Analysis of Potential Impacts of CO_2 Emissions Limits on Electric Power Costs in the ERCOT Region

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Executive Summary

The Electric Reliability Council of Texas (ERCOT) was requested by Public Utility Commission of Texas (PUCT) leadership to conduct an "analysis of the likely effects of proposed climate change legislation on electricity prices in the ERCOT market." Consistent with a similar study conducted by the PJM Interconnection, ERCOT focused on the near-term impacts of this potential legislation. Longer-term effects, such as changes in the installed generation capacity as a result of the impacts of the legislation, were not studied. Changes to the transmission system and related costs that might be warranted due to changes in generation dispatch as a result of the imposition of carbon allowance costs or decreases in system load were not evaluated or included. The analysis assumes that the goals of the legislation must be met directly by reductions in carbon emissions by ERCOT-region generation. ERCOT has not attempted to determine the equilibrium price of allowances or the appropriate level of tax to result in the level of reduction targeted in proposed climate-change legislation.

ERCOT performed this analysis by simulating the cost-based, hourly dispatch of all existing and committed generation in ERCOT region to serve the electric load in the region for the year 2013. The generation was dispatched according to its variable cost, including carbon emissions allowance costs, while adhering to the limitations of the transmission system and other reliability requirements. Because the economic dispatch used in the simulations performed for this study is cost-based, it does not include any market-driven bidding behavior or scarcity pricing, and the wholesale prices and wholesale market costs reported from the simulations are also cost-based as a result.

The simulations were performed for several scenarios defined by: 1) the level of natural gas prices ($7 and $10 per MMBtu); 2) the size of potential reduction in energy use as compared to the forecasted load for 2013 (0%, 2% , 5% and 10% reductions); and, 3) the amount of installed wind generation (the approximately 9,400 MW of existing and committed wind generation capacity and the 18,456 MW of total wind generation capacity for which the PUCT has ordered a transmission plan to be constructed in the Competitive Renewable Energy Zones (CREZ) Docket 33672). For each scenario, simulations were performed at increasing carbon allowance costs of $0, $10, $25, $40, $60 and $100 per ton of CO_2.

The change in total annual wholesale power costs (the costs paid by consumers) and wholesale prices (expressed as load-weighted average locational marginal prices or LMPs), production costs, total CO_2 emissions and similar output variables were noted for each scenario. The following insights can be obtained from the results of this analysis:

- In the reference case, with $7/MMBtu natural gas prices, expected load levels and the existing and committed level of wind and other generation, the carbon allowance costs must rise to between $40 and $60 per ton in order to reduce carbon emissions from electric generation in ERCOT to 2005 levels by 2013. *This level of allowance costs would result in an annual increase in wholesale power* *costs of approximately $10 billion and would increase a typical consumer's monthly bill by $27*;

- At higher natural gas prices, brought about by increased demand for natural gas due to carbon dioxide emission limitations or other reasons, allowances would rise to a higher cost (well over $60/ton in the case of $10/MMBtu natural gas prices) in order to achieve the desired reductions. *At this higher gas price, the annual increase in wholesale power costs to meet the 2005 level of emissions through reductions by generators in the ERCOT region would be in the range of $20 billion*;

- Increases in wholesale power costs due to carbon emissions limits may result in lower energy demand. These reductions in system energy use have the potential to allow the emission reduction targets to be met at a lower allowance cost. Total CO_2 emissions are reduced below 2005 levels at a carbon allowance price between $40 and $60 per ton for expected load levels at $7/MMBtu natural gas, but fall below 2005 levels between $25 and $40 per ton if total energy use was reduced by 10%. *This level of allowance costs would result in an annual increase in wholesale power costs of approximately $7 billion, a savings of $3 billion over the cost of meeting the 2005 levels of CO_2 emissions in the reference case. At this allowance cost, a typical consumer's monthly bill would increase by $17, a monthly savings of $10 over the reference case;*

- The additional wind generation envisioned by the CREZ plan (up to a total of 18,456 MW) reduces carbon emissions by 17.6 million tons above the reduction due to existing and committed wind generation even with no carbon emissions limits imposed by climate-change legislation;

- The additional CREZ wind generation allows the targeted emissions reductions to be met at a lower allowance cost. *At $7/MMBtu gas, the 2005 carbon emissions levels are met at an increase in annual wholesale power costs of approximately $7 billion, which is a $3 billion savings compared to the reference case. At this allowance cost, the increase in a typical consumer's monthly bill would be $22;*

- The combination of additional CREZ wind and lower energy usage results in smaller increases due to CO_2 emissions limits in both wholesale power costs and the typical consumer's monthly bill at a $7/MMBtu gas price, as compared to the reference case;

- The combination of additional CREZ wind generation and 2% lower energy usage does not offset the impact of an increase of natural gas prices from $7/MMBtu to $10/MMBtu on the level of allowance costs at which emissions reductions targets would be met.

1. Introduction

On April 1, 2009, U.S. Representatives Henry Waxman (D-CA) and Edward Markey (D-MA) posted a "discussion draft" entitled the "American Clean Energy and Security Act of 2009." This bill intends to establish a mechanism to reduce U.S. CO_2 emissions to 3% below the level of CO_2 emitted in the U.S. in 2005 by 2012. This reduction target would increase to 20% below 2005 levels in 2020 and would further increase to a targeted reduction of 83% by 2050. Several mechanisms for accomplishing these reduction goals have been discussed: a cap and trade program in which all allowances are auctioned, one in which some or all allowances are assigned based on historic emissions, and the implementation of a federal tax on carbon emissions.

Since the electric power sector accounts for approximately 40% of CO_2 emissions in the U.S., according to the U.S. Energy Information Administration (EIA)[1], meeting these goals will necessarily result in a significant impact on the electric power sector. Regardless of which mechanism is implemented, the cost or opportunity cost of the carbon allowances or the cost of the carbon tax will likely result in higher offers by generators in the ERCOT wholesale market and, in turn, these additional wholesale market costs will result in higher prices to retail consumers in the ERCOT region.

On April 2, 2009, the Electric Reliability Council of Texas (ERCOT) was requested by Chairman Barry T. Smitherman of the Public Utility Commission of Texas (PUCT) to conduct an "analysis of the likely effects of proposed climate change legislation on electricity prices in the ERCOT market," (Appendix A). This report provides the results of this analysis.

In order to analyze the impact of climate change regulation on the ERCOT electric market, ERCOT performed computer simulations of the electric system for the region under certain scenarios. These scenarios are intended to illustrate the impacts due to several discrete levels of carbon emissions costs, natural gas prices, and reductions in consumer electrical demand due to higher electric prices, as well illustrate the impact of increased penetration of wind generation in combination with some of these other variables. In these simulations, the generating units connected to the ERCOT system were economically dispatched to serve the projected hourly electric load on the system, subject to transmission system limitations. The resulting emissions, wholesale prices, and cost of producing electricity were calculated on an annual basis.

In his request, Chairman Smitherman referenced a study performed by the PJM Interconnection entitled "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market[2]," as well as a study by the Western Business Roundtable, as indicative of the type of analysis to be performed. ERCOT has replicated many of the input parameters and assumptions used by PJM in performing its analysis. As such, the

[1] http://www.eia.doe.gov/oiaf/1605/ggrpt/excel/tbl_statesector.xls
[2] http://www.pjm.com/Media/documents/reports/20090127-carbon-emissions-whitepaper.pdf

ERCOT analysis focuses on the near-term impacts of climate change regulation; that is, the studies performed for this analysis focus on conditions that are expected in the year 2013 and take into account the existing and committed generation connected to the ERCOT system.

In the longer term, changes will occur in the installed base of generation as a result of such greenhouse-gas regulation; these changes are not reflected in the analysis. The analysis assumes that the goals of the legislation must be met directly by reductions in carbon emissions by ERCOT-region generation; however, data is provided to allow for assessment of costs at other equilibrium values that may develop due to allowance trading and offsets. While the analysis includes any transmission system improvements that are necessary to meet established reliability standards and integrate committed generation (including the lines associated with the implementation of the Competitive Renewable Energy Zones (CREZ) transmission plan ordered in PUCT Docket 33672), no attempt was made to assess any additional transmission system improvements that might be warranted given the different economic conditions reflected in the various scenarios. The economic dispatch used in the simulations performed for this study is cost-based; it does not include any market driven bidding behavior or scarcity pricing, and the locational marginal prices and wholesale market costs reported from the simulations are also cost-based as a result.

As the independent grid operator, ERCOT does not advocate for or against policy positions, except in cases where electric grid reliability may be affected, and makes no policy recommendations in this analysis.

