Exploring Natural Gas and Renewables in ERCOT, Part IV

The Future of Clean Energy in ERCOT

PREPARED FOR

The Texas Clean Energy Coalition

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THE Brattle GROUP

Agenda

Exploring Natural Gas and Renewables in ERCOT

Over the past three years, the Texas Clean Energy Coalition has engaged Brattle for a series of original, Texas-specific reports to explore the future of clean energy in ERCOT.

June 2013 – Part I: Natural gas and renewables can work together to create a cleaner power grid in Texas, depending on market and policy factors including long-term prices for natural gas prices and renewable energy technologies.

December 2013 – Part II: Over the next 20 years, all new power plants built in ERCOT will use natural gas, wind and solar power. While the actual mix of fuels will vary based on price and other factors, ERCOT's grid can accommodate any of the likely combinations without sacrificing reliability.

June 2014 – Part III: Clean energy from renewables and natural gas, combined with expanded energy efficiency (EE) and demand response (DR) programs, could cut the projected growth of peak electric demand in ERCOT by up to 50% over the next 20 years. By reducing the growth in our maximum power demand, EE and DR can help the ERCOT grid become cleaner and more reliable over time.

Exploring Natural Gas and Renewables in ERCOT

May 2016 -- Part IV:

How might market and regulatory factors affect how electricity will be generated in ERCOT, how much it will cost and how much CO_2 will be emitted?

Results: Key Findings

If:

- Natural gas prices remain low (<$4/MMBtu)
- Solar PV prices continue to decline as forecast
- Market forces are allowed to work unimpeded

Over the next 20 years the ERCOT electric grid will:

- Be much cleaner, resulting in less carbon pollution in Texas
- Rely primarily on Texas' own natural gas, wind and utility-scale solar PV power
- Cost virtually the same wholesale price as 2014 (other than inflation)
- Make proposed new federal regulations (CPP and Regional Haze Rule) largely irrelevant

Results: Highlights of a Low Gas/Low PV Scenario

- **Market Forces Drive The Transition:** The price of natural gas is driving change in the ERCOT grid, much more than any other factor.

- **Natural Gas Displaces Older Coal Plants**: Persistently low natural gas prices could cause the retirement of sixty percent (12 GW) of ERCOT's current fleet of coal-powered plants by 2022.

- **Natural Gas, Wind and Solar PV Will Largely Power ERCOT**: By 2035, about 85% of ERCOT power generation will come from natural gas, wind and solar power, with NGCC plants providing the lion's share of new generation.

- **Wind and Solar PV Will Grow**: Both wind and large-scale solar PV power will see swift, major additions of new generating capacity – 9 GW for wind by 2019 and 13 GW for solar by 2021.

Results: Highlights of a Low Gas/Low PV Scenario

- **ERCOT Will Get Much Cleaner**: Annual CO_2 emissions in ERCOT will drop by an average of 28% below 2005 levels – an average of 61 million tons less of CO_2 in Texas air every year.
- **A Cleaner ERCOT Grid Will Cost The Same As Today**: Wholesale electricity prices will stay around $41/MWh, similar to 2014 prices – virtually no price increase (other than for inflation).
- **Currently Proposed Environmental Regulations Will Be Largely Irrelevant**: Market forces will reduce CO_2 emissions in ERCOT below the requirements of proposed new standards in the EPA's controversial Clean Power Plan through 2035. Likewise, the EPA's Regional Haze Rule (if implemented) would have only a marginal impact (<15%) on projected coal plant retirements through 2022.
- **Energy Efficiency Can Save Money, Cut Carbon Pollution**: By accounting for enhanced energy efficiency to reduce demand for electricity an additional 5% by 2035, the need for electric plants on the ERCOT grid could be reduced by 4.7 GW, cutting CO_2 emissions and holding down power prices.

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Modeling Scenarios

The impact of market forces in the ERCOT grid is captured in four Reference Case scenarios:

- Low/high natural gas price
- Low/high cost of utility-scale solar PV
- These assumptions are based on natural gas futures, and forecasts from ERCOT and NREL

To explore the potential impact of state and federal policy, three policy scenarios are evaluated for each Reference Case:

- Enhanced state energy efficiency (EE) programs
- An emission cap similar to the CPP requirement (mass cap with new source complement)
- An emission rate standard similar to the CPP requirement (state average rate standard)

Four Reference Cases

	Natural Gas Price	PV Cost
Reference Case 1	Low	Low
Reference Case 2	Low	High
Reference Case 3	High	Low
Reference Case 4	High	High

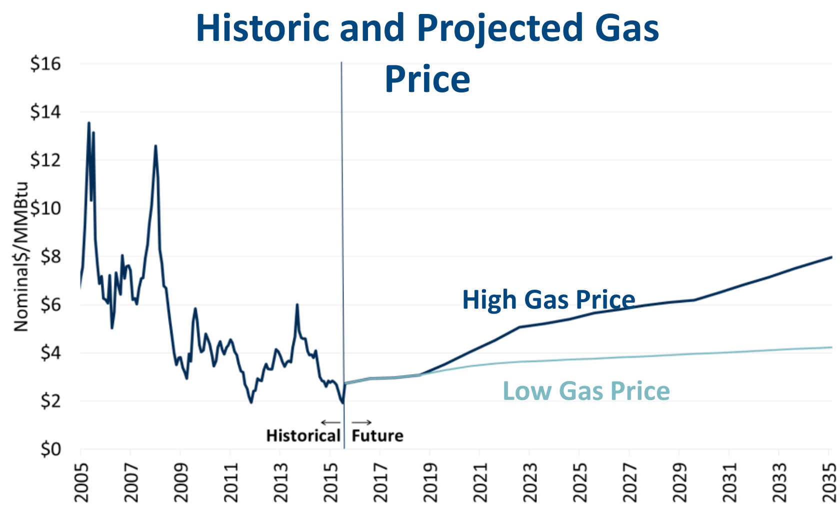
Natural Gas Prices

Near term (2016-2019) natural gas price forecasts are based on NYMEX gas futures.

For the long term, two natural gas price scenarios are modeled, based on ERCOT's 2016 LTSA gas price assumptions:

- **High Gas Price Forecast:**
  - Consistent with ERCOT's 2016 LTSA "Current Trends" forecast
  - Average of the 2015 AEO "Reference" and "High Oil and Gas" cases
  - Increases to $8/MMBtu (nominal) by 2035
- **Low Gas Price Forecast:**
  - Consistent with ERCOT's 2016 LTSA "Low" forecast
  - Grows slowly over time and reaches about $4/MMBtu (nominal) by 2035

2020-2023 is the transition period from NYMEX futures to ERCOT LTSA gas price assumptions.



Sources and Notes:
Historic data is Henry Hub spot price from SNL. Futures data are NYMEX Henry Hub monthly forwards as of 10/27/2015.

Renewable Power Prices

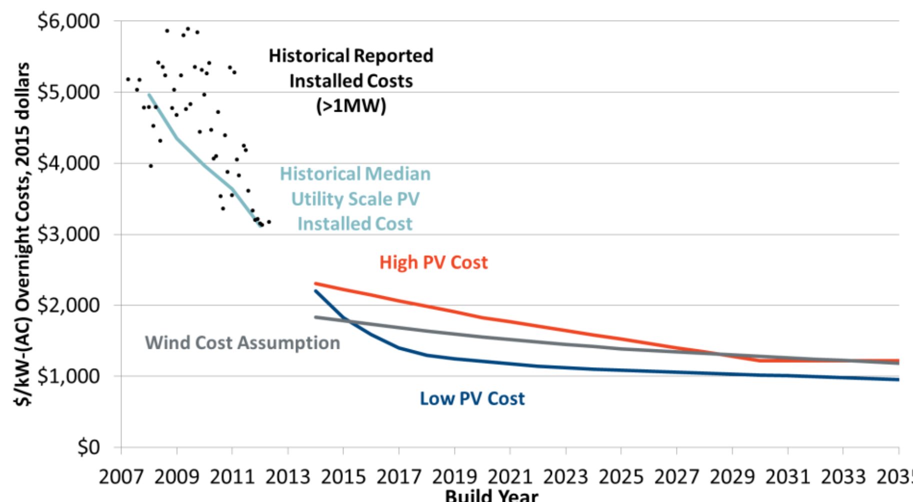
Utility-Scale Solar PV:

- The installed cost declines over time and is modeled in two trajectories:
  - The high PV cost projection is NREL's mid case
  - The Low PV cost is ERCOT's 2016 LTSA projection
  - We constrain the rate of PV additions and model the reduction of PV capacity value as penetration increases
- The model does not include additional high voltage transmission costs that might be required with high solar PV penetration

Wind:

- Installed cost projections are from ERCOT's 2016 LTSA base case assumptions.
- We model three different wind profiles based on the location: Coastal, Inland, and Panhandle.
- Wind capacity additions are limited by the capacity of the CREZ system; coastal wind capacity is limited to 4,600 MW

Renewable Power Installed Cost Projections



Sources and Notes:
Historical PV costs: reported costs from NREL and median from LBNL;
Forecasts: ERCOT 2016 LTSA Base Case; NREL

Modeling of the Production Tax Credit (PTC) for wind and the Investment Tax Credit (ITC) for solar PV are based on the 2016 Consolidated Appropriations Act.

Future Electric Demand and Energy Efficiency

The forecast for future electric demand is the average of ERCOT's 2016 "frozen efficiency" load forecast and the ERCOT load implied by the EIA 2015 AEO Reference Case growth rate. AEO2015 accounts for new standards and known EE programs.

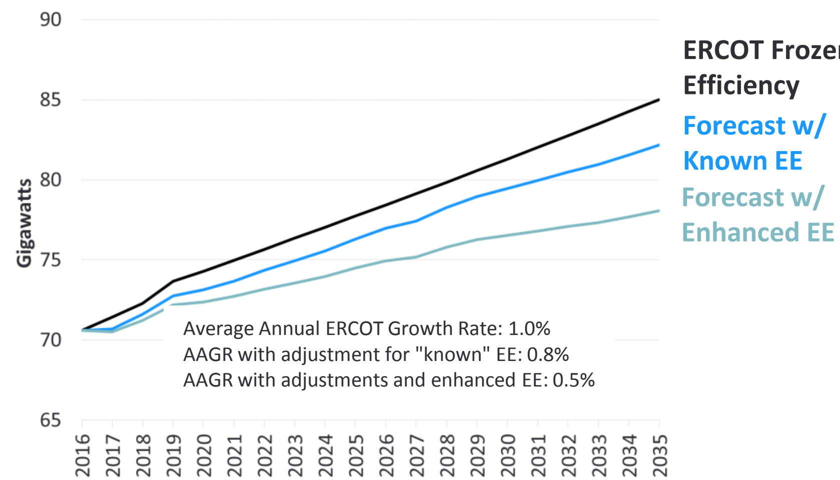
- This approach leads to a 3.4% reduction in total energy demand and peak demand from **known EE programs** in 2035, comparable to ERCOT LTSA assumptions of 3.5% by 2031.

