

Needs For and Alternatives To

APPENDIX 3.1

**Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO
- The Brattle Group**

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Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO

Prepared for
Manitoba Hydro
For Internal Use Only

The Brattle Group

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Appendix: Scenario Results

Context and Assignment

Manitoba Hydro is the primary electricity provider to Manitoba

- ◆ Hydro-dominated generation, serving Manitoba and export markets
- ◆ Significant exporter to the U.S. upper Midwest (MISO – Minn Hub)

Manitoba Hydro engaged *The Brattle Group* to prepare a long-term electricity price forecast (2015-2049) for its U.S. export market – Minn Hub in MISO

- ◆ To be used in the context of its long-term planning process, to understand potential opportunities for long lead-time infrastructure investments and long-term power sales

Deliverables:

- ◆ Detailed analytic assumptions, model inputs and results
- ◆ Standalone, presentation-style final report
- ◆ Conference call to review and discuss report

Disclaimer

While this report may assist Manitoba Hydro in rendering an informed decision regarding the future value of potential investments, it is not meant or permitted to be a substitute for the exercise of Manitoba Hydro's own business judgment. This applies equally for potential partners of Manitoba Hydro who may have access to this report, or other parties who may review it. The analyses and report necessarily involve the use of assumptions and projections with respect to conditions that may exist or events that may occur in the future. Although *The Brattle Group* has applied assumptions and projections that it believes to be reasonable, they are subjective and may differ from those that might be used by other economic or industry experts to perform similar analysis. In addition, and equally as important, actual future outcomes are dependent upon future events that are outside *The Brattle Group's* control. No one can give any assurance that the assumptions, projections, or judgments used will prove to be correct or that actual future outcomes will match the forecasts. *The Brattle Group* cannot, and does not, accept liability under any theory for losses suffered, whether direct or consequential, arising from any reliance on this report, and cannot be held responsible if any conclusions drawn from this report should prove to be inaccurate.

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2. Conceptual Issues

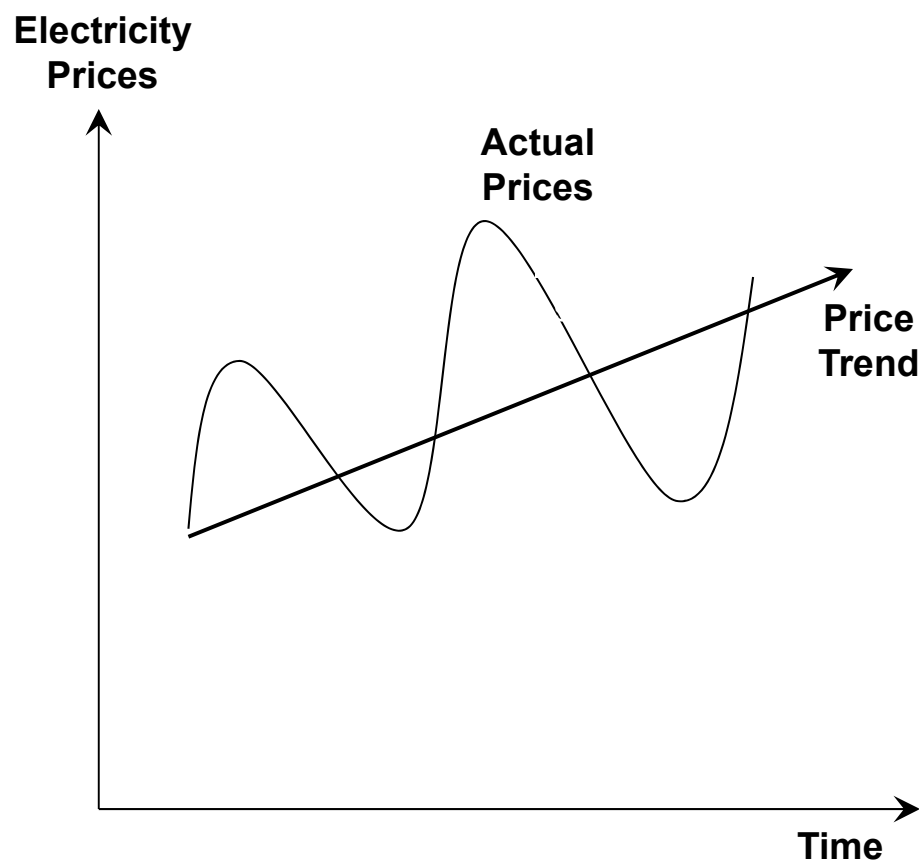
Conceptual Issues: Price Trends vs. Volatility

Distinguish between price trends and price volatility

- ♦ Electricity prices are the most volatile of all energy prices, though do follow trends

This forecasting effort focuses on potential long-term price trends, not short-term volatility

- ♦ Long-term investment relies mostly on trends, not short-term volatility. Price volatility can be avoided, to an extent, through contracting.



Conceptual Issues: Uncertainty

Power prices are influenced by many engineering, economic, and social factors which are highly uncertain (some will remain so far into the future)

- ◆ Fuel cost and availability, particularly natural gas
- ◆ Climate policy and resulting CO₂ price, if any
 - Also related policies: requirements/subsidies for renewables, etc.
- ◆ Retirements and other restrictions on coal: recent and evolving EPA regulations
 - Rules have become more clear, and much coal is retiring, but ultimate effects are still uncertain
- ◆ Public acceptance, investor confidence and policy support for new infrastructure
 - Shale gas fracking
 - Transmission infrastructure expansion for large-scale renewable additions
 - New nuclear power plants
 - Carbon capture and sequestration
- ◆ Technological and cost uncertainty for new generating technologies
 - Renewable generation (wind, solar, and other emerging technologies)
 - Coal generation, with or without carbon capture and sequestration (CCS)
 - Advanced nuclear generation
- ◆ Hydrologic variability and uncertainty
- ◆ etc. ...

Uncertainties are substantial over the extremely long forecast horizon. Our analysis and modeling, therefore, focuses on identifying key drivers and the conditions under which different price trends may occur.

Conceptual Issues: Feedbacks and Interrelationships

Strong negative feedback effects tend to pull prices away from extremes over the long-term, but allow high short-run volatility, and still a broad range of long-term outcomes

- ◆ High power prices will reduce demand, encourage efficiency and demand response, spur newer and lower cost supply, and may reduce the political will to impose stringent and costly environmental policies, all of which tend to limit how high prices get
- ◆ Lower prices spur demand, reduce incentives for efficiency and demand response, slow entry of new generation, and make stricter environmental policies more politically palatable, limiting further price reductions

Our forecasting accounts for the long-run price elasticity of demand, as well as market responses regarding the addition of new generation, economic retirement of existing capacity, and system operation

- ◆ In the very long run, prices should be closely related to long-run marginal cost (at least in expectation). But since energy infrastructure is very long-lived, the “long run” can be very far in the future, and conditions may change again before we get there.

3. Approach

Approach: Scenario Forecasting

Rather than attempting to develop the “best” single point-forecast, a scenario forecasting approach recognizes the inherent uncertainty of the future, characterizes this uncertainty and analyzes its effect

- ◆ “Business as usual” or “expected” outcome is not at all certain, particularly over a long horizon. It can be equally important to consider other, “not-expected” potential outcomes
 - Decisions should be informed by other plausible outcomes and potential extremes
- ◆ A scenario is an internally consistent narrative describing a plausible future
- ◆ Recently, the future seems even more uncertain than usual. E.g.:
 - Uncertainties in long-run environmental policies (coal retirements, climate policy, CO₂ price, renewable requirements/subsidies, Smart Grid, transmission expansion)
 - Evolution of low-carbon generation technologies (wind, solar, nuclear),
 - Long run price effects of unconventional gas development,
 - Coal plant retirements due to new EPA requirements
- ◆ Differences between scenarios, and the factors that cause them, may be as instructive as the absolute price level in any given scenario

Approach: Scenario Selection

Scenarios are selected in part based on reasonable potential to occur

- ◆ Particularly, combinations of factors that complement one another and collectively make a plausible description of the future world
 - Also consider extreme scenarios that may be particularly bad or good for the decision contemplated (here, the addition of hydro generation to export energy and capacity to MISO) to better understand the relevant risks and opportunities
 - Focus on factors expected (and previously shown) to have large effects
 - Additional emphasis on downside scenarios
 - Relatively more “low power price” scenarios were considered
 - Enables fuller characterization of downside risk
- ◆ Scenarios are qualitatively the same as those used in 2012 projections
 - But quantitative updates reflect changes in the past year – e.g., gas price values reflect range around current price expectations
- ◆ Probabilities were not assigned, though individuals may have views
 - Not all plausible scenarios can be examined; other scenarios may be valid
 - Actual future may be even more extreme than any scenario evaluated, though scenarios are designed to span a broad range

Approach: Scenario Selection

Each scenario is a “story” that endures over the full 35-year study horizon

- ◆ These may be “too persistent” – historically, things change more quickly
 - 1970s: Fuel price shocks
 - 1980s: Slower load growth, nuclear construction stops
 - 1990s: Restructuring; emergence of gas generation (cheap fuel, efficient)
 - 2000s: Fuel price volatility, emerging climate concerns
 - 2010s: Dominance of natural gas??
- ◆ The next 35 years may have several different themes, in sequence
- ◆ But scenario analysis can illuminate future risks and opportunities

For each scenario, input variables were extrapolated to 2050 to forecast power prices over the entire horizon

- ◆ Any forecast for this distant horizon is highly uncertain; scenario results for the distant future should be interpreted in that light
- ◆ Many factors, some highly uncertain and others impossible to foresee, may affect power markets over this horizon

Approach: Overview of the ReCap Model

Scenarios analyzed using ReCap (Regional Capacity Expansion) which is a high-level capacity expansion simulation model

- ◆ Use of a simple model facilitates “seeing the forest beyond the trees”

ReCap was developed by *The Brattle Group* and has been used in numerous studies, including previous forecasts for Manitoba Hydro in 2009, 2011 and most recently in 2012

- ◆ Simulation and optimization model - minimizes total cost of serving load (as do markets, sort of)
 - Has perfect foresight (certain future) in a given scenario; multiple scenarios are simulated
- ◆ Simplified system characterization:
 - Load profile characterized with an 18-step seasonal load duration curve constructed from hourly load shape
 - Each type of dispatchable generation is divided into several classes with similar dispatch characteristics, by region – e.g., coal with 10,000 heat rate, coal with 10,500 heat rate, etc.
 - Hourly wind profile (specific to each region) captures temporal relation to load
 - Six regions modeled, without internal constraints but with transmission interconnections between regions
- ◆ Simulation and optimization
 - Online capacity in each given year is operated to serve energy load
 - New capacity is added if necessary to meet peak load plus reserve margin requirement (~15%)
 - Most economic type of capacity is added (beyond reserve requirement, if enough energy value)
 - Additional renewable capacity (mostly wind) is added to meet RPS goals, at several alternative levels
 - Generator operation and type and timing of new capacity additions and retirements are simultaneously optimized over the full horizon, to minimize cost
 - Accounting for capital costs and fixed and variable operating costs (fuel, CO₂, FOM, VOM)
 - Capacity additions are continuous – not lumpy additions of large plant
 - Capacity will be retired if energy margins and capacity value fail to cover to-go costs

Approach: Overview of the ReCap Model (cont'd)

Some of the capabilities of ReCap include:

- ◆ Seasonal modeling
 - Including load, outages, hydro production, seasonal generating capacity, imports from Manitoba
 - Wind energy output profile, based on hourly wind profile data at a regional level (incorporated as a reduction to gross load; dispatchable fleet serves net load after wind generation is accounted for)
- ◆ Transmission limits modeled between regions (simple “pipes” model); no constraints within region
- ◆ Based on load forecast and capacity data from EIA’s 2013 Annual Energy Outlook (AEO) Early Release. Underlying generation characteristics mostly from Ventyx, the Velocity Suite.

ReCap does not include:

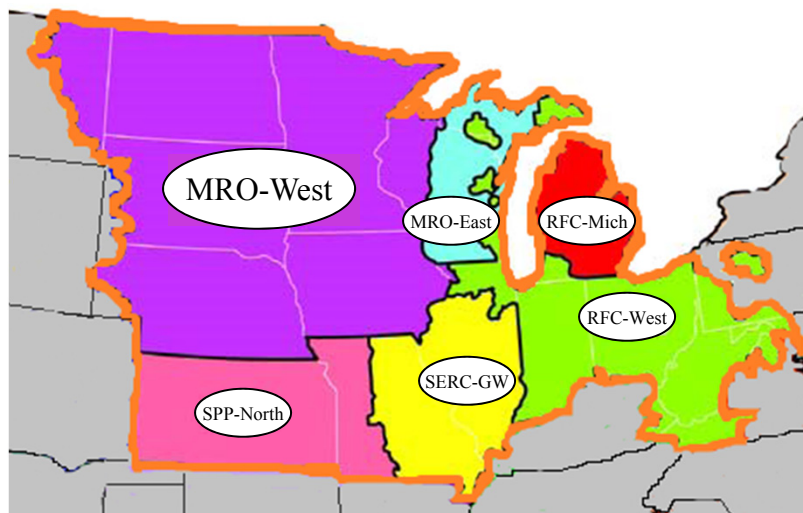
- ◆ Operational constraints such as unit commitment costs (e.g., start-up, min-load costs) and ancillary services
 - Actual market prices may differ due to these factors. Operational constraints may cause market prices to be lower off-peak, higher on-peak, and overall more volatile, than simulated by a model like ReCap.
 - ReCap was recently improved to capture these effects to some extent
- ◆ Strategic bidding behavior, which can raise prices above fully competitive levels
- ◆ Randomized forced outages, which can cause significant short-term price volatility
- ◆ Non-CO₂ pollutant costs and environmental upgrades
 - Variable cost of non-CO₂ emissions is modest, relative to major drivers of energy prices
 - Capital costs of upgrades are unlikely to have a major effect on energy prices in a marginal-bid wholesale market. Coal retirements due to potential stricter requirements are considered.
- ◆ While these factors can be important in particular hours, their overall impacts are generally modest, and unlikely to affect overall prices (and long-term investment strategy) significantly
 - Could plausibly amount to a few dollars per MWh

Approach: ReCap Model – Implementation

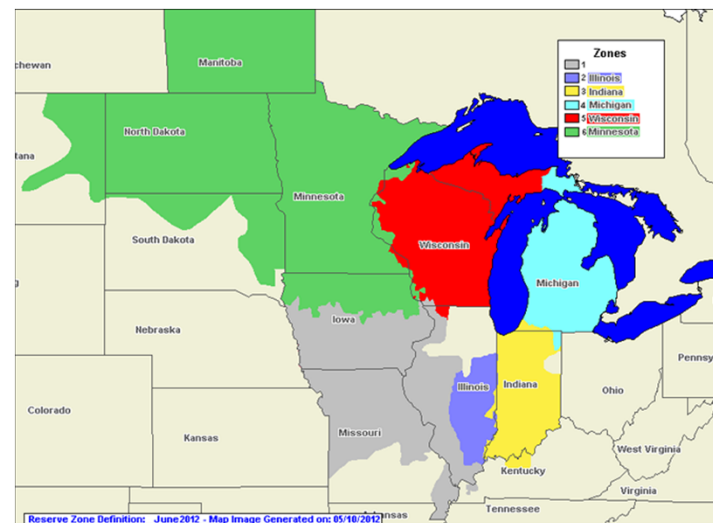
MRO-West region is primary interest

- ♦ MRO-West footprint is similar to MISO's reserve zone 7 and MAPP : Most or all of Minnesota, Iowa, North and South Dakota, Nebraska, parts of Montana, Wisconsin
 - Transmission constraints within the regions and local congestion are not modeled
- ♦ Also model neighboring regions, with dynamic transmission flows between: MRO-East, RFC-West, RFC-Michigan, SPP-North, SERC-Gateway
 - Aggregate 2013 peak for 6-region area is about 180 GW (non-coincident)
 - Aggregate existing generating capacity is 261 GW (nameplate)

Region Modeled (MRO-West Focus)

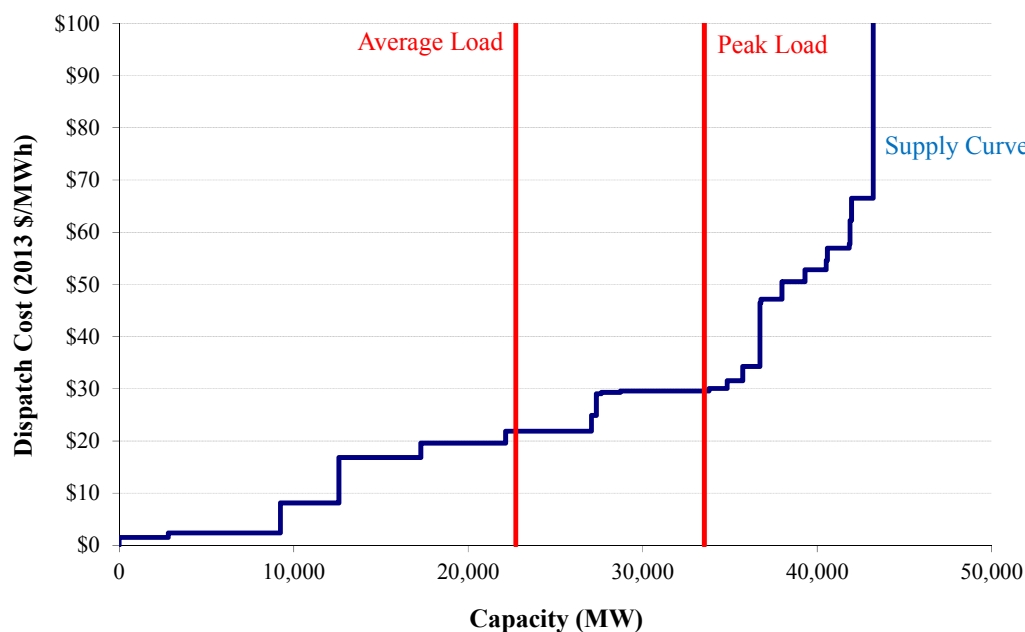


MISO Reserve Zones



Approach: ReCap Model – Implementation

MRO-West Existing Supply Curve



Note: Capacity adjusted for forced outages; wind based on average capacity factor

Starting system characterization

- ◆ Existing generating capacity and performance parameters (from AEO 2013, Ventyx Inc.) characterized for each region
 - Generation characterized as “classes” of capacity with similar operating attributes (e.g., 4 coal classes per region)
- ◆ Load forecast – AEO 2013 provides starting point
 - Price elasticity adjustments and DSM programs are included in scenarios
- ◆ Gas price – base forecast from recent futures prices; assumed high & low values in scenarios
- ◆ Coal price – based on AEO data
- ◆ Renewables – current state RPS requirements, potential federal RPS (higher)
- ◆ Climate legislation (CO₂ price) – several trajectories examined
 - Also considered non-price mechanisms
- ◆ New generation technologies: cost, performance, and availability
 - AEO assumptions for cost and performance parameters

Approach: ReCap Outputs

- ◆ Seasonal wholesale energy price by load tranche, mapped to on-peak and off-peak hours, and capacity price, for MRO-West region
 - Prices set by marginal costs to meet energy demand, resource adequacy
 - Generic depiction of power prices; future markets may bundle products differently
 - E.g., Capacity may be bundled with energy into firm power
 - MISO has a resource adequacy requirement, will soon implement a short-term capacity market (though even that may not capture long-term capacity value)
- ◆ Generating capacity additions and retirements - by technology, over time
 - Assumed additions, primarily renewables to meet RPS requirements
 - Assumed retirements, primarily coal due to environmental regulations
 - Additional economic additions and retirements as determined by ReCap, to maintain required reserve margins
- ◆ System operation over time (energy production by generation type), with associated costs (fuel, emissions, O&M, and capital recovery)
- ◆ CO₂ emissions over time
- ◆ Load (peak and energy) over time, including price elasticity effects
- ◆ Energy and capacity transfers between model regions
- ◆ Study horizon to 2049 (though distant future is highly uncertain)
- ◆ All costs and prices are reported in constant 2013 dollars

4. Scenario Elements and Definitions

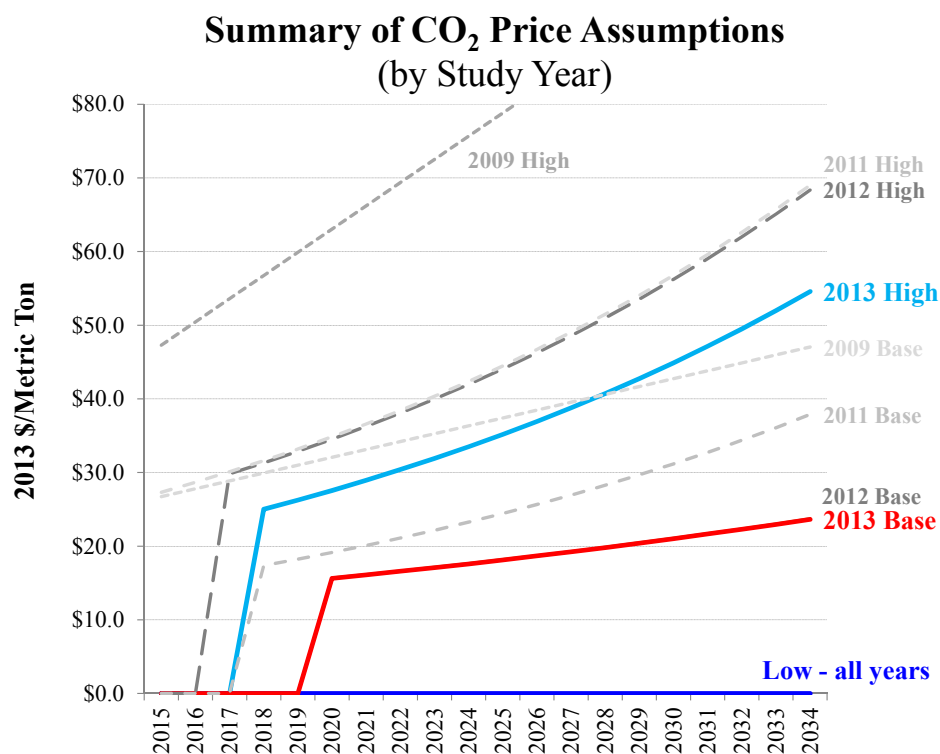
Key Scenario Dimensions

- ◆ Climate policy – stringency and form both have an effect
 - CO₂ price (cap, tax) vs. non-price (promote renewables, retire coal, etc.)
- ◆ Fuel price – primarily natural gas; coal prices may also have an effect
- ◆ Renewable additions, with the enabling expansion of transmission
 - Renewable energy requirements: State-level RPS, or Federal RPS
 - Large additions require significant regional transmission expansion
- ◆ Coal unit retirements
 - Driven partly by EPA non-GHG requirements, which are becoming clearer, and in large part by low gas prices – many units are retiring
 - Potential for climate policy may tip the balance for marginal coal units
 - Additional retirements (economic) optimized by model
- ◆ Load growth
 - Price response effect: load responds to price level in each scenario
 - Declining CO₂ allowances allocated to load, phasing in price effect
 - Demand-side management: Energy efficiency, load shifting (peak shaving)

Climate Policy

U.S. carbon-pricing legislation (cap & trade, carbon tax) remains unlikely in the near term

- ◆ Despite continued scientific agreement on the need for large emission cuts, and even greater urgency, U.S. politicians have not addressed comprehensive climate legislation
 - Obama may push climate in his second term, but partisan politics still obstructs progress
- ◆ Non-price mechanisms have gotten some traction, and will dominate in near-term
 - E.g., renewable requirements, EPA regulations and coal limits, efficiency standards, nuclear subsidy
- ◆ Though carbon price is probably still necessary to reach goals, non-price mechanisms lead to lower CO₂ prices, if a carbon-pricing policy is implemented
 - Low gas prices would also reduce CO₂ price (under cap & trade)
- ◆ CO₂ price expectations continue to get lower and later
 - Included phase-in of costs to consumers, via declining allocation of emission allowances



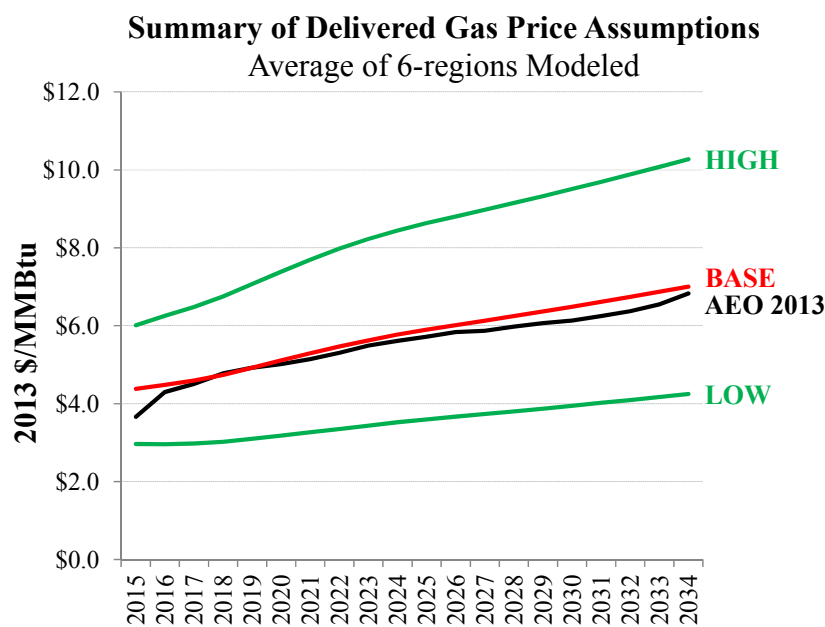
Fuel Prices: Natural Gas

Base Case Gas Price: current gas futures prices, extended at EIA growth rates

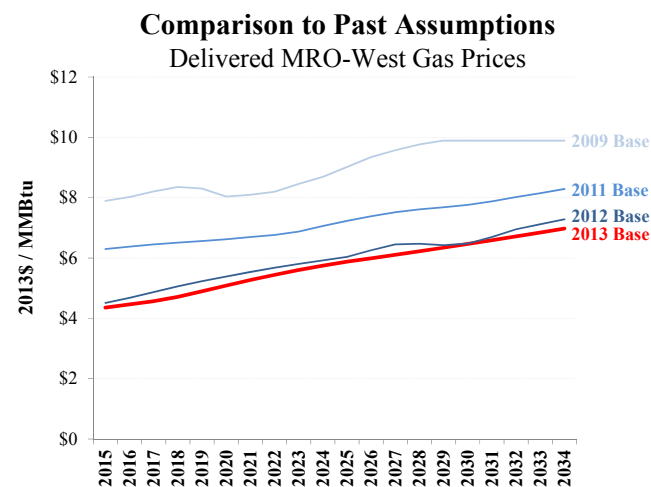
- ◆ Delivered price is NYMEX Henry Hub futures (grown at AEO escalators beyond futures data), plus regional basis futures and \$0.25 transportation cost
- ◆ Long-run gas price expectations have dropped considerably from several years ago, due to demand reduction and the development of unconventional gas
 - Down just slightly from a year ago, with prices still expected to rebound somewhat over time

High and Low Gas Price cases defined to yield plausible range

- ◆ Based on implied volatility, historical variance, and historical forecast error



Continued shale gas success has caused gas prices to fall consistently over the past few years, though they now appear to have stabilized. Long-term price expectations are down considerably from a few years ago.



Fuel Prices: Coal

Coal prices are based on AEO's regional delivered coal price forecast

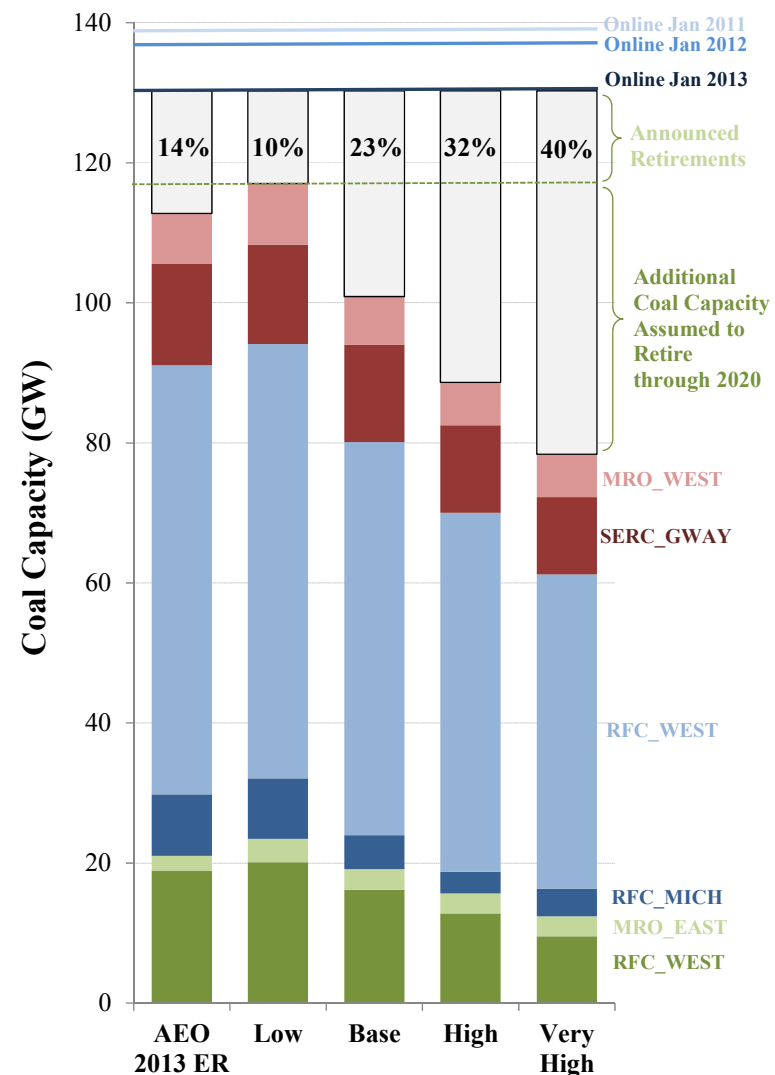
- ◆ There is some uncertainty in coal prices as well
 - Coal price projections may fluctuate with production and transportation costs
- ◆ In some circumstances, coal price may tend to move with gas price
 - At low gas price (when gas begins dispatch switching with coal, as now), reduced coal demand can depress near to medium term coal prices
 - Coal production may cut back longer term, partly mitigating this effect
 - Or, coal price may link to world markets, if large-scale exports materialize
- ◆ Coal prices may be only a modest driver of uncertainty in long-run power prices, even in a coal-dominated region
 - The potential magnitude of coal price variation is modest compared to the effect of other variables such as CO₂ and gas prices, and retirement of coal plants

Coal price uncertainty (lower coal price) was examined in one scenario, in combination with low gas price

Initial Coal Plant Retirements

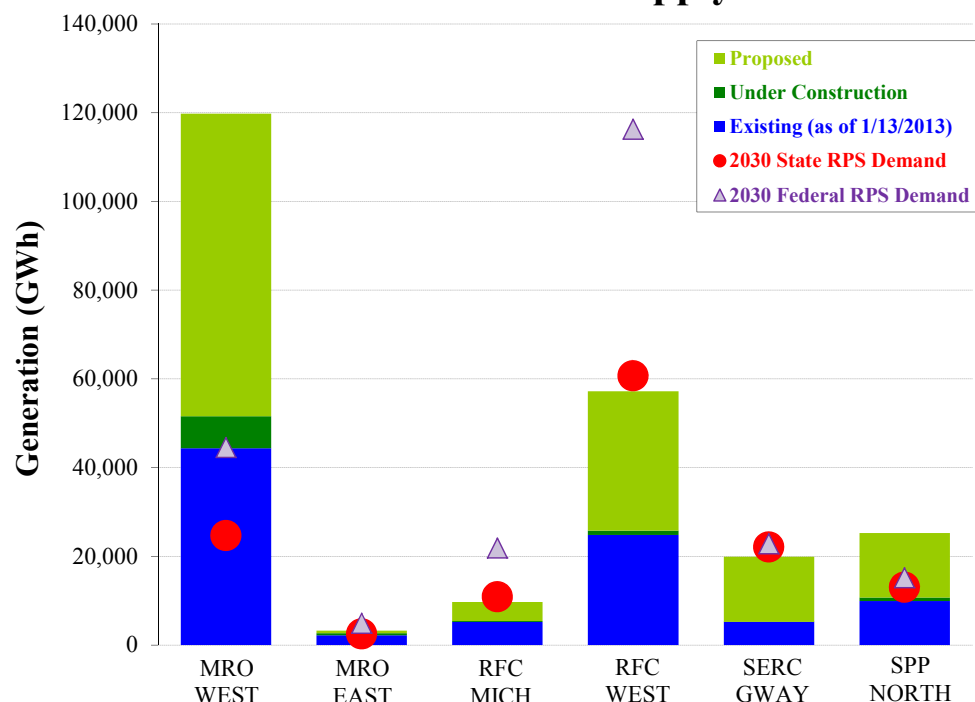
Low gas prices and still-evolving EPA regulations push coal plants to retire

- ◆ Some plants need large capital investment in emission control technologies
 - MATS (mercury, acid gas) compliance
 - CSAPR (SO₂, NO_x) vacated, but largely redundant with MATS
 - Possible cooling water, ash requirements, even CO₂ limits on existing plants??
- ◆ Some coal plants may be uneconomic and retire rather than upgrade
 - Poor economics (under low gas prices) make it unattractive to invest in emission controls
 - Initial capacity surplus doesn't help
- ◆ Updated Brattle study (and others) project potential coal plant retirements under new EPA requirements
 - Considering these, we developed several plausible levels of coal retirements



Renewable Portfolio Standards

Summary of Existing and Planned Renewable Supply



Sources and Notes:

- [1] Data downloaded from Ventyx, the Velocity Suite.
- [2] "Under Construction" includes the following status: Under Const, Testing, Site Prep
- [3] "Proposed" includes the following status: Proposed, App Pending, Feasibility, Permitted
- [4] Wind, solar capacity factors based on generation profiles from NREL; assumed 85% for biomass, and 50% for small hydro
- [5] State RPS demand does not include voluntary goals in Dakotas, Indiana, and Virginia.

