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Effects of technology assumptions on US power sector capacity, generation and emissions projections: Results from the EMF 32 Model Intercomparison Project☆

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ABSTRACT

This paper is one of two syntheses in this special issue of the results of the EMF 32 power sector study. This paper focuses on the effects of technology and market assumptions with projections out to 2050. A total of 15 models contributed projections based on a set of standardized scenarios. The scenarios include a range of assumptions about the price of natural gas, costs of end-use energy efficiency, retirements of nuclear power, the cost of renewable electricity, and overall electricity demand. The range of models and scenarios represent similarities and differences across a broad spectrum of analytical methods.

One similarity across almost all results from all models and scenarios is that the share of electricity generation and capacity fueled by coal shrinks over time, although the rate at which coal capacity is retired depends on the price of natural gas and the amount of electricity that is demanded. Another similarity is that the models project average increases in natural gas power generating capacity in every scenario over the 2020–2050 period, but at lower average annual rates than those that prevailed during the 2000–2015 period. The projections also include higher gas capacity utilization rates in the 2035–2050 period compared to the 2020–2050 period in every scenario, except the high gas price sensitivity. Renewables capacity is also projected to increase in every scenario, although the annual new capacity varies from modest rates below the observed 2000–2015 wind and solar average to rates more than 3 times that high. Model estimates of CO_2 emissions largely follow from the trends in generation. Low renewables cost and low gas prices both result in lower overall CO_2 emission rates relative to the 2020–2035 and 2035–2050 reference. Both limited nuclear lifetimes and higher demand result in increased CO_2 emissions.

1. Introduction and Background

The Energy Modeling Forum (EMF) 32 model intercomparison project recently engaged 16 modeling teams to investigate a common set of power sector scenarios.[1] The scenarios include a range of assumptions about the price of natural gas, costs of end-use energy efficiency, availability of nuclear power, the cost of renewable power, and overall electricity demand.

The EMF has a long history of model intercomparison projects involving the power sector and the economy (Murray et al., in this volume). EMF 24 analyzed the role of technology in meeting climate goals in the United States, using economy-wide models (Weyant et al., 2014). However, resource and cost changes have rendered projections of even a few years ago outdated (Palmer, Paul, and Keys, in this volume; EIA, 2016b).

This paper synthesizes the results of EMF 32 with a particular focus on the technology and energy market scenarios.[2] The sensitivities include a range of assumptions about the price of natural gas, costs of end-use energy efficiency, availability of nuclear power, the cost of renewable power, and the level of electricity demand. We address key

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[1] 15 models produced unique results for the technology scenarios considered here, we present only these results.

[2] A companion paper focuses on policy scenarios and results (Bistline et al., in this volume).

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0140-9883/

Table 1
Overview key characteristics of participating models.

Model name	Coverage/equilibrium approach	Intertemporal approach for electricity	Electric sector detail	Institution
AMIGA	CGE with least cost electricity	Perfect foresight	32 technologies, 6 US regions	Argonne National Laboratory
DIEM	CGE with electricity LP	Perfect foresight	29 technologies, 48 US regions	Duke University
ReEDS-USREP	CGE with electricity LP	Recursive	20 technologies, 134 US regions	National Renewable Energy Laboratory, MIT
Energy2020	PE with electricity LP	Systemic	22 technologies, 24 US regions	Systematic Solutions Inc.
EPSA-NEMS	PE with electricity LP	Perfect foresight	16 technologies, 22 US regions	OnLocation, Inc.
FACETS	PE with electricity LP	Limited foresight	9 technologies, 41 US regions	Sustainable Energy Economics, KanORS-EMR
GCAM-USA	PE with electricity logistic shares	Recursive	17 technologies, 51 US regions	Pacific Northwest National Laboratory
MARKAL	PE with electricity LP	Perfect foresight	30 technologies, 9 US regions	National Energy Technology Lab
NEMS	PE with electricity LP	Perfect foresight	16 technologies, 22 US regions	Energy Information Administration
ReEDS	PE with electricity LP	Recursive	20 technologies, 134 US regions	National Renewable Energy Laboratory
RHG-NEMS	PE with electricity LP	Perfect foresight	16 technologies, 22 US regions	Rhodium Group
E4ST	Electricity LP	Sequential	6670 US regions, inc'l transmission	Resources for the Future, Cornell Univ.
Haiku	Electricity	Perfect foresight	24 technologies, 26 US regions	Resources for the Future
N_{ew}ERA -Elec	Electricity LP	Perfect foresight	20 technologies, 61 US Regions	NERA Economic Consulting
USREGEN	Electricity LP	Perfect foresight	100+ technologies, 48 US regions	Electric Power Research Institute

Notes: CGE: Computable General Equilibrium; PE: Partial Equilibrium; LP: Linear Programming. Perfect foresight models solve simultaneously for all time periods. Recursive models solve sequentially.

questions facing the electricity sector today: Will the gas boom continue, and what if it does not? What is the role of end use energy efficiency? What is the effect on emissions and generation of increasing nuclear licensing lifetimes? What if renewable energy technologies continue to outperform market expectations on cost and penetration? And what if economic growth, and electricity demand, return to a more robust level than in the recent past?

1.1. Participating models

An important feature of this study is its inclusion of a large range of model types that vary by level of detail analyzed in the power sector and breadth of coverage of the economy. A total of fifteen models participated (Table 1). Three are computable general equilibrium (CGE) models that link an electricity module to a comprehensive representation of the US economy. These models solve for market-clearing prices in all sectors in each period, providing dynamic feedbacks between the power sector and the rest of the economy. Eight models are partial equilibrium (PE) models that link an electricity model to representations of key input and demand sectors. This group generally provides more detail in electricity and covered input sectors than the CGE models. The power-sector-only models provide highly detailed representations of the electric power sector, some including transmission and generating unit details.

The remainder of this paper proceeds as follows. Section 1.1 details the study design for EMF 32. Section 2 then discusses the nature of the emissions and energy system transitions in the reference scenarios and the technology scenarios. Section 3 concludes.

2. Study design

Analyses included 56 scenarios, with results projected out to 2050, across a policy dimension and a technology dimension. The policy dimension includes one reference scenario (i.e., no policy, or "business as usual") and four scenarios that varied by carbon tax[3]. The technology dimension includes the aforementioned reference scenario and sensitivities in five main areas: natural gas prices (high and low); end use energy efficiency costs (high and low); low nuclear energy availability; low renewable energy costs; and increased overall demand. These technology areas are shown in Table 2 and detailed below.

[3] ibid.

2.1. The reference scenario and technical sensitivity scenarios

The reference scenario assumes no new federal, regional, or state energy policies and no federal or state regulations targeting GHG emissions from stationary sources beyond those codified in existing law. To the extent feasible, modelers calibrate to the Energy Information Administration's Annual Energy Outlook Early Release, No Clean Power Plan case from April 2016 (EIA, 2016a)[4]. Note that in 2015 EPA promulgated carbon pollution standards requiring new, modified and reconstructed coal-fired generating units to have the same CO_2 rates as natural gas combined cycle (NGCC) technology. To model the provisions of the performance standards for new plants, the AEO2016 assumes that the only coal technology allowed to be built in the future includes 30% carbon capture to ensure the ability to meet the standard of 1400 lb CO_2 per MWh (EIA, 2016a).

Fig. 1 shows reference projections for GDP and electricity generation. Note that 5 of the models included projections for GDP. In this reference case, GDP is expected to grow 2.2% annually over the 2020–2050 period (cross model average). Over this same period, electricity generation is expected to grow just 0.8% annually across the 15 models reporting.

The technical sensitivity assumptions are summarized in Table 3, and described below.

2.2. Sensitivity to Gas Prices

Gas prices have been a key driver of change in the electricity sector (Huntington, 2013, 2015). We investigate two scenarios featuring lower and higher gas prices, shown in Fig. 2. In the low gas price case, modeling teams used gas prices projected in the High Oil and Gas Resource and Technology side case in AEO16. [5] In this scenario, gas prices remain relatively constant in real terms, falling an average of 0.01 percent per year over the 2015–2040 period. In the high gas price case, modelers implemented price assumptions based on the Low Oil and Gas Resource and Technology side case in AEO16. In this scenario, gas prices increase an average of 2% per year over the forecast period.[6] The range is noteworthy, as the natural gas price in 2040 is roughly three times as high in the high gas price case as in the low gas price case and nearly twice as high as in the reference case.

[4] A business as usual trend estimate that assumes the Clean Power Plan is not implemented. Other key updates in the AEO16 include: updated, lower renewable capital costs; limited extension of the production tax credit for wind and 30% investment tax credit for solar as provided in the Consolidated Appropriations Act of 2015 (phased out starting in 2020); and lower near-term crude oil prices. https://www.eia.gov/outlooks/aeo/er/.

[5] In Annual Energy Outlook terminology, low prices are associated with "high" resource availability cases.

[6] Additional details are provided in Appendix Table A1.

Table 2
Number of models participating by technology and policy scenarios.

Policy dimension	AEO16 reference assumptions	Technology sensitivities (number of models participating)						
		Natural gas prices		End use energy efficiency costs		Nuclear lifetimes	Renewable energy costs	Higher electricity demand
		Low	High	Low	High	Low	Low	
Reference	15	14	15	6	6	12	10	12

Notes: AEO16 refers to the 2016 Annual Energy Outlook (EIA, 2016a).

2.3. Sensitivity to end-use energy efficiency cost

End use efficiency gains are important because they partly explain the difference between growth of electricity generation and growth in the economy (Fig. 1). End-use energy efficiency programs can be an important part of utility policy planning, yet the models show a variety of approaches to their incorporation. Most of the models in this study focus on the electric power sector, thus end use energy efficiency measures enter only exogenously as a reduction in electricity demand. Other models capture consumers' energy use, but simply use an exogenous rate of energy efficiency improvement determined by historical changes. Still others may endogenize the decision to purchase energy saving technology. For this study, modeling teams were instructed to vary their own internal cost of energy efficiency, cutting them by 50% (for the low EE cost case) or doubling them (for the high EE cost case). Note that many teams did not perform these scenarios (Table 1, above).[7]

2.4. Sensitivity to renewable energy costs

We explore a renewable technology cost sensitivity. This is particularly important, because more renewable energy has been deployed to-date than had been projected in previous AEOs, the studies which underpin the reference assumptions in EMF 32 (e.g. EIA, 2016b). Tax credits for wind and solar, extended in December 2015, and quickly decreasing technology costs have increased renewable energy generation faster than projected. EIA closely tracks generation costs, and updated their renewable cost estimates for AEO16.

For the scenarios involving sensitivity to lower costs, an alternative set of cost estimates was used. Modelers use the 2015 Annual Technology Baseline mid case projection from NREL.[8] These estimates are about 20% lower than AEO16 for solar photovoltaics, and about 9 percent lower for land-based wind.[9]

2.5. Sensitivity to electricity demand growth

Lastly, we examine the impact of stronger demand growth. Under the AEO16 high macroeconomic growth case, GDP grows an average of 2.8% per year over the forecast period (2015–2040) compared with 2.2% per year in the reference case. Total electric power generation grows an average of 1.1% per year as compared with 0.8% per year in the reference case.

This demand sensitivity is particularly important when interacted with the emissions taxes in the policy scenarios, as it approximates a future where the objectives of increased electrification and decreased emissions are pursued concurrently. The Fourth National Climate Assessment also notes how a warming climate could increase electricity demand 2.4–4.8% by 2050 while decreasing the efficiency of electricity generation and delivery (USGCRP, 2017).

