DOE Quadrennial Energy Review

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Department of Energy
Quadrennial Energy Review

Second set of Comments of the Edison Electric Institute

Executive Summary

The Edison Electric Institute (EEI), on behalf of its member companies, hereby respectfully submits these comments, and accompanying materials, in response to the Department of Energy's (DOE) Quadrennial Energy Review (QER). EEI filed an initial set of comments on June 10, 2014 (Initial Comments); this additional set is intended as a supplement. As stated by DOE, the QER is intended to provide a multiyear roadmap that outlines federal energy policy objectives, legislative proposals to Congress, Executive Branch actions, an agenda for research, development and demonstration (RD&D) programs and funding, and financing and incentive programs. The first phase of the QER is focused on transmission, storage, and distribution (TS&D) with a report due in January, 2015.

EEI has observed numerous regional QER public meetings, and acknowledges the opportunities, challenges, and many stakeholders engaged, in this process. This additional set of comments is intended as a response to some, but not all, views shared throughout the public meeting process. Additionally, these comments are, in part, in response to other efforts currently under way at DOE in parallel or in conjunction with the QER process.

Consistent with our Initial Comments, given the QER's initial focus on TS&D, the use of the "the Grid" addresses the non-supply portions of the Grid, principally the infrastructure impacting the safe, reliable, secure, and economical delivery of electric service. However, as illustrated by our Initial Comments, it is impossible to discuss the nature of electricity delivery in isolation from production and consumption. In general, the Grid is a complex and highly integrated network, comprised of generation, transmission, distribution, and consumption--because electricity must be produced and consumed simultaneously.[1] Technological changes, combined with changing customer preferences call for an even higher level of Grid integration than we have today.

As noted in our Initial Comments, EEI believes that the traditional flow of power from centralized generation resources through bulk transmission and distribution infrastructure to load will continue to be a predominate supply for our nation's electricity needs, providing the foundation to both access diverse generation resources and transition to new technologies. As the penetration of DER increases, the Grid will evolve to accommodate two-way power flows across the distribution and bulk power systems. The emerging mix of central station generation (renewable, fossil and nuclear generation) and distributed energy resources (DER) will require an integrated Grid as the Electric Power Research Institute (EPRI) envisions.[2]

Grid improvements continue to be made to address our country's needs: modernizing infrastructure to include technology innovations, improving resiliency, implementing public

[1] Storage is discussed later in these comments.
[2] *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, EPRI, February 2014.

policy requirements, addressing environmental concerns, responding to emerging physical and cyber threats, and meeting changing customer expectations.

EEI members are proactively engaged in efforts to reliably, safely, and cost-effectively integrate the Grid. This set of comment continues to espouse the following tenets, highlighted in our Initial Comments. The QER process must:

- Recognize the value of the Grid
- Recognize that the safety and security of the Grid to maintain reliability is best addressed through coordinated industry actions, industry-government partnerships, and recognition of federal and state authorities.
- Preserve policies that encourage investment, mitigate risk, and provide regulatory certainty.
- Recognize jurisdictional boundaries and the role that utilities are legally obligated to perform in the states.[3]
- Ensure all beneficiaries of the Grid pay their fair share.

EEI Initial Comments specifically recommended that:

- The industry, along with federal and state regulators, will continue to focus on innovative utility rate design models as appropriate, subject to jurisdictional approvals.
- Federal officials should seek to enhance tax provisions and other federal programs to ensure consistent funding for long-term plans, particularly for extreme (or extreme weather) events.
- Federal and state governments, utilities, and other grid operators should explore new and/or improved opportunities to increase bi-directional, confidential information

[3] *See* Federal Power Act, Section 201. In addition, there are numerous state and local statutes governing utility franchises and operations.

sharing regarding potential cyber and physical security threats. Solutions should seek to reduce liabilities associated with information sharing.

- Wholesale electricity markets should continue to promote reliability and fuel diversity.

- Regulatory certainty must be provided to assure needed grid investments are made and emerging technologies are reliably integrated into the Grid.

Based on the QER process to-date, EEI also makes the following recommendations:

- Recommendations made as a result of the QER process should be thoroughly assessed by states, regulators, and industry stakeholders to avoid unintended and costly consequences; this includes a full, fair, and inclusive analysis of costs and benefits of each recommendation.

- DOE and policy makers must recognize jurisdictional boundaries. Utilities are required to provide distribution service under existing state and local franchise agreements and are best positioned to safely provide reliability, power quality, and cost effective service.
  - Incumbent utilities are best positioned to incorporate DER at strategic locations on the Grid by optimizing the overall investment and system impacts.
  - Utilities should be allowed to compete in evolving markets, including those for DER; in this context, utilities should also be allowed to engage in business partnerships with unaffiliated third parties.
  - Utilities will continue to work with regulators to develop new and flexible business models, where necessary.

- DOE should recognize the significant activity that is occurring to resolve gas-electric coordination issues and allow the industries, regions, FERC, and states to continue to evaluate the issues and implement changes as needed.

- Coal generation depends heavily on rail deliveries, which can in turn, affect fuel stocks and reliability. DOE should work with the Surface Transportation Board (STB) to encourage sufficient rail infrastructure to move all necessary traffic, enhance rail competition, and enhance rail system transparency to better optimize supply chain and system operations.

- DOE, in collaboration with states, regulators, and the industry, should work together to understand how increased penetration of DER and microgrids will affect the bulk and local distribution electric grids. Cost effectiveness, efficiency and reliability of the Grid under varying penetration scenarios should be studied. These efforts should, among other things:

- Identify the characteristics in which DER and microgrids can be best integrated with the Grid, provide the greatest benefit, and warrant increased costs.
- Reduce or eliminate the negative power quality impacts/characteristics of distributed generation systems on the distribution grid.
- Improve the ability of DER and customer-side end-use equipment to handle normal variations that occur with power supply to make the distribution grid more stable.
- Study best practices for optimal integration of intermittent DER, energy efficiency, demand response, and storage with the Grid.

- The federal government should continue its efforts to substantially improve the overall quality and timeliness of the existing federal permitting process for electric transmission infrastructure on federal lands, and to codify and uniformly apply those improvements.
  - The Federal Government should continue to improve the Integrated Interagency Pre-Application Process (IIP).
  - Federal agencies should accept currently proposed Best Management Practices as effective conservation measures.
  - DOE and the other involved federal agencies should consult with EEI member companies, states, regulators, and other stakeholders to designate additional corridors under the Energy Right-of-Way Corridors on Federal Land Section 368 of the Energy Policy Act of 2005 (EPAct 2005) to meet the intent of Congress.
  - Federal agencies responsible for transmission permit approvals should evaluate federal staff expertise to ensure that transmission experts are available to ensure timely processes.
  - DOE and our international neighbors should continue to work to align their permitting requirements and processes for cross-border power lines and electricity exports.

- Policymakers should ensure a fair playing field by embracing the same pricing and planning approaches for both traditional and new technologies such as DER.

- Cost-competitive storage applications capable of sustained, long-term performance are necessary. DOE and the industry should continue research and collaboration to develop advanced storage applications. Research that focuses on reducing costs, improving performance (in terms of cycles of operation, longevity, durability, etc.), and addresses environmental issues associated with battery technologies (e.g. safe disposal and recycling), will provide the most value.

I. Recommendations made as a result of the QER process should be thoroughly assessed by states, regulators, and industry stakeholders to avoid unintended and costly consequences.

EEI strongly recommends that any policy recommendations made as a result of the QER be well thought out and thoroughly assessed by states, regulators, and industry stakeholders to avoid unintended and costly consequences. All policy recommendations made as a result of the QER should appropriately evaluate costs, benefits, and feasibility. Many feasibility studies have been produced on a single policy goal or wide adoption of a technology, without evaluation of system-wide or associated cost impacts. While feasibility studies are a step in the right direction, decision makers should have the most complete set of facts possible on which to make policies that drive long-lived capital investments. Because of the complex and interconnected nature of our energy system, changes to one aspect of the network system could have unintended consequences on another. To the greatest extent possible, policy makers should endeavor to fully consider all impacts of proposed policy.