State-level RPS: Many states have RPS requirement

- ♦ Minnesota and Wisconsin in MRO-West; largest requirements from RFC-West (Illinois, Ohio)
- ♦ Most states require delivery to ISO, so RPS is effectively a regional requirement

Federal RPS (hypothetical): rising to 20% by 2025

- ♦ E.g., Clean Energy Standard Act of 2012 (proposed by Bingaman)

Large wind potential in MRO-West (Dakotas) make it a likely exporter

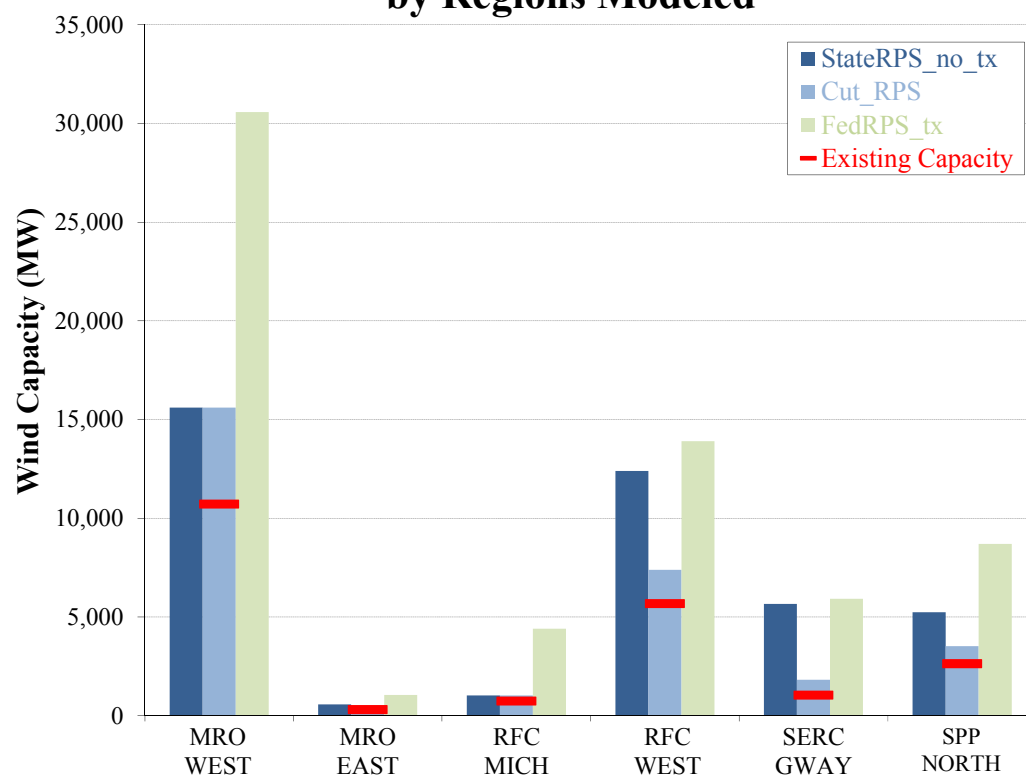
- ♦ Current MRO-West wind additions far outpace local RPS requirements
- ♦ Large transmission expansion is needed to enable even more exports

But there could also be a rollback of state RPS due to cost concerns

- ♦ Long-term RPS targets may not be met (esp. if federal incentives do not get continued renewal)

Renewable Generation and Transmission

**Assumptions for Wind Capacity Additions
by Regions Modeled**



Transmission overlay: expansion enables locating wind where best potential exists, exporting to load

- ◆ Existing transmission, without major expansion
- ◆ 10 GW incremental capability out of MRO-West (to all regions; mostly RFC-West); est. \$6 billion

Examine 3 cases of renewables buildout with transmission:

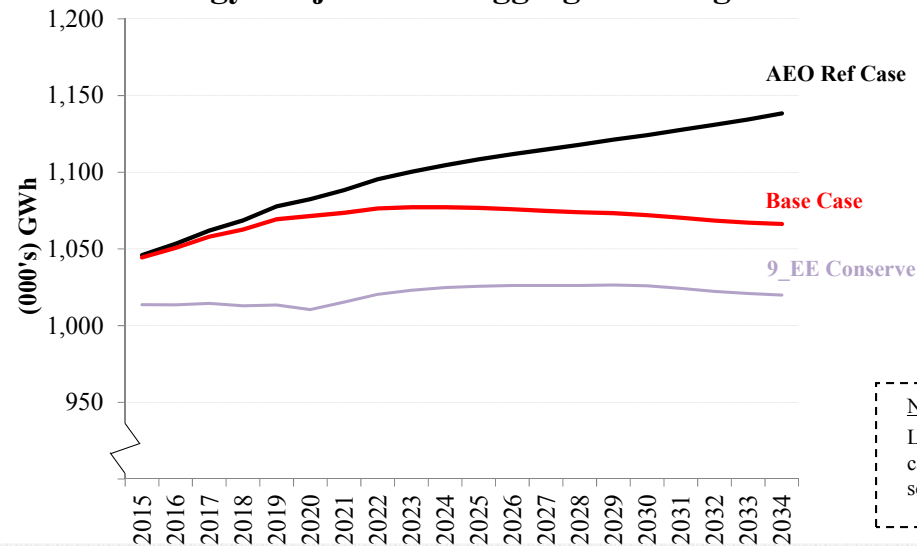
- ◆ Existing state-level RPS (about 12% of renewables by 2025) – Base Case
 - Existing transmission
- ◆ Federal RPS (20% by 2025)
 - Add much larger transmission overlay
 - 10 GW increase in export limits from MRO-West
- ◆ Cut RPS – State RPS rolled back
 - Projects under construction are completed (but no more)

Load Projections

Reference load from 2013 AEO forecast

- ◆ Peak grows at 0.7%, energy at 0.4%, on average (just below AEO 2012 forecast)
- ◆ Load responds via price elasticity to retail power price in each scenario
 - Short-run and long-run price elasticity effects (elasticity of -0.1 and -0.4, respectively)
 - CO₂ costs phase in due to declining free allowance allocations over time
 - Base Case load rises slowly over the next 10 years, then flattens and declines slightly post-2020 due to CO₂ cost (peak still grows slightly). MRO-W has slightly higher growth.
- ◆ Also examine DSM program effects on load
 - E.g., utility efficiency programs (which can cannibalize price effect)

Annual Energy Projections - Aggregate 6-Region Area



Note:

Load differs in other scenarios. Retail cost differences cause different price elasticity responses. Higher-price scenarios have lower load levels, all else equal.

Scenario Development Process

Key scenario elements were combined to create scenarios

- ◆ Fuel prices, coal retirements, climate policy and CO₂ price, renewable generation, transmission expansion, load growth

Scenario set was chosen to span a plausible range of future outcomes

- ◆ It does not (cannot) capture all potential outcomes, nor contain the most extreme possible outcomes
- ◆ It does attempt to capture the relevant range of factors and their relationships, to characterize the likely or plausible range of future power prices

Scenario set is based on the same qualitative combinations of scenario elements as in 2012 forecast

- ◆ Quantitative updates were made – e.g., the “Low Gas Price” trajectory reflects the current view of what a low gas price future would entail
- ◆ Recent market changes – e.g., slightly lower gas prices, delayed CO₂ prices, but more coal retirements – have differing effects on power price expectations.
 - These effects are captured in the Base Case and in the other scenarios.
- ◆ Again, more focus was put on combinations of factors that lead to lower prices
 - More “low price” scenarios were chosen, to illuminate what could push prices downward

Scenario Descriptions

Scenario Name	Natural Gas Price	CO2 Price	Renewable Additions	Transmission Limits	Coal Retirement (MRO-West)
BASE CASE	Base \$4.4 → ~\$7	Base \$15.7 in 2020, +3%/yr	Meet State RPS ~12% by 2025	Current system	Moderate 4.3 GW by 2020
1 Low CO2	Base \$4.4 → ~\$7	Zero CO2 price	Meet State RPS	Current system	Moderate 4.3 GW by 2020
2 High CO2	Base \$4.4 → ~\$7	High \$25 in 2018, +5%/yr	Meet State RPS	Current system	Moderate 4.3 GW by 2020
3 Low Gas	Low \$3 → ~\$4	Base \$15.7 in 2020, +3%/yr	Meet State RPS	Current system	Moderate 4.3 GW by 2020
4 High Gas	High \$6 → ~\$10	Base \$15.7 in 2020, +3%/yr	Meet State RPS	Current system	Moderate 4.3 GW by 2020
5 Strict Climate	Base \$4.4 → ~\$7	High \$25 in 2018, +5%/yr	Increased Federal RPS 5% in 2015 → 20% in 2025	10 GW increase	High 7.7 GW by 2020
6 NonPrice Climate	Base \$4.4 → ~\$7	Zero CO2 price	Increased Federal RPS 5% in 2015 → 20% in 2025	10 GW increase	Very High (Forced) 11 GW by 2020
7 LoGas/BroadMkt	Low \$3 → ~\$4	Base \$15.7 in 2020, +3%/yr	Increased Federal RPS 5% in 2015 → 20% in 2025	10 GW increase	Moderate 4.3 GW by 2020
8 Load Shifting	Base \$4.4 → ~\$7	Base \$15.7 in 2020, +3%/yr	Meet State RPS	Current system	Moderate 4.3 GW by 2020
9 EE Conserve	Base \$4.4 → ~\$7	Base \$15.7 in 2020, +3%/yr	Meet State RPS	Current system	Moderate 4.3 GW by 2020
10 HiGas/LoCO2	High \$6 → ~\$10	Zero CO2 price	Limited RPS (targets not met)	Current system	Low 0.4 GW by 2020
11 Extreme Low	Low \$3 → ~\$4	Zero CO2 price	Meet State RPS	Current system	Low 0.4 GW by 2020
12 AEO Ref Case	EIA Gas Price \$3.7 → ~\$7	Zero CO2 price	Limited additions	Current system	EIA Retirements 1.6 GW by 2020

Note:
This set of scenarios does not encompass all possible outcomes, and does not necessarily contain the most extreme outcomes possible. However, it does attempt to capture the relevant range of factors and their relationships, with the goal of characterizing the likely or plausible range of long run power prices.

5. Forecast Results

- Base Case Scenario -

(Results for other scenarios are included in Appendix)

Simulation Results

Base Case results are summarized below; results for each of the other scenarios are summarized in similar format in the Appendix

- ◆ **Input Assumptions:** describes scenario, summarizes inputs
 - Fuel prices, coal retirements, renewable and transmission additions, CO₂ prices, demand
- ◆ **Model Results**
 - Graphic results showing energy and capacity prices; also online capacity (with additions, retirements) and CO₂ emissions
 - For MRO-West region specifically (1st page)
 - Aggregate results for 6-region study footprint (2nd page)
 - Useful for high-level diagnostics
- ◆ **Discussion:** Observations and insights on scenario

Interpreting Results – Interconnected Regions

Manitoba Hydro's export market (Minn Hub in MISO) is interconnected with neighboring regions

- ◆ It is influenced by the supply-demand balance and power prices in those regions, and not only by local conditions

Similarly with the ReCap simulations: we model several interconnected regions, so MRO-West prices are often affected by circumstances in those other regions, and may not be fully explained by what is going on in MRO-West itself

- ◆ E.g., capacity prices may become positive in a given year in MRO-West, even though capacity is not needed (or added) in MRO-West in that year. This can occur because capacity is needed (and added) in a neighboring region; a positive MRO-West capacity price reflects the aggregate supply-demand balance in the broader region.
- ◆ E.g., new CC capacity may be economic in MRO-West but is not added. It may be slightly more economic in a neighboring region; capacity is added there, and power can flow to MRO-West as needed.

It is often easier to follow the economic causes and effects driving power prices by looking at the “Aggregate” results (aggregating over the 6 regions modeled)

- ◆ These “Aggregate” measures are aggregate results, useful for understanding and interpretation only. They do not represent prices available or capacity additions required in any particular region or pricing point.
- ◆ “Aggregate” prices are simple average of prices across 6 regions
- ◆ Capacity additions and retirements are also aggregated over all 6 regions
- ◆ These aggregate measures do not account for availability of transmission capacity between regions, but may nonetheless give useful insight into the factors driving results

Base Case Scenario

Key Input Assumptions

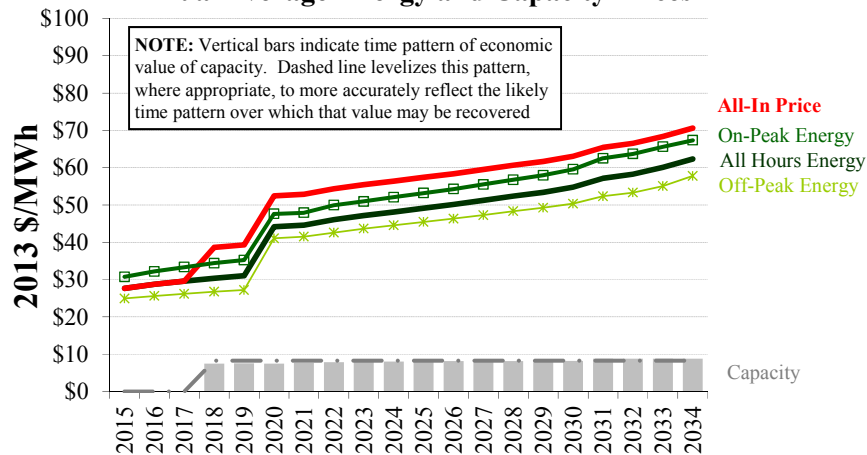
The Base Case scenario represents a continuation of current trends; essentially all input factors meet current expectations

- ◆ AEO 2013 Reference Case used as a starting point, but some factors differ
- ◆ CO₂ price starts at \$16/ton in 2020, grows at 3% to \$21/ton in 2030, reaching \$28/ton by 2040
- ◆ Fuel price updated to current market outlook
 - Natural gas: \$4.4/MMBtu in 2015, to \$5.9/MMBtu in 2025 (slightly above AEO)
 - Coal: \$1.7/MMBtu in 2015, to \$2.0/MMBtu in 2025 (AEO projections)
- ◆ Demand adjusted downward – elasticity response to higher prices (mostly CO₂)
 - Peak growth rate is roughly half that of the AEO Reference Case
 - Energy demand essentially flat starting in 2020 when CO₂ price manifests
- ◆ New generation additions:
 - Renewable additions are based on existing state RPS requirements, and include ~5,000 MW new wind generation in MRO-W for export (mainly into RFC-West)
 - New conventional generation already under construction is added at its expected online year (MRO-W adds no new coal and 150MW new gas CT; more elsewhere)
 - Nuclear becomes available in 2026, additions limited to 1,000 MW/year
- ◆ Planned unit retirements:
 - ~21% of the existing MRO-W coal capacity retires by 2020 to comply with EPA regulations that are expected to be in place (23% across all 6 regions modeled)
 - Nuclear plants assumed to retire after 60 years of operation (Kewaunee in 2013)

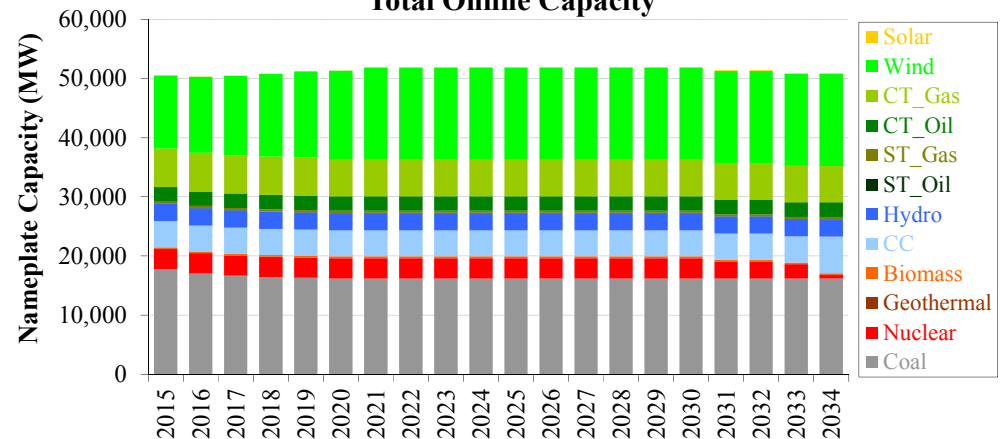
Base Case Scenario

Results for MRO-West Region

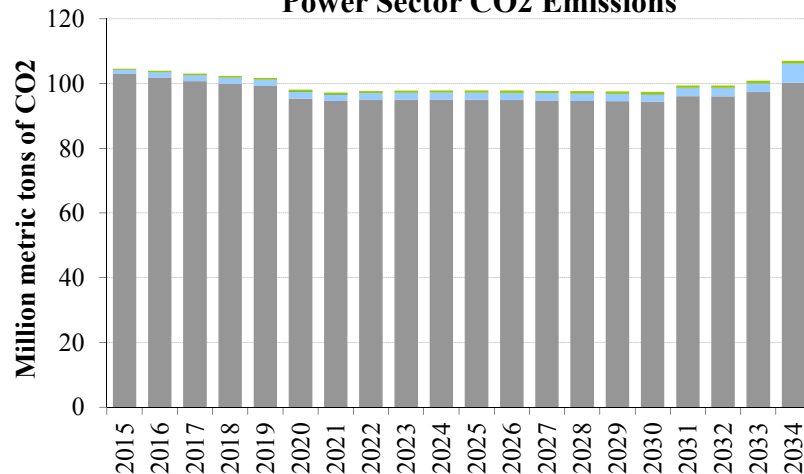
Annual Average Energy and Capacity Prices



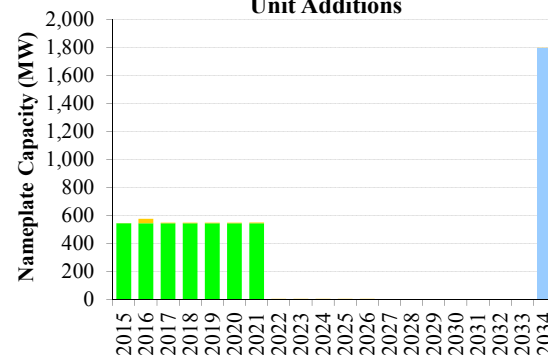
Total Online Capacity



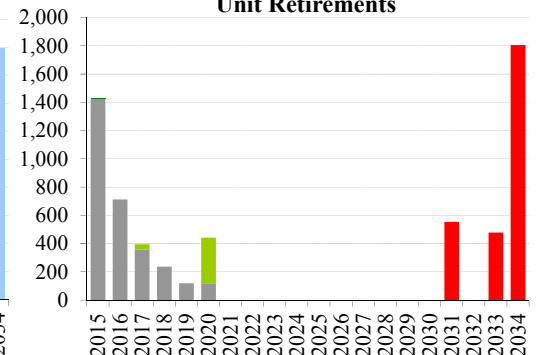
Power Sector CO2 Emissions



Unit Additions



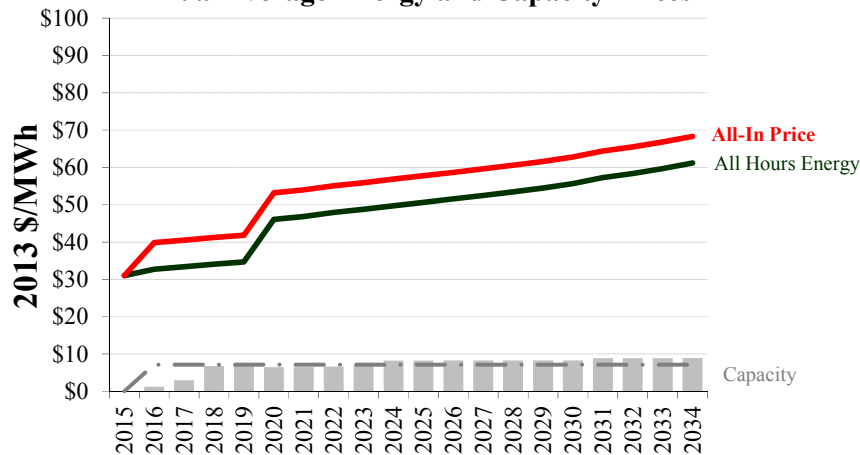
Unit Retirements



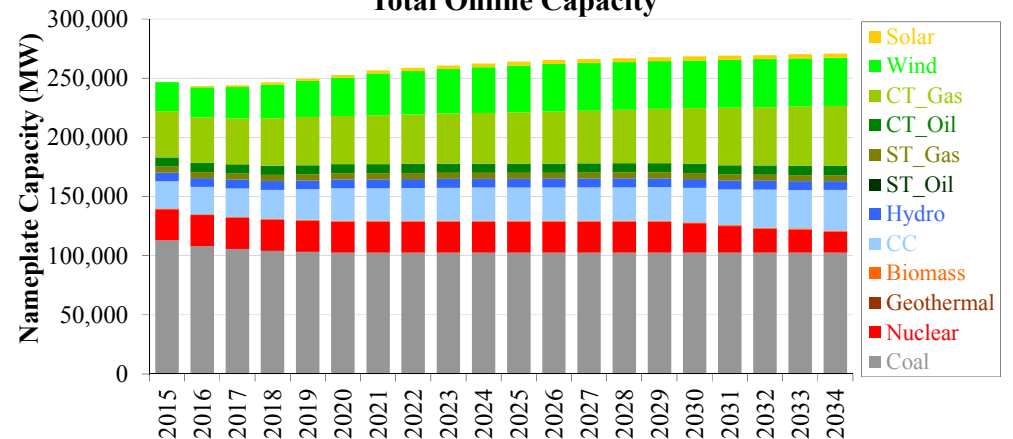
Base Case Scenario

Aggregate Results for the 6-Region Area Modeled

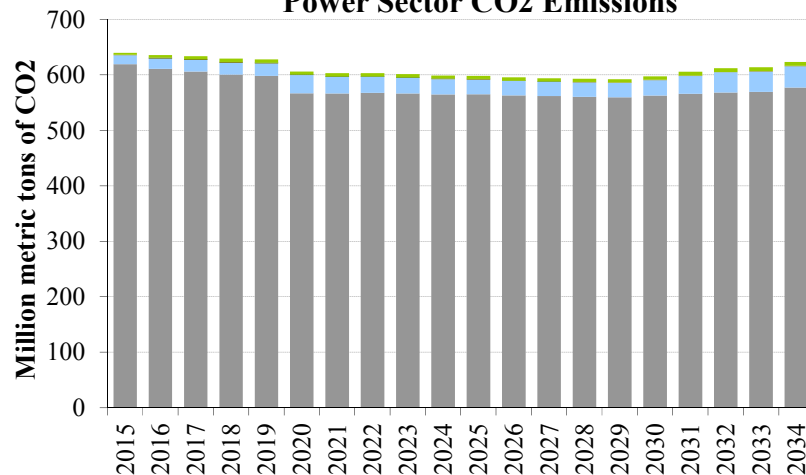
Annual Average Energy and Capacity Prices



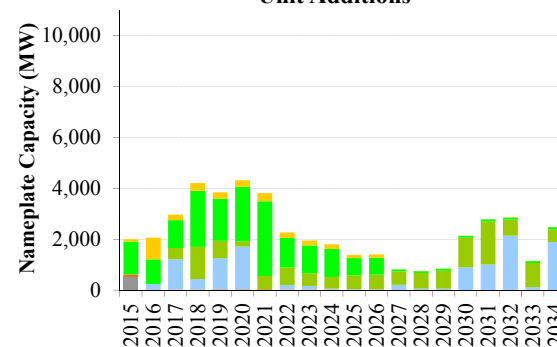
Total Online Capacity



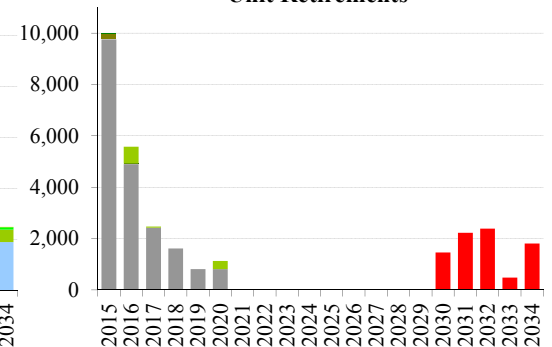
Power Sector CO2 Emissions



Unit Additions



Unit Retirements



Base Case Scenario

Discussion

Relatively low system load, combined with RPS additions, lead to modest capacity excess until ~2018, despite significant coal retirements

- ◆ Load grows more slowly than in AEO Reference Case
- ◆ ~21% of MRO-W coal capacity (23% across 6 regions) retires in initial years – mostly “forced” by EPA regulations, but also a small amount of “economic” retirements due to low gas prices, rising coal prices and anticipated future CO₂ prices

Wind is much of the generation added near-term

- ◆ Renewables (mostly wind) added to meet state RPS
- ◆ No conventional generation added until 2018 (beyond what’s already under construction)
- ◆ Gas CT/CCs added elsewhere starting in 2018 to maintain reserve margins – renewable additions slow down, load grows gradually, and after 2030, nuclear units begin to retire

Energy prices climb modestly, driven by fuel prices and coal retirements, with CO₂ price causing a jump in 2020

- ◆ Increase in gas and coal prices, plus coal retirements, lead to somewhat higher energy prices, compared to near-term lows
- ◆ CO₂ prices cause nearly a dollar-for-dollar increase off-peak; slightly less on-peak

Capacity prices ~\$65/kW-yr, but not until 2018

- ◆ Needed to support new capacity resources added (primarily gas CT/CC, outside MRO-W)

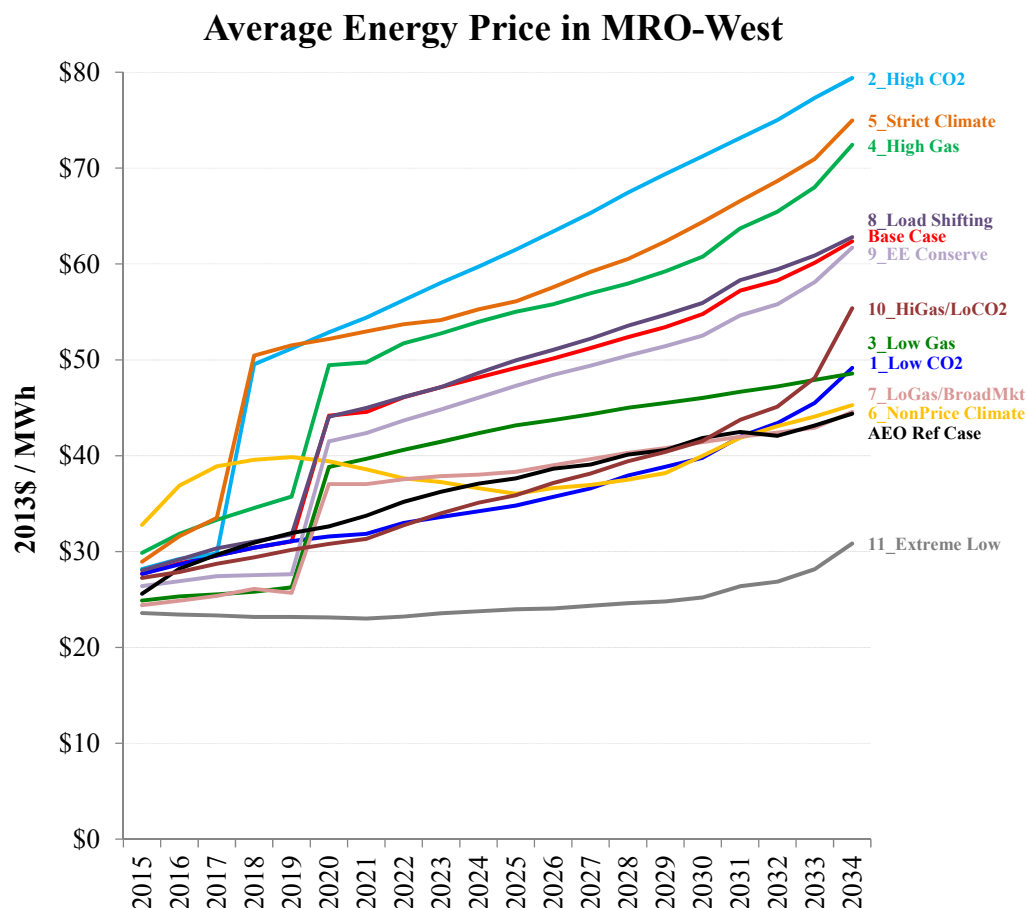
CO₂ emissions remain relatively flat

- ◆ Coal remains the primary generation source despite retirements and wind additions
- ◆ CO₂ price not high enough (nor gas low enough) to trigger major coal-to-gas switching

6. Interpreting Results and Conclusions

Range of Power Prices

Scenarios evaluated show a broad range of possible future market prices. By 2030, scenarios show energy prices ranging from \$25/MWh to \$70/MWh.



- ♦ CO₂ price drives the extreme values
 - Heavily coal-based regional generation fleet is strongly influenced by CO₂ price
- ♦ Gas prices also have a significant effect, though smaller than CO₂
- ♦ Coal retirements increase power prices; how much depends on prevailing CO₂ and gas prices
 - More retirements lead to higher prices, and greater gas sensitivity
 - More coal retirement causes slightly higher prices vs. 2012 forecast
- ♦ Large renewable additions may push prices down somewhat, but effect is limited if transmission is also expanded, as is likely
- ♦ Load levels (including DSM) only modestly affect energy prices
 - Load shifting affects only a few peak hours, but delays capacity needs
 - EE may cut energy price a couple dollars

CO₂ Price is Biggest Power Price Driver

The regional supply curve is heavily coal-dominated, even after increased expectations for coal retirements over the next few years

- ◆ Continuing expectations for low load growth, combined with ongoing renewable additions, mean that the supply mix and the generation on the margin (setting price) will not change much, until/unless a lot of existing coal capacity gets retired
 - Recent/planned renewable additions dispatch below coal (when available), partially offsetting the effect of coal plant retirements
 - The middle of the Midwest supply curve is quite flat, so price effects tend to be modest except at very high loads (if fuel prices are similar)
 - Retirement of coal plants do increase prices by several dollars as it compresses the supply curve and puts gas plants on the margin more often

These factors combine to create power prices that are heavily influenced by coal-fired power, and very susceptible to CO₂ price

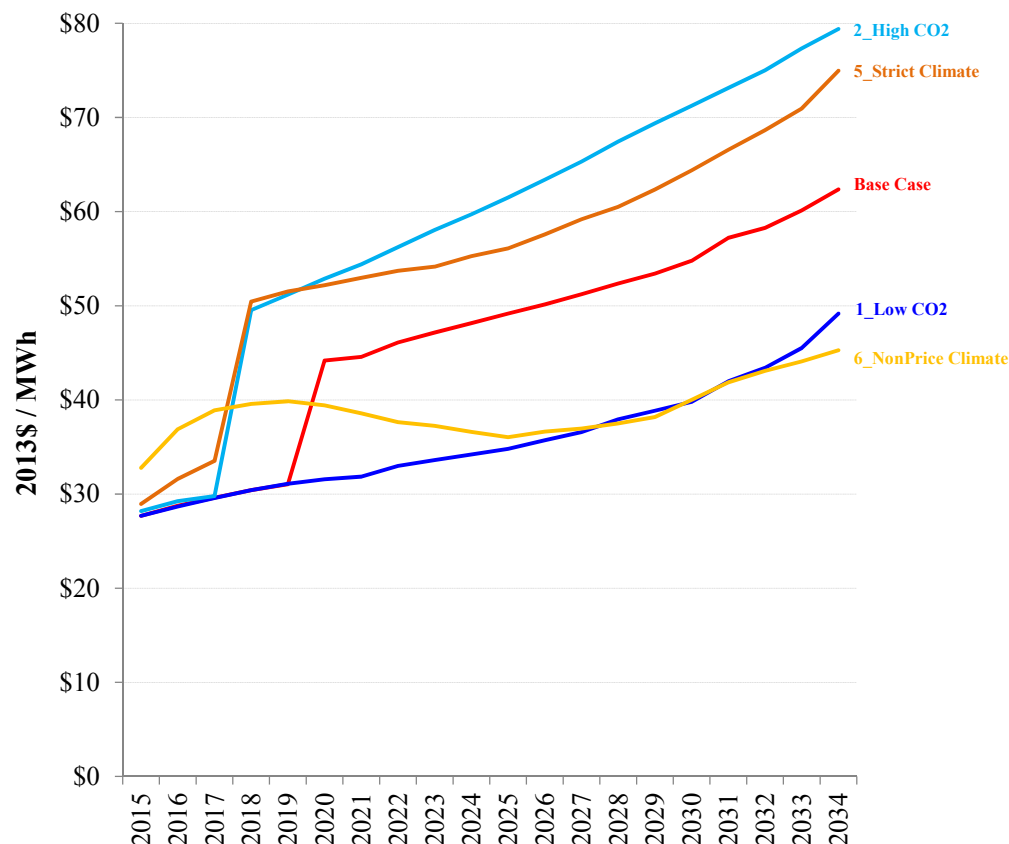
- ◆ Coal-to-gas dispatch switching can moderate CO₂ effect to some extent
 - Even in scenarios with dispatch switching, CO₂ price is a major factor driving the supply curve, due to the heavy dominance by coal

Climate Policy and CO₂ Price

Despite continued decline in expectations for future climate policy, CO₂ price is still the major potential driver of future power prices

- ◆ Affects dispatch cost of fossil, which is always on the margin setting price
 - \$1/ton of CO₂ price adds ~\$1/MWh to coal plants' dispatch cost; about half this for gas CCs
 - Midwest is heavily coal-based, so is particularly affected by CO₂ price
 - Renewables are below fossil in dispatch order, so fossil stays on the margin
 - CO₂ price tends to flatten the supply curve, depressing peak/off-peak price differential, particularly at lower gas prices
- ◆ Market response mitigates some of the effect on power prices
 - Despite coal's dominance, power price increases by less than coal's CO₂ cost
 - \$1/t CO₂ increases power price by about \$0.75/MWh
 - Increase is mitigated by operational changes (dispatch switching, inter-regional power flows), renewable (or nuclear) additions in the long run

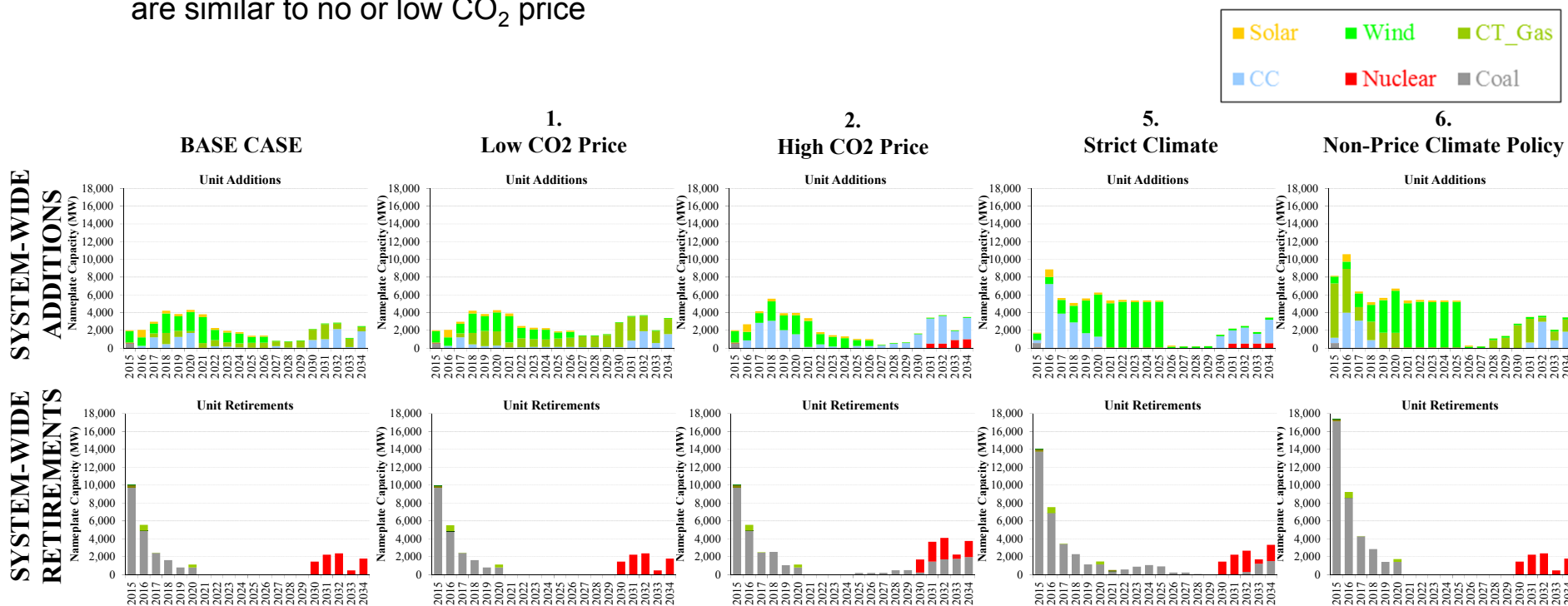
Average Energy Price in MRO-West



Climate Policy and CO₂ Price (cont'd)

CO₂ price and other climate policy mechanisms drive very different amounts and types of capacity additions and retirements

- ◆ High CO₂ prices lead to retirement of more coal plants, and ultimately large additions of less carbon-intensive generation (nuclear)
- ◆ Results under low CO₂ prices are similar to Base Case, but with slightly higher load and additions
 - Non-Price Climate policy may force higher coal retirements (replaced with wind, gas) but economics are similar to no or low CO₂ price



