects. This study was awarded to ABB Inc. and was completed in December 2010. The results of the CREZ Reactive Power Study were reviewed by the TSPs and additional reactive power capacity was added as recommended [2].

Prior to the CREZ project there were no ERCOT transmission lines extending into the Texas Panhandle and therefore no load or generation in the area connected to ERCOT. Furthermore, at the time the PUCT ordered the CREZ transmission projects to be constructed, there were no generation plants with signed generation interconnection agreements (SGIA) for connection to the proposed Panhandle CREZ facilities. The reactive equipment necessary to support the export of power from the Panhandle was implemented for 2,400 MW, even though the transmission lines were constructed to accommodate a much larger capacity. Figure 1-2 shows the implemented Panhandle transmission topology. There were two main drivers for this decision. First, at the time, there was not a clear indication of how much wind generation capacity would interconnect in the area or how quickly it would develop. Second, since the CREZ Reactive Power Study indicated that the export of power from the Panhandle will be voltage-stability constrained, the location and amount of wind generation facilities within the area will dictate the location and size requirement for additional reactive support devices. Hence, the details concerning additional reactive equipment needs for the Panhandle were left for later studies when more information would be available.

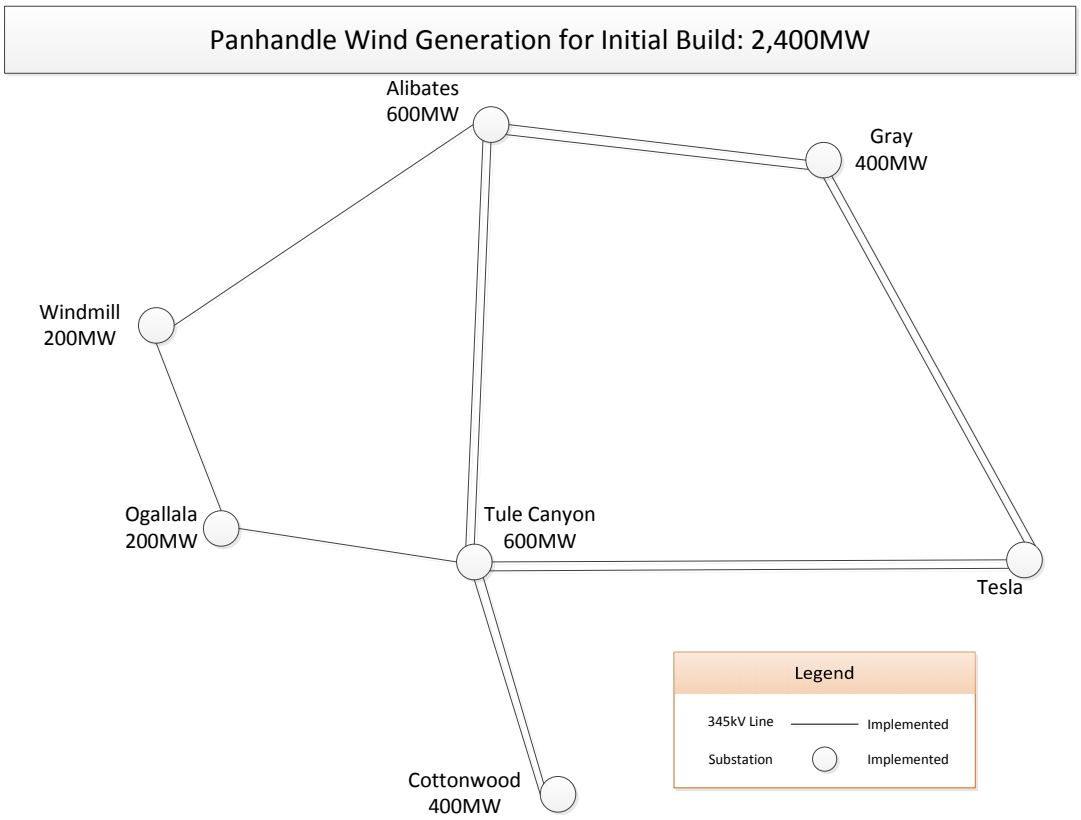


Figure 1-2 Panhandle Topology

The ERCOT 2012 Long-Term System Assessment (LTSA) report [3] indicated that the northwestern-most portion of the Panhandle CREZ system could see a significant amount of wind generation development and could exceed voltage stability limits which would lead to constraining wind power delivery to the rest of the ERCOT system. As of 2013, there was over 11 GW of wind generation in service on the ERCOT system. According to the Generation Interconnection Request list reviewed in December 2013, there was over 4 GW of

wind generation capacity with a signed interconnection agreement (SGIA) in the Texas Panhandle. The accumulated Panhandle wind generation capacity with SGIA based on the signing date as reviewed in December 2013 is shown in Figure 1-3. Additionally, more than 10 GW of wind generation capacity proposed to connect to the Texas Panhandle was actively progressing through the interconnection process. This indicates that the wind generation projects located in the Texas Panhandle will likely exceed the 2,400 MW capacity for which reactive support was initially installed.

The ERCOT Panhandle grid is remote from both synchronous generators and load centers. It requires long distance power transfer from the Panhandle region to the load centers in ERCOT. Large amounts of wind generation with advanced power electronic devices that are expected to be installed in Panhandle grid will further weaken the system strength. Dynamic response in the area will be dominated by power electronic devices (wind plants, SVC, etc.) such that voltage control will be very difficult because of the high voltage sensitivity of dV/dQ. In other words, under weak grid conditions, a small variation of reactive support results in large voltage deviations.

Based on the abovementioned reasons and observations, stability challenges and weak system strength are expected to be the significant constraints for Panhandle export. The purpose of the PREZ study was to identify the potential system constraints and upgrade needs for the Panhandle region to accommodate wind generation projects that exceed the existing designed Panhandle export capability. The PREZ study included both reliability and economic cost analysis. The reliability analysis identified the upgrade needs to integrate Panhandle wind generation. The economic cost analysis, following the ERCOT economic planning criteria in ERCOT Protocol 3.11.2 [4], determined the trigger point for when the upgrades will be economically justified.

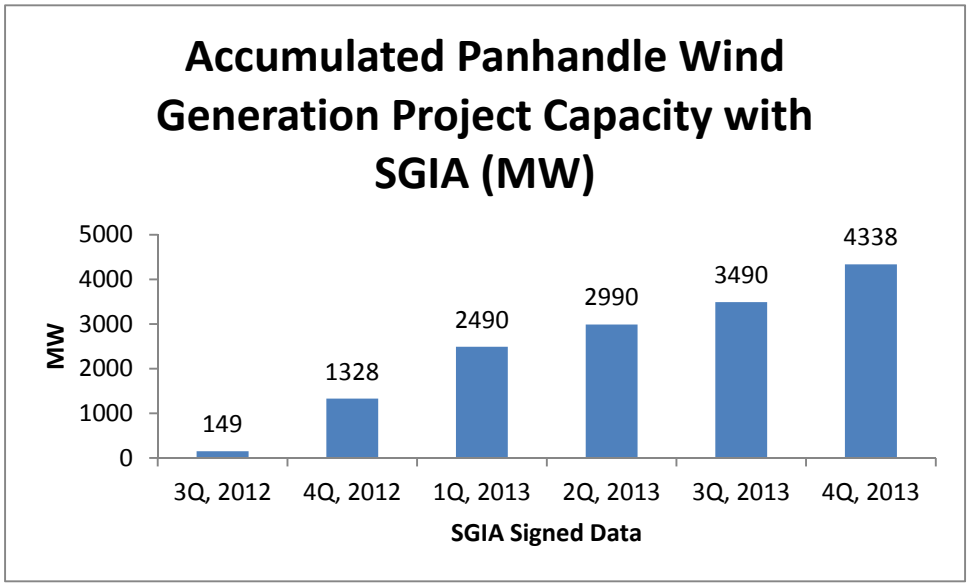


Figure 1-3 Accumulated Panhandle Wind Generation Project Capacity with SGIA

2. STUDY DEVELOPMENT AND PROCESS

This section describes the study cases, study scenarios, and study criteria for both the reliability and economic cost analyses in this PREZ study.

2.1. Base Case Development

The 2013 developed DWG high wind low load flat start case for the year 2016 was used as the reliability study base case. The system load was 36,500 MW. There was a total of 10,785 MW of wind generation capacity dispatched at 8,946 MW output from the existing wind generation projects to provide 24.5% of the system demand. There was no wind generation modeled in Panhandle in the base case. All wind projects studied in the Panhandle were added based on the generation interconnection information available at the time the study started in March 2013.

The 2017 UPLAN case from the 2012 Five-Year Transmission Plan was used as the economic study base case. All of the wind projects in the economic case were consistent with the reliability case.

2.2. Study Scenario

To obtain a robust and adequate transmission upgrade plan for a broad range of system conditions, multiple Panhandle wind generation output scenarios were studied. The scenario descriptions are as follows:

- Mid-Term – this case included the high wind generation levels anticipated in the Mid-Term. This case included wind projects that have either signed the interconnection agreement or completed interconnection studies. It represented 5,043 MW of wind generation capacity dispatched at 95% output in the Panhandle region.
- Long-Term – this case included the high wind generation levels anticipated in the Long-Term. All the wind generation projects in the Mid-Term case are included in this case. Approximate 5,000 MW wind projects were in the interconnection study process and 50% of these projects were added for the anticipated Long-Term Panhandle wind generation capacity. It represented 7,845 MW of wind generation capacity dispatched at 95% output in the Panhandle region.
- Low Wind – this case included conditions where high voltages are probable and need to be adequately held to appropriate levels. It represented 0 MW of wind generation in the Panhandle region.
- Roadmap – using upgrades identified in Mid-Term and Long-Term as references, the roadmap provided the most effective transmission upgrades associated with the assumed wind generation development.

The purpose of the Mid-Term and Long-Term scenarios was to understand the needs and challenges for various wind generation output levels in the Panhandle. The challenges identified in both scenarios were not necessarily fully addressed since the upgrade needs identified in both Mid-Term and Long-Term scenarios serve as a reference for further roadmap development. The upgrade needs further developed in the roadmap fully addressed all the challenges and provided acceptable simulation results.

2.3. Study Contingency and Criteria

Both three-phase-fault normal clearing and single-line-to-ground-fault stuck breaker events were tested in the reliability analysis. The following criteria were applied in the studies.

- Steady state voltage stability analysis

  Thermal: 100% rate A for base case and 100% rate B for contingency analysis

  Voltage: 0.95~1.05 pu for base case and 0.9~1.05 pu for contingency analysis
- Transient stability analysis

  Post disturbance voltage recovers within the range from 0.9 to 1.1 pu

  Post disturbance frequency recovers within the range from 59.4 Hz to 60.4 Hz
- Economic cost analysis

  Thermal: 100% rate A for base case and 100% rate B for contingency analysis

2.4. Short Circuit Ratio (SCR)

2.4.1. Introduction to System Strength and Short Circuit Ratio

System strength is a common concern in the integration of renewable energy sources. The performance of various components in a power system depends on the system strength, which reflects the sensitivity of system variables to various disturbances. Short circuit ratio (SCR) is often used as an index of the system strength to show how strong a network bus is with respect to the rated power of a device. SCR is defined as the ratio of the short circuit capacity at the bus the device is located to the MW rating of the device [5]. A strong AC system is defined as having an SCR above five, and the SCR of a weak system is below three [6].

Wind plants are often connected to weaker portions of the system remote from synchronous generators and load centers. Voltage stability issues caused by large-scale wind integration in weak systems are important topics to be addressed [7]-[9]. Some wind turbines have minimum system strength requirements. For example, the default GE wind turbine model parameters are suitable for SCRs that are 5 or higher. For connection to weaker systems, additional analyses are required to ensure proper tuning of model parameters [10]. Specially designed control schemes of wind turbines or system strength enhancement are necessary to ensure acceptable performance.

2.4.2. SCR Calculation Method

Conventionally, SCR is defined as the ratio of the short circuit capacity at the bus the device is located to the MW rating of the device. Based on this definition, SCR is given by:

$$\mathrm{SCR} = \frac{S_{\mathrm{SCMVA}}}{P_{\mathrm{RMW}}} \qquad (1)$$

where S_{SCMVA} is the short circuit capacity at the bus before the connection of the device and P_{RMW} is the rated MW of the device to be connected. Equation (1) is the commonly used SCR calculation method when evaluating system strength. The key assumption and limitation of this SCR calculation method is that the

studied wind plant does not interact with other wind plants in the system. When wind plants are electrically close to each other, they may interact with each other and oscillate together. In such cases, the SCR calculation using equation (1) can result in an overly optimistic result.