2. Overview of Relevant Sections of Title III of Waxman-Markey Proposed Climate-Change Legislation

The proposed "American Clean Energy and Security Act of 2009" establishes economy-wide reduction goals of global warming pollution to 97% of 2005 levels by 2012, 80% by 2020, 58% by 2030, and 17% by 2050. Recognizing that it is difficult to predict the final form any legislation may take or even whether and when such legislation may become law, this bill was used as a starting point for analysis.

The bill also seeks to achieve additional low-cost reductions in global warming pollution by using a small portion of the emissions allowances to provide incentives to reduce emissions from international deforestation. Relevant emissions include carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons (HFCs) emitted as a byproduct, perfluorocarbons, and nitrogen trifluoride, provided that EPA may designate additional anthropogenic greenhouse gases by rule.

In terms of emission allowances, the bill establishes an annual tonnage limit on greenhouse gas emissions from specified activities. Allowances equal to the tonnage limit are set for each year (with one allowance representing the permission to emit one ton of greenhouse gases, measured in tons of carbon dioxide equivalent). The bill requires covered entities to hold or submit emission allowances equal to the amount of greenhouse gas emissions for which they are responsible. Sources representing about 85 percent of U.S. carbon emissions are covered by a cap on their emissions. Electric generating units and fuel refiners and importers are covered starting in 2012, major industrial emitters in 2014, and natural gas local distribution companies in 2016.

With respect to disposition, the bill establishes a general framework based on auctions and allocations. In addition, a small percentage of allowances is dedicated for the purpose of mitigating international deforestation: 5% of allowances for the years 2012-2025, 3% for 2026-2030, and 2% for 2031-2050. The auction procedures are based on a single-round, sealed-bid, uniform-price auction, but may be modified by the Administrator.

Entities can bank allowances for future compliance years. The bill creates a two-year rolling compliance period by allowing covered entities to borrow an unlimited number of allowances from one year into the future. Parties may also satisfy up to 15% of their compliance obligations by submitting emission allowances with vintage years 2 to 5 years in the future, but they pay an 8% premium (in allowances) to do so.

In lieu of holding (or submitting) emission allowances, covered entities may also satisfy specified portions of their compliance obligation with EPA-approved domestic or international offset credits. The total quantity of reductions compensated for with offsets in any year cannot exceed two billion metric tons, split evenly between domestic and international offsets to allow one billion metric tons of each. Covered entities using offsets must submit five tons of offset credits for every four tons of emissions being offset. Covered entities may also submit an international emission allowance or compensatory allowance in place of a domestic emission allowance.

The bill also creates a Strategic Reserve comprised of 2.5 billion metric tons of emission allowances by setting aside a small number of allowances from each year's tonnage limit. The purpose of the reserve is to mitigate spikes in carbon prices. Allowances would be auctioned from the reserve if prices reach certain thresholds.

There are no restrictions on who can hold an allowance, or on the purchase, sale, or other transactions involving allowances. However, the bill gives the Federal Energy Regulatory Commission oversight and regulation authority for the markets for carbon allowances and offsets. Some key market protections include limits on auction purchases and market derivatives – no company can purchase more than 20% of allowances in any auction or own more than 10% of a particular derivative. In addition fines up to $25 million can be assessed for manipulation.

In general, the draft bill respects state authority to establish greenhouse gas regulation programs that are more stringent than federal requirements. However, there is a six-year suspension - 2012 through 2017 - of authority to impose state cap and trade programs. The bill provides for recognition/exchange of state-issued allowances by the State of California or the Regional Greenhouse Gas Initiative prior to commencement of federal program.

3. Description of ERCOT

ERCOT manages the flow of electric power to 22 million Texas customers – representing 85 percent of the state's electric load and 75 percent of the Texas land area. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects 40,000 miles of transmission lines and more than 550 generation units. ERCOT also manages financial settlement for the competitive wholesale bulk-power market and administers customer switching for 6.5 million Texans in competitive choice areas. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT's members include consumers, cooperatives, independent generators, independent power marketers, retail electric providers, investor-owned electric utilities (transmission and distribution providers), and municipal-owned electric utilities.

The ERCOT region is one of three electrical interconnections in the United States. There are no synchronous (alternating current or AC) electrical interconnections between ERCOT and the rest of the United States (or with Mexico). Except for power that may be scheduled over the 1,106 MW of asynchronous tie capability (high-voltage direct-current connections) between ERCOT and the Southwest Power Pool and Mexico, the electricity that is generated in the ERCOT region is used only in ERCOT. Additionally, the energy generated and used must be kept in instantaneous balance in order to maintain system reliability.

Some understanding of the current operations of the ERCOT market may be helpful in understanding the impact of potential carbon limits. The primary fuels used by generating units in ERCOT are nuclear, coal, natural gas and wind. There are four nuclear units in ERCOT, with a total capacity of 4,892 MW, which run at or near full capacity all hours in which they are available. There is 16,420 MW of coal capacity currently installed in ERCOT, and five new coal plants are under construction, bringing the total expected coal capacity in 2013 to 21,515 MW. Due to their low variable costs, coal plants currently run at or near full capacity in most hours.

There is also currently approximately 53,900 MW of gas generation installed or committed in ERCOT. Much of this generation is highly efficient combined-cycle technology. The remainder of this natural gas generation is either quick-start combustion turbines, or older, less efficient gas-steam technology. The combined-cycle units typically are utilized as intermediate load generation, running in most daytime hours, but ramping down to minimum output during off-peak hours, or cycling off at night. The combustion turbine units and gas steam units are typically operated as peaking units, providing power during periods of increased demand such as summer daytime hours.

There is also over 9,400 MW of wind generation installed or committed in ERCOT. Much of this wind generation is located in west Texas, and there is insufficient transmission capacity from this area to the remainder of ERCOT for all of this wind to generate simultaneously due to limitations on the current transmission system. However, in 2008, the Public Utility Commission of Texas issued an Order in Docket 33672, Commission Staff's Petition for Designation of Competitive Renewable Energy Zones, specifying transmission improvements sufficient to allow 18,456 MW of wind generation to be integrated into ERCOT. In following decisions, the PUCT has specified that these transmission improvements are to be completed by the end of 2013. Wind generation typically is the lowest variable cost resource on the system, displacing other fuel types in the dispatch when it is available. However, it is intermittent; it is only available when the wind is blowing.

There are other generation technologies in ERCOT, including units that are fueled by petroleum coke and biomass, but these represent less than 1% of the energy produced in ERCOT, and do not have a significant impact on carbon emissions.

Figure 1 shows a typical generation pattern for a high-load, summer day in ERCOT. This chart indicates that, given current economic conditions, the nuclear and coal units produce near maximum capacity in all hours. The natural gas units that remain on-line overnight increase their dispatch as load increases in the morning hours, and additional gas peaking generation, i.e., the natural gas steam units and simple-cycle gas turbines, are brought on-line in the late morning and provide generation throughout the peak afternoon hours. Generation is dispatched in this manner in order to minimize total variable costs.

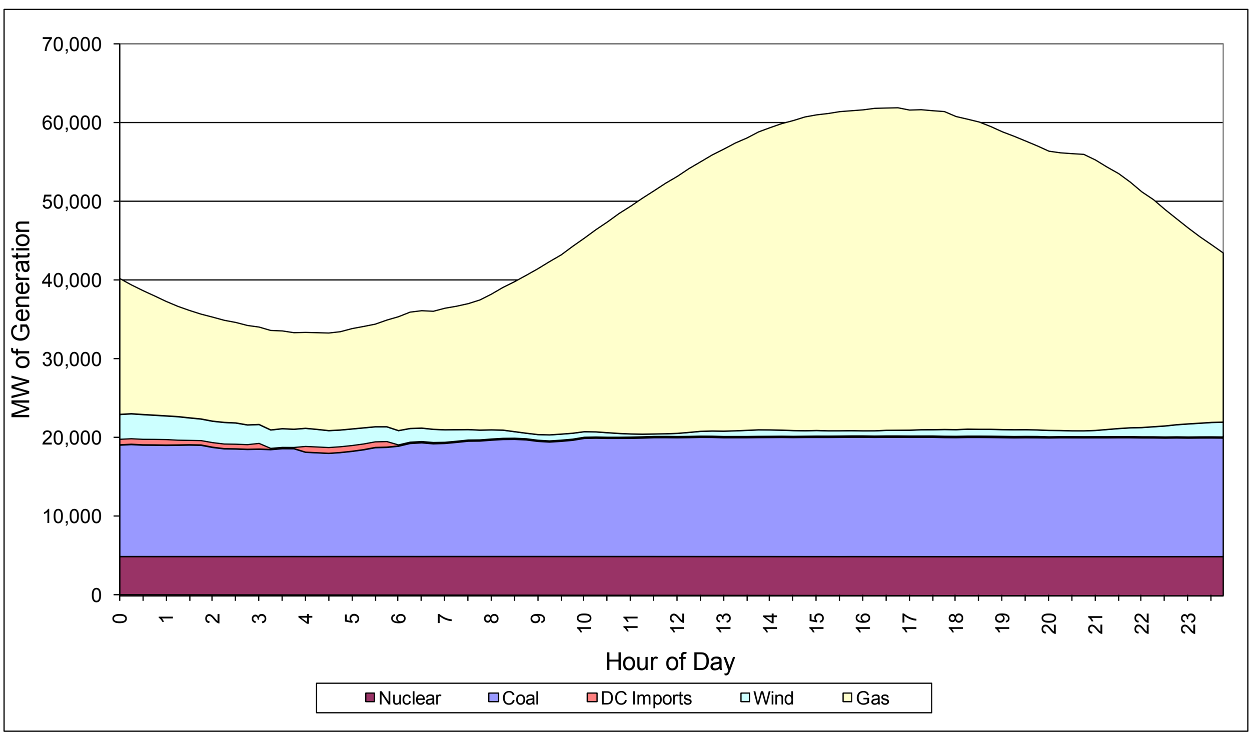


Figure 1: Generation Dispatch in ERCOT (August 4, 2008)