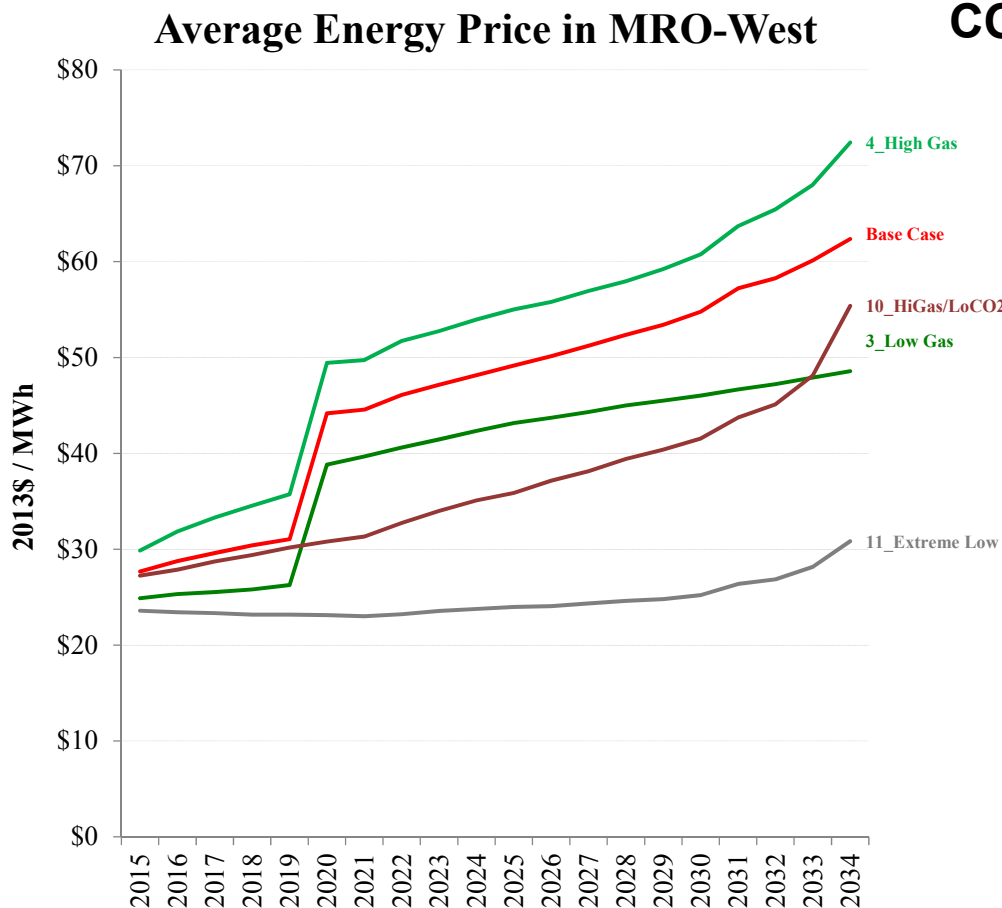
Climate Policy and CO₂ Price (cont'd)

Details of climate policy can affect CO₂ price

- ◆ Policy that relies primarily on CO₂ price requires a very high CO₂ price to achieve long run targeted cuts across the economy – much higher than levels here
 - “High” CO₂ price evaluated here – reaching about \$45 by 2030 – does cut electric sector CO₂; just how much depends on gas price and renewable additions
 - Other sectors are less sensitive to CO₂ price, which means that it could get quite high, e.g., under an economy-wide cap-and-trade scheme (politically unlikely now)
- ◆ Alternative policy mechanisms help reduce CO₂ without such a high CO₂ price
 - E.g., more renewables (Fed RPS in Scens 5, 6, 7), forced coal retirement (Scen 6)
 - Actions in other sectors also contribute to overall CO₂ reductions: vehicle mileage standards, equipment efficiency standards, new building codes, building retrofit
 - Not modeled directly, but these affect CO₂ price with economy-wide Cap & Trade
 - International offsets are also important: if they count toward U.S. targets, cheap reductions “purchased” from developing world reduce domestic cuts needed
 - Offsets are likely to be limited, but how strict the limit may be is unclear
- ◆ In the very long term, cost/availability of economical low-CO₂ alternatives in power and transport sectors will affect CO₂ price under Cap & Trade or responsive Carbon Tax
 - With strict CO₂ limits, low carbon technologies will set power prices in the very long term, beyond ~2035. But for the foreseeable future, existing technology of one sort or another will likely determine power prices

Natural Gas Price

Low price makes gas plants nearly competitive with coal (at zero or modest CO₂ prices)



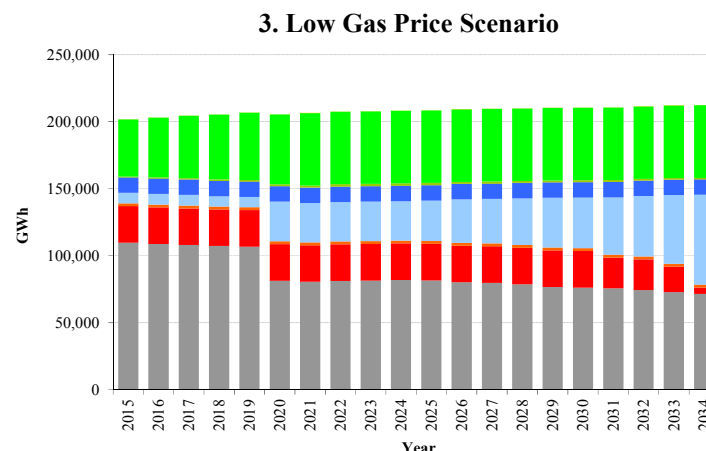
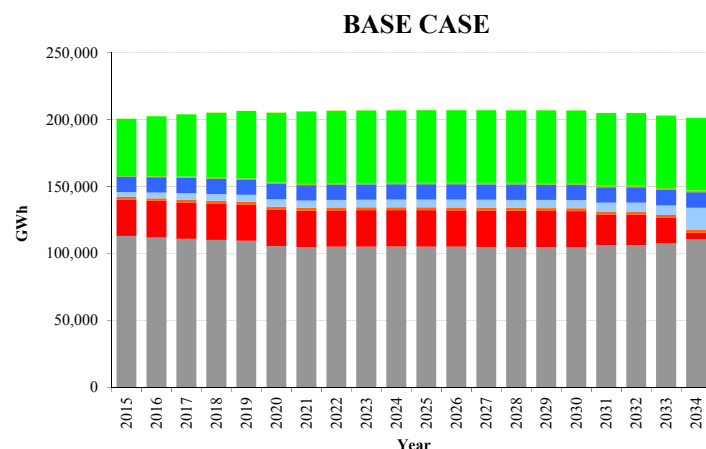
- ◆ Gas price has more leverage than a year ago, due to higher coal retirements
 - The supply curve shifts left with more coal plant retirements
 - Even though gas price is relatively low, coal retirements put gas on the margin more, so gas price has a bigger effect
 - Gas price (Low vs. High) can account for \$10-20 difference in regional power prices
- ◆ Further gas price drop would induce more coal plant retirement (but not dramatic)
 - Somewhat more CC added; bigger effect on utilization of gas v coal
 - Not much additional coal retires, absent higher CO₂ price
 - Low gas with low CO₂ causes very low prices (Scen 11 also has cheaper coal) – similar to near-term conditions
 - But low gas price can mitigate effect of higher CO₂ price (Scen 3)
 - More short-run dispatch switching

Natural Gas Price – Low Gas

Low Gas scenario (\$3-4/MMBtu gas price, with moderate CO₂ prices) causes some additional replacement of coal capacity with gas CCs

- ◆ Additional coal plant retirements, replaced by gas CCs added
- ◆ More prominent effect is on utilization: much higher for gas, lower for coal
 - ~5-10% of energy from gas plants in Base Case; ~15-30% with Low Gas Price
 - MRO-West itself uses less gas (due to more wind), but similar power price effect
- ◆ This presumes that this much gas could be supplied at this low price
 - Feedback effects could cause gas prices to rebound somewhat; uneven infrastructure expansion may cause regional differences (no shale in upper Midwest)
 - But shale gas reserves are huge; if gas stays cheap, infrastructure will expand
 - See discussion of interaction between CO₂ price and gas price, below

MRO-West Generation in 2030 (GWh)

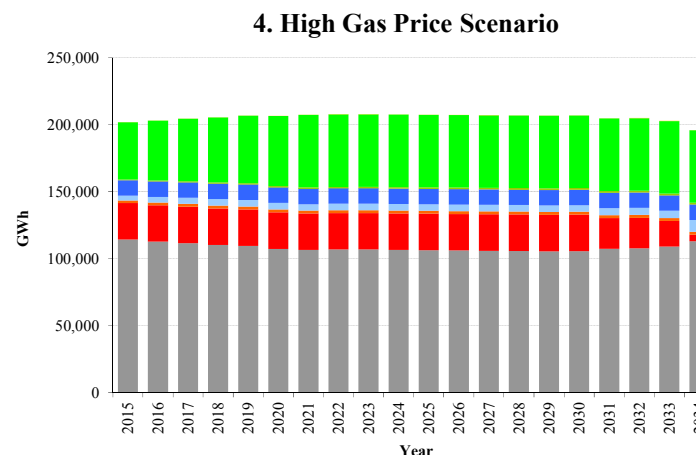
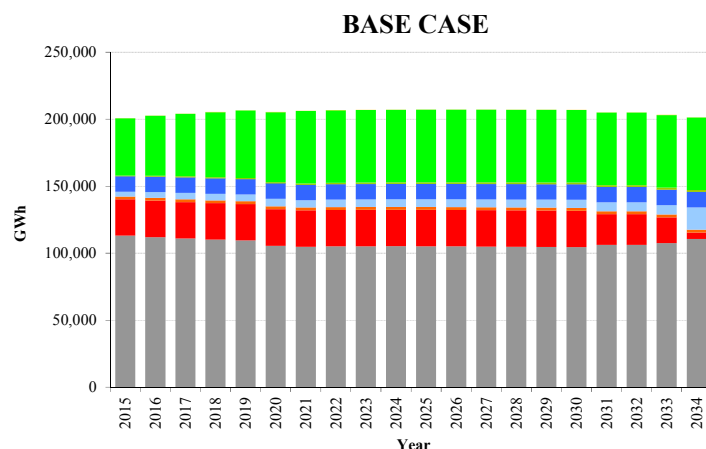


Natural Gas Price – High Gas

High Gas scenario (\$6-10/MMBtu gas) has a different kind of effect

- ◆ Higher gas price depresses new gas CC additions in the very long run
- ◆ Not much effect on utilization: with coal plants retired, gas must be relied upon during high load hours
 - ~5-10% of energy from gas plants in Base Case; drops to ~4-6% with High Gas Price
 - Coal plant retirements, higher than previously expected, force reliance on gas
 - Despite a small energy share, gas can have a big price effect since it's on the margin
- ◆ High gas price pushes up power prices considerably
 - Especially during on-peak period
 - Though not as much in MRO-West as in other regions; it has less gas and more wind

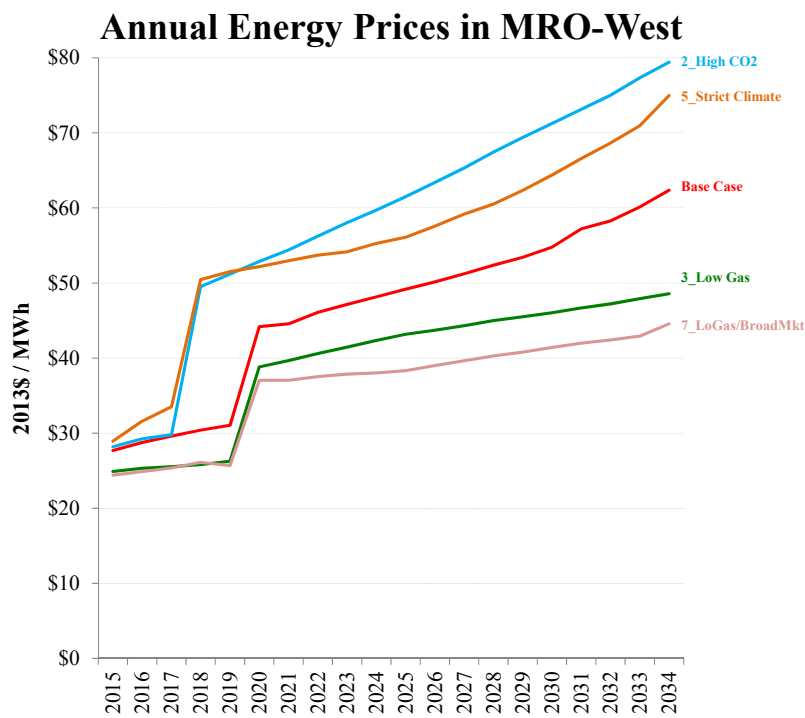
MRO-West Generation in 2030 (GWh)



RPS and Transmission

Price effect of more MRO-West wind additions (with expanded transmission) is moderate

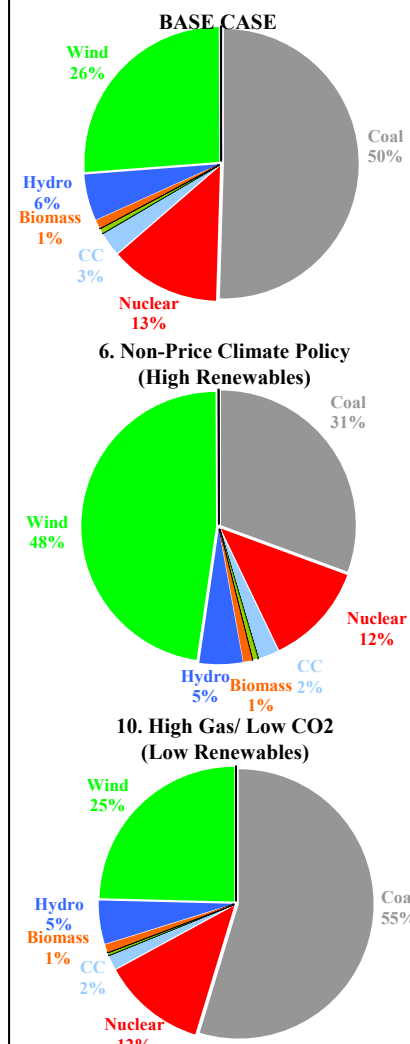
- ◆ Added transmission integrates MRO-W with broader region
 - Reduces locational price differentials
 - If transmission not sized (or timed) to match additions, local effects could be larger
 - All else equal, more wind depresses price; the effect is larger than seen previously, due to greater coal retirements
- ◆ Renewables often displace coal in operation, cutting CO₂ emissions



↓ Difference due to more wind generation (and more coal plant retirement)

↓ Difference due to more wind generation

Share of Annual Generation in MRO-West by 2030



Potential for Coal Plant Retirements

New EPA requirements will cause large amounts of coal plant retirements

- ◆ Base Case: 30 GW retired, out of ~130 GW of coal capacity across all 6 regions modeled
- ◆ Additional coal capacity may retire if operating economics are unfavorable (due to CO₂ price and/or low gas price)
 - In the extreme, over 50 GW may retire by 2030 (at such an extreme, pace may be limited by the need to replace capacity)
- ◆ Even under extremely poor operating economics, some coal is retained (moving upward in the supply curve to become intermediate/peaking)

Other than coal, little capacity is likely to retire in the near term

- ◆ Perhaps limited peaking retirements (Oil CT, Gas Steam)
 - Some of these might be retained for local reliability
- ◆ Nuclear retirements in 2030-2040 (though some might retire earlier)

Potential for Nuclear Plant Retirements

Potential new wild card is the possibility of nuclear retirements

- ◆ Prompted by poor economics (low gas price causes low power prices), new post-Fukushima safety requirements, and idiosyncratic issues
- ◆ Kewaunee (550 MW) will close May 2013 – “canary in the coal mine”
 - Other nuclear plants retiring too: Crystal River, maybe Vermont Yankee, ...
 - Are other nukes in upper Midwest region vulnerable as well?

Additional nuclear retirements were not analyzed in scenarios

- ◆ 26 GW nuclear in study region (10% of total), to retire starting 2030
 - Comparable in total to Base Case coal retirements
- ◆ Unless a very large share of nuclear capacity were to shut down early, the effect is likely to be moderate
 - But a few more early nuclear closures could occur, and would augment the effects of coal retirements, pushing prices a bit higher

Capacity Needs and Capacity Value

In most scenarios, generation additions are not needed until late this decade or beyond, despite significant coal plant retirements

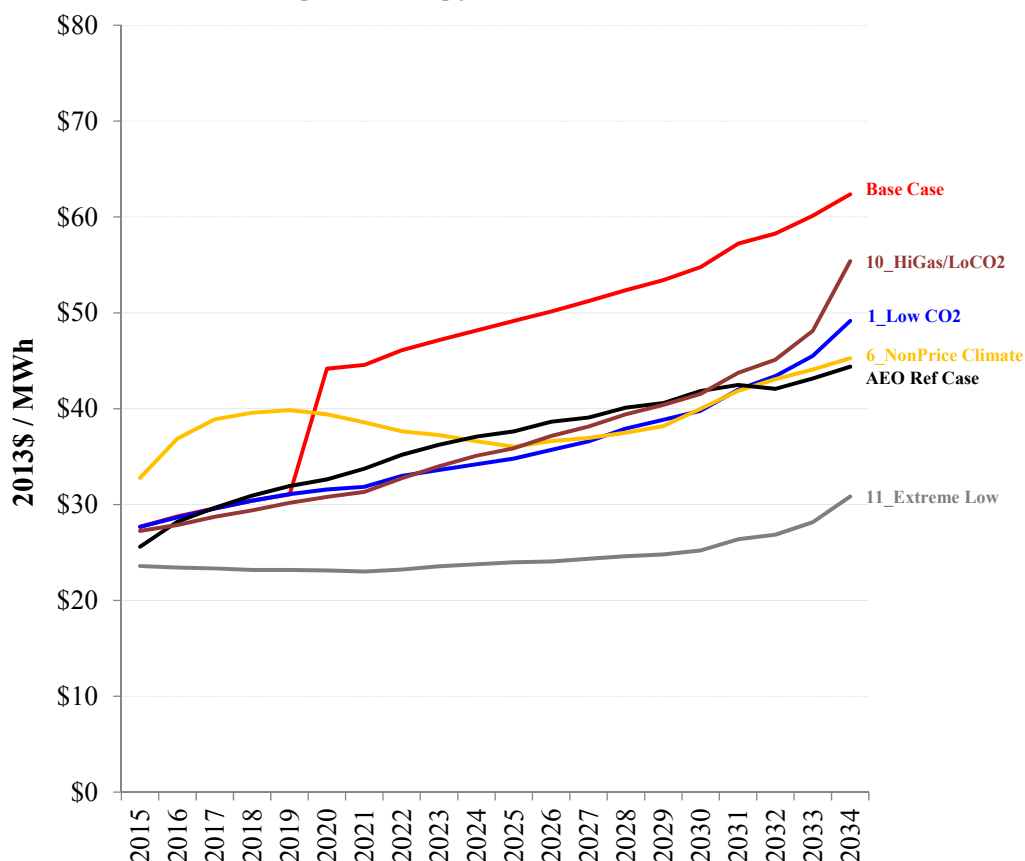
- ◆ Large initial capacity surplus, low load growth, added renewable generation delay the need
- ◆ Capacity not needed until after 2015 in most scenarios (after 2020 in some) – meaning capacity value may remain quite low for some time
 - Earlier with high(er) coal plant retirements; later with low retirements or DSM
- ◆ Gas capacity added when capacity is needed, including to replace additional economic coal retirements
 - Mix of CTs and CCs in most cases (more CCs in scenarios with Low Gas or High CO₂)

In distant years, more coal capacity may retire, requiring replacement baseload

- ◆ Gas CC replaces coal when gas and/or CO₂ prices are low
- ◆ Nuclear may be the long-run (i.e., 2030 and beyond) replacement in cases with high CO₂ and gas price
 - Or Coal/CCS, if it is available and economic

Drivers of Low Power Prices

Average Energy Price in MRO-West



Biggest driver of low prices is no CO₂ price

- ◆ But even scenarios without CO₂ price show significant differences
- ◆ Low gas price also keeps prices low

AEO Ref: future like the past; very cheap gas

- ◆ No CO₂ price, little wind; maintains gen mix
- ◆ 8 GW more coal capacity retires than in AEO 2012 (but less than Base Case)

Scen 1: Low CO₂ (otherwise same as Base)

- ◆ Similar to AEO; higher gas price but more renewables, retirements yield higher price

Extreme Low is the “perfect storm”

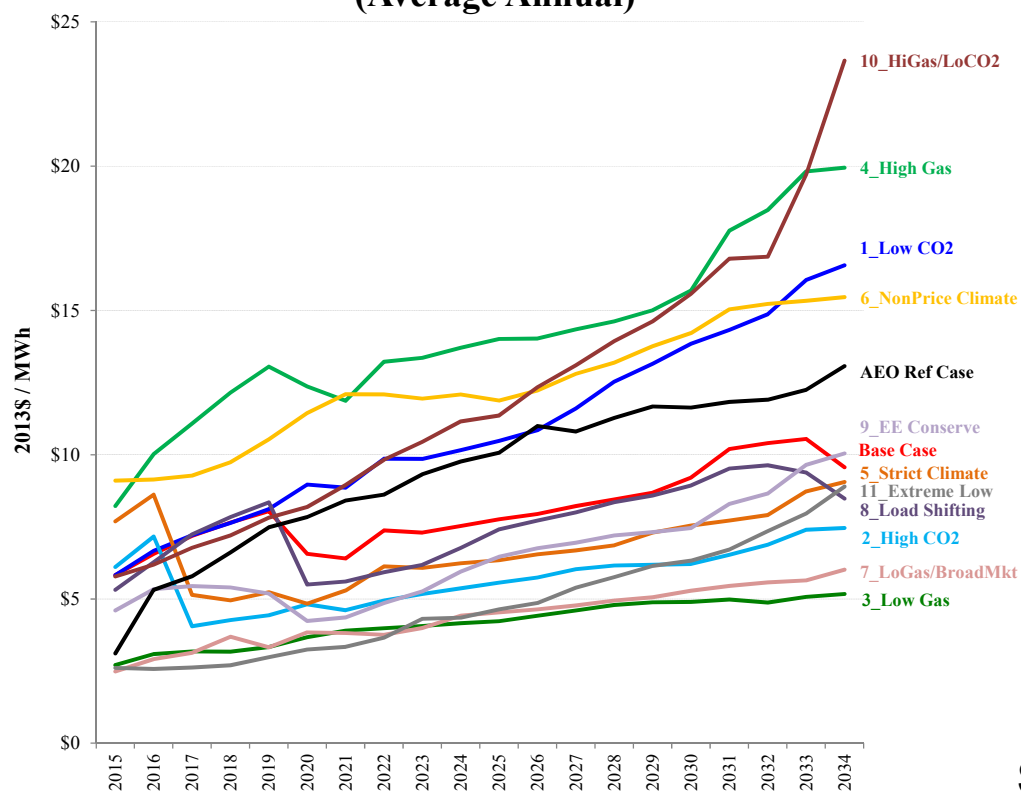
- ◆ Low gas, coal, & CO₂; moderate coal retirement (due to low gas); added wind
- ◆ Slightly higher power price than in last year’s study, though more of a low outlier
- ◆ Prices remain very flat until ~2030
- ◆ Unlikely, though not entirely implausible

Non-Price Climate is a low-price scenario

- ◆ Prices rise temporarily (retirements), but large wind additions depress price for years
- ◆ Large coal retirement assumed as “forced” by climate concerns; otherwise prices might be lower still

Peak/Off-Peak Price Differentials

**MRO-West Peak/Off-Peak Price Differentials
(Average Annual)**



Scenarios have varying Peak/Off-Peak price differential

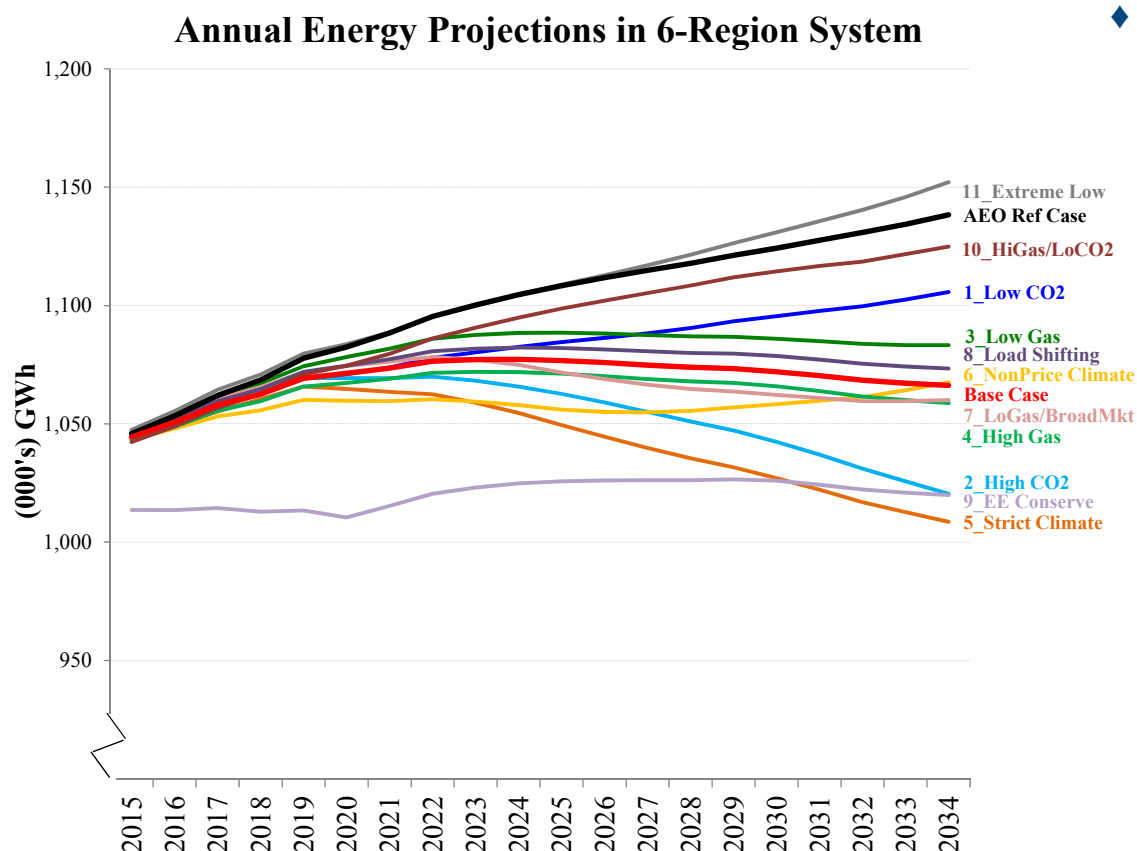
- ◆ Generally between \$4-12/MWh
- ◆ Load growth raises differential over time
- ◆ CO₂ price increases off-peak price by more than Peak, squeezing differential (Scens 2 & 5 vs. 1)
- ◆ High gas price increases peak price and differential (Scen 4)
 - Low gas does the opposite (3 & 7)
- ◆ Coal retirements increase difference, but are swamped by CO₂ price
 - Scens 2 & 5
- ◆ High differential with High Gas/Low CO₂ (Scen 10), though average price is low
 - Off-Peak price low (no CO₂ price), while Peak price high (high gas)

Slightly smaller differentials than last year's forecast – flatter load shape

Load – Price Elasticity Effects

Load in each scenario includes price elasticity response

- Scenario load differs from Reference load based on the scenario's retail power cost compared to Reference cost



Note:

This analysis reflects a climate policy that phases in the costs of CO₂ allowances over time (i.e., it reflects a policy that initially allocates most allowances for free, then gradually shifts to auctioning more and allocating less allowances). The issue of free allowances vs. auction will likely be a subject of active debate when/if serious climate policy negotiations resume.

- Retail price driven by fuel and CO₂ prices (CO₂ is initially offset by free allocations); also by REC cost of renewables, transmission upgrade cost, and new generation capital costs
- Price elasticity is modeled conservatively: relatively low long-run elasticity of -0.4
 - Still, the effect on load is significant, due to relatively large price changes
 - Retail price increase in Base Case causes 0.1% annual load loss past 2022, vs 0.3% Reference growth
- The most extreme scenarios show >5% load loss (~0.4% annual) in 2020-2035 period

Load Growth

Load typically has only a modest effect on power prices

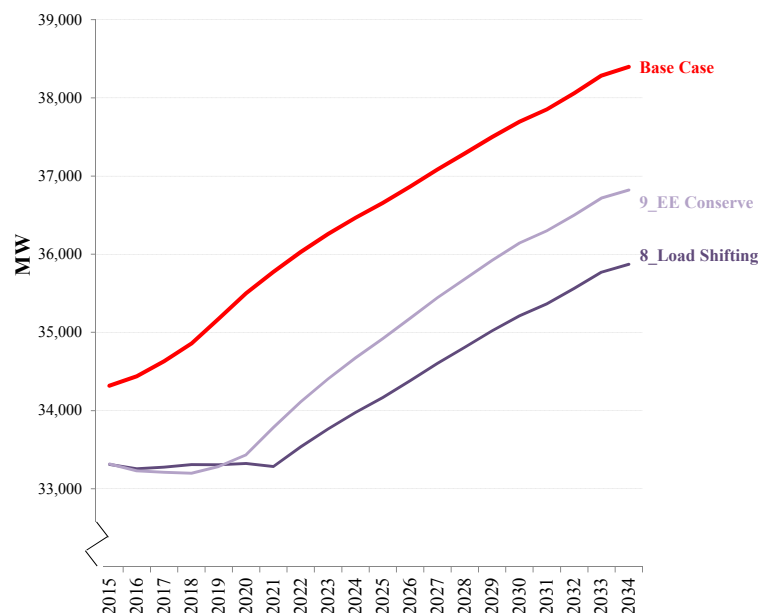
- ◆ In the long run, supply will generally adjust to load so that similar capacity is on the margin setting energy price
 - Load levels, if they change slowly, affect how much generation is added/retired, but change energy prices only modestly. Supply-demand balance is similar to what it would be with different growth
 - Growth can have a bigger effect on timing of capacity needs and capacity value
 - New electric demands, e.g., charging plug-in vehicles, is limited
 - Such new loads are likely to be small, even late in the horizon
- ◆ Scenarios show lower growth than AEO due to price elasticity (AEO Ref is a low-price scenario)
 - Sensitivity analyses on higher load growth showed an earlier capacity need (as expected), but only a modest energy price effect

Load Effects – Demand Side Management

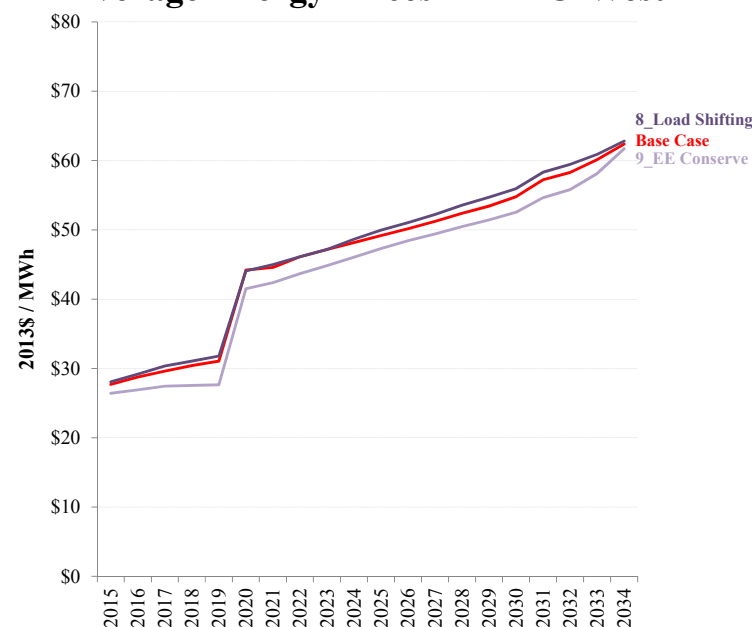
Active demand-side management programs can affect power prices somewhat, by shifting load relative to the existing supply mix

- ◆ Energy Efficiency (Scen 9) lowers prices slightly
 - Load reduction affects both peak and off-peak hours; peak effect is slightly larger
- ◆ Load Shifting (Scen 8) has very little effect on price
 - Affects only a few peak hours; little effect on energy price (slightly higher due to more retirements), but delays capacity needs and capacity price by over a decade
- ◆ Significant effect on load translates to small effect on energy price

Peak Load in MRO-West



Average Energy Prices in MRO-West



Distant Forecast Horizon – Beyond 2035

For the later years (to 2049), key variables were extrapolated for each scenario.

- ◆ Uncertainty over this time frame is very high; not only can market fundamentals like fuel price vary considerably, but industry and market structure may also change (new technologies, regulatory framework, market mechanisms)

Observations:

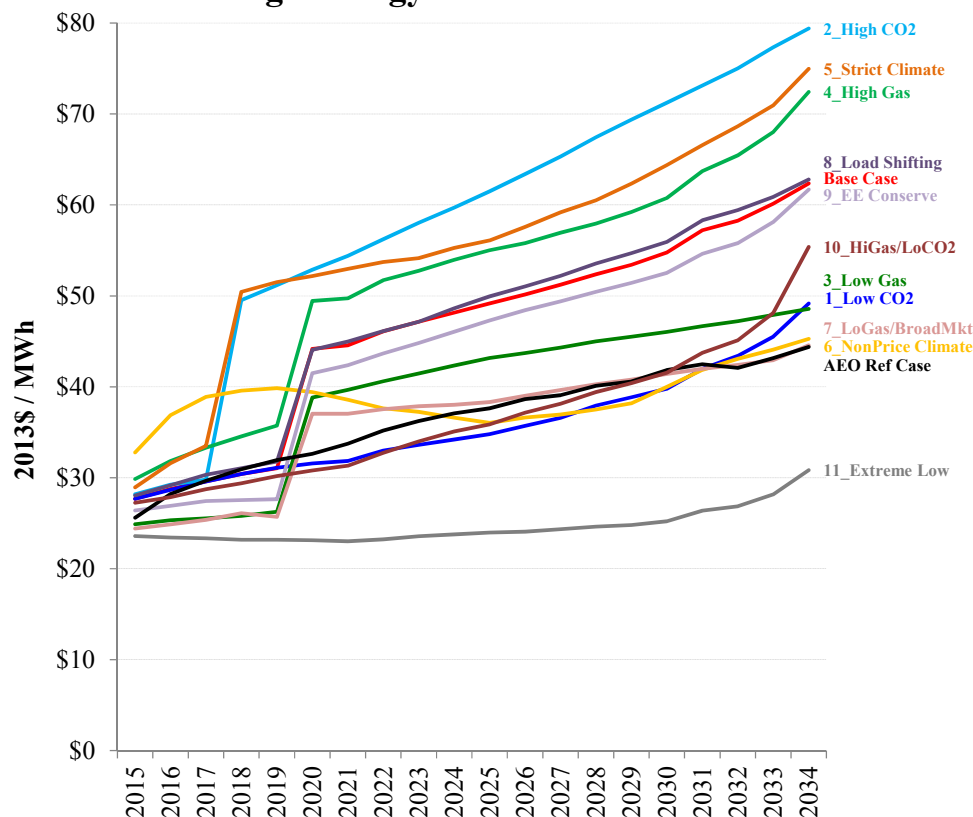
- ◆ Power prices generally continue the trends they were on, or sometimes stabilize, depending on the assumptions about the particular variables driving price in that scenario – e.g., whether they are assumed to continue growing (CO₂ price) or to stabilize (gas price)
 - Of course, this is because the input trends continue, by assumption
 - Scenarios reflect persistent trends over the full horizon, but reality may differ. A future with low prices in the upcoming decade could have very high prices in the following decade, though by design, these scenarios do not reflect such behavior.
- ◆ Price separation between MRO-West and surrounding regions that is evident in many scenarios tends to diminish and ultimately vanish, usually around 2030-2035
 - Nuclear retirements start 2030 (3.5GW in MRO-W; 26 GW total); replacements (type and location) are chosen economically which tends to equalize prices across regions.
- ◆ Over this long period, disruptive changes may be likely. The “iPod of power” will have unpredictable consequences for power markets. But hydro will not become uneconomic (no fuel cost, low operating cost, no CO₂), and its flexibility may be in higher demand.

Clearly, any forecast for this distant horizon is highly uncertain, and the extrapolated forecasts for this period should be interpreted in that light

Conclusion: Prices Trending Upward in All Cases

- ♦ **CO₂ price is the primary driver of power prices** (coal-dominated region exposed to CO₂ costs)
- ♦ **Gas price also plays a significant role** (more so due to recent & ongoing coal plant retirements)

Average Energy Price in MRO-West



Prices trend upward in all scenarios, due to rising fuel prices and coal retirements

Key influences:

- ♦ Wild card is future U.S. climate policy and what, if any, CO₂ price it creates (compared to current status, this is only upside potential)
- ♦ Gas price risk goes both ways – though gas remains so low now that a further large decrease seems unlikely
- ♦ Coal retirements are a positive effect, raising price expectations somewhat
- ♦ Renewable additions, if they continue, will depress prices moderately

If a material CO₂ price is enacted, power price outlook is unequivocally positive. But in the absence of CO₂ price, gas price is the primary driver.

- ♦ Without CO₂ prices, high gas price has little effect in MRO-W (though bigger effect elsewhere). With large coal retirements expected, power prices are more exposed to gas price, though economic retirements may counteract this somewhat.
- ♦ Low coal prices may be correlated with low gas prices; the combination could lead to very low power prices
 - More coal retirements may help mitigate

Conclusion: What Has Changed since 2012?