There is currently no industry-standard approach to calculate the proper SCR index for a weak system with high penetration of wind power plants. To take into account the effect of interactions between wind plants and give a better estimate of the system strength, a more appropriate quantity is the weighted short circuit ratio (WSCR), defined by:

$$WSCR = \frac{Weighted \quad S_{SCMVA}}{\sum_{i}^{N} P_{RMWi}} = \frac{(\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}) / \sum_{i}^{N} P_{RMWi}}{\sum_{i}^{N} P_{RMWi}} = \frac{\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}}{(\sum_{i}^{N} P_{RMWi})^2} \quad (2)$$

Where S_{SCMVAi} is the short circuit capacity at bus i before the connection of wind plant i and P_{RMWi} is the MW rating of wind plant i to be connected. N is the number of wind plants fully interacting with each other and i is the wind plant index.

The proposed WSCR calculation method is based on the assumption of full interactions between wind plants. This is equivalent to assuming that all wind plants are connected to a virtual Point of Interconnection (POI). For a real power system, there is usually some electrical distance between each wind plant's POI and the wind plants will not fully interact with each other. The WSCR obtained with this method gives a conservative estimate of the system strength and is considered as a proper index to represent the system strength for the studied Panhandle region. A small sample system with four wind plants, as shown in Figure 2-1, is used to demonstrate the proposed WSCR concept. The subsystem consisting of four wind plants connects to the main system with weak links. There is no significant electrical distance between each wind plant's POI. Table 2-1 shows the wind plant sizes and SCR values calculated using equation (1).

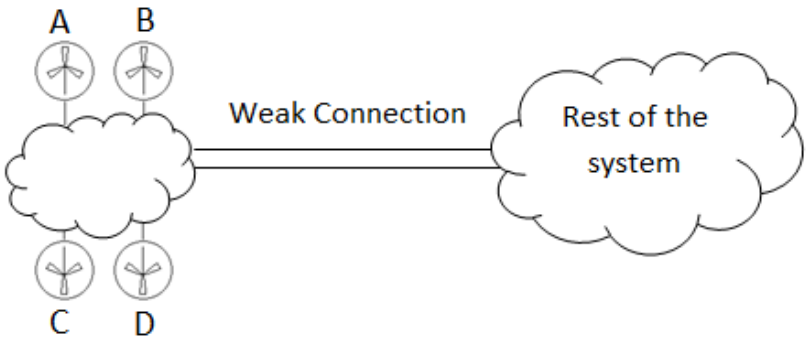


Figure 2-1 Four Wind Generation Plants Integrated into the System with Weak Connections

Table 2-1 Wind Capacity and SCR Values Assuming No Interaction

Wind plant	Wind Capacity (MW)	Short Circuit Capacity (SCMVA)	SCR
A	1,200	6,500	5.42
B	1,000	8,000	8.00
C	800	8,500	10.63
D	2,000	7,000	3.5

The weighted SCR is calculated following equation (2) in below:

$$WSCR = \frac{1{,}200 * 6{,}500 + 1{,}000 * 8{,}000 + 800 * 8{,}500 + 2{,}000 * 7{,}000}{(1{,}200 + 1{,}000 + 800 + 2{,}000)^2} = 1.46$$

The above calculation shows that even though all SCRs at each individual POI are larger than 3, the WSCR of the equivalent virtual POI to represent the region is only 1.46. This means the actual system strength is much weaker since the wind plants interact with each other.

The undesired oscillatory response within wind plants in the Panhandle area was observed in a dynamic simulation. Figure 2-2 shows one of the simulation results when modeling 6.2 GW wind generation capacity in Panhandle and the WSCR is close to 1.0. The power output of all wind plants oscillated together in the same pattern. The fault was a three-phase fault with 4 cycles clearing time applied to a 345 kV bus close to the Panhandle area. This actually shows the potential of the full interaction between wind plants in a weak system, and therefore, justifies the assumption of the WSCR calculation and the need for system strength enhancement.

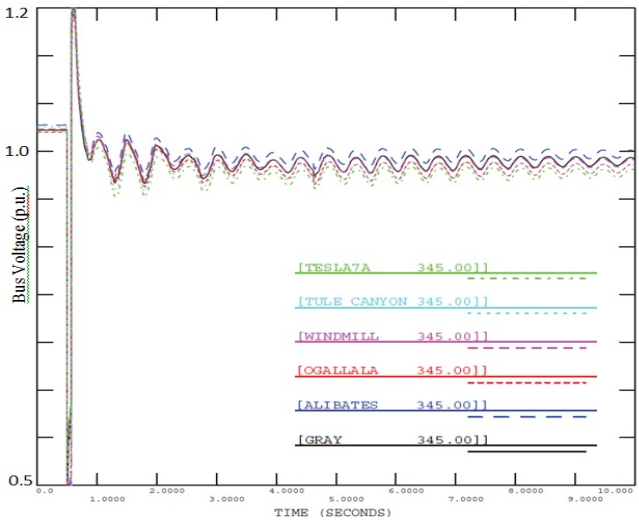


Figure 2-2 Wind Generation Oscillation Under Weak Conditions

2.4.3. System Strength Enhancement Options

To obtain an acceptable system response, a minimum level of system strength is needed in the Panhandle region. Several technologies were tested to examine their impact on the system strength and a summary is listed in Table 2-2.

Table 2-2 Comparison of System Strength Enhancement Options

Option	Synchronous Condenser (SC)	Static Var Compensator (SVC)	Variable Frequency Transformer (VFT)
Dynamic Reactive Support	√	√	√
System Strength	√	–	√
Cost	$$	$$	$$$

Some key observations are:

- Synchronous condensers are a good option for improving system strength by increasing short circuit levels [11]. Other positive attributes of synchronous condensers include high overload capability, good reactive power support under low voltage conditions, contributions to system inertia, and harmonics-free operation [12]. Reference [13] describes a synchronous condenser application with the latest technology at VELCO's Granite Substation.
- Utilizing SVCs instead of synchronous condensers produced an oscillatory response and it confirms that the SVC option does not really address the fundamental system strength issue. It may be possible to mitigate this result by tuning the SVC controls to resolve the oscillatory response, but it is not desirable to rely on a complicated coordination of many power electronic controls. Furthermore, the necessary tuning would likely require a reduction in the SVC response time which would defeat one of the primary advantages in selecting an SVC. Thus, the SVC option does not appear to be appropriate for the purpose of system strength enhancement. The same conclusion applies to STATCOMs since STATCOMs also do not address the system strength issue.

- The use of VFTs appears to be a viable alternative to synchronous condensers. However, the contribution of the VFT is dependent on the strength and appropriate modeling of the adjacent SPP system and additional analysis is recommended to assess the impact of variations in the SPP equivalent model.

Based on the results in Table 2-2, synchronous condenser was determined to be the best transmission upgrade option to provide system strength enhancement in this PREZ study. It should be noted that additional study may be required to address the potential susceptibility of synchronous condensers to Subsynchronous Resonance (SSR) issues when the proposed synchronous condenser is close to the series compensated transmission lines.

2.4.4. Optimal Locations for System Strength Enhancement

The effect of weak system strength on the WPP voltage control performance can be best demonstrated with a recent event in ERCOT. An existing wind power plant (WPP) connected to a weak system in ERCOT experienced undesirable poorly damped and un-damped voltage oscillations under weak grid conditions [14]. The WPP is connected to the ERCOT grid through two transmission lines. When one line was taken out of service, the WPP experienced poorly damped or un-damped voltage oscillations, which were recorded by Phasor Measurement Units (PMUs). The investigation of the event showed that the key cause for the oscillatory response was the plant level voltage control of the WPP was not suitable for a weak grid condition. The calculated SCR at POI after losing one line is less than two. The event was simulated with the WPP represented with a detailed dynamic model to re-create the oscillatory response; simulation results are presented in Figure 2-3. The voltage oscillation is effectively damped when modeling system strength improvements that increase the SCR as shown in the purple color curve. Tuning the voltage controller gains based on the lower SCR value also improved the oscillatory response as shown in the green color curve.

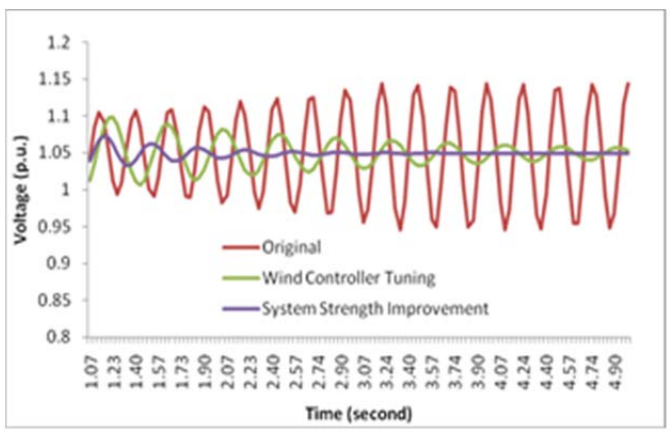


Figure 2-3 Voltage Response at WPP's Point of Interconnection

This actual experience demonstrates potential operational challenges and resolutions for a WPP to operate reliably under low SCR conditions. Considering the Panhandle system characteristics, as stated in section

2.4.2, the WSCR is a more appropriate quantity to represent the Panhandle system strength. Based on the operational experience for the past several years and the information received from various wind turbine manufactures, a WSCR value of 1.5 is proposed to provide a reasonable minimum level of system strength for reliable WPP operation. A step-by-step procedure, as shown in Figure 2-4, is proposed to determine the optimal synchronous condenser ratings and locations to meet the WSCR requirements. The process starts with adding a step size of synchronous condenser at a candidate location and calculating the WSCR. After all candidate locations are tested, the synchronous condenser installation resulting in the best WSCR is obtained. The process is repeated until the WSCR meets the requirement.

It must be recognized that the synchronous condenser rating and location obtained with this procedure is based on the assumption of full interaction between wind plants. It ensures the required minimum system strength for the worst scenario and provides some stability margin. To determine the synchronous compensation level and locations that meet dynamic response criteria, dynamic simulation with detailed dynamic models of all participating devices is recommended.

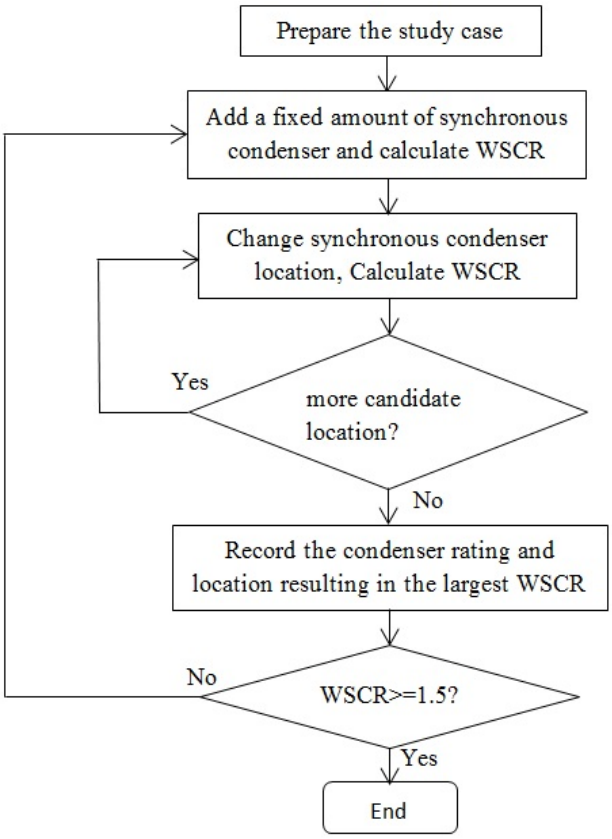


Figure 2-4 Process to Identify Synchronous Condenser Rating/Location

3. STUDY RESULTS and KEY FINDINGS

3.1. Steady State Voltage Stability Analysis

Static voltage stability analysis in the Panhandle area was performed on the 2016 high wind low load (HWLL) base case to identify the weak areas in terms of reactive power deficiency and to identify the critical contingencies limiting power transfer. The study results identify voltage stability margins and serve as a starting point for developing possible reactive compensation schemes and transmission upgrades. A Power-Voltage (PV) analysis was performed for the power transfer between the Panhandle and the rest of the ERCOT system, as shown in Figure 3-1. At each step, the wind generation in the Panhandle area was increased and conventional generation outside of the Panhandle area was reduced. Contingencies were independently applied, followed by a power flow solution. The process was repeated for higher power transfer levels until the base case voltage collapsed under no contingency, or the Panhandle generation reached its maximum capacity.

