April 20, 2015

Guy Donaldson, Chief
Air Planning Section (6PD-L)
Environmental Protection Agency
1445 Ross Avenue Suite 1200
Dallas, Texas 75202-2733

Re: Docket ID Number EPA–R06–OAR–2014–0754

Dear Mr. Donaldson,

The Public Utility Commission of Texas (PUCT) and the Texas Commission on Environmental Quality (TCEQ) appreciate the opportunity to comment on the proposed rule to partially approve and partially disapprove a revision to the Texas State Implementation Plan (SIP) that addresses regional haze and the corresponding Federal Implementation Plan (FIP) for Texas. These actions were published in the *Federal Register* on December 16, 2014 (79 FR 74818).

Detailed comments on the proposed SIP disapproval and FIP are enclosed.

If you have questions concerning TCEQ's comments on the proposed rule, please contact Mr. Steve Hagle, P.E., at (512) 239-1295 or by e-mail at steve.hagle@tceq.texas.gov. If you have questions concerning the PUCT's comments, please contact Mr. Tom Hunter at (512) 936-7280 or by e-mail at tom.hunter@puc.texas.gov.

Sincerely,

Richard A. Hyde, P.E.
Executive Director
TCEQ

Brian H. Lloyd
Executive Director
PUCT

Enclosure

COMMENTS BY THE TEXAS COMMISSION ON ENVIRONMENTAL QUALITY REGARDING THE PROPOSED TEXAS AND OKLAHOMA REGIONAL HAZE FEDERAL IMPLEMENTATION PLAN AND INTERSTATE TRANSPORT STATE IMPLEMENTATION PLAN TO ADDRESS POLLUTION AFFECTING VISIBILITY AND REGIONAL HAZE

DOCKET ID NO. EPA-R06-OAR-2014-0754

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I. Summary

On December 16, 2014, the United States (U.S.) Environmental Protection Agency (EPA) published in the *Federal Register* a notice of proposed rulemaking regarding the Texas and Oklahoma regional haze federal implementation plan (FIP) and interstate transport state implementation plan (SIP) to address pollution affecting visibility and regional haze (79 FR 74818). The Texas Commission on Environmental Quality (TCEQ) provides the following comments on this proposed rule.

For purposes of abbreviation, the Texas 2009 Regional Haze SIP Revision may be shortened to the 2009 RH SIP. Big Bend National Park may also be referred to as Big Bend; Guadalupe Mountains National Park as Guadalupe Mountains; and Wichita Mountains Wilderness as Wichita Mountains.

II. Comments

A. General Comments

A.1. The TCEQ does not support the proposed partial disapproval of Texas' RH SIP or adoption of the proposed FIP. The EPA's proposed partial SIP disapproval and FIP ignores the flexibility the Federal Clean Air Act (FCAA) provides to states in crafting regional haze plans and thus is arbitrary, capricious, and an abuse of discretion. The EPA should withdraw this proposal and propose to approve the TCEQ's 2009 RH SIP as meeting the statutory and regulatory requirements for regional haze.

The TCEQ submitted a RH SIP that meets all requirements of the Federal Clean Air Act (FCAA) and the regional haze rule (RHR). The 2009 RH SIP includes a detailed analysis of each requirement of a regional haze plan, as identified in FCAA, §169A(b)(2) including: a determination of which sources are subject to Best Available Retrofit Technology (BART); reasonable progress goals for the state's Class I areas, based on the four statutory factors; calculations of baseline and natural visibility conditions; consultations with states; and a long-term strategy and a monitoring strategy.

The EPA bears the burden to show Texas' judgment was unreasonable or does not meet the statutory requirements. As the U.S. Supreme Court opined in *Alaska Dept. of Environmental Conservation v. EPA* (540 U.S. 461, 484-89 *(ADEC)*): in reviewing an EPA disapproval of a state's exercise of discretion, courts must defer to state judgments, and the EPA bears the burden of establishing that those judgments were unreasonable. States are due even greater deference under FCAA, §169A (USC 7491) than under the standard articulated under the Supreme Court's decision in *ADEC*.[1] The RHR and EPA guidance suggest that states have a large degree of flexibility in crafting regional haze plans.

The EPA's determination that the TCEQ did not meet all applicable requirements of the FCAA regarding regional haze is flawed. The state plan submitted in 2009 followed all the EPA rules and guidance and contains a thorough analysis and justification for its conclusions for each statutorily required element. The EPA states that the TCEQ did not 'reasonably consider' the four statutory factors in developing the reasonable progress goals (RPG) for its Class I areas, Big Bend and Guadalupe Mountains National Parks. The FCAA requires states to develop RPGs "tak[ing] into consideration" the factors listed in §169A(g)(1). Texas' plan does this. The EPA's complaint is that it would have considered these factors differently than Texas. This is not a valid basis for disapproval of the Texas plan. The EPA proposes to find that it would have developed certain elements of the visibility plan differently, thus holding Texas to a different standard of compliance than what is provided for in statute and rule. This is the very nature of an arbitrary and capricious action. The EPA also proposed that the Texas uniform rate of progress (URP) is faulty because it assumes the TCEQ's natural visibility conditions estimate is incorrect.[2] This is an estimate that was developed by the TCEQ following the EPA's own guidance and rules that provide the states broad flexibility and discretion in their calculation. Again, it appears the EPA prefers a different outcome than that of the Texas plan. The EPA's proposed disapproval of the long-term strategy for Wichita Mountains in Oklahoma is based on new and unfounded interpretations without basis in the FCAA or its rules. First, the EPA claims that the four statutory factors for RPGs apply to the long-term strategy. This is not found in the statute and is not supported by the RHR. The EPA also proposes disapproval of the long-term strategy and state consultations - in which both states agreed with the reductions calculated for sources in Texas that impacted the Wichita Mountains - because Oklahoma's 'progress goal' established for Wichita Mountains must be "approved or approvable" in order for Texas to rely on it in its own plan.

It appears that the EPA has carried out the process of developing its proposed partial SIP disapproval and proposed partial FIP in the following sequence: First, the EPA decided to find a way to impose additional control requirements beyond those in Clean Air Interstate Rule (CAIR) on multiple electric generating units (EGU) in Texas. The EPA then analyzed the Texas 2009 RH SIP using new approval criteria that were not in place in either the RHR or in the EPA's

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[1] See American Corn Growers Assn. v. EPA, 291 F3d., 1 (2002).

[2] "...we propose to find the TCEQ has calculated this rate of progress on the basis of, and compared baseline visibility conditions to, a flawed estimation of natural visibility conditions for the Big Bend and Guadalupe Mountains, as we describe above. Therefore, we propose to disapprove the TCEQ's calculation of the URP needed to attain natural visibility conditions by 2064." 79 FR 74818, 74833

guidance when it was submitted in 2009. Again, the EPA's proposed partial SIP disapproval and FIP is an attempt to force its preferred outcome for specific sources in Texas. This is arbitrary and capricious and does not comport with the FCAA.

A.2. The projected visibility improvement from the proposed FIP requirements are imperceptible at all three Class I areas. The EPA's modeling analysis projects that the combined effect of all the proposed scrubber upgrades (for seven individual units at four sites) will achieve at most only an imperceptible improvement of 0.14 deciviews at Wichita Mountains. Even smaller improvements are projected for Big Bend and Guadalupe Mountains, 0.03 and 0.04 deciviews, respectively. Tables 44 and 45 in the preamble exaggerate the potential benefits of the EPA's proposed FIP and are irrelevant to the approvability of the 2009 RH SIP.

As fully explained in comment J.6., both Table 44: *Calculated RPGs for 20% Worst Days*...and Table 45: *Anticipated Visibility Benefit*... should be removed from the final action because they tabulate calculated benefits that will not occur by 2018, the only year that is appropriate for evaluating the visibility impacts of proposed controls. The 2018 visibility conditions that the 2009 RH SIP will produce are the appropriate starting points for evaluating the effects of the EPA's proposed FIP. Table 45 misleads a reader to believe that the EPA's proposed FIP action would produce a 0.62 deciview improvement in visibility at Wichita Mountains. Instead of calculating a benefit from the air quality that the 2009 RH SIP would produce in 2018, Table 45 misleads the reader by calculating "benefits" from 2011 through 2013 emissions, long before the 2009 RH SIP is fully effective instead of from 2018.

Table 43 in the Preamble presents the calculated benefits in 2018 that could result from the EPA's proposed FIP. However, the potential 0.14 deciview improvement at Wichita Mountains is almost certainly an overstatement of the incremental benefit from the proposed FIP in 2018 because SO_2 emission reductions are occurring due to other requirements, and the actual SO_2 emissions will likely be lower than those in the CENRAP 2018 emissions projections.

Typically, a person can perceive a one (1.0) deciview change in visibility impairment. Visibility differences of 0.14, 0.04, and 0.03 deciview are imperceptible.

Table 1. Visibility Data (in Deciviews)[3]

	Big Bend	Guadalupe Mountains	Wichita Mountains
Baseline Visibility Impairment 2000 – 2004	17.30	17.19	23.81
State-established RPG for 2018	16.60	16.30	21.47
Incremental 2018 Improvement from EPA's Proposed FIP Scrubber Upgrades	0.03	0.04	0.14
EPA-proposed RPGs for 2018	16.57	16.26	21.33
Current Visibility 2009 - 2013	16.30	15.30	21.20

[3] From Table 43, (79 FR 84887), and the Western Regional Air Partnership-Technical Support System (WRAP-TSS)

Also, the potential improvement from the proposed FIP is 2% or less of the total impairment projected to exist in 2018 on the most impaired 20% days and even that is likely an overestimate of the FIP's potential benefit because the EPA's analysis does not consider the reductions that will occur from other federal programs, such as the Mercury and Air Toxics Standards (MATS) rule and the implementation of the sulfur dioxide (SO_2) National Ambient Air Quality Standard (NAAQS).

The actual effects of the EPA's proposed FIP are correctly represented in Table 43, which includes the only controls that could be in place by the end of 2018, which is the end of the first regional haze planning period established by the RHR.

With current monitored visibility better than the EPA calculates the proposed FIP would achieve in 2018 and the potential visibility improvements from the proposed FIP are both small and uncertain, the EPA does not have an appropriate basis for adopting the proposed FIP.

A.3. The Texas 2009 RH SIP, as submitted, would ensure more than Texas' proportional contribution to progress toward improved visibility conditions at Wichita Mountains through the first planning period that runs through 2018.

By 2018, Texas' 2009 RH SIP reduces Texas' apportioned contribution to total visibility extinction at Wichita Mountains by more (26.1%) than the reduction from all other states combined (24.5%). Also, Texas' 2009 RH SIP reduces Texas' visibility impairment impact at Wichita Mountains by slightly more than its proportional share of the total baseline visibility impact at Wichita Mountains. Additionally, the Central Regional Air Planning Association (CENRAP) states were in agreement about the amount of progress that was reasonable at Wichita Mountains during the first planning period.

The EPA's proposed partial SIP disapproval and partial FIP undervalue the effectiveness of the long-term strategy embodied in the Texas 2009 RH SIP. Without presenting evidence, the EPA dismisses the progress made as being due to "meteorological conditions, reduction in the impacts from SO_2 emissions, and a reduction in the impacts from coarse materials" (79 FR 74843). The EPA makes the meteorological assertion in spite of the fact that 2011 was one of the hottest and driest years in Texas history and there were unprecedented wildfires that year. The current visibility conditions in Big Bend, Guadalupe Mountains, and Wichita Mountains are already better than the respective state-established and the EPA-proposed RPG for these three Class I areas.

A.4. The requirements in the proposed FIP are untimely for the first regional haze planning period due to the EPA's delay in acting on the 2009 RH SIP submittal.

The EPA is evaluating the approvability of the Texas 2009 RH SIP, which covers the first planning period that runs only through 2018. The EPA has been so untimely in its review of the 2009 RH SIP that only the proposed scrubber upgrades in the proposed FIP could possibly be in place by the end of 2018. The projected benefit of the other proposed FIP controls, the scrubber retrofits, is irrelevant to the approvability of Texas' 2009 RH SIP because they would not be in place during this first planning period.

A.5. Texas disagrees with the EPA's technical approach of evaluating only Texas sources when considering more controls to reduce haze at the Wichita Mountains.

In preparing its proposed actions, the EPA carried out a technical project evaluating the connection between emissions of SO_2 and nitrogen oxides (NO_X) from 38 sources in Texas and visibility impairment at several Federal Class I areas.[4] The EPA's approach to evaluating the

[4] The 38 Texas sources evaluated are: Big Brown, Big Spring Carbon Black, Borger Carbon Black, Borger Carbon Black Plant, Coleto Creek Plant, Fayette Power Project, Fullerton Gas Plant, Gibbons Creek,

possibility that it might be reasonable to add additional controls to sources of visibility-impairing pollutants is inherently arbitrary and capricious, biased, discriminatory, and unreasonable because, while focusing primarily on the Wichita Mountains in Oklahoma, the approach considered only sources in Texas for possible additional controls. The approach did not consider whether additional controls on sources in Oklahoma, Arkansas, Kansas, or New Mexico may be equally reasonable or more reasonable. The existing EGUs in Texas and the other states surrounding Oklahoma as well as in Oklahoma are in the same category in that they have all been subjected to BART requirements or better-than-BART requirements.

A.6. The EPA's action is based not on current law or guidance but rather the agency's preference of what the law and guidance should be. This is apparent from recent meetings the EPA has conducted with regional planning organizations (RPOs), federal land managers (FLMs), and states on possible changes to the RHR and guidance – changes that in many ways would codify the approach that the EPA has taken in proposing disapproval of the Texas and Oklahoma SIPs.

The EPA has indicated intentions to revise the RHR and guidance and is in the process of holding meetings with relevant stakeholders such as states, FLMs, and RPOs to receive feedback and input on what these revisions should entail. This is the correct approach for an agency considering making changes to properly promulgated rules. Several stakeholders have already expressed to the EPA that the agency needs to more clearly articulate expectations in the rule or guidance for how to consider the four statutory factors used in setting RPGs. The EPA has posed a series of questions to stakeholders on how to revise the RHR and guidance, including how states should address each RPG factor. For example, the EPA asks if the RPG analysis should include a presumption that certain controls are needed for reasonable progress. This is precisely what the EPA has done in reviewing the Texas 2009 RH SIP and developing the proposed FIP, an action that is without a basis in the current regulations. If the EPA finds that in its review of state RH plans there are flaws in its own rules, the appropriate mechanism for correcting those flaws is not disapproving those plans; it is through prospective, FCAA-compliant rulemaking. The EPA must base its review of the Texas 2009 RH SIP on what the rule and guidance required at the time Texas submitted the plan in 2009. Changes to the law must be properly made through notice and comment rulemaking and not imposed prematurely and without notice to states after plans are submitted. It is arbitrary and capricious, as well as contrary to current case law, to require a state to guess what the EPA may choose to require from a state for an approvable plan. The EPA had appropriate rules and guidance, these were correctly and appropriately followed by the TCEQ in developing the 2009 RH SIP, and the EPA is obligated to follow its own rules and guidance that were in place when the plan was developed as it evaluates the merits of the submission.

B. Visibility Transport

The EPA's interpretation of the RHR is unprecedented, incorrect, and unreasonable. The EPA exceeded its authority in disapproving Texas' long-term strategy.

Goldsmith Gasoline Plant, Great Lakes Carbon LLC, Guadalupe Compressor Station, Harrington Station, Holcim (Texas) LP, HW Pirkey Power Plant, Keystone Compressor Station, Keystone Plant, Lignite-Fired Power Plant, Martin Lake Electrical Station, Midlothian Plant, Monticello Steam Electric Station, Newman Station, North Texas Cement Co., Odessa Cement Plant, Oklaunion Power Station, Pegasus Gas Plant, Reliant Energy Limestone, Sandow Steam Electric, Sherhan Plant, Sommers Deely Spruce Power, Streetman Plant, Texarkana Mill, TNP One Steam Electric Station, Tolk Station, W A Parish Station, Waha Plant, Welsh Power Plant, Works No 4, and Sandow 5 Generating Plant.

The EPA has misinterpreted the requirements in FCAA, §§51.308(d)(1) and (d)(3) and improperly gives meaning to a phrase in order to fill a perceived gap in their own regulations. The RHR requires upwind states to consult with downwind states and develop coordinated strategies to address the upwind state's share of impairment in the downwind state's Class I areas that are impacted. Texas met these long-term strategy requirements. As the EPA admits on 79 FR 74856, in its evaluation of the consultation with Oklahoma, both states agreed with the 2009 Texas plan. Therefore Texas met its obligation under the RHR for the long-term strategy assessment for Class I areas outside the state, specifically Wichita Mountains. The EPA may be correct that its own rules do not address situations where a downwind state's RPG for an area is not properly set, but that does not give the EPA the authority to arbitrarily revise its rules ad hoc, without the proper notice and comment procedures; nor does the flaw in the EPA's rules mean that the Texas plan addressing the long-term strategy is deficient.

The EPA exceeded its authority in disapproving Texas' long-term strategy. First, the EPA bases its proposed disapproval of the RPG and long-term strategy on a new interpretation of FCAA, §51.308(d)(3)(ii) that the 'progress goal' established by a downwind state, i.e. Oklahoma, must be "approved or approvable." This new definition in 2014 of the term progress goal in order to justify the proposed disapproval of the 2009 RH SIP is arbitrary and capricious. The EPA is proposing to disapprove Texas' portion of the RPG calculation for Wichita Mountains, not because of a flaw in Texas' analysis, but because the EPA does not agree with Oklahoma's RPG. The EPA maintains that in this case, it must disapprove both Texas and Oklahoma's plans regarding Wichita Mountains. This interpretation is not found in the rule or statute and is not legally valid for reviewing Texas' long-term strategy or RPG. In fact, the FCAA, §51.308(d)(1) standard for determining the acceptability of the RPG is "it must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." The EPA agrees that both Texas' RPGs for Big Bend and Guadalupe Mountains and Oklahoma's RPG for Wichita Mountains meet this requirement (79 FR 74834).[5]

In developing its long-term strategy for impacts to Wichita Mountains, Texas relied on an agreed upon approach to emission reductions. Oklahoma and Texas both agreed to the Texas SIP long-term strategy during consultation. Texas' long-term strategy was based partly upon meeting the RPG for Wichita Mountains established by Oklahoma. That plan and those consultations are what the EPA must review for compliance with the FCAA. The EPA also relies on an incorrect interpretation of the long-term strategy requirements in (d)(3). Texas is not required to consider the four statutory factors for Class I areas outside the state. These factors are considered in the determination of 'reasonable progress' in FCAA, §169A(g)(1) for Class I areas located in the state. For Class I areas located outside the state, Texas is required to consult with those 'downwind' states in developing coordinated emissions management strategies *as may be necessary* to achieve the RPGs established by the host state.[6] In establishing its long-term strategy, the TCEQ properly relied on its consultation and concurrence with Oklahoma at the time the Texas 2009 RH SIP was developed. That consultation resulted in concurrence that controls - additional to those already required under existing regulations - were not reasonable for Texas sources. The EPA is changing the rules after the fact to give a never before used meaning to 'progress goal' that those goals for Oklahoma must be approved or approvable in order to approve Texas' long-term strategy. The EPA cannot rely on the deference from the

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5 Once again, the EPA engages in creative interpretation of its rules that is not based in the FCAA. The EPA maintains that "ODEQ's RPGs for the Wichita Mountains are consistent with *minimum* requirements of §51.308(d)(1)....." (emphasis added) This section of the rule makes no mention of a minimum level of progress and in fact provides all of the requirements for what the RPG must provide.

6 For Wichita Mountains, the host state is Oklahoma. See 40 CFR §51.308(d)(3).

courts as this interpretation is inconsistent with the regulation and clearly not found in the RHR.

C. Natural and Baseline Visibility Conditions

C.1. The natural conditions estimates that the EPA proposes are not technically supportable and should be withdrawn. The EPA failed to meaningfully address Texas' justification for its RPG and natural visibility condition analysis. The TCEQ urges the EPA to approve Texas' estimation that 100% of the coarse mass and fine soil observed at Big Bend and Guadalupe Mountains is the best estimation available.

The EPA's proposal to use the Natural Conditions II (NCII) Committee estimations of natural conditions for coarse mass, i.e., dust, and fine soil, ignores the site-specific evidence and analysis presented on page 5-4 of the 2009 RH SIP. Further information and evidence is presented clearly in the appendices and in peer-reviewed scientific publications that are cited.[7]

The technical evidence submitted in the 2009 RH SIP demonstrates that, on the most impaired 20% of days, the suspended soil (coarse mass and fine soil) at Guadalupe Mountains and Big Bend is best estimated by calculating that 100% of the soil is natural. The TCEQ asks the EPA to take note of the following conclusion in Chapter 5, page 5-4, the second paragraph of the 2009 RH SIP:

> The times when human-caused dust is likely to be more important at these sites are on days with less visibility than on the worst dust impaired days, since the most dust impaired days are dominated by dust storms and other blowing dust from the surrounding desert landscapes.

In the proposal, the EPA correctly states:

> We note that with any of the methodologies for calculating natural conditions discussed above, Texas' Class I areas are not projected to meet the URP in 2018 according to the CENRAP modeling and are not projected to meet the goal of natural visibility conditions by 2064 (79 FR 74832).

Importantly however, the EPA failed to note that, since over 50% of the visibility impairment at Big Bend on the most impaired 20% days comes from outside the U.S. and since there is no basis for projecting a reduction in that impact, the goal of reaching natural conditions at Big Bend is unrealistic, as is the implied goal of attaining the URP at any time. A more appropriate goal would be to achieve an appropriate reduction of the visibility impairment caused by anthropogenic emissions in Texas and the rest of the U.S.

The TCEQ correctly calculated natural visibility conditions at Big Bend and Guadalupe Mountains in accordance with FCAA, §51.308(d)(2)(iii) and EPA guidance. The use of a refined estimate is allowed under the rule and guidance. The EPA's determination that this refined approach to estimating natural visibility conditions is "not adequately demonstrated" is improper. Such a basis for review is not found in rule, statute or guidance. The EPA cites "uncertainty" in the TCEQ's assumptions yet the EPA's proposed disapproval and use of the default NCII values is contrary to the evidence presented in the 2009 RH SIP and is unjustified. The EPA admits that dust storms and blown dust from deserts, in a very arid region, are

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7 See Appendix 5-1: Discussion of the Original and Revised Interagency Monitoring of Protected Visual Environments (IMPROVE) Algorithms; Appendix 5-2: Estimate of Natural Visibility Conditions; Appendix 5-2a: Natural Events: Dust Storms in West Texas; Appendix 5-2b: Estimating Natural Conditions Based on Revised IMPROVE Algorithm; Appendix 5-2c: Texas Natural Conditions SAS Program File and Data; see under References - Gill et. al. 2005; Kavouras et. al. 2006, 2007.

significant contributors to impairment in Big Bend and Guadalupe Mountains. The EPA's preference for the default estimates is equally unjustified. It is reasonable to assume coarse mass and dust as 100% naturally sourced for the natural visibility estimate for these areas that are located in a desert environment and close to sources of wind-blown dust. The EPA has not demonstrated that the TCEQ's estimate violates the rule or runs afoul of guidance, or is more uncertain than using the default values. Just because everyone else used the default is not a valid basis for disapproval given that the EPA's rules allow such a refined approach.

C.2. If the EPA does not approve the TCEQ natural conditions estimation that 100% of the soil dust at Big Bend and Guadalupe Mountains on the 20% most impaired days is natural, it should choose an estimate between the 80% natural estimate and 100% approximation.

The FLMs commented that 80% would be more reasonable, but they did not present evidence to support this suggestion. However, the TCEQ considers that 100% is well supported in the 2009 RH SIP.

C.3. Texas agrees with the proposed EPA finding that the TCEQ's estimate of baseline visibility conditions at Big Bend and Guadalupe Mountains have satisfied the requirements of §51.308(d)(2)(i).

D. Natural Visibility Impairment

D.1. In Section V. B. 3 of the preamble, the EPA has mischaracterized the requirement for states to calculate natural visibility impairment beyond natural conditions. Table 3: *Natural Visibility Impairment* on page 74832 of the proposal is an incorrect and misleading characterization of Chapter 5, Table 5-2: *Visibility Metrics for the Class I Areas in Texas*, page 5-4 of the 2009 SIP. The TCEQ disagrees with the EPA's assessment of compliance with this requirement and urges the EPA to approve TCEQ's appropriate and technically defensible estimates of natural conditions, such as those used in the 2009 RH SIP.

Section 51.308(d)(2)(iv)(A) of the RHR says:

> For the first implementation plan addressing the requirements of paragraphs (d) and (e) of this section, the number of deciviews by which <u>baseline conditions exceed natural visibility conditions</u> for the most impaired and least impaired days...[underline added]

Although the EPA appropriately proposes to find that the 2009 RH SIP correctly stated the baseline conditions at Big Bend and Guadalupe Mountains, the subsection just cited requires that the natural visibility conditions for the most and least impaired days at each Class I area be subtracted from the baseline conditions for the most and least impaired days to determine the number of deciviews by which baseline conditions exceed natural conditions on the respective sets of days.

D.2. The TCEQ urges the EPA to accept the use of 100% natural dust as the most reasonable estimate for calculating natural conditions. The EPA's proposal presents no evidence that human activity contributes to the coarse mass or fine soil (dust) at Guadalupe Mountains or Big Bend.

The EPA did not do what the rule requires to calculate natural conditions "by estimating the degree of visibility impairment existing under natural conditions for the most impaired and least impaired days, based on available monitoring information and appropriate data analysis techniques."[8] Since the Texas 2009 RH SIP did present substantial evidence that natural blowing dust is the cause of the coarse mass and fine soil at both parks on the 20% of days with the most visibility impairment, the TCEQ strongly urges the EPA to accept the use of the 100% approximation.

