



Interactions of Multiple Market-Based Energy and Environmental Policies in Transmission - Constrained Competitive National Electricity Markets

Final Project Report

Power Systems Engineering Research Center

*Empowering Minds to Engineer
the Future Electric Energy System*



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Power Systems Engineering Research Center

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Executive Summary

Energy futures for the United States depend critically on the electric power system. Goals of energy independence, cleaner energy sources for industry, commercial and residential uses, as well as transportation, are in great part determined by investment in the future power system. A planning tool that optimizes investment in generation is needed because the electric power industry faces the possibility of increased loads from energy users trying to find cleaner sources of energy, including transportation, renewable portfolio standards, and integration of a smart grid that allows for demand response. These challenges need to be met while maintaining reliability and with a \$1000 bid cap for generators (in areas with markets) that may limit a free market solution for new investment in generation. Both reliability and investment require planning. This report uses an integrated engineering, economic and environmental modeling framework for the electric power system (the SuperOPF Planning Tool), developed with support from the Department of Energy CERTS program. The model maximizes the net expected benefits of electricity production, optimizes investment in new generation, and includes environmental and other regulations and incentives. This report examines alternative futures for the electric power industry for the continental United States over the next 20 years by using the SuperOPF Planning Tool to analyze plausible policy and fuel price scenarios.

This research depends critically on detailed network reductions for the ERCOT (Texas), WECC (Western States), and EI (Eastern Interconnection) systems. To maintain acceptable accuracy in line flows for the Eastern Interconnection needed, for optimal investment in generation, the research showed that a model with more than 5,200 busses was necessary. Since the full EI network is much more tightly connected than the ERCOT and WECC systems, it is expected that the errors in the PF and OPF solutions for the equivalent for EI will be larger than that for the ERCOT and WECC systems when the percentage of buses retained for the equivalent is the same for each model. The results of the model evaluations demonstrated that a 279-bus equivalent for ERCOT has more than acceptable accuracy in terms of both PF and OPF solutions, indicating that even a smaller equivalent would likely be acceptable. For the WECC system, a similar size system, a 300-bus equivalent, is adequate for performing an optimal generation investment study.

To assess the response of long-term generation investment to alternative future natural gas prices, environmental regulations and renewable incentives, studies are conducted using six possible scenarios. Each future (case) consists of three simulation years: 2012, 2022 and 2032, an interval which is based on the assumption that each investment cycle takes ten years and generation is optimized in 2022 and 2032 for conditions in that year. The simulation year 2012 is assumed to have generation as built today.

The cases studied in this report are described as follows. The first case is referred to as the base case. In the base case, no environmental regulation or subsidies for renewable energy are included.

In the second case, a CO₂ emissions price is added to represent a cap-and-trade auction for CO₂. This cap-and-trade auction for CO₂ is assumed to have a price cap similar to that

proposed in the Kerry-Lieberman Bill. This case is referred to as the cap-and-trade (C&T) case. In the C&T case, the CO₂ price starts at 36.94 \$/ton in 2022 and rises to 60.18 \$/ton in 2032, equivalent to the Kerry-Lieberman price cap. Besides modeling CO₂ emissions prices, subsidies for wind and solar generation are included. An incentive of 22 \$/MWh for wind and solar generation is included to model the Federal Renewable Electricity Production Tax Credit [28].

Similar to the C&T case, the third case also includes the production tax credit incentives for wind and solar generation. However, instead of cap-and-trade, the EPA proposed rule aimed at regulating CO₂ emissions from power plants is included, a rule that is expected to be finalized later in 2012. This rule requires all new fossil-fuel-fired generation of 25 MW or larger to emit no more than 1000 lbs. of CO₂ per MWh. Since coal-fired plants cannot meet this standard, the standard effectively prohibits the construction of new coal plants. Therefore, in the third case, no new coal-fired plants can be built in 2022 and 2032. The third case is referred to as the EPA case.

All of the three cases are simulated with two different sets of gas prices, yielding six futures in total. The first set of gas prices is referred to as the high gas price set, which is 2.5 \$/MMBTU in 2012, 7 \$/MMBTU in 2022 and 14 \$/MMBTU in 2032. The low gas price of 2.5 \$/MMBTU modeled in 2012 is based on the current availability of shale gas but it is possible that the costs of extracting shale gas will start to rise by 2022 and so the gas price increases to 7 \$/MMBTU. Then in 2032, the gas price converges to a world price of about 14 \$/MMBTU. The natural gas price of 14 \$/MMBTU may seem large, but the gas price was in the neighborhood of 15 \$/MMBTU in 2005.

The second set of gas prices is referred to as the low gas price set, which is 2.5 \$/MMBTU in 2012, 4.77 \$/MMBTU in 2022 and 5.86 \$/MMBTU in 2032. This set of gas prices is based on estimates by the EIA [27].

Based on the different sets of gas prices used, the scenarios studied can be categorized into two groups. The cases that are run with the high gas price set are referred to as high-gas-price cases (HG) and similarly the cases that run with low-gas-price set (LG) are referred to as low gas price cases.

The results suggest that alternative policies may have very different outcomes in terms of electricity prices and CO₂ emissions that vary across regions of the continental United States.