Figure 2 depicts similar information from December 26, 2008, a day in ERCOT with relatively low loads and high wind generation. This chart indicates that even coal generation is backed down in hours of low load levels and high wind generation.

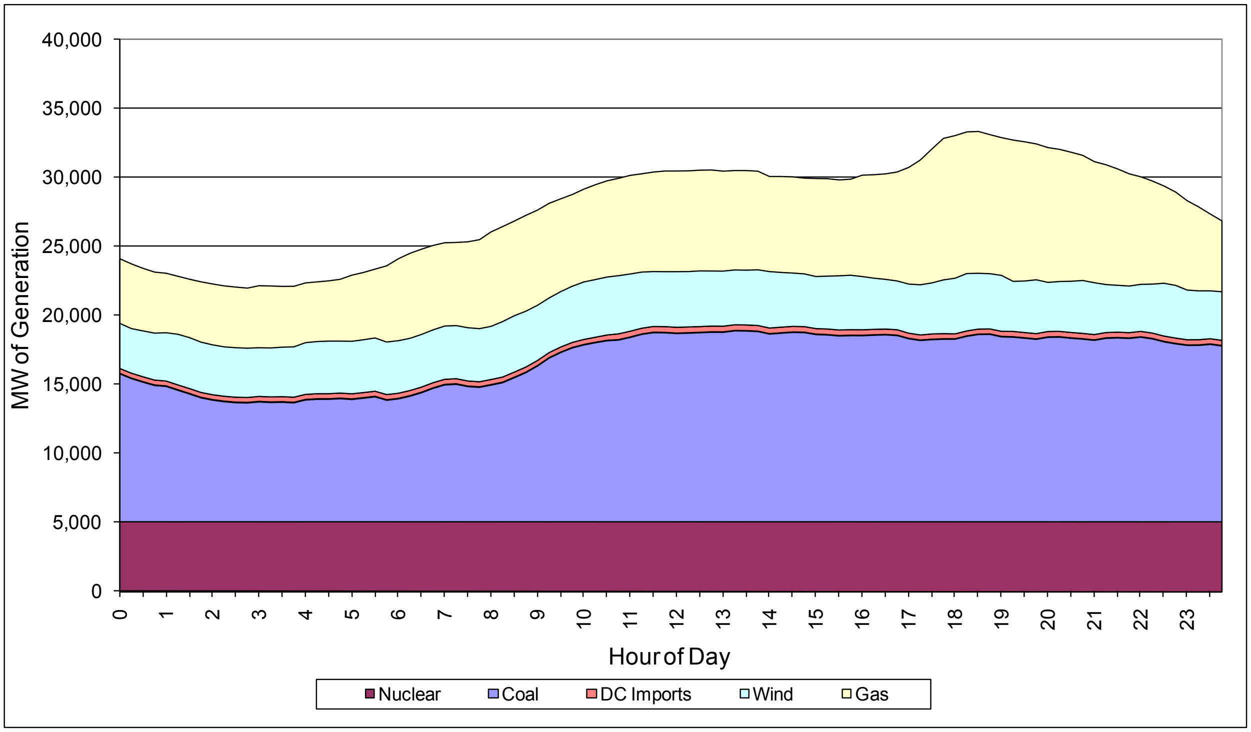


Figure 2: Generation Dispatch in ERCOT (December 26, 2008)

Again, it must be noted that these dispatch patterns are the result of current variable costs of the different technologies. If the price of natural gas were to fall to \$2.00/MMBtu, the variable cost for the combined-cycle units would be competitive with coal generation, and coal generation could be ramped down in order to allow more combined-cycle generation on the system. In a similar manner, carbon allowance costs are likely to change the relative costs of the various technologies, and, at a high enough level, will make natural gas combined-cycle generation competitive with coal generation as a base-load generation source because coal generation results in higher carbon emissions per MWh than natural gas generation. At a high enough carbon allowance cost, the carbon allowances will result in coal generation replacing inefficient gas steam units as a peaking resource. Coal units in ERCOT typically are not designed to function in this manner, and the increased number of unit starts would likely increase overall maintenance costs for these units.

Based on typical unit heat rates, for every \$1/ton increase in carbon allowance costs, the variable cost of combined-cycle gas generation will increase approximately \$0.50/MWh. The actual increase will depend on the efficiency of the specific generating unit. At the same time, for every \$1/ton increase in carbon allowance costs, the variable cost of coal generation will increase by approximately $1/MWh. The difference between these two impacts is approximately $0.5/MWh. As a result, if the variable cost of combined–cycle gas generation is currently $10/MWh more than the variable cost of coal generation, then an increase in carbon allowance costs of $20/ton would make the two technologies economically competitive.

4. Study Approach

4.1. Modeling Methodology

ERCOT System Planning simulates how the generation in ERCOT would generally be used to serve expected future hourly loads using a program that models a security-constrained unit commitment and economic generation dispatch. This model simulates the operation of the generation units in ERCOT in a manner consistent with market conditions while adhering to the limitations of the transmission system and applicable NERC and ERCOT reliability requirements. Units are committed and dispatched based on variable costs – i.e., startup costs, fuel costs, variable operations and maintenance costs, and emissions costs. The resulting hourly locational marginal prices (LMPs) are based on these marginal generation costs, and do not reflect potential bidding behavior of individual market participants.

This software was used to simulate the generation dispatch given expected system conditions in 2013 in order to estimate CO_2 emissions from electric generation sources for this carbon limitation study. Generation units that are currently in operation, or for which there are signed interconnection agreements, have been included in these simulations. This existing and expected generation fleet has not been adjusted to reflect potential market impacts due to the imposition of carbon allowance costs or decreases in system load. The transmission system expected to be in service in 2013 was modeled along with the transmission improvements included in the CREZ transmission plan ordered by the PUCT in Docket 33672. Changes to the transmission system and related costs that might be warranted due to changes in generation dispatch as a result of the imposition of carbon allowance costs or decreases in system load were not evaluated or included.

4.2. Scenario Assumptions

In order to provide information on the impact of potential carbon emissions limits over a range of conditions that might be experienced, ERCOT performed system dispatch simulations for several scenarios. These scenarios were defined by varying the level of CO_2 allowance costs, natural gas prices, reductions in system load, and the level of installed wind generation that were provided as inputs to the simulation model. Simulations were then run and results quantified for each of these variables and several combinations.

4.2.1. CO_2 Cost Adders

Regardless of what mechanism is implemented to produce the desired reduction in CO_2 emissions, the mechanism will result in an additional cost on the dispatch of electric generation. ERCOT has not attempted to determine the equilibrium price of allowances or the appropriate level of tax to result in the level of reduction targeted in proposed climate-change legislation, since an analysis of that sort would necessarily include interregional and inter-industry sector considerations that are outside the scope of this study. The U.S. Environmental Protection Agency has conducted an analysis of this issue[3]. Instead, ERCOT simulated the inclusion of a range of CO_2 emissions cost adders to the unit commitment and dispatch decisions of the electric power generators in the ERCOT market. The levels of CO_2 costs evaluated were $0, $10, $25, $40, $60 and $100 per short ton of CO_2 emitted.

4.2.2. Natural Gas Prices

The quantity of emissions generated in serving the system load is dependent not only on the level of the CO_2 cost but also on the relative dispatch cost of the different types of generating units. The relative dispatch cost is a function of the relative efficiencies of generating units but also of the relative price of their fuel. In order to capture the impact that fuel prices have on the quantity of CO_2 emissions for a given level of CO_2 cost adder, scenarios were run with two different levels of natural gas prices, at $7/MMBtu and at $10/MMBtu.