For enhanced EE programs, we assume an additional 5% reduction in electric demand by 2035 beyond the known EE programs, based on ERCOT's analysis of proposed CPP.

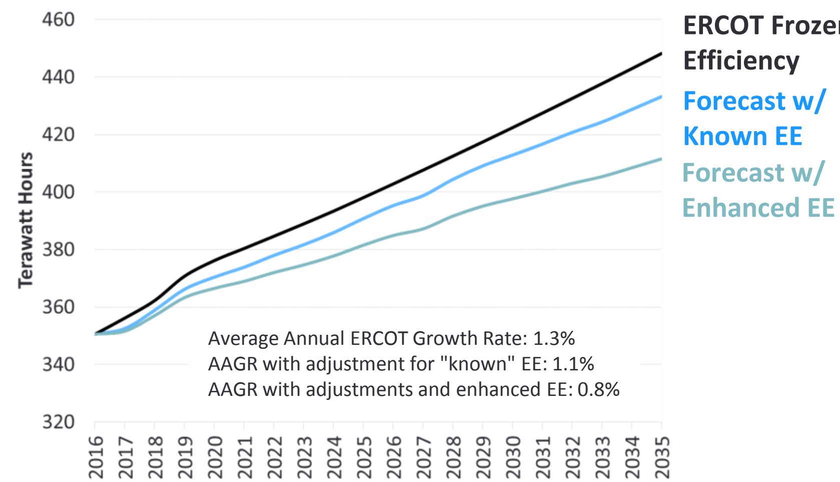
- This is more than what ERCOT assumes in its analysis of final CPP, but less than the EE potential reported by several studies of future EE potential in Texas.

In total, known and enhanced EE programs together would reduce electric demand by 8.2% compared to ERCOT's "frozen efficiency" forecast.

Peak Electric Demand Forecast



Energy Forecast



Sources and Notes:
2016 Long-Term Load Forecast, EIA 2015 AEO forecasts.

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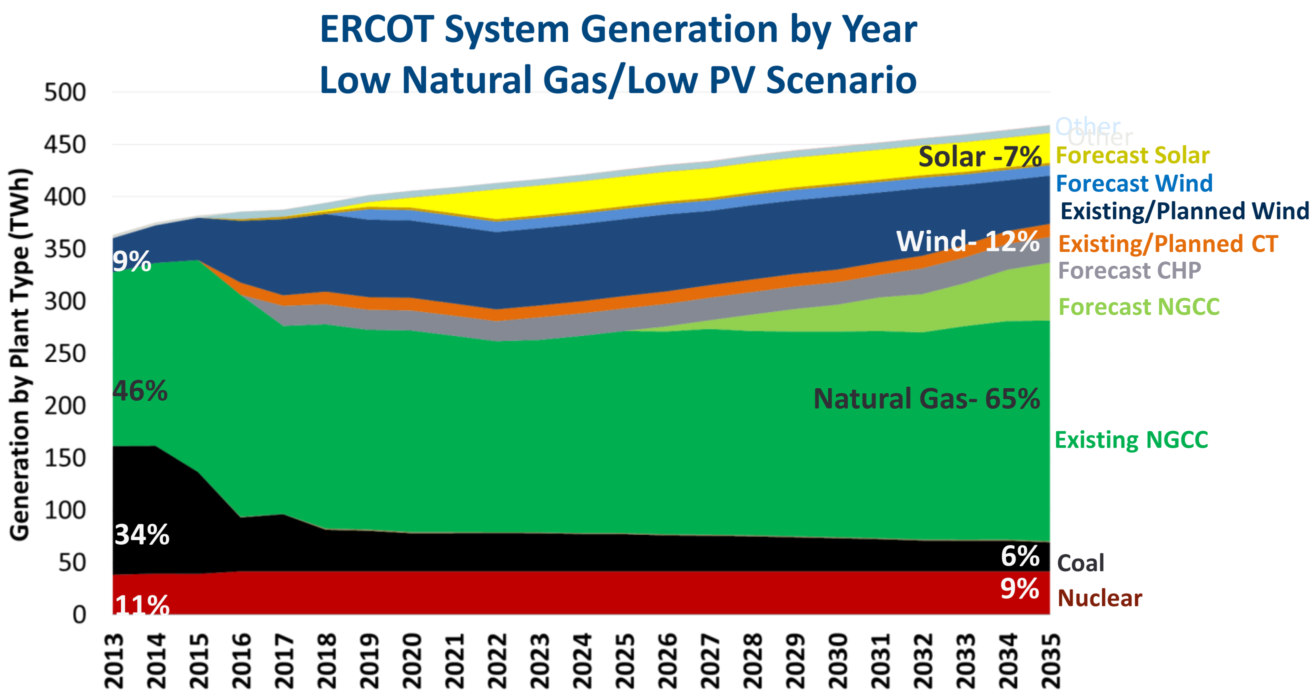
ERCOT System Energy Use 2013-2035

With low prices for natural gas and utility-scale solar PV, if market forces are allowed to work, 12 GW of coal generation is retired by 2022. It is replaced by natural gas generation (existing and new) and new solar PV.

By 2035, natural gas plants and renewable power would provide about 85% of all energy used in ERCOT; coal plants would provide 6%.

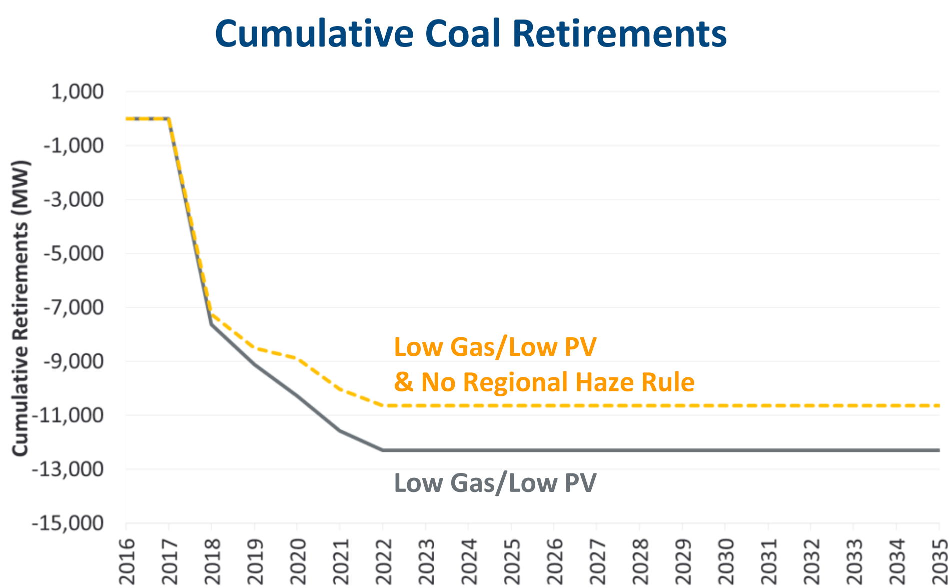


Notes: (1) 2013-2015 values are from ERCOT historical generation data and adjusted to include self-serving generation from PUNs which is not included in ERCOT's data. (2) The natural gas percentage groups NGCC, CHP, and Combustion Turbine (CT) generation.

Coal Retirements

Low natural gas prices are the main driver of coal retirements.

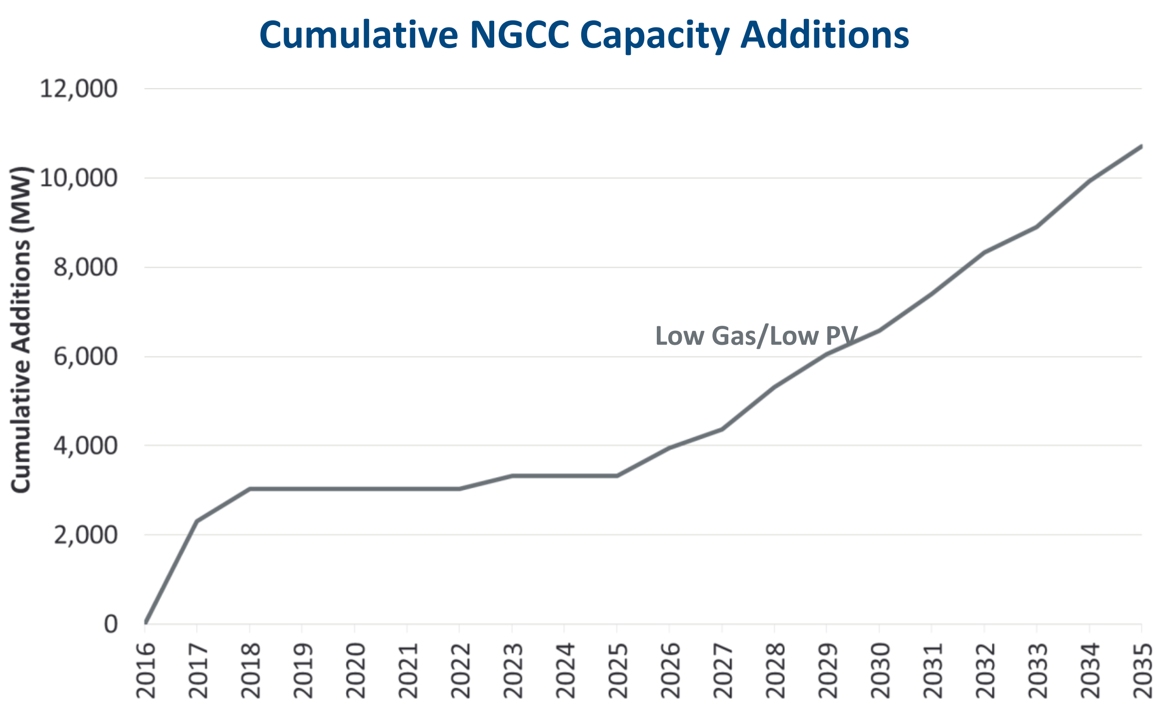
- Of the 19.6 GW of coal currently online in ERCOT, approximately 12 GW of coal would retire by 2022. (CPS has announced that it will retire the 900 MW JT Deely plant in 2018.)
- Only 1.7 GW (<15%) of the projected 12 GW of retirements is due to the proposed Regional Haze rule.