Regardless of the business model, the electricity industry constantly balances costs and benefits; policy makers must also do the same. At the end of the day, it is critical to work together to find simultaneous solutions that minimize costs, maximize reliability, and minimize environmental damage.

Recommendations should include an evaluation of costs and benefits. Throughout the regional QER meetings, investor owned utilities, electric cooperatives, public power, and state commissioners emphasized that costs to customers matter; costs for customers must remain as low as possible. As noted at the New Jersey regional meeting, "we need to keep the face of families that make hard kitchen table decisions as the face of our customers." [4]

For example, a study by the National Renewable Energy Laboratory (NREL) concluded that renewable energy could supply about 80% of electric demand by 2050.[5] However, neither associated costs, nor an assessment of impacts on reliability, nor a comparison of costs and benefits was provided. NREL recognizes that additional work needs to be done, but these limited reports are nonetheless influencing policy and public opinion today and could result in unintended consequences.

For example, as a result of several factors, including regulation, the U.S. is facing a less diverse generation portfolio. When comparing the costs and benefits of today's generation portfolio with a less diverse portfolio, IHS Energy found that power price impacts would reduce U.S. Gross Domestic Product (GDP) by nearly $200 billion, lead to roughly one million fewer jobs, and reduce the typical household's annual disposable income by around $2,100. Thus, "these negative economic impacts are similar to an economic downturn."[6]

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[4] Tom Fanning, Chairman, President and CEO, Southern Company.

[5] M. Milligan, E. Ela, J. Hein, T. Schneider, G. Brinkman, and P. Denholm, "Bulk Electric Power Systems: Operations and Transmission Planning," NREL/TP-6A20-52409-4, 2012. Vol. 4 of Renewable Electricity Futures Study, Golden, CO: National Renewable Energy Laboratory. Available: http://www.nrel.gov/docs/fy12osti/52409-4.pdf

[6] In this less diverse scenario, called the *reduced diversity case,* wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas–fired power plants account for the remaining 61.7% of installed capacity and 73.7% of

EEI strongly urges that recommendations made as a result of the QER provide policy makers with the most complete knowledge possible. For example, while there is a push for rooftop solar, the numbers demonstrate that community and grid level solar are more cost effective.[7] As Mr. Hallquist shared at the New Jersey Regional Meeting, despite state regulators' preference for rooftop solar, Vermont Electric Cooperative is pursuing a community solar program that will cost half the amount of the rooftop solar program. Thus, societal goals can be met cost-effectively.

Proper, detailed assessments and quantifications will help us to reach our societal goals while ensuring safe, reliable, cost-effective energy for our citizens and economy.

II. Reliability

EEI envisions continued significant growth in wind and solar generation, including customer-owned behind-the-meter resources, combined with the anticipated continued shift toward natural gas-based generating facilities and retirement of many large baseload, coal-fired generating facilities. In addition, some areas of the country rely on considerable amounts of

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generation. IHS: US Power Diversity Special Report, July 2014. Lawrence. J. Makovich, Aaron Marks, Leslie Martin. Available at: http://www.ihs.com/info/0714/power-diversity-special-report.aspx

[7] Based on current prices, DER are associated with higher capital and installation costs on a per-kilowatt KW basis than larger centralized resources. For example, according to a recent study by GTM Research and the Solar Energy Industries Association, in the first quarter of 2014, the average installed system price of solar PV was: $3.73/watt for residential rooftop, $2.53/watt for commercial rooftop, and $1.77/watt for utility scale. Solar Energy Industries Association. (2014). *U.S. Solar Market Insight Report, Q1 2014, Executive Summary*. Retrieved from: http://www.seia.org/research-resources/us-solar-market-insight. PV cost studies generally find that utility-scale systems might cost roughly half as much, or even less, compared to much smaller rooftop systems. *A Review of Cost Comparisons and Policies in Utility-Scale and Rooftop Solar Photovoltaic Projects,* NRRI, June 2014. Retrieved from: http://www.nrri.org/documents/317330/b549f302-f563-437f-87b7-36c7dc06d989?version=1.1

customer demand response. Since the economic viability of wind and solar resources varies considerably, natural gas pipelines have targeted delivery systems, and anticipated coal generation retirements differ across regions, changes in the patterns of production, consumption, and electricity flows are not uniform throughout the country.

Regardless of how these patterns evolve over the next several years, the types of business models used, or federal or state policy decisions that take place, EEI strongly believes that customers will continue to express their increasingly higher expectations for reliability service levels depended upon by residential customers and various industries including manufacturing, communications, and transportation, as well as commercial activities. The electricity industry continues to make strong commitments to satisfy these rising customer demands. Planning and operations experts must ensure that the constantly changing combinations of resources and customer demands remain in balance within extremely tight tolerances in real time. Now and going forward, companies must be able to invest and recover their investments in transmission and distribution assets with capabilities to perform under a much wider range of operating tolerances in anticipation of a broader set of potential operating conditions.

Several strong structural tools exist for reliability. For the bulk power system, Section 215 of the Federal Power Act (FPA) authorizes the Federal Energy Regulatory Commission (FERC) to approve and oversee the enforcement of mandatory reliability standards. Since 2007, FERC-approved reliability standards have been in place and actively enforced.[8] Accordingly, bulk power system performance remains very high.[9]

Distribution-level reliability and service quality matters are addressed for the most part at the state and local level. Investor-owned utilities must comply with service requirements imposed by state utility regulatory commissions. Customer-owned or cooperative utilities, and municipal utilities, may impose their own service quality requirements. In most states, customer service requirements are embedded within tariffs. In addition, and since distribution-level reliability depends to a very large extent on weather-related events --- hurricanes, tornadoes, ice storms, severe thunderstorms or wind --- there may also be specific provisions to address service restoration.[10]

III. Interdependencies

A. Gas-Electric Fuel Interdependencies

EEI appreciates DOE's consideration of the issues related to electric and natural gas interdependencies as part of its QER process. As noted in the DOE background memo and by the speakers at the QER Regional Public Meetings, the increased use of natural gas by electric

[8] For a more detailed description of compliance and enforcement activities, see NERC Compliance Monitoring and Enforcement Annual Report 2012 available at http://www.nerc.com/pa/comp/Reports%20DL/2012_CMEP_Report_Rev1.pdf.

[9] See NERC State of Reliability Report, 2014 available at http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf.

[10] The NERC State of Reliability Report underscores also the strong influence of weather events on bulk power system performance. During 2008-2013, the top ten reliability events in this country were caused by severe weather.

utilities due to lower natural gas prices, the retirement of coal plants, various environmental regulations, and the need for fast-ramping natural gas power plants to back up variable resources has placed a new focus on the interdependence between electricity and natural gas.[11]

It is important to note that the need for, the accessibility to, and the impacts of the increased use of natural gas in electric generation are not uniform across the country. There are regional differences in fuel diversity (including dual-fuel capability), the use of firm or interruptible pipeline capacity by electric generators, gas pipeline capacity availability and flexibility, natural gas storage availability, and communication protocols. Additionally, potential reliability impacts or system vulnerabilities will continue to change as the generation fuel mix changes in the various regions.

The FERC has been working on gas-electric interdependency issues, and the North American Electric Reliability Council (NERC), as well as the different regional transmission organizations (RTOs) and independent system operators (ISOs) have studied the adequacy of the natural gas infrastructure system to ensure that electric reliability is maintained when natural gas use for power generation increases. Significant FERC activity began on this issue in August 2012, when FERC held five regional forums to discuss electric/gas coordination issues. The regional conferences highlighted the regional nature of these issues. Since that time, FERC

[11] Memo dated July 24, 2014, to Members of the Public, From Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, United States Department of Energy, Re: July 28 Stakeholder Meeting on Natural Gas – Electricity Interdependence. Retrieved from: http://energy.gov/sites/prod/files/2014/07/f17/qermeeting_denver_backgroundmemo.pdf

has been working to address issues that may be more national in nature while encouraging the various regions to identify and address any issues that they may have.