4.2.3. Load Reductions

It is expected that for some of the CO_2 cost adders included in this study, the price of retail electricity may increase significantly, resulting in a reduction in electricity use by consumers. In addition, some portion of the desired CO_2 reductions could be met by programs that increase the efficiency of energy use, and thus decrease consumer electrical demand. In this study, ERCOT has not attempted to evaluate the level of demand response that may occur due to increased prices, nor has it evaluated specific energy efficiency measures that might be implemented to achieve this response or their impact on demand. Any costs associated with achieving this response are likewise not included. Instead, ERCOT simulated several scenarios of reductions in electricity use in combination with the different levels of CO_2 cost adders noted above.

4.2.4. Increased Wind Penetration

In order to show the impact of the additional wind expected to be integrated into ERCOT following completion of the CREZ transmission improvements, scenarios have been included in this study that include the full build-out of CREZ wind generation (a total wind generation capacity of 18,456 MW of wind). While the base model includes approximately 9,400MW of wind generation, this scenario adds an additional

[3] http://www.epa.gov/climatechange/economics/economicanalyses.html

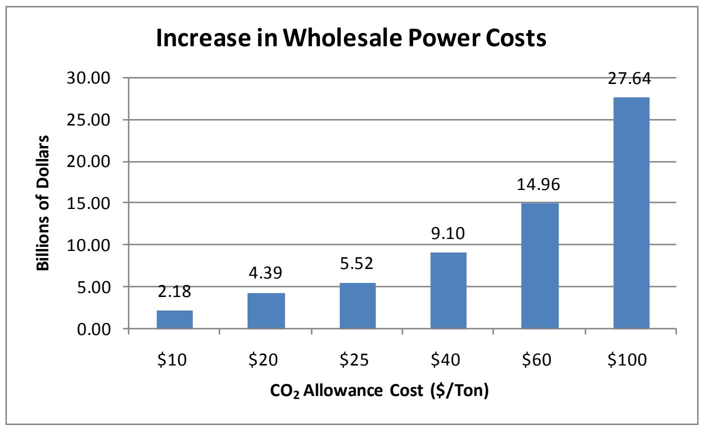
approximately 9,000 MW. These wind resources have been located on the system consistent with the Order on Rehearing in Docket 33672.

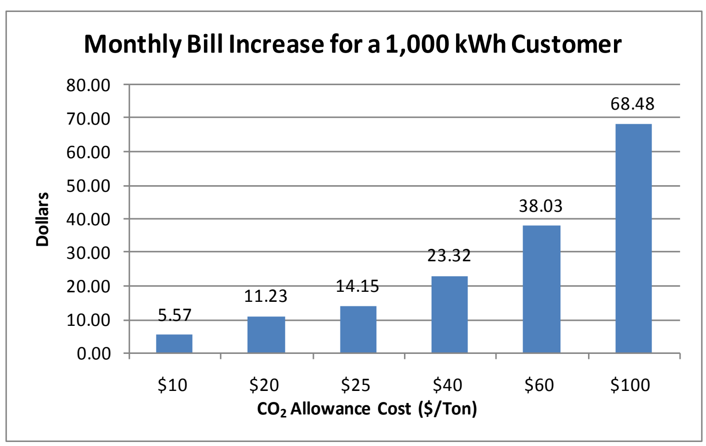
5. Results

5.1. Reference Case

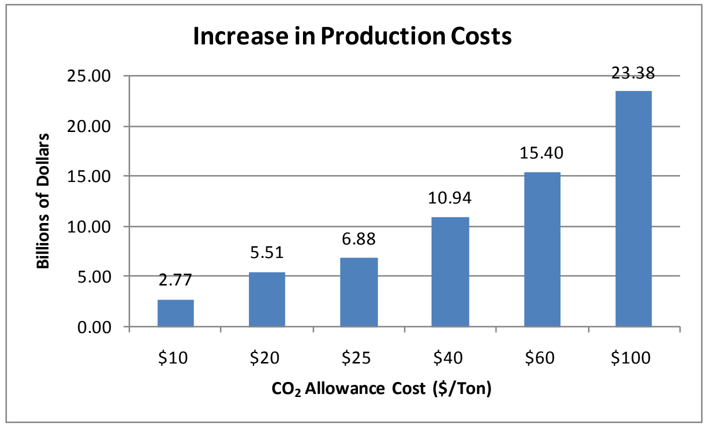
In this case, the current expected load forecast for 2013, the existing and committed amount of wind generation and the current expected natural gas forecast are utilized, along with increasing costs for carbon dioxide emission allowances. As discussed above, the carbon dioxide emission allowance prices analyzed were $0/ton, $10/ton, $20/ton, $25/ton, $40/ton, $60/ton, and $100/ton. Also as discussed above, for every $1/ton increase in carbon dioxide allowance prices, the difference in variable cost between a generic coal plant and a generic combined-cycle plant is reduced by approximately $0.50/MWh. With a natural gas price forecast of $7/MMBtu, the difference between the variable cost of a coal plant and that of a combined-cycle plant is approximately $35/MWh. As such, in this scenario, at or above a carbon dioxide allowance price of $60/ton, combined-cycle units become cost-competitive with coal units. At a carbon dioxide allowance price of $100/ton, combined-cycle units replace coal units as the predominant base-load technology.

The first two charts show increases in annual wholesale power costs (total cost to end-use consumers in the aggregate) and the impact on the monthly bill of a typical consumer (using 1,000 kWh) resulting from the different levels of carbon dioxide allowance prices modeled in this scenario. The increasing carbon dioxide allowance costs have an increasing impact on monthly bills. While the $10/ton carbon allowance cost increases bills by $5.57, this ratio increases consistently to the $100/ton allowance cost, which increases a typical monthly bill by $68.48.

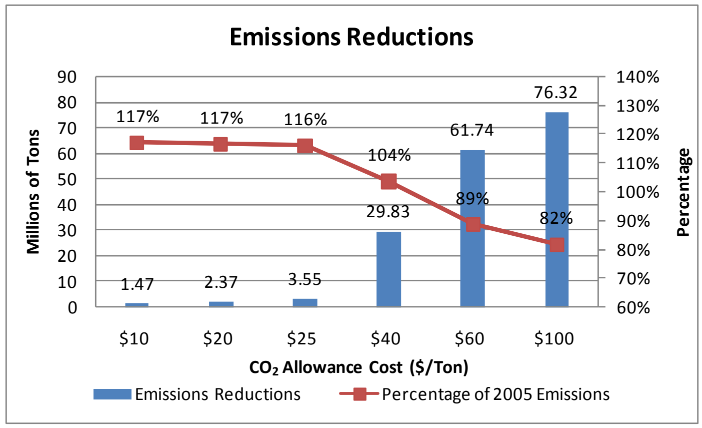




The next chart shows the difference in system production costs, i.e., the sum of the variable costs of generation, at different levels of carbon allowance costs. The annual increase in production costs ranges from $2.77 billion in the scenario with $10/ton carbon dioxide allowance costs to $23.38 billion in the scenario with $100/ton carbon dioxide allowance costs. The difference between the production cost and the wholesale power costs (cost to end-use consumers) is a combination of generator profit and the congestion rent.



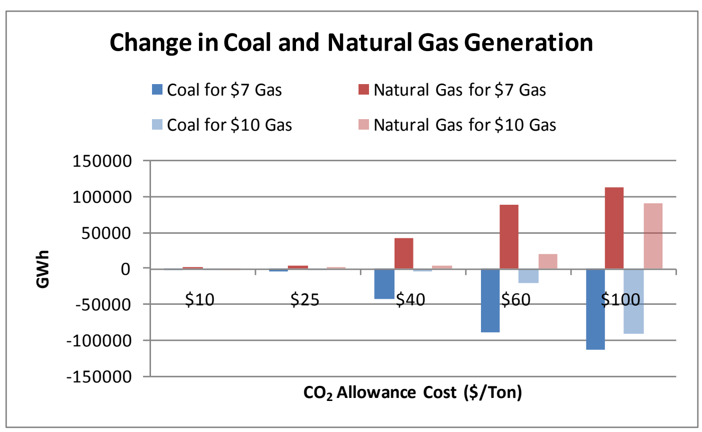
The following chart shows emissions reductions in two formats. The bar graph depicts aggregate reductions from the baseline iteration (with no carbon dioxide allowance costs). The line graph shows annual emission levels as a percentage of emissions recorded for the ERCOT region in 2005 (source: EPA EGrid database[4]). This chart indicates that, for this scenario, a carbon dioxide allowance price of over $40/ton is required in order to achieve reductions below 2005 emission levels. Complete tabulated results are provided in Appendix B.