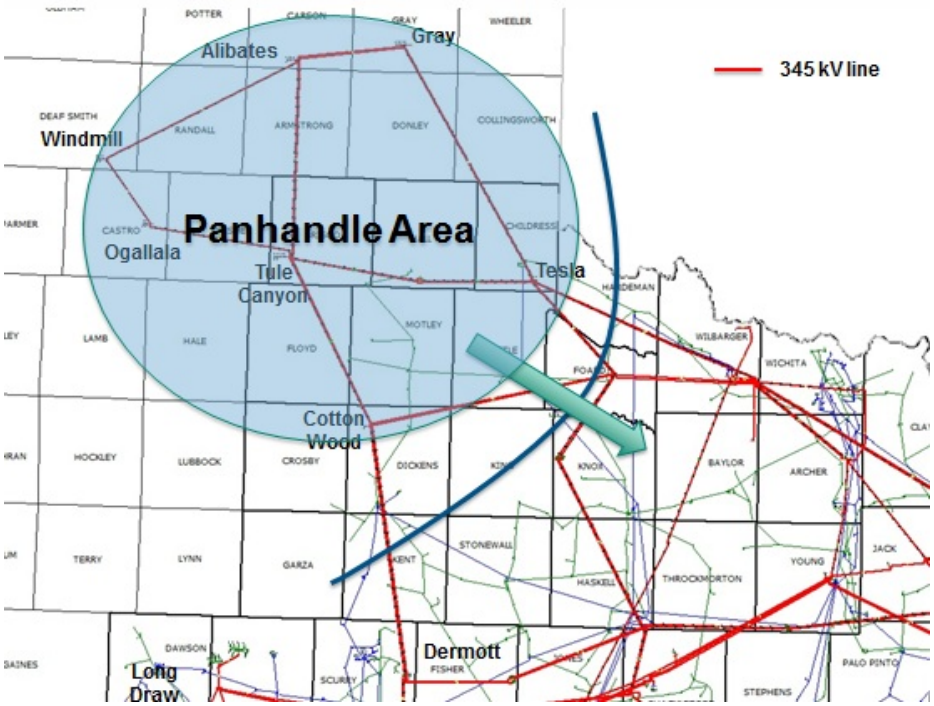


Figure 3-1 PV Analysis Scenario for ERCOT Panhandle Region

The following assumptions were used in the PV analysis:

- Oklaunion generator was turned off. Without its reactive support, a conservative result for the transfer limit is expected;
- Switched shunt and SVC adjustments were allowed post-contingency;
- The reactive power capability for voltage support of the modeled Panhandle wind generation projects was assumed to meet the voltage support requirement in ERCOT Protocol Section 3.15.;
- NERC category B, C, and D contingencies, as well as contingencies defined in SSWG contingency list, of 100 kV and above in North and West Texas were tested;

- Voltages of 100 kV and above buses in North and West Texas were monitored;
- Power flow of 100 kV and above transmission lines in North and West Texas were monitored with the threshold of 100% of rate B;

Two scenarios were studied. The Mid-Term scenario had 5,043 MW of wind generation resources modeled in the Panhandle area. The Long-Term scenario had 7,845 MW of wind generation resources modeled in the Panhandle area. A summary of wind plants modeled in both the Mid-Term and Long-Term scenarios, as well as the initial build CREZ case in the CREZ Reactive Power Compensation study, are shown in Table 3-1.

Table 3-1 Panhandle Wind Projects Modeled in the PV Study

	Initial Build CREZ(MW)	Mid-Term(MW)	Long-Term(MW)
Windmill+Ogallala	400	1,800	3,552
Rest of Panhandle	2,000	3,243	4,293
TOTAL	2,400	5,043	7,845

3.1.1. 2016 HWLL Base Case

As shown in Figure 1-2, the reactive equipment necessary to support the export of power from the Panhandle was implemented for 2,400 MW. A PV study was performed on the 2016 HWLL base case to identify the critical contingencies without any additional system upgrades in the Panhandle region. The PV analysis results are reported in Table 3-2. The limiting event is a breaker failure event, which is a NERC category C contingency. The event trips two transmission lines and causes voltage collapse in the Panhandle region.

Table 3-2 PV Analysis Result of 2016 HWLL Base Case

Limiting Contingency	Contingency Description	NERC Category	Violation
1	Breaker Failure Event	C	Voltage Collapse
2	Single Circuit	B	Voltage Collapse
3	Double Circuit	C	Voltage Collapse
4	Double Circuit	C	Voltage Collapse
5	Double Circuit	C	Voltage Collapse
6	Breaker Failure Event	C	Voltage Collapse
7	Single Circuit	B	Voltage Collapse

The PV curves of selected Panhandle 345 kV buses under the most limiting output of 3,620 MW are shown in Figure 3-2. The most significant observation from Figure 3-2 is that the voltage collapse occurred at a relatively high voltage level. The commonly accepted normal operating voltage range is from 0.95 to 1.05 p.u., but all bus voltages were higher than 0.96 p.u. at the collapse points of the PV curves. The reason the voltage collapse occurred at such a high voltage level is that the CREZ system is essentially a weak system that is highly compensated with switch shunts and SVCs. These reactive compensation devices kept the voltage high while the power transfer level approached the steady state voltage stability limit.

Since the Panhandle region is remote from synchronous generators, the voltage level at the collapse point indicates that more transmission lines are required to achieve higher transfer limits (rather than additional reactive compensation). Continuing to add reactive compensation resources has a minimal effect with respect to increasing transfer limits and results in even higher voltage levels at the collapse point. This conclusion was verified by another PV analysis performed on a case with 600 Mvar of shunt capacitors added in the Panhandle area. As shown in Figure 3-3, after adding more shunt compensation, the transfer limit was increased only by 200 MW (from 3.6 GW to 3.8 GW), and the voltage level at the collapse point was around 1.0 p.u. Based on this observation, several system transmission upgrades were proposed for the Mid-Term and Long-Term scenarios. The test results for these upgrades are shown in the following sections.

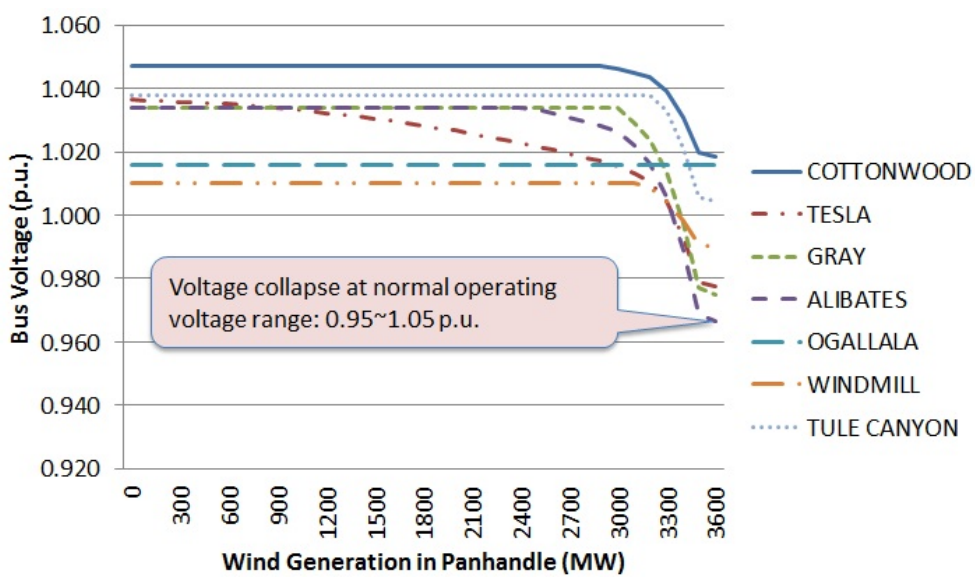


Figure 3-2 PV Curves of Panhandle Buses – Base Case

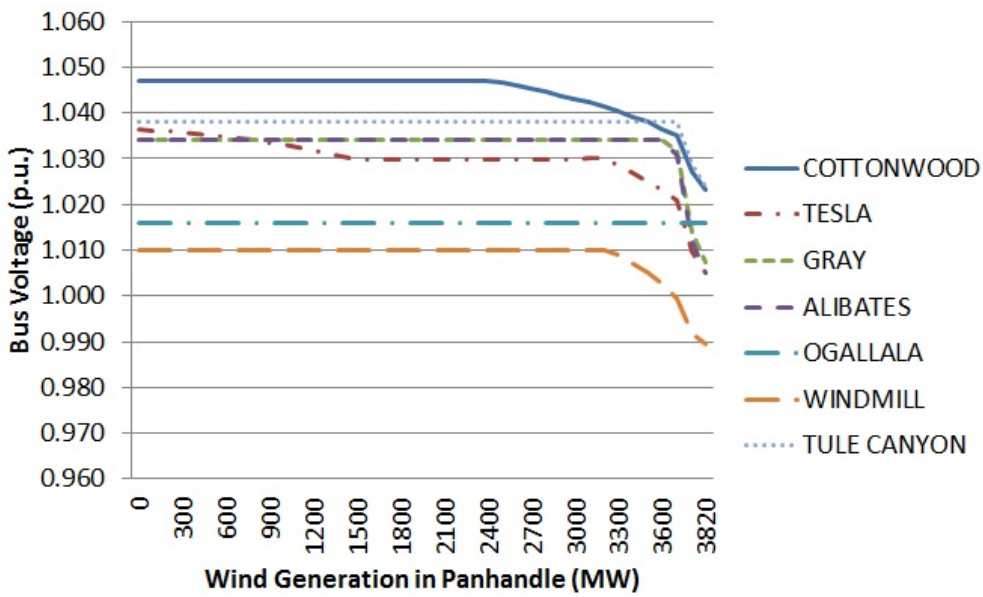


Figure 3-3 PV Curves of Panhandle Buses – with Reactive Compensation

3.1.2. Evaluation of Mid-Term Scenario – 5 GW Wind Generation Output in Panhandle

Various upgrade options were tested for Mid-Term scenario and study results are reported in Table 3-3.

Table 3-3 PV Study Results of Tested System Upgrades for the Mid-Term Scenario

Opt #	Upgrades	Panhandle Export Limit (MW)	Limiting Contingency	Violation	WSCR
1	[+300, -100] SVC at Alibates	3,620	Single Circuit	Voltage collapse	0.871
2	Two phase shifter transformers between Gray and Tesla	3,620	Double Circuit	Voltage collapse	0.87
3	Ogallala-Tule Canyon (345 kV, SC*)	3,960	Double Circuit	Voltage collapse	0.922
4	Ogallala-Cottonwood (345 kV, SC*)	3,840	Double Circuit	Voltage collapse	0.933
5	Ogallala-Dermott (345 kV, SC*)	3,800	Double Circuit	Voltage collapse	0.957
6	Ogallala-Long Draw (345 kV, SC*)	3,820	Double Circuit	Voltage collapse	0.976
7	Ogallala-Windmill (345 kV, SC*) + Ogallala-Cottonwood (345 kV, SC*)	3,920	Double Circuit	Voltage collapse	0.95
8	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Cottonwood (345 kV, SC*)	4,840	Double Circuit	Voltage collapse	0.97
9	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Cottonwood (345 kV, SC*) + 750 Mvar shunt capacitors	5,043	--	--	0.97
10	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Cottonwood (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*)	5,043	--	--	0.991

11	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Cottonwood (345 kV, SC*) + Ogallala-Dermott (345 kV, SC*)	5,043	--	--	1.036
12	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Cottonwood (345 kV, SC*) + Ogallala-Long Draw (345 kV, SC*)	5,043	--	--	1.057
13	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*) + Alibates-Windmill (345 kV, SC*)	4,720	Double Circuit	Voltage collapse	0.962
14	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*) + Alibates-Windmill (345 kV, SC*) + Ogallala-Cottonwood (345 kV, SC*)	5,043	--	--	1.016
15	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*) + Alibates-Windmill (345 kV, SC*) + Ogallala-Cottonwood (345 kV, DB**)	5,043	--	--	1.052
16	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*) + Alibates-Windmill (345 kV, SC*) + Ogallala-Dermott (345 kV, SC*)	5,043	--	--	1.048
17	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*) + Alibates-Windmill (345 kV, SC*) + Ogallala-Dermott (345 kV, DB**)	5,043	--	--	1.115
18	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*) + Alibates-Windmill (345 kV, SC*) + Ogallala-Long Draw (345 kV, SC*)	5,043	--	--	1.07
19	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*) + Alibates-Windmill (345 kV, SC*) + Ogallala-Long Draw (345 kV, DB**)	5,043	--	--	1.145
20	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*) + Alibates-Windmill (345 kV, SC*) + Gray-Riley (345 kV, SC*)	4,820	Single Circuit	Overload	1.025
		5,043	--	--	
21	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*) + Alibates-Windmill (345 kV, SC*) + Gray-Riley (345 kV, DB**)	4,720	Single Circuit	Overload	1.075
		5,043	--	--	
22	Ogallala-Tule Canyon (345 kV, SC*) + Ogallala-Windmill (345 kV, SC*) + Alibates-Windmill (345 kV, SC*) + Ogallala-Long Draw (500 kV, DB**)	5,043	--	--	1.194