FERC issued Order No. 787 in November 2013.[12] Through this order FERC sought to improve and clarify the types of communications that could occur between interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce. This order was used by RTOs/ISOs during the cold weather events in January and February 2014 to facilitate communications.

As discussed by the participants at the FERC meeting held on July 28, 2014, FERC has turned its attention to natural gas and electric scheduling, and issues related to whether and how natural gas and electric industry schedules and practices could be harmonized to achieve the most efficient scheduling systems for both industries.[13] Stakeholders will be filing comments in response to the FERC proposal on November 28, 2014.

The ability of the nation's natural gas infrastructure (pipeline, storage, markets) to deliver natural gas where and when it is needed by electric generators in some areas is an issue of serious concern for electric regulators. This issue, along with other issues related to infrastructure adequacy and flexibility, are being discussed at the regional level and at FERC. The following are some of the RTO/ISO groups that have been formed to discuss regional issues and solutions:

- New England States Committee on Electricity (NESCOE) Gas-Electric Focus Group – Final Report issued March 31, 2104
- ISO NE Electric – Gas Operations Committee

[12] Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators, 145 FERC ¶ 61,134, Order No. 787 (November 15, 2013).
[13] *See* Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, 146 FERC ¶ 61,201 (2014).

- NY ISO Electric – Gas Coordination WG
- MISO Electric – Natural Gas Coordination Task Force
- PJM – Gas-Electric Senior Task Force
- SPP Gas – Electric Coordination Task Force

Due to the interconnected nature of the electric and natural gas systems, regional studies, in addition to the RTO/ISO activities, are also being conducted to determine what needs to be done to maintain reliability going forward. Generally, most of these studies are examining issues such as the existing natural gas and electric system infrastructure, what is the capability of the natural gas system to meet the needs of the electric system now and going forward, and what are the contingencies on the natural gas system that could adversely affect electric and gas system reliability. Some of these activities are:

- EIPC – Eastern Interconnection Planning Collaborative
- EISPC – Eastern Interconnection States Planning Council
- Western Governors Task Force/ Western Interstate Energy Board – Phase 2 Report issued July 30, 2014
- Desert Southwest Pipeline Stakeholders
- Northwest Mutual Assistance Agreement
- PNUCC – Pacific Northwest Utilities Conference Committee
- Columbia Grid

DOE has also funded a continuation of the EIPC which is currently evaluating the adequacy of the gas system to meet electric reliability needs, and vice versa. The targeted completion date for this study is mid-2015. While the results of this analysis are unknown, working through the process it appears clear that there are numerous challenges and assumption necessary to model potential cross-system impacts over the 2018 and 2023 study horizon. Accordingly, the results may not be a conclusive representation of the issues that regions must address. However, the analysis should aid regional stakeholders in evaluating potential gas/electric infrastructure issues, and therefore provide value. DOE should continue to support the continued efforts of FERC and geographic regions in their ongoing evaluation of the issues and implementation of changes as needed.

DOE could help inform long-term planning by assessing the benefits of a diverse portfolio structure, or the vulnerabilities of a lack thereof. Specifically, the study could examine the reliability, vulnerability, and resiliency impacts of relying too heavily on one fuel over another, across regions. In addition, DOE may consider continued funding and support of inter-regional gas/electric infrastructure planning studies to aid regional stakeholder processes.

B. Coal and Rail Interdependencies

Coal generation provides significant reliability benefits, as it is one of the few generation sources able to store significant amounts of fuel on site. However, there is a significant interdependence between coal and rail car service, which must be reliable. If rail service is compromised, fuel inventories can fall rapidly, eroding the reliability advantage. Rail capacity appears to be reaching a limit, as it provides delivery for many products including oil produced in North Dakota, crops, and other manufactured products.

Many coal generation units across the country are now facing compromised rail service due to lack of rail car capacity, which was amplified during the extreme weather experienced in the 2013/14 winter. Data from the Energy Information Administration (EIA) found that coal stocks dropped by more than one-fifth from July 2013 to July 2014. Further, EIA found that more than three-quarters of the total non-lignite capacity in the U.S. was under 60 days of burn

26.5 percent of capacity was at less than 30 days and 50.7 percent was between 30 to 60 days of burn).[14]

Reduced rail service results in diminished fuel stock, mothballed or idled facilities, or sub-optimal generation levels to conserve fuel. For example, Minnesota Power idled four generators for three months in 2014 because rail could not deliver enough coal.[15] As another example, in March 2014 Wisconsin Public Service Corporation instituted coal conservation measures- the fuel inventory did not significantly recover for several months.[16] Both examples of coal conservation measures increased costs for customers.

Quality of rail service is not a new issue. Utilities experienced similar service disruptions in 2006. That year, both the Senate Committee on Energy and Natural Resources and FERC held hearings to discuss the issue.[17] The most recent rail service problems have attracted executive and legislative attention again. The Surface Transportation Board (STB) opened a docket (Ex Parte No. 724) to consider rail service issues and held public hearings in Washington, DC and Fargo, North Dakota. [18] The Senate Commerce Committee held a hearing as well.[19]

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[14] EIA Electricity Monthly Update, Data for July 2014; September 25, 2014; http://www.eia.gov/electricity/monthly/update/archive/september2014/fossil_fuel_stocks.cfm

[15] http://www.marketplace.org/topics/business/rail-delays-shut-down-midwestern-power-plants

[16] *See* Written Comments of Dave Wanner – Wisconsin Public Service Corporation, 2014 QER August 8th Public Meeting In Chicago – Rail Infrastructure Presentation. Retrieved From: http://energy.gov/sites/prod/files/2014/08/f18/chicago_qermeeting_wanner_statement.pdf

[17] Full Committee Hearing: "Coal-Based Generation Reliability" May 25, 2006 http://www.energy.senate.gov/public/index.cfm/hearings-and-business-meetings?ID=c30108b1-0b1a-41fc-a66c-a3849ed54c60; FERC Docket No. AD06-8-000, "Discussions with Utility and Railroad Representatives on Market and Reliability Matters" June 15, 2006

[18] STB EP-724 Public Hearing, Washington, DC April 10, 2014, http://www.stb.dot.gov/TransAndStatements.nsf/8740c718e33d774e85256dd500572ae5/a3e019b85169e49285257d27006bc689/$FILE/final%20transcript%20for%20April%2010%202014-%20EP-724.pdf; Public Hearing, Fargo, ND September 4, 2014.

EEI, in conjunction with the Consumers United for Rail Equity (CURE), which represents a broad coalition of railroad customers representing a range of U.S. manufacturing, agricultural, and energy industries, sent a public letter to members of Congress highlighting the need for rail policy modernization. The letter contains specific policy recommendations related to enhanced efficiency of STB operations, reforms to rate challenge procedures, and removal of barriers to rail competition. The letter and these recommendations are attached to these comments.[20] Many of these suggestions were adopted by Senate Commerce Committee Chairman Jay Rockefeller and Ranking Member John Thune in their bill – S.2777, the Surface Transportation Board Reauthorization Act of 2014 – which passed the Committee in September 2014.

In addition to these suggested reforms and paying special attention to rail delivery issues of coal used for electric generation, EEI recommends that the QER advocate for reliable generation service and adequate coal feedstock by encouraging:

- Sufficient rail infrastructure to move all necessary traffic.
- Enhanced rail competition.
- Enhanced rail system transparency to better optimize supply chain and system operations.

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[19] Senate Committee on Commerce, Science & Transportation; "Freight Rail Service: Improving the Performance of America's Rail System," September 10, 2014 http://www.commerce.senate.gov/public/index.cfm?p=Hearings&ContentRecord_id=4ed919c1-31c2-4ce7-b641-6e3b70bf7b0d&ContentType_id=14f995b9-dfa5-407a-9d35-56cc7152a7ed&Group_id=b06c39af-e033-4cba-9221-de668ca1978a

[20] Letter to Majority Leader Harry Reid, Minority Leader Mitch McConnell, July 10, 2014 http://www.americanchemistry.com/Policy/Rail-Transportation/Joint-Shipper-Letter-Urging-Congress-to-Act-on-Freight-Rail-Reform.pdf

C. Environmental Protection Agency 111(d)

The U.S. Environmental Protection Agency (EPA) issued proposed guidelines pursuant to Clean Air Act Section 111(d), as part of the Clean Power Plan and expects to issue a final rule in June 2015.[21] The industry, states and stakeholders are analyzing the draft guidelines. The full extent is not yet known but it is clear that the guidelines are likely to have broad impacts on infrastructure needed at the electric generation and transmission level as well as on gas supply and transportation infrastructure. Early review indicates the proposed guidelines may also significantly impact organized electricity markets operated by RTOs and ISOs.