5.2. Impact of Higher Gas Prices

With higher natural gas prices, the difference between the variable cost of a combined-cycle plant and that of a coal plant increases. At a natural gas price of $10, the variable cost of a typical coal unit is approximately $50 per MWh lower than the typical combined-cycle plant. As such, a higher carbon dioxide allowance price is required for combined-cycle units to become cost-competitive with coal units.

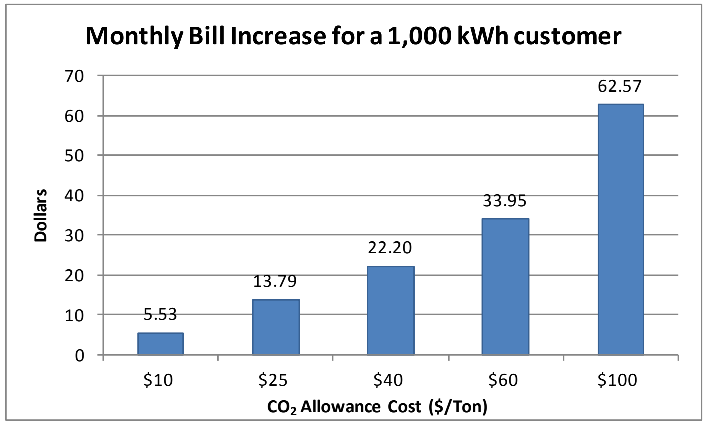
The first chart illustrates this comparison; with $7 gas, the increasing carbon allowance cost causes a displacement of coal generation by natural gas generation. However, with $10 gas, the carbon allowance cost



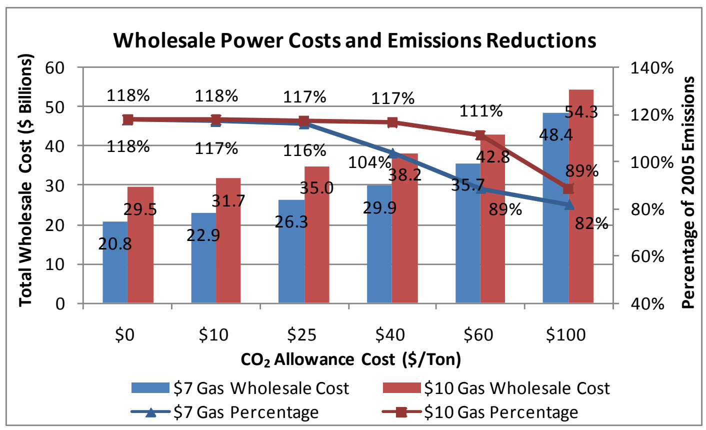
4 http://cfpub.epa.gov/egridweb/

must be higher to create the same displacement.

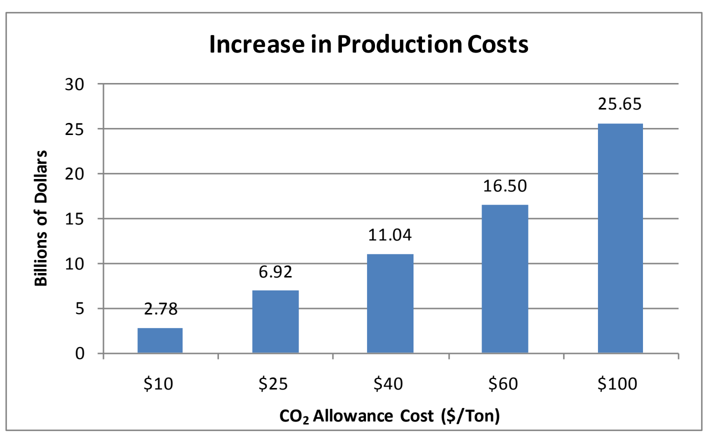
The next chart in this section shows the increases in typical monthly bills resulting from the carbon dioxide allowance prices modeled with a $10/MMBtu natural gas price. The incremental impacts of carbon allowance costs are similar to those in the reference case, although the total monthly bill is higher with higher gas prices.



The following chart shows total wholesale costs and total CO_2 emissions as a percentage of emissions in ERCOT from 2005. This chart shows the impact that higher gas prices have both on wholesale prices and on the price of emissions allowances required to reduce emissions from generating units to the level recorded in 2005. With $7/MMBtu natural gas, a CO_2 allowance price just greater than $40/ton is required to reduce emissions to 2005 levels. The total wholesale cost with $7/MMBtu gas (as shown by the blue columns) at this level of allowances is slightly higher than $30 billion. With $10/MMBtu natural gas, a CO_2 allowance price well over $60/ton is required in order to achieve this level of reductions. At this cost of CO_2 allowances, total wholesale costs (as shown by the red columns) are close to $50 billion. As a result, the increase in natural gas from $7/MMBtu to $10/MMBtu is expected to raise the cost required to achieve 2005 emission levels by over $20 billion.



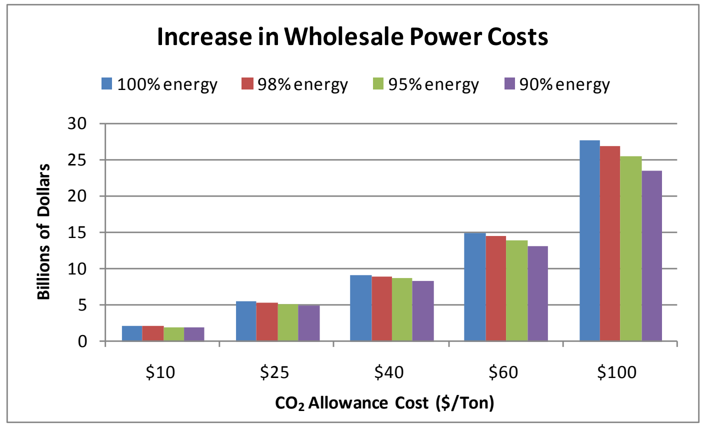
The last chart shows the difference in system production costs at different levels of carbon allowance costs. The annual increase in



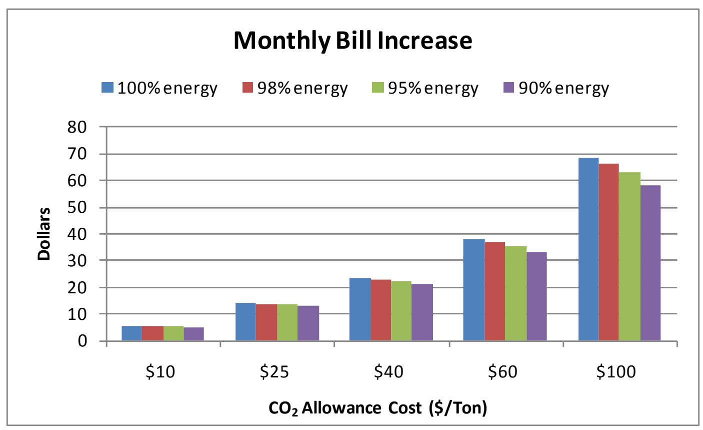
production costs ranges from $2.78 billion in the scenario with $10/ton CO_2 allowance costs to $25.65 billion in the scenario with $100/ton CO_2 allowance costs as compared to the case with $0/ton CO_2 allowance costs.

5.3. Impact of Load Reductions

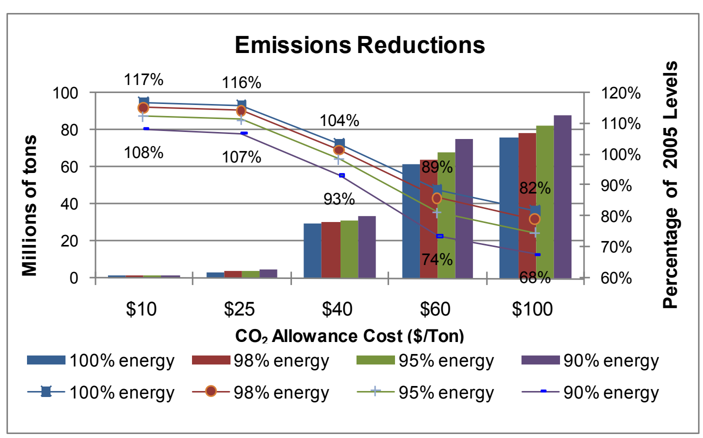
The following graphs show a comparison of the increase in annual wholesale power costs and a typical monthly consumer's bill for cases with $7/MMBtu natural gas and base case wind generation with different levels of load reduction due to price response or energy efficiency measures. The impact of reduced loads was analyzed using hourly loads reduced by 2%, by 5%, and by 10%. As would be expected, wholesale power costs are less as the amount of energy used decreases, for a given level of carbon allowance cost (depicted in the first chart).