The changes seen from 2009 to 2012 have stabilized; we may be settling into a “new normal” characterized by cheap gas, lower loads, large coal retirements and renewable additions, and no CO₂ price (for now). These factors might nonetheless change in future

- ◆ All these factors, except coal retirements, have pushed down long-term price expectations

Load fell initially because of economic downturn, but growth is expected to remain low

- ◆ Current MRO reserve margins are well above target; low growth is expected to persist

Gas prices are low, due to continuing success of shale gas

- ◆ Long run gas price outlook has stabilized, following a drop of ~\$3 from 2009-2012

CO₂ price expectations are still pushed off, with high CO₂ price probably less likely

- ◆ Rejuvenated concern for climate, but continuing political gridlock makes CO₂ price unlikely

New EPA regulations are expected to cause large coal retirements, with more confidence

- ◆ Many units have already retired or announced, with increasing expectations for totals

Renewable buildout continues

- ◆ Large-scale transmission upgrades still lack specificity

Power price expectations have rebounded a bit since 2012 – mostly due to retiring coal

- ◆ Large retirements and announcements to date, and some more regulatory clarity

Most other factors – gas prices, CO₂ expectations, renewables – haven’t changed significantly in the past year

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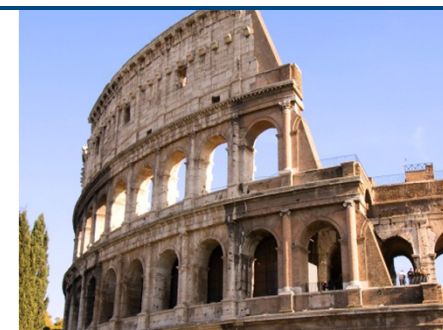
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- Appendix - Forecast Results for Scenarios

Detailed analytic results are provided separately in spreadsheet format.

Note: In the discussions of individual scenarios that follow, relative comparisons are to the “Base Case” scenario, unless otherwise specified

Simulation Results

Base Case results and results for each scenario are summarized in this Appendix

- ◆ Input Assumptions page: describes scenario, summarizes inputs
 - Fuel prices, coal retirements, renewable and transmission additions, CO₂ prices, demand
- ◆ Model Results pages
 - Graphic summary of results showing energy and capacity prices; also online capacity (with additions, retirements) and CO₂ emissions
 - For MRO-West region specifically (1st page), and aggregate results for 6-region area modeled (2nd page; useful for diagnostics)
- ◆ Discussion of results page: Observations and insights

Interpreting Results – Capacity Price

In a few scenarios, capacity value shows an unusual pattern in the model results: a very high capacity value in one year (well above CT carrying cost), followed by years of low or zero capacity value

- ◆ This is caused by an unusual pattern of capacity demand relative to supply:
 - Coal retirements create an initial, foreseeable need for additional capacity
 - In some scenarios, this is followed by foreseeable flat or declining load, combined with required renewable additions, leading to a subsequent capacity surplus
- ◆ Capacity value is generally zero when there is a surplus. To recover its full costs, a CT must recover more than one year's amortized value in the year capacity is needed (potentially much more, if the surplus is prolonged)
- ◆ This pattern of capacity supply and demand is unusual relative to historical experience
 - We usually expect consistent load growth and “normal” capacity prices (approx. the annual carrying cost of a CT). Sometimes we experience periods (like now) where load is unexpectedly lower, leading to a temporary capacity glut and low prices.
 - We do not typically foresee a medium-term capacity need, followed by an expected long-term surplus.
 - But this unfamiliar pattern may occur in a future where foreseeable coal retirements create a medium-term capacity need, followed by a longer-term capacity surplus that results from flat/declining load and/or renewable additions

This unusual pattern of economic capacity value is unlikely to be reflected in how it is recovered

- ◆ Likely to be recovered via long-term contract, with levelized cost recovery profile (maybe bundled with energy)
- ◆ Short-term MISO capacity markets (which currently includes a very low cap at 1xCONE) may not fully reflect capacity value time pattern
 - Regulated utilities with load obligations may be willing to commit to long-term capacity
- ◆ To better approximate the time pattern of capacity value recovery, economic capacity value is levelized across such periods
 - On output graphics, vertical bars indicate the time pattern of the economic value of capacity. In cases where that pattern differs significantly from the likely pattern of value recovery, capacity value is levelized to approximate the likely recovery pattern.
 - But under such conditions, capacity value may be unstable and uncertain, and may not warrant high confidence
 - E.g., there may be other, less costly ways (not modeled) to supply a temporary capacity need. For instance, demand response (peak shaving) could depress capacity prices below these levels

Base Case Scenario

Key Input Assumptions

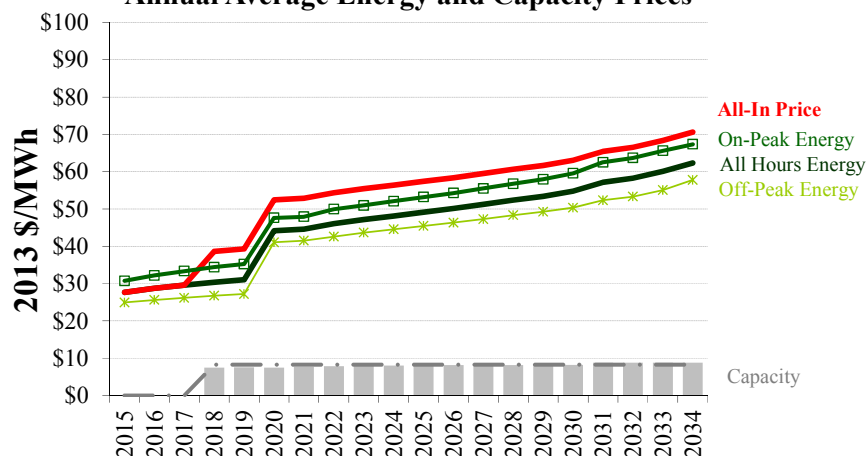
The Base Case scenario represents a continuation of current trends; essentially all input factors meet current expectations

- ◆ AEO 2013 Reference Case used as a starting point, but some factors differ
- ◆ CO₂ price starts at \$16/ton in 2020, grows at 3% to \$21/ton in 2030, reaching \$28/ton by 2040
- ◆ Fuel price updated to current market outlook
 - Natural gas: \$4.4/MMBtu in 2015, to \$5.9/MMBtu in 2025 (slightly above AEO)
 - Coal: \$1.7/MMBtu in 2015, to \$2.0/MMBtu in 2025 (AEO projections)
- ◆ Demand adjusted downward – elasticity response to higher prices (mostly CO₂)
 - Peak growth rate is roughly half that of the AEO Reference Case
 - Energy demand essentially flat starting in 2020 when CO₂ price manifests
- ◆ New generation additions:
 - Renewable additions are based on existing state RPS requirements, and include ~5,000 MW new wind generation in MRO-W for export (mainly into RFC-West)
 - New conventional generation already under construction is added at its expected online year (MRO-W adds no new coal and 150MW new gas CT; more elsewhere)
 - Nuclear becomes available in 2026, additions limited to 1,000 MW/year
- ◆ Planned unit retirements:
 - ~21% of the existing MRO-W coal capacity retires by 2020 to comply with EPA regulations that are expected to be in place (23% across all 6 regions modeled)
 - Nuclear plants assumed to retire after 60 years of operation (Kewaunee in 2013)

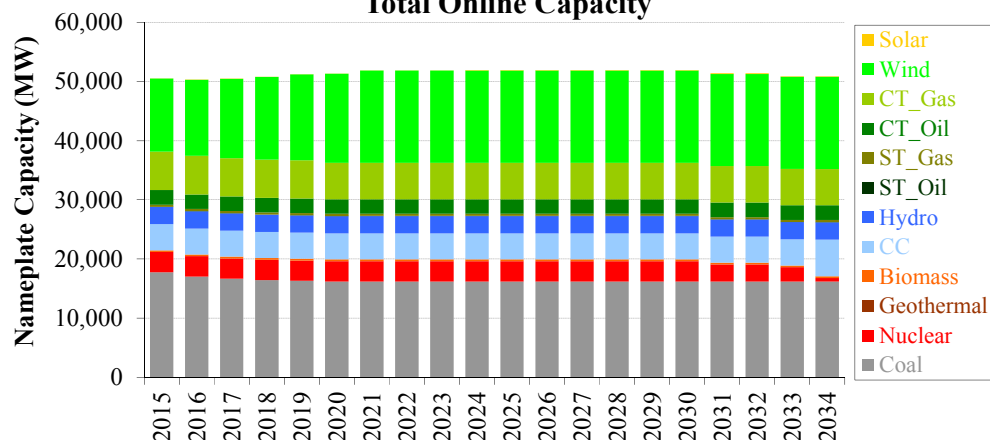
Base Case Scenario

Results for MRO-West Region

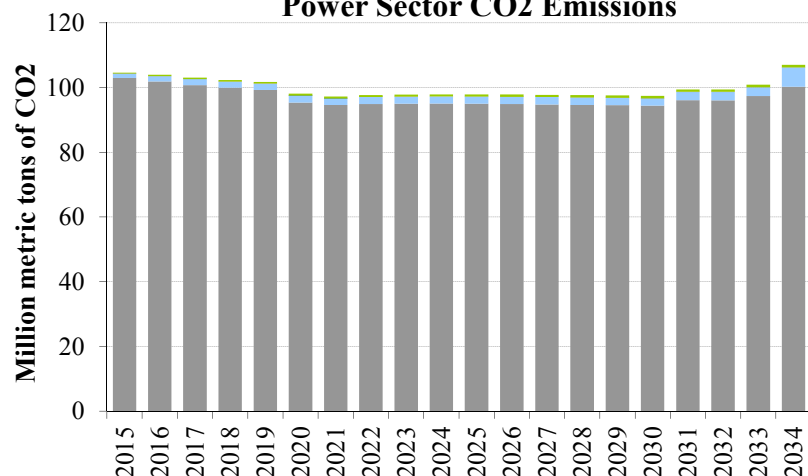
Annual Average Energy and Capacity Prices



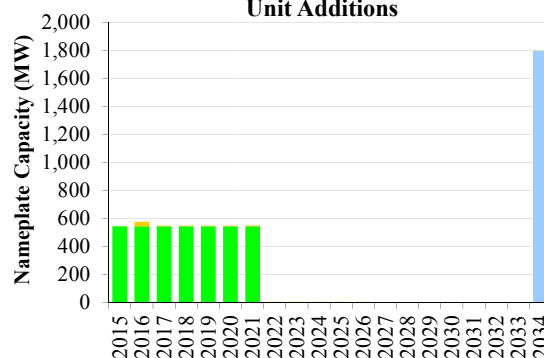
Total Online Capacity



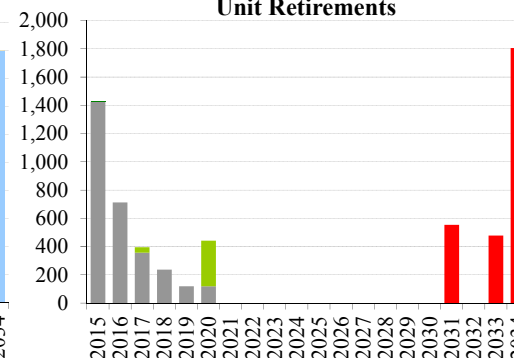
Power Sector CO2 Emissions



Unit Additions



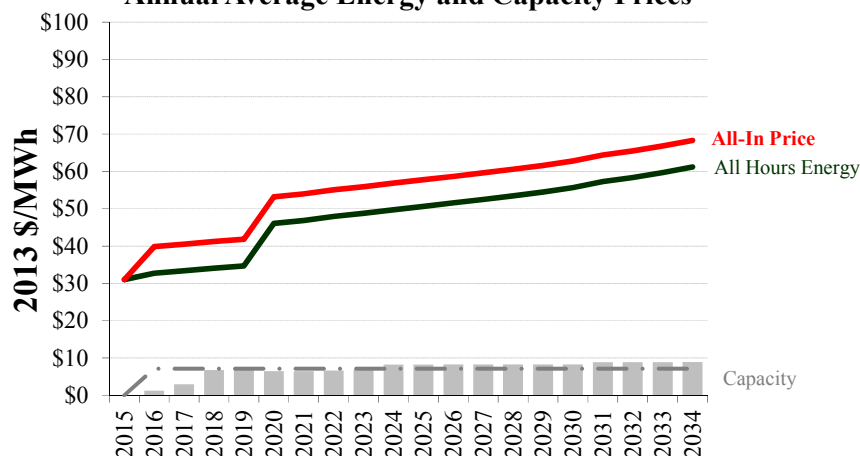
Unit Retirements



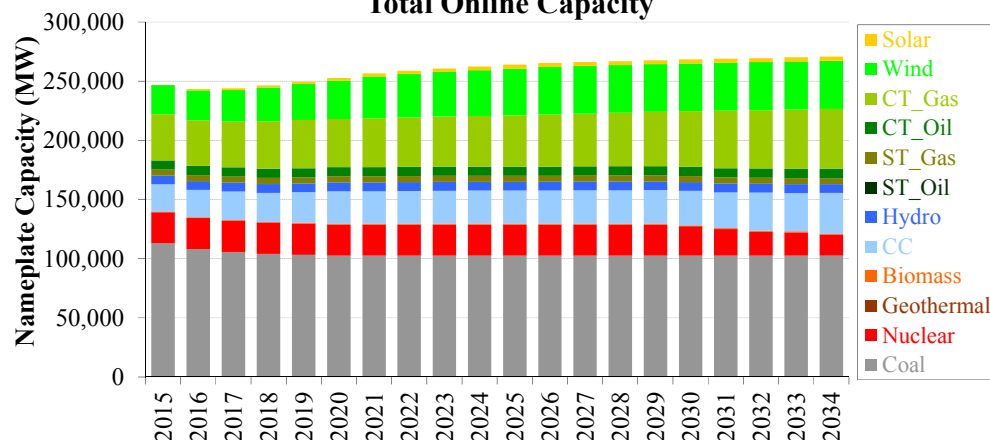
Base Case Scenario

Aggregate Results for the 6-Region Area Modeled

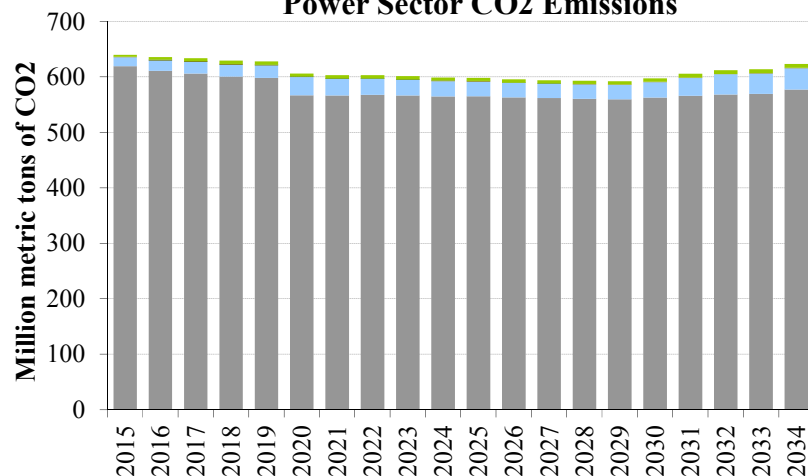
Annual Average Energy and Capacity Prices



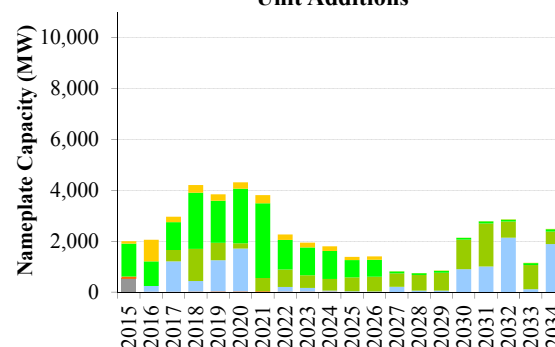
Total Online Capacity



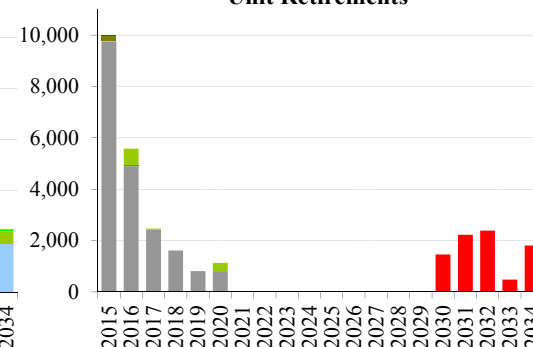
Power Sector CO2 Emissions



Unit Additions



Unit Retirements



Base Case Scenario

Discussion

Relatively low system load, combined with RPS additions, lead to modest capacity excess until ~2018, despite significant coal retirements

- ◆ Load grows more slowly than in AEO Reference Case
- ◆ ~21% of MRO-W coal capacity (23% across 6 regions) retires in initial years – mostly “forced” by EPA regulations, but also a small amount of “economic” retirements due to low gas prices, rising coal prices and anticipated future CO₂ prices

Wind is much of the generation added near-term

- ◆ Renewables (mostly wind) added to meet state RPS
- ◆ No conventional generation added until 2018 (beyond what’s already under construction)
- ◆ Gas CT/CCs added elsewhere starting in 2018 to maintain reserve margins – renewable additions slow down, load grows gradually, and after 2030, nuclear units begin to retire

Energy prices climb modestly, driven by fuel prices and coal retirements, with CO₂ price causing a jump in 2020

- ◆ Increase in gas and coal prices, plus coal retirements, lead to somewhat higher energy prices, compared to near-term lows
- ◆ CO₂ prices cause nearly a dollar-for-dollar increase off-peak; slightly less on-peak

Capacity prices ~\$65/kW-yr, but not until 2018

- ◆ Needed to support new capacity resources added (primarily gas CT/CC, outside MRO-W)

CO₂ emissions remain relatively flat

- ◆ Coal remains the primary generation source despite retirements and wind additions
- ◆ CO₂ price not high enough (nor gas low enough) to trigger major coal-to-gas switching

1. Low CO₂ Price Scenario

Key Input Assumptions

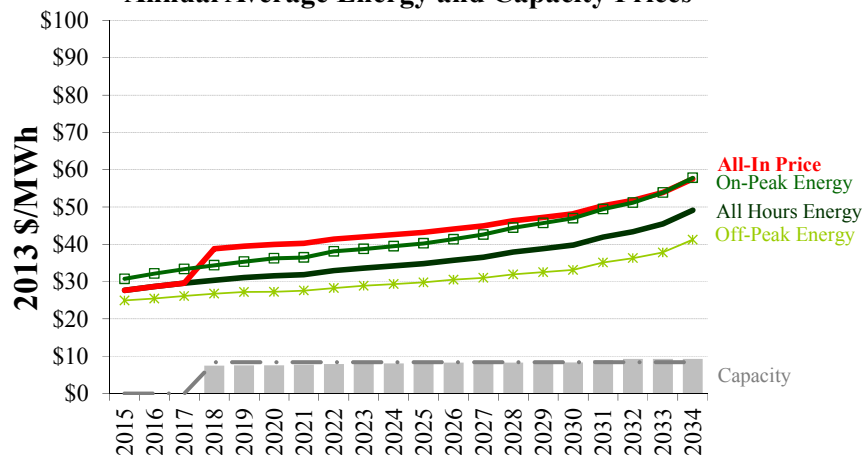
This scenario reflects a failure to enact any climate policy (zero CO₂ price) in an environment otherwise similar to the Base Case.

- ◆ No CO₂ price – climate policy not passed
- ◆ Demand grows at a modest 0.4% per year (higher than the Base Case load forecasts, but slightly below AEO 2013 Reference Case)
- ◆ Other inputs similar to Base Case

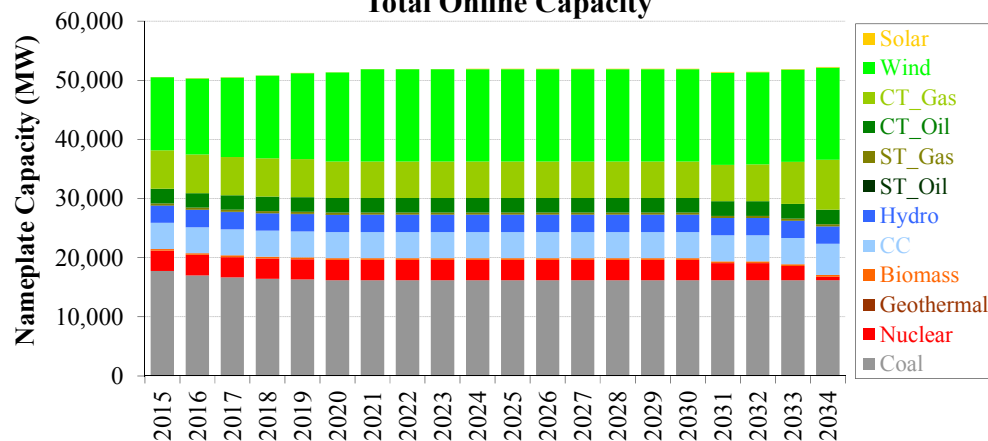
1. Low CO2 Scenario

Results for MRO-West Region

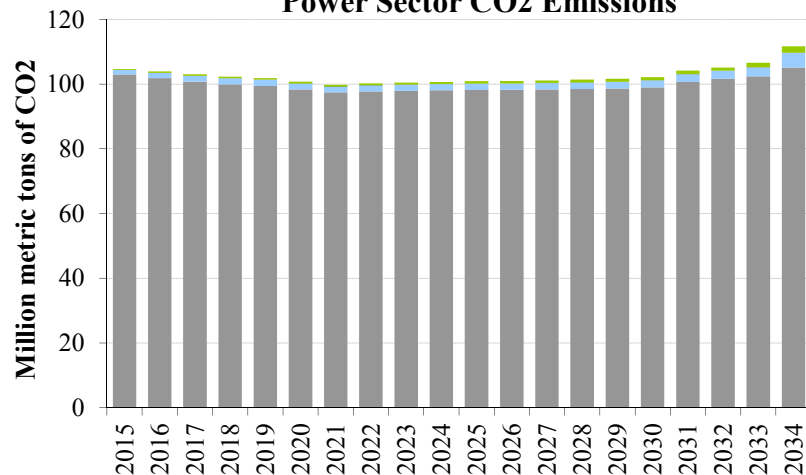
Annual Average Energy and Capacity Prices



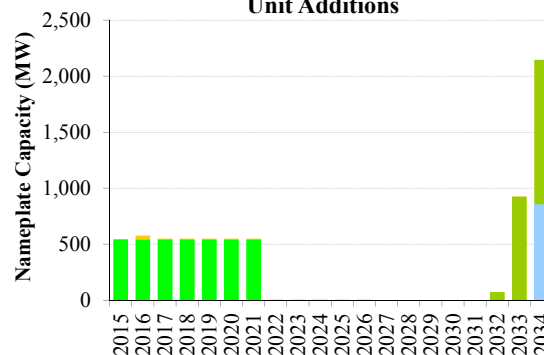
Total Online Capacity



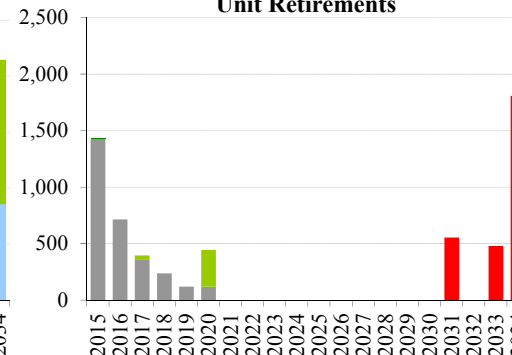
Power Sector CO2 Emissions



Unit Additions

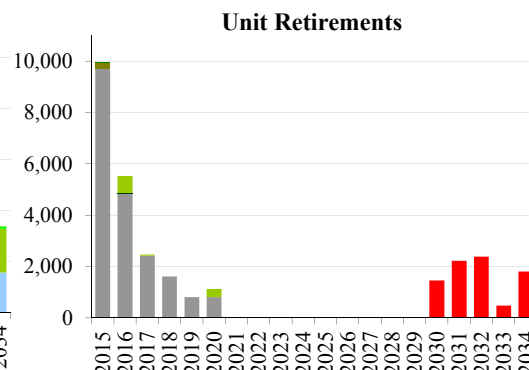
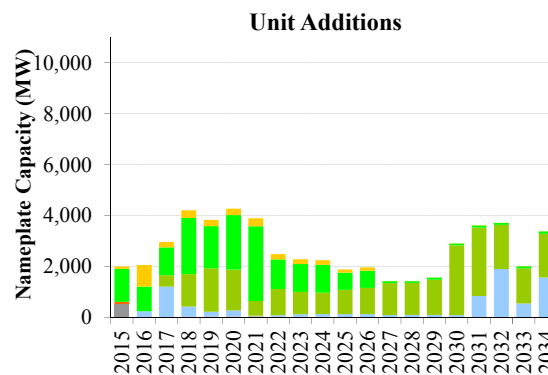
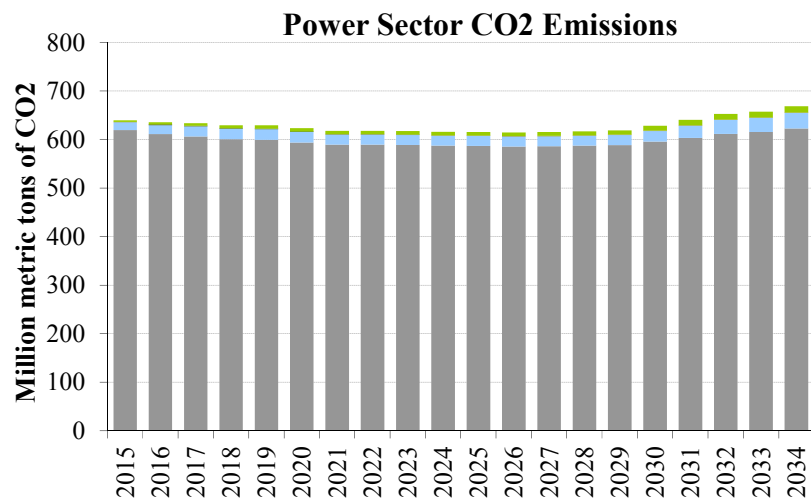
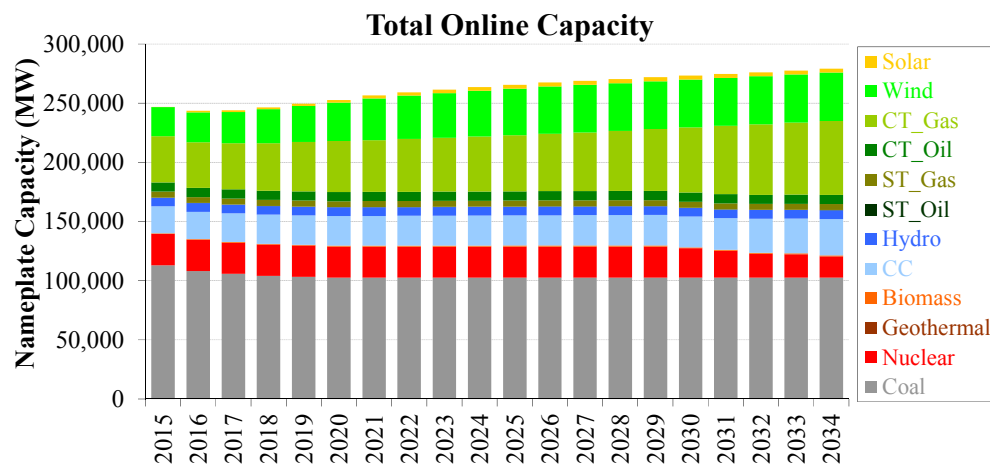
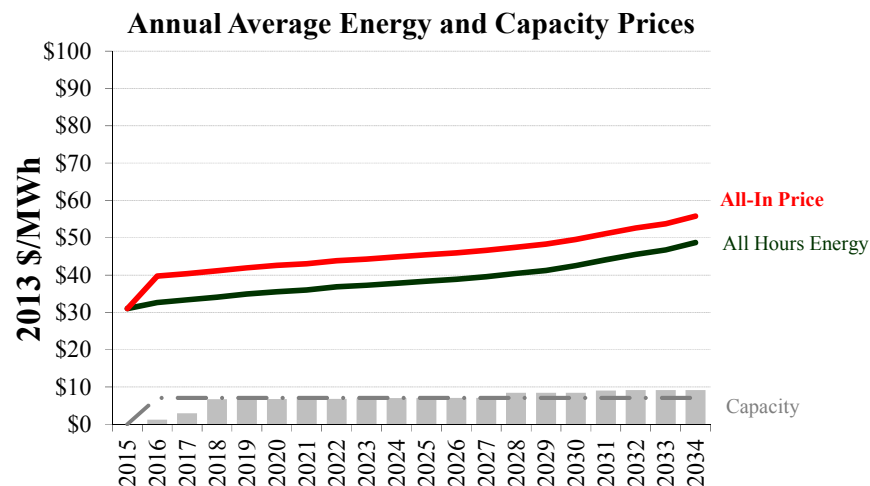


Unit Retirements



1. Low CO2 Case Scenario

Aggregate Results for the 6-Region Area Modeled



1. Low CO₂ Price Scenario Discussion

Load continues to grow moderately

- ◆ Load grows faster than in Base Case, but still slightly slower than in AEO Reference Case
- ◆ ~21% of existing coal in MRO-W retires through 2020, no additional “economic” retirements projected due to lack of CO₂ price

Generation additions are similar to Base Case

- ◆ Renewables (mostly wind) added to meet state RPS
- ◆ Gas CTs are added after 2016 to maintain reserve margins across the 6 regions modeled; more MWs added than in Base Case to match higher load growth

Energy prices stay fairly stable without a CO₂ price

- ◆ Peak price climbs moderately with increasing gas prices over time
- ◆ Off-peak price increase very slowly (coal prices grow modestly over time)
- ◆ Spread between peak and off-peak prices is somewhat higher than Base Case
- ◆ Prices also increase after 2030 due to nuclear retirements

Capacity prices ~\$65/kW-yr after 2017

- ◆ Needed to support new gas CTs
- ◆ MRO-West does not need new capacity until early 2030's; other regions with higher share of coal retirements, such as RFC-West, start adding capacity around 2017

CO₂ emissions remain relatively flat

- ◆ Coal plant retirements and renewable generation additions keep emissions stable at current levels despite modest load growth

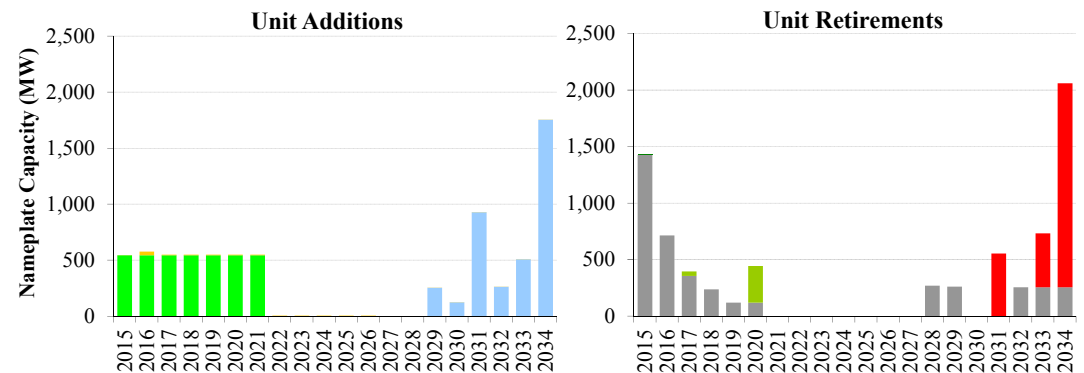
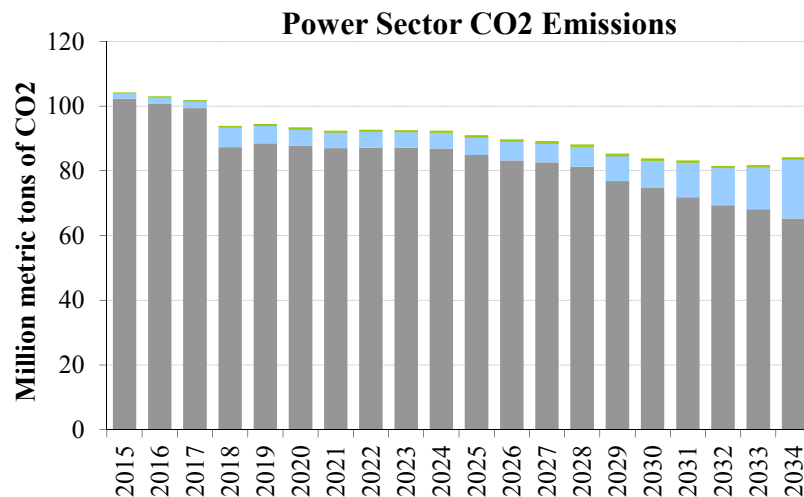
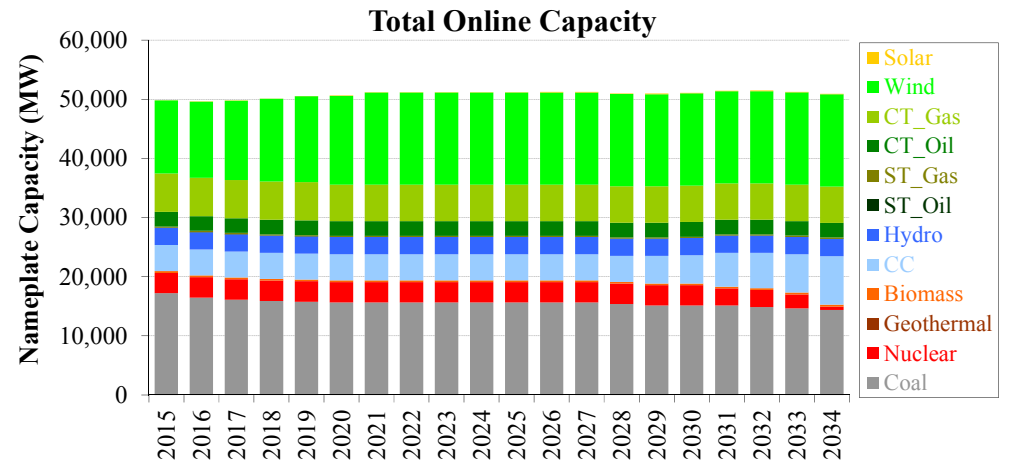
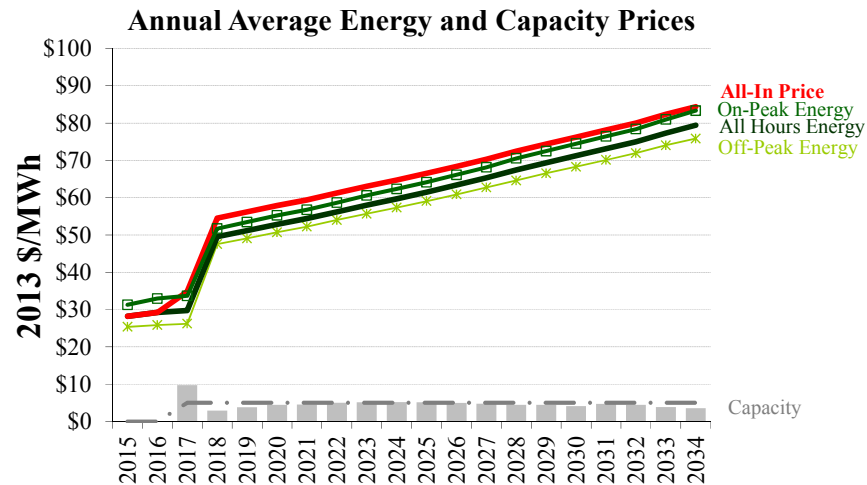
2. High CO₂ Price Scenario

Key Input Assumptions

This scenario represents a future in which persistently high CO₂ prices prevail (e.g., due to a relatively stringent policy) in an environment otherwise similar to the Base Case.