Beyond permitting and siting of projects on federal lands, including presidential permits, DOE actions related to development of infrastructure related to the implementation of 111(d) may be limited in scope.[22] However, DOE and other federal agencies with authorities over permitting/siting on federal lands and specific aspects of permitting certain projects (e.g., the U.S. Forest Service (USFS), Fish and Wildlife Service, and National Park Service (NPS)) have important roles to play. In particular, the speed with which transmission permitting and siting is completed by federal agencies and the states will be paramount in implementation of EPA's proposed rule. As currently proposed, compliance is required beginning in 2020. The average 7-10 years to plan, permit, site, and build interstate transmission, presents significant

[21] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units: issued by the EPA pursuant to section 111(d) of the Clean Air Act (CAA). 79 *Fed. Reg. 34830* (June 18, 2014).

[22] However, the QER and DOE have opportunities to "assess and recommend priorities for research, development, and demonstration programs to support key goals; and identify analytical tools and data needed to support further policy development and implementation." Retrieved from: http://www.whitehouse.gov/the-press-office/2014/01/09/obama-administration-launches-quadrennial-energy-review

challenges to infrastructure development necessary to meet compliance requirements of the proposed rule.[23]

EEI recommends that DOE pursue specific actions to improve the siting process as discussed in these comments.

IV. Transmission

The QER has identified transmission expansion as critical to meeting the President's and the nation's energy goals.[24] Transmission will be needed to move renewable energy from new resource centers in the Midwest and Central United States to more populated demand centers along both coasts.[25] As noted throughout the QER process, while states have primary transmission siting and permitting authority, numerous federal agencies also play a role in transmission siting.[26] EEI supports the Institute of Electrical and Electronics Engineers's (IEEE's) Report to DOE QER on Priority Issues (IEEE Report) findings that expanded transmission is "an

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[23] As discussed later in these comments, permitting and siting of transmission lines on federal lands can take well beyond 10 years for completion.

[24] E.g., Memo for the Stakeholder Meeting on Infrastructure Siting, dated August 20, 2014, to Members of the Public from the Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, U.S. Department of Energy. Retrieved from: http://energy.gov/sites/prod/files/2014/08/f18/Cheyenne%20briefing%20memo%20Revised%208%2020%2014%20FINAL%20%283%29.pdf

[25] E.g., Memo for the Stakeholder Meeting on State, Local and Tribal Issues, dated August 6, 2014, to Members of the Public from the Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, U.S. Department of Energy. Retrieved From: http://energy.gov/sites/prod/files/2014/08/f18/20140808%20State-Local-Tribal%20Memo%20Final.pdf

[26] States retain the primary transmission siting jurisdictional authority, while the Federal Government has transmission siting jurisdictional authority on federal lands. The Federal Government has multiple agencies with differing responsibilities related to the permitting process. See, for example: Memo to Members of the Public, From: Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, U.S. Department of Energy, Re: Stakeholder Meeting on Infrastructure Siting. *Id.*

essential step in integrating increasing levels of intermittent renewables" and that "increased transmission connectivity among neighboring and distant regions" is needed.[27]

Our flexible system has "enabled grid operators to adjust smoothly and efficiently to unexpected yet ongoing changes in the relative prices of generation fuels, diverse renewable resource profiles, economic volatility, new environmental requirements, unanticipated outages of major generation and transmission facilities, and natural disasters."[28] This flexibility will be critical in meeting national energy goals, accommodating a greener fleet, and increased resiliency for unforeseen events.

The electric industry needs the expeditious cooperation of the federal government to meet national policy goals and objectives by ensuring timely permitting and siting of transmission projects on federal lands. As stated by Patrick Reiten, President and Chief Executive Officer, Pacific Power at the regional Portland QER meeting, "Turning to transmissions siting and permitting. Simply put, we need federal agencies to truly work together to assure consistent application of permitting requirements."[29]

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[27] IEEE Report to DOE QER on Priority Issues, September 5, 2014. Retrieved from: http://ieee-pes.org/final-ieee-report-to-doe-qer-on-priority-issues

[28] Draft for Public Comment: National Electric Transmission Congestion Study, August 2014. Retrieved from: http://www.energy.gov/sites/prod/files/2014/08/f18/NationalElectricTransmissionCongestionStudy-DraftForPublicComment-August-2014.pdf

[29] *See:* Page 41 of Transcript of: QUADRENNIAL ENERGY REVIEW PUBLIC MEETING #5: Electricity Transmission, Storage and Distribution – West, Friday, July 11, 2014. Portland, Oregon. Retrieved from: http://energy.gov/sites/prod/files/2014/08/f18/transcript_portland_qer.pdf

A. Federal Permitting and Siting Issues

EEI and its members strongly encourage the Federal Government to continue its efforts to substantially improve the overall quality and timeliness of the existing federal permitting process for electric transmission and energy infrastructure, and to codify and uniformly apply those improvements using the authority granted to the Department of Energy by EPAct 2005 section 216(h) in the Energy Policy Act of 2005. Strong leadership is needed from and across the federal agencies, as well as effective communication to field offices, in order to prioritize, communicate, and uniformly implement national goals. EEI and its members encourage federal agencies to equitably share the responsibility with states and industry stakeholders for meeting national goals and requirements by establishing and codifying agency goals in the federal public land siting and permitting processes that are measurable, accountable, and reported. EEI strongly encourages federal agencies to continue working collaboratively with states, local interests, and industry to develop flexible mechanisms to meet local, state, regional, and federal goals. EEI also encourages federal agencies to examine federal staffing levels and expertise to ensure that its workforce can make decisions on a timely basis in the face of sweeping infrastructure changes.

B. Current Federal Initiatives

EEI commends the administration for initiatives in recent years to create a more efficient, consistent, and transparent federal permitting and review process for energy infrastructure, such as the Rapid Response Team for Transmission (RRTT), Executive Order

13604: *Improving Performance of Federal Permitting and Review of Infrastructure Projects*, and the Interagency Steering Committee on Federal Infrastructure Permitting and Review Process Improvement. These efforts should continue to be results-oriented at all levels of the federal government. However, more work needs to be done. Even as the need for new and upgraded transmission facilities has accelerated (e.g., to connect remote wind and solar resources to cities and other load centers), obtaining federal permits for the facilities has become more difficult and time consuming. Federal approvals for energy infrastructure are time intensive and create considerable uncertainty, making it difficult for utilities to secure adequate financing on reasonable terms and to ensure timely build out of needed infrastructure. An example is Gateway West, now entering its eighth year of federal permitting, with two more years needed to complete a Supplemental Environmental Impact Statement (EIS) for the two remaining segments in Idaho.[30] Another example is the Mountain States Transmission Intertie (MSTI), which was ultimately canceled for a number of reasons, including an EIS scoping process without measurable goals; the write-off for this project was $24 million.[31]

In many cases, federal permit decisions for transmission projects lag behind siting and permitting decisions at the state level, complicating the siting process and significantly delaying

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[30] See Memo dated August 20, 2014, to Members of the Public from Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, U.S. Department of Energy, Re: Stakeholder Meeting on Infrastructure Siting at FN 4: The multistate Gateway West transmission in the northwest was first proposed in 2007. The Bureau of Land Management released its record of decision in November 2013 on the siting of the line for eight of the ten segments involving federal land segments. A decision on the remaining two segments has not been reached yet. One estimate is that the line will not be in operation until 2023. Retrieved from: http://energy.gov/sites/prod/files/2014/08/f18/Cheyenne%20briefing%20memo%20Revised%208%2020%2014%20FINAL%20%283%29.pdf

[31] See documents submitted and presented by Michael Cashell, Vice President- Transmission, NorthWestern Energy- Presentation for the QER Public Meeting In Cheyenne, WY: Infrastructure Siting, held August 21, 2014. Retrieved from: http://energy.gov/sites/prod/files/2014/09/f18/cashell_presentation_qer_cheyenne.pdf

construction of important facilities. Many of the state and local permitting processes depend on the results of federal permitting, which adds more time to the process. The efficiency and effectiveness of multiple federal agency reviews and decisions for major transmission projects must be improved, and the uncertainty associated with federal agency reviews must be reduced.