The next chart in this section shows the impact on a typical residential customer bill of the different levels of carbon allowance costs for the different load reduction levels. The graph assumes that a typical residential customer uses 1,000 kWh in the base load case, but participates in the load reduction and uses 980 kWh in the 98% load case, etc. This load reduction mitigates the impact of carbon allowance prices on a typical monthly bill.



The final chart in this section shows annual emissions reductions for these cases. The chart shows that, as the quantity of energy produced decreases, CO_2 emissions



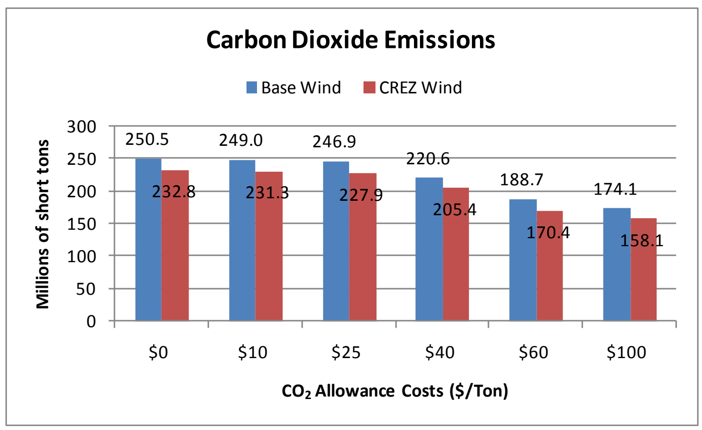
fall below the 2005 level for a lower carbon allowance price.

Total CO_2 emissions are reduced below 2005 levels at a carbon allowance price between $40 and $60 per ton in the base load case, but fall below 2005 levels between $25 and $40 per ton in the 90% energy reduction case.

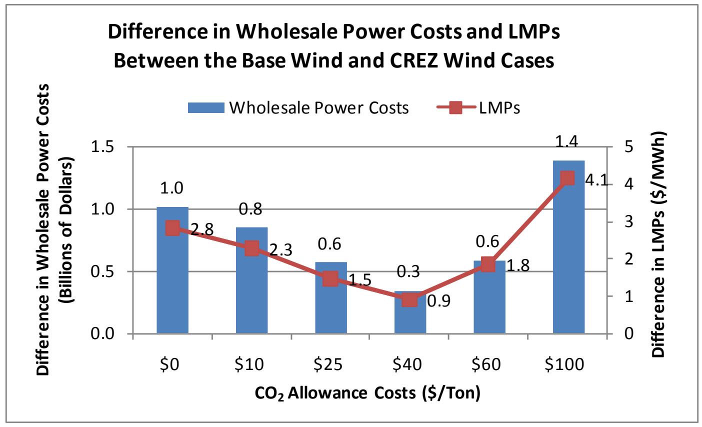
5.4. CREZ Wind Analysis

The development of wind generation in the Competitive Renewable Energy Zones (CREZ) is likely to reduce overall carbon dioxide emissions in ERCOT, as wind generation replaces thermal generation resources. "Base Wind" scenarios included in this study indicate the impact of currently existing wind resources (including wind resources for which there is a signed contract for interconnection). CREZ wind scenarios include the amount of wind expected as part of the development of transmission improvements to serve the CREZ, as ordered by the Public Utility Commission of Texas in Docket 33672.

Modeling conducted as part of this study indicates that the additional CREZ wind is expected to result in an annual reduction of carbon dioxide emissions of 17.6 million tons in the case with no carbon dioxide allowance costs. The following chart shows that this expected reduction is generally consistent across the levels of carbon dioxide emission allowance prices evaluated.



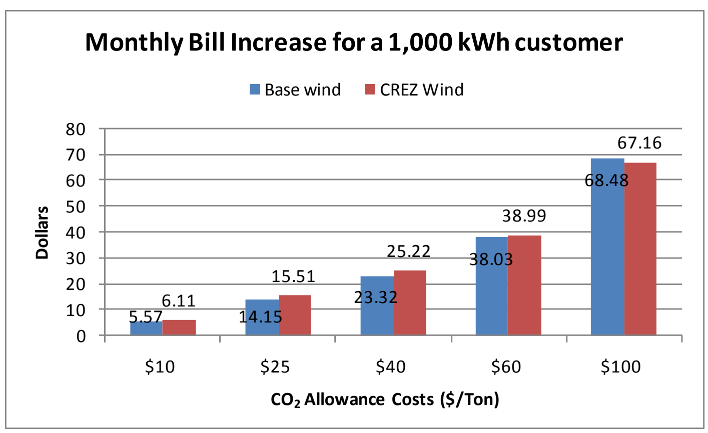
The impact of CREZ wind on wholesale power costs and resulting load-weighted average annual LMPs is not as consistent. With no carbon allowance costs, the additional CREZ wind is expected to reduce wholesale power costs approximately $1 billion, and average annual LMPs by $2.80/MWh. Reductions in wholesale power costs and LMPs are lower in the cases with $10, $25 and $40/ton carbon dioxide allowance costs, but then increase again in the cases with $60 and $100/ton carbon dioxide allowance costs, reaching $1.4 billion dollars in reduced wholesale power costs annually and $4.10/MWh in reduced average annual LMPs in the $100/ton case.



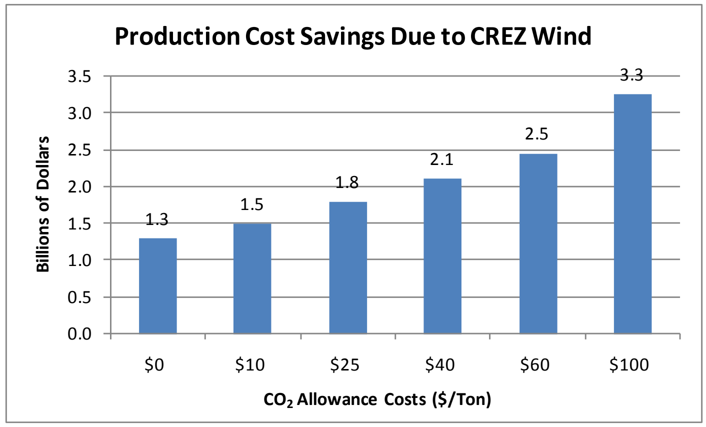
These benefits are not consistent across all cases because the reductions in wholesale power costs are greater when one fuel is significantly higher in variable cost than another. In such cases, the wind generation replaces this higher cost fuel and has a significant impact on marginal prices. When natural gas generation and coal generation are roughly equivalent in marginal cost (in the $40/ton case) the impact of wind generation on marginal prices is minimized. At carbon dioxide emission allowance prices above $40, coal increasingly becomes the more expensive marginal fuel in this scenario, and wind generation has a larger impact on marginal energy prices.

It should be noted that these results only indicate the impact of the additional CREZ wind (a total of 18,456 MW) beyond the existing and committed wind resources (~9400 MW). As the transmission ordered in Docket 33672 is included in the base case and the CREZ wind case, this analysis does not quantify the incremental benefits resulting from those transmission improvements, only the benefits from the incremental wind generation.

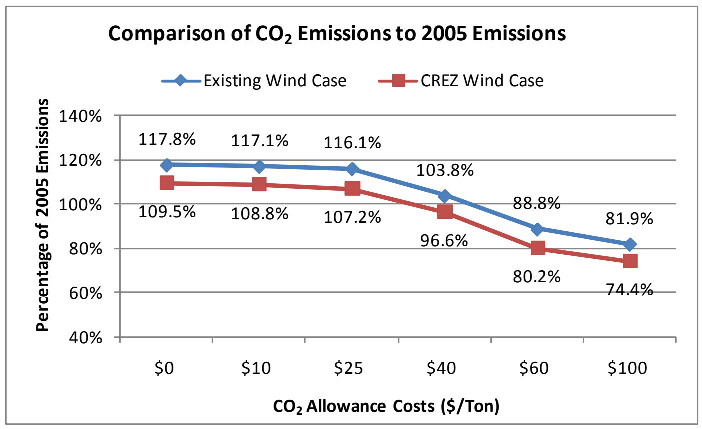
The next chart shows the impact on a typical consumer monthly bill of different levels of carbon allowance prices with the wind generation increased to CREZ levels. For the CREZ wind case, with $0/ton carbon allowance price, a typical monthly bill is less than with base wind, but the increase in a typical monthly bill at several levels of carbon allowances prices is higher.



Annual production cost savings (comparing the reductions in the sums of the variable costs to generate electricity in the cases with existing wind and with CREZ wind) increase consistently across the cases evaluated for the addition of CREZ wind, from $1.3 billion in the case with no carbon dioxide allowance prices to $3.3 billion in the case with a carbon dioxide emission price of $100/ton. This finding is consistent with the Carbon Dioxide Emissions graph on page 18, which shows that renewable energy which replaces thermal generation results in a reduction in carbon dioxide emissions in all cases. This reduction in emissions has an increasing impact on production costs as carbon dioxide emission prices increase.