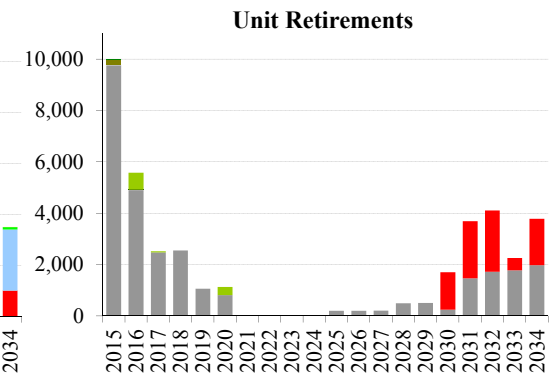
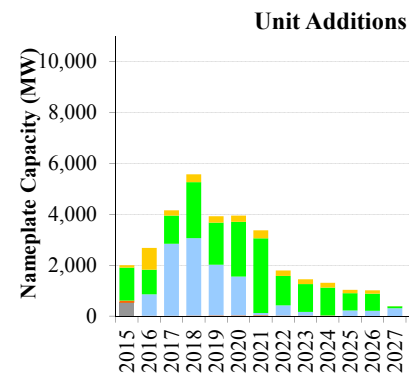
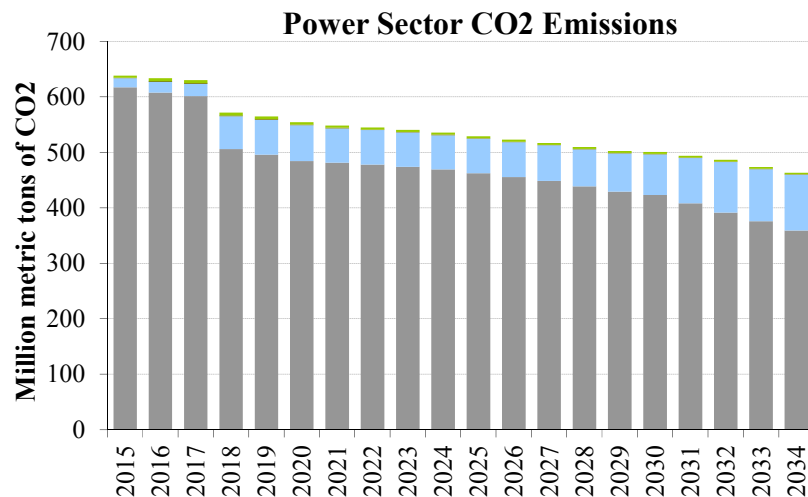
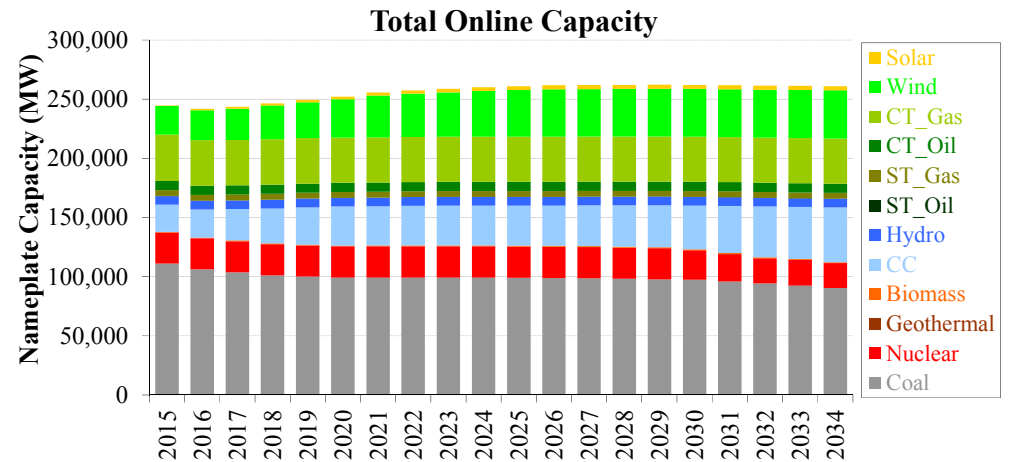
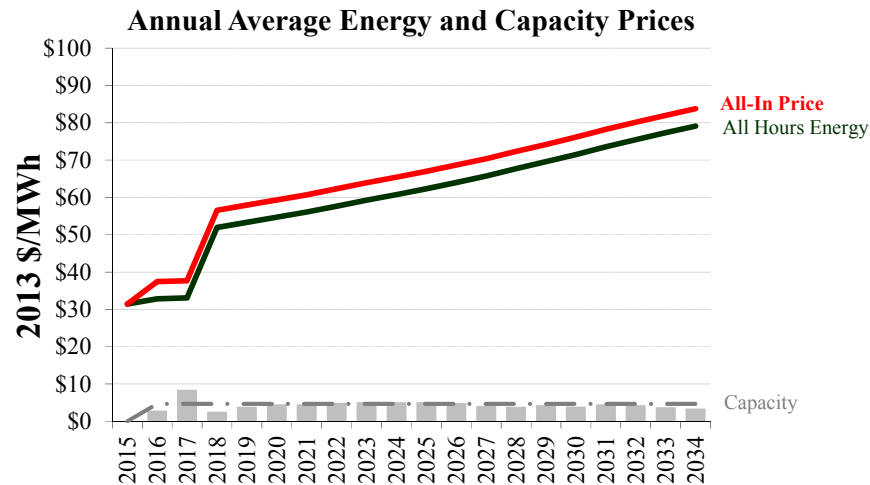
- ◆ Higher CO₂ price – starts at \$25/ton in 2018, grows at 5% to \$45/ton in 2030, and reaches \$73/ton by 2040
- ◆ Demand is lower in the long-term – greater elasticity response to higher retail prices (CO₂ price adder, plus wind capital costs)
 - Peak and energy levels similar to the Base Case through 2021, then decline gradually at ~0.2% per year
- ◆ Other inputs similar to Base Case

2. Hi CO2 Price Scenario Results for MRO-West Region



2. Hi CO2 Price Scenario

Aggregate Results for the 6-Region Area Modeled



2. High CO₂ Price Scenario Discussion

Much lower load, combined with higher CO₂ prices

- ◆ Significant coal retirements – 24% of existing MRO-W coal retires by 2020
 - ~5 GW in MRO-West, and 33 GW across all 6 region modeled

Large additions of low-CO₂ generation

- ◆ Renewables (mostly wind) added to meet state RPS
- ◆ New capacity needed starting 2016 to replace coal retirements; gas CCs added starting 2016 (and nuclear after 2030) to replace retiring coal

Energy prices are significantly higher due to CO₂ price

- ◆ High coal plant retirements also contribute to increased energy prices
- ◆ Peak/off-peak price spread is depressed by CO₂ price (hits coal harder than gas)
 - In the very long-term, this could change as coal moves to the top of the dispatch ladder to become a cycling resource, and gas becomes baseload (though operational issues may affect coal's ability to cycle)

Capacity prices ~\$45/kW-yr after 2017 – in levelized terms

- ◆ Needed to support new gas CC additions
- ◆ Capacity additions needed in 2016 – two years ahead of Base Case, due to higher coal retirements

CO₂ emissions decline sharply – down ~25% by 2030

- ◆ Large coal retirement, dispatch switching, falling load, added wind and nuclear
- ◆ High CO₂ price by itself may not induce the magnitude of reductions needed to meet climate goals – this CO₂ price is not particularly high, reflecting U.S. political conditions

3. Low Gas Price Scenario

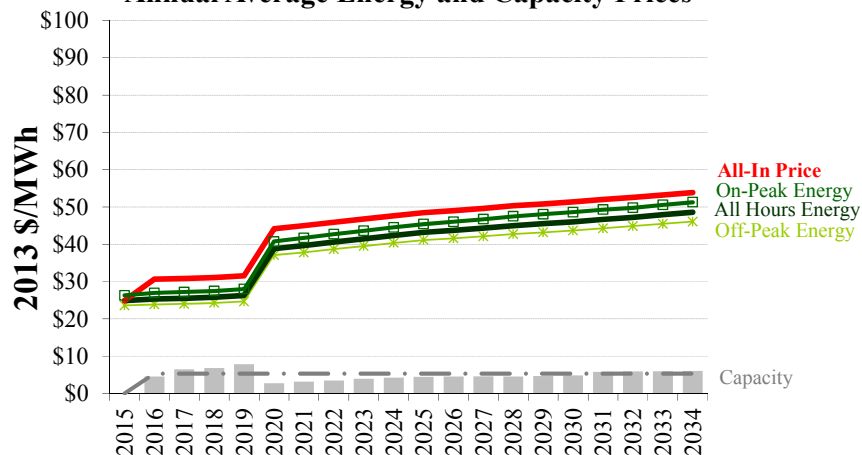
Key Input Assumptions

This scenario reflects very low natural gas prices, and CO₂ prices similar to the Base Case. This would correspond to a more strict CO₂ cap, under a cap-and-trade policy, which might be politically easier to implement if gas prices are low.

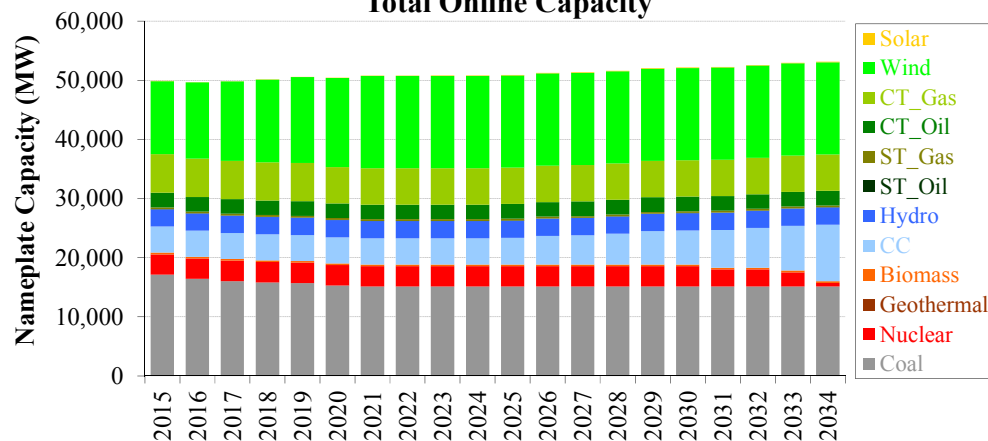
- ◆ Lower gas price – \$2.9/MMBtu in 2015, and \$3.6/MMBtu in 2025
 - Below current near-term prices and recent expectations, but not unprecedented
- ◆ Other inputs similar to Base Case

3. Low Gas Price Scenario Results for MRO-West Region

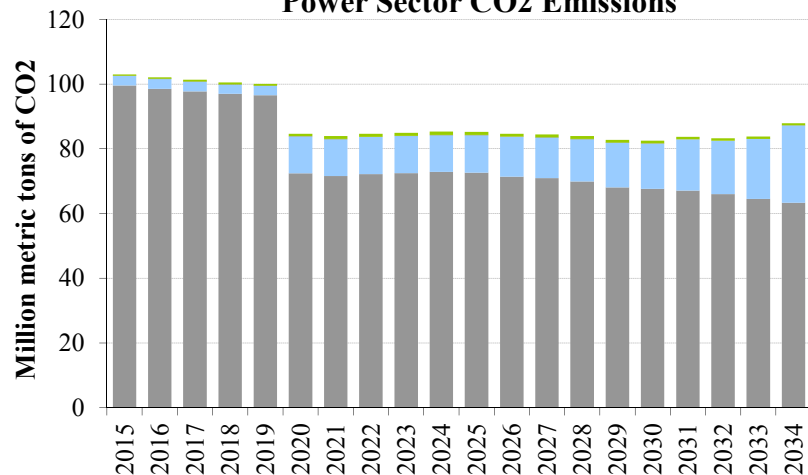
Annual Average Energy and Capacity Prices



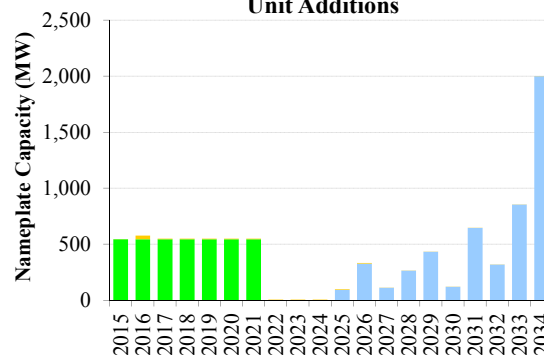
Total Online Capacity



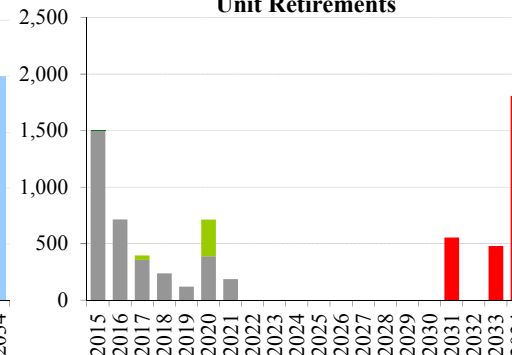
Power Sector CO2 Emissions



Unit Additions

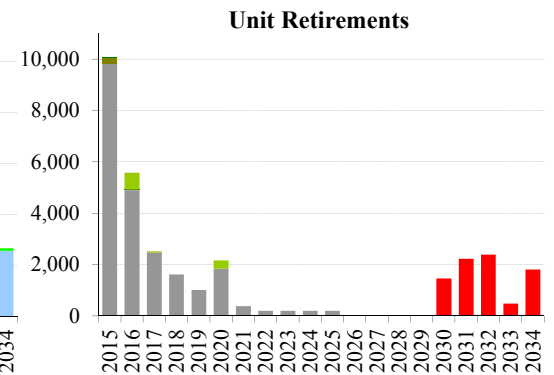
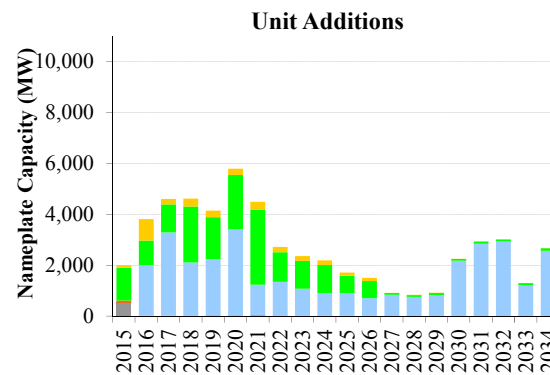
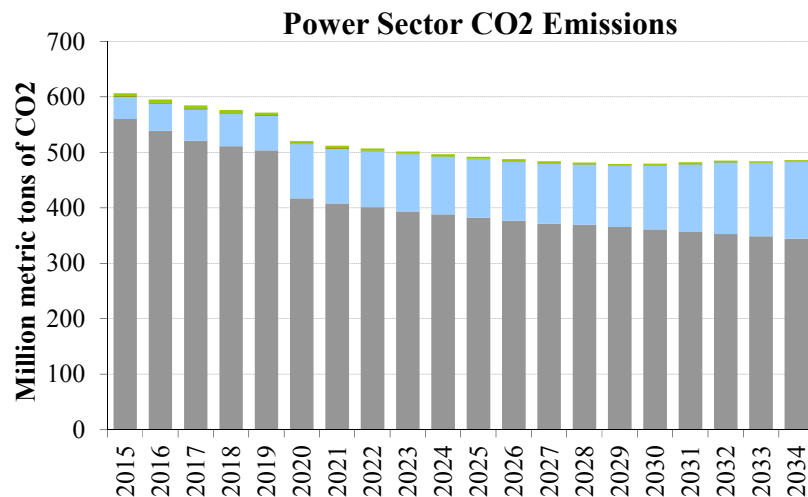
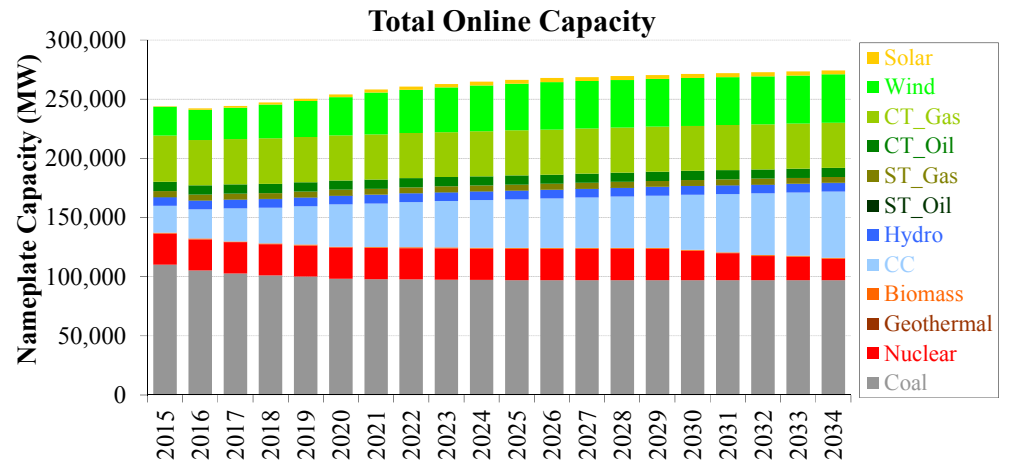
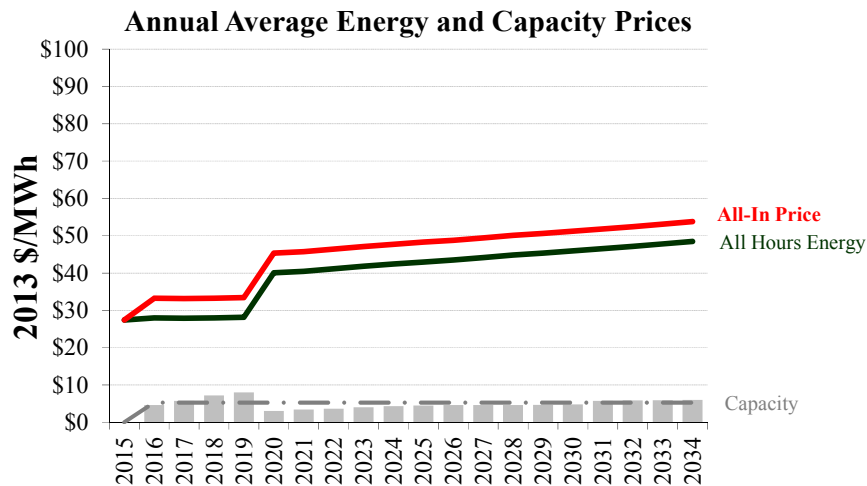


Unit Retirements



3. Low Gas Price Case Scenario

Aggregate Results for the 6-Region Area Modeled



3. Low Gas Price Scenario Discussion

Higher “economic” coal plant retirements due to low gas prices

- ◆ In addition to the 21% of “forced” retirements (in MRO-W) to comply with EPA regulations, 5% more retires by 2034 because of reduced coal energy margins under lower gas prices

Generation additions to meet RPS and replace retirements

- ◆ Wind added near-term to meet RPS
- ◆ New gas plants added to replace retired coal capacity – mostly gas CCs, starting 2016
- ◆ No other baseload additions – new gas CCs dominate at low gas prices

Energy prices are lower than Base Case, though still trend upward due to CO₂ prices

- ◆ Low gas prices suppress on-peak prices that are mostly set by gas plants (off-peak prices also decrease in the long-term as a result of higher wind additions)
- ◆ Peak/off-peak spread is significantly lower than in Base Case, around \$4/MWh, due to lower peak prices

Capacity prices ~\$50/kW-yr after 2016

- ◆ Capacity price needed to support new gas plants (primarily CCs)
- ◆ Capacity prices are variable, especially during initial years, due to changing energy margins

CO₂ emissions decrease moderately – about 25% by 2030

- ◆ Dispatch switching reduces overall emissions across all 6 regions modeled (a little less in MRO-W, as it continues to rely on coal)

4. High Gas Price Scenario

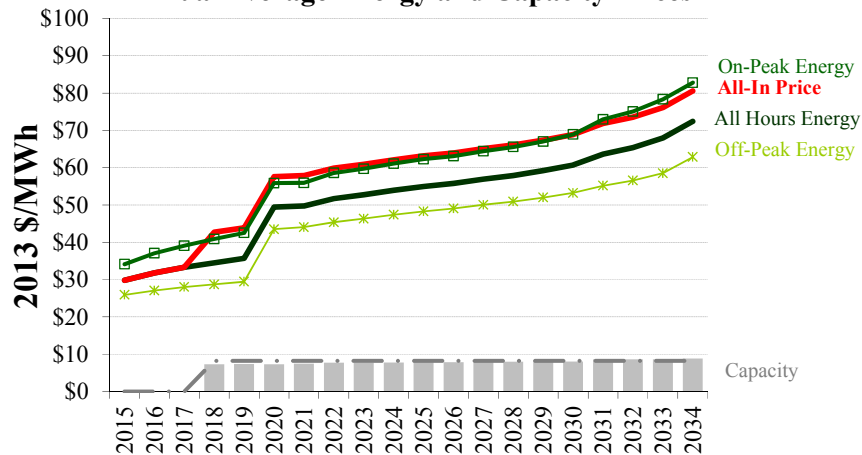
Key Input Assumptions

This scenario reflects very high natural gas prices, in an environment otherwise similar to the Base Case.

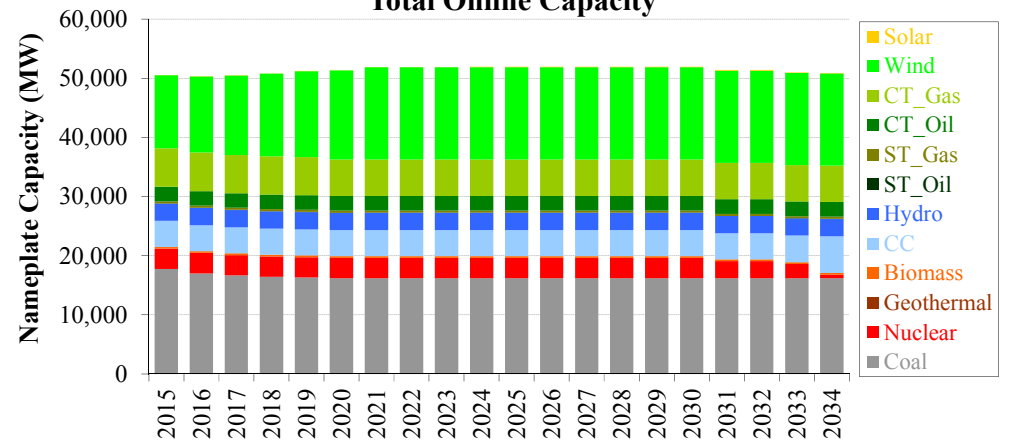
- ◆ Higher gas price – \$6.0/MMBtu in 2015, and \$8.6/MMBtu in 2025
 - Close to market expectations during mid-2008 fuel price run-up
- ◆ Other inputs similar to Base Case

4. High Gas Price Scenario Results for MRO-West Region

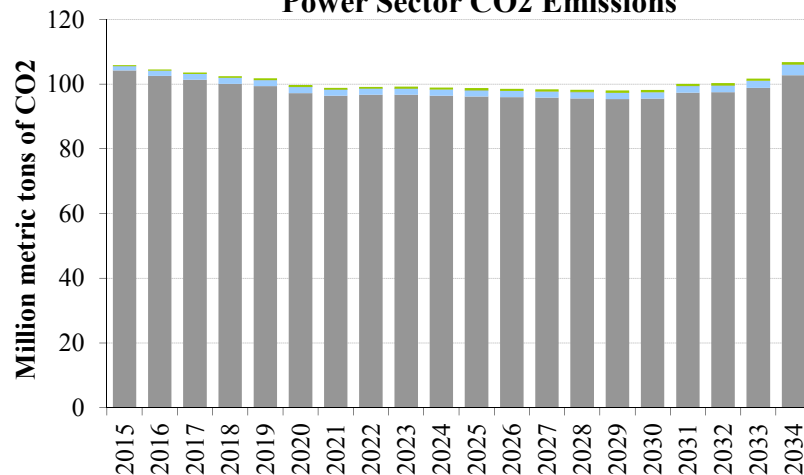
Annual Average Energy and Capacity Prices



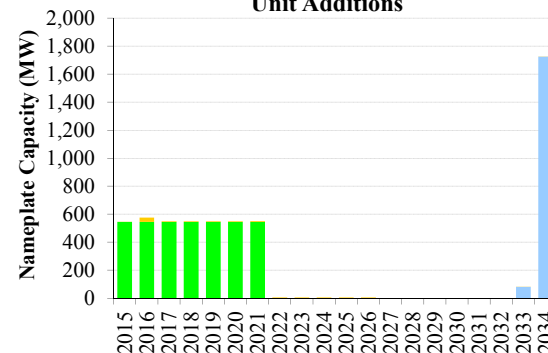
Total Online Capacity



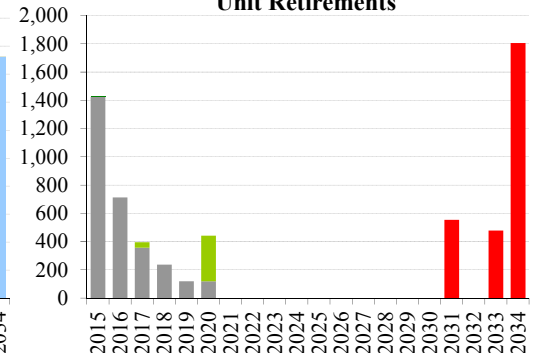
Power Sector CO2 Emissions



Unit Additions

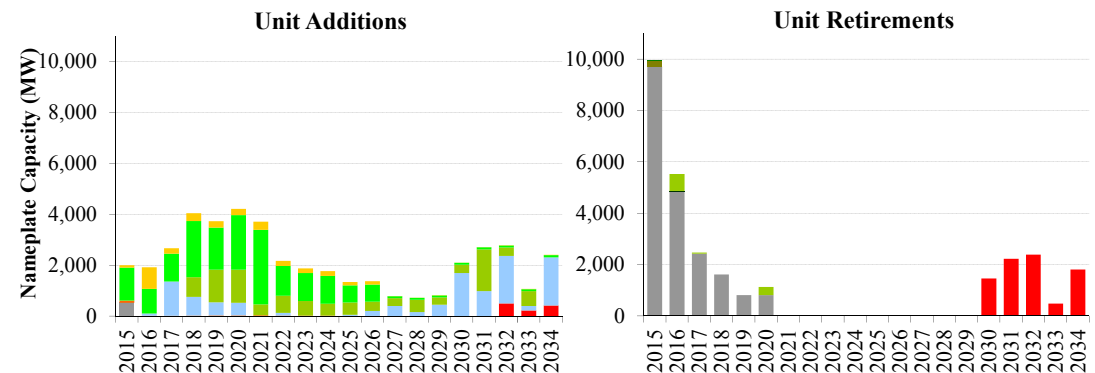
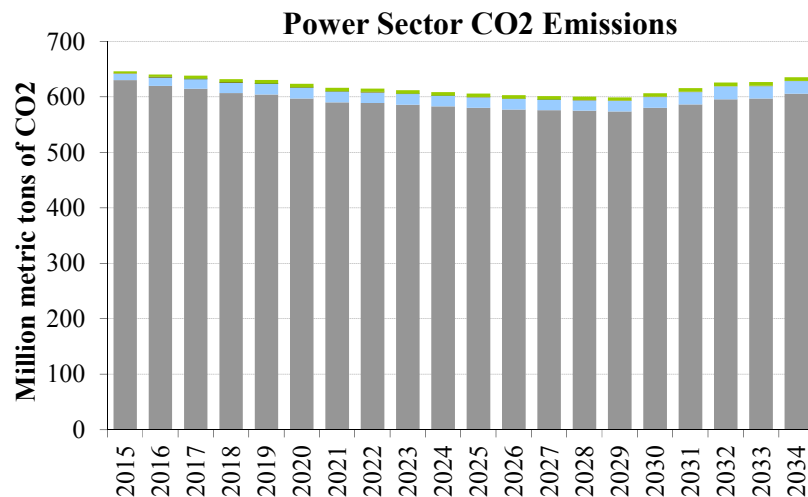
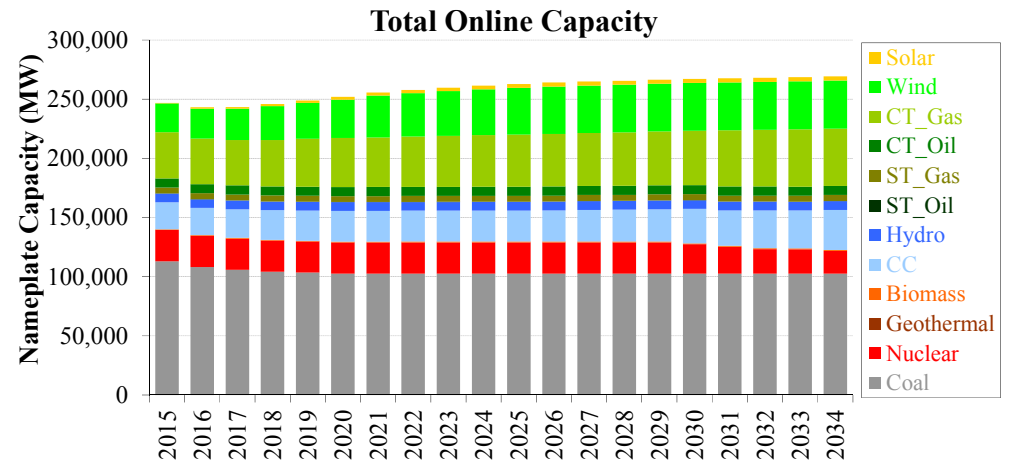
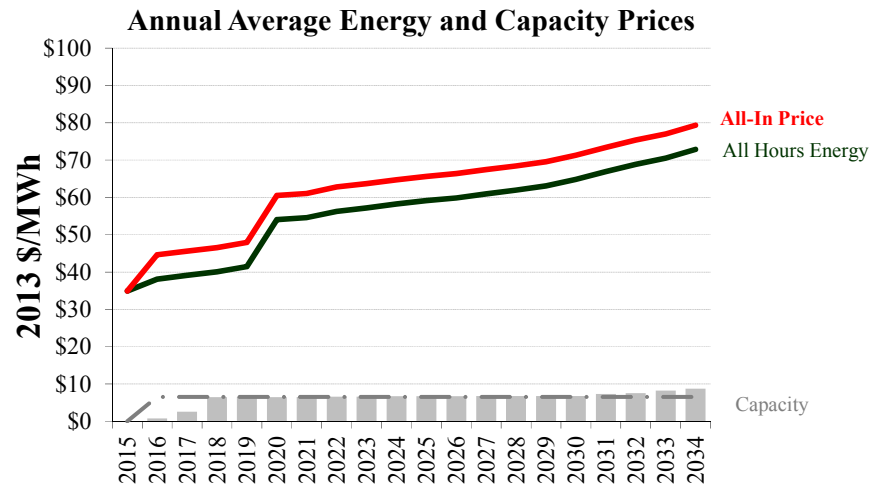


Unit Retirements



4. High Gas Price Case Scenario

Aggregate Results for the 6-Region Area Modeled



4. High Gas Price Scenario

Discussion

Modest load growth, combined with higher gas prices

- ◆ Load projections similar to Base Case; no “economic” retirements of coal since energy margins are better under high gas prices
- ◆ Additional capacity is needed after 2016 to maintain reserve margin

Wind is the primary addition over the next 10 years, followed by gas CTs and CCs

- ◆ Renewables added to meet state RPS (also has some capacity value)
- ◆ Gas CTs and CCs added later to maintain target reserve margins

Energy prices much higher than Base Case but not the highest among scenarios

- ◆ Higher gas prices push up the energy prices, but less than the effect of high CO₂ prices in Scens 2 and 5
- ◆ Peak prices increase with higher gas prices, and off-peak prices remain unchanged, leading to a peak/off-peak differential that significantly is wider than Base Case

Capacity prices ~\$65/kW-yr after 2018

- ◆ To support new gas CTs and CCs additions that maintain reserve margins

CO₂ emissions remain relatively flat

- ◆ Initial coal retirements and wind additions do not reduce emissions, because remaining coal is dispatched more often to avoid burning gas

5. Strict Climate: High CO₂ / Federal RPS Scenario

Key Input Assumptions

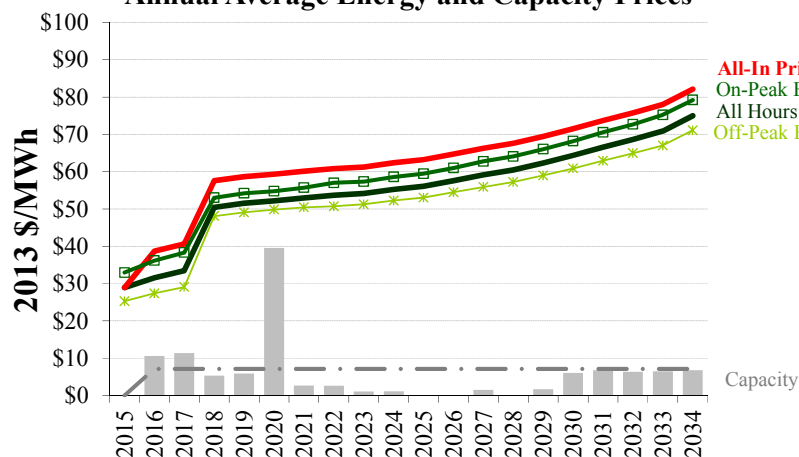
This scenario reflects a strong, multi-pronged climate policy that puts a high price on CO₂ emissions. It also encourages very large renewable additions and an extremely large transmission overlay to move up to 18.5 GW out of the wind-rich Dakotas, primarily to RFC-West

- ◆ Higher CO₂ price – starts at \$25/ton in 2018, grows at 5% to \$45/ton in 2030, and reaches \$73/ton by 2040
- ◆ Demand is substantially lower – greater elasticity response to much higher retail prices (CO₂ price adder, plus wind capital costs)
 - Peak and energy levels decline by ~0.3% per year after 2020
- ◆ Higher Federal RPS requirements – start about the same as State RPS level, but almost double that by 2025
 - ~20,000 MW of new wind generation is added by 2034; 18,500 MW is to be exported, primarily into RFC-West
 - Inter-regional transmission limits increased to reflect an extremely large transmission overlay needed for the wind exports (~\$6 billion cost recovered through an “adder” to the T&D component of retail prices)
- ◆ High “forced” coal plant retirements – in response to reduced energy margins under higher CO₂ prices
 - ~38% of existing MRO-W coal generation retires by 2020 to comply with EPA regulations that are expected to be in place (~32% across all 6 regions modeled)
- ◆ Other inputs similar to Base Case

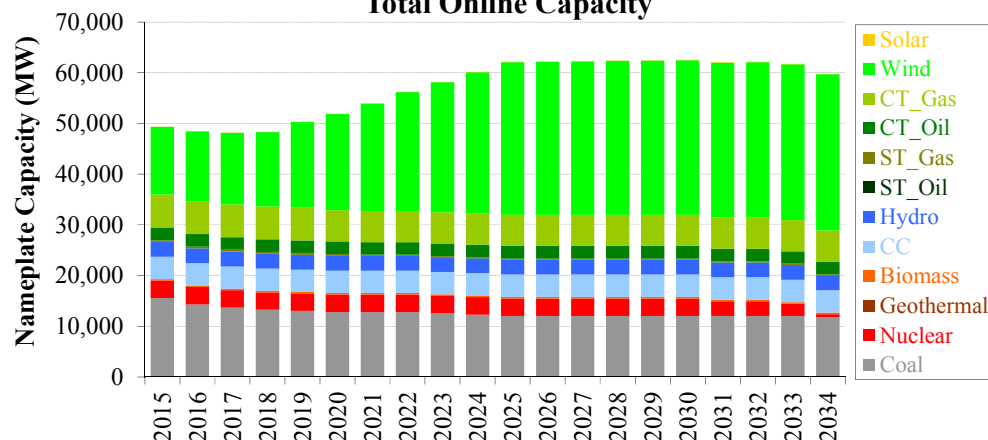
5. Strict Climate: Hi CO2 / Federal RPS Scenario