D.3. If the EPA chooses not to accept that estimate or to withdraw its proposed partial SIP disapproval and FIP, the TCEQ urges the EPA to choose an estimate that the dust is between 80% and 100% natural.

The 2009 RH SIP submittal presented strong, peer-reviewed publication evidence that, on the most impaired 20% of days, essentially all the coarse mass and fine soil at Guadalupe Mountains National Park is natural. It also presented evidence assembled by six scientists, including the chairman of the IMPROVE steering committee, that the dust impacts at Big Bend are largely from locally windblown dust. Because of the strong National Park Service restrictions on human activity in Big Bend and the fact that the IMPROVE monitor in Big Bend is surrounded in all directions by 10 or more miles of the park, the conclusion is that naturally eroded soil contributes all or nearly all the coarse mass and fine soil at Big Bend on the 20% of days with the most impaired visibility. The FLMs commented that an approximation of 80% natural would be more reasonable, but they did not present evidence to support this suggestion.

E. Uniform Rate of Progress (URP)

Texas disagrees with the EPA's proposed URP and natural conditions for both the Texas Class I areas. Once a final, technically supportable estimate of natural conditions has been selected, the URP can be calculated by straight-line interpolation from the baseline visibility conditions (2000 – 2004) to the estimated natural conditions in 2064 for each of the Texas Class I areas.

Importantly, the EPA failed to note that, since over 50% of the visibility impairment at Big Bend on the most impaired 20% days comes from outside the U.S. and since there is no basis for projecting a reduction in that impact, the goal of reaching natural conditions at Big Bend is unrealistic, as is the implied goal of attaining the URP at any time.[9] A more appropriate goal would be to achieve an appropriate reduction of the visibility impairment caused by anthropogenic emissions from Texas and the rest of the U.S. Later in the first full paragraph on page 79 FR 74843, the EPA correctly concluded that "it is not reasonable to meet the URP for the Texas Class I areas for this planning period." The EPA also recognized that "emissions and transport from Mexico and other international sources will limit the rate of progress achievable on the 20% worst days..."

F. Reasonable Progress Goals

F.1. The TCEQ agrees with the EPA's proposal to find that Texas' submission meets the requirements of §51.308(d)(1)(iv) regarding reasonable progress goal minimum and state consultations for the two Texas Class I areas.

F.2. The EPA's proposed disapproval of Texas' RPGs and its substitution with new RPGs in the proposed FIP is based on EPA's flawed interpretation of what the FCAA requires for "reasonable progress goals." This action is based on the EPA's conclusion that "reasonable progress" must be determined based on source-specific cost of controls even though such a requirement did not exist in the statute, the RHR, or the guidance available in 2009.

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[8] See 40 CFR §51.308(d)(2)(iii).

[9] See the EPA's approval of Arizona's natural conditions goal of 767 years out for Saguaro East in 79 FR 52469.

The Texas 2009 RH SIP established RPGs for both Big Bend and Guadalupe Mountains that provide for visibility improvement for the most impaired days over the period of the SIP and ensure no degradation in visibility for the least impaired days over the same period. The EPA agrees the SIP meets these requirements. The EPA also agrees that the TCEQ considered the four statutory factors in establishing the RPGs for its Class I areas, in accordance with the RHR. The RHR requires states to establish RPGs that "....must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period"(§51.308(d)(1)). The four statutory factors in subparagraph (i) are factors the state must consider in developing the RPGs. These factors in and of themselves do not determine the reasonableness of the goals for the planning period. The RHR, in 40 Code of Federal Regulations (CFR) §51.308((d)(1)(iii), requires the EPA to evaluate whether the state's goal for visibility improvement provides for reasonable progress based on a demonstration of which the four statutory factors are only one element. The EPA's proposed disapproval is a substitution of Texas' statutory responsibility with their own flawed interpretation of what the "reasonable progress goals" must provide and how they are to be determined. This action is based on the EPA's conclusion that 'reasonable progress' must be determined based on source-specific cost of controls even though there is no statutory, regulatory, or precedential basis for this conclusion.

G. Reasonable Progress Four Factor Analysis and Consultation

G.1. The EPA has no basis to disapprove the state's RPGs because the TCEQ did not examine the four statutory factors on a unit-by-unit basis. The TCEQ's analysis of the statutory factors using a source category approach was consistent with the statute, the RHR, and the existing EPA guidance.

Neither FCAA, §169A, the RHR, nor the guidance available in 2009 required a unit-by-unit four factor analysis even where the state's RPGs would improve visibility less than the URP. The statute simply provides that in determining reasonable progress, the four statutory factors shall be taken into consideration (§7491(g)(1)). The statute does not direct how. The RHR provides the same in 40 CFR §51.308(d)(1)(i)(A). In addition, the EPA's RPG guidance does not refer to a unit-by-unit four factor analysis but instead says that states have "flexibility" in how to consider the factors. The EPA has failed to establish that Texas' RPGs do not meet the RHR for improvement in visibility for the most impaired days and no degradation for least impaired days. The EPA also fails to establish that Texas' determination - that additional controls are unnecessary and that they would not provide a discernable visibility improvement for the added cost - is unreasonable based on the text of the FCAA and the EPA regulations.[10] The EPA itself supported the non-source specific four factor analysis approach in reviewing New Mexico's regional haze plan. In a challenge to New Mexico's plan, the EPA "points out that

[10] Dissent in *Oklahoma et al v. EPA* (challenges to the EPA's SIP disapproval and FIP of Oklahoma's RH BART determinations.) 10th circuit July 2013, pages 4-5:

"Finally, it is worth noting that the EPA's regional haze program is distinct in the amount of power given to the states......There are a number of reasons for this approach, not the least of which is that its goals and standards are purely aesthetic rather than directly related to health and safety. The EPA's rule here requires OG&E to make a $1.2 billion investment over the next five years that will, even under EPA's estimate, result in no appreciable change in visibility....

Although the EPA has at least some authority to review BART determinations within a state's SIP, it has no authority to condition approval of a SIP based simply on a preference for a particular control measure. *Texas v. EPA* 690 F3d 670,684 (5th Cir. 2012) see *EME Homer City Generation L.P. v. EPA* 696 F3d 7, 29 (D.C. Cir. 2012) (reviewing a different rule and concluding that the FCAA 'prohibits EPA from using the SIP process to force states to adopt specific control measures'). Oklahoma considered the cost and resulting benefit of such a large investment in scrubbers, and its conclusion was not unreasonable."

[§51.308(d)(1)(i)(A)] does not require a source-specific analysis."[11] The 10th Circuit agreed that "[N]either the Clean Air Act nor the Regional Haze Rule requires source-specific analysis in determination of reasonable progress." (*id*) The EPA has also ignored its own words from the RHR preamble: "....EPA is not specifying in this final rule what specific control measures a State must implement in its initial SIP for regional haze. That determination can only be made by a State once it has conducted the necessary technical analyses of emission, air quality, and the other factors that go into determining reasonable progress" (64 FR 35721).

G.2. The TCEQ disagrees with the EPA's conclusion that $2,700 per ton was too low of a threshold for cost-effective controls.

The EPA stated that CAIR was considered acceptable in lieu of BART but not necessarily designed as a reasonable progress strategy. The TCEQ selected the $2,700 per ton threshold because it was used in the CAIR analyses to control NO_X and SO_2. CAIR was a contemporary program designed for controlling primary and precursor pollutants for health-based ozone and particulate matter NAAQS. The cost rate was not selected because CAIR was considered acceptable for BART, but because it met the high standards for a health-based emissions reduction program. And thus, it was considered more than adequate for the standards of a visibility-based program.

G.3. The TCEQ disagrees with the EPA's assertion that an analysis of controls for a group of sources should not have been performed because this grouped analysis hid potential improvements of smaller-costing controls from individual equipment.

Site specific analyses were not considered necessary because visibility improvements from a group were not perceptible. Thus, a subset of the sources could not result in a better controlled approach or improvement in the visibility predicted by the larger group. The TCEQ performed a grouped source analysis because it was allowed under the EPA's rule and the guidance available at the time the analysis was performed.

G.4. The TCEQ disagrees with the EPA's approach of requiring emissions reductions at certain sites, not necessarily because the reduction had any perceptible improvement in visibility at a Class I area, but because emissions from that source may be significant when compared to other sources.

Reductions to sources that do not have any perceptible impact are not effective regardless of their cost. The regional haze program is designed to improve visibility. The analysis approach completed by the TCEQ was to determine potential, cost-effective controls that would have a perceptible impact on visibility at a Class I area. The program was not designed to make reductions because reductions were possible, nor is that required by either the FCAA or the RHR.

Texas analyzed emissions reductions using four factor analysis, as required by the EPA's RHR (64 FR 35766). Emissions reductions were estimated for sources with the potential suite of controls selected using a $2,700 per ton threshold. A four factor analysis was performed on this group of sources; no perceptible visibility improvement was determined. The goal of the regional haze program is to focus on reasonable progress towards visibility improvement at each Class I area, not to target reductions at specific sources. The EPA appears to have performed its control analysis in the proposed FIP in a reverse-logic form. It targeted reductions at larger-emitting sources, only because they are larger emitting, not through an application of the reasonable progress four factor analysis on potential controls when considering perceptible progress towards achieving natural visibility.

[11] See Wildearth Guardians v. EPA, 770 F3d 919, 944.

G.5. The TCEQ disagrees with the EPA's position that it was unreasonable for Texas not to ask for site-specific data to perform a site-specific analysis because the TCEQ does not have the legal authority to require companies to submit the information necessary to properly evaluate flue gas desulfurization (FGD) scrubber upgrades. It is unreasonable for the EPA to expect the TCEQ to perform an analysis of scrubber upgrades on the specific EGUs when only the EPA has the legal authority to obtain the necessary information to conduct such an analysis.

The EPA stated in its Cost Technical Support Document and in the *Federal Register* notice that the nature of acceptable scrubber upgrades is site-specific and the data were not publicly available. Under FCAA, §114(a), the EPA required companies to submit detailed information regarding the facilities' current scrubber systems and any improvements that have been made since initial installation. The EPA indicated the information was necessary in order to properly evaluate the potential for upgrades to the FGD scrubbers (79 FR 74876).

The TCEQ agrees that such extensive knowledge of the existing scrubber systems is necessary to properly evaluate the viability of upgrading an FGD scrubber. However, the TCEQ does not have any authority equivalent to the EPA's authority under FCAA §114(a) to require submission of cost data or design requirements for a suite of potential scrubber upgrades at individual sites. The TCEQ cannot require the companies to provide the information that the EPA admits is necessary to evaluate FGD scrubber upgrades. There are many possible control strategies TCEQ could of have considered, but it can only evaluate controls for which we have credible and defensible information to support. Additionally, the TCEQ is not aware if this information was even available at the companies in 2008 when this portion of the SIP was developed.

It is unreasonable for the EPA to disapprove a SIP submittal on the basis of the state failing to perform an analysis when only the EPA has the legal authority to require submission of the necessary information for such an analysis. The EPA should not hold the states to a standard for SIP approvability that only the EPA is capable of meeting.

G.6. The EPA's finding that the TCEQ should have considered scrubber upgrades in the 2009 RH SIP is arbitrary and capricious. While the EPA did comment on the TCEQ's proposed 2009 RH SIP, the EPA did not suggest in any way in those comments that the TCEQ should consider scrubber upgrades in the control strategy analysis for reasonable progress goals. The EPA is attempting to hold Texas to a standard created five years after the TCEQ submitted the 2009 RH SIP.

The EPA states in the proposed FIP that it was "unreasonable" for Texas to not perform an analysis of potential scrubber upgrades on coal-fired units in Texas that were already equipped with FGD scrubbers (79 FR 74841). However, in the comments (dated February 15, 2008) that the EPA submitted on the proposed 2009 RH SIP, the EPA did not suggest the TCEQ consider scrubber upgrades as a possible control strategy or indicate in any manner that not considering this potential measure would be grounds for the EPA proposed disapproval of the SIP. Furthermore, in the agency's comments (dated September 30, 2013) on the proposed 2014 Five-Year Texas RH SIP Revision, the EPA again did not mention the subject of FGD scrubber upgrades. The EPA had multiple opportunities to inform the TCEQ that considering FGD scrubber upgrades was as critical as the EPA now claims it to be; however, the EPA did not even mention the subject of scrubber upgrades in any of the formal comments it submitted to the TCEQ during the comment period for the 2009 RH SIP.

The EPA attempts to back-fill its lack of any notice to Texas regarding the consideration of FGD scrubber upgrades by citing statements made by the EPA in the 2005 final BART rulemaking recommending that states consider scrubber upgrades for BART analysis purposes (*Technical Support Document for the Cost of Controls Calculations for the Texas Regional Haze Federal*

Implementation Plan, page 26). However, the EPA's statements in the final BART rulemaking were made solely in the context of BART analysis (70 FR 39171). As Texas was included in the CAIR in 2008 and the EPA determined that CAIR was better than BART, the EPA's comments regarding scrubber upgrades and BART were not relevant to Texas. Furthermore, the EPA did not mention in the 2005 BART rulemaking that states should also consider scrubber upgrades for reasonable progress purposes even if the state's BART-eligible EGUs were subject to CAIR.

The EPA is attempting to hold Texas to a standard of SIP approvability arbitrarily created by the EPA five years after the TCEQ submitted the SIP revision. The EPA is creating impossible standards for SIP approvability by expecting states' SIP revisions to meet requirements created by the EPA after the states are required to submit the SIP revision.

H. BART Determinations

The TCEQ supports the EPA's intention to approve TCEQ's BART determination.

The EPA proposes to approve Texas' determination of which sources in the state are BART-eligible. The EPA also proposes to approve Texas' determination that none of the state's BART-eligible non-EGUs is subject to BART requirements because they are not reasonably anticipated to cause or contribute to visibility impairment in any Class I areas. The EPA proposes to approve the provisions in Texas' BART rules at 30 TAC Subchapter M, with the exception of 30 TAC §116.1510(d), which relies on CAIR.

I. Long-Term Strategy

I.1. The RHR does not require that a downwind state's RPG must be "approved or approvable" in order to determine if the upwind state's long-term strategy meets the statute or the rule. This is a new and illegal change to the RHR without going through notice and comment rulemaking as required by the Administrative Procedures Act and is thus an arbitrary and capricious determination by the EPA.

The EPA's proposed disapproval of the state consultation requirements is based upon Oklahoma's determination, subsequent to submittal of the Texas 2009 RH SIP, that it required further reductions from Texas. The EPA has not justified its determination that Texas failed to meet the requirements of FCAA, §51.308(d)(3)(i) and in fact the record shows that the process as laid out in the SIP and as required by the rule was followed by Texas. The EPA's determination is based on a new definition of progress goal in subsection (d)(3)(ii) and a misstatement of the actual rule itself in subparagraph (i).

Texas met the consultation requirements in §51.308(d)(3)(i). Texas determined where emissions were reasonably anticipated to contribute to visibility impairment in Oklahoma. Texas consulted with Oklahoma. The EPA asserts that the TCEQ should have provided information necessary to identify reasonable reductions, which is not required by the RHR. Oklahoma requested information on controls identified by CENRAP. Oklahoma had information on control upgrades contained in the proposed Texas 2009 RH SIP. Yet, it did not request additional controls on Texas sources or disagree with Texas' determination that additional controls were not warranted during the first planning period. It was only after consultation with Texas that Oklahoma argued that it needed controls that they did not have authority to require from Texas sources. Oklahoma's after-the-fact change in position and the EPA's subsequent proposed disapproval of their RPGs for Wichita Mountains does not provide the legal basis for proposed disapproval of Texas' long-term strategy consultations. The RHR does not require that a downwind state's RPG must be "approved or approvable" in order to determine if the upwind state's long-term strategy meets the statute or the rule. This is a new and illegal change to the RHR and is thus an arbitrary and capricious determination by the EPA.

I.2. The EPA's finding that the TCEQ did not meet the long-term strategy consultation requirements of 40 CFR §51.308(d)(3)(i) and (ii) ignores the voluminous and detailed consultation record contained in the Texas 2009 RH SIP. The EPA holds Texas to a different standard of review than it has with other similar regional haze SIPs.

Section 51.308(d)(3) requires, (i) that Texas consult with other states if its emissions are reasonably anticipated to contribute to visibility impairment at that state's Class I areas(s), and (ii) if so, it must demonstrate that it has included in its SIP all measures necessary to obtain its share of emission reductions needed to meet the RPG for that Class I area.

As the EPA acknowledges, the TCEQ relied on CENRAP source apportionment modeling and its own supplemental analysis, available to all affected states, FLMs, and tribes, to evaluate and identify reasonable controls. The TCEQ did include additional controls or measures in its SIP, beyond those required to meet other programs, and every state in the consultation, including Oklahoma, concurred. For Wichita Mountains, additional controls were not deemed reasonable given that the CENRAP modeling – agreed to by all the states – showed that the visibility impairment contributions from Texas go down during the planning period (2002 – 2018). The EPA's preamble, and Table 26 acknowledge this.[12] Most importantly, Oklahoma did not request additional controls from Texas during consultation. The EPA ignores the record and proposes to hold the Texas plan to a standard that is not found in the RHR. The EPA merely disagrees with the TCEQ's conclusions and attempts to apply a 'reasonableness" standard to §51.308(d)(3)(ii) where none exists. That section only requires that the TCEQ demonstrate that all controls necessary to meet the progress goal, for Wichita Mountains, are included. Oklahoma agreed that no additional controls were needed at the time, and the evidence that the contribution to visibility improvement from emission reductions at Texas sources during the planning period is a sufficient basis for these conclusions.

The EPA has viewed similar consultations in other state SIPs, using the same CENRAP information, as meeting the RHR requirements for long-term strategy consultations. A case in point is Arkansas's regional haze plan. The CENRAP modeling that the EPA now finds lacking for Texas and Oklahoma's consultation was perfectly fine for Arkansas. It demonstrated that visibility impairment from Arkansas sources at Hercules Glades in Missouri was projected to increase during 2002-2018. In consultations with Missouri, Arkansas made no commitment for additional controls beyond those already factored into CENRAP's modeling for 2018. All states agreed with this determination, including Missouri. Yet, with no further explanation, the EPA approved Arkansas' consultation and its determination that no additional controls were necessary, as consistent with the RHR, even though the data that was clearly available to everyone showed impairment at Hercules Glades due to Arkansas' sources would increase (76 FR 64186, 64216).

I.3. The TCEQ disagrees with the EPA's positon that Texas did not adequately address the documentation requirements in 40 CFR §51.308(d)(3)(iii) regarding the technical basis for Texas' long-term strategy.

The proposal quotes the RHR:

> The State must document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area it affects. The State

[12] "The contributions from Texas sources on total visibility impairment decreases from 2002 to 2018 at all impacted Class I areas shown in the tables below." 79 FR page 74860.

> may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all State participants (79 FR 74861).

Texas documented the modeling, the monitoring, and emissions information data used for the 2009 RH SIP. The modeling was completed by CENRAP and available for all states. The monitoring data were available from the IMPROVE monitors and the emissions data had been previously approved by the EPA. The preamble contains a lengthy discussion – over eight *Federal Register* pages, plus the Technical Support Document - of Texas' consultation with Oklahoma, Colorado, Arkansas, and New Mexico, the CENRAP process and modeling and the TCEQ's supplemental analysis of CENRAP's technical analysis. This discussion belies the EPA's claim that the TCEQ did not adequately meet the requirements in 40 CFR §51.308(d)(3)(iii) to document the technical basis for the TCEQ's apportionment determination. The EPA and Oklahoma cannot fairly argue that not all relevant data was available to inform them of Texas source's visibility impact on neighboring Class I areas and the reasoned analysis that additional controls would not be necessary to reduce visibility impairment outside Texas.

I.4. The TCEQ's analysis of potential additional controls is adequate and approvable. The EPA's proposed finding that a specific type of unit-by-unit cost and effectiveness analysis was necessary to have an approvable long-term strategy and an approvable consultation with Oklahoma contradicts the EPA's own June 1, 2007 *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*. The EPA's methodology of evaluating possible additional controls on existing EGUs is not required by the RHR or by the guidance in place at the time Texas prepared its 2009 RH SIP.

The EPA's own guidance, Chapter 4: Identify Control Measures for Contributing Source Categories for the First Planning Period, page 4-2, states:

> The Regional Haze Rule gives States wide latitude to determine additional control requirements, and there are many ways to approach identifying additional control measures; however, you must at a minimum, consider the four statutory factors.

The TCEQ prepared its analysis of the cost and effectiveness of additional controls by selecting sources and controls that met a $2,700 per ton threshold. This threshold amount was used in CAIR, as well as used by the EPA in preparing its BART rules and guidance.

The control package Texas considered included SO_2 controls at 24 facilities from 15 sites. The NO_X controls included 24 facilities at 15 sites. The calculated haze index improvements at affected Class I areas from the additional controls ranged from a low of 0.04 deciview at Wheeler Peak in New Mexico to 0.36 deciview at Wichita Mountains in Oklahoma. The estimated annualized cost for the controls necessary to achieve these calculated benefits was $324 million. Texas determined that this cost is unreasonable for a visibility improvement that is below the threshold of perception and below the 0.5 deciview criteria the EPA used for "contribute to."

Also on page 4-2, the guidance refers to the EPA's AirControlNET database as a source of $324 million a year. In its analysis, Texas relied on the cost and effectiveness information supplied by AirControlNET regarding control techniques for specific source categories. In preparing the 2009 RH SIP, Texas did use appropriate areas of influence; it did consider controls from the EPA's AirControlNET database; and it did consider the four statutory factors in considering whether additional controls were reasonable to implement.

The EPA's preference for a different analysis procedure that reaches a similar conclusion about cost and effectiveness is not a justifiable basis for the EPA to disapprove Texas' process in developing its 2009 RH SIP submittal nor is it a justifiable basis for the EPA to disapprove the Texas-Oklahoma consultation about Texas' impact on visibility impairment at Wichita Mountains.

J. Response to Proposed FIP Requirements

J.1. The EPA's proposed FIP is contrary to authority provided in the FCAA. The statute provides the EPA with authority to address state plans that it believes are substantially inadequate to comply with the Act's requirements. The EPA RHR identifies periodic reviews and plan updates as the remedy for addressing RH SIPs that are inadequate.

In order to promulgate a FIP, the FCAA requires that the EPA disapprove a state plan in whole or in part for not meeting the applicable requirements of §110(k). Texas' plan was complete by operation of law and met all requirements. The EPA has no authority to impose a FIP that merely replaces the EPA's judgment for Texas' but does not correct an error or is not based on a failure of Texas' plan to meet the requirements of the RHR or FCAA.[13]

The EPA's RHR established the remedy for a substantially inadequate plan as periodic updates, not a federal plan.[14] The nature of regional haze and the statutory requirement for reasonable progress and *long-term* solutions to visibility impairment require regular updates and reviews of state plans by the states themselves. Thus, the very nature of regional haze planning recognizes that the solution to plans that don't make adequate progress towards the natural visibility condition goal is an update of the plan, not a FIP.

J.2. The FCAA gives states authority to develop regional haze plans that reflect state needs. The EPA should not get deference for its own choices in its FIP over those of Texas.

The EPA's interpretation of its authority to review regional haze submissions under FCAA, §169A is flawed. While the EPA review and state revision of regional haze SIPs is a component of §110, the FCAA also provides an independent grant of authority to states, and specific language identifying the EPA authority to establish goals and guidance for regional haze. The use of the word "guideline" in the in §169A evidences a clear congressional intent that states be granted wide latitude in decision-making here. FCAA, §169A inherently limits the EPA's SIP approval and review authority in §110.

The EPA's only complaint regarding the 2009 Texas SIP is that it would have taken a different approach to meet the statutory and regulatory requirements. The EPA's suggested reliance on the NCII default values in estimating natural visibility conditions at Big Bend and Guadalupe Mountains rather than the FLM's 80% approach was not adequately justified and therefore is unreasonable.

The statute requires that in developing the RPG, the regulating entity must consider "the energy and non-air quality environmental impacts of compliance." Nowhere in the EPA's proposal is this factor further defined. The EPA provides guidance to states on how to consider this factor,

[13] See Train, 421 U.S. 60, 79 "The CAA gives the [EPA] no authority to question the wisdom of a State's choice of emission limitations if such choices are part of a plan which satisfies the standards of 110(a)(2)."
[14] See 64 FR 35745: "...section 110(a)(2)(F) of the CAA provides that SIPs are to require 'periodic reports on the nature and amounts of emissions and emissions-related data' and 'correlation of such reports....with any emission limitations or standards establish pursuant to this chapter.' Moreover, section 110(a)(2)(H) requires SIPs to provide for revision when found to be substantially inadequate to 'comply with any additional requirements established under...[the CAA].'"

but ignores a crucial part of the term. The EPA cites only one element of its BART guidance as the basis of its analysis of this factor, but ignores another more important element: the impact to energy reliability and costs due to compliance with the RPG controls in the proposed FIP that are developed for a large segment of the electric energy production in Texas.

J.3. The EPA's cost analysis for the proposed FIP is not adequate, in particular regarding the FGD scrubber upgrades. The EPA cannot use the claim of confidential business information to circumvent its obligation to provide the public with adequate information regarding the economic analysis of its regulatory actions or to defend its decision to disapprove the Texas 2009 RH SIP.