III. Scenario Results: Low Natural Gas/Low Solar PV

NGCC Generating Capacity

With low natural gas prices, a total of 10.7 GW of natural gas combined cycle (NGCC) generating capacity will be added by 2035 to replace retiring coal plants and meet increased electric demand. This includes 3.0 GW of CHP and 7.7 GW of NGCC plants.

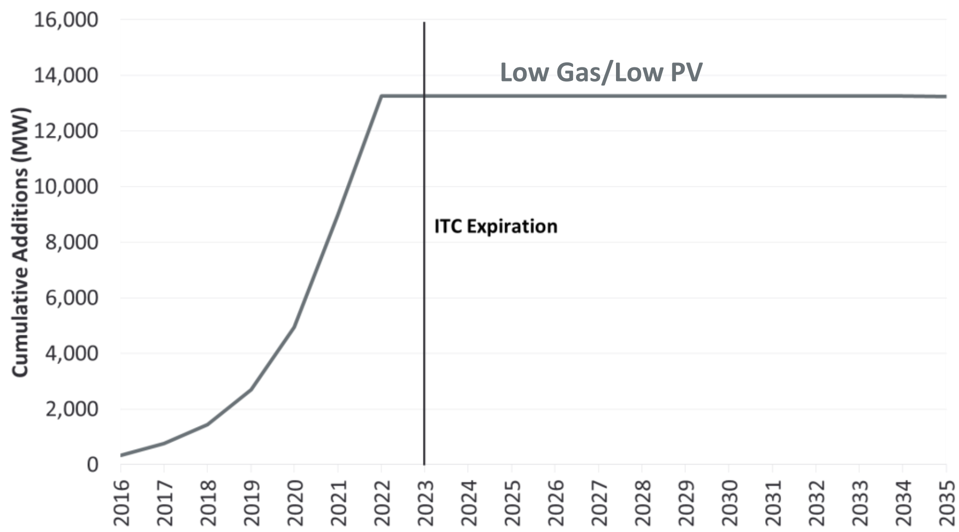


Utility-Scale Solar PV Generating Capacity

Declining prices for utility-scale solar PV drive the installation of 13.3 GW of new solar PV capacity, which is a significant increase over the 288 MW of installed solar capacity in ERCOT as of 2015.

All of the new solar PV capacity is added before the ITC expires in 2021.

Cumulative Utility-Scale Solar PV Capacity Additions



Sources and Notes:
ITC expiration date set to 2023 to account for a 2 year assumed construction time (ITC actually expires in 2021) The capacity factor for utility-scale solar PV is 26%.

III. Scenario Results: Low Natural Gas/Low Solar PV

Wind Generating Capacity

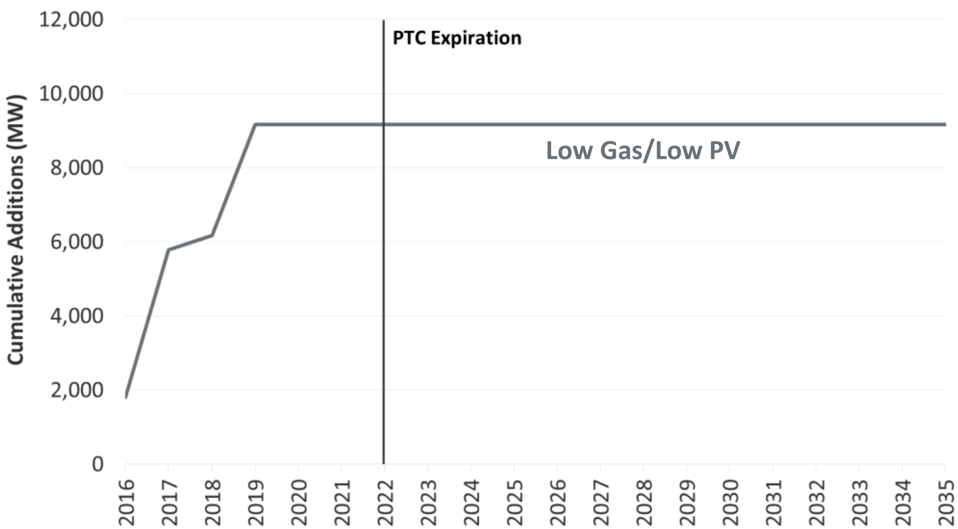
A total of 9.2 GW of new wind capacity would be added before 2019, including 3 GW of projected new coastal wind. In 2015 ERCOT had nearly 16 GW of installed wind capacity.

The model includes 6.2 GW of new wind projects that are already planned:

- 2.9 GW under construction or in site testing (Velocity Suite, ABB Inc.)
- 3.3 GW (50%) of permitted new wind capacity awaiting construction (ERCOT CDR, December 2015)

Existing wind is assumed to retires after a 25 year lifespan.

Cumulative Wind Capacity Additions



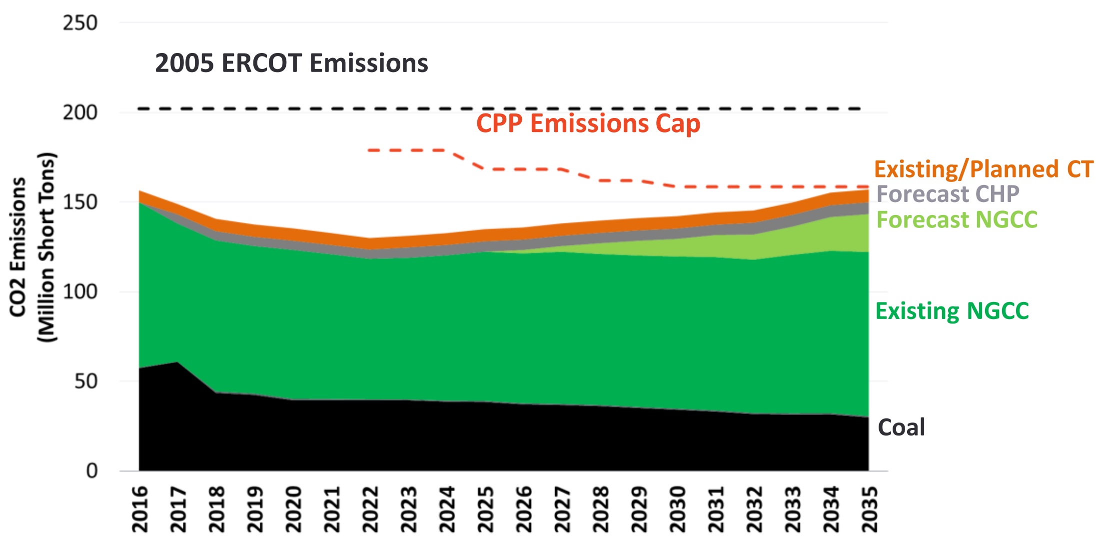
Sources and Notes: PTC expiration date set to 2022 to account for 3 year assumed construction time (PTC actually expires in 2019). The capacity factor for coastal wind is 37%, inland wind is 35%, and panhandle wind is 42%.

Declining CO_2 Emissions

As market forces drive the ERCOT grid to cleaner generation from natural gas NGCC, solar PV and wind power, CO_2 emissions will drop dramatically.

- CO_2 emissions in ERCOT would be about 28% below 2005 levels on average from 2016-2035, reducing emissions by an average of 61 million tons per year.
- CO_2 emissions would remain below the requirements of proposed new standards in the EPA's Clean Power Plan through 2035.

Annual ERCOT CO_2 Emissions
Low Gas/Low Solar PV Scenario



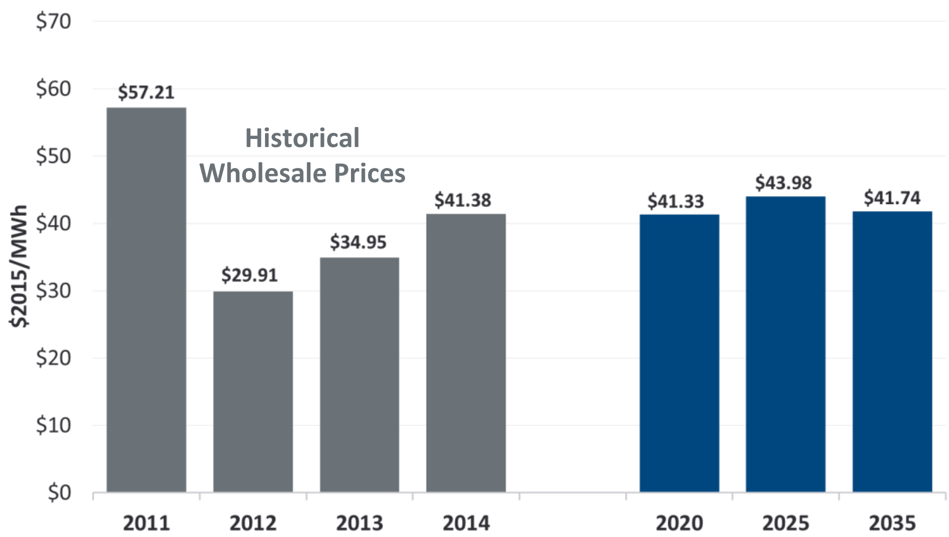
Sources/Notes: 2005 emissions from Velocity Suite.

III. Scenario Results: Low Natural Gas/Low Solar PV

Customer Costs Would Remain at 2014 Prices

If natural gas prices stay below $4/MMBtu for a prolonged period, wholesale electricity prices would be around $41/MWh by 2035 in real terms, similar to prices observed in recent years (except for inflation).