3. Results

3.1. Reference scenario results

Fig. 3 shows electricity generation by fuel source in the reference scenario for all the models, in 2020 and 2035.[10] In 2015, EIA reports 4060 TWh of electricity generated. All models project baseload growth in the reference case, reaching an average of 4454 TWh of electricity in 2030 and growing to 5271 TWh in 2050. Most of the models show less coal generation in the reference case, up to 29% less in 2035 relative to 2020 (9 models). The average total change in coal generation across models between 2020 and 2035 is −4%. All of the models project gas generation increasing, from 23% to a max of 79%, with a cross model average of 39% between 2020 and 2035. All of the models also show growth in wind and solar generation over the 2020–2035 period. The cross model average total change in solar generation between 2020 and 2035 is 162% (20% for wind). Most of the models show declines in nuclear generation. The cross model average total change between 2020 and 2035 is −4%.[11]

Fig. 3 also shows CO_2 emissions in the reference case between 2020 and 2035 (right axis). The US Greenhouse Gas Inventory reports the 2015 CO_2 emissions from electricity generation were 1901 million metric tons (MMt) (EPA, 2017). Most models show emissions growth in the reference case of about 4% over the 2020–2035 projection period, from an average of 1887 MMt CO_2 in 2020 to 1965 MMt CO_2 in 2035.

Next, we examine the sensitivity of net capacity to key technology assumptions. We focus on net capacity additions (calculated as the difference in generating capacity across 5-year time steps, divided by 5) rather than generation for this investigation because we expect new capacity to respond most directly to changes in technology and fuel prices. By comparison, electricity generation reflects a mix of new and existing units that responds more slowly as the fleet turns over. However, generation is the more appropriate measure for policy scenarios, as policy affects the entire fleet dispatch and capacity utilization (Bistline et al., in this volume).

3.2. Effects of the technology scenarios on net electric generating capacity additions

Fig. 4 shows the various models add (net basis) between 1 and 10 GW generating capacity annually between 2020–35 and between 7 and 18 GW annually between 2035–50 in the reference case.[12] Over the 2000–2015 period, there was a relatively larger amount of new capacity additions (average 17 GW per year, shown in red) that accompanied the gas boom and increased wind and solar development due to domestic policies, reduced costs and other factors. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Three technology cases, the high gas price scenario, the low renewables cost scenario and the high demand scenario result in larger

[7] Of the teams reporting results for the energy efficiency scenarios, two models included final demand sectors and four models represent the electricity sector only. See Table 3 for more details about the participating models.

[8] www.nrel.gov/analysis/data_tech_baseline.html.

[9] A comparison based on levelized cost of electricity is summarized in Appendix Table A1.

[10] For other years see also Appendix Table A1 and Fig. A1.

[11] At the time the reference scenario was developed, the Vogtle (GA) and Summer (SC) nuclear plants were still under construction. Construction was halted when the contractor, Westinghouse, filed for bankruptcy in March of 2017.

[12] An alternate view of Fig. 4 is presented in Appendix Fig. A4.

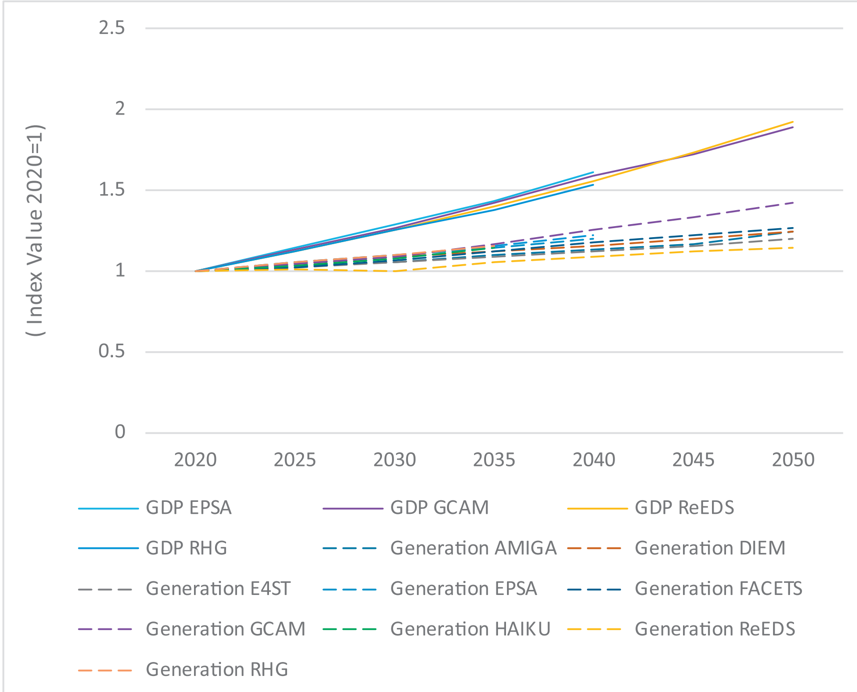

Fig. 1. GDP and electricity generation by model.

average net capacity additions on average than the reference case (but are not out of line with historical gross capacity additions from 2000–2015). In the high gas price scenario, new capacity grows 44% higher than in the reference over the 2020–2035 period (37% over the 2035–2050 period). In the low renewables cost case, average new capacity additions are 56% above reference in the 2020–2035 period (75% higher over the 2035–2050 period). In the high demand scenario average new capacity additions are 65% higher over the 2020–2035 period (35% higher over the 2035–2050 period).

In the high gas price scenario and the low renewables cost cases, these changes are of course related to the difference in relative marginal costs for wind and solar, which are not dispatchable technologies, and thus require more capacity per unit output. In the high demand scenario, the increase in capacity is the result of overall expansion in the electricity sector to meet higher demand requirements.

The low gas price scenario and the limited nuclear lifetimes scenario both result in little change in net capacity relative to the reference case. As we show below, this is partly explained by the ability of gas capacity to increase capacity utilization, boosting generation without additions to capacity.

The end-use energy efficiency scenarios present mixed results. Some models show that both low end use EE cost and high end use EE cost result in generally less new capacity relative to the reference case. Interpretation of the EE results is hampered by the fact that a minority of models provided results (Table 1). In the remainder of this section, these results are presented but not discussed in detail because of these challenges.

Table 3
Technology scenario assumptions.

Technology scenario	Description
Low natural gas prices	Based on "High Oil and Gas Resource and Technology" case in AEO16 – for example \$4.06/Mcf (\$4.21/MMBtu) in 2030[a]
High natural gas prices	Based on "Low Oil and Gas Resource and Technology" case in AEO16 – for example \$8.21/Mcf (\$8.51/MMBtu) in 2030[b]
Low end-use energy efficiency costs	Reduce by half the model-specific costs of energy efficiency measures from reference levels
High end-use energy efficiency costs	Double the model-specific costs of energy efficiency measures from reference levels
Limited nuclear lifetimes	For existing units, limit operational lifetime to 60 years. For new units, limit operational lifetime to 60 years plus limit capacity expansion to 7 GW per decade
Low renewable energy costs	Use NREL's Annual Technology Baseline 2015 mid case. For example, in 2022 the ATB had the levelized cost of energy from solar photovoltaic systems at \$68 per MWh 20% below the AEO16 estimate of \$85 per MWh
Higher electricity demand	Use the AEO16 High macroeconomic growth case, where the US economy grows an average rate of 2.8% per year compared to 2.2% per year in the reference case

[a] https://www.eia.gov/outlooks/archive/aeo16/tables_side.cfm.
[b] ibid.

3.3. Coal generating capacity and utilization

Fig. 5 shows net coal capacity additions. Few models show any net new coal capacity in the future under any scenario, continuing past industry trends.[13] Over the historical 2000–2015 period, the average US (net) capacity change was −2.3 GW per year.[14]

Comparing scenarios to the reference case, the low gas price scenario has the biggest difference in net coal capacity, increasing the rate of retirements 86% in the 2020–2035 period (60% between 2035–2050). Low renewables costs also will speed retirements on average, 24% in the 2020–2035 period (10% between 2035–2050).

Conversely, coal retirements are slowed on average in the high gas price scenario, the limited nuclear lifetimes scenario and the high

[13] As described above, these scenarios and the reference case include performance standards that require new, modified or reconstructed coal units to include 30% carbon capture to ensure the ability to meet the standard of 1400 lb CO_2 per MWh. It is not known if this constraint is binding in these models and scenarios. Previous studies, without the new source performance standards, showed constant or declining coal capacity even under a higher demand growth scenario (EIA, 2015; EPA, 2015).
[14] An alternate view of Fig. 5 is presented in Appendix Fig. A5.

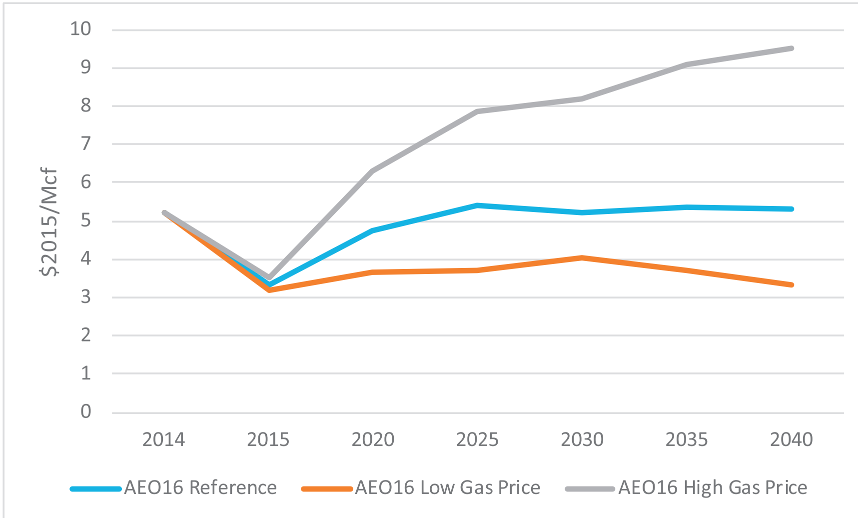

Fig. 2. Gas prices in reference case and gas price sensitivities.
Source: AEO16 https://www.eia.gov/outlooks/archive/aeo16/tables_side.cfm.

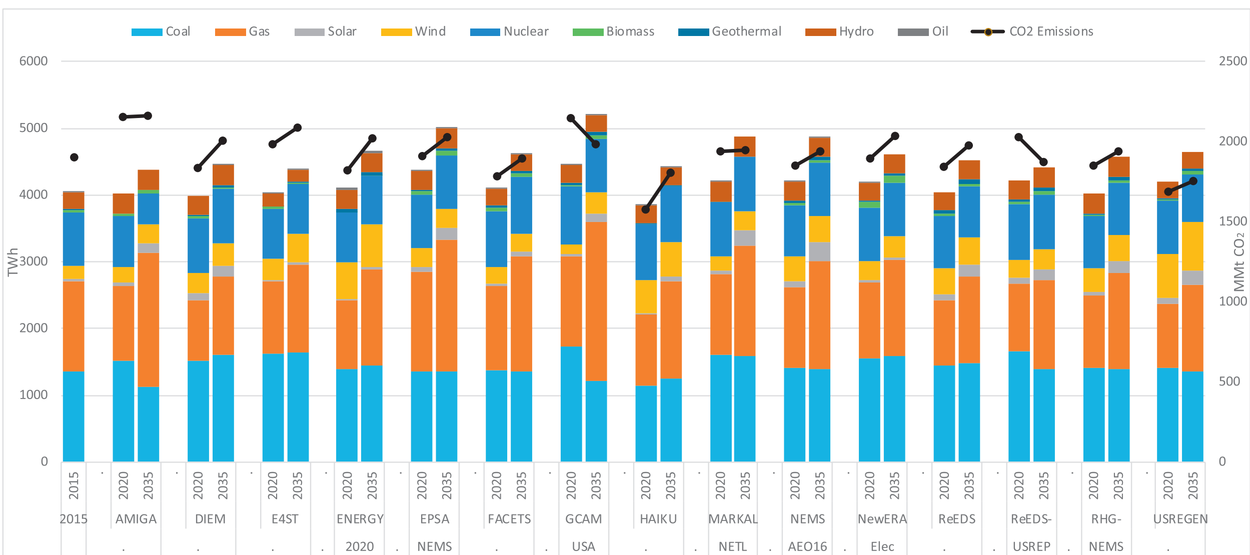

Fig. 3. Generation by fuel source and model, 2020 and 2035, (TWh), and emissions (MMt CO_2 -right axis) – reference scenario.

demand scenario.[15] In the high gas price case, retirements are 19% lower than in the reference case in 2020–2035 (35% lower over the 2035–2050 period). In the limited nuclear lifetimes scenario, retirements are 10% higher than in the reference case between 2020–2035 (40% lower over the 2035–2050 period). In the later term, as the nuclear limitations become more binding, the models respond to the need for low marginal cost dispatchable generation by keeping coal plants in the portfolio. In the high demand case, retirements are 10% lower than in the reference case in 2020–2035 (35% over the 2035–2050 period).