* : SC - single circuit
** : DB - double circuit

3.1.3. Key Findings of Mid-Term Scenario

Some key observations from Table 3-3 are:

- Adding more SVCs in the Panhandle area didn't increase the transfer limit (Option 1);
- Adding a phase shifter transformer didn't increase the transfer limit (Option 2);

- Adding the second circuits to all single circuit lines in the Panhandle area increased the steady state transfer limit from 3,620 MW to 4,720 MW. However, the WSCR of 0.962 indicated a weak system in which the dynamic voltage stability can be a more limiting factor (Option 13);
- Among all upgrade options tested that can transfer 5,043 MW (the total capacity of wind installation in Panhandle for the Mid-Term scenario), Options 19 and 22 (both included a double circuit between Ogallala and Long Draw) provided the most benefit in terms of system strength indicated by WSCR value;
- Installing a 500 kV double circuit (instead of 345 kV) between Ogallala and Long Draw provided only marginal benefit in terms of system strength indicated by the WSCR value (Options 19 and 22);

It should be noted that the export limits shown in Table 3-3 are based on steady-state PV analysis only. These limits may not be achievable when considering the dynamic stability analysis. Nonetheless, the results are useful in screening options for the dynamic stability analysis which is described in section 3.2.1 of this report.

Based on the above observations, the system upgrades providing both the best WSCR and 5,043 MW transfer capability for the Mid-Term scenario are listed in Table 3-4.

Table 3-4 Select Upgrades for the Mid-Term Scenario

Component	Location	Comment
345 kV single circuit	Alibates to Windmill	On the existing tower
345 kV single circuit	Windmill to Ogallala	On the existing tower
345 kV single circuit	Ogallala to Tule Canyon	On the existing tower
345 kV double circuit	Ogallala to Long Draw	New line

3.1.4. Evaluation of Long-Term Scenario: 7.5GW Wind Generation Output in Panhandle

Various AC and DC upgrade options were tested for the Long-Term scenario. The VSC-based ±640 kV overhead line with a rating of 1.2 GW HVDC technology option was used for the DC options listed in Table 3-5. To enhance the system strength, two synchronous condensers with a rating of 350 MVA each were added as a placeholder for system strength enhancement for the Long-Term scenario. The PV study results are listed in Table 3-6.

Table 3-5 Tested VSC-Based HVDC Upgrade Options for the Long-Term Scenario

Index	VSC-based HVDC upgrades
DC1	Windmill – W. Shackelford (single VSC converter pair, single HVDC line)
DC2	Windmill – W. Shackelford (double VSC converter pairs, double HVDC lines)
DC3	Windmill – Graham (single VSC converter pair, single HVDC line)
DC4	Windmill – Graham (double VSC converter pairs, double HVDC lines)
DC5	Gray - Graham (single VSC converter pair, single HVDC line)
DC6	Gray - Graham (single VSC converter pair, single HVDC line) + Windmill – W. Shackelford (single VSC converter pair, single HVDC line)
DC7	Windmill – Zenith (single VSC converter pair, single HVDC line)
DC8	Windmill – WAP (single VSC converter pair, single HVDC line)
DC9	Windmill – WAP (double VSC converter pairs, double HVDC lines)
DC10	Gray - Graham (single VSC converter pair, single HVDC line) + Windmill – Zenith (single VSC converter pair, single HVDC line)
DC11	Gray - Zenith (single VSC converter pair, single HVDC line) + Windmill – WAP (single VSC converter pair, single HVDC line)

Table 3-6 PV Study Results of Tested System Upgrades for the Long-Term Scenario

Opt #	Upgrades	Panhandle Export Limit (MW)	Limiting Contingency	Violation	WSCR
1	Mid-Term Upgrades* + Windmill–Cottonwood(345 kV, DB***)	6,820	(DB)	Voltage collapse	0.967
2	Mid-Term Upgrades + Windmill–Cottonwood-W. Shaceklford(345 kV, DB)	7,640	(DB)	Voltage collapse	1.008
3	Mid-Term Upgrades + Windmill–Edith Clarke(345 kV, DB)	5,820	(SC)	Overload	0.931
		6,820	(DB)	Voltage collapse	
4	Mid-Term Upgrades + Gray–Riley (345 kV, DB)	6,840	(DB)	Voltage collapse	1.009
5	Mid-Term Upgrades + Windmill–Cottonwood(345 kV, DB) + Gray–Riley (345 kV, DB)	7,540	(DB)	Voltage collapse	1.045
6	Mid-Term Upgrades + Windmill–Edith Clarke-Graham(345 kV, DB)	7,320	(DB)	Voltage collapse	1.001
7	Mid-Term Upgrades + Windmill–Edith Clarke-Graham (345 kV, DB) + Gray-Riley (345 kV, DB)	6,840	(SC)	Overload	1.077
		7,840	--	--	
8	Mid-Term Upgrades + Windmill–Tule Canyon-W. Shackelford (345 kV, DB)	7,120	(DB)	Voltage collapse	1.037
9	Mid-Term Upgrades + Gray-Riley (345 kV, DB) + Windmill–Tule Canyon- W. Shackelford (345 kV, DB)	7,800	(DB)	Voltage collapse	1.063
10	Mid-Term Upgrades + Gray- Edith Clarke (345 kV, DB) + Windmill–Tule Canyon- W. Shackelford (345 kV, DB)	7,720	(DB)	Voltage collapse	1.089

11	Mid-Term Upgrades + Gray- Edith Clarke-Graham (345 kV, DB) + Windmill–Tule Canyon- W. Shackelford (345 kV, DB)	7,840	--	--	1.139
12	Mid-Term Upgrades + Windmill–Cottonwood- W. Shackelford (345 kV, DB) + Gray-Riley (345 kV, DB)	5,840	(SC)	Overload	1.093
		7,540	(DB)	Overload	
13	Mid-Term Upgrades + Windmill– Edith Clarke (345 kV, DB) + Gray-Riley(345 kV, DB)	5,300	(SC)	Overload	1.063
		6,200	(DB)	Overload	
		7,560	(DB)	Voltage collapse	
14	Mid-Term Upgrades + Windmill–Cottonwood- W. Shackelford (345 kV, DB) + Gray- EDITHCLA (345 kV, DB)	6,480	(SC)	Overload	1.066
		7,840	(DB)	Voltage collapse	
15	Mid-Term Upgrades + Windmill–Cottonwood- W. Shackelford (345 kV, DB) + Gray- Edith Clarke-Graham (345 kV, DB)	7,840	--	--	1.107
16	Partial Mid-Term Upgrades **+ Ogallala-Long Draw (500 kV, DB) + Gray-Riley (500 kV, DB)	5,420	(SC)	Overload	1.045
		6,120	(DB)	Overload	
		7,440	(DB)	Voltage collapse	
17	Partial Mid-Term Upgrades + Ogallala-Long Draw (500 kV, DB) + Windmill- Edith Clarke (500 kV, DB)	6,020	(SC)	Overload	1.029
		6,340	(DB)	Overload	
		7,080	(DB)	Voltage collapse	
18	Partial Mid-Term Upgrades + Ogallala-Long Draw (500 kV, DB) + Windmill- Cottonwood- W. Shackelford (500 kV, DB)	7,020	(DB)	Overload	1.054
		7,740	(DB)	Voltage collapse	
19	Partial Mid-Term Upgrades + Ogallala-Long Draw (500 kV, DB) + Gray-Riley (500 kV, DB) + Windmill- EDITHCLA (500 kV, DB)	5,380	(SC)	Overload	1.117
		5,880	(DB)	Overload	
20	Partial Mid-Term Upgrades + Ogallala-Long Draw (500 kV, DB) + Gray-Riley (500 kV, DB) + Windmill- Cottonwood- W. Shackelford (500 kV, DB)	6,120	(SC)	Overload	1.145
		7,120	(DB)	Overload	
		7,320	(DB)	Overload	
21	Mid-Term Upgrades + DC1****	6,760	(SC)	Overload	0.93
		7,060	(SC)	Voltage collapse	
22	Mid-Term Upgrades + DC2	6,580	(DB)	Voltage collapse	0.93
		7,380	(SC)	Overload	
23	Mid-Term Upgrades + DC3	5,420	(DB)	Overload	0.93
		7,020	(SC)	Voltage collapse	

24	Mid-Term Upgrades + DC4	5,460	(DB)	Overload	0.93
		7,060	(DB)	Voltage collapse	
25	Mid-Term Upgrades + DC5	5,440	(DB)	Overload	0.93
		7,040	(SB)	Voltage collapse	
26	Mid-Term Upgrades + DC6	6,280	(DB)	Overload	0.93
		6,900	(DB)	Voltage collapse	
27	Mid-Term Upgrades + DC7	6,860	(SC)	Voltage collapse	0.93
		7,160	(SC)	Overload	
28	Mid-Term Upgrades + DC8	6,860	(SC)	Voltage collapse	0.93
		7,160	(SC)	Overload	
29	Mid-Term Upgrades + DC9	6,660	(DB)	Voltage collapse	0.93
30	Mid-Term Upgrades + DC10	6,660	(DB)	Overload	0.93
		6,860	(DB)	Voltage collapse	
31	Mid-Term Upgrades + DC11	6,780	(DB)	Voltage collapse	0.93
		7,780	(SC)	Overload	

* All the upgrades included in Table 3-4
** Without Ogallala-Long Draw 345 kV double circuit in Table 3-4
*** SC: single circuit, DB: double circuit
**** DC upgrades are defined in Table 3-5

3.1.5. Key Findings of Long-Term Scenario

Some key observations from Table 3-6 are:

- Overload violations outside of the Panhandle may constrain the Panhandle export during high wind generation output conditions in Panhandle before reaching voltage stability limit;
- To achieve a transfer capacity larger than 7.2 GW, at least two new double circuit lines are needed in addition to the Mid-Term upgrades;
- Because of the power flow carried by the HVDC lines (in options with an HVDC line), contingencies of the HVDC lines become the critical contingency that lead to a potential voltage collapse.

It should be noted that the export limits shown in Table 3-6 are based on steady-state PV analysis only. These limits may not be achievable when considering the dynamic stability analysis. Nonetheless, the results are useful in screening options for the dynamic stability analysis which is described in section 3.2.3 of this report.

3.2. Dynamic Analysis

3.2.1. Evaluation of Mid-Term Scenario - (5.04 GW Capacity at 95% Output in Panhandle)

Numerous dynamic contingency simulations were run to test options for accommodating Mid-Term wind output from the Panhandle. Options were initially tested with contingencies in the immediate Panhandle area. Options that passed this initial test were further investigated with more comprehensive contingency sets that included breaker failure events and faults throughout the West Texas system. The electrical characteristics of the upgrade options are listed in the Appendix 6.1. A summary of simulation results for a selected set of tested upgrade options is provided in Table 3-7.