Average Wholesale Electricity Prices
Low Natural Gas/Low Solar PV Scenario

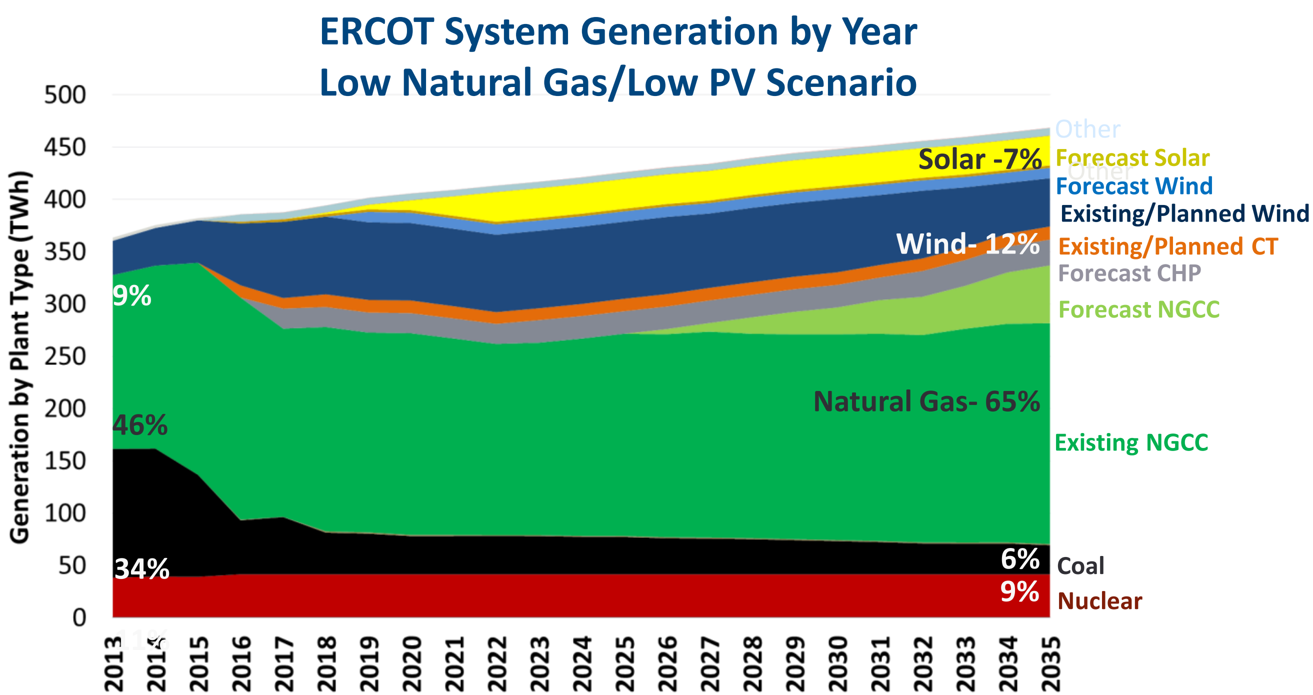


Sources: Historical whole electricity prices are from "2014 State of the Market Report for the ERCOT Wholesale Electricity Markets" ; 2013 Texas retail prices are from State Energy Data System.

Recap: ERCOT System Energy Use 2013-2035

Over the next 20 years, if market forces are allowed to work, most coal generation in ERCOT will be replaced by natural gas (NGCC), utility-scale solar PV and wind power.

Air pollution from CO_2 will decline dramatically, and customer costs will remain flat at 2014 prices (except for inflation).



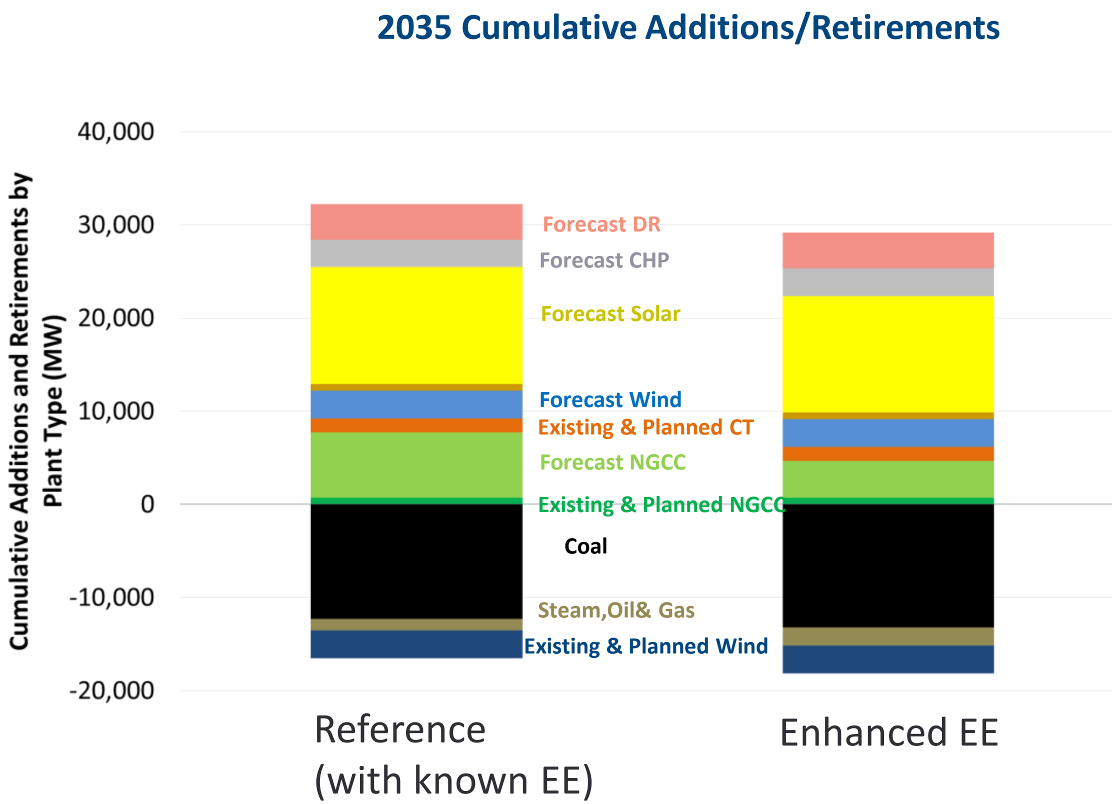
Notes: (1) 2013-2015 values are from ERCOT historical generation data and adjusted to include self-serving generation from PUNs which is not included in ERCOT's data. (2) The natural gas percentage groups NGCC, CHP, and Combustion Turbine (CT) generation.

III. Scenario Results: Low Natural Gas/Low Solar PV

Effect of Enhanced Energy Efficiency (EE)

By using enhanced energy efficiency (EE) programs to reduce demand for electricity by an additional 5%, ERCOT can reduce the projected fleet of electric plants, reduce CO_2 emissions and keep electric prices down.

- Shrink the projected fleet of electric plants by 4.7 GW in 2035, avoiding the need for new plants and retiring more old steam units.
  - 3 GW less NGCC, 0.9 GW of more coal retirement, and 0.7 GW of more steam oil and gas retirement.
- Reduce cumulative CO_2 emissions by 98 million short tons, or 3.5% between 2016 and 2035.
- Help keep wholesale electric prices down with about a \$0.20/MWh in 2035.



IV. Appendix
Alternative Scenarios and Background

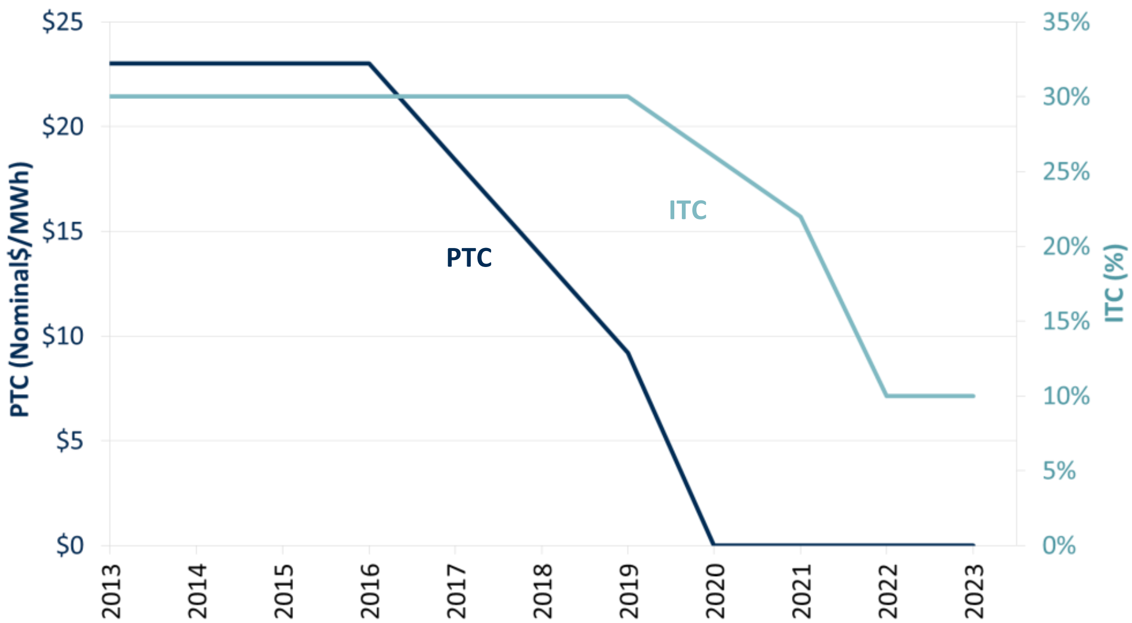
Renewable Tax Credits

Production Tax Credit (PTC) for Wind:

- The PTC for wind is extended by 2020 with the $23 per MWh credit falling gradually during that five-year period.

Investment Tax Credit (ITC) for Solar:

- The ITC for solar was amended to take effect when construction begins, instead of operations
- It is extended by five years, falling gradually through 2021, after which it retains a 10% investment tax credit



Sources and Notes:
"Consolidated Appropriations Act, 2016," December 2015.

Modeling Scenarios and Key Assumptions

Regional Haze Compliance

The Regional Haze Rule requires states to implement air quality protection plans to improve visibility in national parks and wilderness areas. The EPA finalized a plan for Texas in December 2014.

- 12 plants within ERCOT, a total of 8129 MW capacity, must either upgrade existing or install new scrubbers to comply with the rule.
- Consistent with ERCOT's assumptions, we assume a one-time cost of $500/kW for all 12 units.
- Upgrades are required by 2018, and new scrubbers must be installed by 2020.

Texas has challenged the legality of this rule.