The two scenarios one might expect to be most favorable to coal are probably the high demand case and the high gas price case, and these produce the lowest coal retirement average rates over the 2020–2035 period. The average projected declines in coal capacity between 2020–2035 shown in Fig. 5 are between 0.5 and 1.4% of the 2015 power sector coal capacity per year.[16]

Fig. 6 shows there is a narrow range of estimates of coal capacity utilization across these scenarios, with the exception of the low gas price case where the average rate drops from 11 percentage points from the baseline, to just 61%. Technological limitations of coal plants and specifically issues with cycling are reflected in these results. Many of the models employ capacity factor-based retirements for coal, so the narrow range of capacity utilization is partly an artifact of that assumption.

3.4. Natural gas generating capacity and utilization

Fig. 7 shows the range of average annual gas capacity additions over the near and later term across the technology scenarios.[17] Not surprisingly, the low gas price scenario has the highest average new capacity

[15] This mirrors the finding in the recent DOE Markets and Reliability Report that "unless natural gas prices or electricity demand rise significantly faster than projected, the economic conditions of baseload generators are not projected to change significantly in the near term (DOE, 2017, p 57).

[16] In 2015 there was 284 GW of coal capacity in the US U.S. Energy Information Administration. The citation "EIA, 2016" has been changed to "EIA, 2016a, b" to match the author name/date in the reference list. Please check if the change is fine in this occurrence and modify the subsequent occurrences, if necessary.(EIA, 2016a, 2016b

[17] An alternate view of Fig. 7 is presented in Appendix Fig. A6.

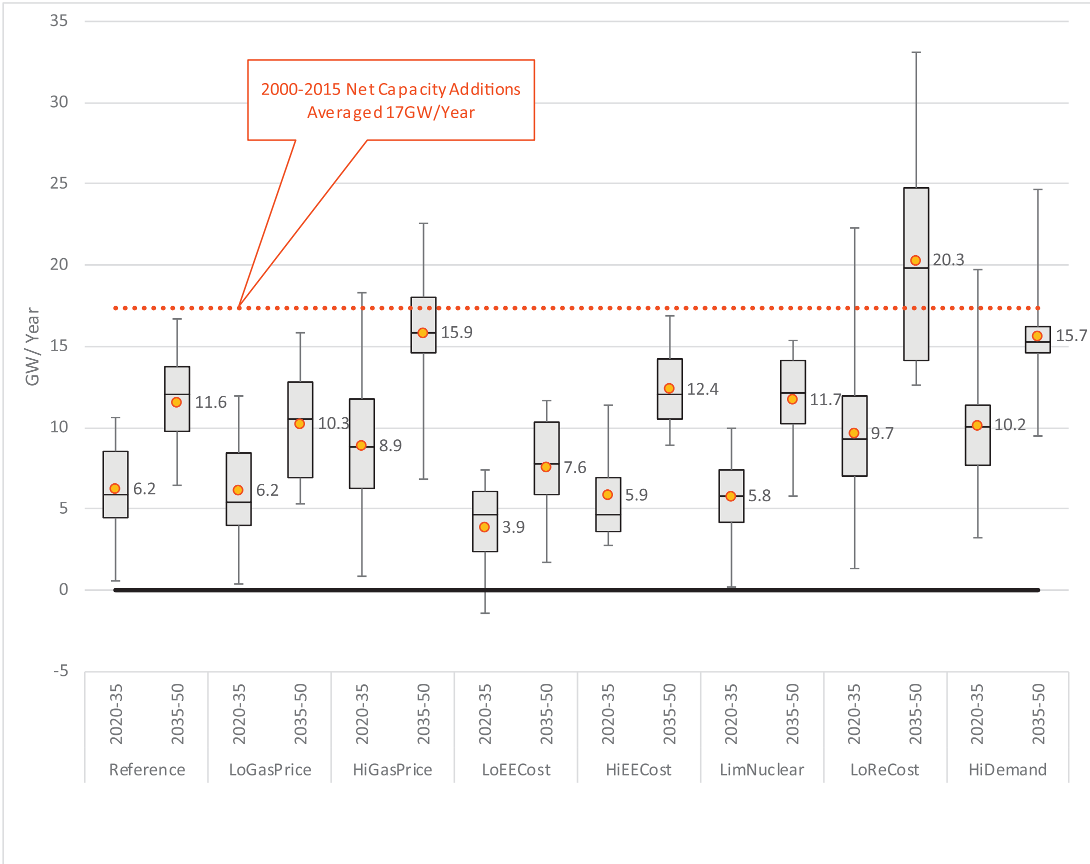

Fig. 4. Total (Net) Capacity Additions: Sensitivity to Technology Assumptions. Notes: Boxes represent 1st–3rd quartiles across participating models. Cross model means are labeled. Total ranges are indicated by bars. Scenarios include the baseline technology scenario (Reference); Low/high gas prices (LoGasPrice/HiGasPrice); Low/high costs of end-use energy efficiency (LoEECost/HiEECost); limited nuclear plant lifetimes (LimNuclear); low renewable energy costs (LoReCost); and higher electricity demand (HiDemand).

additions. The average capacity additions in the low gas price scenario represent an increase of 3.1 GW per year (109%) relative to the reference in the 2020–2035 period (3.7 GW per year, or 43% higher in 2035–2050). These rates, especially in the 2035–50 period, approach the historic 2000–2015 average added (net) capacity of 15 GW per year, which was largely driven by the gas boom.

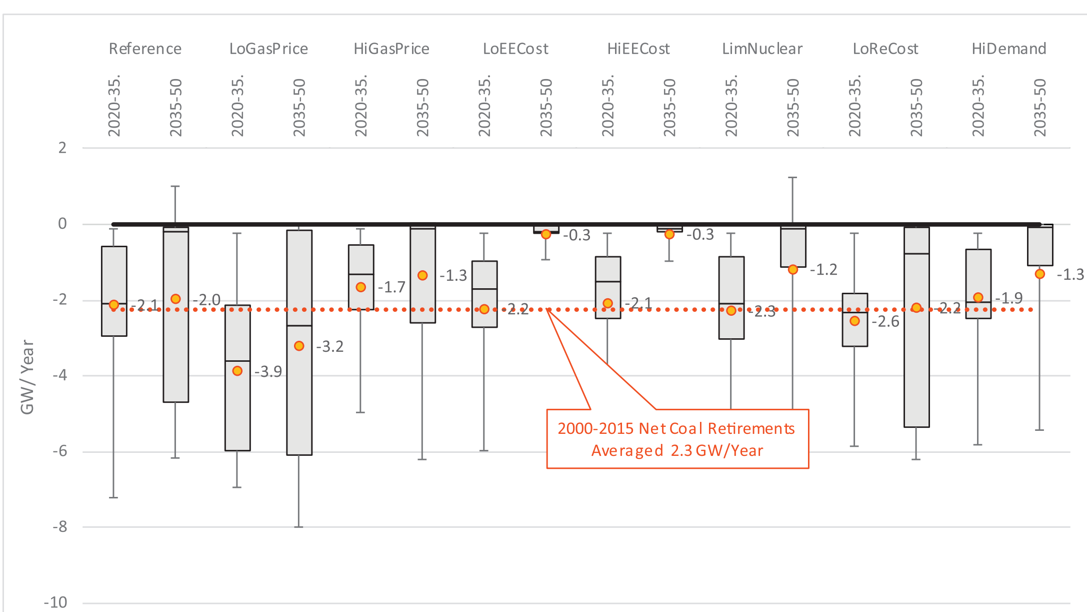

Fig. 5. Net coal capacity additions: sensitivity to technology assumptions. Notes: Boxes represent 1st–3rd quartiles across participating models. Cross model means are labeled. Total ranges are indicated by bars. Scenarios include the baseline technology scenario (Reference); low/high gas prices (LoGasPrice/HiGasPrice); low/high costs of end-use energy efficiency (LoEECost/HiEECost); limited nuclear plant lifetimes (LimNuclear); low renewable energy costs (LoReCost); and higher electricity demand (HiDemand).

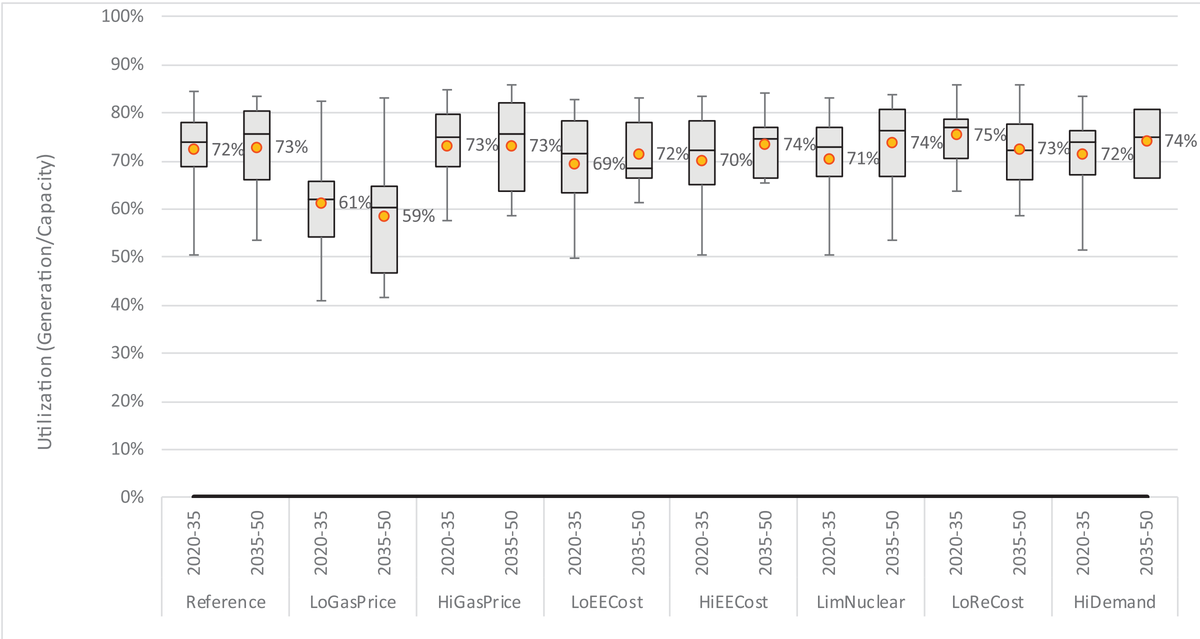

Fig. 6. Coal capacity utilization, 2020–2035 and 2035–2050. Notes: Calculated as electricity generated from coal divided by coal capacity. Boxes represent 1st–3rd quartiles across participating models. Cross model means are labeled. Total ranges are indicated by bars. Scenarios include the baseline technology scenario (Reference); low/high gas prices (LoGasPrice/HiGasPrice); low/high costs of end-use energy efficiency (LoEECost/HiEECost); limited nuclear plant lifetimes (LimNuclear); low renewable energy costs (LoReCost); and higher electricity demand (HiDemand).

Limited nuclear lifetimes and high electricity demand both have slightly higher gas builds relative to the baseline. In the limited nuclear lifetimes scenario, there is a 45% increase over the reference rate of capacity additions in the 2020–2035 period (33% in 2035–2050). In the high demand scenario, there is a 61% increase over the reference average rate of capacity additions in the 2020–2035 period (26% in 2035–2050).