Results for MRO-West Region

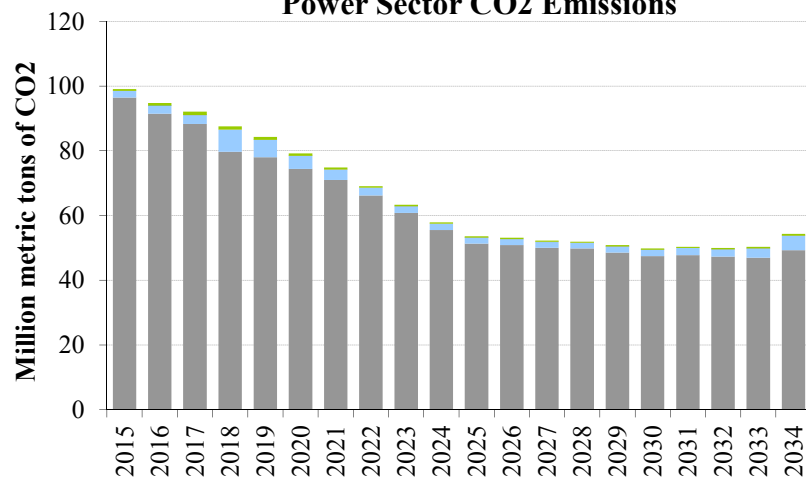
Annual Average Energy and Capacity Prices



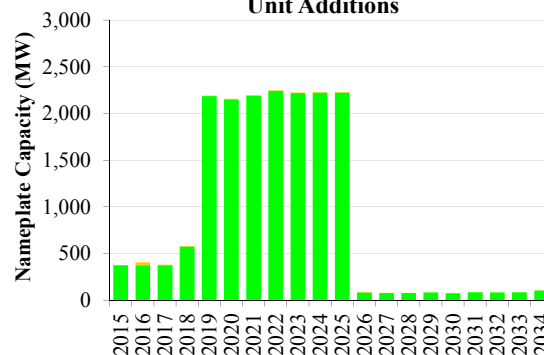
Total Online Capacity



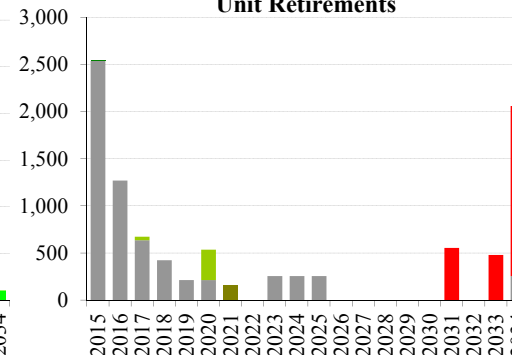
Power Sector CO2 Emissions



Unit Additions

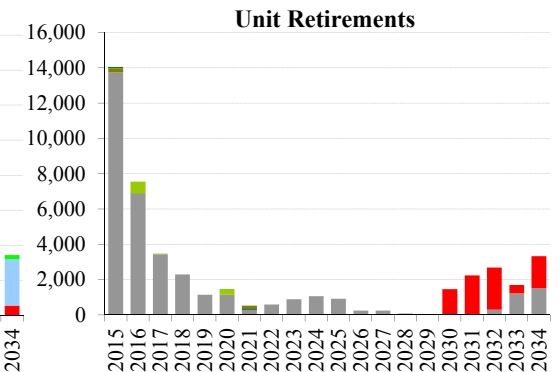
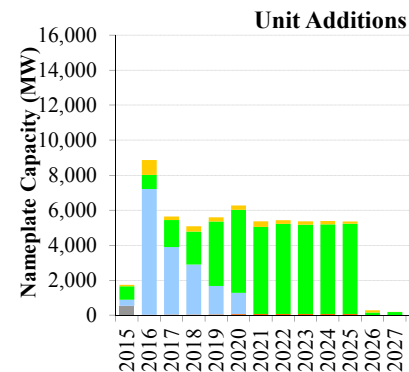
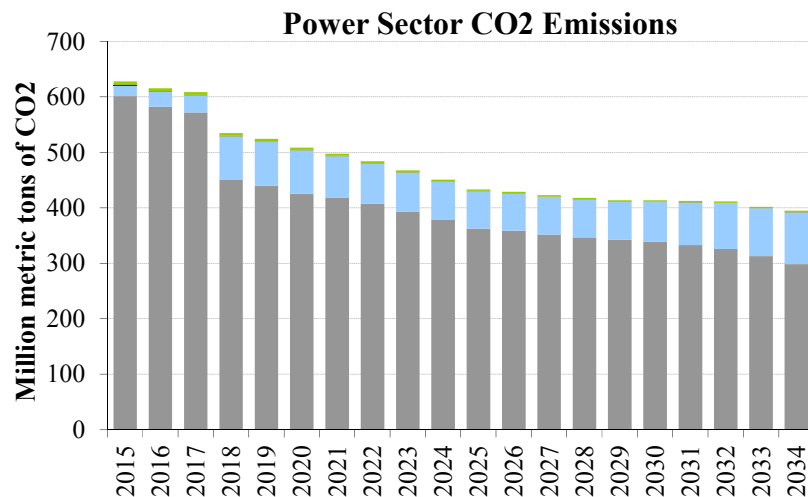
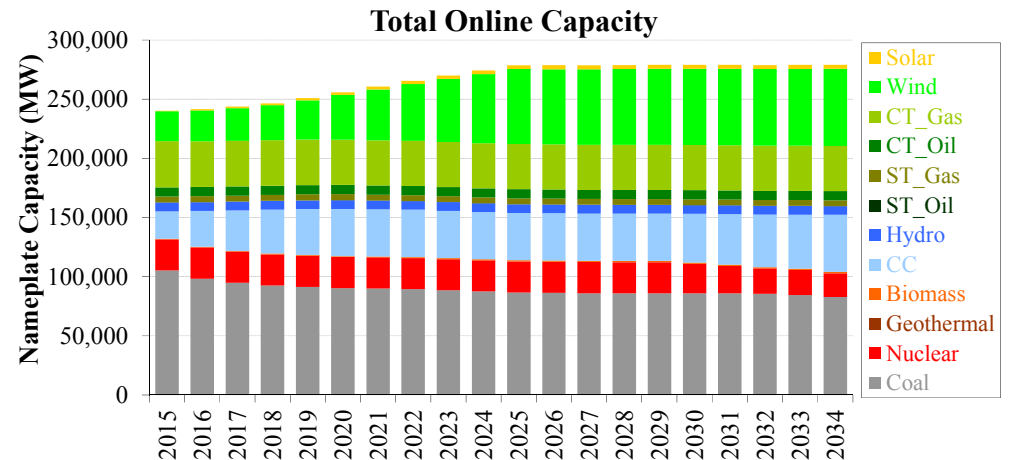
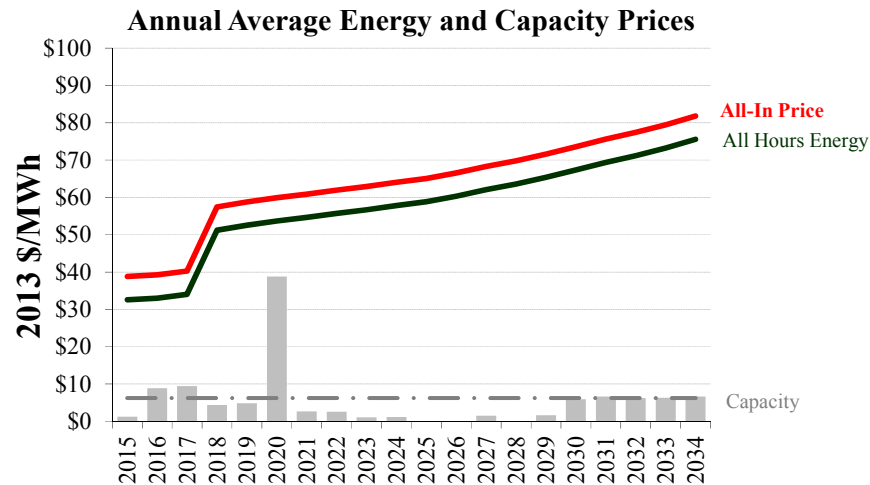


Unit Retirements



5. Strict Climate: Hi CO2 / Federal RPS Scenario

Aggregate Results for the 6-Region Area Modeled



5. Strict Climate: High CO₂ / Federal RPS Scenario Discussion

Higher CO₂ price and increased renewable addition, combined with much lower load

- ◆ Significant coal retirements – over 35% of the existing coal capacity retires by 2034 (~8 GW in MRO-West, and 50 GW across all 6 regions modeled)

Large additions of low-CO₂ generation

- ◆ Substantially higher renewable additions to meet Federal RPS – mostly wind generation
 - ~20 GW in MRO-West, and 44 GW across all 6 regions modeled
- ◆ New capacity is needed to replace retiring coal - Gas CCs in 2016-2020
- ◆ But falling load thereafter induces a capacity surplus until 2030
- ◆ Nuclear (and more CCs) added after 2030 as baseload generation

Energy prices are significantly higher, mostly due to CO₂ price

- ◆ CO₂ prices account for almost dollar-for-dollar increase off-peak, with a smaller increase on-peak
- ◆ Price projections much higher than Base Case, but slightly below High CO₂ Scenario prices, due to price suppression effect of higher renewable additions

Capacity value is variable, but averages ~\$65/kW-yr starting in 2016

- ◆ Large wind additions have little capacity value; new gas CCs needed starting 2017
- ◆ Temporary drop in 2020s – no new gas CCs added; low capacity price keeps existing capacity from retiring (initial spike reflects the additional amount needed by plants added in 2020, given the future period of suppressed prices)

CO₂ emissions decline sharply – down ~40% by 2030

- ◆ Combination of climate policy elements (CO₂ price, large coal retirements, added wind/nuclear, falling load) may induce enough reductions to meet climate goals

6. Non-Price Climate Policy Scenario

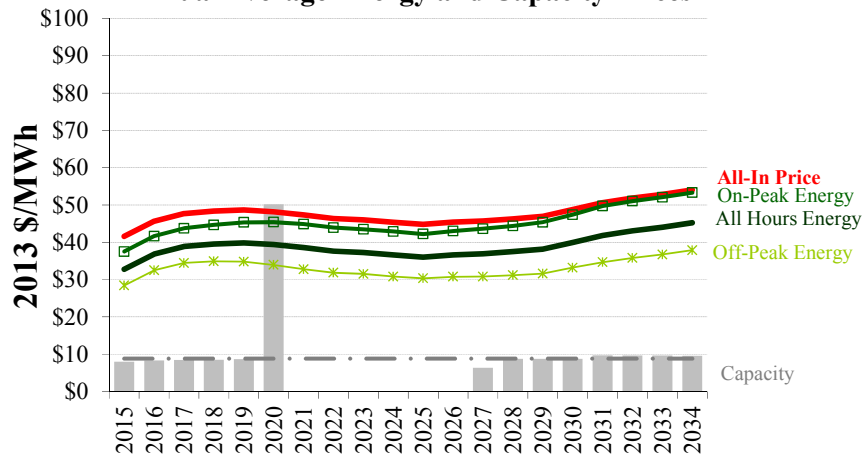
Key Input Assumptions

This scenario reflects a strong climate policy that emphasizes non-price policy mechanisms, but no CO₂ price. It imposes a 20% Federal RPS, including an extremely large transmission overlay to move up to 18.5 GW out of the wind-rich Dakotas, primarily to RFC-West. It also forces the retirement of a significant share of the coal fleet.

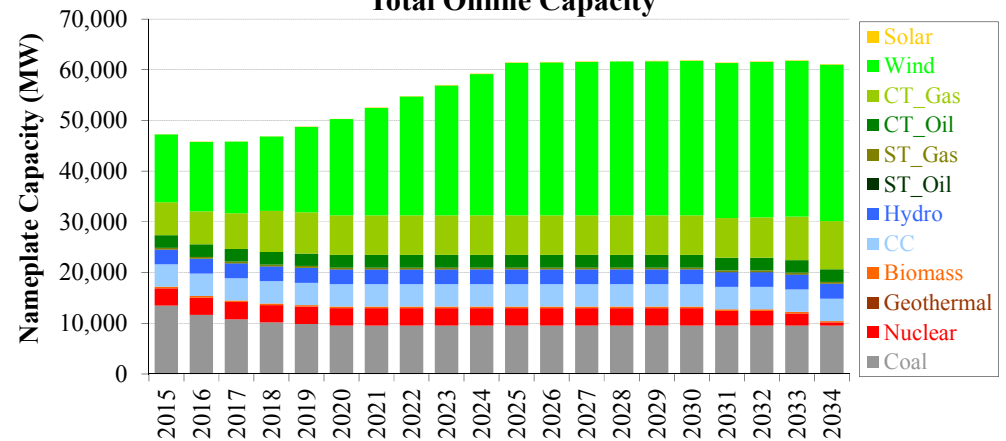
- ◆ No CO₂ price – climate policy shifts to non-price alternatives
- ◆ Demand is slightly lower – greater elasticity response to much higher retail prices (capital costs of wind and transmission)
 - Peak and energy levels decline on average by 0.3% per year between 2019 and 2029, and begin to grow at ~0.4% per year afterwards
- ◆ Higher Federal RPS requirements – start about the same as State RPS level, but almost double that by 2025
 - ~20,000 MW of new wind generation is added by 2034, with 18,500 MW exported (primarily into RFC-West)
 - Inter-regional transmission limits increased to reflect an extremely large transmission overlay needed for the wind exports (~\$6 billion cost recovered through an “add-on” to the T&D component of retail prices)
- ◆ Higher “forced” coal plant retirements – e.g. a policy of CO₂ emission limits on existing plants
 - ~54% of existing MRO-W coal generation retires by 2020 to comply with new policies (~40% across all 6 regions modeled)
- ◆ Other inputs similar to Base Case

6. Non-Price Climate Policy Scenario Results for MRO-West Region

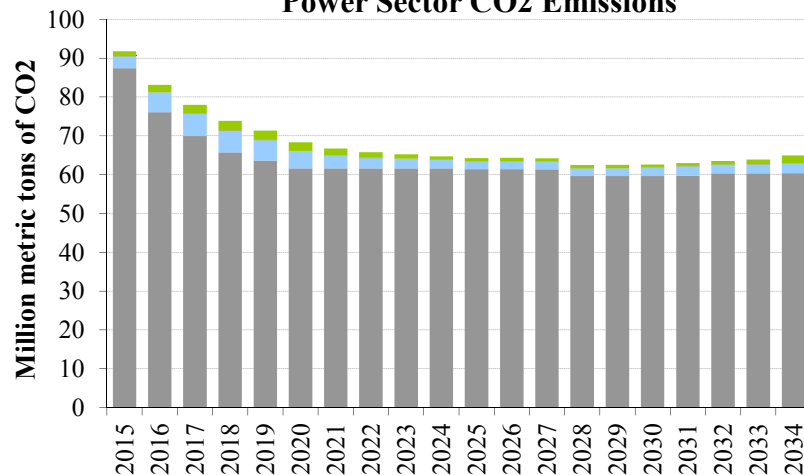
Annual Average Energy and Capacity Prices



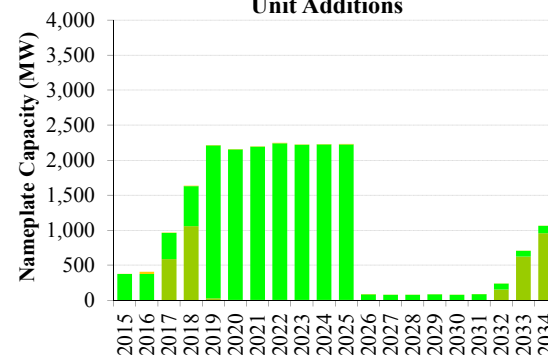
Total Online Capacity



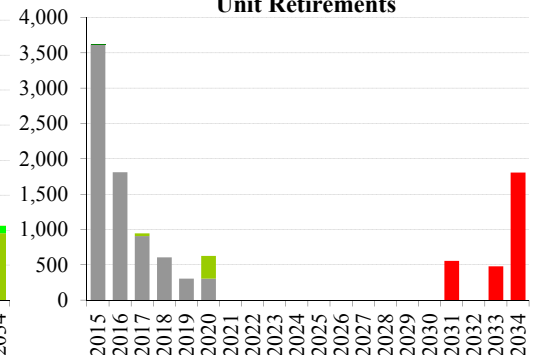
Power Sector CO2 Emissions



Unit Additions

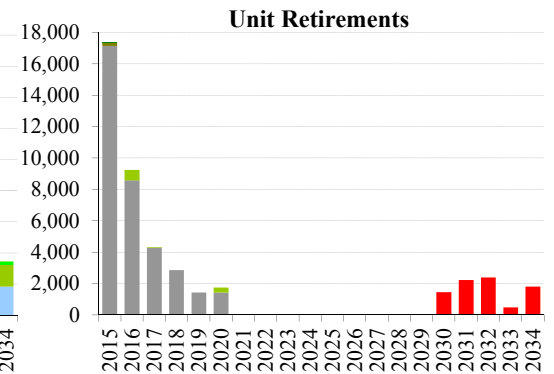
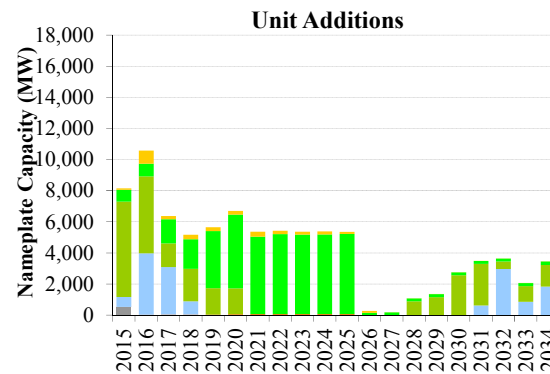
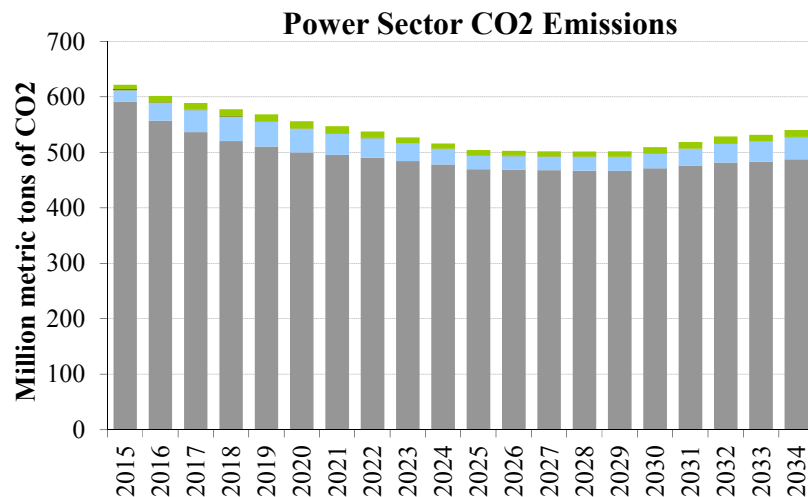
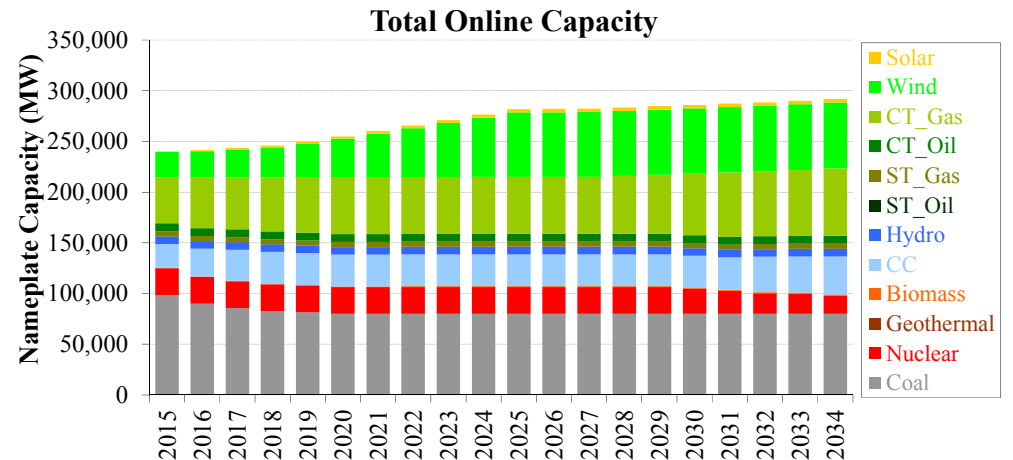
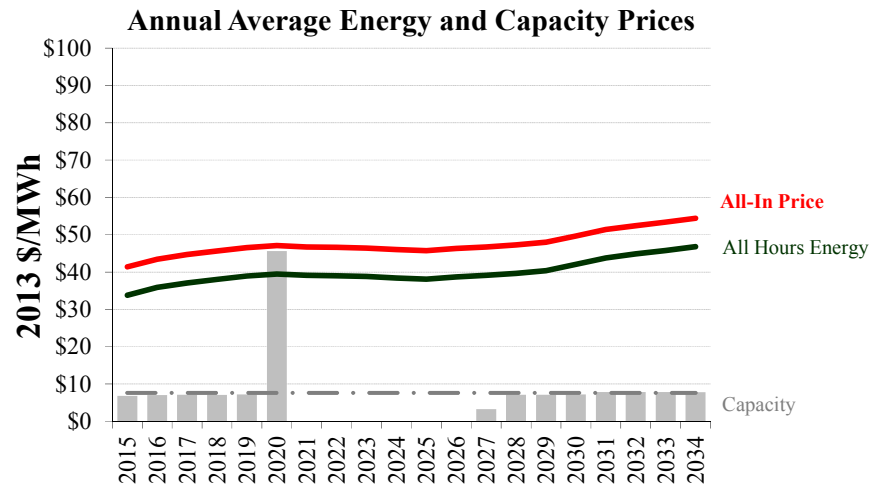


Unit Retirements



6. Non-Price Climate Policy Scenario

Aggregate Results for the 6-Region Area Modeled



6. Non-Price Climate Policy Scenario Discussion

Lower load, and higher “forced” coal retirements to reflect tighter restrictions on coal

- ◆ Significant forced coal retirements – about 35% by 2015, another 20% through 2020
 - 11 GW in MRO-W; 52 GW across 6 regions
- ◆ No further economic retirements; coal economics are otherwise reasonable

Generation additions to meet higher renewable requirements and replace retirements

- ◆ Substantially higher renewable additions to meet Federal RPS – mostly wind generation
 - ~20 GW in MRO-West, and 44 GW across all 6 regions modeled
- ◆ Gas CTs added to maintain reserve margins during the initial wave of coal retirements

Energy prices relatively stable without a CO₂ price

- ◆ More gas utilization, especially on-peak, increases prices gradually
- ◆ Prices suppressed by wind additions 2019-2025, then increase as load growth resumes
- ◆ Prices remains significantly below those of the price-based policy in the Scen 5: Strict Climate after that scenario has a CO₂ price

Capacity prices ~\$75/kW-yr starting in 2015 – in levelized terms

- ◆ Capacity needs occur sooner than in Base Case, due to higher initial coal retirements
- ◆ Temporary capacity surplus after 2020 – retail price increases from renewable additions causes load to decline (initial capacity price spike reflects the additional amount needed by plants added in 2020, given the future period of zero prices). Surplus disappears when CO₂ price gets high enough to prompt another wave of coal retirements.

CO₂ emissions decrease moderately – about 25% by 2030

- ◆ Lower load, large coal retirement, and more wind cut emissions 25% (more in MRO-West than other regions due to higher share of wind added), but later they begin to grow again
- ◆ By themselves, non-price mechanisms are not a fully effective climate policy

7. Low Gas in Broad Market Scenario

Key Input Assumptions

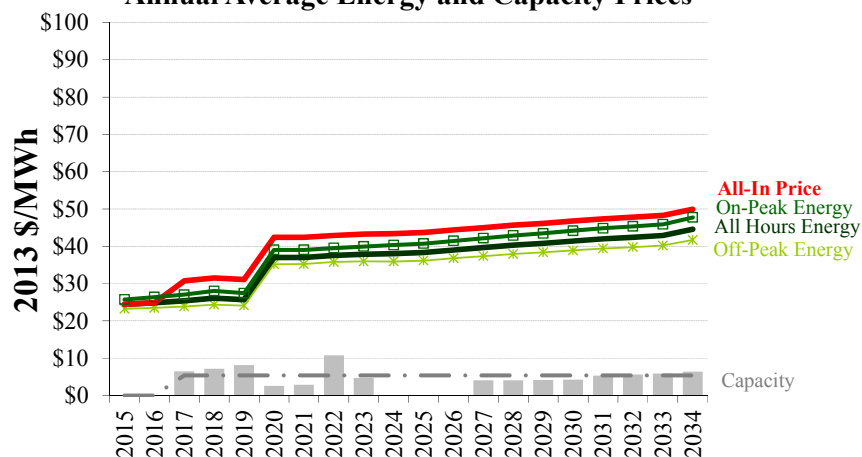
This scenario reflects a modest climate policy that puts a price on CO₂ emissions, but also encourages large renewable additions by providing access to wind-rich locations such as the Dakotas. In addition, gas prices are assumed to be very low (e.g., due to significant technological improvements in shale gas production methods).

- ◆ Lower gas price – \$2.9/MMBtu in 2015, and \$3.6/MMBtu in 2025
 - Below current near-term prices and recent expectations, but not unprecedented
- ◆ Higher Federal RPS requirements – start about the same as State RPS level, but almost double that by 2025
 - ~20,000 MW of new wind generation is added by 2034, with 18,500 MW exported (primarily into RFC-West)
 - Inter-regional transmission limits increased to reflect an extremely large transmission overlay needed for the wind exports (~\$6 billion cost recovered through an “add-on” to the T&D component of retail prices)
- ◆ Other inputs similar to Base Case

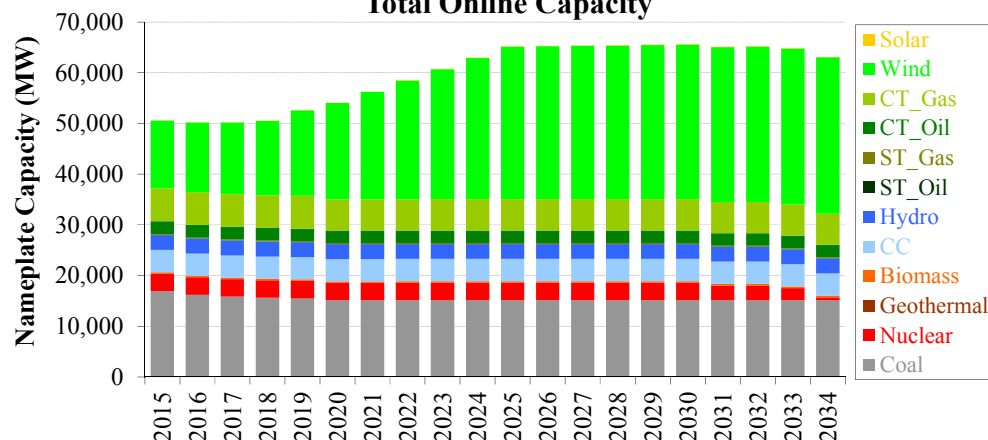
7. Low Gas in Broad Market Scenario

Results for MRO-West Region

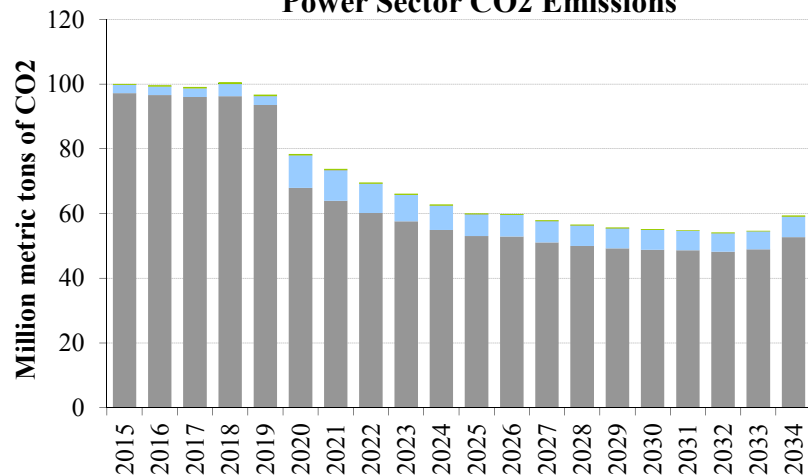
Annual Average Energy and Capacity Prices



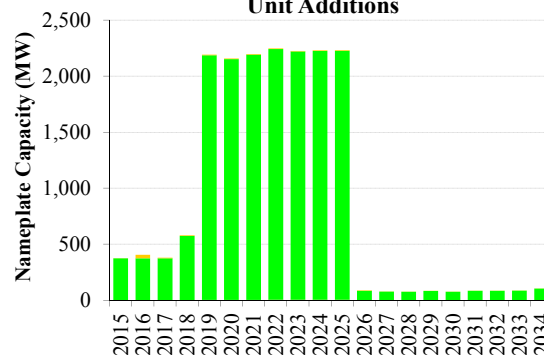
Total Online Capacity



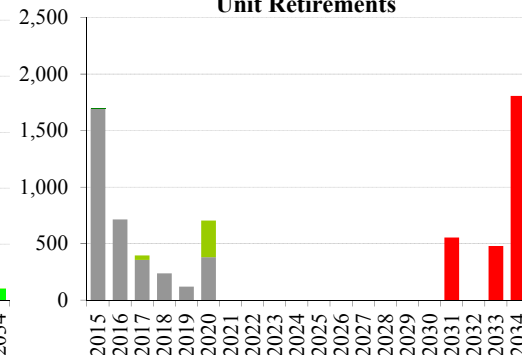
Power Sector CO2 Emissions



Unit Additions



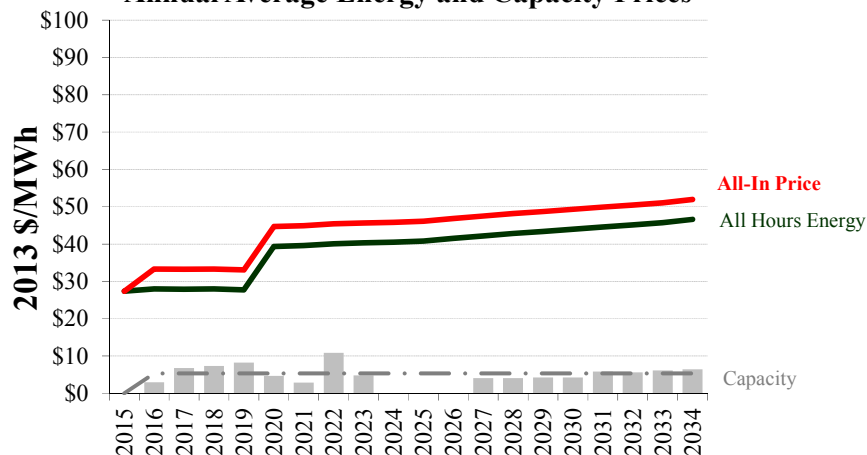
Unit Retirements



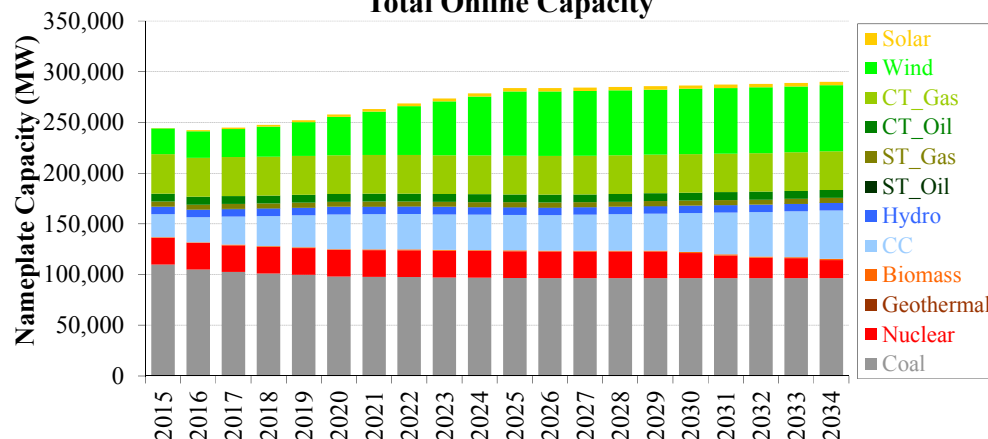
7. Low Gas in Broad Market Scenario

Aggregate Results for the 6-Region Area Modeled

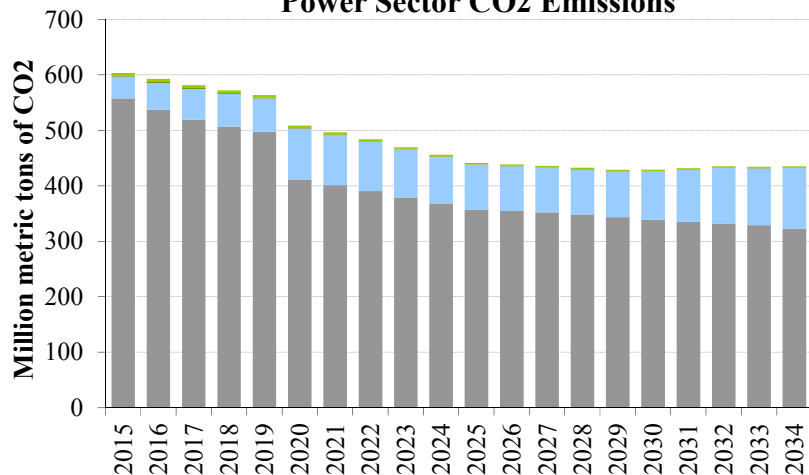
Annual Average Energy and Capacity Prices



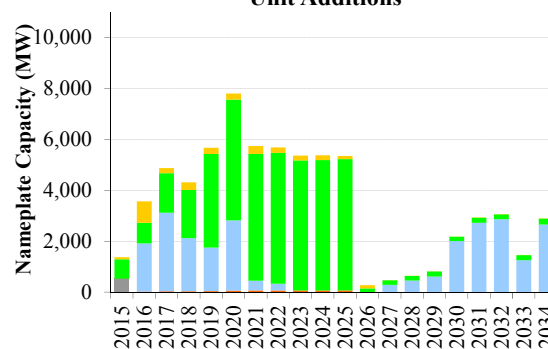
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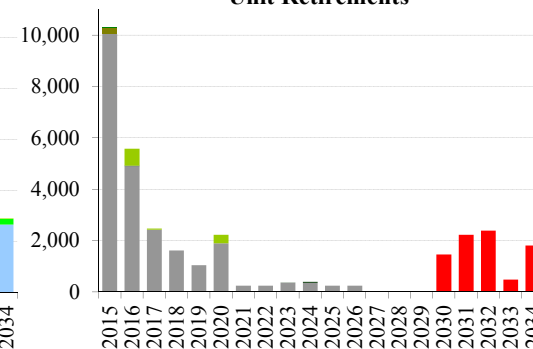
Power Sector CO2 Emissions



Unit Additions



Unit Retirements



7. Low Gas in Broad Market Scenario Discussion

Higher “economic” coal plant retirements due to low gas prices

- ◆ In addition to the 21% of “forced” retirements (in MRO-W) to meet new EPA regulations, poor energy margins under lower gas prices cause another 5% retirements by 2034
- ◆ Retirements are significantly lower than in the price-based strict climate policy (Scenario 5) and Non-Price Climate Scenario (Scenario 6)

Generation additions to meet higher renewable requirements and replace retirements

- ◆ More wind added to meet Federal RPS (especially in MRO-West)
- ◆ Gas CCs added in 2016-2022, but then more gas capacity is not needed until 2027, since load remains relatively flat

Lower gas prices and more wind additions cause much lower energy prices

- ◆ Low gas prices suppress on-peak prices that are mostly set by gas plants
- ◆ Off-peak prices also decrease in the long-term as a result of higher wind additions
- ◆ Prices slightly below Low Gas Scenario due to greater wind additions
- ◆ Peak/off-peak spread is very low: \$4-5/MWh

Capacity prices ~\$55/kW-yr starting in 2016 – in levelized terms

- ◆ Needed to support new gas plants – primarily CCs
- ◆ Temporary drop in 2023-2026 when additional capacity is not needed (initial spike reflects the additional amount needed by plants added in 2021, given future period of low prices)

CO₂ emissions decrease significantly – about 30% by 2030, then fairly constant

- ◆ Dispatch switch and increased wind additions reduce overall emissions; MRO-West adds much more wind than other regions, causing a larger decrease in local CO₂ emissions

8. Smart Grid: Load Shifting Scenario

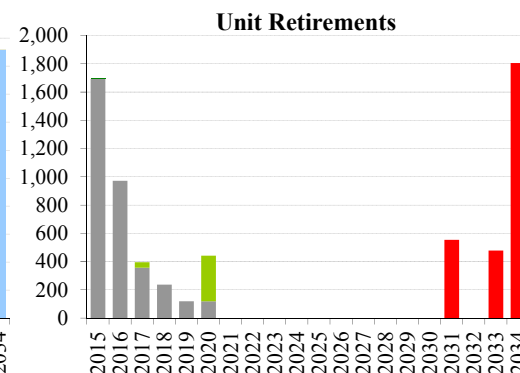
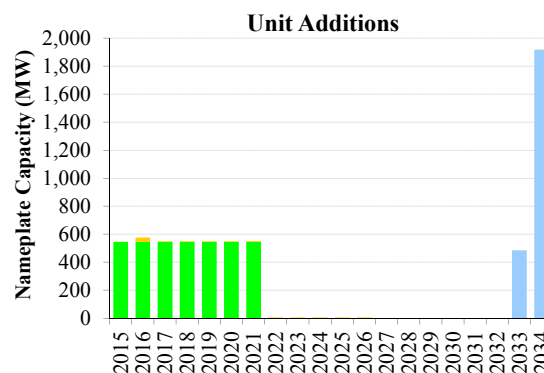
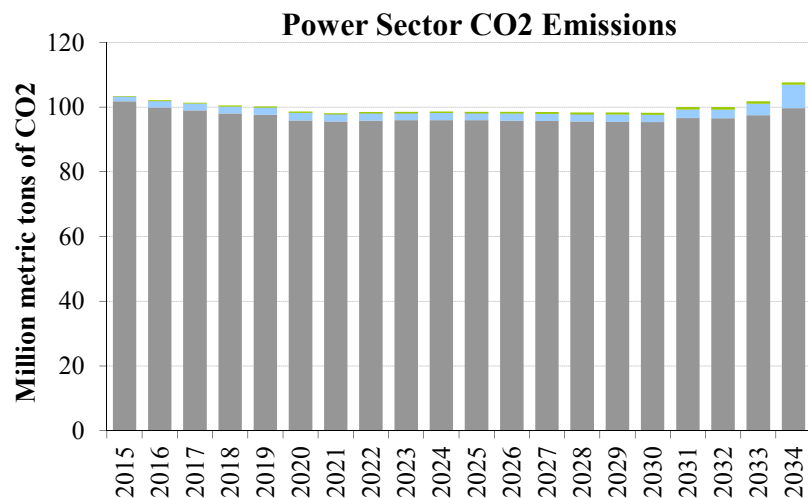
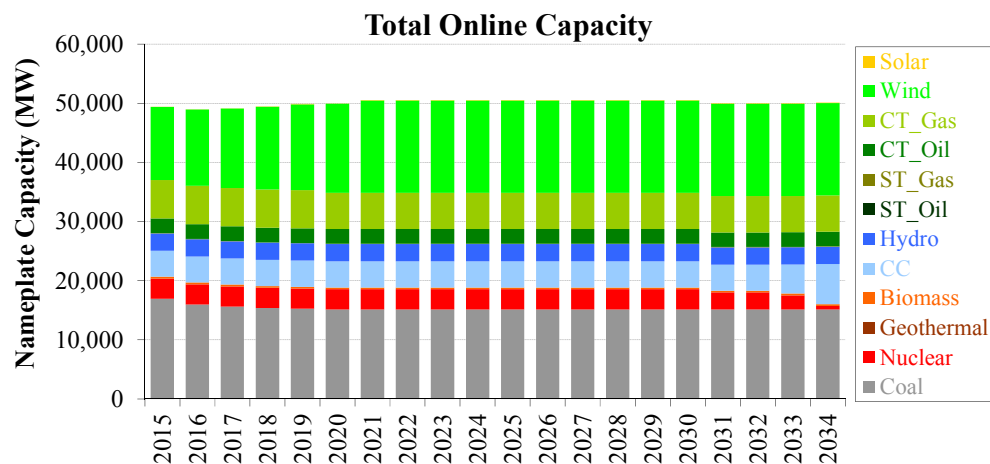
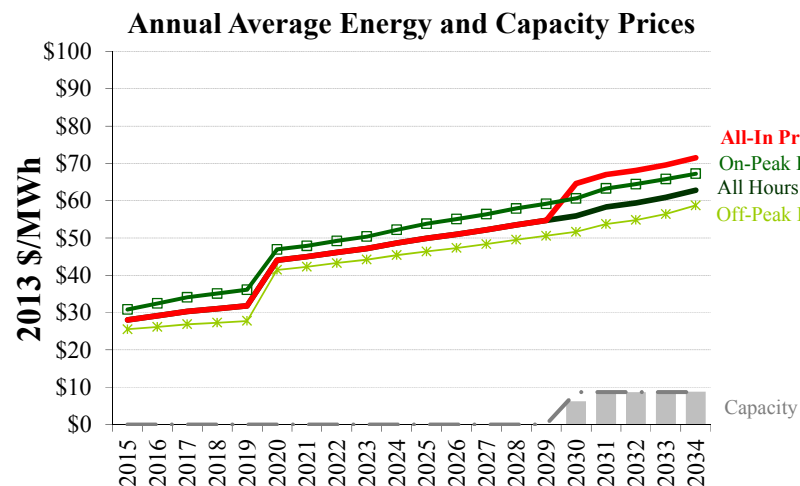
Key Input Assumptions

This scenario focuses on smart grid and demand side management (DSM) efforts to reduce peak loads without a substantial effect on energy consumption, in an environment otherwise similar to the Base Case.