The model also accounts for the fixed and operating costs of other current and future environmental upgrades (e.g. baghouses and SCRs).

Coal Plants Affected by Regional Haze

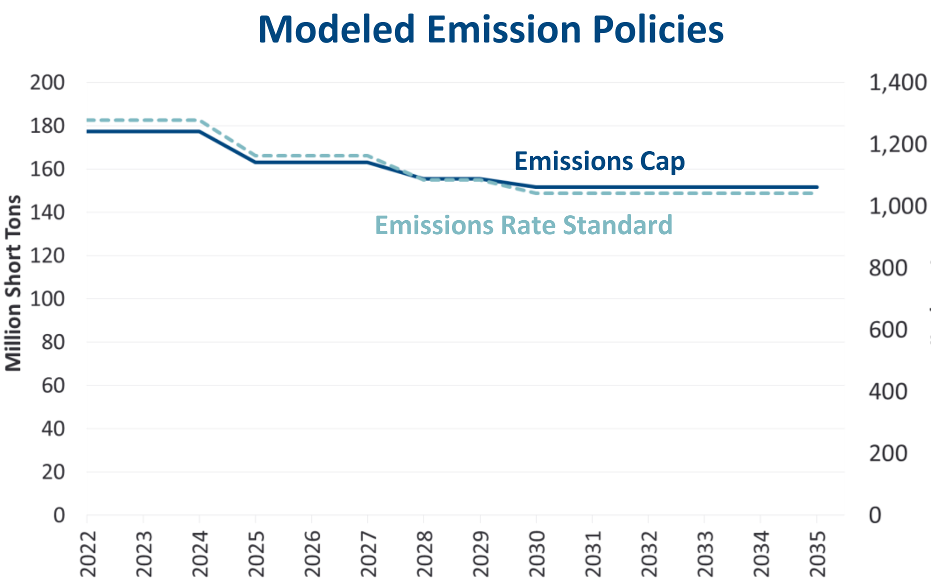
Unit Name	Capacity (MW)	Upgrade or New
Limestone 1	831	upgrade
Limestone 2	858	upgrade
Martin Lake 1	800	upgrade
Martin Lake 2	805	upgrade
Martin Lake 3	805	upgrade
Monticello 3	795	upgrade
Sandow 4	297	upgrade
Big Brown 1	606	new
Big Brown 2	602	new
Monticello 1	535	new
Monticello 2	535	new
Coleto Creek 1	660	new
Total	8,129	N/A

Sources and Notes:
"Impacts of Environmental Regulations in the ERCOT Region," ERCOT, December 16, 2014.

Carbon Policy Modeling

We developed two scenarios based on CPP compliance options:

- Emission cap:
  - Average 22% reduction from 2022 to 2035 from 2005 levels based on CPP's mass cap with new source complement compliance option.
  - We assume ERCOT has 80% of Texas CPP compliance goals based on ERCOT's share of Texas generation.
  - Some Private Use Network units are excluded.
- Emission rate standard:
  - 1,125 lbs/MWh average from 2022 to 2035 based on the CPP's state average rate standard, which applies to *existing fossil plants* operating or under construction by January 2014.
  - We include renewables that come online after January 1, 2013 are included in the emission rate calculation, lowering the average emissions rate, but do not include EE.



Sources and Notes:
Clean Power Plan Final Rule, August 2015. Caps are assumed to stay constant after 2030.

Reference Cases Results

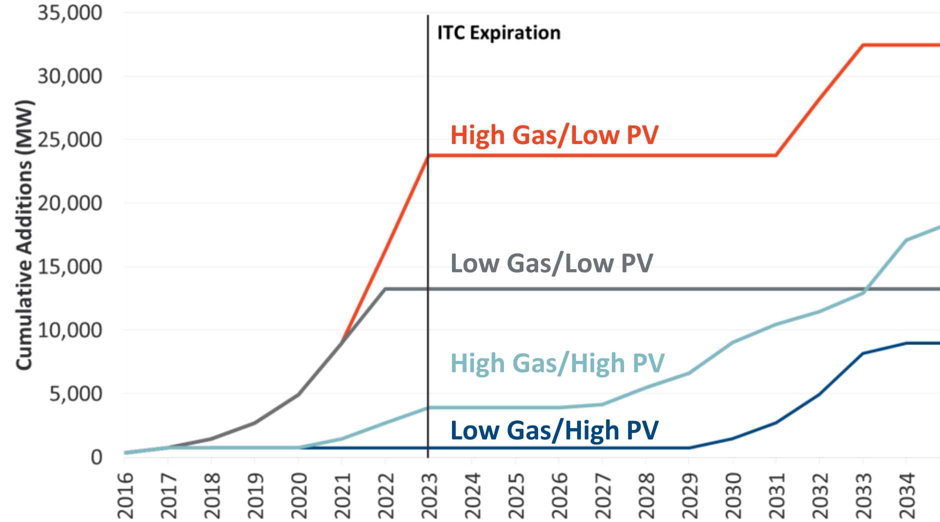
Utility-Scale PV Capacity Additions

Over the next decade, PV cost is the main driver of PV penetration. Over the longer term, natural gas price also matters and there is substantial growth of PV across all scenarios.

High Gas/Low PV is the most optimistic scenario for PV, which increases to about 24 GW by 2023 (ITC expiration in 2021) and then has a second wave of additions after 2031 to 32 GW as cost continues to decline.

Low Gas/High PV scenario represents the smallest PV build-out scenario with 9 GW by 2035. No PV is added until after 2029 when gas price increases and PV cost declines make PV competitive.

Cumulative Utility-Scale Solar Capacity Additions



Sources and Notes:
ITC expiration date set to 2023 to account for a 2 year assumed construction time (ITC actually expires in 2021)

Reference Cases Results

Wind Capacity Additions

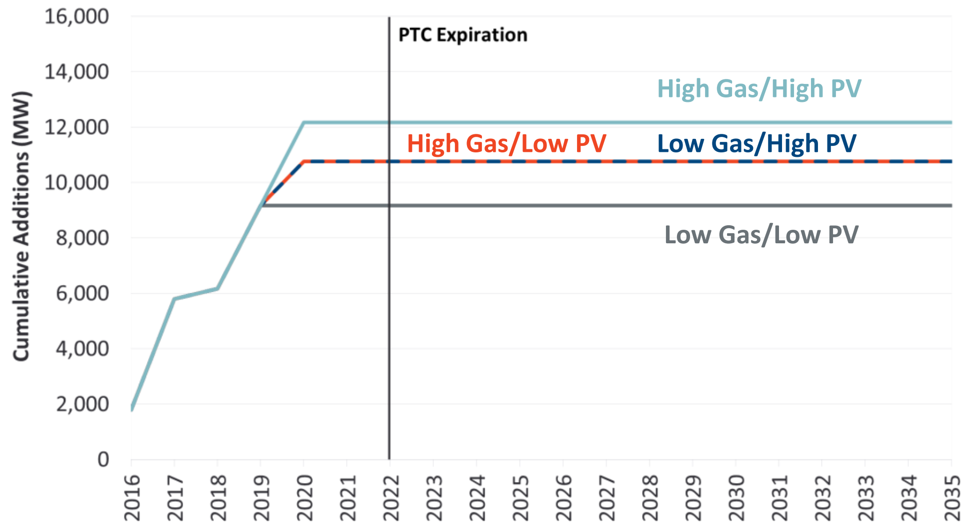
All cases have wind capacity additions prior to the PTC expiration because the PTC will be and has been a strong factor in wind development.

Wind capacity additions are the same under High Gas/Low PV and Low Gas/High PV. In both cases, only Rio Grande Valley/Coastal wind is economic due to better coincidence with high load hours.

In the High Gas/High PV scenarios, inland wind is built as well.

Existing wind retires after its 25 year lifespan and usually is not replaced. Instead, new solar PV capacity is added as it is more competitive under its assumed cost trajectory.

Cumulative Wind Additions



Sources and Notes:
PTC expiration date set to 2022 to account for 3 year assumed construction time (PTC actually expires in 2019).

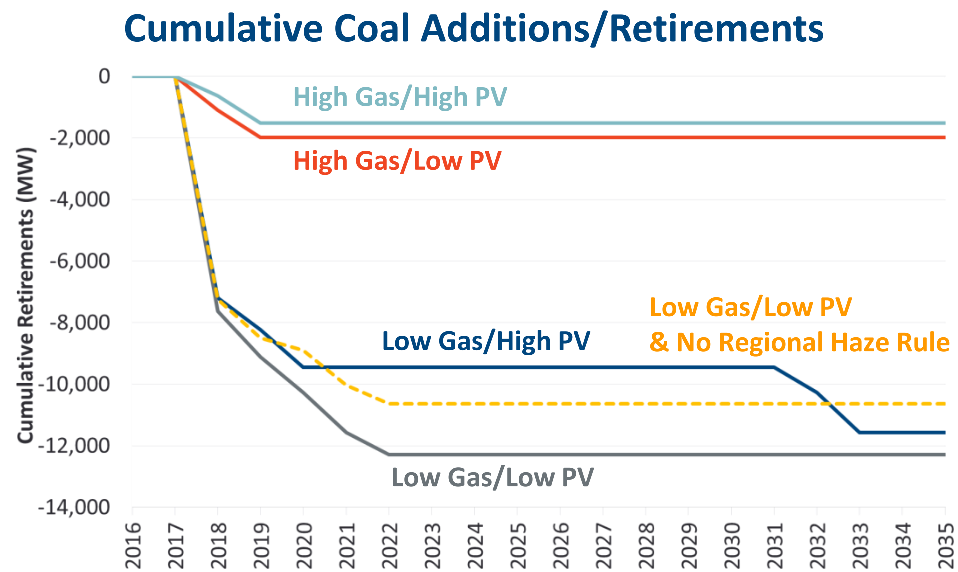
Reference Cases Results

Coal Retirements

Currently, 19.6 GW of coal is online in ERCOT. Of this, JT Deely (about 900 MW) will retire in 2018 according to CPS.

Natural gas price is the main driver of coal retirements.

- Approximately 10 - 12 GW of coal would retire if natural gas prices remains low for a prolonged period, mostly by 2020.
- A sensitivity case without Regional Haze under Low Gas/Low PV case indicates that only 1.7 GW of the projected 12 GW of retirements is due to Regional Haze rule.
- PV costs have a relatively small effect on coal retirements; however low PV costs may accelerate coal retirements due to ITC-induced construction of new solar PV capacity.