The lowest new gas capacity estimates are in the high gas price scenario, and the second lowest gas average new capacity estimates are in the low renewables cost estimates, suggesting competition between gas and renewables. In the high gas price scenario, there is an 81% decrease compared to the reference average rate of capacity additions in the 2020–2035 period (−48% in 2035–2050). In the low renewables cost scenario there is a 19% decrease in new capacity compared to the reference average rate in the 2020–2035 period (−33% in 2035–2050).

Fig. 8 shows the distribution of gas capacity utilization rates projected by the models across the reference and technology scenarios.

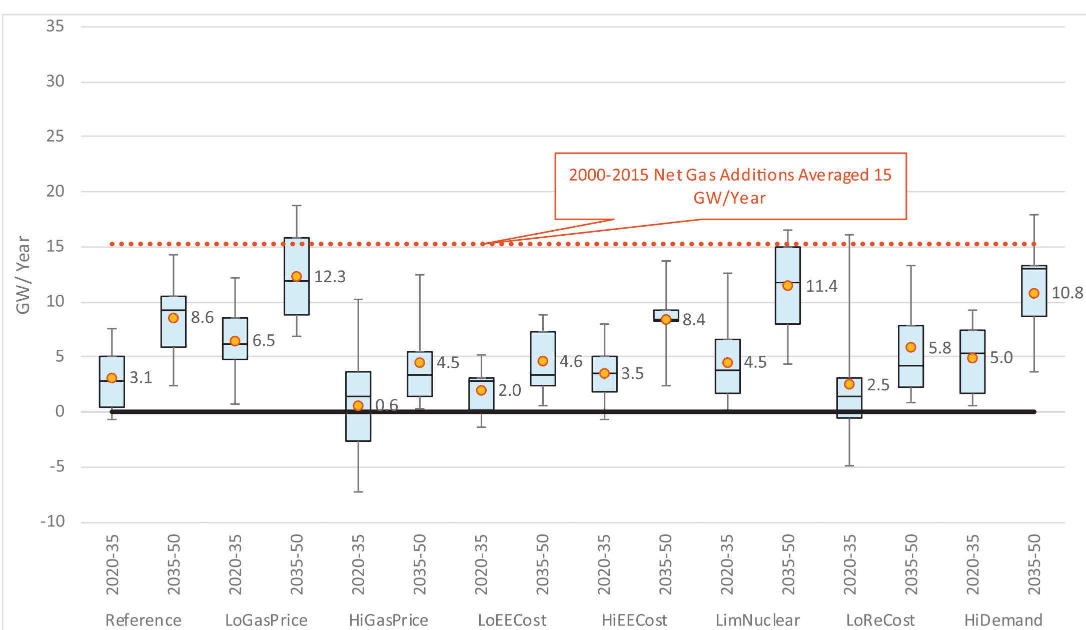

Fig. 7. Net natural gas capacity additions: sensitivity to technology assumptions. Notes: Boxes represent 1st–3rd quartiles across participating models. Cross model means are labeled. Total ranges are indicated by bars. Scenarios include the baseline technology scenario (Reference); low/high gas prices (LoGasPrice/HiGasPrice); low/high costs of end-use energy efficiency (LoEECost/HiEECost); limited nuclear plant lifetimes (LimNuclear); low renewable energy costs (LoReCost); and higher electricity demand (HiDemand).

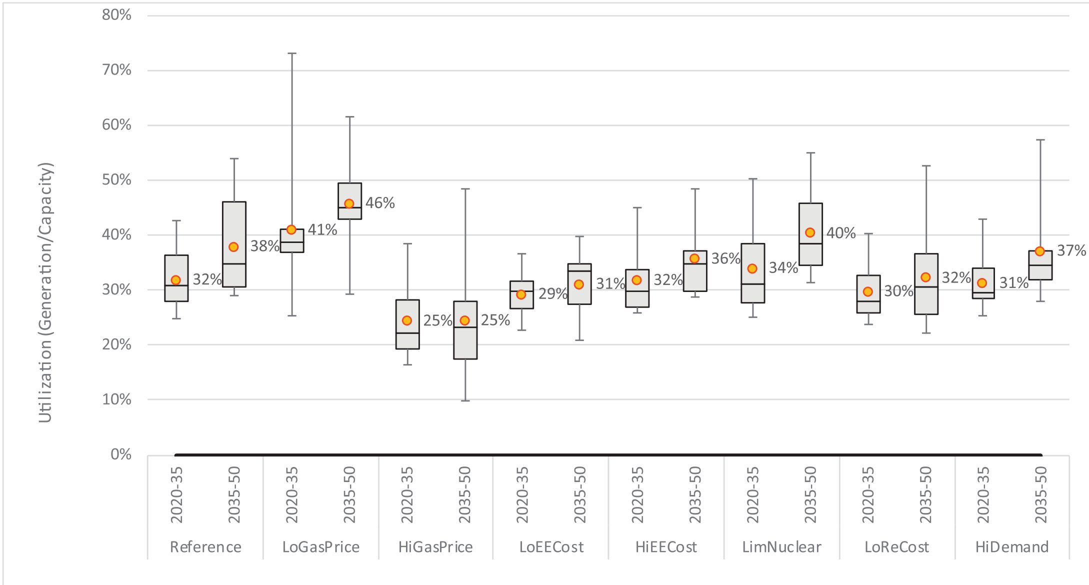

Fig. 8. Gas capacity utilization, 2020–20135 and 2035–2050. Notes: Calculated as electricity generated from gas divided by gas capacity. Boxes represent 1st–3rd quartiles across participating models. Cross model means are labeled. Total ranges are indicated by bars. Scenarios include the baseline technology scenario (Reference); low/high gas prices (LoGasPrice/HiGasPrice); low/high costs of end-use energy efficiency (LoEECost/HiEECost); limited nuclear plant lifetimes (LimNuclear); low renewable energy costs (LoReCost); and higher electricity demand (HiDemand).

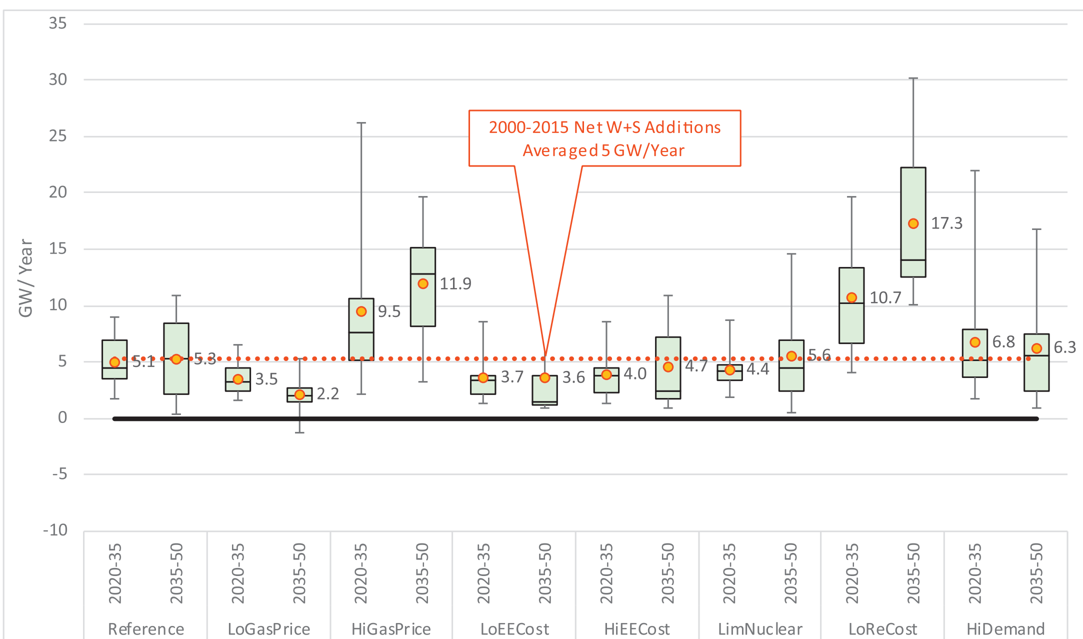

Fig. 9. Net wind + solar capacity additions: sensitivity to technology assumptions. Notes: Boxes represent 1st–3rd quartiles across participating models. Cross model means are labeled. Total ranges are indicated by bars. Scenarios include the baseline technology scenario (Reference); low/high gas prices (LoGasPrice/HiGasPrice); low/high costs of end-use energy efficiency (LoEECost/HiEECost); limited nuclear plant lifetimes (LimNuclear); low renewable energy costs (LoReCost); and higher electricity demand (HiDemand).

The capacity utilization constraints used for coal do not apply for gas, and as a result there is more variability in the gas capacity utilization estimates. Overall they follow a pattern similar to new gas capacity, with low gas prices, limited nuclear retirements increasing capacity utilization compared to the reference case and high gas prices and low renewables costs decreasing gas capacity utilization relative to the reference.

In the high demand case, the cross model averages are the same as the reference case, but the range given by the first and third quartiles would suggest lower capacity utilization in this case. In this case new capacity is growing faster than generation, keeping capacity utilization rates from rising.

Note also the projections suggest higher gas capacity utilization rates in the 2035–2050 period compared to the 2020–2050 period in every scenario, except the high gas price sensitivity.

3.5. Wind and solar generating capacity

Fig. 9 shows the sum of net wind and solar capacity additions.[18] Historically, the 2000–2015 average added solar and wind (net) capacity

[18] Wind and Solar net capacity are shown separately in Appendix Figs. A2 and A3. An alternate view of Fig. 9 is presented in Appendix Fig. A7.

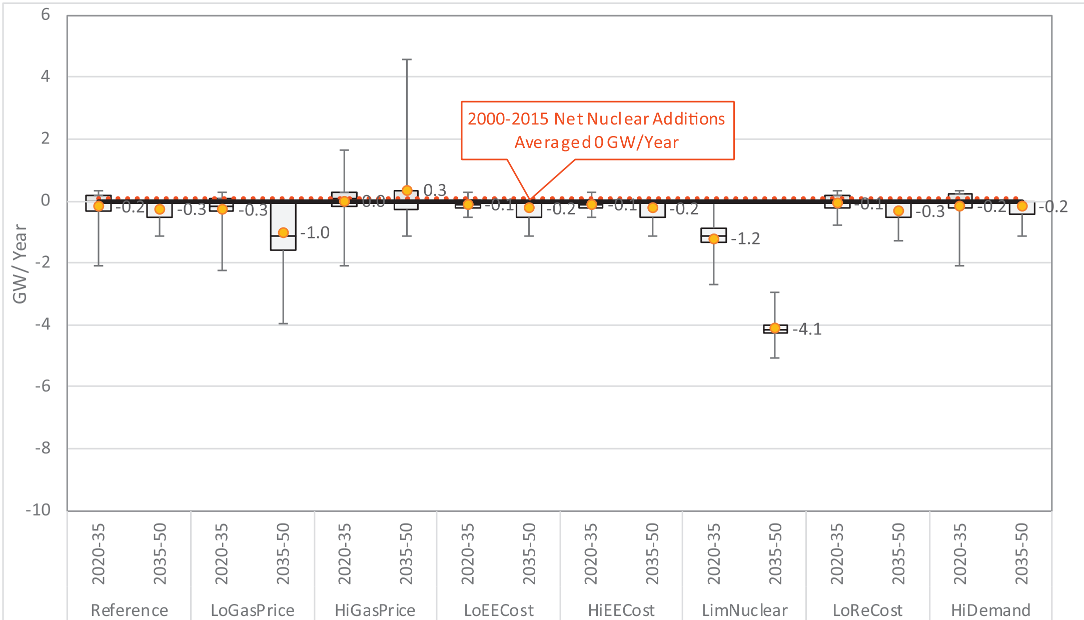

Fig. 10. Net nuclear capacity additions: sensitivity to technology assumptions. Notes: Boxes represent 1st–3rd quartiles across participating models. Cross model means are labeled. Total ranges are indicated by bars. Scenarios include the baseline technology scenario (Reference); low/high gas prices (LoGasPrice/HiGasPrice); low/high costs of end-use energy efficiency (LoEECost/HiEECost); limited nuclear plant lifetimes (LimNuclear); low renewable energy costs (LoReCost); and higher electricity demand (HiDemand).

was 5 GW. The cross-model average for the reference case is similar, at 5.1 GW/year in the near term and 5.3 GW/year in the long term.