- ◆ Demand-side management programs shift load and reduce peak – adjusted to account for price elasticity effects
 - Peak load is reduced in each region to the level of the Achievable Participation scenario from the FERC Assessment
 - Additional load shifting occurs in the top 25% of hours to account for price response
 - All peak load reduction is assumed to be shifted to off-peak hours – consistent with the general view of customer price responsiveness
 - DSM programs and price-induced demand reductions partially cannibalize each other, so their combined demand reduction is less than the sum of the individual effects
 - After accounting for the partial cannibalization, DSM programs provide an incremental 2-3% peak reduction in 2014, and 6% by 2020, remaining relatively constant afterwards
 - Peak drops 6-7% below 2012 levels by 2020, and then increases gradually afterwards
- ◆ Other inputs similar to Base Case

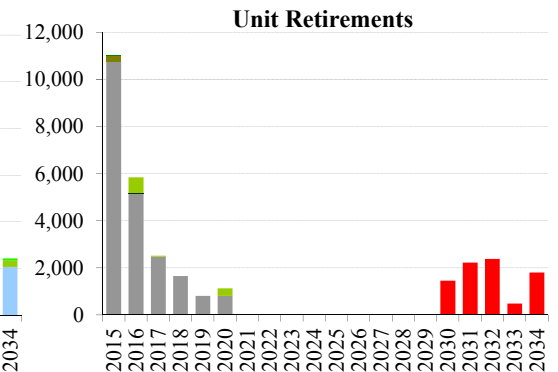
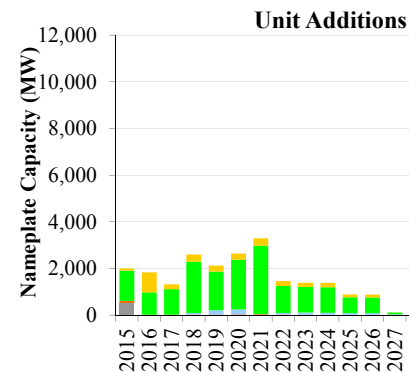
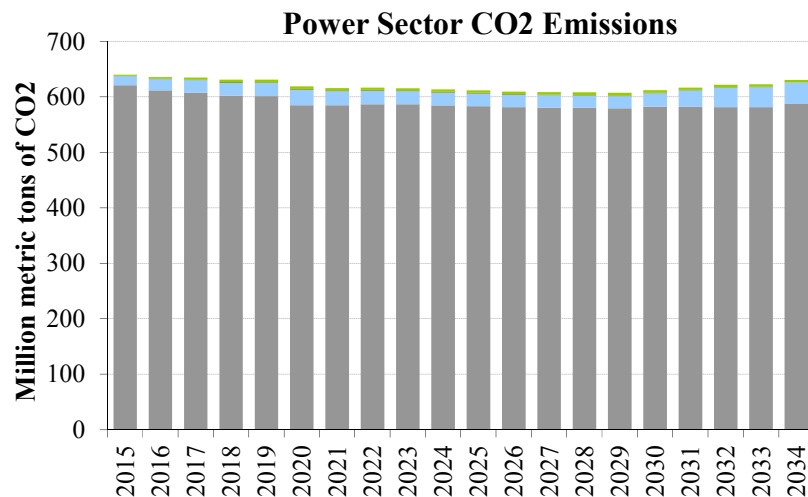
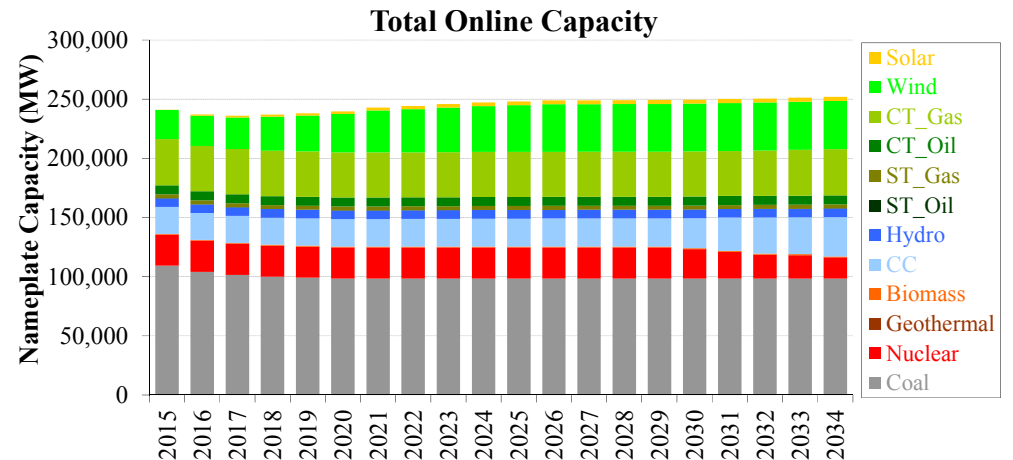
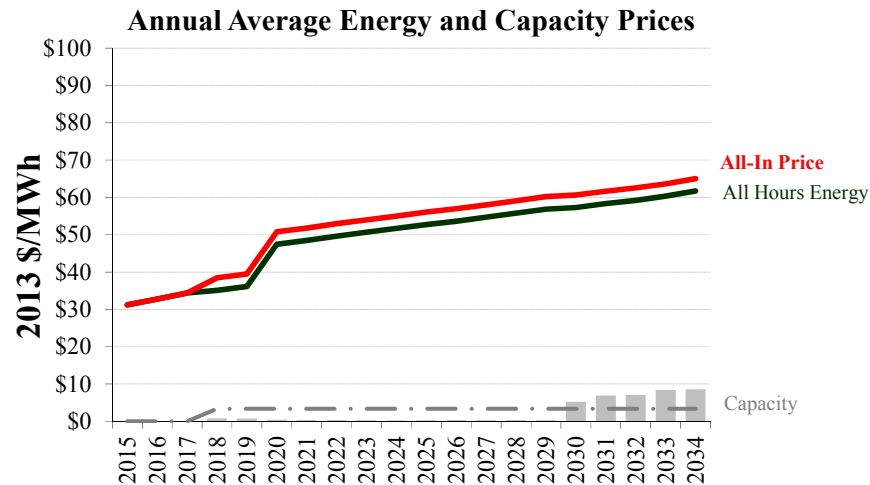
8. Smart Grid: Load Shifting Scenario

Results for MRO-West Region



8. Smart Grid: Load Shifting Scenario

Aggregate Results for the 6-Region Area Modeled



8. Smart Grid: Load Shifting Scenario

Discussion

Lower peak load plus renewable additions lead to larger capacity surplus, and more coal retirement

- ◆ ~26% of existing coal (in MRO-W) retires, well above 21% in Base Case
- ◆ Some inefficient peakers (both gas and oil) also retire early as they are no longer needed as a capacity resource

Renewables are almost the only generation added near-term

- ◆ Wind and solar added to meet state RPS
- ◆ A very small amount of new CCs are added in 2018-2026 – very near capacity balance
- ◆ Significant CC additions begin in 2030 to replace nuclear retirements

Average energy prices very similar to Base Case

- ◆ Slightly higher due to more coal retirements
- ◆ Load shifting reduces the peak/off-peak slightly
 - Load shifting reduces on peak prices slightly (affecting only a very few hours) and raises off-peak prices slightly due to higher coal retirements

Capacity prices near zero until 2030

- ◆ Capacity is not needed due to reduced peak load (except very small amounts to replace some retiring coal)

CO₂ emissions remain flat, similar to Base Case

- ◆ Despite some coal retirements, CO₂ emissions go up slightly because lack of capacity need means CCs are not built, thus coal must run a bit more

9. Energy Efficiency / Conservation Scenario

Key Input Assumptions

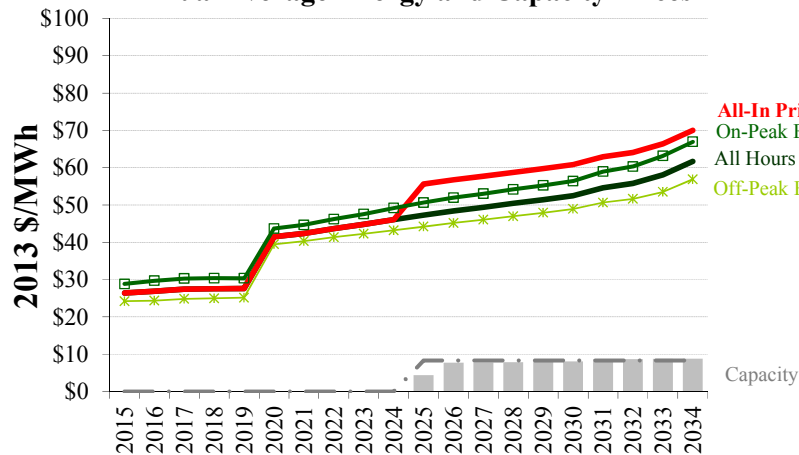
This scenario focuses on energy efficiency and conservation efforts in an environment otherwise similar to the Base Case.

- ◆ Energy efficiency (EE) programs reduce peak and energy – adjusted to account for price elasticity effects
 - Peak and energy reductions based on Maximum Achievable Potential from the EPRI DSM potential study
 - EE programs and price-induced demand reductions partially cannibalize each other, so their combined demand reduction is less than the sum of the individual effects
 - After accounting for the partial cannibalization, EE programs provide an incremental 3.3% peak reduction in 2014 (relative to Base Case), increasing to 7% by 2020, and remaining relatively constant afterwards
 - Load falls ~3% below 2012 levels by 2020, and then increases gradually afterwards
- ◆ Other inputs similar to Base Case

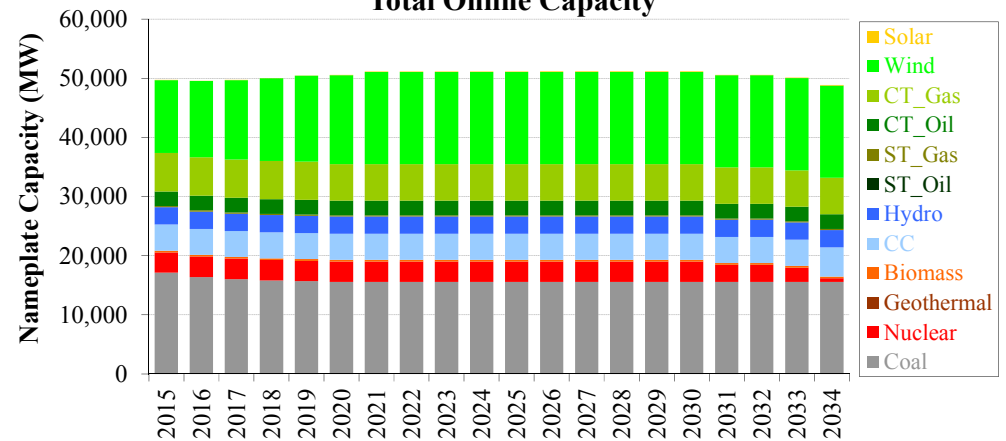
9. Energy Efficiency / Conservation Scenario

Results for MRO-West Region

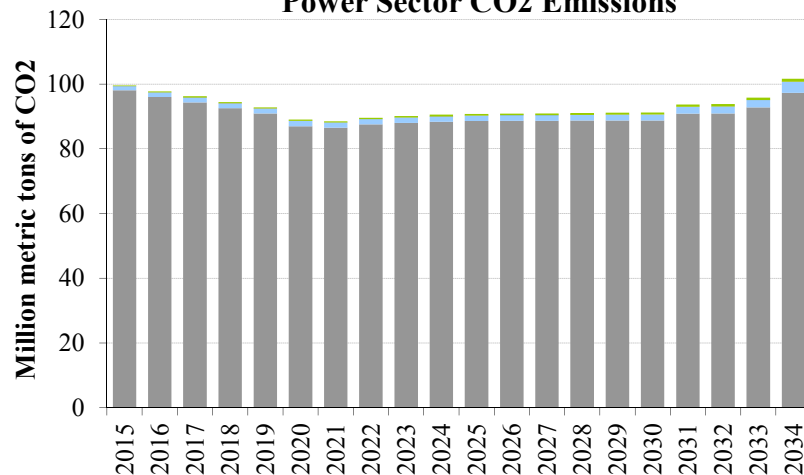
Annual Average Energy and Capacity Prices



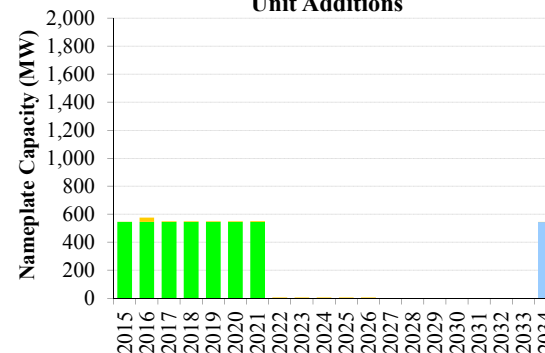
Total Online Capacity



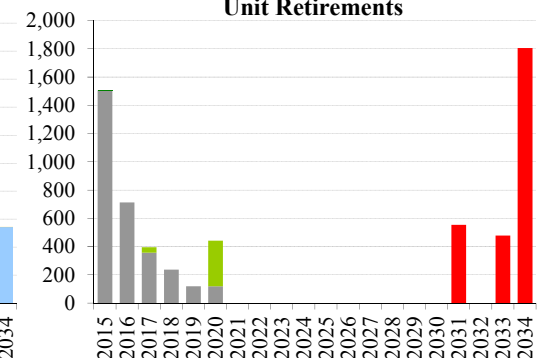
Power Sector CO2 Emissions



Unit Additions

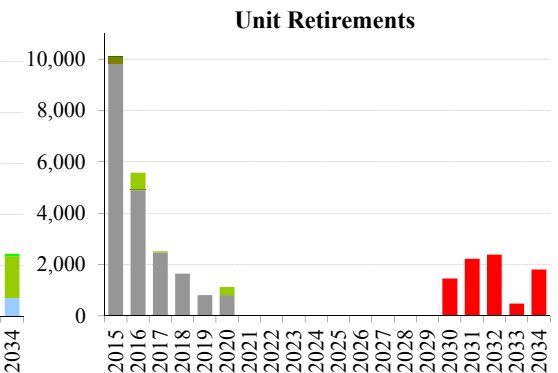
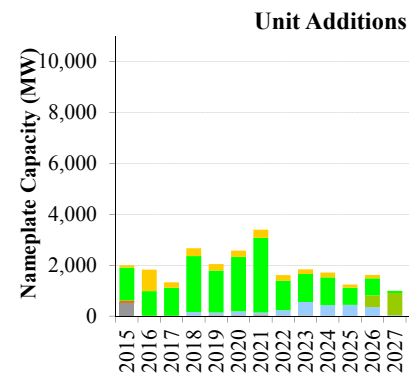
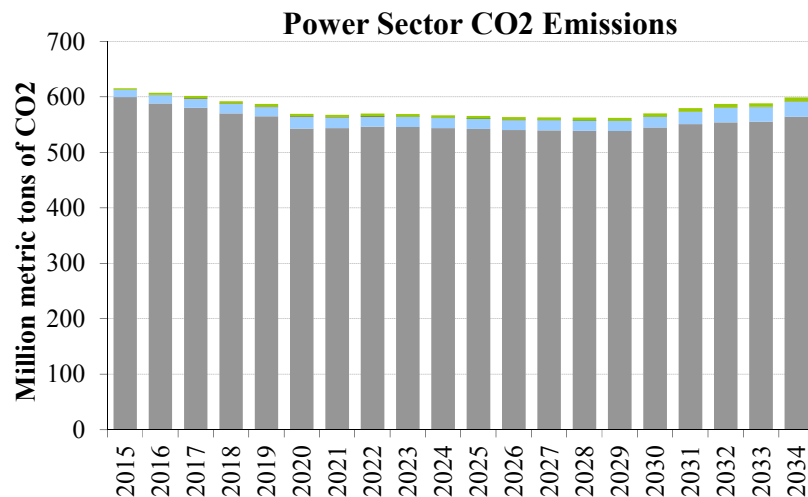
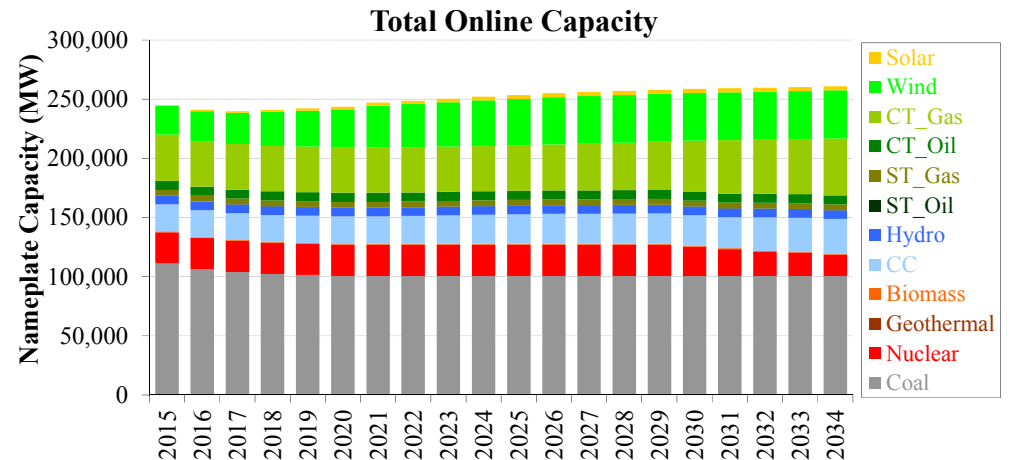
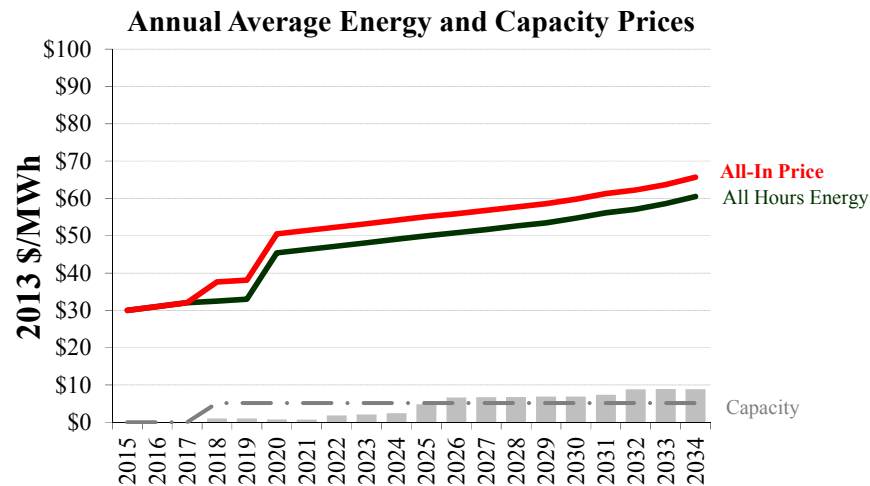


Unit Retirements



9. Energy Efficiency / Conservation Scenario

Aggregate Results for the 6-Region Area Modeled



9. Energy Efficiency / Conservation Scenario Discussion

Similar results as in Smart Grid: Load Shifting Scenario

- ◆ Lower peak load, plus renewable additions lead to larger capacity surplus and larger coal retirements (compared to Base Case)
- ◆ Some inefficient peakers (gas) also retire in 2013
- ◆ Renewables are the only generation added near-term (other than projects under construction)

Energy prices are depressed several dollars relative to Base Case, but generally similar

- ◆ Prices slightly lower because load is lower in all hours (unlike Load Shifting Scenario, which affects only a few hours)

Capacity prices at zero through late 2020s (very low outside MRO-W a few years sooner)

- ◆ Capacity needs delayed due to lower peak load
- ◆ Some gas units are added starting around 2020, more later to replace retiring nuclear

CO₂ emissions decline moderately relative to Base Case

- ◆ Falling load, modest coal retirement, and wind additions cut the emissions ~8% from current levels by 2020
- ◆ Emissions remain relatively flat through 2030 until existing nuclear plants start to retire, when they begin to rise again

10. High Gas & Low CO₂ Price Scenario

Key Input Assumptions

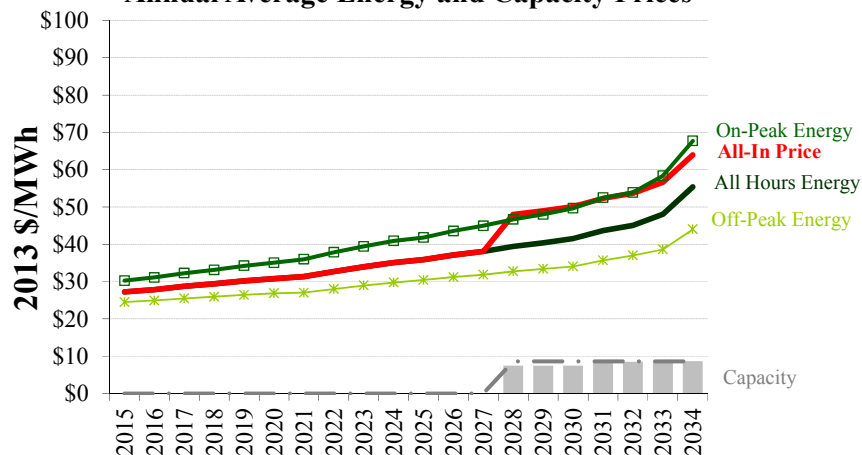
This scenario represents the combined effect of high gas prices with no CO₂ price, including also a rollback of existing RPS requirements.

- ◆ No CO₂ price – climate policy not passed
- ◆ Higher gas price – \$6/MMBtu in 2015, and \$8.6/MMBtu in 2025
 - Close to market expectations during mid-2008 fuel price run-up
- ◆ Demand grows at a modest 0.5% per year – results in higher load than the Base Case, and slightly below the AEO 2013 Reference Case
- ◆ Limited renewables – no new renewables are added beyond what is already under construction
- ◆ Lower “forced” coal plant retirements than Base Case, due to better energy margins under zero CO₂ prices
 - ~2% of existing MRO-W coal generation retires by 2020 to comply with EPA regulations that are expected to be in place (~10% across all 6 regions modeled)
- ◆ Other inputs similar to Base Case

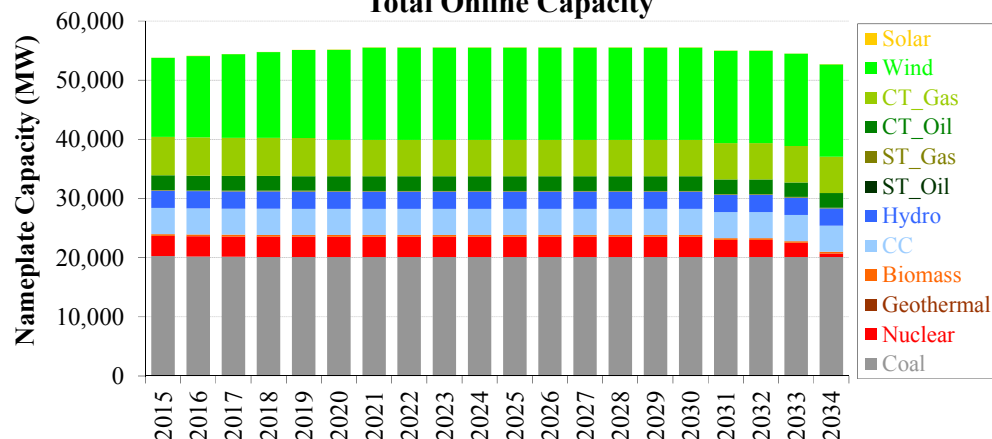
10. HiGas/ LoCO2 Scenario

Results for MRO-West Region

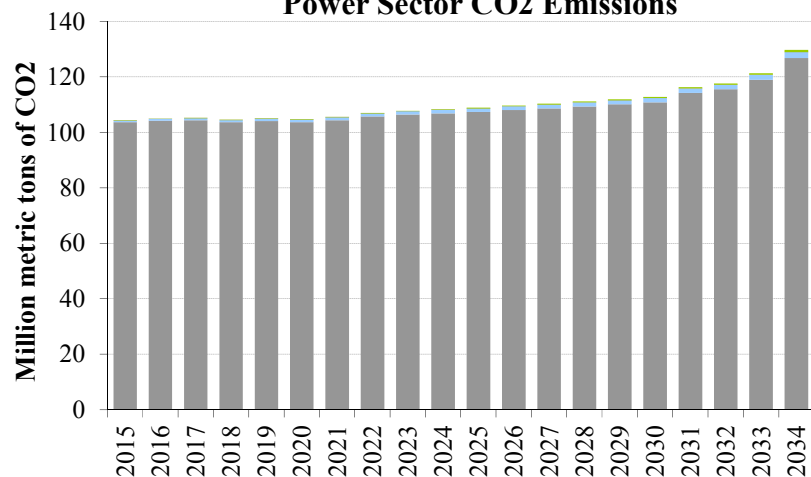
Annual Average Energy and Capacity Prices



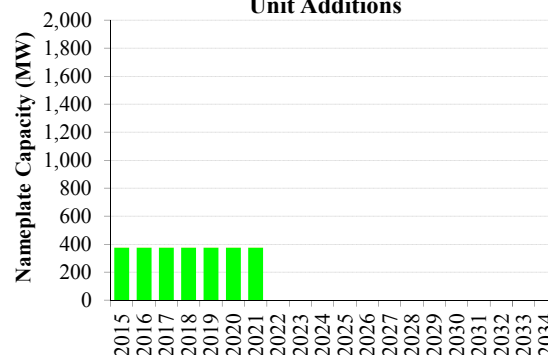
Total Online Capacity



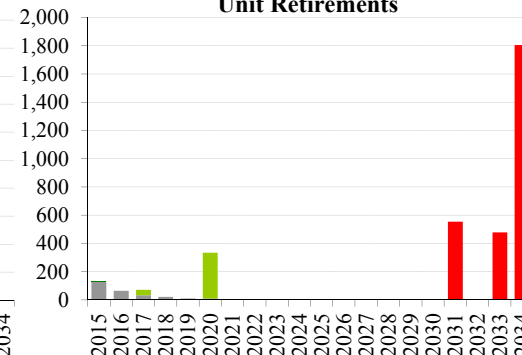
Power Sector CO2 Emissions



Unit Additions

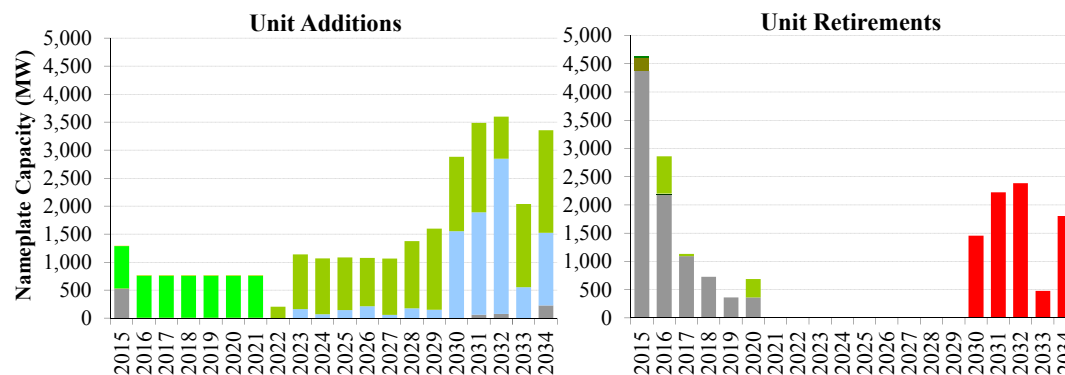
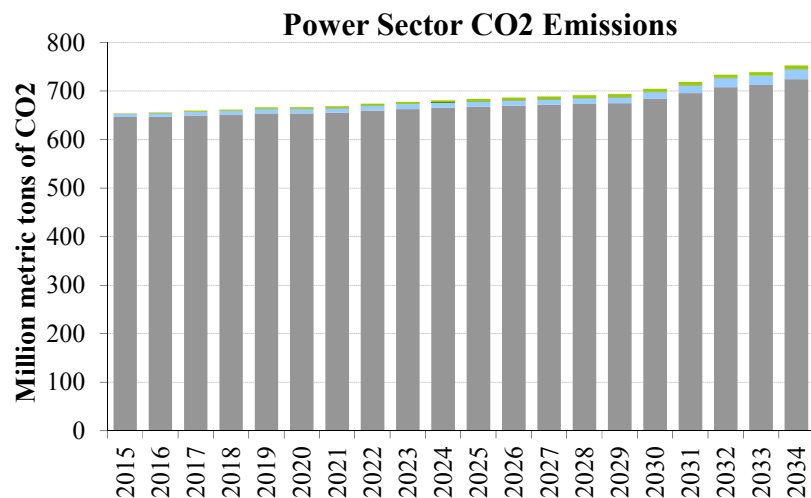
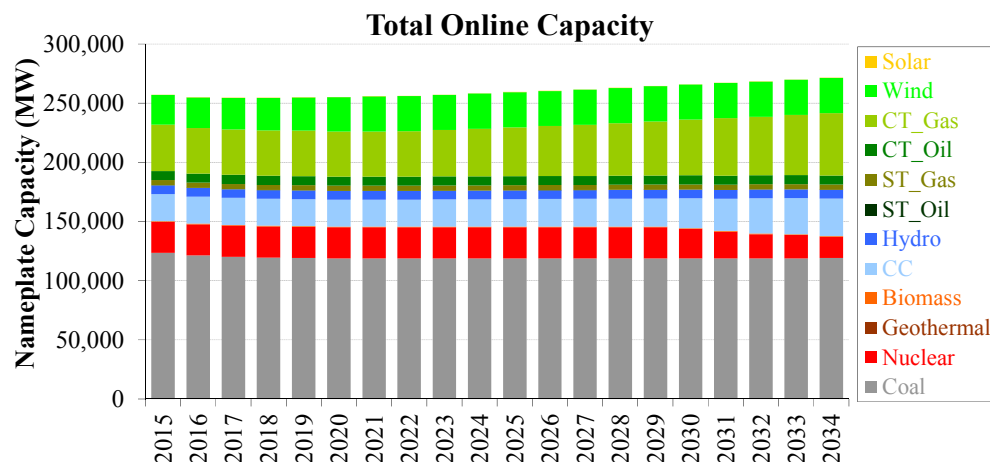
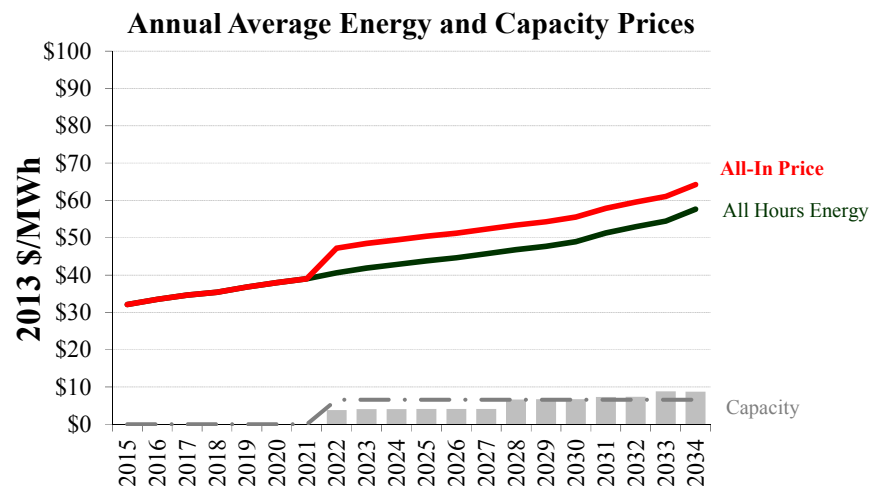


Unit Retirements



10. HiGas/ LoCO2 Case Scenario

Aggregate Results for the 6-Region Area Modeled



10. High Gas & Low CO₂ Price Scenario

Discussion

Moderate load growth in absence of CO₂ price – despite higher gas price

- ◆ Much lower coal retirements than Base Case (no economic retirements) delays capacity needs. Additional capacity is needed starting 2022 to maintain reserve margin

No capacity additions over the next 10 years – beyond what's already under construction

- ◆ Renewables added to meet state RPS (also has some small capacity value)
- ◆ Gas CTs added later to meet reserve margin targets, in regions where it is less expensive
- ◆ Conventional coal added after 2030 – as base load to replace retiring nuclear units
 - New coal may be economic with no CO₂ price and high gas price – though its viability depends on long-term climate policy (e.g., would require overturn of EPA restriction on new unit CO₂ limits)

Energy prices increase modestly over time

- ◆ Higher gas prices push up energy prices somewhat, though less than CO₂ prices would
- ◆ Near-term prices are modestly higher than Base Case, but prices are lower beyond 2020 due to lack of CO₂ price
- ◆ Prices rise more quickly after 2030 with nuclear retirements
- ◆ Peak prices increase with gas price, and off-peak prices remain similar, leading to large peak/off-peak differential – wider than Base Case (and most other scenarios)

Capacity prices ~\$70/kW-yr starting in 2022

- ◆ Needed to support new gas capacity to maintain reserve margins

CO₂ emissions increase – about 10% by 2030

- ◆ With lower coal retirements and lower renewable additions, and no hope of gas-for-coal dispatch switching, emissions gradually increase over time
- ◆ If new coal is actually added after 2030, CO₂ emissions begin climbing even faster

11. Extreme Low Scenario

Key Input Assumptions

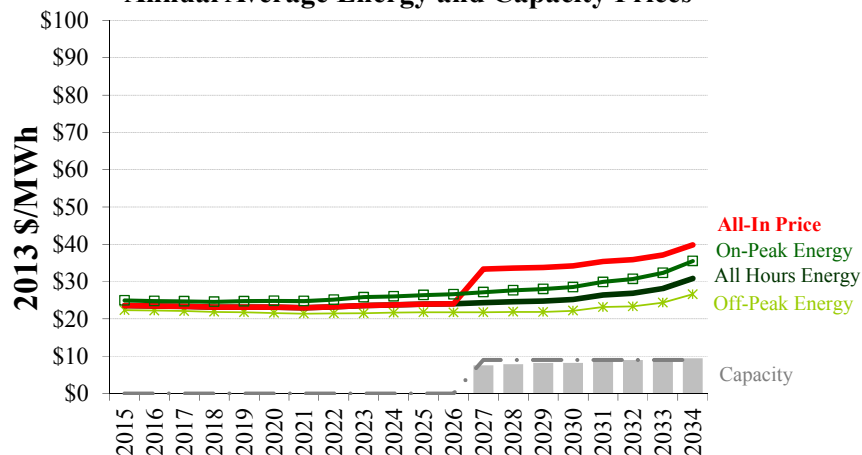
This scenario reflects a failure to enact any climate policy (zero CO₂ price), while additionally, gas prices are assumed to be very low (e.g., due to significant technological improvements in shale gas production methods). This is a “perfect storm” of price-depressing factors that are not necessarily related, but could plausibly occur together, and would lead to very low power prices if they did.