The EPA cites the companies' claims of confidential business information to defend its complete lack of any cost information regarding upgrades to scrubbers and merely claims that all the scrubber upgrades were less than $600 per ton (79 FR 74877). Confidential business information is not a justification for failing to provide proper cost impact information of a proposed rule. The EPA could have provided example cost information for each type of scrubber upgrade considered without disclosing any specific information claimed confidential by the companies. The EPA has not even provided a total cost for all the scrubber upgrades. Additionally, while the proposal preamble and *Technical Support Document for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan* include detailed information on the costs of the scrubber retrofits, the EPA also did not provide a total cost estimate of the seven EGUs that EPA has proposed standards that would require installation of new FGD scrubbers. The only total cost estimate provided by the EPA for the proposed FIP is the approximate $2 billion provided by EPA staff in informal discussions with the TCEQ.

The EPA claims the TCEQ should have considered scrubber upgrades as a cost-effective control measure in the Texas 2009 RH SIP revision. Yet, even with the proposed FIP, the EPA has not provided the TCEQ or the public with any information to evaluate the cost-effectiveness of scrubber upgrades. Neither the TCEQ nor the public is required to accept the EPA's unsubstantiated claim that the cost-effectiveness of the scrubber upgrades is less than $600 per ton. The EPA is using the cost-effectiveness of scrubber upgrades as a basis for disapproving the Texas 2009 RH SIP and must provide adequate information for evaluating the basis of the EPA's decision. The EPA should provide cost information for all scrubber upgrade methodologies considered by the agency.

J.4. The TCEQ disagrees with the EPA proposal to calculate visibility impairment, (i.e., baseline visibility conditions minus natural visibility conditions) using the EPA's proposed substitute natural visibility conditions for Big Bend and Guadalupe Mountains instead of the natural visibility conditions calculated by Texas for its two Class I areas.

The EPA should accept Texas' calculation of natural visibility conditions at Big Bend and Guadalupe Mountains. These calculations followed the requirements of 40 CFR §51.308(d)(2)(iii) using data and analyses specific to each of the Class I areas. The EPA's proposed substitute estimates of natural conditions were developed by a committee working on national estimates rather than using site specific scientific studies. The EPA did use the correct Baseline Visibility Conditions, 2000-2004, in Table 40.

J.5. The TCEQ supports the EPA's proposal to find that it is not reasonable to provide for rates of progress at Wichita Mountains, Big Bend, or Guadalupe Mountains that would attain natural visibility conditions by 2064 and to use the baseline conditions calculated by Texas in establishing the URP at Big Bend and Guadalupe Mountains.

Once technically supportable natural conditions estimates are selected for these two Class I areas, the URP can be established for them. However, as discussed in comment C.1., the TCEQ disagrees with the EPA's proposal regarding the natural conditions estimates.

J.6. The TCEQ urges the EPA to remove all text about benefits of emission reductions from "actual emission levels" from its final action and technical support documents. These discussions exaggerate the potential benefits of the EPA's proposed FIP and are irrelevant to the approvability of the 2009 RH SIP.

Both Table 44: *Calculated RPGs for 20% Worst Days*...and Table 45: *Anticipated Visibility Benefit*... should be removed from the final action because they tabulate calculated benefits that will not occur by 2018, the only year that is appropriate for evaluating the visibility impacts of proposed controls. The 2018 visibility conditions that the 2009 RH SIP will produce are the appropriate starting points for evaluating the effects of the EPA's proposed FIP.

The EPA inappropriately suggests in its proposal and technical support documents that emission rates in 2011, 2012, or 2013 are relevant to what the Texas 2009 RH SIP will achieve by 2018. The RHR sets 2018, the last year in the first planning period, as the time by which a state's SIP must provide for reaching the state's RPG. The RHR does not imply the need for particular emission levels during any intermediate year between the baseline period and 2018.

There is no technical basis for the EPA's selection of actual emissions from 2009 through 2013 as the base from which to calculate the benefit of applying the FIP controls. During the 2009 through 2013 period, the emissions were not affected by the full range of additional emission reduction requirements contained in the 2009 RH SIP.

Choosing 2011 ignores seven more years of emissions reductions required under Texas' long-term strategy. As Texas' 2014 Five-Year RH SIP submittal shows in Figure 4-1: *Texas Modeled Emissions Inventory Summary for 2002* and Figure 4-2: *Updated Texas Emissions Inventory Summary for 2005*, the SO_2 and NO_X emissions in Texas are already lower than the straight line between the 2000 through 2004 baseline condition period and the 2018 SO_2 and NO_X emissions estimates used to develop the 2009 RH SIP.[15]

Table 45 misleads a reader to believe that the EPA's proposed FIP action would produce a 0.62 deciview improvement in visibility at Wichita Mountains. However, as discussed in comment A.2., the potential 0.14 deciview improvement at Wichita Mountains is almost certainly an overstatement of the incremental benefit from the proposed FIP in 2018 because SO_2 emission reductions are occurring due to other requirements and the actual SO_2 emissions will likely be lower than those in the CENRAP 2018 emissions projections.

K. Proposed Disapproval of the Infrastructure SIPs

The TCEQ disagrees with the EPA's proposed disapproval of §110(a)(2)(D)(i) requirement for visibility protection for the Texas infrastructure SIP submittals for ozone, particulate matter ($PM_{2.5}$), nitrogen dioxide (NO_2), and SO_2 NAAQS. The EPA fails to go into any detail on the reasons for disapproving these multiple, separate SIPs.

For the 1997 eight-hour ozone standard, the EPA only states that Texas originally failed to make a timely submission, and notes that CAIR was then promulgated and implemented by the EPA. Texas was not in CAIR for ozone, and subsequently submitted a separate transport SIP for the 1997 eight-hour ozone NAAQS. The EPA neglects to offer any reason or explanation for why this submission was inadequate or deserving of disapproval, other than the promulgation and implementation of the CSAPR. Although Texas was included in CSAPR for the 1997 eight-hour

[15] See https://www.tceq.texas.gov/assets/public/implementation/air/sip/haze/13012SIP_ado.pdf.

ozone standard, Texas has from the beginning challenged that inclusion, and litigation over the matter is on-going. Additionally, the EPA failed to act on, or even mention the Texas ozone transport SIP submission before including Texas in CSAPR for the 1997 ozone standard.

For the 1997 $PM_{2.5}$ NAAQS, Texas was included in CAIR, and subsequently complied with CAIR requirements. The EPA included Texas in CSAPR for the 1997 $PM_{2.5}$ NAAQS at final promulgation of the rule, without having given Texas proper notice of this inclusion by including Texas in the proposed rule. Texas has challenged its inclusion in CSAPR for the 1997 $PM_{2.5}$ NAAQS, and litigation over this matter is also on-going. The linkage of Texas to a single monitor in an area already attaining the relevant NAAQS is a clear case of over-control, something explicitly prohibited by the FCAA, as acknowledged by the Supreme Court.[16] Texas also submitted a transport SIP for the 2006 $PM_{2.5}$ NAAQS. Although this SIP did rely on CAIR, the EPA has failed to offer any substantive reason why this is inappropriate, given that CSAPR replaced CAIR, and the sole Texas linkage in the final CSAPR for 2006 $PM_{2.5}$ are to the same inappropriate monitor in an area already attaining the NAAQS.

As for the 2008 ozone, 2010 SO_2, and 2010 NO_2 standards, Texas has submitted transport SIPs for each of these standards demonstrating that Texas does not have transported emissions out of state that interfere with attainment or maintenance in any downwind state.

The EPA fails to offer any rational or reasoned explanation for why these SIP submissions are inadequate. In fact, the EPA fails to offer any analysis of these SIP submissions at all; therefore, this proposed disapproval is arbitrary, capricious, and not supportable. Finally, the EPA states that because it is proposing the need for additional SO_2 controls on Texas sources to prevent interference with measures required to be included in the Oklahoma Regional Haze SIP to protect visibility, the EPA must therefore disapprove the §110(a)(2)(D)(i) submittals for 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, and 2010 SO_2 NAAQS. The EPA fails to offer any support for this contention, or the inclusion of the $PM_{2.5}$ standards in this list. The EPA has repeatedly stated that infrastructure requirements, including transport requirements, are pollutant specific. Therefore, a requirement to increase SO_2 controls does not, without further explanation, necessarily include the requirements for $PM_{2.5}$. Although the EPA has taken other actions in conflict with its guidance on this issue, there is no rational reason to continue to perpetuate this error.

L. Nationwide Scope and Effect

The TCEQ disagrees with the EPA's assertion that this action is a rulemaking of nationwide scope and effect. Any appeal of the EPA's final action on Texas' regional haze plan and FIP should be filed the 5th Circuit Court of Appeals.

The EPA argues that the proposed FIP and SIP disapproval actions for Texas and Oklahoma have nationwide scope and effect and therefore, under FCAA, §307(b)(1), appeal must be to the D.C. Circuit. First, the TCEQ notes that the EPA has in fact taken the opposite position in several final actions on regional haze plans in Oklahoma, New Mexico and Arizona.[17]

These EPA actions do not have nationwide scope and effect; they are not nationally applicable, but apply only to two states. The EPA has provided no legal basis - beyond a one sentence assertion - to support that its actions interpreting the RHR as they apply to Texas and Oklahoma are of "nationwide scope and effect." This interpretation of the RHR as it applies to Texas and Oklahoma Regional Haze SIPs is unsupported by the EPA's proposed action. The action here specifically deals with plans adopted by Texas and Oklahoma to meet the FCAA and regional haze regulations as they apply in their respective jurisdictions. Each regional haze plan

[16] See E.P.A. v. EME Homer City Generation, L.P., 134 S.Ct. 1584, at 1608 (April 29, 2014).
[17] See for example: 79 FR 12944, 12954 March 7, 2014; 77 FR 70693, 70705, Nov. 27, 2012; 78 FR 46142, 46174 July 13, 2013; 79 FR 52420, 52479, Sept. 3, 2014.

submitted by the various states is unique, addressing visibility impairment at Class I areas in those states and in surrounding states. The EPA's proposed partial disapproval of Texas' plan and proposed imposition of a FIP does not rely solely on an interpretation of their rules but rather on a review of the Texas plan's comportment with those rules. The EPA has proposed determinations that Texas did not develop its natural visibility conditions and RPG correctly. The EPA then goes on to draft RPG controls for 15 Texas units and redo the natural visibility estimates. This proposal is *Texas-centric*; it is not nationally applied.

The EPA then attempts to plug the obvious hole in its position by pointing to congressional report language that allows the Administrator to determine its action has nationwide scope and effect if the rulemaking extends to two judicial districts. This is not found in the FCAA. In fact, §307(b)(1) specifically states that "any implementation plan" or "any other final action of the Administrator under this chapter....which is locally or regionally applicable may be filed only in the United States Court of Appeals for the appropriate circuit." The fact that Oklahoma is in the Tenth Circuit and Texas is in the Fifth Circuit is immaterial to potential petitions for review. The TCEQ's comments and any future actions it may or may not take in court will be based on the EPA's action on Texas' SIP and any FIP the EPA has imposed on Texas, not Oklahoma. As stated previously, venue for regional haze plans in several neighboring states, including Oklahoma, is already established in their respective circuits.

M. Electric Reliability

M.1. The EPA should consider the findings of the Electric Reliability Council of Texas (ERCOT) report *Impacts of Environmental Regulations in the ERCOT Region.*

The EPA has not evaluated any potential impacts of the proposed FIP to reliability and prices of electricity in Texas, as further discussed below. In 2014, ERCOT conducted a study of the impacts that environmental regulations have in the ERCOT Region. The report, entitled *Impacts of Environmental Regulations in the ERCOT Region*, was finalized on December 16, 2014, and is included as Appendix 1 to the TCEQ's comments. While the report included a number of environmental regulations, such as the MATS rule, Clean Power Plan, and CSAPR, ERCOT also included the EPA's proposed Regional Haze FIP for Texas in its analysis. The TCEQ incorporates the ERCOT report into the agency's comments and encourages the EPA to consider the findings of the ERCOT report.

M.2. The EPA is using a loophole in Executive Order 12866 to avoid evaluating the potential energy impacts of the proposed action as required by Executive Order 13211. The proposed FIP affects a significant portion of Texas' base load power generation fleet and the EPA should evaluate and consider the impacts of the proposed FIP on the reliability and price of electricity in Texas.

The EPA claims that the proposed FIP is not subject to Executive Order 12866, regarding Regulatory Planning and Review, because the proposed rule is not a rule of general applicability and therefore, is not a significant regulatory action (79 FR 74889). If the proposed FIP is not a significant regulatory action under Executive Order 12866, then the EPA indicates the rule is not subject Executive Order 13211, regarding actions that significantly affect energy supply, distribution, or use (79 FR 74890). However, while the EPA claims that the rule is not of general applicability to avoid trigging the requirements of Executive Orders 12866 and 13211, the EPA also claims that the rule is of nationwide scope and effect in an effort to have any petitions for review be filed in the United States Court of Appeals for the District of Columbia (79 FR 74888). The EPA claims the rule is of national scope for purposes of legal challenges, but then claims the rule is of limited scope for the purposes of avoiding Executive Orders 12866 and 13211 without any explanation of how this action can have two contradictory scopes. The scope of the regulatory action proposed by the EPA is either nationwide or limited to Texas; it cannot be both.

As discussed in TCEQ comment II. L, the TCEQ disagrees with the EPA's position that the proposed action is of nationwide scope (79 FR 74888). However, the TCEQ also disagrees with the EPA position that the potential impact to the supply, distribution, and use of energy does not need to be considered in this proposed action. While the EPA has not provided a complete economic impact analysis for the proposed FIP, the annualized cost for the scrubber retrofits portion of the proposal is estimated to be approximately $238 million per year, greatly exceeding the $100 million per year threshold established under Executive Order 12866. Furthermore, the EPA's proposed FIP would meet Executive Order 13211 criteria for being "likely to have a significant adverse effect on the supply, distribution, or use of energy" based on the guidance provided in Office of Management and Budget (OMB) Memoranda 01-27, July 13, 2001 Guidance for Implementing Executive Order 13211. Section 4 of the OMB Memoranda 01-27 provides a number of examples of adverse effects for the purpose of Executive Order 13211. One of the listed examples is a reduction in electricity production in excess of 1 billion kilowatt-hours or in excess of 500 megawatts (MW) of installed capacity. According to a recent ERCOT report included in Appendix 1 to the TCEQ's comments, ERCOT's modeling indicates that approximately 1,800 MW of capacity from the affected coal-fired EGUs are expected to retire due to the EPA's proposed Regional Haze FIP requirements, exceeding the threshold in the OMB guidance for an adverse effect.[18] Also, with the exception of the San Miguel facility, each of the units subject to the EPA's proposed FIP is greater than 500 MW. If just one of these units is no longer economically viable as a result of the EPA's FIP, it would result in the reduction of more than 500 MW of installed capacity.

According to OMB Memoranda 01-27, the basic purpose of Executive Order 13211 is to ensure that agencies "appropriately weigh and consider the effects of the Federal Government's regulations on the supply, distribution, and use of energy." The EPA's interpretation of Executive Orders 12866 and 13211 would mean that a national rule applying to all coal-fired EGUs in the country with an annualized cost of $100 million per year that might result in the loss of only 500 MW of a capacity would require an energy impact analysis because it may have a significant adverse effect on the supply, distribution, or use of energy. However, according to the EPA's interpretation, a rule costing more than twice that cost threshold and potentially resulting in the loss of more the three times the capacity but focused within a discrete electric reliability region in a single state that has limited connections to the rest of the United States' grid does not require any analysis or consideration of the possible adverse impacts on energy. In other words, the EPA's position is that the Federal Government does not need to concern itself with a potentially severe impact of this proposed rule on the supply, distribution, or use of energy within ERCOT because the impact is limited to a single state. Such an interpretation and outcome is illogical and clearly contrary to the stated intent of Executive Order 13211. The potentially for adverse effects from the EPA's proposed rule is actually increased, not lessened, because the costs and impacts of the rule are focused within a smaller region.

Additionally, FCAA, §169A(g) requires that the State and the Administrator consider the energy and non-air quality environmental impacts of compliance when determining the best available retrofit technology. While the EPA's guidance on evaluating energy impacts for BART analyses does not specifically address considering electrical grid reliability and electricity prices, the guidance does make allowance for considering indirect energy impacts as well as potential impacts such as locally scarce fuels and significant economic disruption or unemployment (70 FR 39169). Furthermore, the EPA recommends that states consider the BART guidelines when

[18] See ERCOT Report Impacts of Environmental Regulations in the ERCOT Region, December 16, 2014, page 27.

evaluating the energy and non-air environmental impacts for reasonable progress goal purposes.[19]

The proposed action affects almost 10,000 MW of generation capacity in Texas and almost 8,800 MW of that capacity is within the ERCOT region. The affected units in ERCOT represent approximately 11% of region's 2015 total capacity based on ERCOT's *Report on Capacity, Demand, and Reserves for the ERCOT Region, 2015 – 2024*.[20] Based on the significant portion of the Texas electrical grid affected by the EPA proposal and the projected retirements estimated by ERCOT to result from this action, the EPA should analyze and consider the possible impacts of the proposed rule on the reliability and prices of electricity in Texas, regardless of the applicability of Executive Orders 12866 and 13211.

M.3. The TCEQ recommends that the EPA withdraw the proposed FIP; however, if the EPA does finalize the FIP, the EPA should include an electric reliability safety valve provision in the final rule.

As discussed in comments sections A, J, and K, the TCEQ maintains that its 2009 RH SIP is approvable as submitted and the EPA should withdraw the proposed FIP. However, if the EPA does finalize the FIP then the final rule should include a reliability safety valve provision. The EPA has not considered the potential electric reliability implications of the proposed rule. A reliability safety valve provision in the rule could be a provision that allows the EPA to grant an extension to the compliance dates in situations where electric reliability is at risk, after consultation with the appropriate Independent System Operator/Regional Transmission Organization.

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[19] See Guidance for Setting Reasonable Progress Goals under the Regional Haze Program, June 1, 2007, page 5-3; 79 FR 74874.
[20] See http://www.ercot.com/gridinfo/resource; December 1, 2014.

Appendix 1: Impacts of Environmental Regulations in the ERCOT Region

Impacts of Environmental Regulations in the ERCOT Region

Executive Summary

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection, which encompasses approximately 90% of electric load in Texas. ERCOT is the independent organization established by the Texas Legislature to be responsible for the reliable planning and operation of the electric grid for the ERCOT Interconnection. Under the North American Electric Reliability Corporation (NERC) reliability construct, ERCOT is designated as the Reliability Coordinator, the Balancing Authority, and as a Transmission Operator for the ERCOT region. ERCOT is also registered for several other functions, including the Planning Authority function.

There are several proposed or recently finalized U.S. Environmental Protection Agency (EPA) regulations that could have an impact on grid reliability in ERCOT. These rules include the Mercury and Air Toxics Standards (MATS), the Cross-State Air Pollution Rule (CSAPR), the Regional Haze program, the Cooling Water Intake Structures rule, the Steam Electric Effluent Limitation Guidelines (ELG) rule, the Coal Combustion Residuals (CCR) Disposal rule, and the Clean Power Plan. This study assesses the individual and cumulative impact of these regulations on generation resources in the ERCOT region, and potential implications for grid reliability.

Resource owners in ERCOT will need to take actions to comply with these regulations in the coming years, or else retire or mothball the units. Table ES-1 and Table ES-2 show the potential compliance requirements for coal and natural gas units, respectively, under these regulations.

Table ES-1: Compliance Requirements for Coal Units

Regulation	Compliance Date	Compliance Requirements	Potential Compliance Actions	Potential Compliance Costs
Mercury and Air Toxics Standards	April 2015 (April 2016 with extension)	Sets emissions limits for acid gases, toxic metals, and particulate matter	Install control technology retrofits (e.g., dry sorbent injection)	$10/kW; $0.75/MWh (based on generator survey responses)
Cross-State Air Pollution Rule	January 2015	Cap and trade program for NO_x and SO_2 emissions	Procure allowances to cover air emissions of NO_x and SO_2	$0.75-$7.25/MWh (based on ERCOT modeled allowance prices)
Regional Haze Program	Three to five years after final Federal Plan issued*	Sets SO_2 emissions limits for specific coal-fired units in the ERCOT region	Install or upgrade scrubbers	$450-$573/kW (based on previous ERCOT study)
316(b) Cooling Water Intake Structures Rule	2018-2022, on each unit's permit renewal cycle	Requires controls for units with once-through cooling	Install or upgrade modified traveling screens and fish return systems	$5-$25/kW; $0.10-$0.50/MWh (based on EPA cost analysis and consultation with Black & Veatch)
Steam Electric Effluent Limitation Guidelines	Three years after publication of final rule*	Sets limits for toxic metal concentrations in wastewater	Upgrade wastewater treatment processes to meet limits	$10-$60/kW; $0.40-$1.40/MWh (based on EPA cost analysis)
Coal Combustion Residuals Disposal Rule	Five years after publication of final rule*	Requirements for future and existing (Subtitle C only) disposal	Groundwater monitoring, liner requirements, liner retrofits (Subtitle C only)	$50/kW; $15-$37.50/ton ash (based on NERC study)
Clean Power Plan	2020-2029 (interim goal); 2030 onwards (final goal)	No specific requirements; EPA assumes heat rate improvements. Likely to result in significant reductions in output from coal units.	Uncertain at this time	Unknown

*Subject to timing of final rule

Table ES-2: Compliance Requirements for Natural Gas Units

Regulation	Compliance Date	Compliance Requirements	Potential Compliance Actions	Potential Compliance Costs
Cross-State Air Pollution Rule	January 2015	Cap and trade program for NO_x and SO_2 emissions	Procure allowances to cover air emissions of NO_x and SO_2	\$0.10-\$2.75/MWh (based on ERCOT modeled allowance prices)
316(b) Cooling Water Intake Structures Rule	2018-2022, on each unit's permit renewal cycle	Requires controls for units with once-through cooling	Install or upgrade modified traveling screens and fish return systems	\$5-\$25/kW; \$0.10-\$0.50/MWh (based on EPA cost analysis and generator survey responses)
Clean Power Plan	2020-2029 (interim goal); 2030 onwards (final goal)	No specific requirements; EPA assumes increased utilization of combined cycle units	Uncertain at this time	Unknown

As shown in Table ES-1, coal units are the most affected by environmental regulations. Without considering the Clean Power Plan, 3,000 MW to 8,500 MW of coal-fired capacity in ERCOT can be considered to have a moderate to high risk of retirement – due primarily to the costs of EPA's proposed requirements for the Regional Haze program. The results of this analysis also suggest potential impacts from CSAPR in the short-term. By comparison, the other regulations are not expected to have a significant system-wide impact, but could affect the economics of a small number of units. The implementation and regulatory timeline of the Clean Power Plan will impact decisions resource owners make about whether to retrofit or retire impacted units. Additionally, the Clean Power Plan itself may cause unit retirements, due to the need to meet stringent CO_2 emissions limits on a state-wide basis. ERCOT's modeling analysis suggests that the Clean Power Plan, in combination with the other regulations, will result in the retirement of up to 8,700 MW of coal-fired capacity.

The results of this study indicate that the Regional Haze requirements and the Clean Power Plan will have significant impacts on the planning and operation of the ERCOT grid. Both are likely to result in the retirement of coal-fired capacity in the ERCOT region. Currently, resource owners are required to notify ERCOT no less than 90 days prior to the date that the unit is retired or mothballed. Given the competitiveness of the ERCOT market and the current uncertainty surrounding environmental regulations, it is unlikely that generators would notify ERCOT of potential retirements or unit suspensions before the minimum notification deadline. If ERCOT does not receive early notification of these retirements, and if multiple unit retirements occur within a short timeframe, there could be periods of reduced system-wide resource adequacy and localized transmission reliability issues due to the loss of generation resources in and around major urban centers. Additionally, loss of the reliability services provided by retiring units will strain ERCOT's ability to integrate new intermittent renewable generation resources. The need to maintain operational reliability (i.e., sufficient ramping capability) could require the curtailment of renewable generation resources. This would limit and/or delay the integration of renewable resources, leading to a delay in achieving compliance with the proposed Clean Power Plan limits.

The Clean Power Plan will also result in increased wholesale and consumer energy costs in the ERCOT region. Based on ERCOT's analysis, energy costs for consumers may increase by up to 20% in 2020, without accounting for the associated costs of transmission upgrades, higher natural gas prices caused by increased gas demand, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in the ERCOT region. Consideration of these factors would result in even higher energy costs for consumers. Though the other regulations considered in this study will pose costs to owners of generation resources, they are less likely to significantly impact costs for consumers.

Table of Contents

1. Introduction

This study assesses the potential impacts of several proposed and recently finalized U.S. Environmental Protection Agency (EPA) regulations on grid reliability in the Electric Reliability Council of Texas (ERCOT) region. The analysis considers the impacts of the Mercury and Air Toxics Standards (MATS), the Cross-State Air Pollution Rule (CSAPR), the Regional Haze program, the Cooling Water Intake Structures rule, the Steam Electric Effluent Limitation Guidelines (ELG) rule, the Coal Combustion Residuals (CCR) Disposal rule, and the Clean Power Plan.

ERCOT approaches this analysis from the perspective of an independent system operator in a competitive market that has achieved significant success in using competition to drive efficient outcomes. Existing market policies and investments in transmission in ERCOT have incentivized market participants to maximize the efficiency of the generating fleet and develop new technologies including renewable generation. With recent investments in transmission, more than 11 GW of wind capacity have been successfully integrated into the ERCOT grid. The ERCOT region maintains a forward-looking open market and provides affordable and reliable electricity to consumers in Texas.

ERCOT undertook two parallel efforts for this study. First, in the summer of 2014, ERCOT distributed a survey to fossil fuel-fired generators on the impacts of relevant environmental regulations. The responses indicate the current compliance status of fossil fuel-fired resources in the ERCOT region. Second, ERCOT conducted a modeling analysis of the impacts of CSAPR, the Regional Haze program, and the Clean Power Plan on generation resources and energy costs in the ERCOT region.