Fig. 9 shows that renewables capacity is most responsive to renewable technology costs and natural gas prices. In the low renewables cost scenario, an average of 5.6 GW per year added 2020–2035 over the baseline (110% increase, and 226% between 2035–2050). The next largest change is the higher gas prices scenario, where in the near term new capacity is increased 86% over the reference case (125% in the 2035–2050 period). In the higher electricity demand scenario, new capacity increases 33% in the near term over the reference case (19% in the later term). The models project larger percentage changes for wind and solar than for gas, for example, due in part to the non-dispatchability of renewables. Also, renewable technologies have lower relative operating costs, and thus new renewable capacity additions are more sensitive to capital costs. As mentioned previously, our results indicate that natural gas competes with renewable generation as the marginal generating resource.

In the low gas price scenario, average new capacity additions are 31% lower than in the reference case for the 2020–2035 period (58% lower 2035–2050). In the limited nuclear lifetimes scenario, new capacity is slightly lower on average in the near term but slightly higher in the later term.

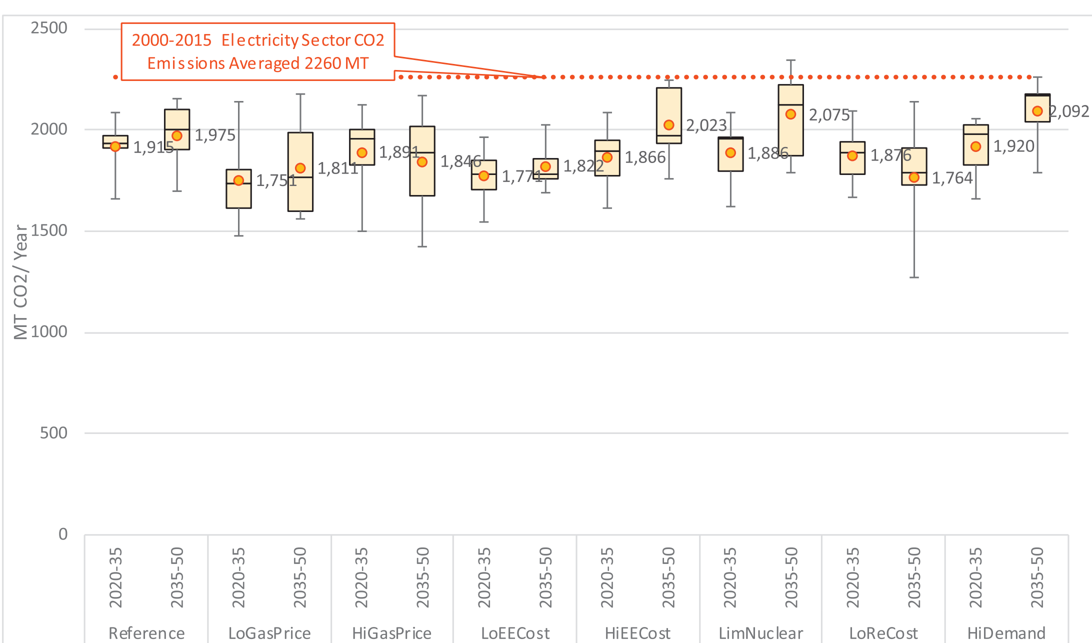

Fig. 11. Average annual emissions from the electric sector: sensitivity to technology assumptions. Notes: Boxes represent 1st–3rd quartiles across participating models. Cross model means are labeled. Total ranges are indicated by bars. Scenarios include the baseline technology scenario (Reference); low/high gas prices (LoGasPrice/HiGasPrice); low/high costs of end-use energy efficiency (LoEECost/HiEECost); limited nuclear plant lifetimes (LimNuclear); low renewable energy costs (LoReCost); and higher electricity demand (HiDemand).

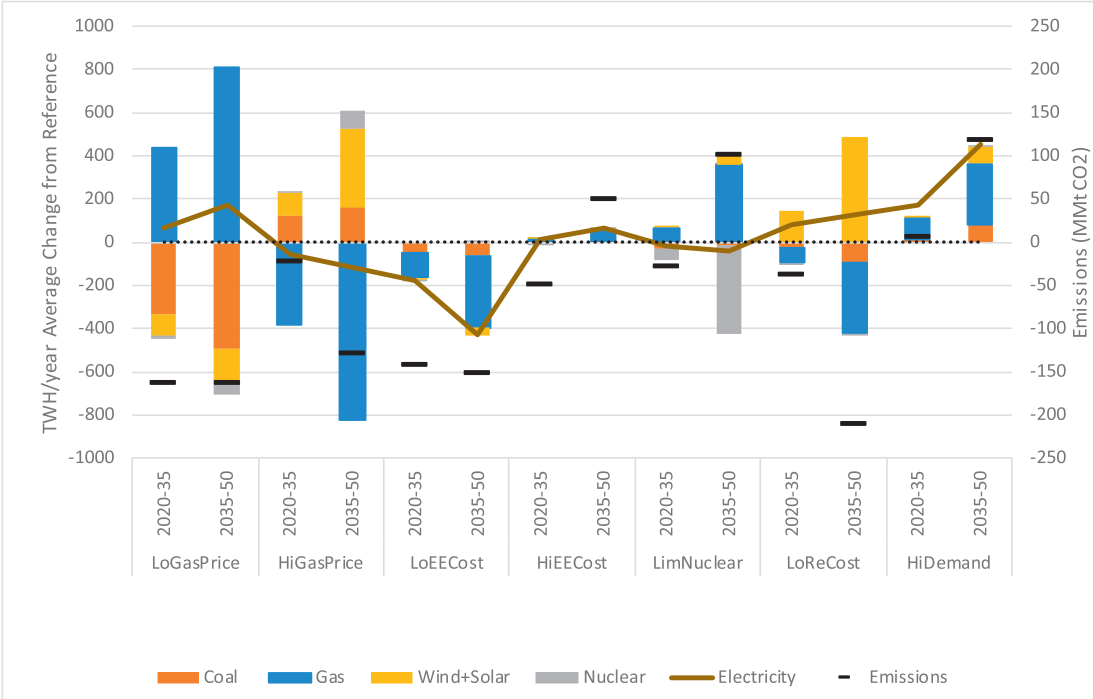

Fig. 12. Electricity generation changes by scenario (TWh/year), and emissions relative to the reference scenario (MMt CO_2 -right axis).

3.6. Nuclear generating capacity

Net nuclear capacity additions are shown in Fig. 10.[19] Nuclear capacity is roughly constant, except in the limited nuclear lifetimes where an average of 4.1 GW/year are retired between 2035 and 2050.[20] As shown above, this loss is compensated by increases in other fuels depending on the region-specific marginal technology.[21]

3.7. CO_2 emissions results

Next, we examine the distribution of emissions results across the scenarios. Fig. 11 shows the range of CO_2 emissions estimates over the near term and later term across the technology sensitivities.

Not surprisingly, low renewables cost and low gas prices both result in lower overall emission rates relative to the 2020–2035 and 2035–2050 reference. For the 2020–2035 period, average emission rates are about 9% lower in the low gas prices scenario and 2% lower in the low renewables cost case. In the 2035–2050 period, average emission rates are about 8% lower in the low gas price case and 11% lower in the low renewables cost scenario.[22]

The higher demand scenario results in increased emissions rates. In the higher demand case, emissions are slightly higher on average over the near term, but about 6 percent higher over the 2035–2050 period.

Interestingly, Fig. 11 shows high gas prices result in lower emissions on average relative to the reference case. The next section investigates this further by comparing generation across fuel types.

[19] An alternate view of Fig. 10 is presented in Appendix Fig. A8.

[20] This is partly an artifact of model construction, as some model's treatment of nuclear fleet dynamics varies. For example, some models do not allow for economic retirements of nuclear generators, only lifetime constraints such as those in the limited nuclear lifetimes scenario.

[21] Note that replacement capacity needs are generally higher than displaced nuclear capacity owing to nuclear energy's high capacity factors.

[22] None of these technological and fuel price scenarios, by themselves and with existing policies in place, are sufficient to reach recent emissions reduction targets, but they may reduce the overall policy costs (Bistline et al., in this volume).

3.8. Summary comparison of sensitivity scenarios to reference case

In the reference case, using the mean of the model's estimates, total additions to gas electricity generation capacity average 3.1 GW per year, and renewable capacity adds another 5.1 GW per year, for a total of 8.2 GW per year. Over the 2020–2035 period, that amounts to over 120 GW of additional capacity. Over the same period, there are (summing cross model averages) over 32GW of coal and nuclear retirements. Thus, the models overall are building about 3.6 GW of gas and renewables capacity for every GW of coal and nuclear capacity that is retired between 2020–2035 in the reference case.

Although none of these results should be considered predictive forecasts of what will happen in the future, we can address predictive uncertainty with the multi model results (Weyant et al., 2014). In this section we return to the motivating questions described in Section 1: Will the gas boom continue, and what if it does not? What is the role of end use energy efficiency? What is the effect on emissions and generation of increasing nuclear licensing lifetimes? What if renewable energy technologies continue to outperform market expectations on cost and penetration? And what if economic growth, and electricity demand, return to a more robust level than in the recent past?

3.8.1. Will the gas boom continue? What if it does not?

Comparing the low and high gas price scenarios, we find that there are similar implications for new capacity additions, and emissions, but differences in the overall fuel mix. In the low gas price scenario, the electricity sector adds 10 GW of gas and renewables capacity per year, or about 2 GW for every GW of coal and nuclear capacity retired. This ratio is 33% lower than the reference case, owing to the relative greater reliance on dispatchable (gas) fuel. New gas capacity comprises about 65% of total capacity additions. In contrast, in the high gas price scenario the sector also adds 10 GW of new capacity annually, but new gas capacity is only about 5% of total new capacity additions. In the high gas price scenario, 5.9 GW of new gas and renewables capacity are added per GW of coal and nuclear capacity retired, showing the higher reliance on nondispatchable (renewable) fuels.

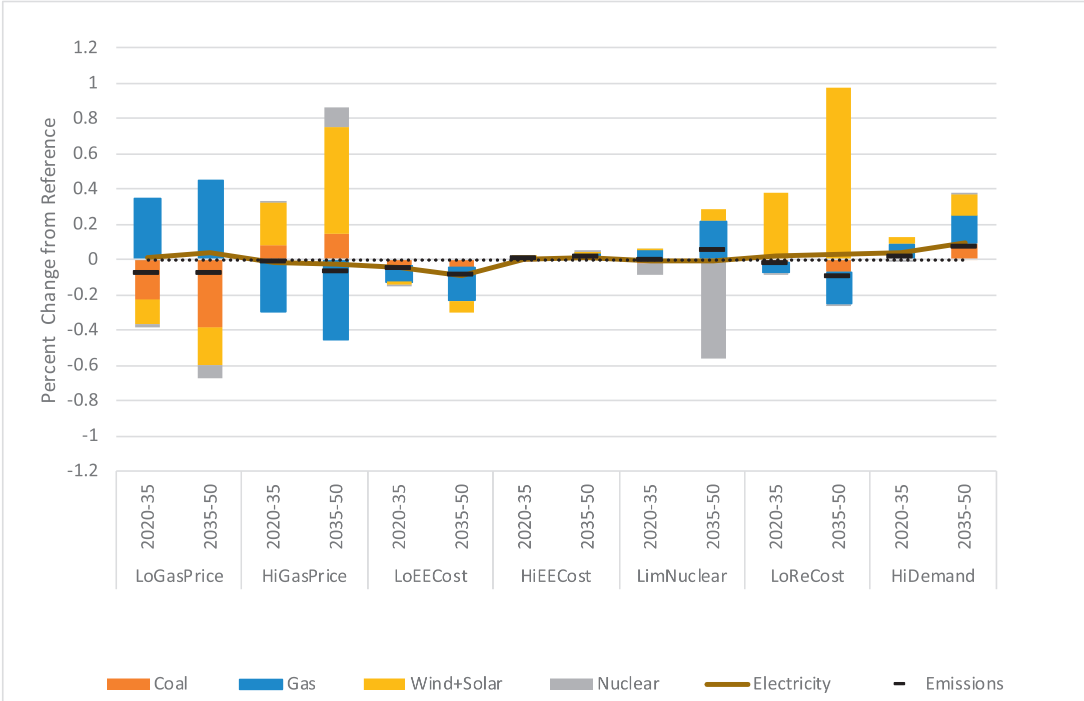

Fig. 13. Electricity generation and emissions changes by scenario relative to the reference scenario.