- ◆ No CO₂ price – climate policy not passed
- ◆ Lower gas price – \$2.9/MMBtu in 2015, and \$3.6/MMBtu in 2025
 - Below current near-term prices and recent expectations, but not unprecedented
 - Coal prices are also lower, which might be prompted by low gas prices
- ◆ Demand grows at a modest 0.5% per year –results in projections higher than the Base Case, and slightly above the AEO 2013 Reference Case
- ◆ Lower “forced” coal plant retirements than Base Case – in response to better energy margins under zero CO₂ prices
 - ~2% of existing coal generation retires by 2020 to comply with EPA regulations that are expected to be in place (~10% across all 6 regions modeled)
- ◆ Other inputs similar to Base Case

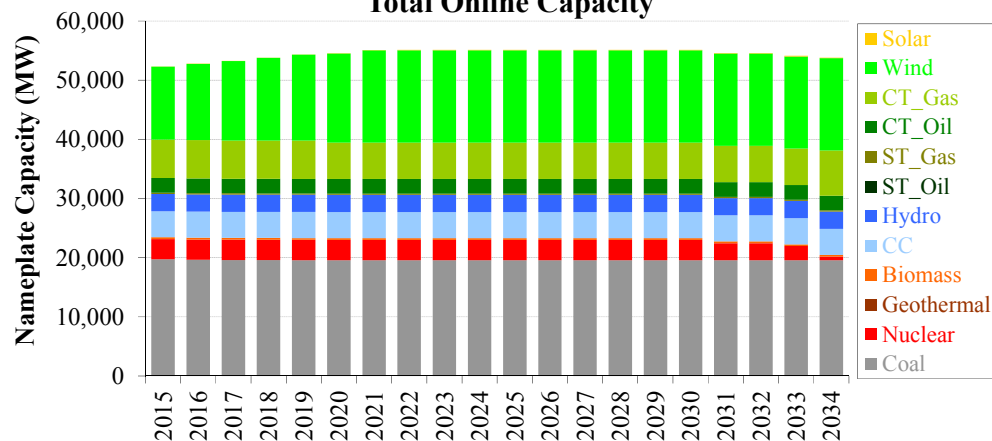
11. Extreme Low Scenario

Results for MRO-West Region

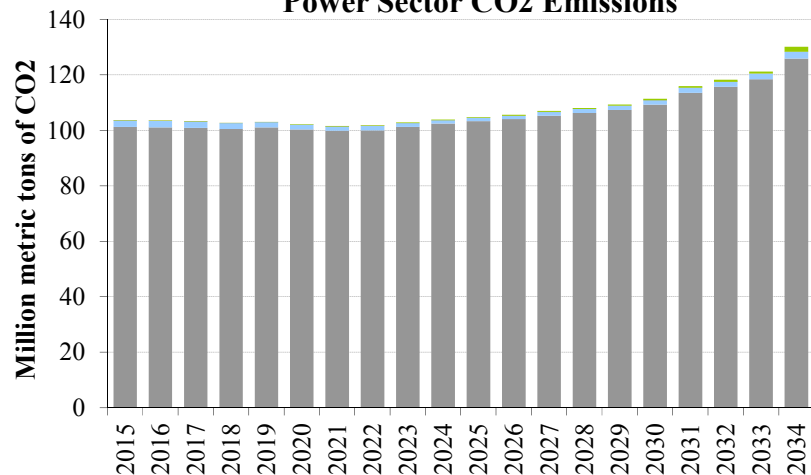
Annual Average Energy and Capacity Prices



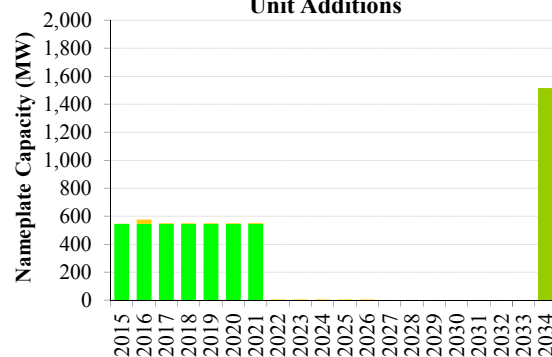
Total Online Capacity



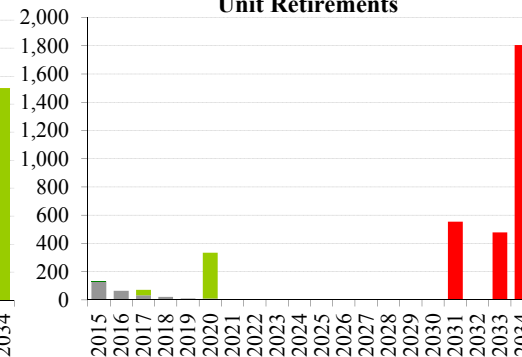
Power Sector CO2 Emissions



Unit Additions

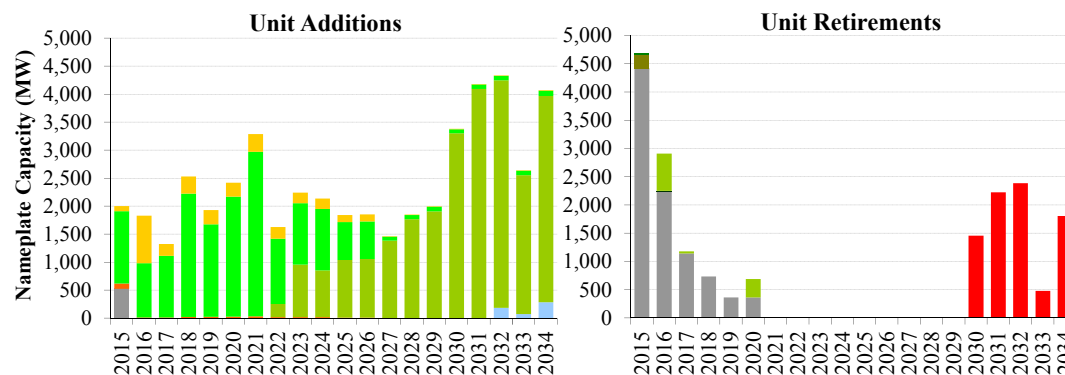
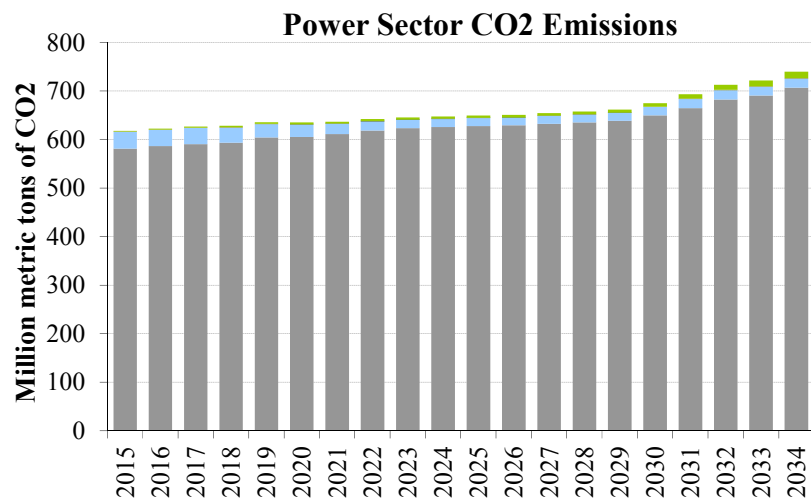
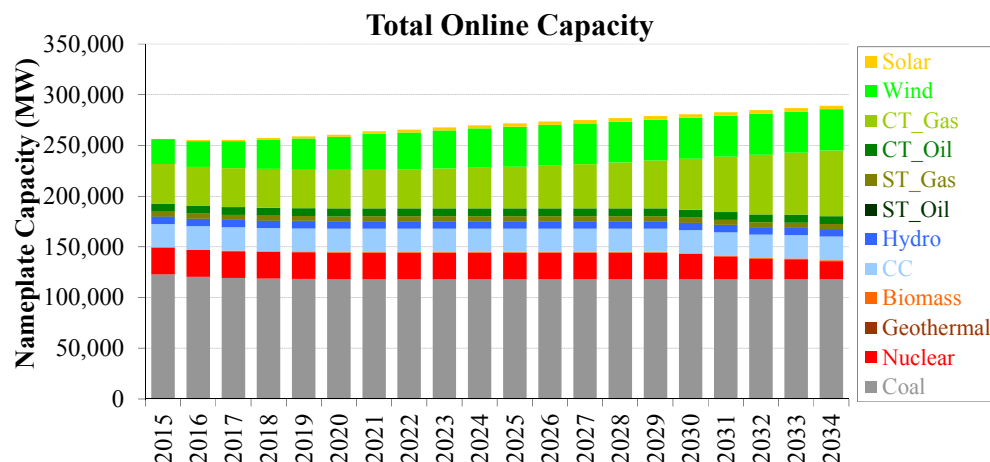
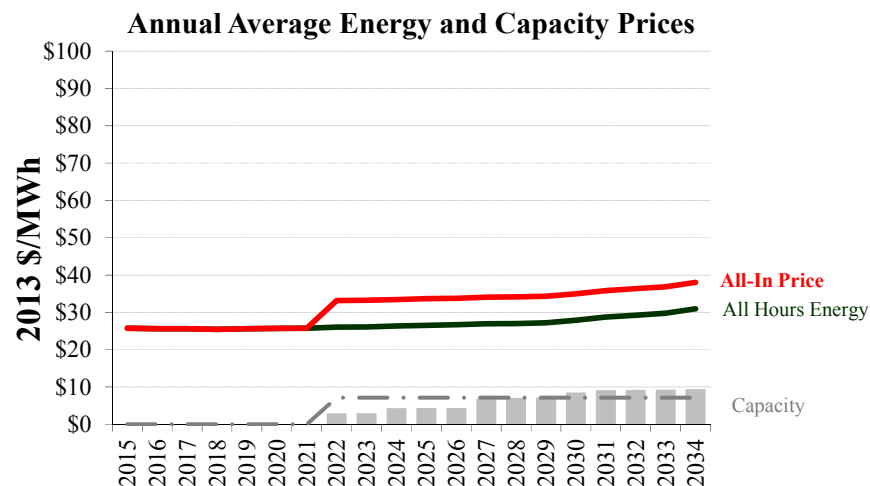


Unit Retirements



11. Extreme Low Case Scenario

Aggregate Results for the 6-Region Area Modeled



11. Extreme Low Scenario

Discussion

Load continues to grow moderately

- ◆ Load grows faster than in Base Case, at a pace similar to AEO Reference Case, due to low power prices
- ◆ In addition to the 2% of “forced” coal retirements to comply with EPA regulation, another 3% retires because of poor energy margins under lower gas prices (despite lower coal prices)

Gas plants are built to keep up with additional capacity needs

- ◆ Capacity needs arise later, due to less coal retiring
- ◆ Gas CTs added to maintain reserve margins, starting in 2022
- ◆ Energy margins under low gas price are not attractive for gas CCs
- ◆ Nuclear, CCs not added – not justified with zero CO₂ price and low gas prices

Energy prices stay low and stable in the absence of a CO₂ price, and with low fuel prices

- ◆ Peak price climbs moderately with slowly rising gas prices (but not as fast as Base Case)
- ◆ Decreasing coal prices lower the off-peak prices slightly
- ◆ Average price is low, and peak/off-peak differential is also low due to low on-peak prices
- ◆ Prices begin to rise a bit more quickly after 2030 with retiring nuclear

Capacity price ~\$65/kW-yr starting in 2022

- ◆ Needed to support additional capacity (mostly gas CT; CCs only much later)

CO₂ emissions are relatively stable to 2030, then increase gradually

- ◆ Modest coal plant retirements and wind additions do not reduce emissions, as the remaining coal is dispatched more often
- ◆ Emissions increase in later years as nuclear plants retire

12. AEO Reference Case Scenario

Key Input Assumptions

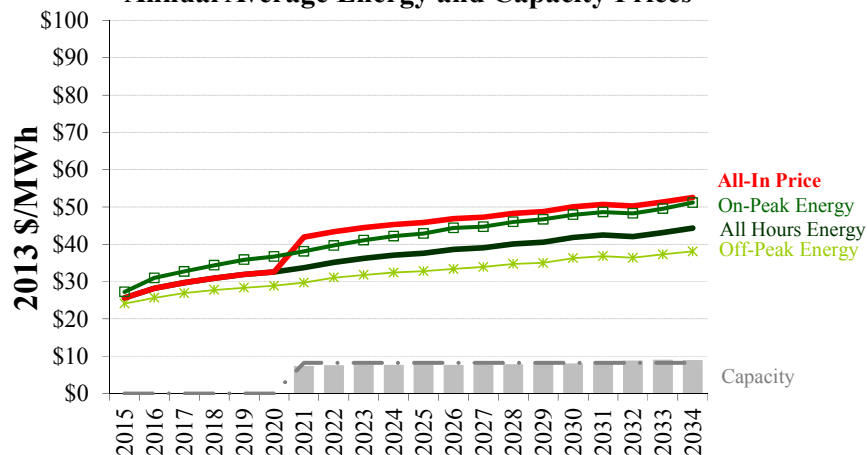
This scenario corresponds to the Reference Case that EIA published in January 2013 in its AEO 2013 Early Release report. This AEO case assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection. Other factors are chosen to match AEO assumptions.

- ◆ No CO₂ price
- ◆ Fuel prices similar to Base Case
 - Natural gas: \$3.7/MMBtu in 2015, and \$6.0/MMBtu in 2025 (in expectation of continued industry success in tapping shale gas resources)
 - Averages ~\$0.20/MMBtu below Base Case forecast, varying by year and region
 - Coal: \$1.7/MMBtu in 2015, and \$2.0/MMBtu in 2025 (modest increase due to higher production costs)
- ◆ Modest demand growth at ~0.5% per year (similar to AEO Reference Case 2012 projections)
- ◆ New generation additions:
 - Limited amounts of solar generation added to meet RPS until 2016 (this seems to be due to an assumption that federal tax credits will not be extended)
 - Plants that are already under construction added in 2013 (approx. 630 MW coal, and 630 MW gas)
 - Additional Gas (CT and CC) units are added starting 2021, and wind after 2030
- ◆ Planned unit retirements:
 - ~8% of existing coal generation in MRO-West retires by 2020 (~12% across 6 regions)
 - Most nuclear plants kept in operation until the end of AEO's study horizon (i.e., 2040)

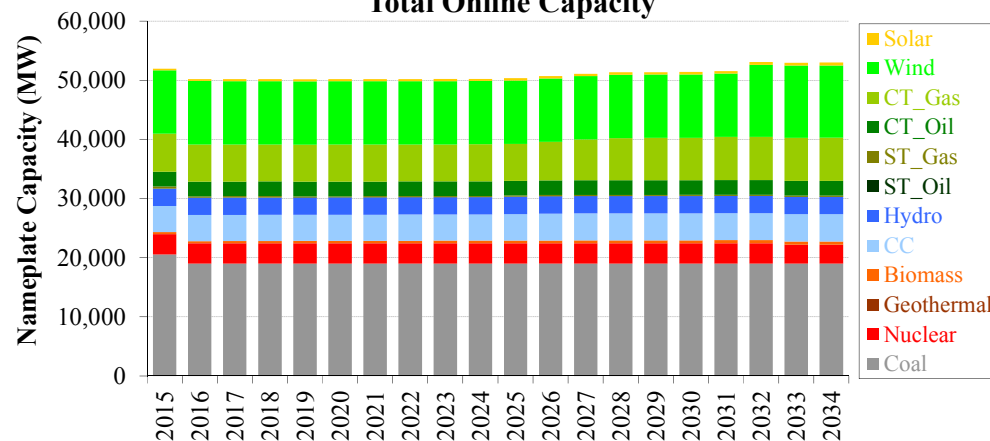
12.AEO Reference Case Scenario

Results for MRO-West Region

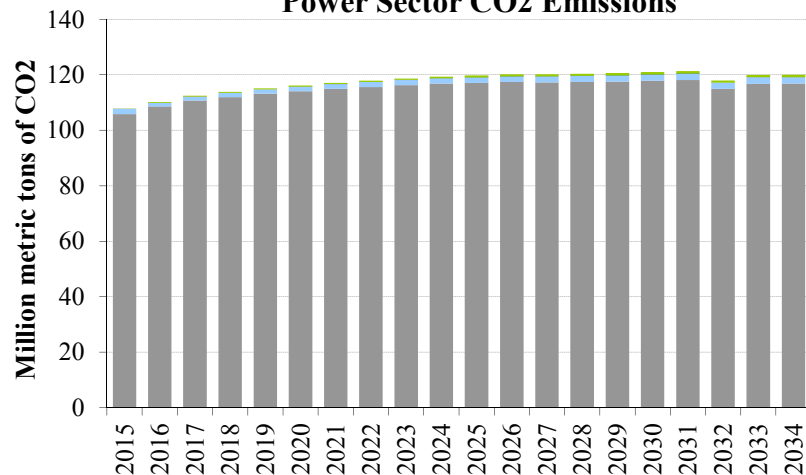
Annual Average Energy and Capacity Prices



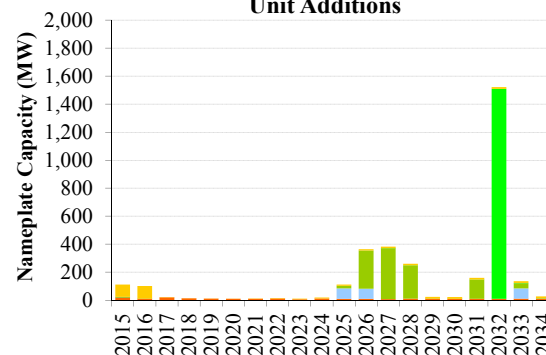
Total Online Capacity



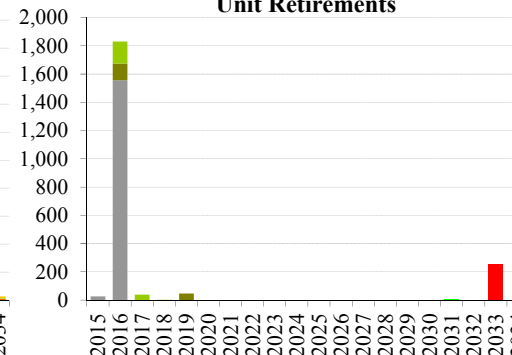
Power Sector CO2 Emissions



Unit Additions

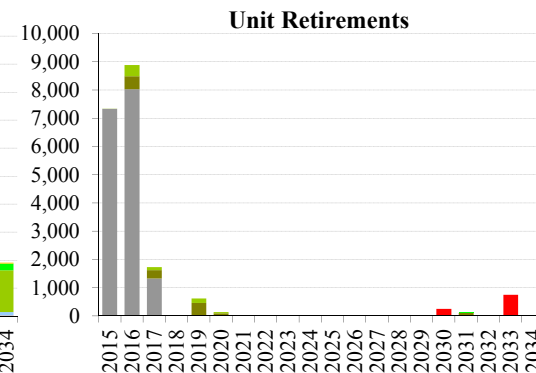
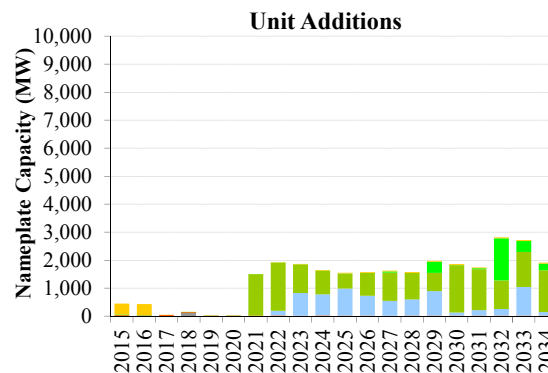
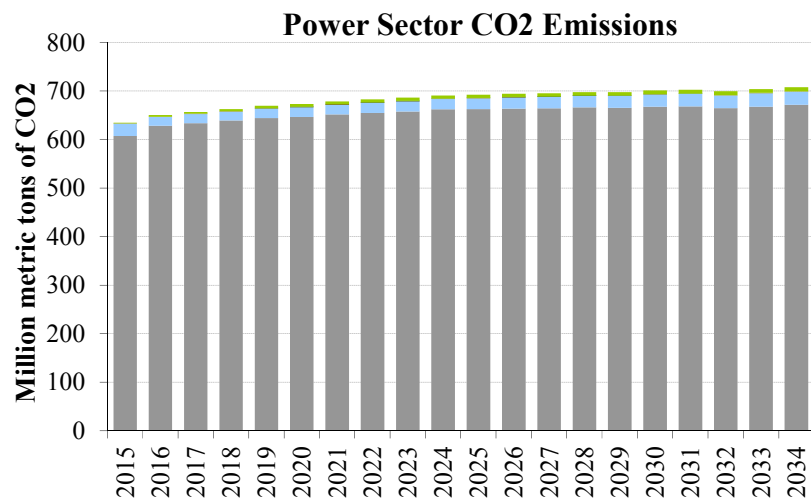
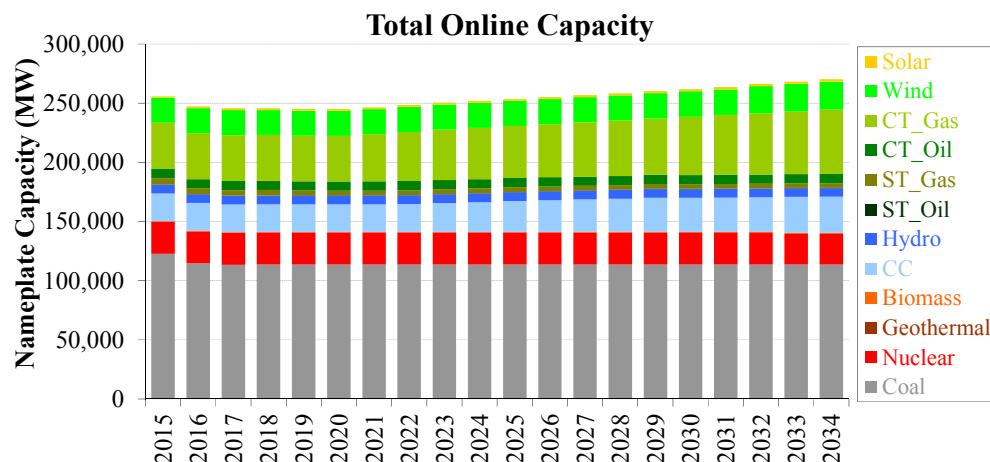
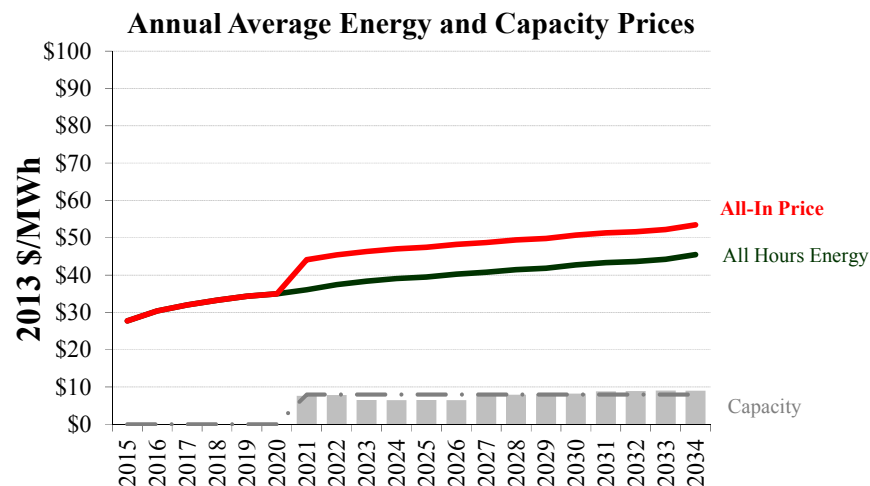


Unit Retirements



12. AEO Reference Case Scenario

Aggregate Results for the 6-Region Area Modeled



12. AEO Reference Case Scenario

Discussion

Load continues to grow moderately

- ◆ Load grows faster than Base Case in the medium to long-term; less renewable additions and no CO₂ price mean retail prices stay lower
- ◆ Coal retirements are much lower than the Base Case (and most other scenarios)

Near-term additions driven by state RPS programs

- ◆ Solar renewables added until 2016, after which AEO reflects minimal renewable additions despite big increases in RPS demand.

Energy prices grow slowly

- ◆ Energy prices are similar to Low CO₂ Scenario (both have no CO₂ price and similar fuel prices); AEO price is slightly higher due to less renewable additions
- ◆ Peak price climbs with rising gas price; load growth causes slow off-peak price growth
- ◆ Peak/off-peak differential increases significantly by 2034 relative to current levels – higher than Base Case

Capacity prices ~\$65/kW-yr starting in 2021

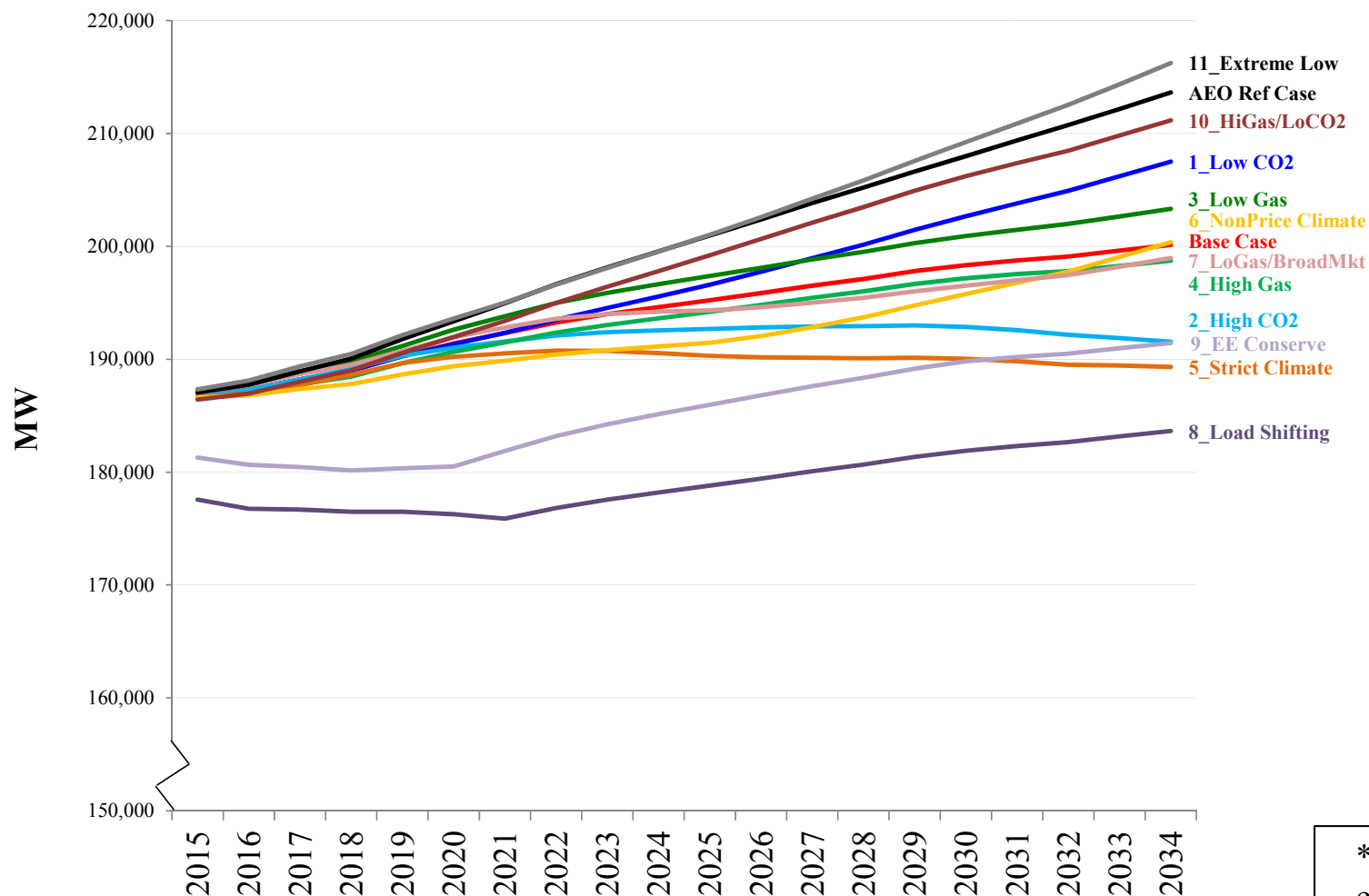
- ◆ Needed to support new gas plants (CTs and CCs) to maintain reserve margins

CO₂ emissions increase over time – about 15% by 2030

- ◆ With lower coal retirements and less renewables, load growth causes emissions to increase gradually

Peak Demand for All Scenarios*

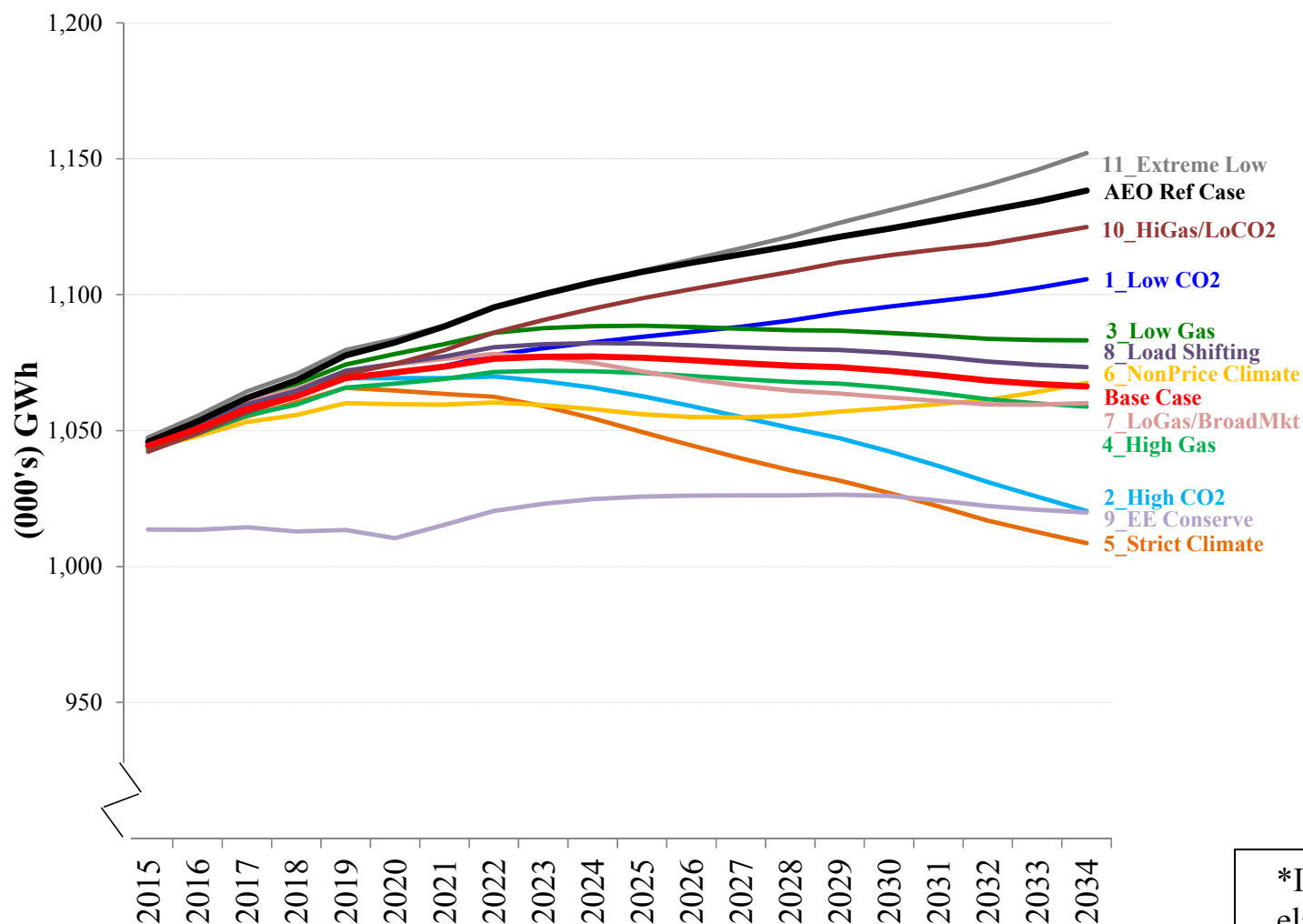
Annual Peak Projections – Aggregate 6-Region Area



*Includes price elasticity effect

Energy Demand for All Scenarios*

Annual Energy Projections – Aggregate 6-Region Area



*Includes price elasticity effect