C. Integrated Interagency Pre-Application Process (IIP)

While interagency coordination and cooperation has improved at the federal agencies headquarters level, there is opportunity for further improvement, including at the local federal office level where many of the siting and permitting decisions are made. EEI has expressed general support for DOE's proposed (2013) IIP process, which focused on enabling early engagement and coordination among federal, non-federal, state, tribal and other stakeholders with permitting authority. The proposed IIP process fulfills the directives of Section 4(a) of the June 2013 Presidential Memorandum: Transforming our Nation's Electric Grid Through Improved Siting, Permitting, and Review, and furthers the Administration's goals of modernizing the electric grid to ensure the growth of America's clean energy economy, improve electric reliability and resiliency, reduce congestion, and create cost savings for consumers.

While EEI supports the IIP process, EEI offers the following recommendations for continued improvement for implementation of a robust and timely pre-application process:

- The IIP process should be applicant-driven, allowing federal permit applicants to decide whether or not to use the process.

- The IIP process should build on and incorporate the positive features of the RRTT and other Administration initiatives in recent years.
- DOE should take the lead agency role in the IIP process and in federal permitting of energy infrastructure.
- All federal agencies with applicable permitting authority should be required to participate in the IIP process.
- The IIP process must not be overly burdensome.
- The IIP process must take into consideration FERC-approved regional planning processes.
- The IIP process should be codified in regulations in conjunction with the FPA section 216(h) DOE-led coordinated permitting process.

Codifying the IIP process with the 216(h) process will ensure a concise and consistent application of coordination efforts and will create regulatory certainty for transmission developers as to what forums are available for obtaining federal permits. Instituting the IIP process will also create certainty for DOE and other federal agencies that conduct and participate in the process with regard to budgeting and staffing needs.

D. Timely Access to Perform Vegetation Management and Other Necessary Operations and Maintenance on Federal Lands

The electric utility industry needs the cooperation of the federal agencies in order to meet mandatory reliability requirements administered by NERC and FERC. The industry faces significant fines and penalties for non-compliance. Reliability failures can cause harm to property and even loss of human life if access to perform vegetation management and other operation and maintenance activities for power lines on public lands is delayed by federal agencies. Once a transmission project has been approved, constructed, and put into operation, federal land management agencies must allow utilities to have timely and unencumbered access to perform routine maintenance and emergency repairs.

EEI is working with the USFS, Bureau of Land Management, Fish and Wildlife Service, NPS, FERC, and other federal agencies on a renewed Memorandum of Understanding intended to facilitate integrated vegetation management (IVM) practices on rights-of-way located on public lands. Agency headquarters staff typically understand the need for utilities to perform IVM. In fact, the USFS is working on revising procedures and manuals to facilitate access. The challenge is getting agency personnel in the field to understand the necessity of vegetation management and its relationship to nationally mandated reliability standards. Unfortunately, too often, some agency field personnel do not.

E. Waters of the United States

EEI is concerned with, and fundamentally opposes, the EPA and the U.S. Army Corps of Engineers (Corps) expansion of the definition of "waters of the United States" (WOTUS) in its currently proposed rule.[32] The proposed rule could hamper electric grid resiliency by delaying critical new power line projects and making it more difficult to perform necessary vegetation management and other maintenance activities. The proposed rule would revise the agencies' regulations to contain a uniform definition of the term "waters of the United States," which is the foundation for the agencies' jurisdiction over particular water bodies under the federal Clean Water Act, 33 U.S.C. §§ 1251 et seq. (CWA), and its various water quality standards and permitting programs.

[32] 79 Fed. Reg. 22,188 (Apr. 21, 2014)

EEI is concerned that in its current form, the proposed rule could trigger substantial additional permitting and regulatory requirements for electric generation and transmission facilities under the Clean Water Act (CWA). This increase will result from increased uncertainty about whether a given water feature or potentially wet area is jurisdictional, and if jurisdictional, what that means for use of the land and water involved. EEI is concerned that the increase in time and financial resources to address marginal water features and potentially wet areas will strain limited company, individual, and agency resources that are already overburdened, without providing commensurate benefits in terms of water quality.

Projects that otherwise would have qualified for relatively streamlined permitting processes under nationwide or regional general permits would be required to undergo lengthier and costlier individual permit procedures and face various other costs because more features will be deemed jurisdictional. The proposed rule appears likely to apply to myriad internal features on utility company facilities, most of which are components of facility systems that are already regulated at their points of discharge to external waters under the CWA, and could result in duplication and unnecessary regulation of features on electric utility sites. This expansion of federal jurisdiction will impede reliance on nationwide and regional general permits and could result in having to obtain individual CWA permits. Individual permits can take years to obtain and add significant costs to a project.

The administration has expressed a strong national interest in a reliable and resilient electric grid.[33] The increased timing and costs associated with individual permitting of critical electricity generation and power line projects, such as permitting administrative costs and mitigation costs, will delay projects. Costlier and lengthier permitting will impede expansion and modification of generation and transmission infrastructure, which is contrary to the White House energy policy, "…it is critical that executive departments and agencies (agencies) take all steps within their authority, consistent with available resources, to execute Federal permitting and review processes with maximum efficiency and effectiveness, ensuring the health, safety, and security of communities and the environment while supporting vital economic growth," and would undermine the purpose of the Interagency RRTT and other Administration initiatives that are meant to streamline permitting reviews and reduce permitting backloads.[34]

Therefore, EEI encourages DOE to request EPA and the Corps to withdraw the proposed rule. EEI further encourages that the EPA and Corps instead engage in dialogue with DOE, other federal and state entities, and the regulated community who are responsible for energy infrastructure projects and managing water quality, to develop more specific changes to the existing regulation defining waters of the U.S. The resulting proposal should be made only after all scientific analysis is complete, should invite comments from all stakeholders, and should be

[33] "[T]he United States must have fast, reliable, resilient, and environmentally sound means of moving people, goods, energy, and information." Exec. Order No. 13,604, 77 Fed. Reg. 18887 (Mar. 22, 2012). S*ee also* "Reliable, safe, and resilient infrastructure is the backbone of an economy built to last." Memorandum on Modernizing Federal Infrastructure Review and Permitting Regulations, Policies, and Procedures, 78 Fed. Reg. 30,733, 30,733 (May 22, 2013).

[34] The Rapid Response Team for Transmission is "working to improve the efficiency and effectiveness of transmission siting, permitting, and review, increase interagency coordination and transparency, and increase the predictability of the siting, permitting, and review processes." *See* Memorandum on Transforming Our Nation's Electric Grid Through Improved Siting, Permitting, and Review, 78 Fed. Reg. 35,539 (June 7, 2013).

reviewed by the public to ensure the agencies' jurisdiction is consistent with Supreme Court precedent, and to resolve areas of uncertainty within the current regulations.

F. Endangered and Other Species Concerns

There is a significant increase in Endangered Species Act (ESA) listing decisions and critical habitat designations which have major implications for the siting, operation, and maintenance of power lines and the infrastructure related to new generation such as wind and solar on federal lands. As a result, there are often costly delays, cancellations, or inefficient re-routing of projects.

Specifically, the pending ESA listing decision for the greater sage grouse will have a significant impact on transmission siting and permitting on federal lands. EEI's Avian Power Line Interaction Committee is developing Best Management Practices (BMPs) for power lines in greater sage grouse habitat. EEI urges federal agencies to accept these BMPs as effective conservation measures.