The report is organized as follows:

- **Section 1.1** provides an overview of the environmental regulations evaluated in this study;
- **Section 1.2** describes prior ERCOT analyses related to the potential impacts of environmental regulations;
- **Section 2** discusses the requirements and associated costs of environmental regulations for generation resources;
- **Section 3** presents the results of the generator survey;
- **Section 4** describes the methodology and results of ERCOT's modeling analysis;
- **Section 5** discusses the impacts of these regulations for grid reliability in the ERCOT region;
- **Section 6** presents a cost analysis of the relevant environmental regulations; and,
- **Section 7** provides a summary of the conclusions of this study.

1.1. Background on Environmental Regulations

There are several proposed and recently finalized environmental regulations that may impact generation resources in the ERCOT region. In the coming years, generators will need to make decisions about how to comply with these regulations in light of market trends in the power sector and other regulations on the horizon. The cumulative impact of market economics and environmental regulations could affect the economic viability of generation resources and result in capacity retirements. In addition, complying with these regulations in the near-term could lead to concurrent unit outages and increased seasonal mothballing of capacity. If these changes result in impacts to grid reliability and transmission constraints, and there is not sufficient time to mitigate these issues, there could be challenges to ERCOT's management of the grid.

This analysis considers the potential impacts of the MATS rule, CSAPR, the Regional Haze program, the 316(b) rule, the ELG rule, the coal ash disposal rule, and the Clean Power Plan. ERCOT elected to study these regulations because of their potential impacts for generation resources, and their anticipated compliance timeframes within the next several years. These regulations are summarized in Table 1, and discussed in further detail in Section 2.

Table 1: Environmental Regulations Impacting ERCOT Generation

Regulation	Compliance Date	Description	Impacts
Mercury and Air Toxics Standards	April 2015 (April 2016 with extension)	Sets limits on hazardous air pollutant emissions at power plants	Owners of coal units without sufficient controls will need to retrofit to comply
Cross-State Air Pollution Rule	January 2015	Addresses cross-state air pollution through limits on annual nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions, and ozone season (summer) NO_x emissions	Most fossil fuel-fired generators in ERCOT are subject to CSAPR; resource owners may need to purchase allowances to comply
Regional Haze	Three to five years after final Federal Plan issued*	Requires controls on air emissions to improve visibility in national parks	Owners of certain coal units are required to retrofit with scrubbers, or upgrade existing scrubbers
316(b) Cooling Water Intake Structures Rule	2018-2022, on each unit's permit renewal cycle	Requires controls to limit impacts to aquatic life at cooling water intake structures	Owners of units with once-through cooling systems may need to install or upgrade controls
Steam Electric Effluent Limitation Guidelines	Three years after publication of final rule*	Regulates toxic metal contaminants in water discharges	Owners of coal units may need to upgrade wastewater treatment processes, but most are anticipated to be compliant as currently operated
Coal Combustion Residuals Disposal Rule	Five years after publication of final rule*	Regulates disposal of coal ash in impoundments and landfills	Owners of coal units may be required to retrofit or close on-site coal ash impoundments
Clean Power Plan	2020-2029 (interim goal); 2030 onwards (final goal)	Sets carbon dioxide emissions limits for existing units	Rule has implications for most fossil-fuel fired generation in ERCOT, as well as for renewable energy and energy efficiency programs

*Subject to timing of final rule

Note that Table 1 is not a comprehensive list of environmental regulations with implications for generation in ERCOT. There are other pending environmental regulatory developments that could also impact generation resources in ERCOT that were not considered in this study. For example, EPA recently issued a proposal to tighten the National Ambient Air Quality Standard (NAAQS) for ozone. This would have implications for nonattainment areas in Texas, as well as future adjustments to cross-state air pollution regulations. Another example is the implementation of the 2010 NAAQS for SO_2. ERCOT continues to monitor these and other environmental regulatory developments closely to ascertain their impacts for grid reliability.

1.2. Prior ERCOT Studies of Environmental Regulations

ERCOT has previously studied the potential impacts of environmental regulations on generation resources in the ERCOT region to understand the potential impacts to grid reliability. The study methodology used in this report is generally consistent with these previous studies.

In June 2011, ERCOT studied the potential impacts of four proposed environmental regulations – 316(b), MATS, CSAPR, and the coal ash disposal rule.[1] The analysis evaluated the economic value of affected

[1] Electric Reliability Council of Texas, Inc. *Review of the Potential Impacts of Proposed Environmental Regulations on the ERCOT System*, June 2011. Available at http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf.

generating units based on likely compliance requirements and future market conditions. The study found that a significant amount of coal retirements would be unlikely, unless several factors, such as low natural gas prices and carbon emission fees, combine to significantly reduce the economic viability of coal generation. However, the study results indicated that a closed-loop cooling tower requirement under the 316(b) rule could result in the retirement of almost 10,000 MW of gas-fired generation, much of which is located in or near Dallas/Fort Worth and Houston. The study found that these retirements could result in localized transmission system impacts in these urban areas.

The potential retirements of gas units identified in the June 2011 study were driven by an assumption that the 316(b) rule would require cooling tower retrofits at existing units. However, the 316(b) final rule, issued in June 2014, did not impose this requirement. Instead, the final rule requires modified traveling screens with fish return systems – a more modest capital investment compared to cooling tower retrofits. The cost of retrofitting existing units with cooling towers is an order of magnitude higher compared to the requirements of the final rule. Based on the final rule provisions, ERCOT anticipates that the impacts of compliance with the 316(b) rule will be modest, as discussed in Section 2.4.

It was also assumed in the June 2011 study that Texas would only be included in the CSAPR program for ozone season NO_x emissions, based on the requirements of the proposed rule. However, the CSAPR final rule, published in July 2011, included Texas in the program for annual SO_2 and NO_x emissions as well. To address the change to the CSAPR program, ERCOT conducted a subsequent study in September 2011.[2] The CSAPR study estimated potential capacity reductions ranging from 3,000 to 6,000 MW during off-peak months, and 1,200 to 1,400 MW during peak months. In developing scenarios for evaluation, ERCOT considered known compliance plans of resource owners, the potential for increased unit maintenance outages due to repeated daily dispatch of traditionally base load coal units, and limited availability of low-sulfur coal imported into Texas from western states (i.e., Powder River Basin (PRB) coal).

Subsequent to the CSAPR study, the U.S. Court of Appeals stayed the rule in December 2011. In 2012, EPA made minor adjustments to the CSAPR program, including increasing the state budget for Texas and allowing more flexibility for compliance in the initial phase of the program. These changes could help mitigate the impacts found in the September 2011 study. Additionally, since 2011 ERCOT has seen the seasonal mothballing of almost 2,000 MW of coal capacity. This has been due primarily to lower wholesale power prices, and not environmental regulations. Even with these changes, the implementation of CSAPR in January 2015 is likely to have impacts for coal-fired capacity in ERCOT. Specifically, compliance with the SO_2 limits may impact the operations of coal units with weak controls, as discussed in Section 2.2.

In the summer of 2013, ERCOT conducted a survey on the impacts of the MATS rule for coal-fired generation. ERCOT did not publish these results, but the survey responses indicated that 6,500 MW of capacity had not yet determined a MATS compliance strategy at the time. This raised questions about whether a significant portion of ERCOT's coal-fired capacity would meet the April 2015 deadline for MATS compliance. The 2013 survey results have been updated based on responses to the survey in this study. As discussed in Section 3, the updated survey results show that owners of most coal-fired units in ERCOT have identified compliance strategies for MATS.

[2] Electric Reliability Council of Texas, Inc. *Impacts of the Cross-State Air Pollution Rule on the ERCOT System*, September 2011. Available at http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf.

2. Requirements and Costs of Environmental Regulations

Each regulation considered in this study has distinct compliance requirements that will affect generators in ERCOT. The costs associated with meeting these requirements vary, with some regulations posing more modest costs compared to others. Both individually and cumulatively, these costs will influence resource owners' decisions about whether to retrofit or retire units to comply with environmental regulations. The sections that follow discuss the specific compliance requirements and associated costs for each environmental regulation considered in this study.

2.1. Mercury and Air Toxics Standards

The MATS rule sets emissions limits for hazardous air pollutants emitted from power plants. The regulated pollutants include acid gases, toxic metals, and particulate matter. The rule will impact coal-fired generators in the ERCOT region. Owners of units without sufficient controls to meet the rule limits will need to install new control technologies to comply. Compliance options include scrubbers, activated carbon injection (ACI), dry sorbent injection (DSI), and use of PRB coal in the fuel mix. Generators have until April 2015 to comply, although resource owners may apply for one-year compliance extensions from the Texas Commission on Environmental Quality (TCEQ). There is also an option for an additional year (to April 2017) for reliability critical units. Table 2 summarizes the impacts of MATS for units in ERCOT.

Table 2: Mercury and Air Toxics Standards Impacts

Mercury and Air Toxics Standards	
Description	Sets limits on hazardous air pollutant emissions at power plants
Compliance date	April 2015 (April 2016 with extension)
Impacts for coal units	
Compliance requirements	Sets emissions limits for acid gases, toxic metals, and particulate matter
Potential compliance actions	Retrofit units with scrubbers, dry sorbent injection, activated carbon injection; use PRB coal in fuel mix
Potential compliance costs	\$10/kW capital cost \$0.75/MWh O&M cost
Impacts for natural gas units	
Compliance Requirements	None
Potential compliance actions	n/a
Potential compliance costs	n/a

Given the April 2015 compliance date for MATS, there is some risk for units that have not yet completed the necessary modifications. Further, for those units with compliance extensions, there is risk that the owners of these units may choose to retire rather than comply with MATS, especially in light of recent Regional Haze developments and eventual compliance with the Clean Power Plan. Given the timeframe for MATS compliance, this could present a risk to reliability if a significant number of units do not meet the MATS requirements over the next two years.

The costs of retrofitting units to comply with MATS will vary depending on the control technology selected. The most common option in the ERCOT region is the installation of DSI and/or ACI systems. The survey, discussed in Section 3, asked resource owners to report the capital and operations and maintenance (O&M) costs associated with outstanding unit modifications for MATS. Based on this information, ERCOT estimates an average capital cost for MATS compliance of approximately \$10/kW, and an average O&M cost of \$0.75/MWh. These costs are the averages of the information reported on the survey, and do not correspond to a specific retrofit technology.

2.2. Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) and its precursor, the Clean Air Interstate Rule (CAIR), focus on the impact of upwind states' emissions to downwind states' air pollution. Both rules set state-wide limits for annual SO_2, annual NO_x, and ozone season NO_x emissions. The CAIR limits have been enforced after a U.S. Court of Appeals decision stayed CSAPR in December 2011. However, in April 2014 the Supreme Court overturned this decision. In October 2014 the stay on CSAPR was lifted, and compliance with CSAPR will begin in January 2015. Table 3 summarizes the impacts of CSAPR for units in ERCOT.

Most fossil fuel-fired generators in ERCOT are subject to both CSAPR and CAIR. Under both programs, each unit is allocated a certain number of emissions allowances, and must either control emissions or purchase additional allowances if their allocations are not sufficient to cover their emissions for the year. The CSAPR limits are more stringent than the current requirements in the CAIR program.

Table 3: Cross-State Air Pollution Rule Impacts

Cross-State Air Pollution Rule	
Description	Regulates air emissions to address cross-state air pollution
Compliance date	January 2015
Impacts for coal units	
Compliance requirements	Cap and trade program for NO_x and SO_2 emissions
Potential compliance actions	Purchase allowances, upgrade controls, or reduce production
Potential compliance costs	$0.75-$7.25/MWh, based on ERCOT modeled allowance prices
Impacts for natural gas units	
Compliance Requirements	Cap and trade program for NO_x and SO_2 emissions
Potential compliance actions	Purchase allowances, upgrade controls, or reduce production
Potential compliance costs	$0.10-$2.75/MWh, based on ERCOT modeled allowance prices

Within the ERCOT region, compliance with the CSAPR SO_2 limits is likely to be difficult for coal-fired capacity. In ERCOT's modeling of CSAPR, discussed in Section 4, the CSAPR SO_2 limit was more difficult for the ERCOT system to meet than the annual and ozone season NO_x limits. Emissions of SO_2 are primarily a concern for coal-fired capacity because the combustion of natural gas emits very low amounts of SO_2. Owners of coal-fired capacity without tight SO_2 controls will likely need to purchase emissions allowances, install or improve unit controls, or reduce operations during non-peak seasons to stay within their allotted emissions allowances.

There is also some uncertainty regarding the availability of SO_2 emissions allowances for purchase by resource owners in Texas. Texas is part of the group 2 trading program for SO_2. The power sector in other group 2 states is primarily vertically integrated, which raises questions about the incentives for resource owners in those states to sell excess allowances.

As part of the modeling analysis in this study (see Section 4), ERCOT estimated an SO_2 emission price of $800/ton, an ozone season NO_x emission price of $1,600/ton, and an annual NO_x emission price of $1,000/ton. These emissions prices were derived based on modeling iterations, and do not correspond to actual emissions prices under the CSAPR program. However, based on these estimates and the emissions rates reported in the survey (see Section 3 and Appendix A), the potential CSAPR compliance costs for coal-fired generation resources can range from $0.75/MWh for a well-controlled unit to $7.25/MWh for an uncontrolled unit. Similarly, the costs for natural gas units could range from $0.10 to $2.75/MWh, depending on the type of generation technology and installed controls.

2.3. Regional Haze

The Regional Haze program regulates air emissions to improve visibility in national parks. The program requires states to develop State Implementation Plans (SIPs) that require the "best available retrofit technology" (BART) for facilities that contribute to haze in national parks. In November 2014, EPA proposed a Federal Implementation Plan (FIP) disapproving portions of the Texas SIP for regional haze, and setting SO_2 emissions limits for certain coal-fired units in Texas that contribute to air pollution in Big Bend and the Guadalupe Mountains in Texas, and the Wichita Mountains in Oklahoma. Table 4 summarizes the impacts of EPA's proposed Regional Haze FIP for units in the ERCOT region.

EPA's proposed FIP would require seven coal-fired units in Texas to upgrade their existing scrubbers, and seven units (five of which are located in ERCOT) to install new scrubber retrofits.[3] The owners of these units would have three years to complete scrubber upgrades and five years to complete scrubber retrofits, from the effective date of the final FIP rule. If EPA publishes the final rule as anticipated in 2015, then the scrubber upgrades and retrofits would be required by 2018 and 2020, respectively. By 2020, the power sector would also need to begin complying with the interim CO_2 emissions limits in the proposed Clean Power Plan.

Though EPA estimates that meeting these requirements is cost-effective on a $/ton SO_2 removed basis, they will likely pose a significant capital investment for these facilities. In a previous analysis, ERCOT estimated the cost to install scrubbers at $450/kW to $573/kW.[4] This does not include any associated increases to O&M costs. The affected resource owners will need to determine whether they will be able to recoup the costs of these scrubber upgrades and retrofits, or else retire or mothball the units. ERCOT anticipates that some of the affected resource owners may choose to retire or mothball their units, due to the current economics in the ERCOT market and pending compliance with other environmental regulations, particularly the Clean Power Plan. If a large portion of the affected capacity retires within the same timeframe, there could be implications for resource adequacy and grid reliability.

Table 4: Regional Haze Program Impacts

Regional Haze Program	
Description	Regulates air emissions to improve visibility in national parks
Compliance date	Three to five years after final FIP issued (i.e., 2018-2020)
Impacts for coal units	
Compliance requirements	Sets SO_2 emissions limits for 13 coal-fired units in the ERCOT region
Potential compliance actions	Install or upgrade scrubbers
Potential compliance costs	$450-$573/kW
Impacts for natural gas units	
Compliance Requirements	No incremental compliance requirements
Potential compliance actions	n/a
Potential compliance costs	n/a

2.4. Cooling Water Intake Structures

EPA's 316(b) Cooling Water Intake Structure rule requires controls to limit impacts to aquatic life at cooling water intake structures. Any generator that withdraws water from a "water of the U.S." for cooling purposes is subject to the rule provisions. Unlike most of the other rules considered by the survey, the 316(b) rule will have implications for both coal and natural gas units.[5] Generators will need to comply from 2018 through 2022 in accordance with their water permit renewal cycle. Table 5 summarizes the impacts of the 316(b) rule for units in ERCOT.

Owners of units with cooling towers or cooling ponds ("closed-loop" cooling) are unlikely to need to take significant action under the final rule provisions. Conversely, owners of units with once-through systems will likely need to install or upgrade modified traveling screens and fish return systems, or install alternative control technologies. Many already have some controls installed at their intakes; however,

[3] The units required to upgrade existing scrubbers are Limestone 1 and 2, Martin Lake 1, 2, and 3, Monticello 3, and Sandow 4. The units required to retrofit with new scrubbers are Big Brown 1 and 2, Monticello 1 and 2, Coleto Creek, and Tolk 172B and 171B. The two Tolk units are not located in the ERCOT Interconnection. The proposed FIP would also set an emission limit for San Miguel, but meeting the limit is not anticipated to require additional controls.

[4] Electric Reliability Council of Texas, Inc. *Review of the Potential Impacts of Proposed Environmental Regulations on the ERCOT System*, June 2011. Available at http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf.

[5] Nuclear generation resources also use cooling water and would be subject to the 316(b) rule if the cooling water is withdrawn from a "water of the U.S."

these controls may need to be upgraded to comply with the rule provisions. Because compliance is phased in over the permit cycle, it is unlikely that the compliance timeframe would result in concurrent unit outages.

As described in Section 1.2, a previous ERCOT study estimated that a closed-loop cooling tower requirement under the 316(b) rule could result in the retirement of almost 10 GW of gas-fired generation.[6] That study estimated the cost of retrofitting existing units with cooling towers at $200/kW. However, the 316(b) final rule did not include such a requirement. The costs of installing modified traveling screens and fish return systems are modest compared to the costs of retrofitting units with cooling towers. ERCOT estimates that the capital costs of the application of this technology at a fossil-fueled power plant generally range from $5-$25/kW, based on EPA's cost analysis of the rule[7] and information reported on the generator surveys, and consultation with Black & Veatch.[8] ERCOT estimates the corresponding O&M costs at $0.10-$0.50/MWh, based on EPA's cost analysis. These values represent an order of magnitude estimate and are intended only to provide an illustrative comparison to the costs of compliance with other regulations.

Table 5: 316(b) Rule Impacts

316(b) Cooling Water Intake Structures Rule	
Description	Requires controls to limit impacts to aquatic life at cooling water intake structures
Compliance date	2018-2022, on each unit's permit renewal cycle
Impacts for coal units	
Compliance requirements	Requires controls for units with once-through cooling
Potential compliance actions	Install or upgrade modified traveling screens and fish return systems
Potential compliance costs	$5-$25/kW capital cost $0.10-$0.50/MWh O&M cost
Impacts for natural gas units	
Compliance Requirements	Requires controls for units with once-through cooling
Potential compliance actions	Install or upgrade modified traveling screens and fish return systems
Potential compliance costs	$5-$25/kW capital cost $0.10-$0.50/MWh O&M cost

Based on the information available to ERCOT, there are two potential risks posed by the 316(b) rule. First, much of the capacity requiring modifications consists of older gas steam units operating at average annual capacity factors well below 10%. There is likely to be little opportunity for owners of these units to recoup the costs of complying with the 316(b) rule if significant capital investments are required. Although potential retirements would be phased over the 2018 to 2022 compliance period, the retirement of this much capacity over a short timeframe could impact grid reliability and transmission constraints. Second, in the final rule EPA gave permitting authorities discretion to require additional controls to address entrainment on a case-specific basis. To the extent that additional requirements are imposed in Texas, there could be implications for grid reliability, particularly during peak summer months.

2.5. Coal Ash Regulations

EPA has currently proposed two regulations pertaining to coal ash waste. The Steam Electric Effluent Limitation Guidelines (ELG) rule regulates toxic metal contaminants in water discharges, which result from contamination by coal ash and combustion control technology residues. The Coal Combustion Residuals (CCR) Disposal Rule proposes to regulate coal ash under the Resource Conservation and

[6] Electric Reliability Council of Texas, Inc. *Review of the Potential Impacts of Proposed Environmental Regulations on the ERCOT System*, June 2011. Available at http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf.
[7] U.S. EPA. *Economic Analysis for the Final Section 316(b) Existing Facilities Rule* and *Technical Development Document for the Final Section 316(b) Existing Facilities Rule*, May 2014. Available at http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/.
[8] The capital costs for a nuclear generation resource would likely be greater.

Recovery Act (RCRA). Table 7 and Table 6 summarize the impacts of the ELG rule and the coal ash disposal rule, respectively, for units in the ERCOT region.

EPA proposed the ELG rule in April 2013, and is under a court-ordered deadline to finalize the rule by September 2015. The rule would set limits on the concentrations of toxic metals in water discharges, which may require upgrades to wastewater treatment processes at some coal-fired units. However, it is anticipated that many units would be compliant with the rule provisions with their current controls, and therefore would not incur significant compliance costs. For those facilities requiring modifications, the costs of compliance will depend on the currently installed wastewater treatment controls and which regulatory option EPA selects in the final rule. Based on the information in EPA's cost analysis of the proposed rule, ERCOT estimated compliance capital costs at \$10-\$60/kW, and O&M costs at \$0.40-\$1.40/MWh. These values represent an order of magnitude estimate and are intended only to provide an illustrative comparison to the costs of compliance with other regulations.

Table 7: ELG Rule Impacts

Effluent Limitation Guidelines Rule	
Description	Regulates toxic metal contaminants in water discharges
Compliance date	Three years after publication of final rule (i.e., 2018)
Impacts for coal units	
Compliance requirements	Sets limits for toxic metal concentrations in wastewater
Potential compliance actions	Upgrade wastewater treatment processes to meet limits
Potential compliance costs	\$10-\$60/kW capital cost \$0.40-\$1.40/MWh O&M cost
Impacts for natural gas units	
Compliance Requirements	None
Potential compliance actions	n/a
Potential compliance costs	n/a

The coal ash disposal rule proposes to regulate coal ash under RCRA as a Subtitle C special waste or as a Subtitle D non-hazardous waste. Listing under either Subtitle C or Subtitle D would require groundwater monitoring and place liner requirements on future disposal in impoundments and landfills; a more stringent Subtitle C listing would also require liner retrofits on existing coal ash impoundments. Though the rule contains provisions for both coal ash landfills and impoundments, the rule would primarily affect coal-fired generators with on-site coal ash impoundments, since these would be required to retrofit with liners or close under a Subtitle C listing. In 2011, NERC estimated the costs of compliance with the ash disposal rule at \$30 million per unit, plus incremental disposal costs of \$15-37.50/ton, depending on whether EPA regulates coal ash waste under Subtitle C or Subtitle D.[9] Based on the capacities of potentially impacted units in ERCOT, the \$30 million capital cost translates to an average of \$50/kW.

Table 6: Coal Ash Disposal Rule Impacts

Coal Combustion Residuals Disposal Rule	
Description	Regulates disposal of coal ash in impoundments and landfills
Compliance date	Five years after publication of final rule (i.e., 2019)
Impacts for coal units	
Compliance requirements	Requirements for future and existing (Subtitle C only) disposal
Potential compliance actions	Groundwater monitoring, liner requirements, liner retrofits (Subtitle C only)
Potential compliance costs	\$50/kW capital cost \$15-\$37.50/ton ash O&M cost
Impacts for natural gas units	
Compliance Requirements	None
Potential compliance actions	n/a
Potential compliance costs	n/a

[9] North American Electric Reliability Corporation. *Potential Impacts of Future Environmental Regulations*, November 2011. Available at http://www.nerc.com/files/epa%20section.pdf.

2.6. Clean Power Plan

In June 2014, the EPA proposed the Clean Power Plan, which calls for reductions in the carbon intensity of the electric sector. The Clean Power Plan would set limits on the carbon dioxide (CO_2) emissions from existing fossil fuel-fired power plants, calculated as state emissions rate goals. For Texas, EPA has proposed an interim goal of 853 lb CO_2/MWh to be met on average during 2020 to 2029, and a final goal of 791 lb CO_2/MWh to be met from 2030 onward. EPA calculated the state-specific goals using a set of assumptions, referred to as "building blocks," about coal plant efficiency improvements, increased production from natural gas combined cycle units, growth in renewables generation, preservation of existing nuclear generation, and growth in energy efficiency.

Table 8: Clean Power Plan Impacts

Clean Power Plan	
Description	Sets carbon dioxide limits for existing units
Compliance date	2020-2029 (interim goal); 2030 (final goal)
Impacts for coal units	
Compliance requirements	No specific requirements; EPA assumes heat rate improvements. Likely to result in significant reductions in output from coal units.
Potential compliance actions	Uncertain at this time
Potential compliance costs	Unknown
Impacts for natural gas units	
Compliance Requirements	No specific requirements; EPA assumes increased utilization of combined cycle units
Potential compliance actions	Uncertain at this time
Potential compliance costs	Unknown

Currently, there is uncertainty as to the form compliance with the Clean Power Plan will take in Texas. For this reason, it is not possible to identify unit-specific compliance actions and associated costs at this time. ERCOT studied the potential system-level impacts of compliance with the Clean Power Plan through a modeling analysis, discussed in Section 4. Additionally, it is important to consider that resource owners will be making decisions about whether to retrofit their units to comply with other environmental regulations in light of eventual compliance with the Clean Power Plan.

3. Generator Environmental Survey

To address the risks associated with environmental regulations, ERCOT developed a survey for fossil fuel-fired generation resource owners to gather information about potential unit-specific compliance strategies. The survey results provide information about the prospective compliance impacts to generation capacity in the ERCOT region in the coming years.