Comparing total electricity generation, results show that lower (higher) gas prices lead to increases (decreases) in gas generation and reductions (increases) in coal and renewables. Fig. 12 shows the cross-model average new capacity changes from Figs. 5-11 together, together with emissions results. Fig. 13 shows the associated changes in electricity generation by fuel.

Emissions continue to decline under higher or lower gas price forecasts, due to the interaction of output and substitution effects. With lower gas prices, Figs. 12 and 13 show that total generation increases, but substitution of gas for coal results in lower overall emissions. Conversely, with the high gas price scenario, total electricity generation declines, but the increases in zero carbon capacity exceed the increase (reduced retirement) of coal units. In the 2035–50 period, growth in clean generation exceeds coal by a factor of over 2.5 (Fig. 12).

3.8.2. What is the role of end use energy efficiency?

Energy efficiency has the potential to reduce electricity emissions through reduced demand. Figs. 12 and 13 shows that with lower energy efficiency costs, the models cut both electricity generation and emissions fall. By fuel, gas generation (as the most dispatchable option) declines the most. Conversely, with costlier energy efficiency, the generation profile looks similar to the reference case.

In terms of new capacity requirements, the low cost energy efficiency scenario results in an average new capacity increase of 5.7 GW – the lowest new capacity requirement of any scenario, with no significant impact on fuel mix represented in new capacity.

Overall, Fig. 13 shows that, in percentage terms, none of the outcomes for energy efficiency move the system very far from the reference case.[23] Our findings are limited by the small number of models addressing those scenarios.

[23] Hodson et al. (in this volume) evaluated a side case where DOE technology efficiency goals were met, and found large potential emissions reductions at lower cost compared to regulatory approaches.

3.8.3. What is the effect on emissions and generation of increasing nuclear licensing lifetimes?

The effects of increasing nuclear lifetimes are revealed as the avoided outcomes of the lower nuclear lifetimes scenario. In terms of new capacity requirements, the models average about 9 GW of new capacity, 1 GW higher than reference. This new capacity is split evenly between gas and renewables.

Emissions are slightly lower on average over the 2020–2035 period, due to reduced generation. However, over the 2035–2050 period emissions increase relative to the reference as gas generation increases along with a slight decrease in the coal retirements, and a slight increase in renewable electricity generation.

3.8.4. What if renewable energy technologies continue to outperform market expectations on cost and penetration?

The analysis of lower renewable energy costs generated large increases in new renewables capacity, rivaling the historical gas capacity additions that accompanied the gas boom. Overall, the models build 13 GW of new capacity per year between 2020–2035 – the highest requirement of any scenario. Of this expansion, 80% is new renewables capacity, and 20% is new gas capacity. Overall, it takes 5 GW of expansion for every GW of coal and nuclear power retired under this scenario because of the increased reliance on non-dispatchable fuels.

Thus renewables cost reductions result in smaller increases in total generation than were found for the low gas price case. However, the emissions reduction is larger in real and percentage terms.

3.8.5. What if economic growth, and electricity demand, return to a more robust level than in the recent past?

In the high demand scenario, there is an increase in capacity across all the fuels relative to the reference case. The total increase in new capacity is 12 GW, the highest of any scenario. The biggest changes are in gas and renewables capacity. As discussed above, these two technologies are the main competitors for new generating capacity. New gas capacity comprises 42% of the additions, and renewables make up 58%.

As with the limited nuclear case, there is a concomitant increase in emissions. As total generation increases 4% between 2020–2035 (9% in the later period), gas generation expands faster than reference, coal retirements are lower than the reference, and renewables expand at approximately the reference rate. Taking these changes together, emissions increase, but at less than the trend rate.

Lastly, as shown in Fig. 13, the effect of these sensitivity scenarios is much larger for individual fuels than for the aggregate measures of total generation or emissions.

4. Conclusions

The EMF 32 power sector study is a model comparison exercise that evaluates projections across assumptions about natural gas prices, energy efficiency, nuclear energy, renewables costs, electricity demand and policy. This paper summarizes and synthesizes the results across the technology sensitivity scenarios. Fifteen models participated, representing a mix of model structures. The reference case, common to all models, was based on the AEO16, No Clean Power Plan Case (EIA, 2016a). The reference case paints a picture of moderately higher electricity demand and continuation of recent generation trends: net coal retirements, steady nuclear capacity, and expanding natural gas and renewables generation.

The most sensitive factors we found were the assumptions about the price of natural gas and cost of renewables – these are competing on the margins for new capacity changes.

The factors most likely to push up CO_2 emissions in the long run are higher than expected demand, and shutting down nuclear plants before their useful life expires.

A number of potentially important technological factors were not included in EMF 32, and could not be addressed here. Some of these topics include power storage technology, advanced nuclear technologies, and other advanced technologies like hydrogen – these are worthy of future research. Additionally, two of the scenarios focused on end-use energy efficiency costs, but these were completed by a minority of model groups. More work is needed to assess the effects of energy efficiency measures.

All told, the differences in results arising from differences between technology assumptions in this study should be interpreted carefully. On one hand, it is possible to draw some conclusions about the implications of different technology developments at a broad level. One potential limitation is that there is just one baseline to compare against, or in other words there are no "combined scenarios", but this effect is at least partially mitigated by the large number and types of models, giving a plausible range of results. On the other hand, our sensitivity analysis is limited to issues seen as important in the current environment, and conclusions cannot outstrip data restrictions and limitations imposed by the models themselves.

Appendix A

Table A1
Price/cost measures used in technology sensitivity scenarios.

Natural gas $2015/Mcf	Low gas price	3.65	4.06	3.32
	Reference	4.75	5.20	5.31
	High gas price	6.32	8.21	9.52
Solar photovoltaic (PV)	Reference	85		71
	Low renewables cost	68	49	49
Solar thermal	Reference	236		205
	Low renewables cost	196	161	161
Land-based wind	Reference	65		58
	Low renewables cost	59	55	52
Offshore wind	Reference	158		133
	Low renewables cost	161	144	140

Notes: Natural gas is the delivered cost to the electric sector in AEO16. Solar PV, Solar Thermal, Land Based Wind, and Offshore Wind compares total system levelized cost, non-weighted averages from Table 2 and B2, EIA, with 2015 ATB estimates.

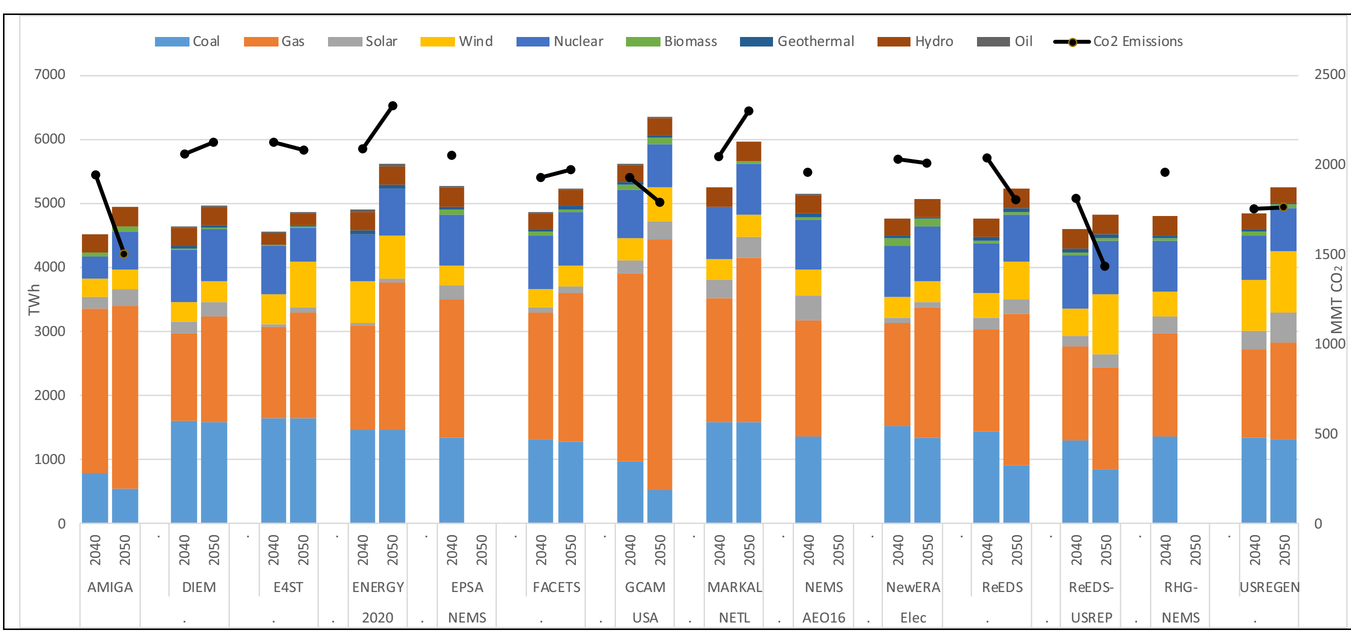

Fig. A1. Generation by fuel source and model, 2040 and 2050, (TWh), and CO_2 emissions (Mt - right axis).

Table A2
Electricity generation by model, coal and natural gas, reference.