Additionally, inconsistent interpretations for implementing the Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act amongst and within federal agencies add to the difficulty in building new transmission and maintaining existing facilities. Federal agencies should work to provide consistent interpretations and applications of these Acts.

G. Siting and Renewing Transmission Lines on Indian Lands

The process for obtaining and renewing rights-of-way on Indian land raises a number of challenges. The current right-of-way negotiation process typically takes years, even for renewal of existing rights-of-way. More elements of proposed agreements are open for negotiation than ever before, creating increased uncertainty. In addition, companies can be faced with large increases in fees for rights-of-way on Indian land, reflecting aggressive measures for setting the fair market value of the land. The duration of the rights-of-way terms are getting shorter over time, which does not take into account the long-asset life of electricity infrastructure investments.

The Bureau of Indian Affairs is currently accepting comments on a proposed rule for Rights-of-Way on Indian Land.[35] This proposal has the ability to make it more expensive for utilities to site transmission facilities on tribal lands. EEI recognizes and appreciates the unique sovereignty interests that tribes have in managing their lands; however, the current practices and the proposed changes make it more likely that utilities will look elsewhere to site their facilities.

[35] Rights-of-Way on Indian Land, 25 CFR Part 169 – Proposed Rule at 79 Fed. Reg. 34455 (Jun.17, 2014), Docket ID: BIA–2014–0001; DR.5B711.IA000814

H. Energy Right-of-Way Corridors on Federal Lands

Section 368 of the EPAct 2005 directed the Secretaries of Agriculture, Commerce, Defense, Energy and Interior to designate corridors for electric transmission and other linear energy facilities on federal land. Applications to construct transmission lines within the designated corridors were to be expedited by the agencies. The agencies designated over 6,000 miles of energy corridors in the 11 contiguous Western States. No corridors have been designated in the remaining states. Unfortunately, EEI member companies have not found the designated corridors to be as beneficial as intended by Congress. The corridors designated under Energy Policy Act of 2005 (EPAct 2005) section 368 are inadequate. Engineering and other considerations have prevented projects from being located entirely within the designated corridors. As a result, projects face the same delays as they would if they were located totally outside the corridors. EEI recommends that DOE and the other involved federal agencies consult with EEI member companies and other stakeholders to designate additional corridors to meet the intent of Congress.

I. International Permitting and Siting

The U.S. and Canada enjoy a strong electricity trading relationship and benefit from a high level of integration between their electric power systems. Enhanced regulatory cooperation and alignment will facilitate increased infrastructure investment and cross-border trade, which in turn will make the North American grid more reliable and secure. The Canada-U.S. Regulatory Cooperation Council was established by President Obama and the Canadian

Prime Minister in February 2011 to increase regulatory cooperation and alignment between the two countries. EEI applauds the memorandum of understanding recently finalized by DOE and Canada's Minister of Natural Resources, pledging cooperation on energy matters between the two agencies.[36]

EEI understands that both DOE and the National Energy Board of Canada (NEB) have already recognized the need to update their permitting processes, and are at various stages of proposing modifications. EEI agrees that significant value will be derived from these activities if they are performed in alignment with each other, and encourages DOE and the NEB to continue their work to align and modernize their respective permitting requirements for international power lines and electricity exports.[37] EEI believes that efforts to streamline permitting for cross-border transmission projects should be executed in a way to avoid delay or add regulatory uncertainty to pending projects.

V. Distribution

The Grid is the great enabler, and the distribution grid will be the facilitator for new customer and technology trends; EEI members are actively engaged in understanding and meeting these new customer expectations. As utilities facilitate the transition to a greener fleet with more DER, customers must be the core focus for utilities and government alike. This

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[36] *Memorandum of Understanding on Energy Cooperation* signed September 18, 2014 by the Honourable Greg Rickford, Canada's Minister of Natural Resources and Minister for the Federal Economic Development Initiative for Northern Ontario and Dr. Ernest Moniz, U.S. Secretary of Energy. The MOU covers many activities, including those related to enhancing reliability and security of energy infrastructure; advancing an efficient, clean electric grid; and cross-border permitting regimes for electric transmission facilities.

[37] See EEI letter dated May 28, 2014 to DOE Assistant Secretary, Office of Electricity Delivery and Energy Reliability.

transition will occur at state and local levels, and should occur while maintaining reliability and keeping customer prices low. Utilities, working with state and local regulators, are best positioned to safely and reliably operate the distribution system and manage its transformation.

Flexibility by region and by utility will be needed to develop the most appropriate regional and local solutions needed to insure continued reliability in a changing distribution environment. DOE, policy makers, and regulators must recognize that there is no “one size fits all” approach to meeting our national energy goals, including the transition of the distribution system. Though technology and service standards will be developed, innovation will take many forms. The potential number of successful models could be as numerous as the number of various state and local regulators.

EEI believes that the traditional flow of power from centralized generation resources through bulk transmission and distribution infrastructure to load will continue to be a predominate supply for our nation’s electricity needs (because of economies of scale, and therefore, cost-competitiveness), providing the foundation to both access diverse generation resources and transition to new technologies. As the penetration of DER increases, The Grid will evolve to accommodate two-way power flows across the distribution and bulk power systems. The emerging mix of central station generation (renewable, fossil and nuclear generation) and DER will require an Integrated Grid as EPRI envisions.[38]

DOE should recognize jurisdictional boundaries. State and local regulators, in conjunction with utilities are best positioned to develop flexible, well-tailored solutions for the distribution system.

State and local regulators will:

- Keep reliability and safety at the top of the priority list.
- Keep customers and their costs at the forefront.
- Provide utilities the flexibility necessary to innovate and provide more products, services, and energy efficiency.
- Provide regulatory certainty so that utilities can ensure their distribution systems are ready for a distributed energy resource future with two-way intermittent power flows.
- Collaborate with industry to understand how increased penetration of renewables, distributed generation and microgrids will affect the bulk electric grid.

The transformation of the existing distribution system to support DER integration may require changing the very design of the system- a considerable task. Increased penetration of DER, and therefore two-way power flows, can over load distribution feeders, leading to system instability and load-shedding in the event of frequency violations.[39] The possible need for re-design, as discussed in the IEEE Report could require conversion of distribution systems to closed-loop operation, which is in essence a way of converting the distribution system into a type of sub transmission system, in order to allow more DER.[40] Integration is achievable if design changes are properly incorporated while the infrastructure investment cycles are underway; utilities should work with state and local to ensure that the appropriate "upsizing" investments in the system are made.

[39] *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, EPRI, February 2014.
[40] *Id.*

The utility industry is already working to create a more integrated grid, for example, by re-conductoring and deploying new technologies (e.g., distribution management systems, high speed communications, advanced sensors, energy storage). Among the most important of these efforts are the following:

(1) Fault location and isolation **–** the ability to automatically detect outages and re-route power to minimize the number of customers experiencing the outage. This is enabled through devices called sectionalizers;
(2) Integrated volt/VAr control **–** the ability to continuously monitor and adjust real and reactive power levels. It is enabled through tap changers and voltage regulators;
(3) Distributed energy resource management systems – the ability to control DER output to prevent back feed that can cause outages.

EEI members are aware that many changes need to be made, and are up to the challenge. Time-scales for reliable operation will become more compressed: from minutes (traditional voltage management) to seconds (distributed controls) and milliseconds (protective devices). Power quality and reliability will be highly sensitive to variability of DER output and changes in customers' load. System operations will have to react quickly to ensure safe, reliable and quality service as required by state law. New designs and control architectures, engineering analyses, and new assumptions must be developed. Collection and analysis of grid asset and operational data will better inform decisions. EEI members are actively engaged with customers and other stakeholders to coordinate the transition of the grid, with the needs of the customer in mind.