Table 3-7 Dynamic Simulation Results for the Mid-Term Scenario

Case	Upgrade Description	Results
1	Ogallala-Tule Canyon 345 kV Circuit Ogallala-Cottonwood 345 kV Circuit Ogallala-Long Draw 345 kV Circuit	Unacceptable
2	Synchronous Condenser (350 MVA) at Ogallala Synchronous Condenser (350 MVA) at Windmill	Unacceptable
3	Synchronous Condenser (350 MVA) at Alibates Synchronous Condenser (350 MVA) at Tule Canyon	Unacceptable
4	Ogallala-Tule Canyon 345 kV Circuit Ogallala-Cottonwood 345 kV Circuit Synchronous Condenser (350 MVA) at Alibates Synchronous Condenser (350 MVA) at Tule Canyon	Unacceptable
5	Ogallala-Tule Canyon 345 kV Circuit Ogallala-Cottonwood 345 kV Circuit Ogallala-Long Draw 345 kV Circuit Synchronous Condenser (350 MVA) at Alibates Synchronous Condenser (350 MVA) at Tule Canyon	Unacceptable
6	Ogallala-Tule Canyon 345 kV Circuit Ogallala-Cottonwood 345 kV Circuit Synchronous Condenser (350 MVA) at Ogallala Synchronous Condenser (350 MVA) at Windmill	Unacceptable
7	Ogallala-Tule Canyon 345 kV Circuit Ogallala-Cottonwood 345 kV Circuit Ogallala-Long Draw 345 kV Circuit Synchronous Condenser (350 MVA) at Ogallala Synchronous Condenser (350 MVA) at Windmill	Acceptable
8	Alibates-Windmill 345 kV Circuit Windmill-Ogallala 345 kV Circuit Ogallala-Tule Canyon 345 kV Circuit Ogallala-Long Draw 345 kV Double Circuit	Acceptable
9	Alibates-Windmill 345 kV Circuit Windmill-Ogallala 345 kV Circuit Ogallala-Tule Canyon 345 kV Circuit Ogallala-Long Draw 345 kV Double Circuit Synchronous Condenser (350 MVA) at Ogallala Synchronous Condenser (350 MVA) at Windmill	Acceptable

3.2.2. Key Findings of Mid-Term Scenario Dynamic Stability Analysis

3.2.2.1. Overvoltage Trip

All of the Panhandle wind generation resources modeled in the study case were based on the actual projects undergoing generation interconnection study, with some projects having less HVRT capability compared to others. The Panhandle grid is remote from synchronous generators and load centers and is considered a weak grid when integrating a large amount of wind generation. A byproduct of this weak grid condition is observed in the simulation results reported in Table 3-7 where wind plants were tripped by overvoltage protection relays. An excessive amount of such tripping can lead to a potential cascading overvoltage collapse as shown in Figure 3-4.

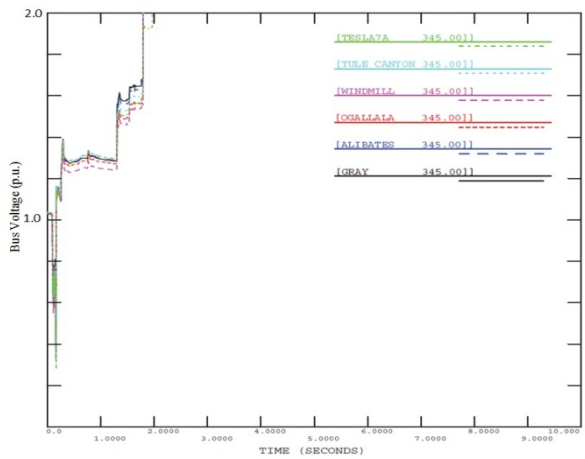


Figure 3-4 Cascading High Voltage Collapse in Panhandle

Reasons for such a collapse caused by overvoltage include:

- Extremely weak system as indicated by low SCR. Under weak grid conditions, the sensitivity of dV/dQ is high, which means the same amount of reactive support results in larger voltage deviation;
- Aggressive voltage control settings of wind generators. The low short circuit level seen by the voltage controllers of wind generators results in a faster response compared to a stronger grid with high SCR. Many wind generation plants retain high reactive output levels upon fault clearance;
- Upon fault clearance, most wind generation plants do not immediately restore their MW outputs to pre-fault levels. The reduced power flows lead to reduced reactive losses and overvoltages due to excessive line charging;
- For the above reasons, the system experiences significant overvoltage upon fault clearance. Wind generation plants lacking sufficient high voltage ride through capabilities would be taken out of service by their overvoltage protection relays;
- The tripping of wind generation plants due to overvoltage further reduced MW flows on the transmission lines, which consequently cause even higher overvoltage due to reduced reactive losses and excessive line charging;

- The wind generation plants continued to trip due to overvoltage until the whole area collapses as the consequence of overvoltage cascading.

In case 9, all the Panhandle wind projects were modified to meet the proposed HVRT capability and a lesser amount of wind generation projects (less than 1000 MW) were tripped by overvoltage. Those overvoltage trips were caused by the weak system conditions. Overvoltage tripping can be minimized through the combination of system strength enhancement and better HVRT capability of wind generation projects. The collapse caused by overvoltage cascading presents a significant reliability risk and suggests a need for wind generation projects to comply with the HVRT requirement shown in Figure 3-5 as proposed in NOGRR 124 [14].

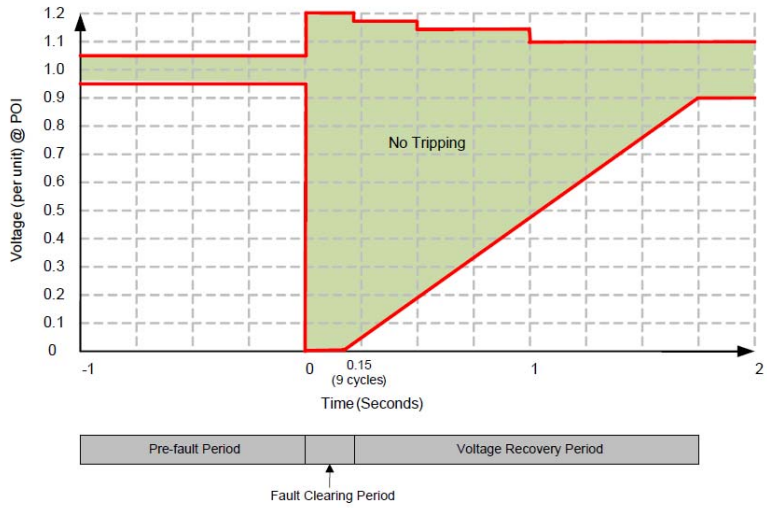


Figure 3-5 Proposed Voltage Ride Through Capability for Wind Generation Resources

3.2.2.2. Upgrade Needs

Based on the results in Table 3-7, Ogallala and Windmill appeared to be better locations for synchronous condenser installations than Alibates and Tule Canyon. Effective solutions for accommodating Mid-Term Panhandle wind output required additional transmission lines. Tested options that included only synchronous condensers were unacceptable.

Case 9 in Table 3-7 is the preferred upgrade option based on the following benefits over other tested cases:

- Add a second 345 kV circuit from Alibates to Windmill, from Windmill to Ogallala, and from Ogallala to Tule Canyon (which are already built to accommodate the installation of a second circuit and would not require any new right-of-way acquisitions);
- Add a new 345 kV double circuit from Ogallala to Long Draw (which is superior to other new line options based on PV analysis results and the effect on SCR).

Results indicate that the installation of synchronous condensers is not absolutely required in conjunction with the preferred option based solely on dynamic simulation results. As discussed in section 2.4.2, synchronous condensers are needed to address system strength issues and achieve specific SCR targets.

Additionally, the amount of observed wind trips was generally reduced when synchronous condensers were included in simulations for additional voltage support to reduce the voltage overshoot.

3.2.3. Evaluation of Long-Term Scenario - (7.8 GW Capacity at 95% Output in Panhandle)

Dynamic contingency simulations were run to test options for accommodating Long-Term wind output from the Panhandle. Based on the findings in the Mid-Term scenario regarding the need for HVRT capability, it was assumed that Panhandle wind resources complied with the high voltage ride through requirements as proposed in NOGRR124 in the Long-Term scenario. A summary of simulation results for a selected set of tested upgrade options is reported in Table 3-8.

Table 3-8 Dynamic Simulation Results for the Long-Term Scenario

Case	Upgrade Description	Results
0	**Base:** Alibates-Windmill 345 kV Circuit Windmill-Ogallala 345 kV Circuit Ogallala-Tule Canyon 345 kV Circuit Ogallala-Long Draw 345 kV Double Circuit Synchronous Condenser (350 MVA) at Ogallala Synchronous Condenser (350 MVA) at Windmill	Unacceptable
1	Base + Gray-Riley 345 kV Double Circuit Windmill-Edith Clarke 345 kV Double Circuit	Acceptable
2	Base + Gray-Riley 345 kV Double Circuit Windmill-Edith Clarke 345 kV Double Circuit Edith Clarke-Graham 345 kV Double Circuit	Acceptable
3	Base + Gray-Riley 345 kV Double Circuit Edith Clarke-Graham 345 kV Double Circuit	Unacceptable
4	Base + Gray-Riley 345 kV Double Circuit Edith Clarke-Graham 345 kV Double Circuit Cottonwood-W. Shackelford 345 kV Double Circuit	Unacceptable
5	Base + Gray-Riley 345 kV Double Circuit Edith Clarke-Graham 345 kV Double Circuit Windmill-Cottonwood 345 kV Double Circuit Cottonwood-W. Shackelford 345 kV Double Circuit	Acceptable
6	Base + Gray-Edith Clarke 345 kV Double Circuit Edith Clarke-Graham 345 kV Double Circuit Windmill-Cottonwood 345 kV Double Circuit Cottonwood-W. Shackelford 345 kV Double Circuit	Unacceptable
7	Base (without synchronous condensers) + Gray-Riley 345 kV Double Circuit Windmill-Edith Clarke 345 kV Double Circuit	Unacceptable
8	Base (without synchronous condensers) + Gray-Riley 345 kV Double Circuit Windmill-Edith Clarke 345 kV Double Circuit Ogallala-Cottonwood 345 kV Double Circuit Cottonwood-W. Shackelford 345 kV Double Circuit	Unacceptable

3.2.4. Key Findings of Long-Term Scenario

3.2.4.1. Frequency Protection Trip

In the Long-Term scenario, wind resources tripped by frequency protection relays were observed under various simulations. This is generally considered to be an anomaly due to the simulation software (PSS/e) methodology for calculating bus frequencies. PSS/e calculates frequency at each bus independently by taking the instantaneous rate of change of angle and placing it through a filter time constant. On a few rare instances where the system is very weak, the filter constant may require adjustment to avoid numerical instability. Such frequency protection tripping was not observed in the scenarios with less Panhandle wind generation output, such as the Mid-Term scenario. Thus, observation of such frequency trips may indicate a need for system strength enhancement, especially when such frequency trips can result in an overvoltage cascading event.

3.2.4.2. Upgrade Needs

Based on the results presented in Table 3-8, the installation of two 345 kV double circuits are required in addition to the assumed base upgrades to achieve acceptable simulation results with Long-Term Panhandle wind output. Cases 7 and 8 in Table 3-8 indicate that synchronous condenser installations are required to achieve acceptable simulation results. Upgrade options (in addition to those proposed in Case 1) tested include:

- Adding a 345 kV double circuit from Edith Clarke to Graham (Case 2);
- Adding 150 MVA SVCs at Bluff Creek, Sam Switch, and Navarro;
- Adding a Riley-Hicks 500 kV circuit;
- Adding a Riley-Carrolton 500 kV circuit;
- Modeling the proposed Ogallala-Long Draw, Gray-Riley and Windmill-Edith Clarke lines as 500 kV double circuits.

None of these upgrades appeared to provide a significant improvement with respect to dynamic performance. It is important to note that system constraints outside the Panhandle region that can potentially limit the Panhandle export in the Long-Term scenario were observed. Further testing and discussions are included in section 3.2.4.3. Two preferred upgrade options are identified for the Long-Term scenario.

- Option A:
    - Add a new 345 kV double circuit from Gray to Riley
    - Add a new 345 kV double circuit from Windmill to Edith Clarke
    - Additional synchronous condensers and reactors for system strength enhancement and steady state high voltage management
- Option B:
    - Add a new 345 kV double circuit from Gray to Riley
    - Add a new 345 kV double circuit from Windmill to Cottonwood and from Cottonwood to West Shackelford

- Additional synchronous condensers and reactors for system strength enhancement and steady state high voltage management

3.2.4.3. Constraints in the Rest of ERCOT System

In the Long-Term scenario, additional system adjustments including de-committing conventional units were made for system power balance. Depending on the location of de-committed conventional units, the voltage support could become insufficient to maintain adequate voltage support for high power transfer from the Panhandle to load centers. Such voltage stability challenges do not necessarily affect the Panhandle export capability, but limits the total power that can be transferred to the load centers. Additional study would be required to fully resolve issues associated with elements that are remote from the Panhandle.

3.3. Economic Cost Analysis and Roadmap Development

According to the definition of Reliability-Driven and Economic-Driven Projects in the ERCOT Planning Guide section 3.1.3.1 [16], the upgrade needs identified in the PREZ study to accommodate wind generation projects are considered Economic-Driven Projects since wind generation plants are expected to be re-dispatched to meet reliability criteria.