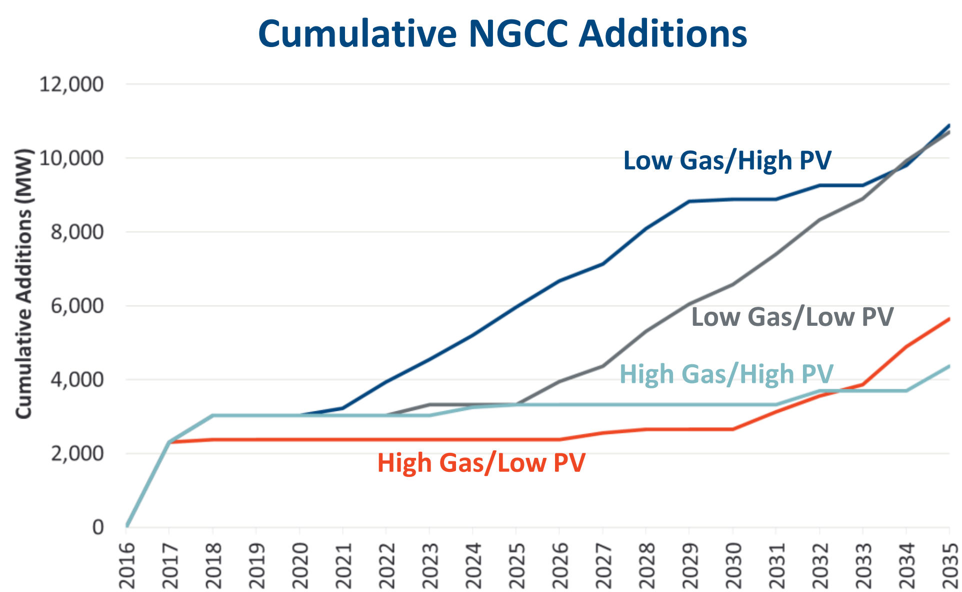


Reference Cases Results

NGCC Capacity Additions

Natural gas price is the main driver of new natural gas capacity; new natural gas plants are primarily natural gas combined cycle (NGCC).

- With high natural gas prices, additions are limited prior to 2030. Solar PV and wind are the main resources added to meet increased demand prior to 2030. Total NGCC added by 2035 is between 4 and 6 GW.
- With low natural gas prices, new NGCC is added starting in 2020 with high PV cost and in 2025 with low PV cost, partially replacing retiring coal capacity. By 2035, about 11 GW of NGCC is added.
- In all cases, 3 GW of CHP is added by 2035.

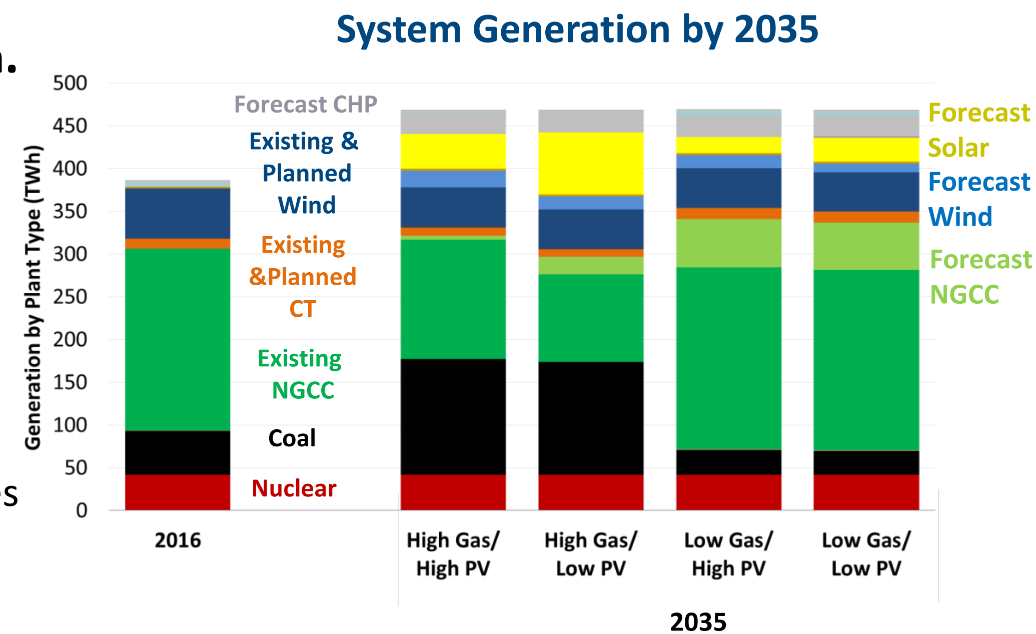


Reference Cases Results:

ERCOT System Generation by 2035

Future generation profiles also vary significantly between scenarios, with natural gas providing 33%-65% of generation, and renewables (wind and solar) providing 18%-30% of generation.

- With low gas prices, natural gas and renewables provide 83% of the generation while only 6% generation is provided by the coal fleet.
- With high gas prices, most of the coal fleet stays online and the share of generation increases to about 30% by 2035 whereas natural gas and renewables provide less than 65% of generation.



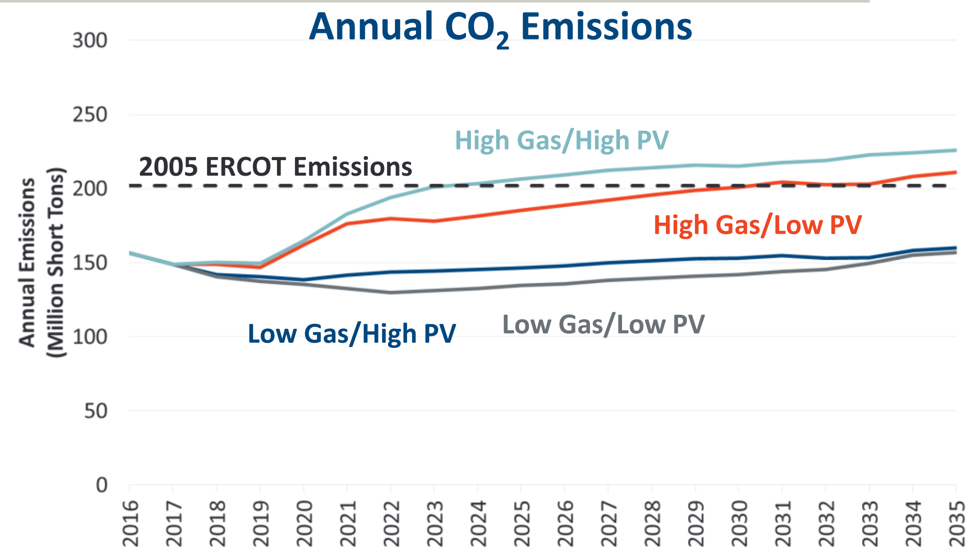
CO_2 Emissions

Low natural gas prices in both PV cases result in ~23% lower CO_2 compared with high gas prices (cumulative 2016-2035) and ~28% below the 2005 emission level on average from 2016-2035.

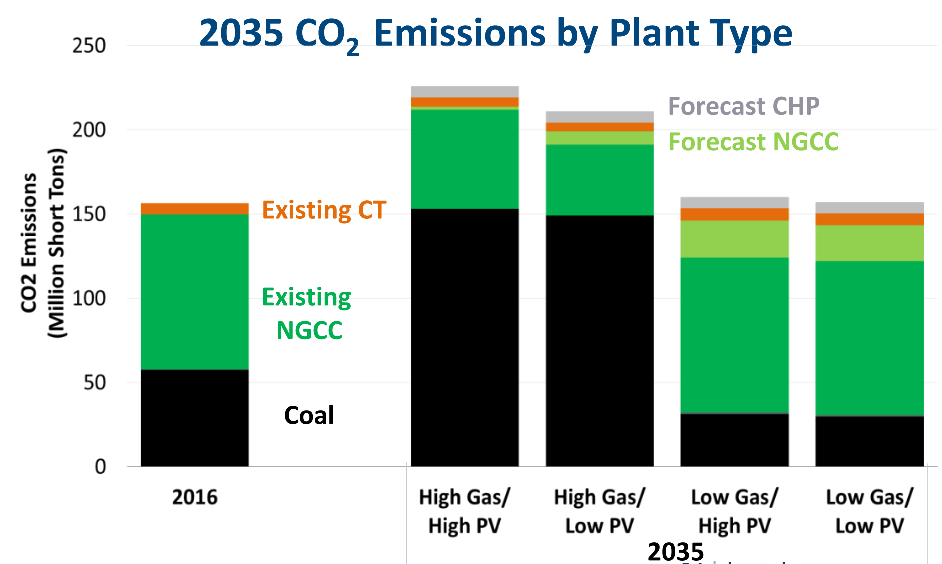
If natural gas prices were to rise, there are fewer emissions reductions from coal to gas switching, and emissions get back to 2005 levels and above after 2023 with high PV cost and after 2030 with low PV cost.

Low solar PV costs in both natural gas cases results in a ~5% reduction cumulatively in 2016-2035.

- Emission reductions are limited, since the marginal generator type offset by solar PV is typically NGCC (which has low CO_2 emissions relative to coal) and the capacity factor of solar PV is only about 26%.



Source: 2005 emissions from Velocity Suite

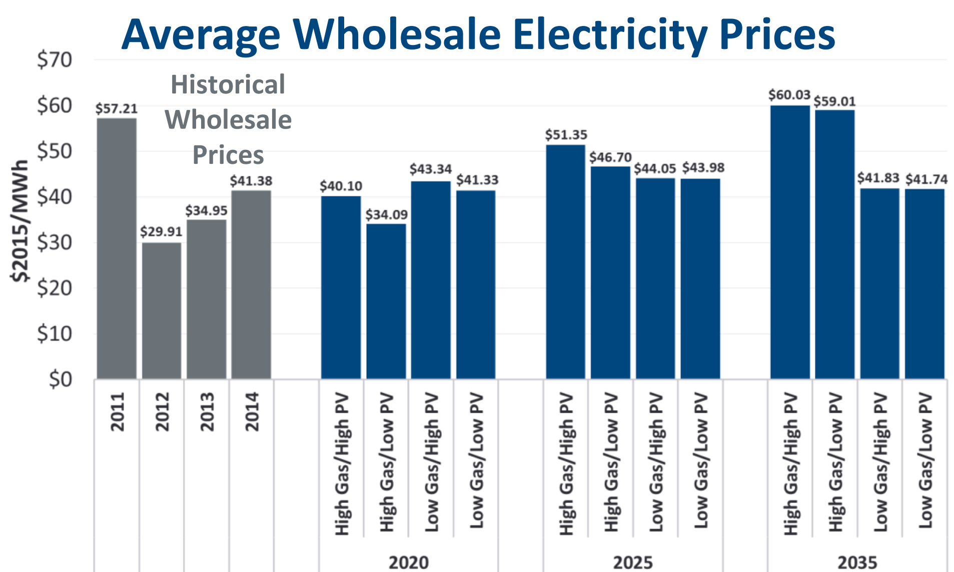


Reference Cases Results

Customer Costs

Natural gas price is the primary driver of electricity prices. If natural gas price stays low for a prolonged period, wholesale electricity prices would be around $40/MWh by 2035, similar to prices observed in recent years. Under higher natural gas prices, wholesale electricity prices increase to about $60/MWh.