First consider fossil fuels. For natural gas, only combined cycle plants are constructed across all scenarios with substantial retirements of single cycle plants by 2022. There is no new construction in ERCOT until 2032 and then only in the scenario with low gas prices and cap-and-trade. There is no new gas generation constructed in WECC under any scenario. The EI is a different story with combined cycle plants constructed both under high and low gas price cases for all scenarios in 2022 and 2032 with the most construction occurring under cap-and-trade. However, retirements generally exceed new construction in 2022 but the reverse is true for cap-and-trade in 2032 and more balanced in the other scenarios. Surprisingly, no new coal is constructed in any of the scenarios, even the base case with high gas prices. Retirement of both existing coal (and single-cycle natural gas plants) is accelerated by low gas prices, the production tax credit for

wind and solar, and by cap and trade. No new oil units are built and retirements are substantial over the 20-year time horizon of the study.

For renewables, wind and solar are encouraged by high gas prices, cap-and-trade, and the production tax credit. No wind is retired under any of the scenarios. In ERCOT, wind is added by 2022 in all but the low gas price base case, but more is added in all cases by 2032. For WECC, wind is added in all cases, mostly by 2022. For the EI there are very large additions under all scenarios, mostly in Kansas and Oklahoma, but some additions in all states except Florida. Note that the model assumes that the existing high voltage network is in place with no new high voltage lines. The geographic distribution of additional wind is likely to change if new high voltage lines are put in place. For solar, by 2022, small amounts are constructed in ERCOT only if cap and trade is implemented, and small amounts are constructed in WECC only in the high gas, cap-and-trade scenario. But, surprisingly, by 2022 in the EI solar is constructed in all cases except the low gas price base case. In the EI by 2032 solar is added in all cases, but the most is added in cases with the production tax credit. Solar investment occurs mostly in Florida, but with the production tax credit, solar is built throughout the southeast. It should be noted that, though no nuclear construction takes place by 2022, substantial nuclear construction takes place by 2032, but only with high gas prices and cap-and-trade. Thus, policies can change how much new generation is built, what types of plants are built, and what types of plants are retired.

Across all regions, electricity prices are highest under cap-and-trade combined with high natural gas prices and lowest with the production tax credit for wind and solar combined with low natural gas prices. CO₂ emissions are lowest with low natural gas prices combined with cap-and-trade and the production tax credit for wind and solar, and highest with high natural gas prices under the base case.

A number of caveats are important in interpreting these results. First, the model assumes that a smart grid is in place in 2022 and 2032 that allows demand response. Second, capital costs are estimated far into the future and, for example, while the costs of wind are well understood, recent cost decreases for solar may, or may not, continue. This study assumes that they do. Similarly, there are several technologies proposed that may lower the costs of nuclear plants. If that were to occur, and nuclear became politically feasible, the results would be quite different than those shown here.

Finally, this study represents the first step in making the SuperOPF Planning Tool publically available as open source software similar to MatPower, since the tool has now been used at both Arizona State and at Wichita State to analyze energy futures for ERCOT and WECC respectively for this report.

Project Publications:

J. Taber, D. Shawhan, R. Zimmerman, C. Marquet, M. Zang, W. Schulze, R. Schuler, S. Whitley, "Mapping Energy Futures Using The SuperOPF Planning Tool: An Integrated Engineering, Economic and Environmental Model," HICSS 46 Proceedings, Jan 2013.

D. Shi, D. J. Tylavsky, "An Improved Bus Aggregation Technique for Generating Network Equivalents," 2012 IEEE Power Engineering Society General Meeting, San Diego, CA.

Y. Qi, D. J. Tylavsky, "Impact of Assumptions on DC Power Flow Accuracy," North American Power Symposium 2012, Champaign Illinois, Sep. 2012, pgs. 6.

N. Li, D. Shi, D. Shawhan, D. J. Tylavsky, J. Taber, R. Zimmerman, "Optimal Generation Investment Planning: Pt 2:, Application to the ERCOT System," North American Power Symposium 2012, Champaign Illinois, Sep. 2012, pgs. 6.

D. Shi, D. Shawhan, N. Li, D. J. Tylavsky, J. Taber, R. Zimmerman, "Optimal Generation Investment Planning: Pt 1:, Network Equivalents," North American Power Symposium 2012, Champaign Illinois, Sep. 2012, pgs. 6.

Z. Hu, W. T. Jewell, "Optimal Power Flow Analysis of Energy Storage for Congestion Relief, Emissions Reduction, and Cost Savings," *2011 Power Systems Conference and Exhibition*, Phoenix, March 2011.

Student Theses:

John Taber, *Essays on Carbon Abatement and Electricity Markets*, PhD thesis at Cornell University, Aug. 2012.

Di Shi, *Power System Network Reduction for Engineering and Economic Analysis*," PhD thesis at Arizona State University, Aug. 2012.

Nan Li, *A Modified Ward Equivalent of ERCOT for Power System Planning Studies*, Masters of Science thesis at Arizona State University, expected in Dec. 2012.

Zhouxing Hu, *Optimization of Electric Power System Operation with Renewables and Energy Storage*, PhD thesis at Wichita State University, expected in December 2012.