To determine the societal benefit of a proposed project, the revenue requirement of the capital cost of the project is compared to the expected savings in system production costs resulting from the project over the expected life of the project. In the PREZ study, ERCOT performed the economic cost analysis using UPLAN to calculate the ERCOT-wide annual production cost savings for year 2017 and compared it to the first year annual revenue requirement of the transmission project. If the production cost saving equaled or exceeded the first year annual revenue requirement for the project, the project was considered economic from a societal perspective and was recommended. Where congestion was identified in the economic cost analysis, projects were tested by comparing the simulation results for models with and without the projects. In this study, it was assumed that the first year annual revenue requirement for the transmission project is approximately one sixth (1/6) of the total transmission project cost.

The study results in the Mid-Term and Long-Term scenarios provided a reference to develop the roadmap of upgrade needs in the Panhandle. Sets of transmission upgrade projects were tested in reliability analysis and using the WSCR criterion to determine the incremental export capability they delivered. The production cost benefit of the additional export capability was then calculated using UPLAN for various levels of wind generation capacity in the Panhandle and compared against the estimated capital cost of the project set.

An iterative process was performed to develop the roadmap with trigger points in terms of Panhandle wind generation capacity. The proposed roadmap includes four stages of Panhandle transmission upgrades to ultimately accommodate a total of 7.5 GW wind generation output in the Panhandle. The reliability and economic cost analysis results for each stage are described in the following sections. It should be noted that all of the upgrades proposed in this report are based on the wind generation projects modeled in the study cases. As of 2013, there were no projects implemented in the Panhandle, and the upgrades may need to be revised based on the actual implementation of wind generation projects.

3.3.1. Economic Cost Analysis Base Case

Economic analysis was conducted by performing production cost simulation for year 2017 (using the 2017 UPLAN scenario from the 2012 Five-Year Transmission Plan). The natural gas prices assumed in this analysis are listed in Appendix 6.2. The wind profiles used in this study were the synthetic curves from AWS Truepower and the average Panhandle wind capacity factor was 42.6%. Figure 3-6 shows the monthly profile wind capacity factors for different ERCOT regions. The identified Panhandle export limit in the reliability analysis was implemented as an interface limit in the analysis. The defined Panhandle interface includes all 345 kV transmission lines between the Panhandle and rest of ERCOT grid, as listed in Table 3-9.

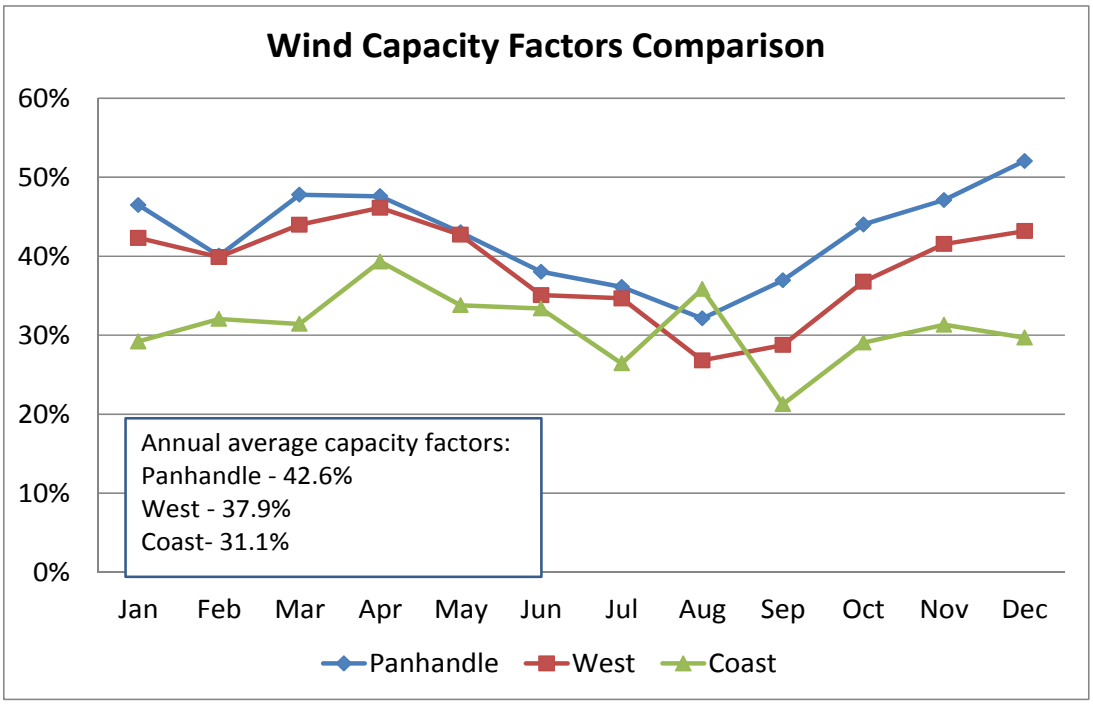


Figure 3-6 Monthly Wind Capacity Factors in ERCOT

Table 3-9 Panhandle Interface Definition

Element	From Station	To Station	Comment
345 kV Line	Gray	Tesla	Double circuit
345 kV Line	Tule Canyon	Tesla	Double circuit with series compensation
345 kV Line	Cottonwood	Edith Clarke	Double circuit
345 kV Line	Cottonwood	Dermott	Double circuit

3.3.2. Roadmap – Stage 1 Upgrade

The stage 1 upgrade includes the addition of a second circuit to all existing single circuit lines in the Panhandle. This would increase the Panhandle export stability limit from 2,400 MW to 3,500 MW. Table 3-10 lists all of the transmission projects associated with the stage 1 upgrade and the estimated cost of each upgrade component. The installation of a synchronous condenser is necessary to satisfy the WSCR criterion of

1.5 and reactors are required to manage high voltage conditions when wind generation output in the Panhandle is low. The estimated transmission project capital cost for the stage 1 upgrade is $115M (million).

The identified Panhandle export limit can be classified as a potential generic transmission limit (GTL) in the Operations horizon. A GTL is usually enforced prior to reaching 100% of the limit to avoid exceeding the establish limit in real time operations [17]. Therefore, the trigger point for the stage 1 upgrade was calculated assuming that a GTL will be enforced at the 90% of the limit. To economically justify the stage 1 upgrade, the annual production cost saving needed to be equal to or greater than $21M based on the one sixth (1/6) economic criteria. The production cost simulation result showed that the trigger point was a total wind generation capacity in the Panhandle of 3,000 MW where $21 million annual production cost saving was observed with the stage 1 upgrade. Figure 3-7 shows the trigger point and increase in the Panhandle export limit for the stage 1 upgrade. The annual cost saving of $21M in the production cost simulation is the difference between the two cases listed in Table 3-11.

Table 3-10 Transmission Projects for Stage 1 Upgrade

Element	Description	Length/Size	Note	Estimated Cost ($M)	Total Cost ($M)
345 kV Line	Alibates-Windmill	93 miles	On the existing tower	63	115
345 kV Line	Windmill-Ogallala	27 miles	On the existing tower		
345 kV Line	Ogallala-Tule Canyon	47 miles	On the existing tower		
Synchronous Condenser	Windmill	200 MVA		43	
Reactor	Alibates	50 MVAr		2.75	
Reactor	Ogallala	100 MVAr		5.5	

Table 3-11 Production Cost Simulation Cases for Stage 1 Upgrade

Case	Panhandle Wind Generation Capacity (MW)	Roadmap Upgrade	90% of Panhandle Export Limit (MW)	Annual Production Cost Saving
A	3,000	No upgrade	2,160	A-B = $21M
B	3,000	Stage 1	3,150	

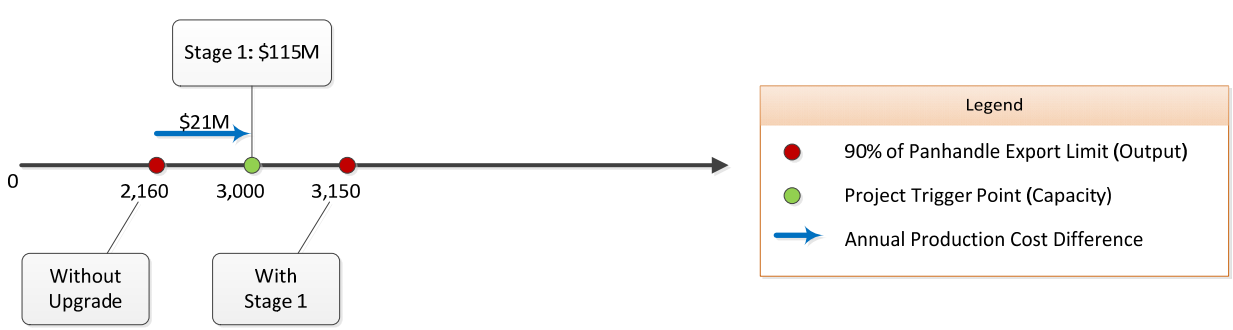


Figure 3-7 Trigger Point and Export Limit for Stage 1 Upgrade

Based on the production cost simulation results, the annual Panhandle wind energy curtailment in case A was 798 GWh (6.3% of the total Panhandle wind generation in case B). For case B, there is no Panhandle wind curtailment caused by a Panhandle export limit; with the stage 1 upgrade, all of the 3,000 MW wind capacity can be exported out of the Panhandle to the load centers.

3.3.2.1. Sensitivity Analysis – Series Compensation

Series compensation reduces the electrical impedance of transmission lines and increases transfer capability. However, the added series capacitance can potentially result in sub-synchronous resonance for both conventional and wind generation projects [18]. Based on the current CREZ transmission project implementation, the design of Rocky Mound series capacitors on the 345 kV double circuits from Clear Crossing station to Willow Creek station is being reviewed and the implementation date has been postponed. A sensitivity analysis was performed to evaluate the impact of by-passing the Rocky Mound series capacitors in the reliability analysis. The study results indicated that it is still acceptable to have a Panhandle export limit of 3,500 MW with the stage 1 upgrade if the Rocky Mound series capacitors were to be bypassed.

3.3.3. Roadmap – Stage 2 Upgrade

The reliability analysis showed that the stage 2 upgrades would increase the Panhandle export limit from 3,500 MW to 5,200 MW. Table 3-12 lists all the transmission projects associated with the stage 2 upgrade and the estimated cost of each upgrade component.

Following the process in Figure 2-4, synchronous condensers were specified to meet the WSCR target of 1.5. Reactors were added to manage high voltage conditions when wind generation output in Panhandle is low. The estimated transmission project capital cost for the stage 2 upgrade is $560M and the Panhandle export limit is increased to 5,200 MW. Similar to stage 1, the trigger point for the stage 2 upgrade was calculated assuming that a GTL will be enforced at the 90% of the limit. To economically justify the stage 2 upgrade, the annual production cost saving needs to be equal to or greater than $93.3M based on the one sixth (1/6) economic criteria. The production cost simulation result showed that the trigger point was a total wind generation capacity in the Panhandle of 6,500 MW where $94 million annual production cost saving was observed with the stage 2 upgrade. Figure 3-8 shows the trigger point and increase in the Panhandle export limit for the stage 2 upgrade. It should be noted that with 6,500 MW of capacity Panhandle exports may still experience congestion based on the identified export limit after the stage 2 upgrade. The annual cost saving of $94M in the production cost simulation was the difference between the two cases listed in Table 3-13.

It should be noted that the Houston Import Project (Limestone-Gibbons Creek-Zenith 345 kV double circuit) was added to both Cases C and D because it was assumed that this project would be completed by the time any upgrade requiring a new line (on new ROW) could be implemented. Preliminary analysis indicated that if the Houston Import Projects were not in place, congestion on the Singleton-Zenith 345 kV line could result in curtailment of Panhandle area wind generation.