Transition to a more integrated grid should simultaneously maximize benefits and minimize costs of portfolio of assets that constitutes the Grid. Utilities are already cost-optimizing distribution investments with state and local regulatory oversight. Increasingly, states and utilities are working together to develop plans for grid modernization; these efforts are already under way, for example, in California, Hawaii and New York.[41] Cost-effective DER opportunities are being integrated in distribution planning. These processes are intend to realize local benefits of DER while also coordinating with bulk power system planning for resource adequacy and transmission planning benefits.[42] Such plans can be reviewed by regulators with public input and serve as the framework for the utility to develop the distribution system platform that enables DER integration in an economic and efficient manner.

EEI believes that recommendations resulting from the QER should recognize the value of the Grid, encourage prudent transmission and distribution investment, allow for integrated planning, ensure reasonable costs for all users, and minimize unreasonable cost-shifting. Experiences in Hawaii and Germany demonstrate the importance of planning for and anticipating the need for grid improvements as we move to integrate more renewable energy. For example, the electric distribution expansions needed in Germany by 2030 are estimated to require investments of between € 27.5 billion and € 42.5 billion, and it is unclear if current regulations are adequate for grid operators to fund these necessary investments. Distribution grid operators whose grids need significant investment- the very entities facilitating the

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[41] *See,* New York Reforming the Energy Vision, Docket Number 14-M-0101. The New York State Public Service Commission launched its Reforming the Energy Vision (REV) initiative "to reform New York State's energy industry and regulatory practices. This initiative will lead to regulatory changes that promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, wider deployment of "distributed" energy resources, such as micro grids, on-site power supplies, and storage. It will also promote greater use of advanced energy management products to enhance demand elasticity and efficiencies. These changes, in turn, will empower customers by allowing them more choice in how they manage and consume electric energy. Retrieved from: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument

[42] *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769*, CPUC, Rulemaking 14-08-013.

transition to DER- will be at a disadvantage.[43] These experiences also vividly highlight the potential cost implications of reactive policy making compared to policy that is guided through proactive planning.[44]

Skilled management of the distribution system transition is necessary, as the distribution system does not possess the same types of characteristics as the bulk electric system, including redundancies.[45] It is important to remember that the distribution system has distinct characteristics from those of the transmission system, such as how supply and demand is balanced, power quality, and equipment sensitivities. Efforts to transition distribution grids will differ from those exercised in the transition of the bulk electric system.

Incumbent utilities are already engaged in upgrading distribution systems; they are the only entities that can provide the tight coordination of people, planning, and technology that will be necessary. Successfully managing the transition to a new operating paradigm, something that has never been done before in the electric sector, will require close

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[43] *See* Press releases from 11 December 2012- Electricity distribution grids require significant expansion for the energy turnaround. Retrieved from: http://www.dena.de/en/press-releases/press-releases/electricity-distribution-grids-require-significant-expansion-for-the-energy-turnaround.html *See also:* Summary of the Essential Results of the Study, Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020 (dena Grid study), retrieved from: http://www.dena.de/fileadmin/user_upload/Publikationen/Energiedienstleistungen/Dokumente/dena-grid_study_summary.pdf. Note: citing this report does not imply endorsement of all the recommendations in it.

[44] As a cautionary note onpolicies related to integration of DERs, EEI references the German experience. Presently, Germany is targeting producing 50% of its electricity from renewable resources by 2030 and 80% by 2050, with costs to do so now estimated at $1.35 trillion over the next 25 years. Attaining these goals will further increasing high German electric rates, already twice the U.S. average and the highest in Europe. Part of problem is a steep renewables surcharge that is added to every bill, which is set to jump another 20%. *Germany's Energy Poverty: How Electricity Became a Luxury Good*, by Spiegel Staff, Der Spiegel, August 26, 2013. Available at: http://www.spiegel.de/international/germany/high-costs-and-errors-of-german-transition-to-renewable-energy-a-920288.html

[45] A redundant system helps to ensure resiliency and reliability.

coordination between ongoing operation of the system and design/construction of system changes.

A. Distribution System Operators (DSOs)

Incumbent utilities should be the Distribution System Operators (DSO). There will be a need for new products and services as new technologies, including DER, are adopted. As two-way power flows grow with DER adoption, the necessity of overall system reliability remains. Some believe that DSOs should be responsible for reliable operation of distribution system, and even provide a transactional platform for a distribution-level market; many believe this function will be similar to that of ISOs/RTOs. Some have further called for independent DSO, also similar to the ISO/RTO structure found in some regions of the U.S.; under this paradigm the independent DSO is responsible for reliable operation of the system and transaction platforms, not the incumbent utility.

While EEI acknowledges the potential need for DSOs in the future, EEI does not believe the independent structure is appropriate. The performance and accountability needed to build and operate integrated grids safely, reliably, and economically will only be possible if incumbent utilities continue to own and operate distribution systems. In fact, incumbent utilities are already required to do so under existing state and local franchise agreements. Incumbent utilities, in conjunction with state and local regulators, must lead the transition to new integrated grids.

An independent DSO would create costly redundancies in operational systems and capabilities, and create additional layers of information sharing- an increased susceptibility to safety and reliability failures. Experience with the development of organized wholesale markets suggests that the additional costs created by independent operators would be substantial. As was pointed out by the City of New York in the Reforming the Energy Vision (REV) proceeding, there have been no cost-effectiveness studies to-date that justify the separation of responsibilities from existing utilities and the creation of an independent operator.[46]

As stated in EEI's Initial Comments, reliability is mission number one; therefore Incumbent utilities must be the DSOs of the future. To ensure continued reliability and safety, real-time physical operation of the distribution system and close coordination with field crews will be imperative, because the electric distribution system is a dynamic, evolving network that is reconfigured daily for routine maintenance, safety, and outage mitigation. Proper coordination, which can only be provided by the incumbent utility, will be necessary to avoid catastrophic and/or deadly outcomes.

B. Microgrids

Microgrids have been widely mentioned throughout the QER process. Indeed, some states and other stakeholders are currently studying the advancement, efficacy, and necessary state and local regulatory changes for this suite of technologies.[47] As with DER integration, as noted above, utilities, working with state and local regulators, are best positioned to safely and reliably integrate microgrids and coordinate their operation with The Grid.

[46] *Comments of the City of New York on Track 1 Policy Questions*, NYPSC, Case 14-M-0101, July 18, 2014.
[47] See EEI Initial Comments at --- for background and definition of microgrids.

EEI does not believe that microgrids will displace central generation or bulk electric infrastructure.[48] Reiterating our Initial Comments, EEI believes that given available technologies, economies of scale inherent in the centralized Grid will continue to provide unmatched efficiencies and cost savings for customers, and will continue to do so for many years to come. Statements of Damir Novosel of IEEE support this conclusion, as he discussed how our grid developed: the first electrical grid was a micro-grid, but then we turned to large interconnected systems for cost effectiveness; we interconnected further because neighbors can help neighbors, facilitating a more reliable grid.[49]

The ability and cost-effectiveness of microgrids to provide the type of resiliency and reliability desired on a widespread basis are yet unknown; however, EEI does believe that microgrids can be valuable in specific circumstances where the costs and benefits are justified. DOE, states, industry, and other stakeholders should continue to work together to understand how to best leverage microgrids, their associated costs and benefits, and how microgrids will interact with the Grid in different regions and at different penetration levels.

Additionally, as we consider moving toward microgrids and increased DER, reliability and safety are paramount. As Mr. Novosel stated, "we need to be cautious about safety- as microgrids and DER gets installed, the equipment will require maintenance and will eventually become old. But if somebody installed the

[48] See, for example, Transcript for the Quadrennial Energy Review Stakeholder Meeting #12: Newark, NJ Electricity Transmission and Distribution – East, September 8, 2014. Retrieved From: http://energy.gov/sites/prod/files/2014/09/f18/qer_transcript_newark_.pdf

[49] Comments of Damir Novosel, IEEE PES President Elect. Transcript of the Quadrennial Energy Review Stakeholder Meeting #12: Newark, NJ Electricity Transmission and Distribution – East, September 8, 2014. Retrieved From: http://energy.gov/sites/prod/files/2014/09/f18/qer_transcript_newark_.pdf

microgrid or DER and then leaves, does not maintain the equipment, what will be the impact on safety?"[48] As the adoption of these types of technologies grows, state and local regulators should work with utilities to equitably ensure reliability and safety.