	2020	2025	2030	2035	2040	2045	2050	%Chg 2020–35	%Chg 2020–35
Coal									
AMIGA3	1511.11	1441.67	1305.56	1130.56	794.45	575.00	544.44	−25%	−52%
DIEM	1527.07	1595.61	1527.37	1602.51	1595.52	1591.85	1582.55	5%	−1%
E4ST_v6	1627.78	1644.67	1635.28	1637.77	1635.16	1642.48	1641.94	1%	0%
Energy2020	1387.58	1429.92	1448.43	1452.58	1455.31	1458.43	1461.87	5%	1%
EPSA-NEMS	1365.87	1417.11	1378.13	1363.23	1342.65	na	na	0%	na
FACETS	1376.98	1378.28	1364.73	1351.60	1318.49	1289.52	1272.45	−2%	−6%
GCAM-USA	1723.85	1601.32	1431.16	1215.58	972.10	737.78	527.58	−29%	−57%
HAIKU	1151.45	1148.24	1192.43	1249.31	na	na	na	8%	na
MARKAL-NETL-2015	1605.56	1580.56	1588.89	1588.89	1588.89	1588.89	1588.89	−1%	0%
NEMS-AEO2016	1416.15	1432.31	1421.46	1398.15	1364.11	na	na	−1%	na
NewERAele	1557.32	1647.86	1585.12	1587.33	1517.03	1426.87	1336.15	2%	−16%
ReEDS	1454.76	1581.71	1515.99	1474.79	1439.80	1266.74	910.77	1%	−38%
ReEDS-USREP	1655.83	1596.30	1456.87	1385.48	1286.01	1117.42	855.10	−16%	−38%
RHG-NEMS	1408.73	1424.36	1413.11	1388.74	1357.17	na	na	−1%	na
US-REGEN	1413.89	1388.89	1383.33	1363.89	1336.11	1316.67	1319.45	−4%	−3%
Gas									
AMIGA3	1119.45	1319.45	1533.33	2002.78	2566.67	2927.78	2841.67	79%	42%
DIEM	890.54	997.16	1167.78	1186.04	1367.53	1555.45	1640.74	33%	38%
E4ST_v6	1075.82	1103.05	1227.98	1319.88	1428.36	1464.81	1652.71	23%	25%
Energy2020	1036.46	1181.99	1308.18	1432.69	1623.50	1934.95	2292.40	38%	60%
EPSA-NEMS	1492.53	1612.70	1819.43	1961.99	2146.88	na	na	31%	na
FACETS	1267.35	1321.65	1506.31	1731.32	1968.49	2164.47	2319.22	37%	34%
GCAM-USA	1361.34	1647.91	1948.37	2378.66	2940.94	3430.99	3907.14	75%	64%
HAIKU	1062.00	1157.58	1293.22	1463.90	na	na	na	38%	na
MARKAL-NETL-2015	1219.45	1375.00	1525.00	1650.00	1927.78	2236.11	2569.45	35%	56%
NEMS-AEO2016	1205.62	1327.26	1491.45	1619.26	1804.98	na	na	34%	na
NewERAele	1135.58	1150.47	1340.60	1444.40	1617.86	1822.55	2027.96	27%	40%
ReEDS	962.20	949.35	1093.74	1314.51	1581.70	1933.96	2362.26	37%	80%
ReEDS-USREP	1019.03	1047.73	1120.32	1347.92	1470.48	1543.36	1578.49	32%	17%
RHG-NEMS	1081.47	1190.06	1327.65	1438.33	1603.30	na	na	33%	na
US-REGEN	961.11	1158.33	1261.11	1297.22	1383.33	1438.89	1497.22	35%	15%
Solar									
AMIGA3	58.33	69.44	130.56	150.00	177.78	191.67	280.56	157%	87%
DIEM	108.89	113.81	126.06	156.04	189.78	223.32	223.13	43%	43%
E4ST_v6	24.00	28.98	39.31	40.12	46.77	55.12	73.52	67%	83%
Energy2020	27.83	36.64	41.00	45.56	51.86	60.16	67.66	64%	48%
EPSA-NEMS	71.70	89.30	118.49	176.27	239.46	na	na	146%	na
FACETS	27.62	45.59	61.37	65.80	78.77	81.69	106.10	138%	61%
GCAM-USA	27.00	50.10	84.15	133.04	192.41	247.96	290.81	393%	119%
HAIKU	17.34	27.01	35.59	58.83	na	na	na	239%	na
MARKAL-NETL-2015	44.44	58.33	102.78	230.56	294.44	308.33	313.89	419%	36%
NEMS-AEO2016	93.32	113.35	180.16	280.82	388.54	na	na	201%	na
NewERAele	34.76	34.76	35.57	35.97	72.23	79.36	86.78	4%	141%
ReEDS	88.41	107.54	137.72	162.54	188.07	194.63	214.02	84%	32%
ReEDS-USREP	85.65	105.09	128.75	157.55	179.12	185.93	209.34	84%	33%
RHG-NEMS	53.34	55.69	108.70	185.94	268.65	na	na	249%	na
US-REGEN	86.11	105.56	116.67	205.56	277.78	375.00	466.67	139%	127%
Wind									
AMIGA3	230.56	230.56	275.00	283.33	291.67	294.44	294.44	23%	4%
DIEM	314.88	318.61	322.06	332.21	292.61	229.79	327.19	6%	−2%
E4ST_v6	328.72	357.26	395.34	423.99	465.78	559.94	722.61	29%	70%
Energy2020	542.19	554.58	590.59	627.96	656.94	671.21	674.11	16%	7%
EPSA-NEMS	268.52	289.04	289.23	289.52	291.45	na	na	8%	na
FACETS	249.40	257.91	263.28	274.99	291.57	309.28	330.22	10%	20%
GCAM-USA	146.51	184.09	237.23	322.01	349.29	442.77	522.16	120%	62%
HAIKU	498.12	518.60	520.80	521.33	na	na	na	5%	na
MARKAL-NETL-2015	219.44	272.22	280.56	288.89	319.44	327.78	338.89	32%	17%
NEMS-AEO2016	361.63	388.32	391.27	394.48	398.89	na	na	9%	na
NewERAele	277.53	284.52	299.49	316.40	324.12	326.39	329.04	14%	4%
ReEDS	406.75	418.69	435.38	413.16	393.42	429.10	591.91	2%	43%
ReEDS-USREP	270.11	289.15	299.50	290.82	422.34	629.58	941.26	8%	224%
RHG-NEMS	357.82	385.15	387.62	390.37	393.87	na	na	9%	na
US-REGEN	652.78	680.56	652.78	733.33	811.11	866.67	958.33	12%	31%
Nuclear									
AMIGA3	761.11	719.45	611.11	458.33	330.56	319.44	597.22	−40%	30%
DIEM	816.14	816.14	813.19	816.14	816.14	816.14	816.14	0%	0%
E4ST_v6	746.19	746.18	746.18	746.17	746.30	736.25	523.23	0%	−30%
Energy2020	750.44	732.36	732.36	732.36	732.36	732.36	732.36	−2%	0%
EPSA-NEMS	803.66	807.52	807.52	807.52	807.52	na	na	0%	na
FACETS	843.31	843.31	843.31	843.31	843.31	843.31	843.31	0%	0%
GCAM-USA	881.81	864.28	831.56	796.22	762.19	717.83	679.61	−10%	−15%
HAIKU	839.04	854.63	840.82	841.37	na	na	na	0%	na

Table A2 (*continued*)

	2020	2025	2030	2035	2040	2045	2050	%Chg 2020–35	%Chg 2020–35
MARKAL-NETL-2015	813.89	813.89	813.89	813.89	813.89	813.89	813.89	0%	0%
NEMS-AEO2016	777.46	789.06	789.06	789.06	789.06	na	na	1%	na
NewERAele	807.32	807.02	797.91	797.91	806.80	828.69	851.48	−1%	7%
ReEDS	768.20	768.20	768.20	761.96	761.96	761.96	745.23	−1%	−2%
ReEDS-USREP	828.90	828.90	828.90	828.90	828.90	828.90	828.90	0%	0%
RHG-NEMS	777.49	789.09	789.09	789.09	789.09	na	na	1%	na
US-REGEN	797.22	777.78	766.67	713.89	691.67	686.11	672.22	−10%	−6%

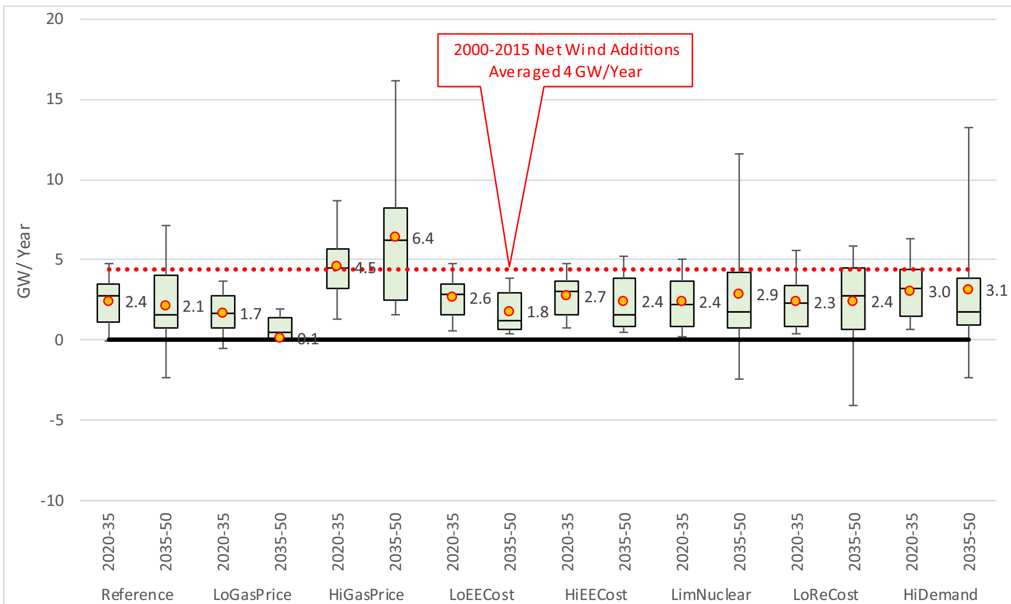

Fig. A2. Net wind capacity additions: sensitivity to technology assumptions. Notes: Boxes represent 1st–3rd quartiles across participating models. Cross model means are labeled. Total ranges are indicated by bars. Scenarios include the baseline technology scenario (Reference); low/high gas prices (LoGas/HiGas); low/high costs of end-use energy efficiency (LoEE/HiEE); limited nuclear plant lifetimes (LoNL); low renewable energy costs (LoRe); and higher electricity demand (HiDem).

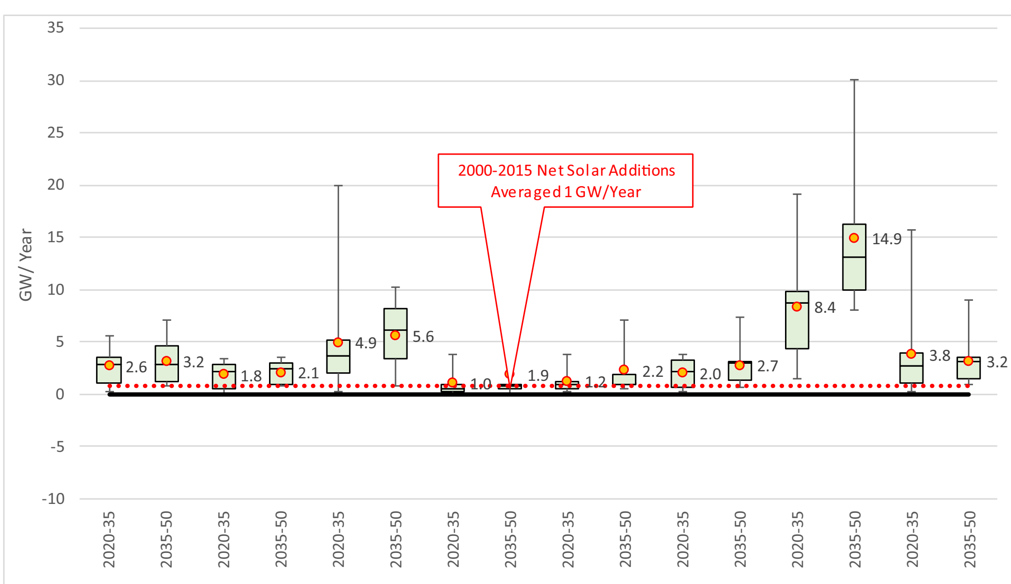

Fig. A3. Net solar capacity additions: sensitivity to technology assumptions. Notes: Boxes represent 1st–3rd quartiles across participating models. Cross model means are labeled. Total ranges are indicated by bars. Scenarios include the baseline technology scenario (Reference); low/high gas prices (LoGas/HiGas); low/high costs of end-use energy efficiency (LoEE/HiEE); limited nuclear plant lifetimes (LoNL); low renewable energy costs (LoRe); and higher electricity demand (HiDem).