Table 3-12 Transmission Projects for Stage 2 Upgrade

Element	Description	Length/Size	Note	Estimated Cost ($M)	Total Cost ($M)
345 kV Line	Ogallala-Long Draw	190 miles	Double circuit, New line	380	560
Synchronous Condenser	Windmill	400 MVA		86	
Synchronous Condenser	Alibates	200 MVA		43	
Synchronous Condenser	Gray	150 MVA		32.25	
Reactor	Windmill	50 MVAr		2.75	
Reactor	Ogallala	150 MVAr		8.25	
Reactor	Long Draw	150 MVAr		8.25	

Table 3-13 Production Cost Simulation Cases for Stage 2 Upgrade

Case	Panhandle Wind Generation Capacity (MW)	Roadmap Upgrade	90% of Panhandle Export Limit (MW)	Annual Production Cost Saving
C	6,500	Stage 1	3,150	A-B = $94M
D	6,500	Stage 2	4,680	

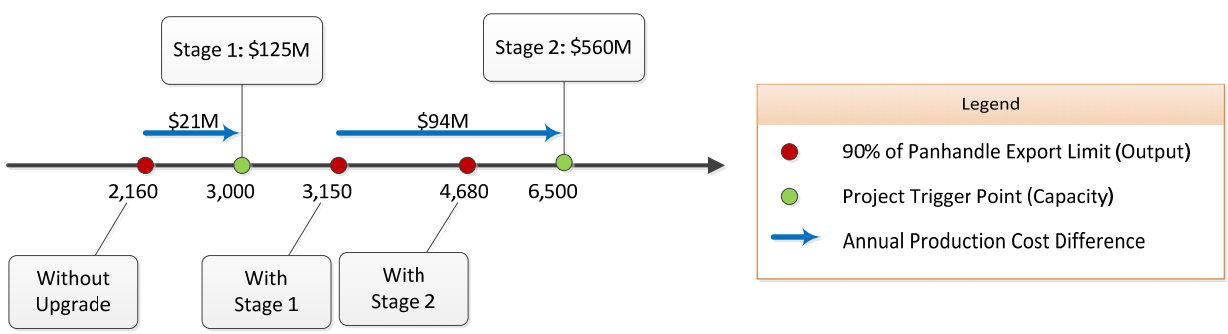


Figure 3-8 Trigger Point and Export Limit for Stage 2 Upgrade

Based on the production cost simulation results, the congestion was reduced to 21.68% of the hours in 2017 after including the stage 2 upgrade to increase the Panhandle stability limit to 4,680 MW. The annual Panhandle wind energy curtailment was 6,335 GWh (23.1% of the total Panhandle un-curtailed wind generation) for case C and was 1,795 GWh (6.5% of the total Panhandle un-curtailed wind generation) for case D.

3.3.3.1. Sensitivity Analysis – Series Compensation

A sensitivity analysis was performed to evaluate the impact of by-passing the Rocky Mound series capacitors in the reliability analysis. The results indicate that the Panhandle export limit determined with the stage 2 upgrade is not valid when the series capacitors were out of service. Under such conditions, a lower export limit would be required.

3.3.4. Roadmap – Stage 3 Upgrade

Based on the Long-Term scenario results in section 3.2.4.2, three additional new transmission paths, listed in Table 3-14, from the Panhandle were identified as feasible options to further increase Panhandle export capability after the stage 2 upgrade.

Table 3-14 Additional Transmission Path Options after Stage 2 Upgrade

Path option	From	To	Description
1	Gray	Riley	345 kV double circuit, New line
2	Windmill	Edith Clarke	345 kV double circuit, New line
3	Windmill	Cottonwood	345 kV double circuit, New line
	Cottonwood	West Shackelford	345 kV double circuit, New line

Numerous dynamic contingency simulations and economic cost simulations were run to determine a stability limit and Panhandle congestion impact for conditions where upgrades included two new transmission paths from the Panhandle (stage 2 upgrade plus one additional path). Table 3-15 summarizes the results of these analyses and indicates there is no significant difference between the three options. Since the upgrade needs may vary based on the locations and sizes of the wind generation projects that actually get built, it is recommended to consider all three options as feasible at this point. When less speculative information regarding the wind generation plants is available, further assessment should be performed to identify the optimal upgrade option and the associated system strength enhancement.

Table 3-15 Study Results Comparison for Three Stage 3 Transmission Options

Path option	Description	Panhandle export limit (MW)	Panhandle wind generation curtailment *	Additional need of synchronous condensers (MVA)
1	Gray-Riley	6,175	1	370
2	Windmill-Edith Clarke	6,175	2	450
3	Windmill-Cottonwood Cottonwood-W. Schackelford	6,175	3	450

*the amount of Panhandle wind curtailment (1- largest, 3-least)

3.3.4.1. Key Findings

In the reliability analysis for stage 3 upgrades, unacceptable responses were observed for some contingencies outside the Panhandle area. This suggests that higher Panhandle export levels can have an adverse effect on system reliability outside the Panhandle region. The following items identify the nature of the observed unacceptable responses and some potential causes:

- As discussed in section 3.2.4.1, wind resources tripped by frequency protection relays were observed when wind generation capacity in Panhandle exceeded 6.2 GW. In many instances, the simulated

contingency was outside the Panhandle region. The observation of such frequency trips may indicate a need for improved system strength.

- Increasing wind generation in the system required the de-commitment of conventional synchronous generators, which further reduced the system strength (in terms of SCR) and dynamic voltage support. When major synchronous generators are de-committed, the weak grid challenges identified in the Panhandle can potentially occur in other areas of ERCOT.
- Synchronous generators are very valuable voltage support resources to maintain reliable high power transfer and the de-commitment of synchronous generators can cause voltage collapse on either the receiving end or along the transfer path. For example, voltage collapse was observed under certain system conditions when large synchronous generators that normally support transfers into the Houston load center were de-committed. The location and size of the de-committed synchronous generators has a significant impact on the transfer capability and a follow up assessment is needed to identify the trend of de-commitment with increasing renewable generation in ERCOT.

3.3.5. Roadmap – Stage 4 Upgrade

Adding one of the three upgrade options in Table 3-15 will increase the Panhandle export stability limit to 6,175 MW. To ultimately accommodate 7.5GW of wind generation in the Panhandle, one additional 345 kV double circuit from one of three options in Table 3-15 is needed. It should be noted that option 1 in Table 3-15 needs to be included in either stage 3 or stage 4 upgrades. In other words, option 1 needs to be included in the overall upgrades to obtain acceptable dynamic responses for the tested contingencies and assumed installation of wind generation projects in the Panhandle. As discussed in section 3.3.4.1, unacceptable responses were observed for some tested contingencies outside the Panhandle region and further study may be required to address the potential reliability issues.

The economic trigger points were not calculated for stages 3 and 4 for the following reasons:

- Based on the results from the stage 2 analysis it can be assumed that the trigger points for stages 3 and 4 will be well beyond 6,500 MW of installed capacity in the Panhandle. Since there is no wind generation currently in the Panhandle it may be several years before such a trigger point is met. At that point more information will be known about the initial Panhandle wind generation plants which will better inform the analysis; and
- As discussed in the previous section more analysis is needed to determine system needs outside of the Panhandle and west Texas for high penetrations of wind generation.

3.3.6. Roadmap – Summary

Figure 3-9 shows the Panhandle export stability limits after each stage of upgrades and Table 3-16 lists the upgrade details associated with each stage. It was assumed that Panhandle wind resources complied with the high voltage ride through requirements as proposed in NOGRR124 for this analysis.

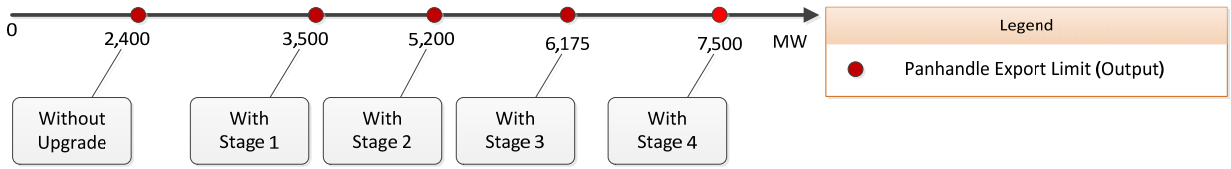


Figure 3-9 Panhandle Export Stability Limit for Transmission Upgrade Roadmap

Table 3-16 Panhandle Transmission Upgrade Roadmap -- Detailed Project List

Stage	Panhandle Export Stability Limit (MW)	Trigger for Upgrade (Panhandle Wind Capacity) (MW)**	Upgrade Element	Estimated Upgrade Cost ($M)
Existing grid	2,400	-	-	-
1	3,500	3,000 MW	• Add second circuit on the existing Panhandle grid • 200 MVA synchronous condensers • 150 MVAr reactors	115
2	5,200	6,500 MW	• Add one new 345 kV double circuit -- (Ogallala-Long Draw) • 750 MVA synchronous condensers • 350 MVAr reactors	560
3	6,175	-	• Add one new 345 kV double circuit -- (Gray-Riley or Windmill-Edith Clarke or Windmill-Cottonwood-W.Shackelford) • 350 MVA synchronous condensers • 300 MVAr reactors	442
4	7,500*	-	• Add one additional new 345 kV double circuit -- (Gray-Riley or Windmill-Edith Clarke or Windmill-Cottonwood-W.Shackelford) • 350 MVA synchronous condenser • 450 MVAr reactors	500

*may be lower due to constraints outside of the Panhandle
**assuming the limit will be enforced at the 90% of the stability limit

Additional sensitivity analyses were performed in the roadmap development process and key observations are listed in the following:

- Replacing the 345 kV transmission upgrades with 500 kV options, including Ogallala-Long Draw and the additional transmission paths, did not significantly increase the stability limit. Therefore, the extra costs associated with 500 kV construction do not appear to be justified at this time.
- The optimal synchronous condenser configuration and best transmission options are dependent on the location of wind power plants. Similarly, the best transmission option is somewhat dependent on the selected synchronous condenser configuration (or other system strength enhancement options) and vice-versa. It should be noted that all of the upgrades proposed in this report are based on the wind generation projects modeled in the study cases. As of 2013, there were no projects implemented in Panhandle, and the upgrades may need to be revised based on the actual implementation of wind generation projects.

- The need for synchronous condensers (or other system strength enhancements) to provide a WSCR of a least 1.5 can be based on total wind generation output. In ERCOT Operations, unstable responses were observed from an existing wind project when connected to a weak grid under a planned transmission outage condition. In [14], it has been observed by ERCOT and Transmission Service Providers (TSPs) that reducing wind generation output can improve the damping of voltage oscillations as shown in Figure 3-10 and Figure 3-11. Additional sensitivity analysis was performed in the PREZ study to compare the system response under two different system conditions as listed in Table 3-17, where wind output is the same, but wind capacity differs. Figure 3-12 shows the Panhandle Windmill 345 kV station voltage responses of the two tested cases after a four cycle 3-phase fault was applied to a 345 kV line in Panhandle. As shown in Figure 3-12, the voltage overshoot following the disturbance is higher for the scenario with lower wind capacity, and no significant difference in dynamic performance was observed that would suggest that the scenario with higher wind capacity was more susceptible to stability issues. Thus, from a real time operations perspective, it should be adequate to evaluate system strength-related limitations and constraints based on actual wind generation output instead of nominal wind generation capacity.

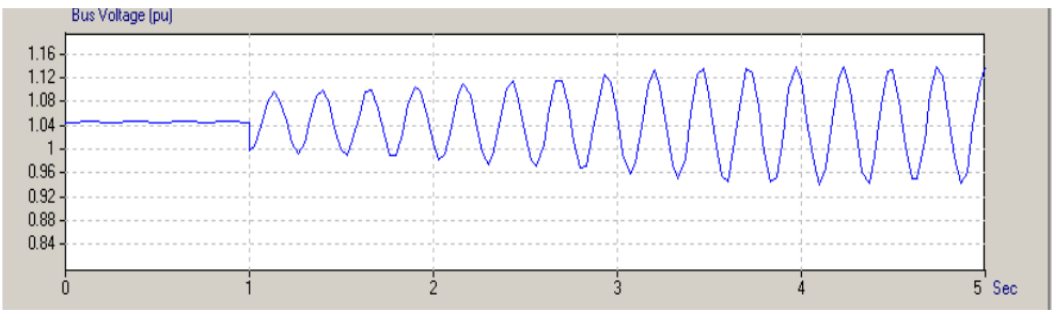


Figure 3-10 Un-Damped Voltage Oscillation under High Wind Output Condition

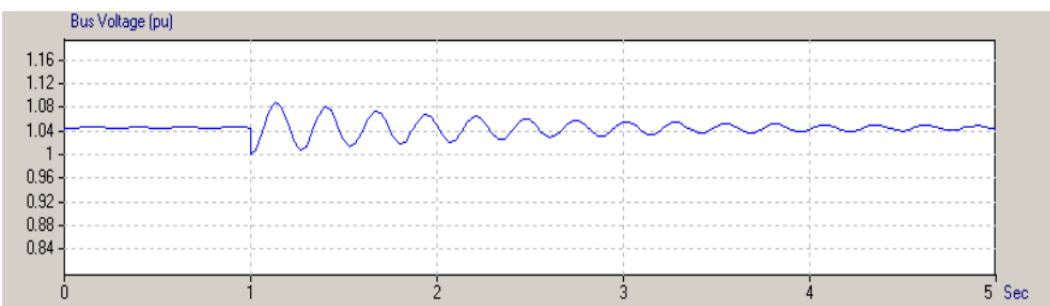


Figure 3-11 Improved Voltage Oscillation Damping under Low Wind Output Condition

Table 3-17 Study Case Conditions for WSCR Sensitivity Analysis

Case	Panhandle wind generation capacity (MW)	Panhandle wind generation output (MW)	WSCR
Base case	3,700	3,500	1.5
Test case	7,400	3,500	0.8