3.1. Survey Methodology

ERCOT administered the survey during July-August 2014. The survey was sent to all coal and natural gas-fired generation resource owners in ERCOT, including some owners of private use network (PUN) generation.[10] The survey asked questions about unit emissions rates, installed control equipment,

[10] ERCOT distributed the environmental surveys to a limited number of PUN generators, based on the amount of generation provided to the grid on an annual basis in 2013.

planned unit modifications, and prospective compliance strategies for MATS, CSAPR, 316(b), and the coal ash regulations.[11]

ERCOT received survey responses from owners of 368 fossil fuel-fired units supplying power to the ERCOT grid, comprising 69,300 MW of capacity. This included 32 coal units, 198 natural gas combined cycle units, 46 natural gas steam units, 84 natural gas combustion turbine (simple cycle) units, and 8 other units. Figure 1 and Table 9 summarize the surveyed capacity by fuel type.

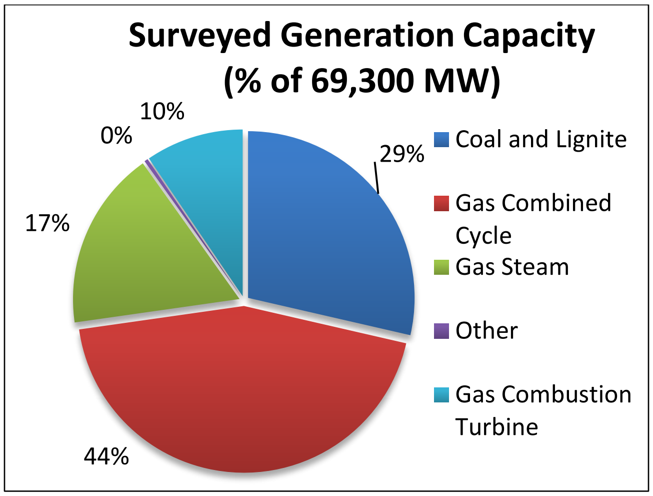

Figure 1: Surveyed Generation Capacity

Table 9: Surveyed Generation Capacity

Generation Type	# Units	Capacity (MW)	% of Surveyed Capacity
Coal and Lignite	32	19,800	29%
Natural Gas Combined Cycle	198	30,600	44%
Natural Gas Steam	46	12,050	17%
Natural Gas Combustion Turbine	84	6,600	10%
Other	8	250	0%
Total	**368**	**69,300**	**100%**

Once the completed surveys were received from resource owners, ERCOT analyzed and aggregated the survey responses. ERCOT followed up with a select number of resource owners for clarification on their responses.

3.2. Survey Results

The survey began with questions about plans for unit retirements, suspended operations, and planned modifications to comply with environmental regulations. No resource owners responded with plans for retirements or suspended operations, except for the previously announced plan to mothball the J.T. Deely 1 and 2 units. However, there is currently a great amount of uncertainty with regard to the compliance requirements of environmental regulations due to pending litigation and the current status of some of these regulations as proposed rules, which may change before they are finalized by EPA. Additionally, resource owners are only required to provide a 90-day notice that a unit will be retired or mothballed. Given the competitiveness of the ERCOT market and the current uncertainty surrounding environmental regulations, it is unlikely that generators would notify ERCOT of potential retirements or unit suspensions before the minimum notification deadline.

Next, the survey asked resource owners to report currently installed control technologies and average NO_x, SO_2, and CO_2 emission rates. These responses help identify potential compliance risks associated with the pending implementation of CSAPR, the Regional Haze program, and CO_2 regulations. Additional information on these responses is provided in Appendix A.

[11] This survey was developed and distributed prior to the U.S. Court of Appeals ruling granting EPA's motion to lift the stay on CSAPR, and EPA's issuance of a Federal Implementation Plan (FIP) for the Regional Haze program for Texas. These developments may change the compliance plans reported by resource owners on the survey.

The remainder of the survey asked resource owners to provide information about their prospective compliance status and planned compliance strategies for several environmental regulations. As noted previously, the reported compliance information is likely to change as compliance requirements become more certain. Even so, the survey results indicate that:

- Owners of most coal-fired units in ERCOT have identified compliance strategies for MATS. The most common compliance strategies reported were the installation of ACI or DSI systems. Though 21 units (14,500 MW) are anticipated to be compliant by the April 2015 deadline, 12 of these units (8,500 MW) have not yet completed the necessary modifications. The remaining 11 surveyed coal units (5,300 MW) have been granted compliance extensions to April 2016 by the TCEQ, or plan to apply for extensions.
- 72% of surveyed natural gas capacity anticipates compliance with the CSAPR limits. However, over half of surveyed coal capacity indicated uncertainty or needing to take some action to comply with the CSAPR limits.[12]
- 161 coal and natural gas-fired units in ERCOT (46,800 MW) are subject to the 316(b) rule, but most (118 units, or 32,600 MW) anticipate that they are already compliant with the rule. The remaining 43 units (14,200 MW) may require modifications to comply.
- 22 coal-fired units (14,200 MW) would be compliant with the ELG rule as proposed. The owners of the remaining 10 surveyed coal units (5,600 MW) may need to take some action to comply with the rule.
- 23 coal units (13,000 MW) in ERCOT have coal ash impoundments on-site, all of which would require compliance actions should EPA move forward with a Subtitle C listing of coal ash. With a Subtitle D listing, the owners of 7 units with impoundments (3,000 MW) reported that they anticipated being compliant as currently configured and operated. The remaining coal units with impoundments would require compliance actions.

ERCOT used these survey responses to inform modeling assumptions, and to determine the cumulative impacts of these regulations on ERCOT units, discussed in Section 5.1.

4. Modeling Analysis

While the environmental survey responses help identify vulnerabilities and risks to individual units resulting from a range of environmental regulations, this study also aimed to project how CSAPR, Regional Haze, and the Clean Power Plan may impact the resource mix and operations in the ERCOT region on the system level. To do so, ERCOT conducted a modeling analysis using stakeholder-vetted planning processes and methodologies consistent with ERCOT's regional Long-Term System Assessment studies. ERCOT developed several scenarios for modeling based on known or likely regulatory developments at the time of the study. The results of the modeling raise several potential reliability issues that will need to be addressed in ERCOT as environmental regulations, particularly the Clean Power Plan, are implemented. While ERCOT analyzed several potential future scenarios, this analysis was not meant to be a comprehensive study of all regulatory impacts and potential compliance pathways. Moreover, ERCOT does not take a position on whether the compliance methods modeled, such as a carbon price or emissions fee, are legally permissible under current law. The sections that follow describe the modeling methodology, summarize the results from the modeling analysis, and compare these results to EPA's analysis of the Clean Power Plan.

[12] This survey was completed prior to the U.S. Court of Appeals decision to grant EPA's motion to lift the stay on CSAPR in October 2014, and the EPA's subsequent issuing of an interim final rule in November 2014 that establishes January 2015 as the start of compliance.

4.1. Modeling Methodology

This study used Energy Exemplar's PLEXOS Integrated Energy Model to estimate changes to electric generation in ERCOT given a set of assumptions about future market trends and the implementation of environmental regulations. ERCOT modeled several distinct scenarios that considered different ways to implement the emissions limits, in comparison to a baseline. The modeling approach draws on stakeholder-vetted assumptions used in ERCOT's Long-Term System Assessment, with additional assumptions specific to this analysis that reflect the environmental regulations studied. The load forecast is based on ERCOT's neural network models that combine weather, demographic, and economic variables to project long-term trends.

The PLEXOS Integrated Energy Model uses mixed integer programming to model the power sector. In this study, ERCOT used the long-term modeling capability in PLEXOS to get an estimate of unit retirements and capacity additions over the 2015 to 2029 timeframe. The long-term expansion is based on economics, and does not consider reliability or operational challenges. Then, ERCOT used PLEXOS's short term modeling capability to mimic chronological hourly unit commitment and economic dispatch for the years 2020 and 2029. ERCOT elected to use the PLEXOS model for this study because it can simulate both real-world market operations and long term capacity expansion planning using either emission constrained or emission price scenarios.

4.1.1. Modeled Scenarios

In approaching this modeling analysis, ERCOT developed a set of scenarios that reflect the potential range of system impacts under likely regulatory outcomes and in light of ongoing trends in the electric sector. To do so, ERCOT focused on those environmental regulations most likely to have system-level impacts in ERCOT, rather than those with more limited or unit-specific implications. Though the 316(b), MATS, and coal ash regulations may cumulatively impact individual resource owners' decisions on whether to retire or mothball units, the impacts of these individual regulations are unlikely to impact overall trends on the ERCOT system as they are not expected to affect the economics of a significant number of units. For this reason, ERCOT focused its modeling efforts on the impacts of CSAPR, Regional Haze and the Clean Power Plan, as these regulations have the greatest potential to shift generation trends in ERCOT.

ERCOT evaluated CSAPR and the proposed Clean Power Plan using two methodologies. First, ERCOT considered scenarios with the emissions limits in these rules applied as a constraint, to allow the long-term simulation model to select the most cost-effective way to achieve compliance from electric generating resources. Second, emissions fees were used to cause the system to achieve the proposed standards. The benefit of the first approach is that it would be expected to minimize the overall cost to the system, and should lead to results that are comparable to the methodology utilized by the EPA in its analysis of the impacts of the Clean Power Plan. However, it may not be a change that is achievable within the current electricity market design in ERCOT.[13] For this reason, ERCOT also modeled emissions fee scenarios. The CSAPR rule uses such an emissions trading scheme to achieve compliance with the limits. Though a carbon price is not an explicit component of the Clean Power Plan proposal, it is often discussed as an option for complying with the limits, and is included here in order to assess the system impacts of a potential approach to compliance. By modeling the carbon price option, ERCOT does not take any position about the policy merits or legal permissibility of such a compliance approach. With

[13] Electric supply is deregulated in the ERCOT region at the wholesale and retail level. As a result, electric generation and construction of new capacity is driven by market forces. As a result, there is no mechanism to force the ERCOT system to achieve compliance with environmental regulations in a specific manner. Resource owners will make decisions about how to operate existing resources and whether to add new capacity based on market forces.

regards to the Regional Haze program, ERCOT modeled the requirements in EPA's proposed FIP as additional costs for impacted generators.

ERCOT modeled six distinct scenarios over the timeframe 2015 to 2029 to evaluate the impacts of CSAPR, Regional Haze, and the Clean Power Plan in the ERCOT region. Table 10 summarizes the assumptions of the six scenarios. The first scenario estimated a baseline of the ERCOT system under current market trends against which anticipated CSAPR and Clean Power Plan changes could be compared. Then, ERCOT modeled five scenarios to simulate the potential impacts of CSAPR, Regional Haze, and the Clean Power Plan. CSAPR and the Clean Power Plan are imposed as system constraints in scenarios 2, 3, and 4; and as emissions prices in scenarios 5 and 6. Scenario 3 also includes the requirements of EPA's proposed Regional Haze FIP for Texas.

Table 10: Scenarios Modeled in Analysis

	Environmental Regulations Included in Scenario			Emissions Limits Modeled As Limit or Emissions Price	
Scenario*	**CSAPR**	**Regional Haze**	**CPP**	**Limit**	**Price**
1. Baseline	No	No	No	No	No
2. CSAPR Limits	Yes	No	No	Yes	No
3. CSAPR Limits and Regional Haze	Yes	Yes	No	Yes	No
4. CSAPR and CO_2 Limits	Yes	No	Yes	Yes	No
5. CSAPR Prices and \$20/ton CO_2 Price	Yes	No	Yes	No	Yes
6. CSAPR Prices and \$25/ton CO_2 Price	Yes	No	Yes	No	Yes

*Note: In the summary report of this analysis published on November 17, 2014, scenarios 4 through 6 were labeled as "CO_2 Limit", "\$20/ton CO_2", and "25/ton CO_2", respectively. Scenarios 2 and 3 were not included in the summary report

4.1.2. ERCOT Long-Term Modeling Assumptions

This study uses stakeholder-vetted assumptions consistent with ERCOT's Long Term System Assessment (LTSA).[14] Specifically, the baseline scenario in this study is based on the Current Trends scenario from the 2014 LTSA, and the subsequent scenarios were layered on top of the baseline scenario assumptions. The LTSA Current Trends scenario assumes that current policies and regulations will remain in place and that no new policies will be introduced. Table 11 summarizes the model input assumptions used in the LTSA Current Trends scenario.

These assumptions include the anticipated expiration of the Production Tax Credit (PTC) and phase out of the Investment Tax Credit (ITC). The PTC expiration assumption is particularly significant because it influences the amount of wind capacity additions predicted by the model.

[14] For more information, visit ERCOT's Regional Planning Group (RPG) website at http://www.ercot.com/committees/other/rpg/index.html.

ERCOT did not require the system to maintain a specific reserve margin in the LTSA Current Trends scenario, or in the scenarios modeled in this analysis. The target reserve margin criterion in ERCOT is not binding and it is possible that market conditions will result in a lower reserve margin than the recommended level. By contrast, EPA's modeling of the impacts of the Clean Power Plan, described in Section 4.3, required that ERCOT maintain a 13.75% reserve margin. This difference in assumptions results in different amounts of capacity additions, and has implications for grid reliability.

Table 11: LTSA Model Input Assumptions

Model Input	Assumption
Natural gas price	Average of EIA AEO 2014 and Wood MacKenzie forecast
Coal price	Average of EIA AEO 2014, EIA AEO 2012, and SNL price forecast
Wind production profiles	Based on county-specific hourly production profiles provided by AWS Truepower
Solar production profiles	Based on county-specific hourly production profiles provided by URS
Unit Retirements	Based on economics
Capacity additions	Based on economics
New Capacity Capital Costs	Taken from EIA AEO 2014 and escalated at 2.4% per year; solar capital costs assumed to decrease over time
Production Tax Credit (PTC)	Expired as per current law
Investment Tax Credit (ITC)	Phased out as per current law
Load growth	Peak increases at an average of 1.25% per year and energy increases at an average 1.68% per year
LNG Exports	Assumes inclusion of Freeport LNG Project
Demand response and energy efficiency	Assumed current penetration levels
Reserve margin	Not imposed as a system requirement
Environmental Regulations	Did not impose any constraints on emissions

4.1.3. Modeling Assumptions Specific to this Study

Though the baseline scenario in this analysis is derived from the LTSA Current Trends scenario, ERCOT modified several of the assumptions to incorporate updated information or better reflect the modeled environmental regulations. First, ERCOT assumed lower solar capital costs compared to those used in the LTSA Current Trends scenario. After review of information provided by stakeholders and updated reports by the National Renewable Energy Laboratory (NREL) and Lazard, it is clear that solar capital costs continue to decline at a rapid rate. To be more in line with these lower costs, solar capital costs were lowered in the near-term years of this study to reflect this trend. ERCOT estimated solar capital costs based on a review of information provided by Lazard,[15] Solar Energy Industries Association,[16] and Citi Research.[17] All solar capacity additions are assumed to be utility-scale photovoltaic with single-axis tracking. Figure 2 displays the solar capital costs used by ERCOT in this analysis.

[15] Lazard. *Lazard's Levelized Cost of Energy Analysis – Version 8.0*, September 2014. Available at http://www.lazard.com/pdf/levelized%20cost%20of%20energy%20-%20version%208.0.pdf.
[16] Greentech Media, Inc and Solar Industries Association. *U.S. Solar Market Insight Report.* Q1 2014. Confidential Report.
[17] Citi Research. *Launching on the Global Power Sector: The Sun Will Shine but Look Further Downstream.* February 6, 2013. Confidential Report.

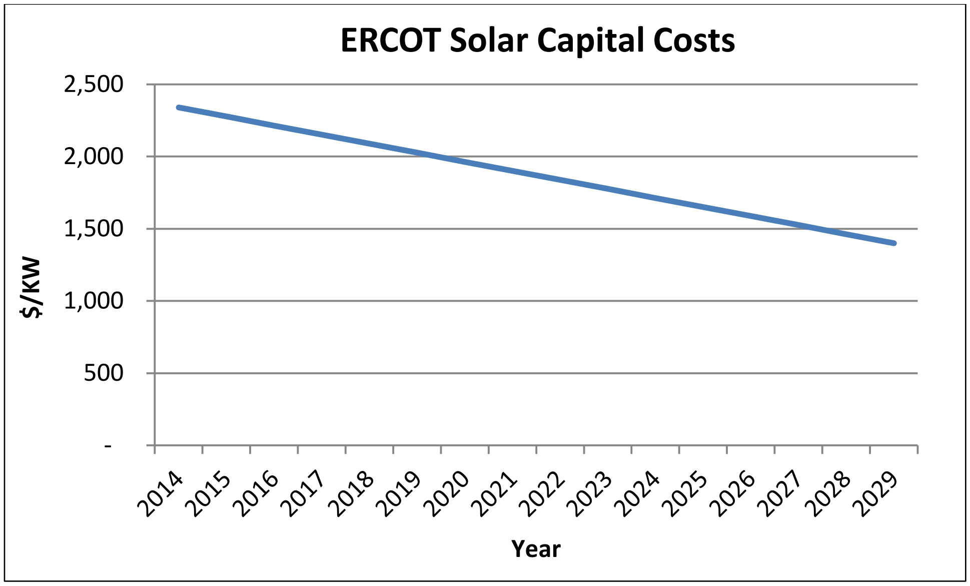

Figure 2: ERCOT Solar Capital Costs

As in the LTSA, natural gas price projections are based on an average of the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2014 forecast and the forecast from Wood Mackenzie, shown in Figure 3. The same natural gas price assumptions were applied in all scenarios.

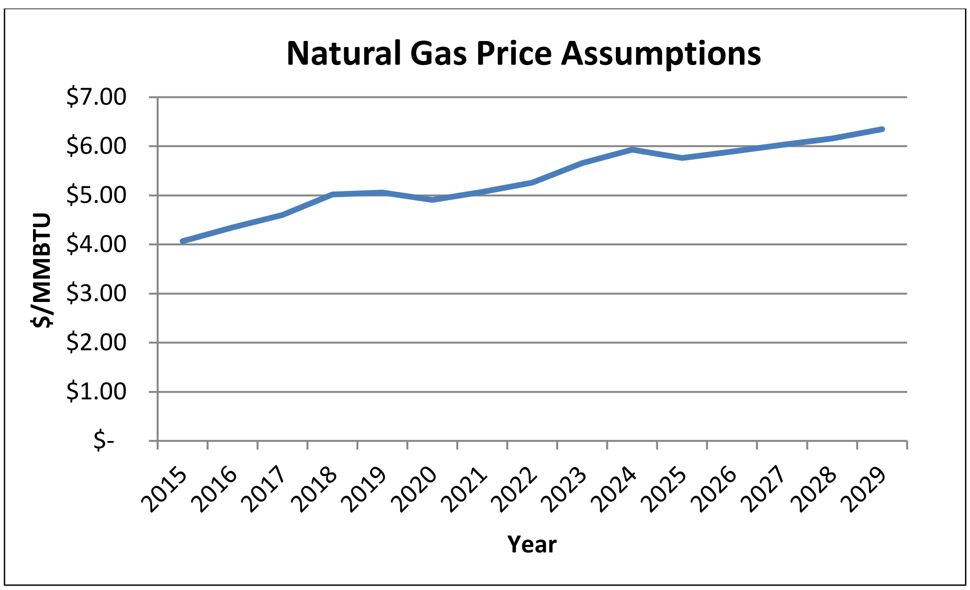

Figure 3: Natural Gas Price Assumptions

There is inherent uncertainty in forecasts of future trends, and changes to the capital cost and fuel price assumptions would likely impact the results of this analysis. For example, a lower solar capital cost would result in more, and possibly earlier, solar capacity additions compared to those found in this study. Along the same lines, a higher price of natural gas could result in higher compliance costs if environmental regulations result in a shift from coal to natural gas capacity.

With regard to the generation fleet, ERCOT modeled the capacity listed in ERCOT's May 2014 Capacity, Demand, and Reserves (CDR) report,[18] with the addition of planned generation resources that had started construction by Summer 2014, as well as the full capacity of PUNs.[19] Table 12 shows the baseline capacity assumptions used in the modeling. Generation from wind and solar resources was modeled based on the same wind and solar production profiles used in the LTSA. These profiles estimate the amount of wind and solar resources available for every hour of the year, based on the 2010 weather year.

ERCOT developed assumptions in order to apply the CSAPR, Regional Haze, and Clean Power Plan requirements to the ERCOT system. In the CSAPR program, states are assigned mass-based limits on how much SO_2 and NO_x they can emit. ERCOT scaled the limits for Texas based on the relative amount of load served by ERCOT within Texas to derive ERCOT-specific limits. Conversely, the Clean Power Plan limits are set as an emissions rate (lb/MWh). ERCOT evaluated the limits in the Clean Power Plan by applying the proposed emissions rate limits for Texas (in lb/MWh) directly to the ERCOT system. ERCOT applied the CO_2 limit only to those units that would be subject to the Clean Power Plan based on the provisions in EPA's proposal.

Table 12: Baseline Capacity Assumptions

Fuel Type	Capacity (MW)
Nuclear	5,200
Coal	19,900
Natural Gas	58,900
Wind	16,700
Solar	250
Hydro	500
Other	1,000
Total	**102,450**

In the price scenarios, ERCOT assumed an SO_2 emission price of \$800/ton, an ozone season NO_x emission price of \$1,600/ton, and an annual NO_x emission price of \$1,000/ton. ERCOT estimated these prices based on a series of model iterations as part of this study. ERCOT did not attempt to calculate a carbon price to precisely meet the emissions limits. Instead, ERCOT modeled a carbon price range within which the system is anticipated to achieve the Clean Power Plan emissions standards.

To model the Regional Haze requirements, ERCOT added the costs of complying with the Regional Haze requirements to units' fixed costs – for those units with requirements for scrubber upgrades or retrofits in EPA's proposed FIP. The analysis uses the same capital costs for scrubber upgrades and scrubber retrofits, due to data limitations.

Due to data availability limitations, ERCOT was only able to model through 2029 in this analysis. In the CSAPR and CO_2 limit scenario, to approximate compliance with the final goal in the Clean Power Plan, ERCOT applied the final CO_2 limit as a constraint over 2028 to 2029, and the interim CO_2 limit over 2020 to 2027. In this scenario, the ERCOT Interconnection was required to meet the interim CO_2 limit every year between 2020 and 2027 and the final CO_2 limit in 2028 and 2029.

Because this study focused on the ability of the ERCOT fleet to meet emissions limits requirements, it was important to develop a more robust emissions rate profile than the generic emissions factors typically used in ERCOT's long-term studies. To do so, ERCOT used unit-specific emissions data from EPA's Air Markets Program Data website.[20] ERCOT calculated unit-specific average monthly emissions rates based on data reported over the past three years. In some cases, the data was adjusted to account for data availability issues, changes to system configurations, and to remove major outliers. A subset of the data was compared to the emissions rates reported in the generator environmental surveys to

[18] ERCOT's *Report on the Capacity, Demand, and Reserves in the ERCOT Region* is available at http://www.ercot.com/gridinfo/resource/index.html.
[19] In addition to PUN capacity, ERCOT also separately modeled PUN load.
[20] For more information, visit http://ampd.epa.gov/ampd/

validate the calculated emissions rates. For units for which this information was not available, ERCOT developed an average emissions profile by generation technology type based on the available data.

Finally, in the baseline and CSAPR limit scenario ERCOT assumed energy efficiency savings at 1% of load for all modeled years, consistent with current levels of energy efficiency as measured by the Electric Utility Marketing Managers of Texas (EUMMOT).[21] For the scenarios with the Clean Power Plan, ERCOT assumed growth in energy efficiency savings to a level of 5% by 2029. By contrast, EPA's building blocks assumed Texas could achieve a cumulative 9.91% savings from energy efficiency by 2029. ERCOT did not use the energy efficiency savings level estimated by EPA because ERCOT believes that a 5% savings level represents a moderate energy efficiency growth assumption, between the current level of savings and EPA's goal. ERCOT's more moderate assumption is also consistent with the approach taken by the Mid-Continent Independent System Operator (MISO) in its analysis of the impacts of the Clean Power Plan.[22] MISO modeled three energy efficiency assumptions: base energy efficiency trends, EPA's Building Block 4, and 50% of EPA's Building Block 4. ERCOT's approach of using 5% is consistent with the third assumption modeled by MISO.

4.1.4. Load Forecast Development

The load forecasts used in this analysis were produced using a set of neural networks to capture and project the long-term trends extracted from historical load data. The long-term trend in monthly energy was modeled separately for each of the eight weather zones in ERCOT. The models incorporated economic, demographic, and weather data to develop the monthly energy forecast.

After the calculation of the monthly energy forecast, the development of the hourly load forecast required the allocation of that monthly energy to each hour in the month. A total of 864 neural network models were developed to produce hourly energy allocations for the twelve months. ERCOT validated the models by back-casting the hourly load allocations against several years of historical hourly load. Model validation was conducted by using historical monthly energy in the modeling networks to back-cast the hourly loads for each day in the historical load database.

A key input of both energy models is the forecasted weather. A normal (typical) weather hourly profile is used in both models. Normal weather means what is expected on a 50% probability basis; i.e., that the forecast for the monthly energy or peak demand has a 50% probability of being under or over the actual energy or peak. This is also known as the 50/50 forecast.

ERCOT's analysis included 12 years of weather data (2002 to 2013). The methodology that ERCOT selected to create the "normal" weather year is commonly referred to as the Rank and Sort methodology. A forecast is created using each of the 12 years of historical weather data. The resultant hourly forecast is ordered from the largest value to the smallest value. The normal weather forecast is then determined by calculating the average of each ordered hourly value.

Another key input of both energy models is the forecast of the number of premises in each customer class. Premises are classified as residential, business (small commercial), or industrial. A weather normalized use per premise is also included in the model.