The expected annual reductions in carbon dioxide emissions in all cases are also evident in the following chart. This chart compares carbon dioxide emissions for two sets of cases, as a percentage of carbon dioxide emissions in ERCOT from 2005: the cases with the existing and committed level of wind generation; and the cases with the additional CREZ wind. As can be seen in this graph, the integration of wind resources results in the ERCOT system consistently meeting specific CO_2 reduction levels at a lower carbon dioxide allowance price. These results indicate that the additional CREZ resources are expected to have a positive impact on achieving carbon dioxide reduction targets.



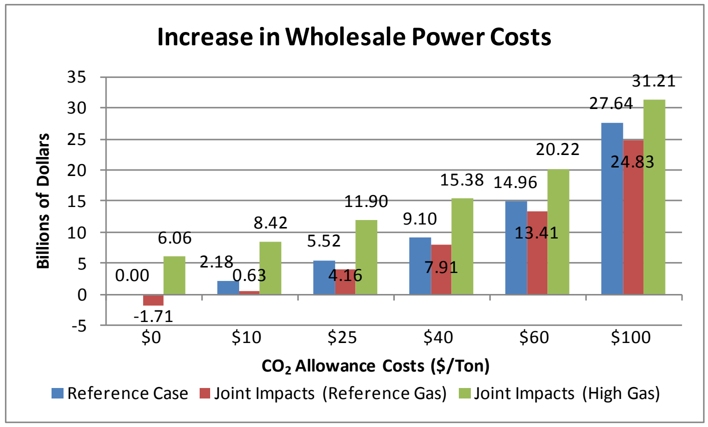
5.5. Potential Joint Impacts of Carbon Dioxide Allowances

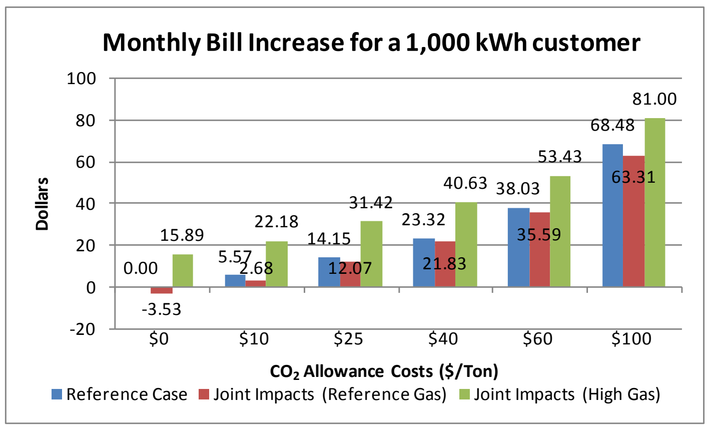
Carbon dioxide emissions allowance prices are likely to affect energy demand and natural gas prices. Two scenarios were included in this study to allow these joint impacts to be evaluated. Both of these scenarios included CREZ wind and reduced load (98% of expected). The first of these scenarios included reference case natural gas prices ($7/MMBtu) and the second scenario included elevated gas prices ($10/MMBtu).

The first two charts show the expected increase in annual wholesale power costs and the monthly bill of a typical 1,000 kWh consumer due to increased carbon dioxide emission allowance prices in these two scenarios as compared to the reference scenario ($7/MMBtu natural gas prices, expected load levels and the existing and committed level of wind and other generation).

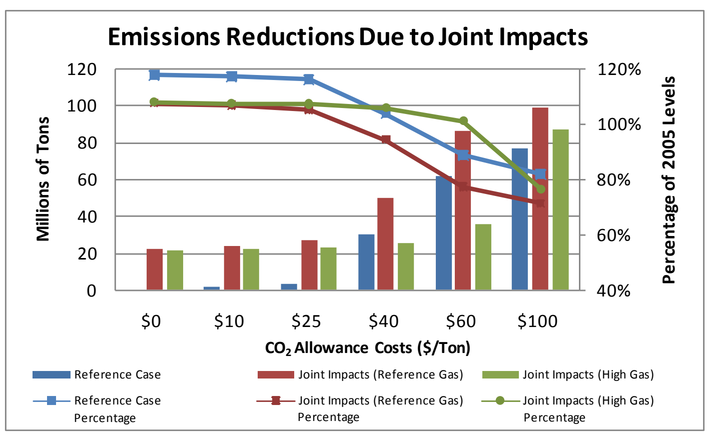
The base level for these comparisons (i.e., the base cost used to calculate the difference in costs for each level of carbon dioxide tax) is the $0/ton case for the reference scenario.

These charts indicate the effect of CREZ wind and reduced loads, as well as the offsetting impact of increased natural gas prices. Whereas the joint impacts of CREZ wind and reduced loads result in lower increases due to CO_2 emissions limits in wholesale power costs and the typical consumer's monthly bill at a $7/MMBtu gas price, these reductions are eliminated by the impact of increased natural gas prices. These charts indicate that if carbon dioxide allowance prices create higher demand for natural gas and as a result increase the price of this fuel to the $10 level, the impact of reduced loads (2% reduction) and increased wind generation (to the CREZ level) will not be sufficient to offset the increases due to higher natural gas prices.





The next chart indicates expected carbon dioxide emissions in these joint impacts scenarios, both as totals (vertical bars on the chart), and as percentages of emissions in ERCOT from 2005 (lines). These results indicate that the reduced loads and CREZ wind result in reductions in CO_2 emissions in all cases, but the higher natural gas price reduces the impact of carbon allowance prices until these prices get above $60/ton.



6. Summary and Conclusions

The analysis documented in this report is intended to provide a broad view of the near-term impacts of proposed legislation to limit carbon emissions on the cost and price of electricity in the ERCOT region of Texas. Numerous assumptions and modeling techniques were used to produce the data included in this report; these assumptions are documented in the report and should be well understood before interpreting the results.

Some of the insights from the analysis are:

- In the reference case, with $7/MMBtu natural gas prices, expected load levels and the existing and committed level of wind and other generation, the carbon allowance costs must rise to between $40 and $60 per ton in order to reduce carbon emissions from electric generation in ERCOT to 2005 levels by 2013. *This level of allowance costs would result in an annual increase in wholesale power costs of approximately $10 billion and would increase a typical consumer's monthly bill by $27*;

- At higher natural gas prices, brought about by increased demand for natural gas due to carbon dioxide emission limitations or other reasons, allowances would rise to a higher cost (well over $60/ton in the case of $10/MMBtu natural gas prices) in order to achieve the desired reductions. *At this higher gas price, the annual increase in wholesale power costs to meet the 2005 level of emissions through reductions by generators in the ERCOT region would be in the range of $20 billion*;

- Increases in wholesale power costs due to carbon emissions limits may result in lower energy demand. These reductions in system energy use have the potential to allow the emission reduction targets to be met at a lower allowance cost. Total CO_2 emissions are reduced below 2005 levels at a carbon allowance price between $40 and $60 per ton for expected load levels at $7/MMBtu natural gas, but fall below 2005 levels between $25 and $40 per ton if total energy use was reduced by 10%. *This level of allowance costs would result in an annual increase in wholesale power costs of approximately $7 billion, a savings of $3 billion over the cost of meeting the 2005 levels of CO_2 emissions in the reference case. At this allowance cost, a typical consumer's monthly bill would increase by $17, a monthly savings of $10 over the reference case;*

- The additional CREZ wind generation allows the targeted emissions reductions to be met at a lower allowance cost. *At $7/MMBtu gas, the 2005 carbon emissions levels are met at an increase in annual wholesale power costs of approximately $7 billion, which is a $3 billion savings compared to the reference case. At this allowance cost, the increase in a typical consumer's monthly bill would be $22;*

- The combination of additional CREZ wind and lower energy usage results in smaller increases due to CO_2 emissions limits in both wholesale power costs and the typical consumer's monthly bill at a $7/MMBtu gas price, as compared to the reference case;
- The combination of additional CREZ wind generation and 2% lower energy usage does not offset the impact of an increase of natural gas prices from $7/MMBtu to $10/MMBtu on the level of allowance costs at which emissions reductions targets would be met.