Solar PV cost does not have a large impact on electricity prices in 2035. The effects of the ITC-induced solar PV capacity additions can be seen in 2020 (15% reduction under high gas/low PV case), diminishing somewhat in 2025.



Source: Historical prices are from “2014 State of the Market Report for the ERCOT Wholesale Electricity Markets”

Effect of Enhanced EE

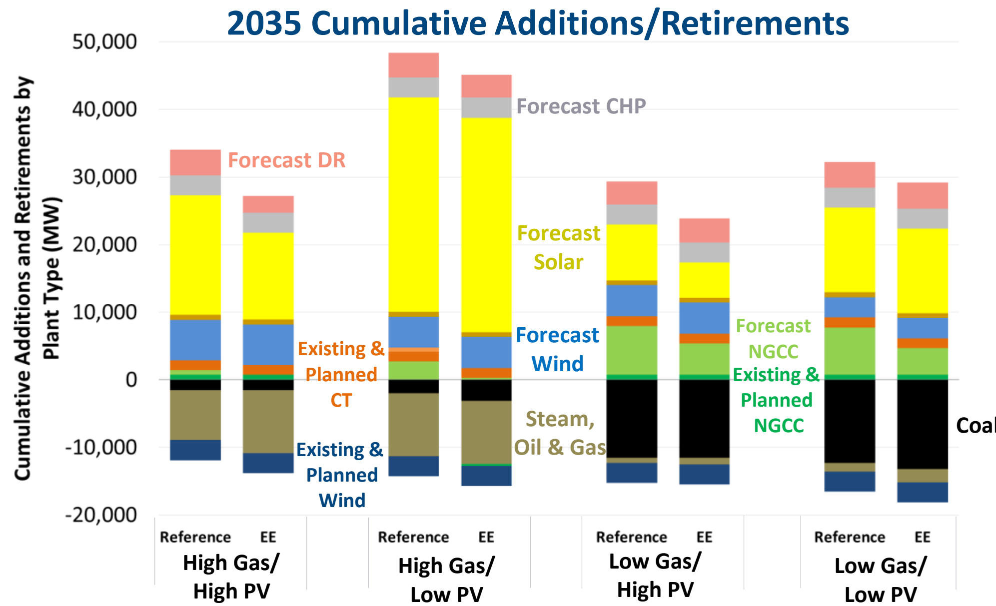
Load reductions due to enhanced energy efficiency shrinks the projected fleet by 4.7 - 9.5 GW in 2035, avoiding capacity additions and resulting in more retirements of steam units, including coal and steam oil and gas plants.

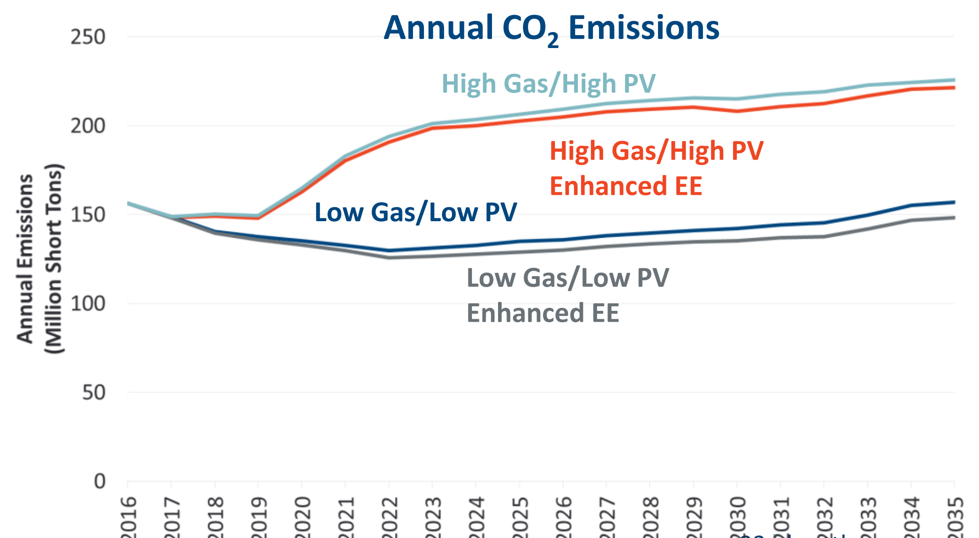
- Capacity additions decrease by 3.1 - 7.6 GW and steam unit retirements increase by 0.2 - 1.9 GW.

Across all scenarios, enhanced energy efficiency reduces cumulative CO_2 emissions by 75 - 179 million tons, or 2-5% between 2016 and 2035.

Electricity prices are slightly lower with enhanced energy efficiency.

- With High Gas/High PV case, it results in \$2.40/MWh price decrease in 2035.
- In the other cases, the effect is almost negligible: a \$0.20/MWh or smaller price reduction.





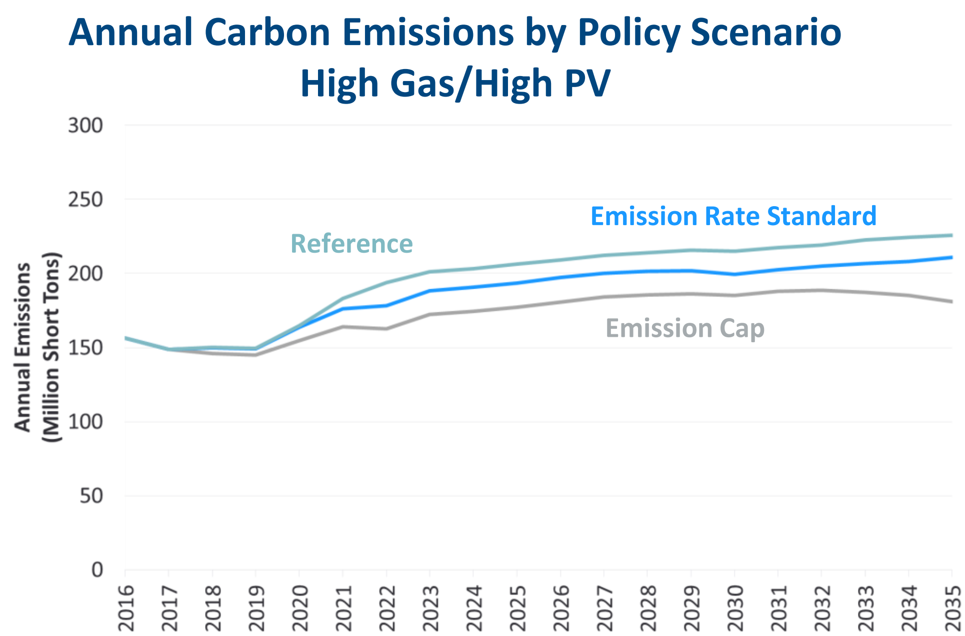
Policy Scenario Results

Effect of Carbon Policies on Emissions

Neither of the emission policies is limiting through 2035 when natural gas prices are low.

With high natural gas prices, different CO_2 policies result in different levels of CO_2 emission reductions.

- Imposing an emission cap results in emission reductions from the parallel reference case by about 12% in 2016-2035.
- The emission rate target is only limiting with high PV costs, leading to about 5% of emission reduction between 2016-2035.



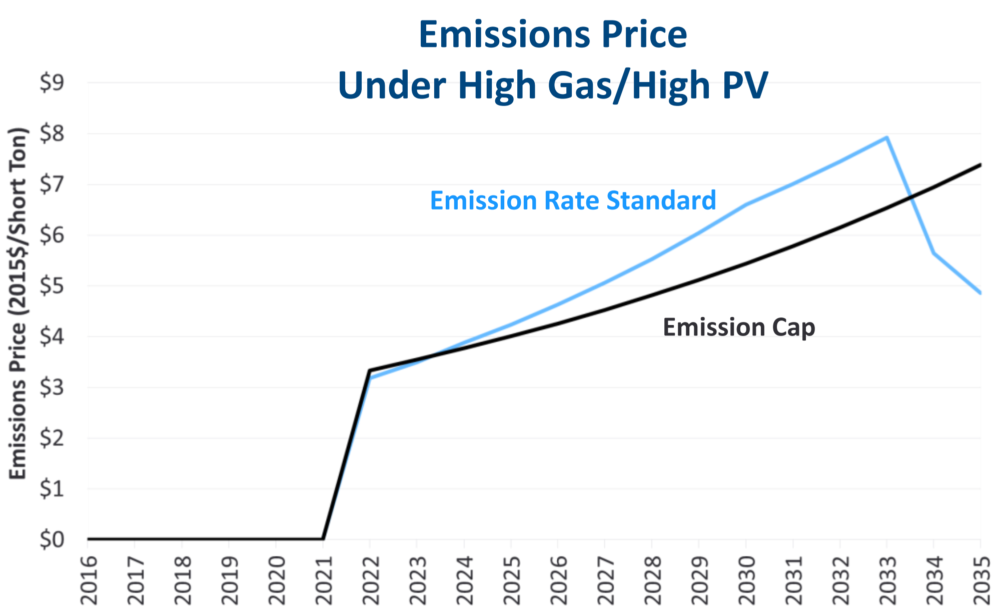
	Emission Cap	Emission Rate Standard
Reduction in 2035 (million short ton)/%	45/20%	15/7%
Cumulative reduction in 2016-2035 (million short ton)/%	480/12%	204/5%

Carbon Prices

With low natural gas prices, there is no CO_2 price since the two CO_2 policies modeled are not limiting.