Premises forecasts are developed using various economic variables such as non-farm employment, housing stock, and population. The current condition of the United States economy and its future direction is an element of great uncertainty. Texas thus far has not been affected to the same extent as the United States as a whole by the current economic downturn. This has led to Texas having stronger

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[21] EUMMOT's *Energy Efficiency Accomplishments Report* is available at http://www.texasefficiency.com/index.php/publications/reports.

[22] MISO. *GHG Regulation Impact Analysis*, July 30, 2014. Available at https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20140730/20140730%20PAC%20Item%2012a%20GHG%20Regulation%20Impact%20Analysis.pdf.

economic growth than most of the nation. Since May of 2010, there has been reasonably close agreement between actual non-farm employment in Texas and Moody's base economic forecast. Given this trend, ERCOT used the Moody's base economic forecast of non-farm employment in these forecasts.

Figure 4 shows the ERCOT load forecast used in this analysis. Detailed documentation of ERCOT's Long-Term Load Forecast is available at http://www.ercot.com/gridinfo/load/forecast/index.html.

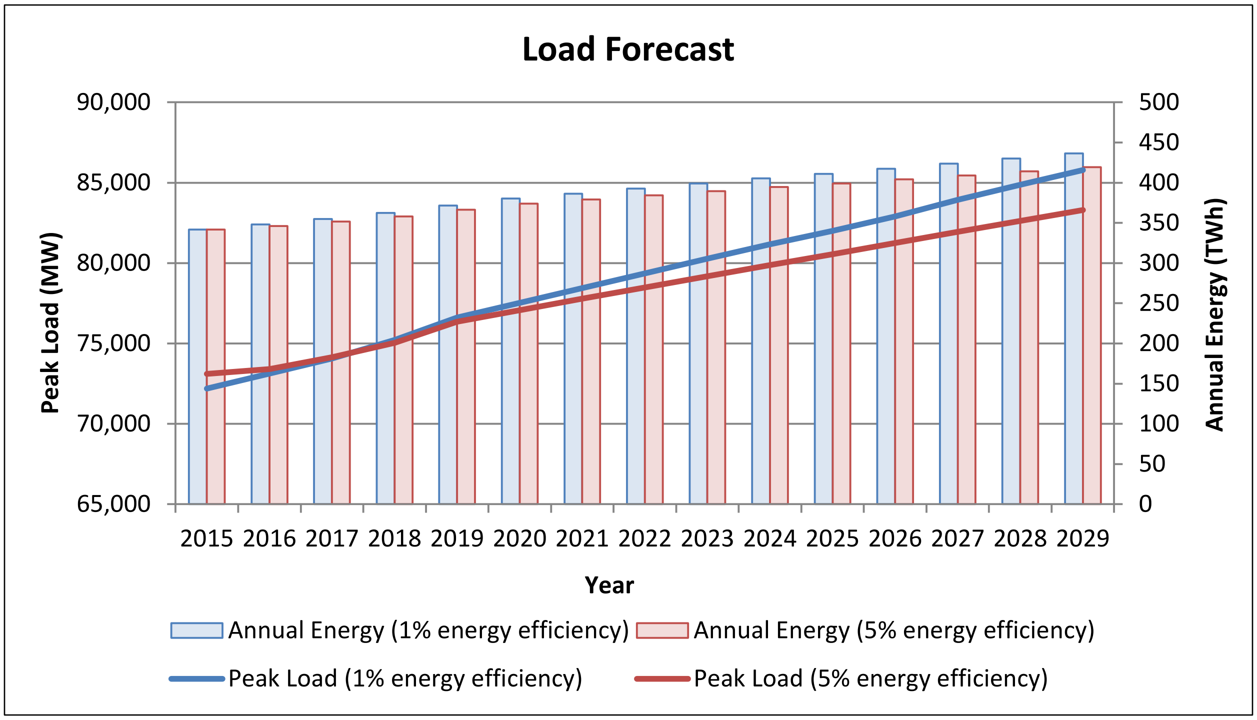

Figure 4: Load Forecast

4.2. Modeling Results

The six modeled scenarios resulted in different amounts of unit retirements and capacity additions, shifts in the generation mix, and different levels of air emissions due to the different ways the emissions limits were applied to the system. Overall, the scenario that included the CSAPR limit was very similar to the baseline, but with a slight shift away from coal toward natural gas. This shift occurs because the SO_2 limit is the binding constraint for the CSAPR limit scenario – in other words, the SO_2 limit is more difficult for the ERCOT system to meet. SO_2 emissions are much higher from coal units, so meeting the SO_2 limit will have more of an impact on coal capacity compared to natural gas. Meeting the Regional Haze requirements results in the retirement of coal-fired units, which are replaced primarily by natural gas combustion turbines. However, these requirements facilitate compliance with CSAPR – in the scenario that includes Regional Haze, none of the CSAPR limits are binding on the system. When the Clean Power Plan is added to the scenarios, the CO_2 limit becomes the binding constraint, resulting in an even larger shift away from coal toward natural gas, and an increased amount of renewable generation on the system. The emissions price scenarios result in similar trends, but represent an alternative mechanism for achieving compliance with the limits.

The modeling results predict 2,800 MW of unit retirements in the baseline, including 2,000 MW of gas steam retirements and 800 MW of coal unit retirements. The 800 MW of coal retirements in the baseline corresponds to the announced mothballing of CPS Energy's J. T. Deely units 1 and 2 in 2018. The natural gas retirements in the baseline are due to economics. There are a similar number of total retirements in the CSAPR limit scenario, but the retirements shift from natural gas steam to coal units. This is due to the impact of the CSAPR emissions limits, which makes natural gas-fired generation more economic compared to coal-fired generation. The addition of Regional Haze requirements results in almost 2,000 MW of additional coal unit retirements relative to the CSAPR limit scenario, or 3,000 MW relative to the baseline. Retirements increase further in the scenarios that include the Clean Power Plan, with 3,300 MW to 5,700 MW of incremental coal unit retirements compared to the baseline. Again, the lower amount of gas steam retirements compared to the baseline is due to the impacts of both the CSAPR and CO_2 limits. Table 13 summarizes cumulative unit retirements in 2029 by scenario.

Table 13: Unit Retirements by 2029

Generation Technology Type	Baseline	CSAPR Limit	CSAPR Limit and Regional Haze	CSAPR and CO_2 Limit	CSAPR and CO_2 \$20/ton	CSAPR and CO_2 \$25/ton
Retired Gas Steam (MW)	2,000	1,000	1,400	1,600	1,600	1,300
Retired Coal (MW)	800	2,000	3,900	4,100	4,100	6,500
Total Retirements (MW)	**2,800**	**3,000**	**5,300**	**5,700**	**5,700**	**7,800**

The model built new capacity to replace retiring units and meet forecasted demand. The baseline and CSAPR limit scenario saw 9,900 MW of new solar capacity and 4,600 MW of natural gas combustion turbines.[23] To adjust for increased coal unit retirements in the CSAPR limit and Regional Haze scenario, the model built an additional 1,800 MW of natural gas combustion turbines and an additional 100 MW of solar. As noted previously, ERCOT assumed the expiration of the PTC as per current law; this assumption resulted in no wind capacity additions in the first three scenarios. In the scenarios with the Clean Power Plan, retiring coal and gas steam capacity is replaced by solar, wind, and natural gas-fired capacity, as well as savings from energy efficiency measures. Compared to the baseline, the scenarios with the Clean Power Plan resulted in an additional 5,500 to 7,100 MW of renewable capacity additions, and fewer natural gas-fired capacity additions. Table 14 summarizes the cumulative capacity additions in 2029 for each scenario.

Table 14: Capacity Additions by 2029

Generation Technology Type	Baseline	CSAPR Limit	CSAPR Limit and Regional Haze	CSAPR and CO_2 Limit	CSAPR and CO_2 \$20/ton	CSAPR and CO_2 \$25/ton
Wind (MW)	0	0	0	3,400	2,800	3,500
Solar (MW)	9,900	9,900	10,000	12,500	12,600	13,500
Gas Combined Cycle (MW)	0	0	0	0	0	1,300
Gas Combustion Turbine (MW)	4,600	4,600	6,400	1,000	1,000	1,000
Total (MW)	**14,500**	**14,500**	**16,400**	**16,900**	**16,400**	**19,300**

By 2029 there are significant renewable and natural gas capacity additions replacing retiring coal and gas steam capacity, as shown in Figure 5. However, in the scenarios with the Clean Power Plan, there are

[23] The solar capacity additions modeled in this study are consistent with the results of ERCOT's 2013 Long-Term Transmission Analysis, which indicated that large amounts of solar would be economic in ERCOT after 2020. For more information, visit ERCOT's Long-Term Study Task Force website at http://www.ercot.com/committees/other/lts/index.html.

some years for which the ERCOT capacity reserve margin may be considerably less than historically targeted for reliability, as capacity retires before new resources come online and energy savings from energy efficiency measures begin to materialize. These shortages occur towards the beginning of the compliance timeframe, between 2020 and 2022. During this timeframe, the modeled retirements and capacity additions result in a reserve margin 2% to 3% below the reserve margin in the baseline scenario for these years in the CO_2 limit and \$20/ton CO_2 scenarios.[24] By 2029, the reserve margin in these scenarios is comparable to the baseline scenario. The reserve margins are generally higher in the \$25/ton CO_2 scenario, because the increased price on CO_2 results in increased capacity additions. Reserve margins in the CSAPR limit and CSAPR limit and Regional Haze scenario are comparable to the baseline scenario throughout the modeled time period. As previously noted, ERCOT did not require the simulation model to maintain a specific reserve margin in the modeled scenarios because the reserve margin in ERCOT is a target, not a mandate.

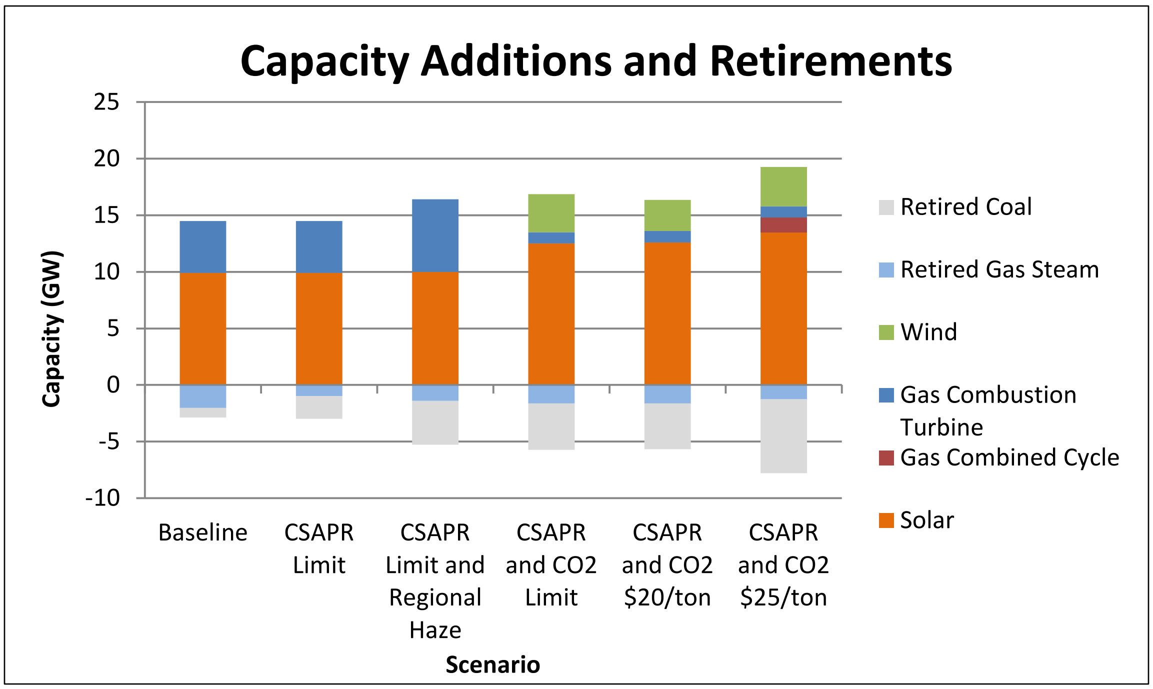

Figure 5: Capacity Additions and Retirements by 2029

Compliance with environmental regulations results in changes to the generation mix in the ERCOT region. Table 15 and Table 16 show the generation mix in 2020 and 2029, respectively, across the modeled scenarios. Under the CSAPR limits, generation from natural gas increases by about 3% in 2020 relative to the baseline, and generation from coal correspondingly decreases by 3%. This is due to the need to comply with the SO_2 limit in the CSAPR program, which affects coal-fired generation more than natural gas. The addition of Regional Haze continues this trend, with generation from natural gas increasing by 4% in 2020 relative to the baseline, and coal generation decreasing by 4%. Generation from renewables is comparable to the baseline in the CSAPR limit and CSAPR limit and Regional Haze scenarios. In the scenarios with the Clean Power Plan, there is a much larger shift away from coal and towards natural gas and renewable generation resources. In 2020, natural gas-fired units contribute 60%

[24] The ERCOT reserve margin is calculated using wind capacity contribution values of 12% for non-coastal resources and 56% for coastal resources, consistent with the ERCOT Board approved methodology outlined in Nodal Protocol Revision Request (NPRR) 611. The data used to calculate the wind capacity contribution is available on the ERCOT website at http://www.ercot.com/gridinfo/resource/index.html. For solar capacity, ERCOT assumes a 70% capacity contribution based on the modeled solar output during peak hours (16:00 to 18:00) as a percentage of total installed capacity.

or more of total energy in these scenarios, an increase of 16% to 19% compared to the baseline. There is a corresponding decrease in generation from coal-fired capacity. By 2029, renewable generation accounts for 21% to 22% of total generation in these scenarios, up from 17% of total 2029 generation in the baseline scenario.

Table 15: Generation Mix in 2020 (% of MWh)

Fuel Type	Baseline	CSAPR Limit	CSAPR Limit and Regional Haze	CSAPR and CO_2 Limit	CSAPR and CO_2 \$20/ton	CSAPR and CO_2 \$25/ton
Natural Gas (%)	44	47	48	60	60	63
Coal (%)	32	30	29	14	14	11
Wind (%)	12	12	12	15	15	16
Solar (%)	< 1	< 1	< 1	< 1	< 1	< 1
Nuclear (%)	10	10	10	10	10	10
Other (%)	1	1	1	< 1	< 1	< 1

Table 16: Generation Mix in 2029 (% of MWh)

Fuel Type	Baseline	CSAPR Limit	CSAPR Limit and Regional Haze	CSAPR and CO_2 Limit	CSAPR and CO_2 \$20/ton	CSAPR and CO_2 \$25/ton
Natural Gas (%)	45	47	49	53	53	55
Coal (%)	29	26	24	16	16	13
Wind (%)	11	11	11	14	14	14
Solar (%)	6	6	6	7	7	8
Nuclear (%)	9	9	9	9	9	9
Other (%)	< 1	< 1	< 1	< 1	< 1	< 1

The modeling results indicate that there will be increased amounts of generation from natural gas-fired resources under the emissions limits, which will increase the consumption of natural gas by the power sector. Compliance with the CSAPR limit alone and the CSAPR limit and Regional Haze result in a 6% increase in annual consumption of natural gas by the power sector in 2020 compared to the baseline, as shown in Figure 6. Again, the impact is larger with the inclusion of the Clean Power Plan, resulting in an increase in natural gas annual consumption of 35% to 50% relative to the baseline. The increase in consumption during peak months increases by 8% to 10% across the scenarios in 2020. This suggests that there is the potential to increase production from the ERCOT natural gas fleet annually, but less so during the peak summer months.

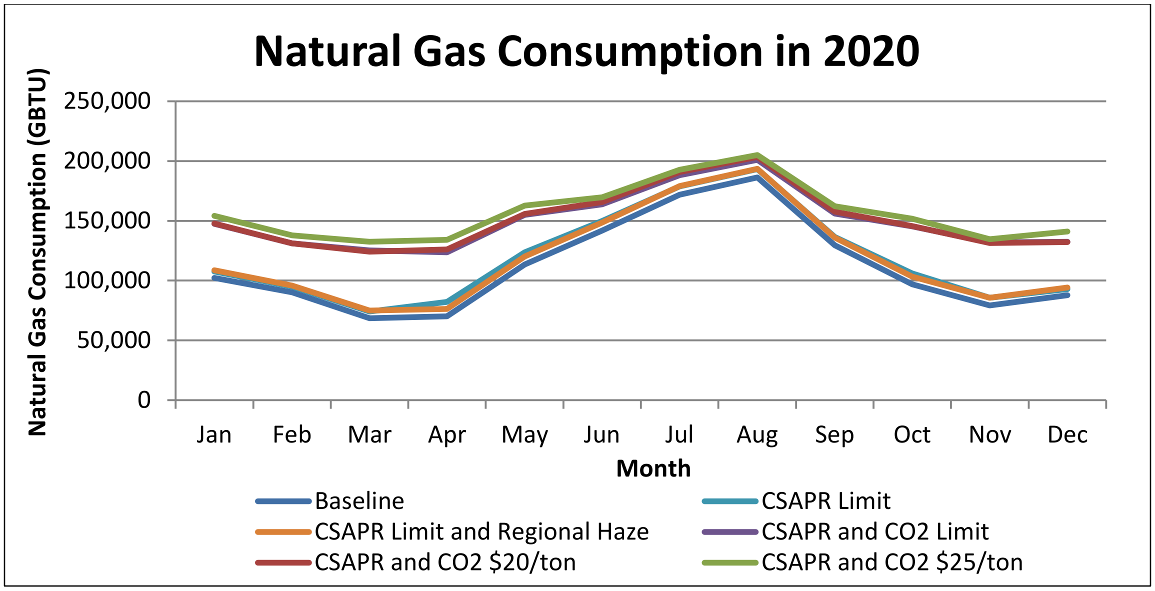

Figure 6: Natural Gas Consumption in 2020

The five scenarios resulted in different levels of carbon intensity. The $20/ton CO_2 scenario resulted in a carbon intensity above both the interim and final emissions limits in the Clean Power Plan, while the $25/ton CO_2 scenario resulted in a carbon intensity below the interim goal and approximately meeting the final goal (see Table 17 and Figure 7). In the baseline scenario, the ERCOT region's carbon intensity is at 1,175 lb/MWh in 2020 and 1,089 lb/MWh in 2029. The projected emissions intensity for ERCOT in the baseline is below the Clean Power Plan emissions rate goals for 19 other states, an indication of the impact that existing market policies and investments in transmission in Texas have had on maximizing the efficiency of the generating fleet and the integration of new technologies including renewable generation.

Table 17: Carbon Dioxide Emissions Intensity

CO_2 Intensity	Baseline	CSAPR Limit	CSAPR Limit and Regional Haze	CSAPR and CO_2 Limit	CSAPR and CO_2 $20/ton*	CSAPR and CO_2 $25/ton
2020 CO_2 Intensity (lb/MWh)	1,175	1,145	1,123	853	905	840
2029 CO_2 Intensity (lb/MWh)	1,089	1,061	1,041	791	857	792

*The 2020 emissions intensity for this scenario has changed slightly from the value included in the summary report due to a calculation error.

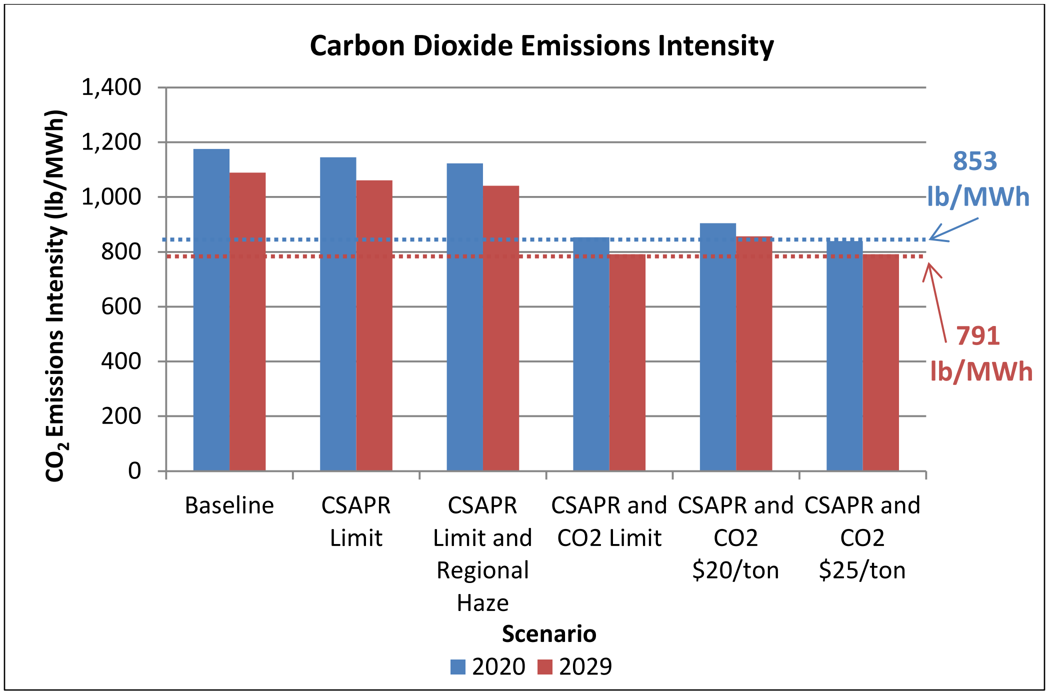

Figure 7: CO_2 Emissions Intensity

4.3. Comparison to EPA's Clean Power Plan Analysis

EPA conducted a modeling analysis of the Clean Power Plan. In the modeling, EPA applied the carbon limits to the U.S. electric system, and allowed their simulation model to solve for the most cost-effective solution. The analysis modeled compliance scenarios, relative to a baseline, that assumed compliance at the state-level and regional-level.[25] Because compliance options are less flexible under a state-level approach, and because the opportunity for Texas to participate in a regional plan is at this point uncertain, the results from the state-only compliance scenario are referenced below. Though EPA provided modeling results to the year 2050, the text below only summarizes modeling results for 2018 to 2030, since this timeframe more closely aligns with the timeframe for the implementation of the Clean Power Plan, and to ERCOT's modeling analysis.

Within the ERCOT region, EPA's modeling predicts that there may be 9 GW of coal unit retirements due to the Clean Power Plan, with most of the retirements occurring prior to the 2020 interim goal compliance date. While the modeling predicted up to 6 GW of coal unit retirements, ERCOT believes that there could be up to 9 GW of coal unit retirements resulting from the Clean Power Plan due to additional factors not considered in the model (discussed in Section 5.1.2). Similarly, both EPA's and ERCOT's modeling predicted a major shift in the generation mix in 2020 to comply with the interim goal, with substantially increased production from natural gas generation resources and substantially decreased production from coal generation resources. However, EPA's modeling resulted in much fewer renewable capacity additions compared to ERCOT's results and significantly more new natural gas generating capacity. The lower amount of renewable capacity additions is due to EPA's use of higher capital cost assumptions for new solar capacity. The larger amount of natural gas capacity additions is due in part to EPA's modeling requirement that ERCOT maintain a 13.75% reserve margin. EPA's

[25] In EPA's regional compliance scenario, ERCOT was grouped with Southwest Power Pool (SPP) into the "South Central" region, which encompasses the states of Nebraska, Kansas, Oklahoma, Arkansas, Louisiana, and Texas.

modeling predicts more than 10 GW of new natural gas capacity by 2030 in the state compliance scenario, whereas ERCOT's carbon scenarios added 1 to 2 GW of new natural gas capacity.

5. Discussion

Both the survey results and modeling analysis indicate that the environmental regulations evaluated in this assessment are likely to result in retirements of a significant amount of existing generation capacity. The Clean Power Plan will also require significant amounts of generation from renewable sources to meet the proposed CO_2 limits. Both unit retirements and new renewable generation could impact the ERCOT transmission system.

5.1. Impact of Unit Retirements

Resource owners in ERCOT, particularly owners of coal units, will need to take actions to comply with several environmental regulations in the coming years. With the implementation of the Clean Power Plan to consider, resource owners may choose to retire units rather than install the required control technology retrofits to comply with other environmental regulations. Because most of these regulations have compliance dates in the 2016 to 2022 timeframe, there is the potential for a significant number of unit retirements within a relatively short period of time, even without considering the impacts of the Clean Power Plan. If ERCOT does not receive early notification of these retirements, and if multiple unit retirements occur within a short timeframe, there could be implications for reliability.

The accelerated retirement or suspended operations of coal resources would pose challenges to maintaining the reliability of the ERCOT grid. Coal resources provide essential reliability services, including reactive power and voltage support, inertial support, frequency response, and ramping capability. The retirement of coal resources will require studies to determine if there are any resulting reliability issues, including whether there are voltage/reactive power control issues that can only be mitigated by those resources; how to replace frequency response, inertial support, and ramping capability provided by retiring units; and the necessity of potential transmission upgrades, which will be discussed later in this document.

The modeling results indicate that generation from retiring coal capacity will in large part be replaced by increased production from existing natural gas capacity. Compared to the rest of the country, Texas has a robust natural gas infrastructure and is not currently affected by natural gas supply issues. However, the increased use of natural gas nationally could lead to increased market dislocations, such those as seen in the winter of 2013-2014, as well as overall increasing prices and price volatility due to higher gas demand. Depending on the magnitude of these issues, there could be implications for maintaining reliable natural gas supply in the ERCOT region for electric generation in the future.