Appendix A – Request Letter

Barry T. Smitherman
Chairman

Rick Perry
Governor

Public Utility Commission of Texas

April 2, 2009

Mr. Bob Kahn, CEO
ERCOT
7620 Metro Center Drive
Austin, Texas 78744

Dear Bob:

Yesterday, U.S. Representatives Waxman (D-Calif) and Markey (D-Mass) posted a "discussion draft" entitled the "American Clean Energy and Security Act of 2009," which contains provisions relating to establishment of a cap and trade mechanism intended to reduce U.S. global warming emissions. This bill envisions a program that is intended to reduce CO2 emissions 3% below 2005 levels by 2012, and increasing thereafter to reductions of 83% below 2005 levels by 2050. I have carefully followed the climate change issue for some time now, including studying the negative efforts on GDP and electricity prices that were projected to occur from a bill which was filed and briefly debated in the Congress last summer-- Senate Bill 2191. I am very concerned about the effects this proposed legislation of Messrs. Waxman and Markey will have on electricity prices in the ERCOT market. Therefore, I would like for ERCOT to analyze this issue.

In January of 2009, PJM Interconnection (PJM), the independent electric grid operator serving the Mid-Atlantic and parts of the Southeast and Midwest regions of the U.S., conducted a study to examine the impacts of potential climate change polices on residential consumer bills under various CO2 price scenarios. Similarly, in February 2009, the Western Business Roundtable (WBR) conducted an analysis of the Western Climate Initiative (WCI), a proposed framework for a Western regional greenhouse gas cap and trade program covering the States of California, New Mexico, Oregon, Wyoming, Arizona and Washington. The WBR analysis looked at the likely effects on gross state product, job creation/destruction, and energy prices as a result of the proposed cap and trade program. Perhaps these two analyses could provide a starting point from which ERCOT could conduct its analysis of the likely effects of proposed climate change legislation on electricity prices in the ERCOT market.

While I realize that ERCOT has a lot "on its plate" at the moment, including successful completion of the Nodal market re-design, it is important that the PUCT and the Texas legislature have some understanding of how federal climate change legislation is likely to affect electricity consumers in ERCOT. Perhaps the recent addition of Mike Cleary, the "Nodal Czar," will free up some ERCOT resources to work on my request; thereafter, I ask to you move on this as expeditiously as possible. If you have any questions or comments, please don't hesitate to call me.

Sincerely

Barry

Barry T. Smitherman,
Chairman

cc: The Honorable Rick Perry
The Honorable David Dewhurst
The Honorable Speaker Joe Straus
Commissioner Donna Nelson
Commissioner Ken Anderson
The Honorable Troy Fraser
The Honorable Chris Harris
The Honorable Kip Averitt
The Honorable Craig Estes
The Honorable Burt Solomons
The Honorable Jose Menendez
The Honorable Joe Deshotel
The Honorable Craig Elkins
The Honorable Jim Keffer
The Honorable Myra Crownover
The Honorable Byron Cook
The Honorable Warren Chisum
The Honorable Allan Ritter
The Honorable Bill Callegari
Chairperson Jan Newton

Appendix B – Tabular Results

Table 1 100% energy - $7 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		20.76	12.23	156,569	167,690	250.5	
$10	5.57	22.94	15.00	154,953	169,298	249.0	1.5
$20	11.23	25.15	17.74	153,645	170,606	248.1	2.4
$25	14.15	26.28	19.10	152,072	172,153	246.9	3.5
$40	23.32	29.86	23.17	114,252	210,194	220.6	29.8
$60	38.03	35.72	27.63	67,719	256,675	188.7	61.7
$100	68.48	48.40	35.61	43,586	280,788	174.1	76.3

Table 2 100% energy - $10 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		29.54	16.07	157,497	166,693	250.9	
$10	5.53	31.71	18.85	156,810	167,386	250.3	0.6
$25	13.79	34.96	22.98	155,529	168,689	249.4	1.6
$40	22.20	38.25	27.10	154,001	170,219	248.1	2.8
$60	33.95	42.84	32.56	137,754	186,683	236.9	14.1
$100	62.57	54.33	41.72	66,901	257,426	188.2	62.8

Table 3 98% energy - $7 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		20.12	11.78	156,412	159,812	246.7	
$10	5.56	22.25	14.51	154,791	161,430	245.2	1.5
$25	14.07	25.50	18.55	151,595	164,627	242.9	3.8
$40	23.20	29.00	22.55	112,813	203,624	216.0	30.7
$60	37.74	34.69	26.90	64,311	252,076	182.7	64.0
$100	67.70	46.90	34.59	40,239	276,129	167.9	78.8

Table 4 98% energy - $10 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		28.62	15.45	157,318	158,879	247.2	
$10	5.53	30.75	18.18	156,592	159,593	246.5	0.7
$25	13.79	33.93	22.26	155,192	161,042	245.5	1.7
$40	22.16	37.11	26.31	153,611	162,640	244.2	3.0
$60	33.80	41.57	31.68	136,876	179,559	232.6	14.6
$100	62.17	52.75	40.59	62,606	253,738	181.5	65.7

Table 5 95% energy - $7 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		19.22	11.14	155,941	148,275	241.0	
$10	5.60	21.28	13.80	154,235	150,034	239.5	1.5
$25	14.23	24.46	17.74	150,919	153,338	237.0	4.0
$40	23.48	27.90	21.63	111,435	192,947	209.5	31.4
$60	37.44	33.21	25.80	58,118	246,200	172.8	68.2
$100	66.57	44.73	33.07	35,723	268,597	159.0	82.0

Table 6 95% energy - $10 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		27.36	14.54	156,888	147,330	241.5	
$10	5.58	29.42	17.21	156,232	147,994	240.9	0.6
$25	13.87	32.49	21.18	154,783	149,471	239.9	1.7
$40	22.19	35.55	25.13	153,051	151,216	238.4	3.2
$60	34.07	39.95	30.37	135,596	168,860	226.3	15.2
$100	61.65	50.53	38.93	56,916	247,389	171.9	69.6

Table 7 90% energy - $7 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		17.78	10.09	155,015	129,261	231.6	
$10	5.68	19.74	12.64	153,214	131,086	230.0	1.6
$25	14.37	22.75	16.42	149,329	135,040	227.1	4.5
$40	23.70	26.06	20.14	107,619	176,762	198.0	33.6
$60	37.12	30.89	24.01	48,017	236,274	156.6	75.0
$100	64.82	41.25	30.60	27,718	256,593	144.0	87.6

Table 8 90% energy - $10 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		25.35	13.07	155,903	128,320	232.1	
$10	5.56	27.26	15.62	155,279	128,990	231.5	0.6
$25	14.02	30.20	19.44	153,807	130,516	230.5	1.7
$40	22.37	33.10	23.22	151,747	132,586	228.7	3.5
$60	34.42	37.31	28.22	132,444	152,008	215.3	16.8
$100	60.95	46.96	36.20	46,884	237,416	155.7	76.4

Table 9 CREZ wind - 100% energy - $7 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		19.75	10.93	149,305	143,692	232.8	
$10	6.11	22.10	13.50	147,580	145,438	231.3	1.5
$25	15.51	25.72	17.31	143,132	150,082	227.9	4.9
$40	25.22	29.52	21.06	110,780	182,598	205.4	27.5
$60	38.99	35.14	25.17	59,758	233,531	170.4	62.4
$100	67.16	47.02	32.35	39,403	254,026	158.1	74.7

Table 10 CREZ wind - 100% energy - $10 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		27.83	14.27	150,299	140,017	233.5	
$10	6.21	30.21	16.84	149,746	140,545	232.9	0.6
$25	15.32	33.72	20.67	148,296	141,979	231.8	1.6
$40	24.56	37.30	24.50	145,391	143,876	229.3	4.1
$60	37.28	42.20	29.51	131,038	158,273	219.5	14.0
$100	64.92	53.46	37.93	59,113	230,254	169.9	63.6

Table 11 CREZ wind - 98% energy - $7 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		19.05	10.51	148,451	133,955	228.6	
$10	6.20	21.39	13.03	146,662	135,745	227.1	1.6
$25	15.59	24.92	16.77	142,261	139,075	223.7	5.0
$40	25.36	28.67	20.45	109,253	172,226	200.7	27.9
$60	39.11	34.17	24.44	56,369	225,007	164.3	64.3
$100	66.84	45.59	31.34	35,924	245,582	151.8	76.8

Table 12 CREZ wind - 98% energy - $10 gas

CT	LMP increase ($)	Adjusted wholesale power costs ($B)	Production cost ($B)	Coal generation (GWh)	Natural gas generation (GWh)	CO_2 emissions (millions short tons)	Emissions reductions (millions short tons)
$0		26.82	13.69	149,459	132,978	229.3	
$10	6.29	29.18	16.22	148,840	133,597	228.7	0.6
$25	15.53	32.66	19.98	147,447	134,990	227.7	1.6
$40	24.74	36.14	23.73	144,444	136,898	225.1	4.2
$60	37.54	40.98	28.64	129,825	151,562	215.0	14.3
$100	65.10	51.97	36.82	55,079	226,285	163.3	66.0