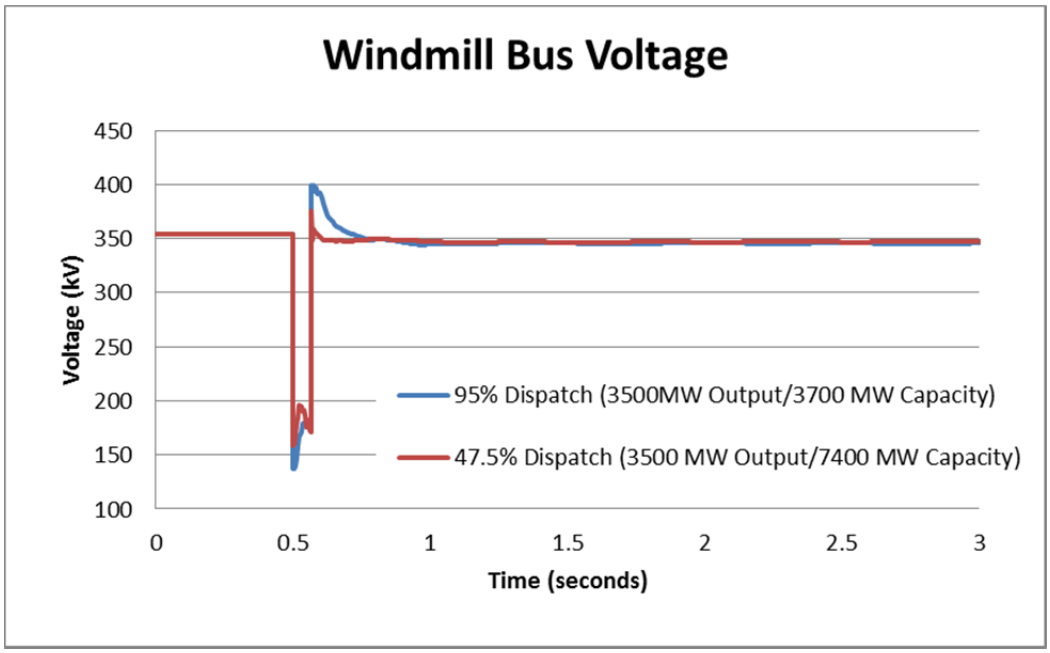


Figure 3-12 Panhandle Windmill 345 kV Bus Voltage Response under Studied Conditions

4. CONCLUSIONS

This report describes the challenges and constraints associated with connecting large amounts wind generation in the ERCOT Panhandle region. It also provides an upgrade roadmap for both ERCOT and TSPs to accommodate Panhandle wind generation in excess of 2,400 MW, the amount consistent with the initial reactive equipment build-out supported by the CREZ Reactive Power Study. Several transmission improvements can be implemented at a relatively low cost and in a relatively short time frame to increase the Panhandle export limit. These include installing shunt reactors, synchronous condensers and adding the second circuit on existing towers that were constructed to be double-circuit capable with originally just one circuit in place. Additional improvements to increase export limits will include new transmission lines on new right of way (ROW). These improvements will require significant wind generation development commitment in order to be economically justified.

Several key findings and proposals in this study are summarized below.

- **Panhandle Weak Grid Characteristics**

The Panhandle grid is remote from synchronous generators and load centers and is considered a weak grid when integrating large amount of wind generation. Several system characteristics and challenges that can occur in a weak grid are:

  - In a highly compensated weak grid, voltage collapse can occur within the normal operating voltage range (0.95 to 1.05 pu) masking voltage stability risks in real time operations. Static capacitor or static var compensators contribute to this effect and have limited effectiveness for further increasing transfer capability.
  - A grid with low short circuit ratios and high voltage sensitivity of dV/dQ requires special coordination of various complex control systems. Typical voltage control settings can result in aggressive voltage support in a weak system and can lead to un-damped oscillations, overvoltage cascading or voltage collapse.
  - Wind projects connected to the Panhandle region are effectively connected to a common point of interconnection (POI) such that each wind plant may interact with other Panhandle wind plants.

- **Weighted Short Circuit Ratio (WSCR)**

The weighted short circuit ratio (WSCR) was used to take into account the effect of interactions between wind plants. WSCR gives a conservative estimate of the system strength and is considered as a proper index to represent the system strength for the Panhandle region.

- **Voltage Ride Through Capability**

Post-disturbance overvoltage is more likely to occur under weak grid conditions. Actuation of wind plant overvoltage relays was observed in various simulation results and can potentially lead to overvoltage cascading. The collapse caused by overvoltage cascading presents a significant reliability risk and suggests a need for wind generation projects to comply with the HVRT requirement as proposed in NOGRR 124.

- **System Strength Enhancement**

A WSCR of 1.5 was proposed as the minimum system strength need for Panhandle. The PREZ study results indicate that the need for the system strength enhancement should be determined by wind generation output instead of wind generation capacity when there is a need to constrain wind plant output in real time operations.

The Panhandle wind generation resources modeled in the study case were based on each project's available generation interconnection information at the time the study was performed. As of 2013, there were no generation projects in-service in the Panhandle, and the proposed upgrades may need to be revised based on actual installed wind generation projects. The study results serve as a reference to both ERCOT and TSPs to identify the challenges, constraints, and upgrade needs in the Panhandle region. These identified projects are not approved transmission projects and may require additional review prior to implementation.

ERCOT staff will continue to work with TSPs to evaluate alternative upgrade options proposed by TSPs and/or stakeholders. ERCOT also will monitor the generation interconnection status for actual implementation of wind projects in Panhandle.

It should be noted that the identified improvements were based on the assumptions used in this study. Should these assumptions change, the results of this analysis will need to be updated which could yield a different set of transmission improvements or trigger points. Assumptions that could change the results of this analysis include the size and location of actual wind generation development in the Panhandle, a change to the assumed high voltage ride through requirement, connection of a proposed DC-tie in the Panhandle, transmission upgrade cost estimates, or natural gas price projections.

Although additional synchronous generators in the Panhandle region can improve the system strength and provide dynamic voltage support, it is unlikely that such synchronous generators will be on-line under high wind output conditions since synchronous generators typically have a higher marginal cost than wind plants. Therefore, the addition of new synchronous generators in the Panhandle region is not expected to change the study results.

5. REFERENCES

[1] Competitive Renewable Energy Zone Program Oversight, CREZ Progress Report, available at http://www.texascrezprojects.com/default.aspx

[2] ERCOT CREZ Reactive Compensation Study, available at http://www.ercot.com/content/news/presentations/2010/CREZ%20Reactive%20Power%20Compensation%20Study.pdf

[3] Long-Term System Assessment for the ERCOT Region, available at http://www.ercot.com/content/news/presentations/2013/2012%20Long%20Term%20System%20Assessment.pdf

[4] ERCOT Protocol, available at http://www.ercot.com/mktrules/nprotocols/current

[5] Abbey, C., B. Khodabakhchian, F. Zhou, S. Dennetiere, J. Mahseredjian, and G. Joos, "Transient modeling and comparison of wind generator topologies," *Proceedings of International Conference on Power Systems Transients*, pp. 131-7. 2005.

[6] Prabha Kundur, "Power System Stability and Control", McGraw-Hill, 1994.

[7] F. Zhou, G. Joos, and C. Abbey, "Voltage stability in weak connection wind plants," Proceedings of 2005 IEEE PES General Meeting, June 12-16, 2005.

[8] Piwko, Richard, et al., "Integrating Large Wind plants into Weak Power Grids with Long Transmission Lines," Proceedings of 2006 Power Electronics and Motion Control Conference, 2006.

[9] Palsson, Magni P., Trond Toftevaag, Kjetil Uhlen, and John Olav Giæver Tande, "Large-scale wind power integration and voltage stability limits in regional networks," Proceedings of 2005 IEEE PES General Meeting, 2002 IEEE, vol. 2, pp. 762-769.

[10] Kara Clark, Nicholas Miller, and Juan J. Sanchez-Gasca , "Modeling of GE Wind Turbine-Generators for Grid Studies," Version 4.2, GE Energy, June, 2008.

[11] O. B. Nayak, A. M. Gole, D. G. Chapman, and J. B. Davies, "Dynamic performance of static and synchronous compensators at an HVDC inverter bus in a very weak ac system," IEEE Trans. Power Syst., vol. 9, no. 3, pp. 1350–1358, August 1994.

[12] Paul E. Marken, Mike Henderson, Dean LaForest, John Skliutas, Jim Roedel, and Todd Campbell , "Selection of Synchronous Condenser Technology for the Granite Substation," Proceedings of 2010 IEEE T&D Conference, April 19-22, 2010, New Orleans.

[13] John skliutas, Dean LaForest, Robert D'Aquila, Dale Derr, and Erik Kronbeck, "Next-Generation Synchronous Condenser Installation at the VELCO Granite Subtation," Proceedings of 2009 IEEE PES General Meeting, Calgary, Alberta, Canada, July 2009.

[14] S.-H. Huang, J. Schmall, J. Conto, J. Adams, Y. Zhang, C. Carter, "Voltage Stability Concerns on Weak Grids with High Penetration of Wind Generation: ERCOT Experience," Proceedings of 2012 IEEE PES General Meeting, July 22-26, 2012, San Diego

[15] Additional VRT Requirement for IRRs, available at http://www.ercot.com/mktrules/issues/nogrr/101-125/124/index

[16] ERCOT Planning Guide, available at http://www.ercot.com/mktrules/guides/planning/current

[17] ERCOT Transmission and Security Operating Procedure, available at http://www.ercot.com/mktrules/guides/procedures/index

[18] ERCOT subsynchronous resonance workshop, http://www.ercot.com/calendar/2013/09/20130909-SSR

6. APPENDIX

6.1. Electrical Characteristics and Cost Estimation of Upgrade Options

This section includes the electrical characteristics and cost estimation of tested upgrade options.

Electrical characteristics for transmission line options

Base kV	Length (miles)	R	X	B	MVA
345	100	0.002914	0.046	0.92065	1,792
500	100	0.0011	0.0237	1.8103	3,464

Electrical characteristics for 345/500 kV transformer

Base kV	X	MVA
345/500	0.008	1,500

Cost estimation for transmission upgrade options

Facility Description	Ampacity	MVA	Cost Estimate
345 kV double circuit	3,000	1,792	$2M/mile
500 kV double circuit	4,950	4,287	$3M/mile
345 kV Reactor	--	--	$5.5M/100 MVAr
Synchronous condenser	--	350	$75M

Note: the cost estimation is based on CREZ Reactive Power Compensation study report and TSPs' references.

6.2. Gas Price in the Economic Cost Analysis

This section includes the natural gas prices that were used in the economic cost analysis for year 2017.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Natural Gas Price ($/MBTU)	5.13	5.10	5.02	4.78	4.79	4.81	4.85	4.87	4.88	4.90	5.03	5.23

(1/15/2015)

GINR	ProjectName	County	Capacity	Projected Commerical Operation Date
13INR0005a	Conway Windfarm	Carson	211	In Service
13INR0005b	Conway Windfarm	Carson	389	10/1/2015
14INR0023	Longhorn Energy Center	Briscoe	361	12/31/2015
14INR0030a2	Panhandle Wind	Carson	218	In Service
13INR0048	Spinning Spur Wind Two	Oldham	161	In Service
14INR0012a	Miami Wind 1 Project	Gray	289	In Service
13INR0059a	Hereford Wind	Castro	200	2/28/2015
13INR0059b	Jumbo Road Wind	Castro	300	4/15/2015
14INR0030b	Panhandle Wind 2	Carson	182	In Service
14INR0032a	Route 66 Wind	Randall	150	8/15/2015
14INR0053	Spinning Spur Wind Three	Oldham	194	5/31/2015
14INR0025a	South Plains Wind 1	Floyd	200	7/31/2015
14INR0025b	South Plains Wind 2	Floyd	150	12/1/2015
14INR0072	Briscoe Wind Farm	Briscoe	150	12/31/2015
14INR0047	Wake Wind Energy	Floyd and Crosby	299	11/1/2015
			3454	