5.1.1. Unit Retirements without the Clean Power Plan

There are a range of environmental regulations for which resource owners will need to determine compliance strategies in the coming years. Some regulations pose more modest costs and will have limited impacts to generators, while other regulations pose much greater costs. For units facing poor economics in the current market, even modest compliance costs could result in decisions by resource owners to retire units. For others, the cumulative costs of compliance with several regulations may affect resource owners' decisions about whether and how to retrofit their units. Because many of these regulations have compliance dates in the 2016 to 2022 timeframe, there is the potential for a significant number of unit retirements within a relatively short period of time.

The survey responses allow ERCOT to determine the amount of capacity at risk from each regulation at the present time. Figure 8 shows the amount of capacity affected by each of the regulations included on the survey. A unit was counted as affected by each regulation if:

- it has not yet completed necessary modifications for the MATS rule;
- scrubber retrofits or upgrades are required at the unit in EPA's proposed FIP for Regional Haze;
- it is a coal unit without tight SO_2 controls, or a natural gas unit without NO_x controls, and could be affected by CSAPR;
- it reported that it would not be compliant with the 316(b) rule as currently operated; and,
- it reported that actions would be necessary to comply with the ELG or coal ash disposal rule.

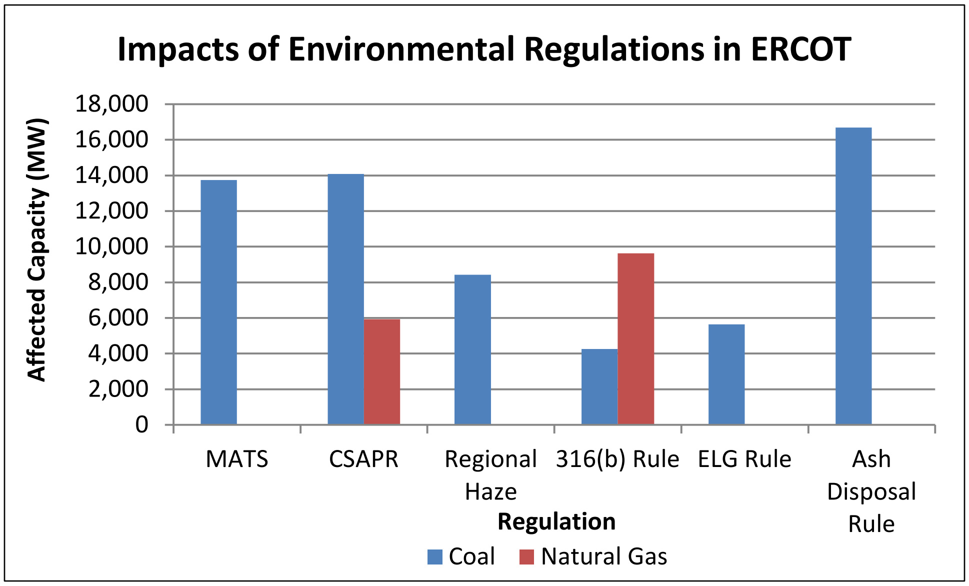

Figure 8: Impacts of Environmental Regulations in ERCOT

As can be seen in Figure 8, coal units are the most affected by environmental regulations. Table 18 shows the cumulative regulatory requirements for surveyed coal capacity based on the combination of applicable regulations for each unit.

Table 18: Cumulative Regulatory Requirements for Coal Units

# of Regulations Significantly* Affecting Unit	# Units	Capacity (MW)	# Units Significantly* Affected by Regulation					
			MATS	CSAPR	Regional Haze	316(b) Rule	ELG Rule	Coal Ash
One regulation	7	5,100	1					6
Two regulations	0	0						
Three regulations	8	3,900	5	8	2	1	2	6
Four regulations	14	8,900	14	11	9	3	5	14
Five or six regulations	3	1,900	3	3	1	3	3	3
Total	**32**	**19,800**	**23**	**22**	**12**	**7**	**10**	**29**

*Regulations were counted if compliance requires or would require unit retrofits or if it has the potential to pose significant costs. This does not include potential impacts of the Clean Power Plan

The costs of complying with these environmental regulations vary in their magnitude. Compliance costs include capital costs for the installation of new controls, as well as variable costs for incremental operations and maintenance activities – including the cost to purchase emissions allowances. Section 2 discussed the potential costs of complying with each environmental regulation considered in this study. The largest capital cost investment will be required to comply with the provisions of the Regional Haze FIP. This cost is an order of magnitude larger than the capital costs associated with other environmental regulations, as shown in Figure 9. Note that these regulations will also pose additional O&M costs, including the price of purchasing emissions allowances under CSAPR. Though not included in Figure 9, increases to generators' O&M costs would also be considered when making decisions to retrofit or retire units.

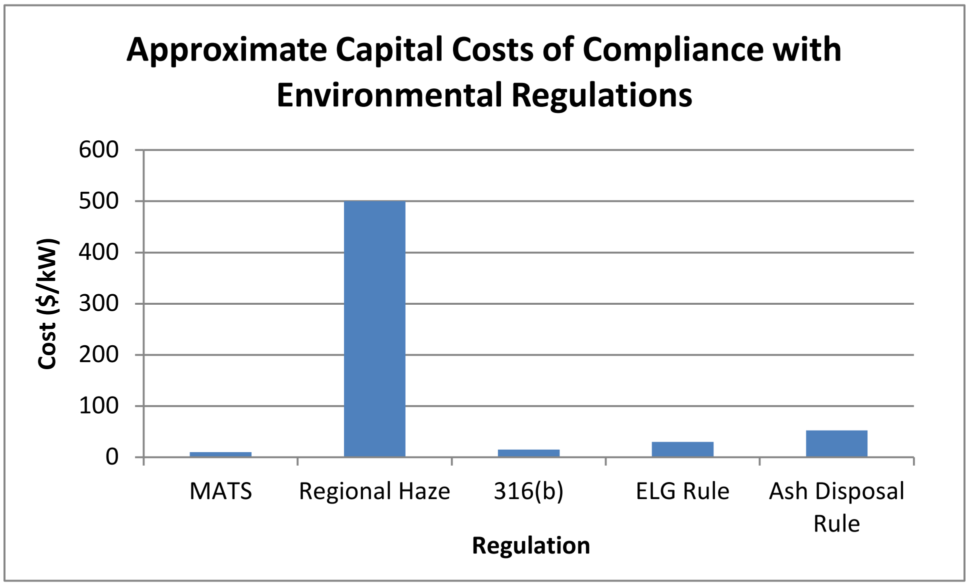

Figure 9: Approximate Capital Costs of Compliance with Environmental Regulations

Combining the information in Table 18 and Figure 9 can provide a rough estimate of the compliance costs faced by coal units in the ERCOT region. Figure 10 shows the cumulative capital compliance costs for coal units. This does not include additional variable costs, or the impacts of the Clean Power Plan.

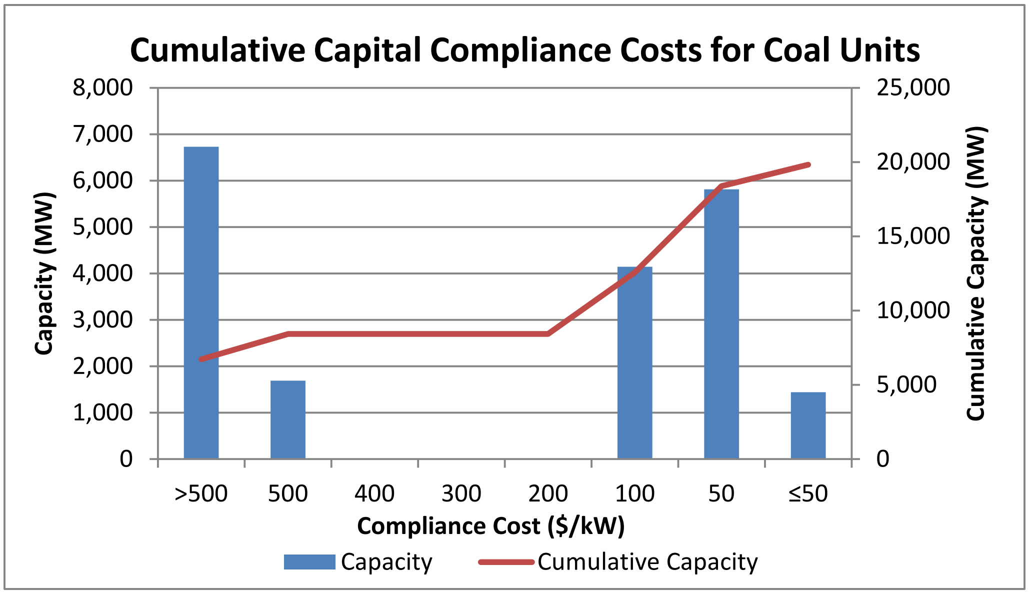

Figure 10: Cumulative Capital Compliance Costs for Coal Units

Based on the information in Figure 10, approximately 8,500 MW of coal-fired capacity in the ERCOT region face cumulative retrofit requirements of $500/kW or more. Given the magnitude of these costs, it is likely that some of the impacted units will be retired. The bulk of the costs for these units come from the Regional Haze requirements. However, this analysis uses the same capital costs for scrubber upgrades and scrubber retrofits, due to data limitations. The costs faced by units required to upgrade existing scrubbers are likely lower compared to the cost of a scrubber retrofit. Therefore, these units (comprising approximately 5,500 MW of capacity) can be considered to face a more moderate risk of retirement compared to units requiring scrubber retrofits (comprising approximately 3,000 MW of capacity), which face a higher risk.

Additionally, Figure 10 does not include the costs of purchasing emissions allowances under CSAPR, which could range from $0.75 to $7.25/MWh, based on ERCOT's modeled emissions prices and depending on the fuel mix and installed controls. Units with weak or no controls would have costs at the upper end of this range. To meet the CSAPR limits in 2015, resource owners may install additional controls, purchase allowances, or mothball affected units on a seasonal basis. Though recent market trends have impacted production from coal generation in the ERCOT region, compliance with CSAPR may have an impact on the economics of certain units. Many of the units facing higher compliance costs for CSAPR would also be affected by the Regional Haze requirements.

ERCOT's modeling analysis assessed the combined impacts of CSAPR and Regional Haze on generation resources. The results predicted 1,200 MW of coal-fired capacity retirements due to CSAPR, and 1,800 MW due to the Regional Haze requirements. This indicates that the combined impact of CSAPR and Regional Haze in ERCOT, as estimated by the model, is 3,000 MW of coal retirements. However, these results likely represent a lower bound on the number of potential coal unit retirements due to the logic used to retire units in the model, generic unit cost information, and the impacts of other environmental regulations. Most notably, the model is not requiring a market rate of return for unit upgrades, but rather a less restrictive positive net present value. Additionally, the modeling does not reflect operational constraints that will impact the ability of resource owners to extract value from their units. For example, increased cycling of coal units would likely result in increased unit outages that would impact the economics of these units. Given these operational constraints, it is likely that there may be additional coal capacity in the ERCOT region that would also retire due to Regional Haze.

Compared to Regional Haze and CSAPR, the other environmental regulations are expected to affect the economics of at most a small number of units and thus are not expected to have a significant system-wide impact. Coal and natural gas units facing compliance with these other regulations thus have a relatively low risk of retirement. Even so, it is possible that resource owners of units facing poor economics may choose to retire rather than retrofit impacted units. For example, owners of older gas steam units with lower capacity factors may choose to retire the units rather than install controls for the 316(b) rule if significant capital investments are required.

5.1.2. Unit Retirements with the Clean Power Plan

The Clean Power Plan is likely to result in coal unit retirements, due to the need to meet stringent CO_2 emissions limits on a state-wide basis. However, the Clean Power Plan will also impact decisions resource owners make about investments to comply with the other environmental regulations, several of which have compliance deadlines in the 2016 to 2022 timeframe. This raises the potential for a significant number of unit retirements within a relatively short period of time.

As noted in Section 5.1.1, 3,000 to 8,500 MW of coal capacity faces a moderate to high risk of retirement due to the Regional Haze requirements. It is likely that some amount of this capacity would retire, even without considering the impacts of the Clean Power Plan. However, in the context of eventual compliance with CO_2 regulations, retrofitting coal units facing significant compliance requirements becomes less economic. Resource owners may be reticent to make significant capital investments, especially for coal units that are not already relatively well-controlled.

ERCOT's modeling results predicted between 3,300 and 5,700 MW of coal unit retirements incremental to the baseline in the scenarios with CSAPR and the Clean Power Plan. As discussed in Section 5.1.1, ERCOT believes that the modeled retirements represent a lower bound on the number of potential coal unit retirements. ERCOT directed the model to retire capacity at the point when generic operating and fixed costs exceed revenues. However, in the modeling results for the scenarios with the Clean Power Plan, there are several units operating at low revenues and/or low capacity factors that would likely be retired, especially when other non-modeled factors are taken into account. Based on a review of capacity factors and operating revenues for the remaining coal units, ERCOT anticipates the retirement of an additional 2,000 MW of coal capacity and the seasonal mothball of 1,000 MW of coal capacity beyond what is specified in the model output, compared to the CSAPR and $25/ton CO_2 modeled scenario. These results indicate the overall impact of CSAPR, Regional Haze, the Clean Power Plan, and other environmental regulations to the current coal fleet will be the retirement or seasonal mothballing of between 3,300 MW and 8,700 MW of capacity.

The model also predicted the retirement of 1,300 to 1,600 MW of natural gas steam capacity in the Clean Power Plan scenarios, which is less than the 2,000 MW retired in the baseline scenario. The fewer retirements of natural gas steam units in the carbon scenarios reflects the impact of both the CSAPR and carbon dioxide limits on production from coal units, which improves the economics of natural gas steam units during this period. However, as with coal resources, there are a number of factors that may result in additional natural gas steam unit retirements compared to those found by the model. ERCOT estimates that an additional 1,500 to 4,500 MW of natural gas steam capacity may be at risk of retirement based on low net revenues in the model results combined with the need to comply with the 316(b) rule, CSAPR, and other environmental regulations.

5.2. Impact of Renewables Integration

Integrating new wind and solar resources will increase the challenges of reliably operating the ERCOT grid. In 2013, almost 10% of the ERCOT region's annual generation came from wind resources. To accommodate this level of intermittent generation, ERCOT has needed to evaluate impacts on operational reliability and improve wind output forecasting capabilities. The increased penetration of intermittent renewable generation, as projected by the modeling results, will increase the challenges of reliably operating all generation resources. If there is not sufficient ramping capability and operational reserves during periods of high renewable penetration, the need to maintain operational reliability could require the curtailment of renewable generation resources. This would reduce production from renewable resources, leading to possible non-compliance with the proposed rule deadlines.

Based on the CSAPR and \$25/ton CO_2 scenario, intermittent renewable generation sources will contribute 22% of energy on an annual basis in 2029. However, during 628 hours of the year intermittent generation will serve more than 40%[26] of system load. During 128 hours, instantaneous renewable penetration will be higher than 50%, and the peak instantaneous renewable penetration from the model results is 61%. The significant change from present experience is that the highest renewable penetration hours will be driven by maximum solar production during relatively high wind periods. These periods occur during the day (8 a.m. to 5 p.m.), as opposed to early morning hours (usually 2 to 4 a.m.), as currently experienced in the ERCOT region. The high instantaneous renewable penetration hours in 2029 occur year round except for the July-September period. Figure 11 shows generation output by fuel type for the days with the highest instantaneous penetration of renewables in 2029 in the \$25/ton CO_2 scenario.

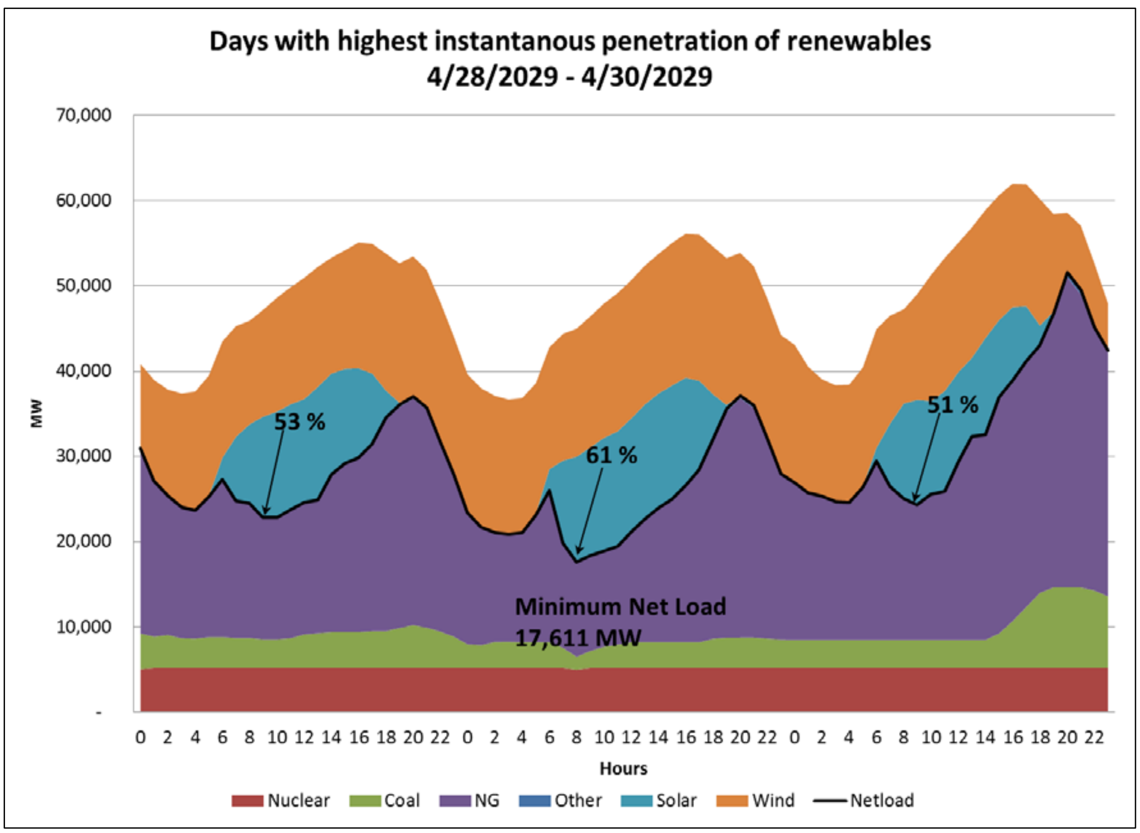

Figure 11: Days with Highest Instantaneous Penetration of Renewables

[26] The record in the ERCOT region for wind penetration occurred on March 31, 2014 at 2:00 a.m., when wind resources met 39.44% of load.

Due to load growth, the lowest net load (defined as total load minus generation from intermittent energy resources) in 2029 is higher than the current record (14,809 MW in 2014 and 17,611 MW in 2029). Therefore, during low net load hours there will be no significant change compared to current operating conditions in terms of MW of thermal generation online, inertial response and frequency response available during generation trip events.

Significant increase can be seen in net load ramps compared to current experience. While the net load down ramps in 2029 are still largely defined by decreases in load at night, as is the case currently, the highest net load up ramps are defined by rapid solar production decline at sunset and simultaneous decline in wind production during evening load pick-up. Table 19 displays the maximum ramp-up and ramp-down in 2029 in the \$25/ton CO_2 scenario. Figure 12 shows wind and solar generation output and customer demand (load) on the day with the highest three hour net load ramp in 2029 from the CSAPR and \$25/ton CO_2 scenario.

Table 19: Maximum Ramp-up and Ramp-Down

Net Load	Maximum 60-min Ramp-up (MW/60Mins)	Maximum 60-min Ramp-down (MW/60Mins)	Maximum 180-min Ramp-up (MW/180Mins)	Maximum 180-min Ramp-down (MW/180Mins)
2011 Net Load (actual)	6,267	-6,124	16,058	-18,985
2012 Net Load (actual)	6,563	-7,019	14,997	-15,977
2013 Net Load (Jan-May) (actual)	6,247	-5,446	12,200	-14,373
2029 Net Load (modeled \$25/ton CO_2 scenario)	11,074	-11,938	22,221	-22,560

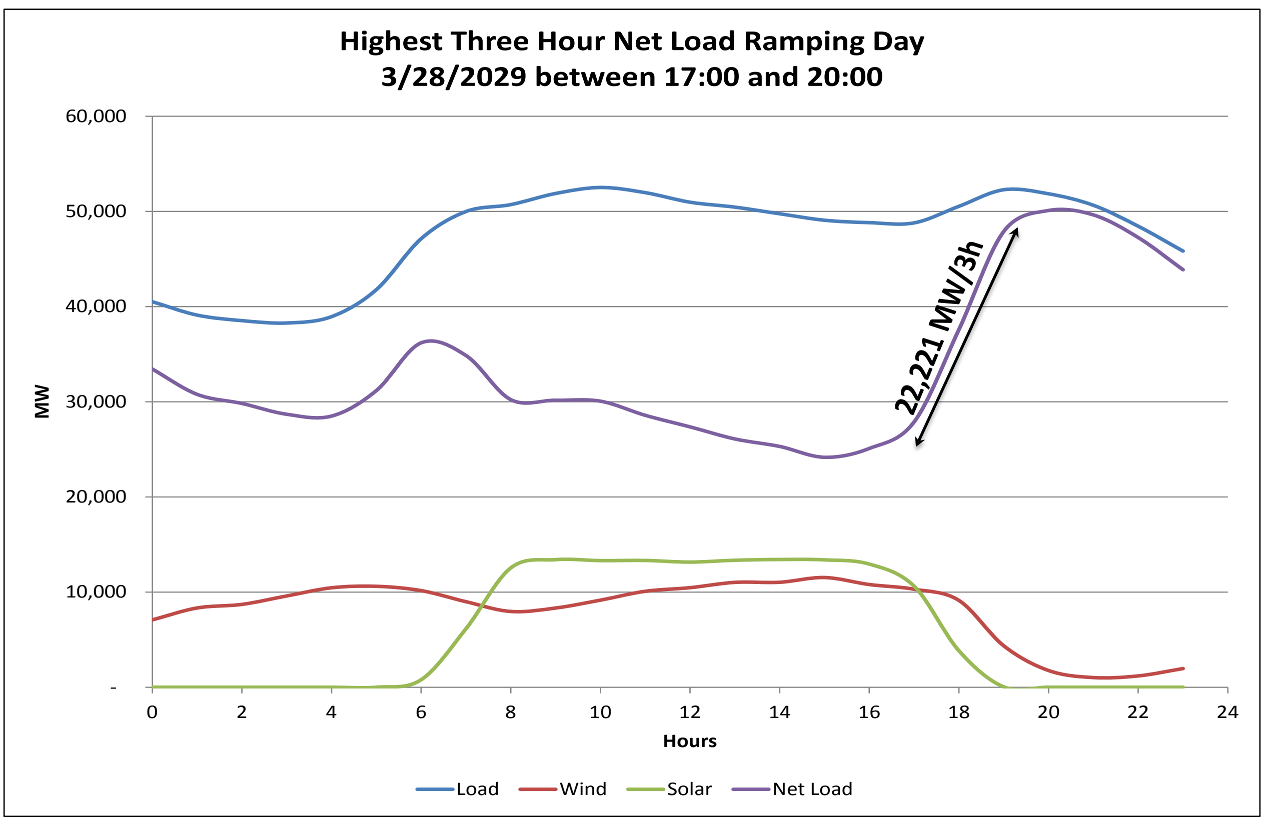

Figure 12: Highest Three Hour Net Load Ramping Day

The simulation model assumes perfect foresight and ensures that there is a sufficient amount of thermal generation with sufficient ramping capability committed to follow such rapid net load ramps. In real time operation, however, accommodating the maximum ramps resulting from simultaneous solar and wind generation decline would be more challenging. At times, the existing and planned generation fleet will likely need to operate for more hours at lower minimum operating levels and provide more frequent starts, stops, and cycling over the operating day. It is important that market mechanisms are adopted so that the need for flexible generation (with short start-up times and high ramping capability) is reflected in real-time energy prices. Market mechanisms to include dispatchable load resources could also help to address flexibility needs. Enhancing wind and solar forecasting systems to provide more accurate wind and solar generation projections will become increasingly important. Regulation and Non-Spinning reserves will need to be increased to address increased intra-hour variability and uncertainty of power production from wind and solar. Tools available to system operators must be enhanced to include short-term (10-min, 30-min, 60-min, 180-min) net-load ramp forecasts and simultaneous assessment of real-time ramping capability of the committed thermal generation to assist operators in maintaining grid reliability.[27]

Though all solar capacity additions predicted by the model were utility-scale, it is likely that a significant portion of future solar generation capacity will be embedded in the distribution grid (e.g., rooftop solar and small scale utility solar connected at lower voltage levels). ERCOT does not currently have visibility of these resources. To produce accurate solar production forecasts, ERCOT would need to have improved information regarding the size and location of distributed solar installations. Additionally, to ensure grid reliability, there would need to be increased consideration of operational activities on the distribution and transmission systems.[28] The PUCT is currently pursuing a rulemaking to improve and expand the data submitted annually to the PUCT on distributed generation facilities.[29]

Based on ERCOT's modeling, the majority of new renewable generation resource additions are anticipated to be solar. However, if instead ERCOT sees a large amount of wind resource capacity additions, then the reliability impacts may be more severe. Wind production in West Texas results in high renewable penetration during early morning hours, when load is lowest. A larger expansion in wind production relative to solar may result in lower net loads and significant reliability issues. If ERCOT cannot reliably operate the grid with these high renewable penetration levels, then production from these resources will be curtailed to maintain operational reliability. Should this occur, it would reduce production from renewable resources, leading to possible non-compliance with the proposed rule deadlines.

5.3. Impact on Transmission

ERCOT's analysis indicates that the impacts of proposed and recently finalized environmental regulations will result in retirement of legacy base-load generation and development of new renewable generation resources. These changes to the ERCOT generation mix will likely require significant upgrades to the transmission infrastructure of the ERCOT system.