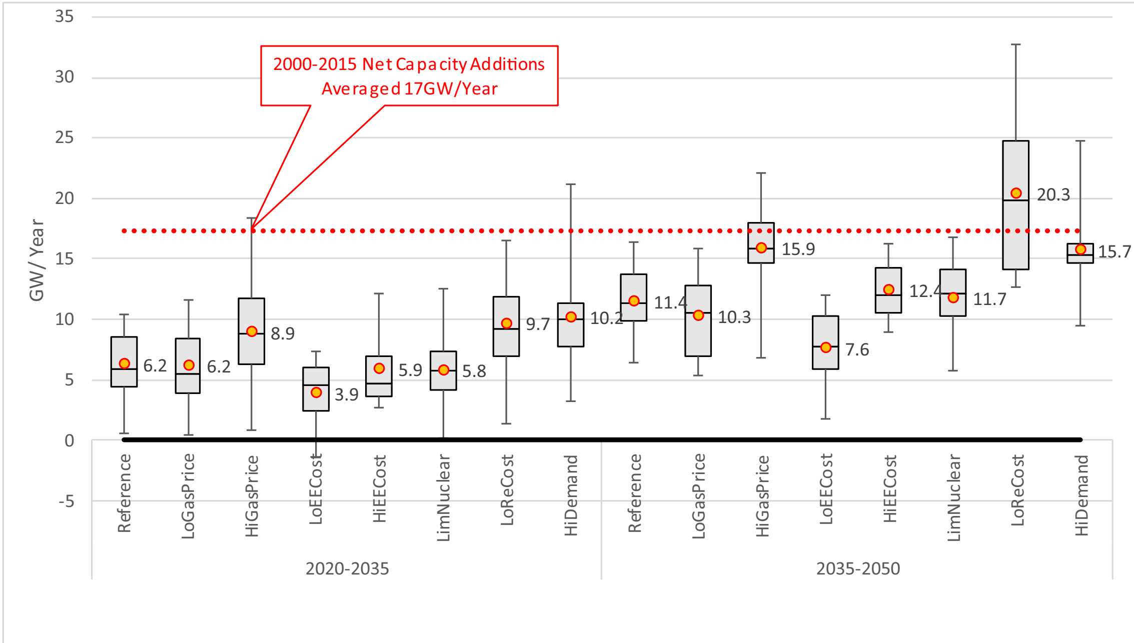

Fig. A4. Alternative view of data in Fig. 4- total net capacity additions.

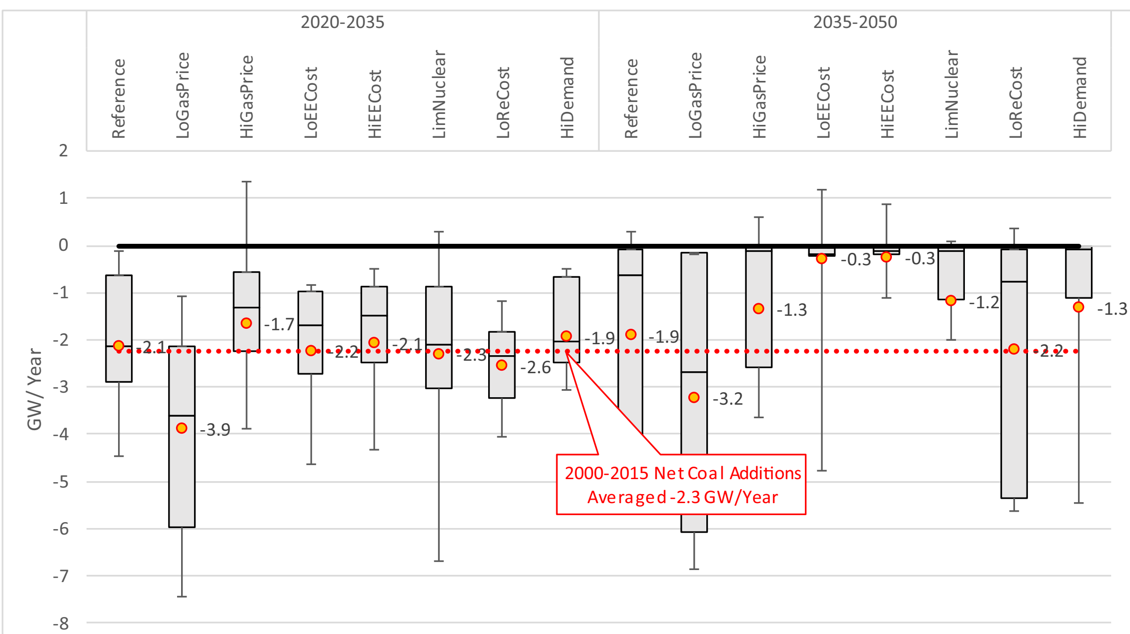

Fig. A5. Alternative view of data in Fig. 5- total net coal capacity additions.

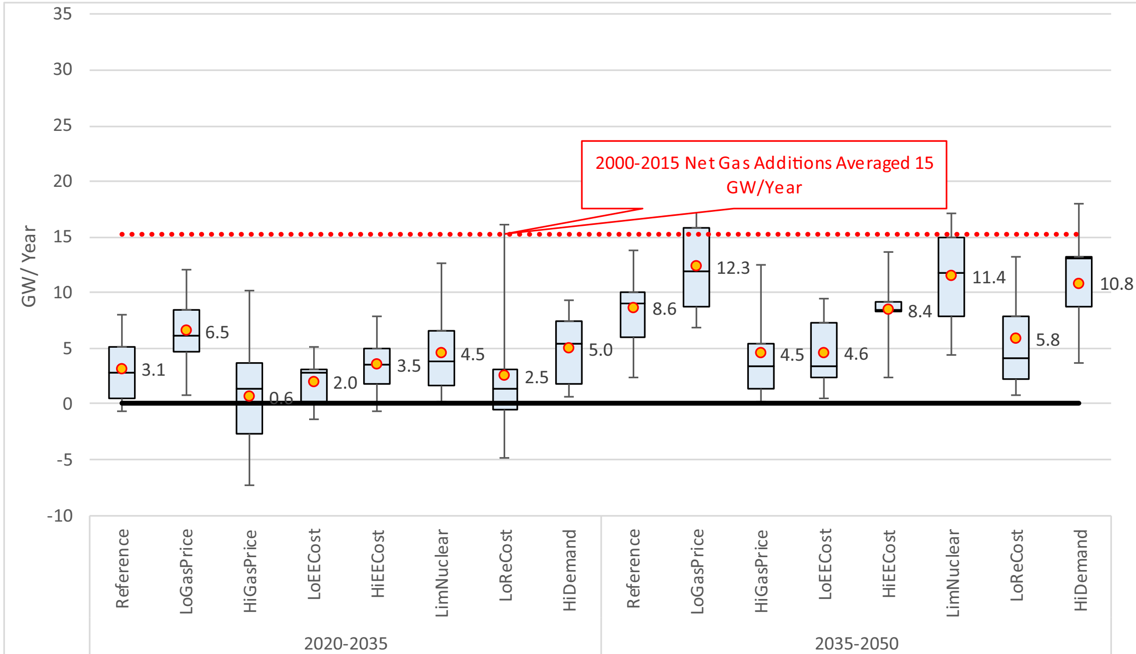

Fig. A6. Alternative view of data in Fig. 7- total net gas capacity additions.

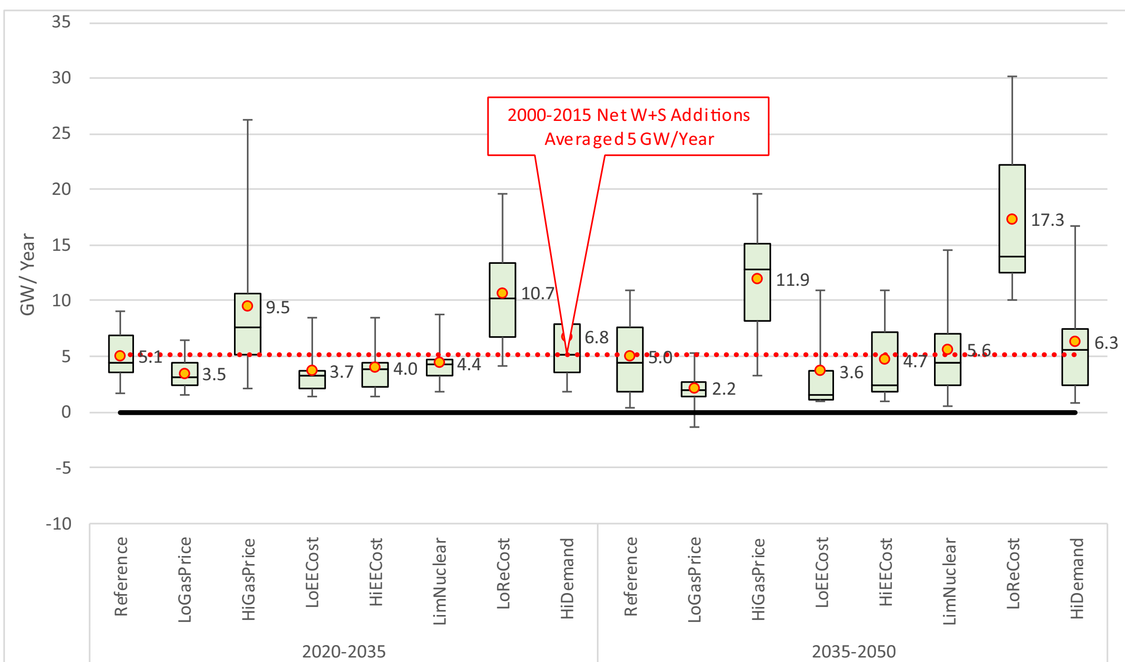

Fig. A7. Alternative view of data in Fig. 9- total net wind & solar capacity additions.

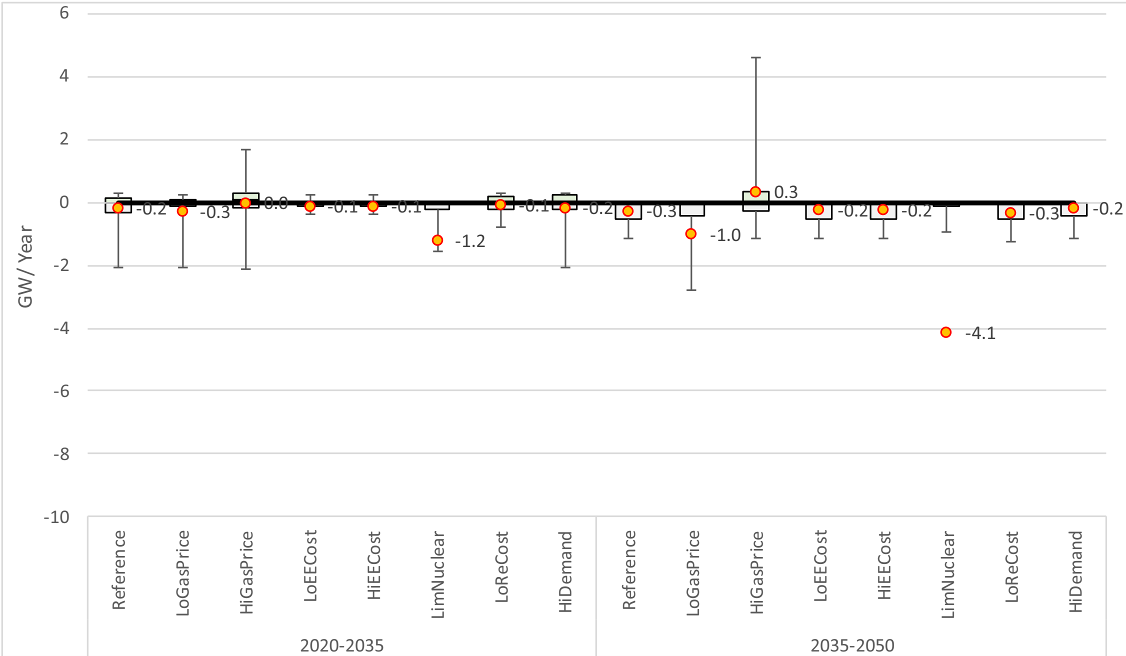

Fig. A8. Alternative view of data in Fig. 10- total net nuclear capacity additions.

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