With high natural gas prices, CO_2 prices are under \$8/ton through 2035.

- Emission rate targets result in a CO_2 price of around \$8/ton in 2033, after which the CO_2 price decreases as PV replaces retiring wind plants.
- The existing wind plants that retire are not included in the rate calculation, but the new PV is, resulting a declining CO_2 prices with the emission rate target.



Notes: Carbon price for state average rate standard is converted to \$/short ton from \$/MWh ERC price

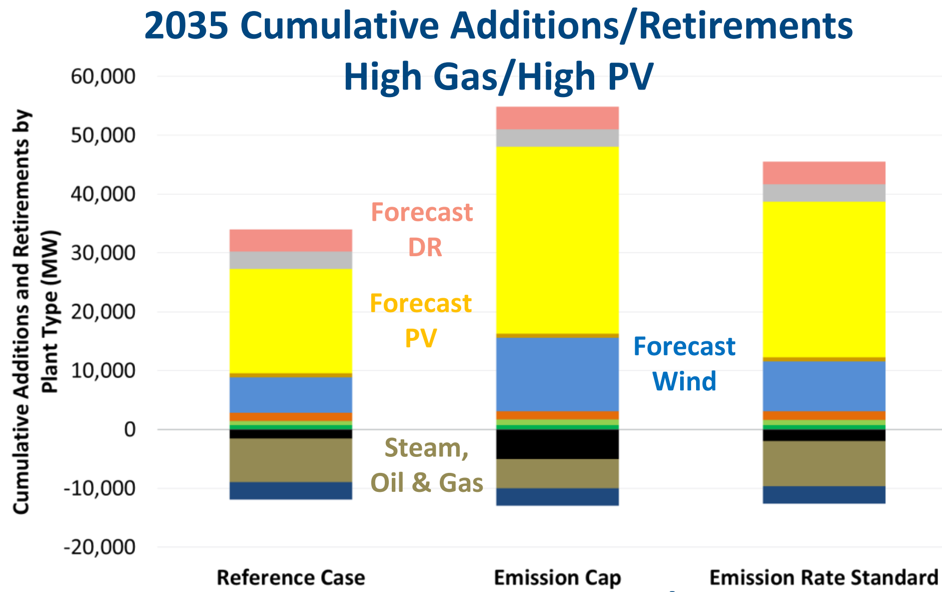
Policy Scenario Results

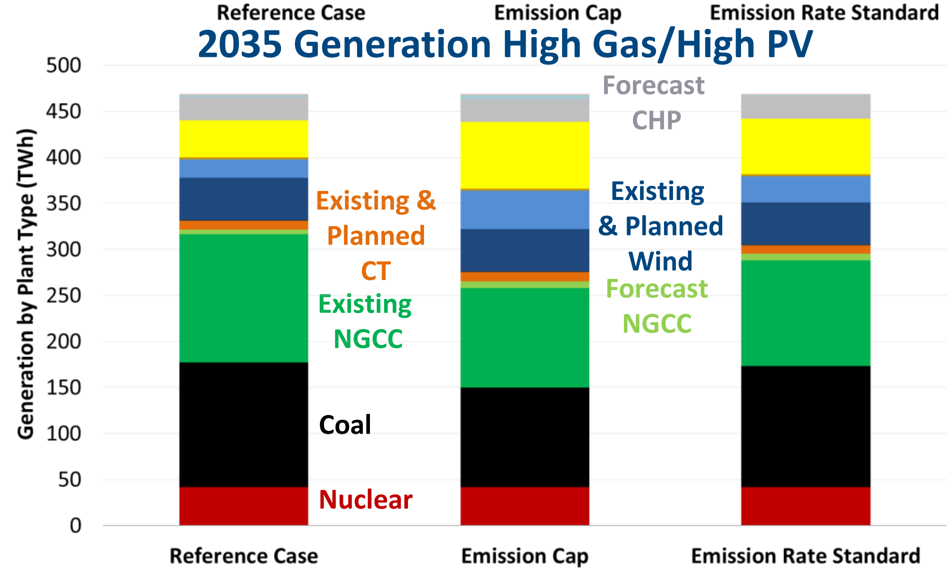
Effect of Carbon Policies on Capacity & Generation

With high natural gas prices, CO_2 policies increase renewable additions and result in the retirement of more existing steam units.

- An emission cap results in up to 3.5 GW more coal retirement and 2.4 GW less steam oil and gas retirement, whereas an emission rate standard has little impact on retirements.
- Between 9 GW and 14 GW of additional PV and up to 6 GW of wind by 2035 are added due to CO_2 policies.

Low gas prices are much more of threats than modeled CO_2 policies to coal generation and capacity.





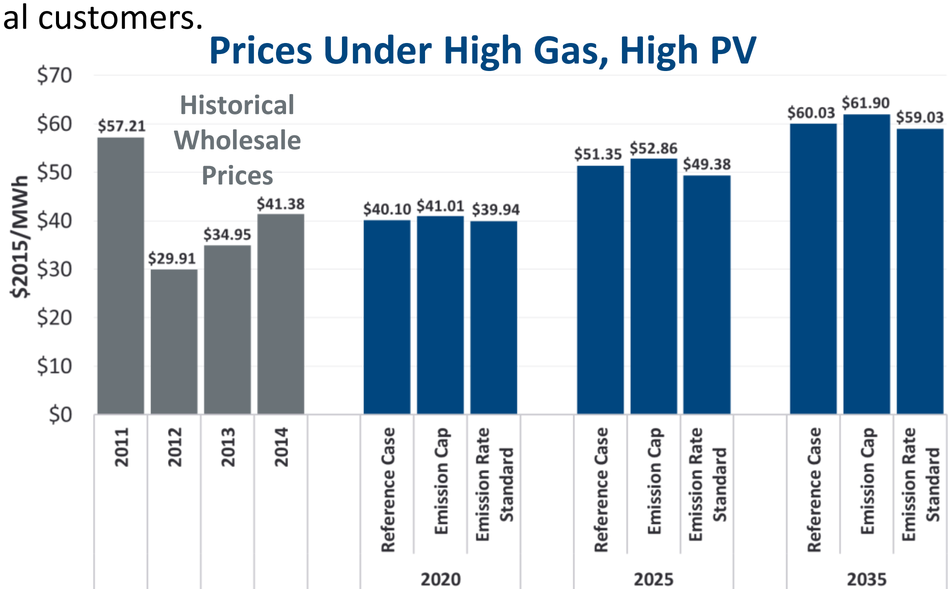
Effects of Carbon Policies on Electricity Prices

Under the emission cap policy, the moderate CO_2 prices increases electricity prices only slightly.

- Under the emission cap, wholesale electricity prices increase about \$2.30/MWh (4.6%) on average from 2022-2035 under High gas/High PV case.
- This implies that the retail rate increase is about 1.8% for residential customers, 2.4% for commercial customers, and 3.1% for industrial customers.

Under the emission rate standard, electricity prices decrease slightly because gas generators receive revenues from selling CO_2 credits to coal generators, which decreases their dispatch costs and, hence, the energy price.

- The energy price decreases by \$1.10/MWh (2.3%) under the High gas/High PV case on average from 2022-2035.
- This implies that the retail rate decrease is about 0.9% for residential customers, 1.2% for commercial customers, and 1.5% for industrial customers.



Source: Historical prices are from “2014 State of the Market Report for the ERCOT Wholesale Electricity Markets”

Carbon Emission Caps vs. Carbon Emission Rates

There are major differences between the two approaches

- A rate limit allows for growth in generation and emissions as long as the mix of generation types still achieves the rate target; whereas a cap limits total emissions and can limit growth in generation
- A rate limit (of the type proposed by EPA that includes future RE and EE in the rate calculation) provides greater incentives for RE and EE than does a cap
- A cap creates allowances that the state must allocate to stakeholders or use for some public purpose. The list of uses include:
  - Allocation to ratepayers to reduce the cost of the program
  - Allocation to affected industries (for example, coal generators and energy intensive industries) to reduce the cost
  - Reduce taxes
  - Incentivize new renewables and energy efficiency

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About The Brattle Group

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governmental agencies worldwide.

We combine in-depth industry experience and rigorous analyses to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

Our services to the electric power industry include:

- Climate Change Policy and Planning
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Presenter Information

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Dr. Shavel is an energy economist with over 30 years of experience in the energy industry, specializing in the economics and operations of the U.S. electric power system, generation and transmission investment, and environmental strategy. He has performed work for a wide range of clients, including generation and transmission companies, natural gas pipelines, marketers, developers, industry research groups, and as federal agencies. Recently he co-authored a study for the Texas Clean Energy Coalition on the future of renewable and natural gas generation in ERCOT.
Dr. Shavel has broad experience developing models of North American power systems, including the Integrated Planning Model by ICF International. He has also directed significant assignments for major electric utilities, independent transmission companies, RTOs, independent power producers and private equity on matters such as coal plant retirements, fuel price forecasting, the benefits of new transmission lines and power plant valuation. Dr. Shavel has testified before the Federal Energy Regulatory Commission (FERC), state regulatory agencies, and the Ontario Energy Board. Prior to joining Brattle, Dr. Shavel was a Vice President at Charles River Associates (CRA). While at CRA, he led the development of the National Energy and Environment Model (NEEM) and contributed to its integration with the Multi-Region National Macroeconomic Model.

Presenter Information

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Dr. Yingxia Yang is currently an associate in the Utility Practice Area of Brattle. Her experience is focused on developing and using economic models to conduct the economic and policy analysis of energy and environmental issues in the energy industries with a focus on the power and natural gas sectors. She has performed the economic and policy analysis of the power system and generation technologies to consult energy industry companies for integrated operation planning and environmental strategies as well as the impact of shale gas production on the electric sector and the whole economy.

Before she joined Brattle, she worked for CRA, where Dr. Yang led the modeling effort of MRN-NEEM (Multi-Regional National model-North American Electricity and Environment Model). Prior to joining CRA, Dr. Yang worked at MIT Energy Initiative during her postdoctoral research where she participated in a large interdisciplinary MIT study entitled "The Future of Natural Gas" and led the quantitative analysis of the impacts of a US climate policy on natural gas consumption in the power sector by employing the MARKAL model and contributed to the chapter, "Demand for gas in the power sector."