The retirement of a large amount of coal-fired and/or gas steam resource capacity in the ERCOT region would have a significant impact on the reliability of the transmission system. The transmission system is

[27] These findings are consistent with an assessment conducted by the North American Electric Reliability Corporation (NERC) and California ISO (CAISO), *Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources*, November 2013. Available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf.

[28] These findings are consistent with an assessment conducted by the North American Electric Reliability Corporation (NERC) and California ISO (CAISO), *Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources,* November 2013. Available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf.

[29] PUCT Project 42532, *Rulemaking regarding third-party ownership of distributed generation facilities.*

currently designed to reliably deliver power from existing generating resources to customer loads, with the existing legacy resources that are located near major load centers serving to relieve transmission constraints and maintain grid reliability. Retirement of these resources would result in a loss of real and reactive power, potentially exceeding thermal transmission limitations and the ability to maintain stable transmission voltages while reliably moving power from distant resources to major load centers. A significant amount of transmission system improvements would likely be required to ensure transmission system reliability criteria are met even if a moderate amount of coal-fired and gas steam resources were to be displaced. If new natural gas combined cycle resources were to locate at or near retiring coal-fired and gas steam resources, the impact would be lessened.

In the ERCOT region, it takes at least five years for a new major transmission project to be planned, routed, approved and constructed. As such, in order for major transmission constraints to be addressed in a timely fashion, the need must be seen at least five years in advance. Given the competitiveness of the current ERCOT market, unit retirement decisions will likely be made with only the minimum required notification (currently 90 days).

The growing loads in the ERCOT urban centers are causing continued growth in customer demand and a resulting need for new transmission infrastructure. As the units that are at risk of retirement from the proposed rule are located near these load centers, future transmission needs would be increased or accelerated by the likely retirements. For example, a new 345-kV transmission line is currently planned to be in place by 2018 to serve customers in the Houston region, at an estimated cost of more than $590 million. Long-term studies indicate a potential need for further upgrades in the mid-2020s. The retirement of generation resources within the Houston area prior to 2018 would likely result in grid reliability issues prior to completion of the proposed project. Retirement of generation after 2018 would accelerate the need for additional transmission from the long-term horizon (6-15 years) into the near-term horizon (1-6 years).

Similarly in the San Antonio and the Dallas-Fort Worth regions there are multiple new transmission projects that are being planned to serve existing load growth. At costs of hundreds of millions of dollars, the need for these and similar projects would be accelerated by retirement of legacy fossil fuel-fired units in these regions.

Growth in renewable generation would also likely have a significant impact on transmission requirements. Although ERCOT did not estimate the costs of these transmission infrastructure improvements in this study, recent projects can be illustrative of the potential costs. In early 2014, the transmission upgrades needed to integrate the Texas Competitive Renewable Energy Zones (CREZ) were completed. These upgrades included more than 3,600 miles of new transmission lines, constructed at a cost of $6.9 billion dollars. The project took nearly a decade to complete. The CREZ project has contributed to Texas' status as the largest wind power producer in the U.S.

While the CREZ transmission upgrades provide transmission capacity beyond current generation development, these new circuits will not provide sufficient capacity to reliably integrate the amount of renewables necessary to achieve the requirements of the proposed rule. Also, if the locations of new renewable generation do not coincide with CREZ infrastructure, further significant transmission improvements will be required. Given the need to increase the amount of renewable resources in order to achieve the proposed compliance requirements in the Clean Power Plan, it is likely that significant new transmission infrastructure would be required to connect new renewable resources.

6. Generation Cost Analysis

The model output included detailed cost information that can be used to characterize the impact of emissions limits on energy prices in ERCOT. This section discusses the cost impacts for each of the modeled scenarios. All cost figures are reported in nominal dollars, except capital costs, which are in real 2015 dollars.

Table 20 shows the average locational marginal price (LMP) for each scenario in 2020 and 2029, which corresponds to wholesale energy prices. The inclusion of emissions prices resulted in higher average locational marginal prices (LMPs) compared to the baseline scenario. In the CSAPR and \$20/ton carbon price scenario, the average LMP in ERCOT was \$66.17 in 2020 and \$81.13 in 2029 – 34% and 13% above the baseline scenario LMPs for those years, respectively. In the CSAPR and \$25/ton carbon price scenario, the average LMP was \$73.58 in 2020 and \$84.28 in 2030 – 49% and 17% above the baseline scenario estimates. The higher LMPs in the CSAPR and CO_2 limit scenario result from the more frequent occurrence of scarcity hours. Scarcity hours are more frequent in this scenario because of operational constraints resulting from the need to keep CO_2 emissions within the limit. In actual operations, it is likely that there may be more flexibility to meet load than allowed by the model. LMPs are lower in the CSAPR limit and Regional Haze scenario in 2029 because there are fewer scarcity hours, due to the additional natural gas combustion turbines built in this scenario to replace retiring coal capacity.

Table 20: Locational Marginal Prices

Locational Marginal Price	Baseline	CSAPR Limit	CSAPR Limit and Regional Haze	CSAPR and CO_2 Limit	CSAPR and CO_2 \$20/ton	CSAPR and CO_2 \$25/ton
2020 LMP (\$/MWh)	\$49.46	\$50.10	\$50.43	\$105.07	\$66.17	\$73.58
2029 LMP (\$/MWh)	\$72.02	\$72.99	\$67.68	\$102.64	\$81.13	\$84.28
2020 LMP % change from baseline	n/a	1	2	112	34	49
2029 LMP % change from baseline	n/a	1	-6	43	13	17
2020 retail energy bill % change	n/a	< 1	< 1	45	14	20
2029 retail energy bill % change	n/a	< 1	-2	17	5	7

As a general estimate, if wholesale power is 40% of the consumer bill, these increases in average LMPs would result in a retail energy price increase of 14% to 20% in 2020, and 5% to 7% in 2029. The increase in wholesale and consumer energy costs compared to the baseline decreases by 2029 due to the addition of new solar capacity, which has virtually no variable costs, and the accrual of energy efficiency savings. The costs of investments in energy efficiency are not estimated in this study. In their comments to the PUCT, EUMMOT estimated the cost of achieving the level of energy efficiency savings estimated by EPA at \$1.6 to \$2.9 billion per year in Texas.[30]

The LMP reflects the variable cost associated with the generation resource on the margin. Though this measure provides an estimate of wholesale energy prices for consumers, the increase in production costs for generators would differ. Table 21 and Table 22 show generators' variable costs (which include fuel and emissions allowance costs) in 2020 and 2029, respectively. The CSAPR limit scenario results in a small increase in variable costs relative to the baseline, due to the slight shift away from coal toward natural gas. The variable costs in the CSAPR and CO_2 limit scenario reflect the increased cost of natural gas generation, and the effects of energy efficiency and additional renewable generation. The emissions price scenarios result in an increase in variable costs of 28% to 32% in 2020, and 15% to 18% in 2029. This increase is due in large part to the CO_2 emissions price, which in 2029 imposed a cost of \$3.8 billion in the \$20/ton CO_2 scenario and \$4.4 billion in the \$25/ton CO_2 scenario, comprising 19% and 21% of

[30] Presentation by Jarrett E. Simon, Director Energy Efficiency, CenterPoint Energy. *PUCT Workshop Project 42636: Comments on Proposed EPA Rule Regarding Greenhouse Gas Emissions for Existing Generating Units*, August 15, 2014. Available from the Public Utility Commission of Texas, Docket 42636, Item 21.

total variable costs for the two respective scenarios. Compared to CO_2 emissions costs, NO_x and SO_2 emissions costs are much smaller, between $165 and $200 million in 2020 in the emissions price scenarios.

Table 21: Fuel and Emissions Allowance Costs in 2020

Variable Costs	Baseline	CSAPR Limit	CSAPR and Regional Haze	CSAPR and CO_2 Limit*	CSAPR and CO_2 $20/ton	CSAPR and CO_2 $25/ton
Total Fuel and Emissions Allowance Costs (billions of dollars)	12.9	13.0	13.0	13.1	16.4	17.0
Total Fuel and Emissions Allowance Costs change from Baseline (%)	n/a	1	1	2	28	32
Average Fuel and Emissions Allowance Cost ($/MWh)**	30.54	30.74	30.73	31.62	39.58	40.91
CO_2 Emissions Allowance Costs Only (billions of dollars)	0	0	0	0	3.5	4.1
CO_2 Emissions Allowance Costs as percent of Total Fuel and Emissions Allowance Costs (%)	0	0	0	0	21	24

*The total fuel and emissions allowance cost cited for the CSAPR and CO_2 limit scenario in the summary report omitted start up and shut down costs. The value has been corrected in this table to include those costs. Start up and shut down costs are also a component of variable costs.
**Average fuel and emissions allowance costs have changed slightly from the values included in the summary report due to a calculation error.

Table 22: Fuel and Emissions Allowance Costs in 2029

Variable Costs	Baseline	CSAPR Limit	CSAPR and Regional Haze	CSAPR and CO_2 Limit	CSAPR and CO_2 $20/ton	CSAPR and CO_2 $25/ton
Total Fuel and Emissions Allowance Costs (billions of dollars)	17.7	18.0	18.0	16.8	20.4	20.9
Total Fuel and Emissions Allowance Costs change from Baseline (%)	n/a	2	2	-5	15	18
Average Fuel and Emissions Allowance Cost ($/MWh)	37.07	37.70	$37.65	36.60	44.28	45.49
CO_2 Emissions Allowance Costs Only (billions of dollars)	0	0	0	0	3.8	4.4
CO_2 Emissions Allowance Costs as percent of Total Fuel and Emissions Allowance Costs (%)	0	0	0	0	19	21

Note that the information in Table 20, Table 21 and Table 22 do not include the associated costs of building or upgrading transmission infrastructure, higher natural gas prices caused by increased gas demand, ancillary services procurement, energy efficiency investments, and potential Reliability Must-

Run contracts. With regard to Regional Haze compliance, these costs do not include the costs of scrubber upgrades or retrofits.

Additionally, there will be capital costs for new generation resources built in both the baseline and emissions scenario cases, shown in Table 23 and Figure 13. Though the baseline and CSAPR limit scenarios add the same amount of new capacity, the costs differ slightly due to differences in the timing of when the new capacity is built by the model. The CSAPR limit and Regional Haze scenario adds 1,900 MW of capacity incremental to the baseline, which results in a 16% increase in capital investments. The scenarios with the Clean Power Plan result in further increases in capital cost investments, increasing by 52% to 77% compared to the baseline. Though not directly reflected in LMPs, these costs will ultimately be reflected in consumers' energy bills.[31]

Table 23: Total Capital Cost Investments by 2029

Capital Costs	Baseline	CSAPR Limit	CSAPR Limit and Regional Haze	CSAPR and CO_2 Limit	CSAPR and CO_2 \$20/ton	CSAPR and CO_2 \$25/ton
Total Capital Cost (billions of 2015$)	14	15	16	23	22	25
Capital Cost change from baseline (billions of 2015$)	n/a	1	2	8	7	11
Capital Cost change from baseline (%)	n/a	5	16	59	52	77

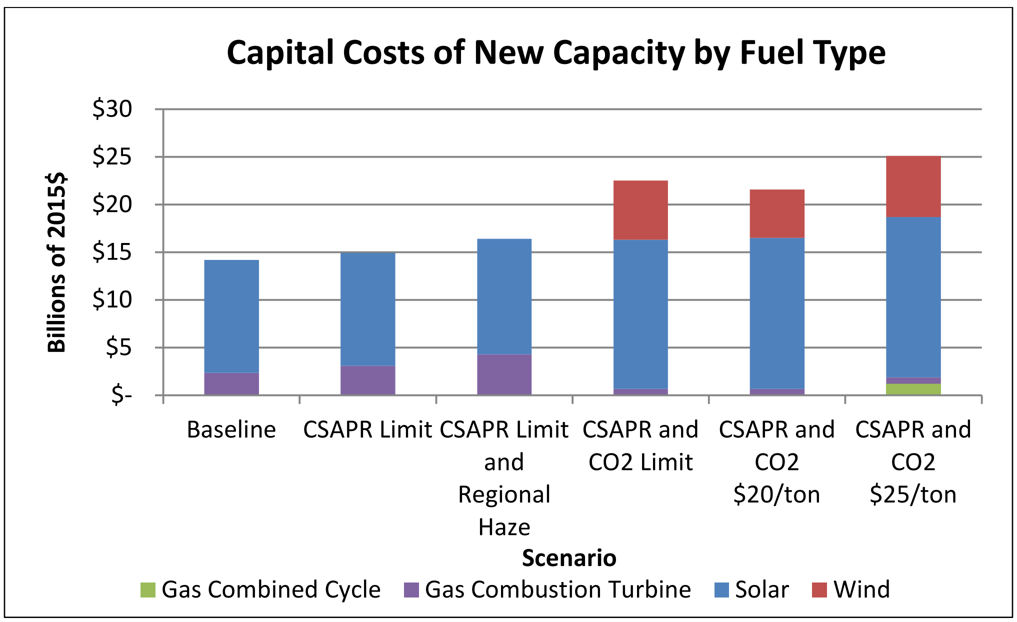

Figure 13: Capital Costs of New Capacity by Fuel Type

As previously described, the modeling results show a decrease in the ERCOT reserve margin in the early years of the Clean Power Plan compliance timeframe. In a recently completed report prepared for the PUCT, the Brattle Group quantified the cost to consumers associated with periods of reduced reserve

[31] The LMP is based on the variable costs of the last unit cleared in the market to serve the last MW of load. Units that clear the market with variable costs below the LMP recover capital and fixed costs through the difference between their variable costs and the LMP. Accordingly, because the LMP contributes to consumer energy bills, those capital costs are ultimately paid by consumers.

margins.[32] These costs include a range of production costs, including the cost of emergency generation, the cost of utilizing interruptible customers, the costs of utilizing all of the available ancillary services, and the impact to consumers from firm load shedding, all of which increase at lower reserve margins. As an example, the retirement of 6,000 MW of generation capacity would be expected to reduce the system reserve margin by about 8%. Based on this report, if this capacity change occurred when the system reserve margin was approximately 14%, the increased annual system costs at the resulting 6% reserve margin would be approximately $800 million higher than would be expected prior to the regulatory impact.[33]

Finally, ERCOT used the same natural gas price assumptions in all of the modeled scenarios. As noted previously, with the increased consumption of natural gas anticipated not only in ERCOT but nationally with the implementation of the Clean Power Plan, natural gas prices could increase beyond the levels anticipated in this modeling analysis. This would pose additional costs to consumers, which are not reflected in this study.

7. Conclusion

The results of this study indicate that the Regional Haze program and the Clean Power Plan will both lead to the retirement of coal-fired capacity in ERCOT. EPA's proposed Regional Haze FIP is likely to result in the retirement of coal units due to the costs associated with upgrading and retrofitting scrubbers. ERCOT anticipates that 3,000 MW to 8,500 MW of coal-fired capacity in ERCOT face a moderate to high risk of retirement due to these requirements. If implemented as proposed, the Clean Power Plan will also result in coal unit retirements, due to the need to meet stringent CO_2 emissions limits on a state-wide basis. ERCOT's analysis suggests that the Clean Power Plan, in combination with other environmental regulations, will result in the retirement of up to 8,700 MW of coal-fired capacity. By comparison, the other regulations are not expected to have a significant system-wide impact, but could affect the economics of a small number of units.

The retirement of existing capacity in ERCOT could result in localized transmission reliability issues due to the loss of fossil fuel-fired generation resources in and around major urban centers, and will strain ERCOT's ability to integrate new intermittent renewable generation resources. If the expected retirement of coal resources were to occur over a short period of time, reserve margins in the ERCOT region could reduce considerably, leading to increased risk of rotating outages as a last resort to maintain operating balance between customer demand and available generation. The need to maintain operational reliability (i.e., sufficient ramping capability) could require the curtailment of renewable generation resources. This would limit and/or delay the integration of renewable resources, leading to possible non-compliance with the proposed Clean Power Plan deadlines. These issues highlight the need for the Clean Power Plan to include a process to effectively manage electric system reliability issues, along the lines of the ISO/RTO Council (IRC) proposal for the inclusion of a reliability safety valve process.

The Clean Power Plan will also result in increased energy costs for consumers in the ERCOT region. Based on ERCOT's modeling analysis, energy costs for consumers may increase by up to 20% in 2020, without accounting for the associated costs of transmission upgrades, higher natural gas prices caused by increased gas demand, procurement of additional ancillary services, energy efficiency investments,

[32] The Brattle Group. *Estimating the Economically Optimal Reserve Margin in ERCOT*, January, 2014. Available at http://interchange.puc.texas.gov/WebApp/Interchange/application/dbapps/filings/pgSearch_Results.asp?TXT_CNTR_NO=40000&TXT_ITEM_NO=649.

[33] See Figure 22 of the Brattle Group report (page 48).

capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT. Consideration of these factors would result in even higher energy costs for consumers. Though the other regulations considered in this study will pose costs to owners of generation resources, they are less likely to significantly impact costs for consumers.

At this time, there is uncertainty regarding the implementation of environmental regulations, particularly the Clean Power Plan. Once EPA finalizes these regulations and pending litigation is resolved, resource owners will need to make decisions about their generation units that could result in reliability and transmission constraints. As new information becomes available, ERCOT will continue to analyze the impacts of regulatory developments that may affect the ability to provide reliable electricity to consumers in Texas.

Appendix A: Unit Emissions and Control Technologies

As discussed in Section 3, the generator environmental survey asked resource owners to report currently installed control technologies and average NO_x, SO_2, and CO_2 emission rates. These responses identify potential compliance risks associated with the pending implementation of CSAPR, the Regional Haze program, and CO_2 regulations. This Appendix discusses the control technologies used in ERCOT for SO_2 and NO_x emissions, and the survey responses pertaining to this information.

Emissions of SO_2 are primarily a concern for coal-fired capacity because the combustion of natural gas emits very low amounts of SO_2. Figure A-1 compares the reported SO_2 emission rates for different types of generation. Coal units may use scrubbers to remove SO_2 from air emissions. Scrubbers vary in their efficiency at removing SO_2. The most efficient scrubbers in the ERCOT coal fleet remove 90 to 99% of SO_2 from air emissions, while others have removal efficiencies in the 60 to 70% range.

Another way to reduce SO_2 emissions is through changes to a unit's fuel mix. Emissions of SO_2 vary with sulfur concentrations in the coal; some coal types have lower sulfur content than others. In ERCOT, coal-fired generators use either Powder River Basin (PRB) coal imported from the Western U.S. or locally mined lignite coal, or a mix of the two coal types. PRB coal has much lower sulfur content compared to lignite, so using PRB coal can, to some extent, help limit SO_2 emissions. Most coal units in ERCOT control their emissions through the use of scrubbers, a fuel mix that contains PRB coal, or both.

Based on the survey responses, 70% of coal capacity in ERCOT utilizes scrubbers to remove SO_2, while 82% of coal capacity uses some amount of PRB coal in their fuel mix. The most tightly controlled units in ERCOT use scrubbers with high SO_2 removal efficiencies in combination with PRB coal. Table A-1 summarizes the SO_2 control strategies used by coal-fired generation in ERCOT.

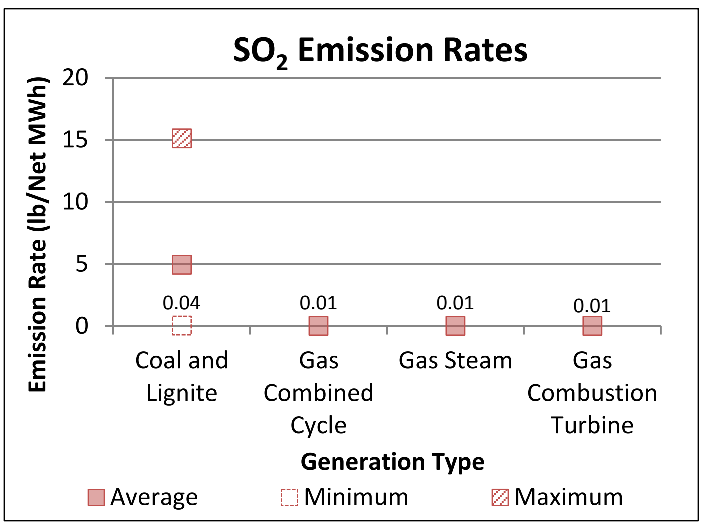

Figure A-1: Average SO_2 Emission Rates

Table A-1: Coal Unit SO_2 Controls and Fuel Mix

SO_2 Controls and Fuel Mix	# Units	Capacity (MW)	% of Surveyed Coal Capacity
Scrubber			
Yes	20	13,800	70%
No	12	6,000	30%
Fuel Mix			
100% PRB	14	8,600	43%
PRB/Lignite mix	11	7,600	39%
100% Lignite	7	3,600	18%

NO_x emissions are relevant for both coal and natural gas-fired capacity. Figure A-2 shows the NO_x emissions rates reported by fuel type. Options for NO_x controls include selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), or NO_x combustion controls. SCR systems provide the tightest controls for NO_x emissions; 35% of surveyed coal capacity and 34% of surveyed natural gas capacity reported using this technology. Table A-2 summarizes the installed NO_x control technologies in the ERCOT fossil fleet.

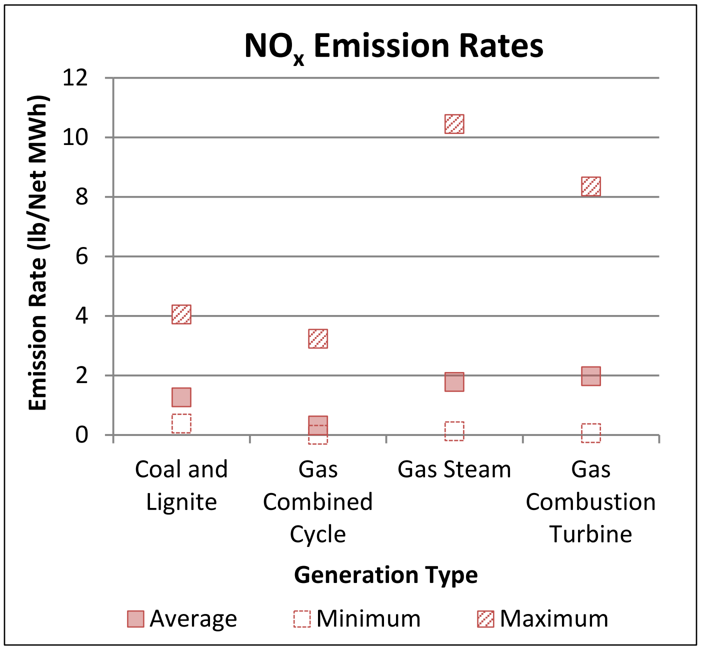

Figure A-2: Average NO$_x$ Emission Rates

Table A-2: Unit NO$_x$ Controls

NO$_x$ Controls*	# Units	Capacity (MW)	% of Surveyed Capacity of Fuel Type
Coal unit NO$_x$ Controls			
SCR	10	7,000	35%
SNCR	6	3,700	18%
NO$_x$ Combustion Controls	23	18,900	95%
Other	1	700	3%
Natural gas unit NO$_x$ Controls			
SCR	100	16,700	34%
SNCR	0	0	0%
NO$_x$ Combustion Controls	203	30,900	63%
Other	10	1,600	3%

*Some units use multiple NO$_x$ control strategies

Units that have good SO_2 and NO$_x$ controls will likely face lower compliance costs under CSAPR or future air emissions regulations. Those units with poor or no controls, particularly coal units, are more likely to incur significant compliance costs under upcoming environmental regulations.

There are no currently available emission control technologies for CO_2 emissions other than carbon capture and storage, though efficient operation of units can reduce CO_2 emissions rates. CO_2 emissions rates are the highest for coal-fired units and lowest for natural gas combined cycle units, as shown in Figure A-3.

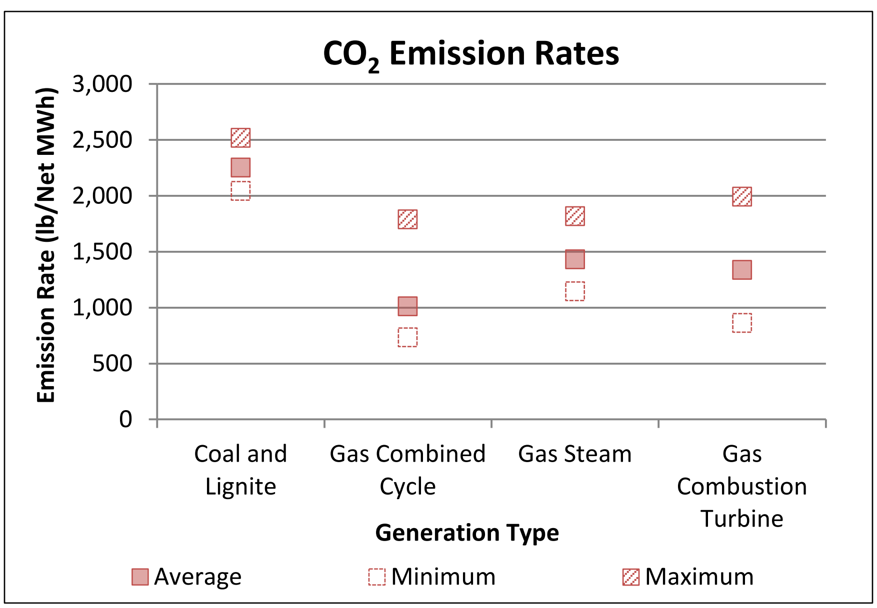

Figure A-3: Average CO_2 Emission Rates