C. Visibility into the System

To properly operate a more integrated grid, accommodate DER, new technologies, and microgrids, and operate a distribution-level market platform envisioned by some, system operators will need increased visibility into the system. Indeed, significant benefits could be derived from increased visibility of the system, many of which are not yet fully recognized. However, the cost of monitoring and control at the distribution level at this time appear to be staggering- not only for physical equipment, but also for data processing, storage, and analytics. The costs of such systems have not yet been systematically determined.

As an additional challenge, Distribution Management Systems (DMS) are currently limited to about one million monitoring and control data points, and the expansion of DER could increase the point requirement by one or more orders of magnitude (10 million – 1 billion). Implementation of such technologies will be costly, technically complex, and will involve new system architectures (e.g., physical assets, computing, and analytical), which are not yet fully developed. This area may benefit from new industry partnerships and collaboration.

D. Power Quality

Utilities in the United States have been providing a very high level of power quality to consumers for well over 100 years.[50] Unfortunately, the increase in end-use equipment that is more sensitive to minor voltage fluctuations and the increase in the amount of DER on the distribution system, whether intermittent or continuous, has led to more concerns over the issue of power quality.[51]

As discussed in the IEEE Report, the following negative impacts can be created by DER:

- Voltage increase
- Voltage fluctuation
- Reverse power flow
- Line and equipment loading increase
- Loss increase
- Power factor decrease
- Interaction with Load Tap Changers (LTC), line voltage regulators (VR), and switched capacitor banks due to voltage fluctuations
- Temporary Overvoltage (TOV)
- Harmonic distortion
- Voltage sags and swells
- Interaction with protection systems
- Voltage and transient stability

Any one or any combination of the impacts listed above can have a significant and negative impact on customer-side equipment as well as utility-side equipment.

EEI suggests that DOE and the QER focus on the following priorities:

[50] The technical definition of power quality, developed by IEEE, is: "The concept of powering and grounding electronic equipment in a manner that is suitable to the operation of that equipment and compatible with the premise wiring system and other connected equipment." See IEEE Standard 1100-1999, *IEEE Recommended Practice for Powering and Grounding Electronic Equipment*, and IEEE Standard 1159-2009, *IEEE Recommended Practice for Monitoring Electric Power Quality*. Retrieved from: https://www.powerstandards.com/IEEE.php

[51] Such equipment could include, for example, personal computers, televisions, and point-of-sale terminals.

-Reducing or eliminating the negative power quality impacts / characteristics of distributed generation systems on the distribution grid.

-Improving the ability of customer side end-use equipment to handle normal variations that occur with power supply.[52]

EEI believes that it is important for DOE to work with product manufacturers, utilities, end-use customers, and research organizations such as EPRI and IEEE, to identify technology and protocol solutions to improve power quality issues presented by DER. Additionally, collaboration to develop less sensitive appliances and equipment that can handle power quality issues that are caused by other- on-site equipment, distributed generation, or distribution system issues, will provide enhanced customer experiences.

VI. New Technologies

The development of new technologies is creating new market opportunities for utilities, their customers, and third parties. It is vital that new technologies, and the new products and services which they enable, compete on a fair playing field. EEI requests that DOE, regulators, and stakeholders embrace fair and efficient competition as new product and services are developed, recognize the value of the Grid, and apply the same pricing and planning approaches for new and traditional technologies alike. Since distribution grid matters are

[52] Certain end-use equipment that can be classified as very "sensitive" to minor fluctuations in delivered power. Voltage provided to customers will fluctuate by +/- 5%, so that a customer that typically receives service at 120 Volts may receive voltage that varies from 114 Volts to 126 Volts. Unfortunately, some end-use equipment will have operational issues even if the voltage varies by as little as 1%-3%, which is a much narrower range of variability.

exclusively within state jurisdiction for both siting and rate regulation, the role of the federal government on these issues is limited. Thus, regions and states must have flexibility to address their individual characteristics and needs as necessary; there is no “one-size-fits-all” solution.

State and local regulators may need to work with utilities and revisit state regulation and franchise agreements to ensure non-discriminatory access to the distribution system, while ensuring reliability (most states have such rules already in place in the context of affiliate codes of conduct), and to allow incumbent utilities to participate in evolving markets (e.g., DER and competitive services). Incumbent utilities should also be allowed to enter into business partnerships with unaffiliated third parties. Allowing incumbent utilities to participate in evolving markets, including DER, will ensure that consumers get the best, most cost-effective service. EEI believes that customers of both regulated and competitive services benefit from taking advantage of superior efficiencies provided by utility networks. Superior efficiencies, arising primarily from *economies of scale, scope and experience* are legitimate and promote consumer welfare; denying companies the ability to take advantage of them is sub-optimal.

As we enter this transition, our industry is concerned that The Grid is not being appropriately valued or compensated, particularly with the increased adoption of DER. As discussed in EEI’s Initial Comments, the Grid currently provides critical services such as access to generation capacity for back-up and replacement power for when the sun does not shine, the wind does not blow, or there is simply not enough DER to meet demand, and provision of grid stability.[53] Failure to appropriately value and compensate the Grid could have negative financial implications, thus threatening the reliability and resiliency currently provided and to develop the increased level of services desired.

EEI highlights one example of grid valuation challenges. In efforts to encourage the deployment of distributed generation technologies, such as rooftop solar, "Net Metering" policies have been adopted, and are still evolving. Under these programs, net-metered customers are typically credited for the power they sell back to the utility at the fully-bundled retail electricity rate instead of the wholesale electricity rate or the avoided cost. Allowing net-metered customers to avoid fully-bundled rates unfairly shields these customers from paying the costs of the grid that they still use (e.g., poles, wires, meters, and back-up power). As a result, costs are shifted to the remaining utility customers, creating an unsustainable subsidy in which customers, who cannot or do not opt to install DER, subsidize those who do make this choice.[54] Many of these customers may be economically disadvantaged and cannot afford DER, but are nonetheless subsidizing DER customers who can most afford to fund these programs themselves.

EEI and its members believe these types of inequities are untenable for continued safe, reliable, affordable, universal service. Ralph Izzo, Chairman and CEO, Public Service Enterprise

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[53] See, for example, EEI Initial Comments, filed June 10, 2014, at Section I.C. Reliability. Current DER penetration is not sufficient to meet total system demand.

[54] Business models for DER, solar in particular, are quickly evolving. For example, many providers and or installers of rooftop solar installations now offer leasing options in which utility customers need not pay large up-front capital costs. The utility customer then pays the leasing company through their utility bill savings. Options such as these may improve accessibility to rooftop solar for utility customers, though the efficacy of these business models is still being observed. However, increased penetration of DER by utility customers under a leasing model, or self-financed, could further contribute to cost-shifting to remaining customers.

Group Inc., highlighted the inequities of the DER subsidies at the regional QER meeting in New Jersey, noting that the national median annual income is $48,000, while New Jersey's is $69,000. In New Jersey, the median annual income for net metered customers is $130,000, and $150,000 for solar loan customers.[55]

A. Compensation for DER resources (and other new technologies) and more traditional resources must be consistent, and there should be parity in how their utility rates are determined

Recognizing that DOE has a limited role in this area, EEI recommends that compensation between DER resources (and other new technologies) and more traditional resources must be consistent, and that there should be parity in how their utility rates are determined. Some advocate for the valuation of distributed technologies based on speculative benefits and on attributes that are not currently recoverable for existing utility assets. To avoid price distortions, DER resources (and other new technologies) should have the same pricing standards as other resources. Unfair valuation and pricing methodologies will produce unfair and inefficient results, ultimately impacting consumers and disrupting the efficiency and cost-effectiveness of the utility system.

Utilities and regulators most often utilize cost-of-service methodologies to derive rates paid by utility customers for the use of the Grid. However, increased penetration of distributed resource and grid technologies, particularly in a period of slow, flat or even declining power

[55] Transcript for the Quadrennial Energy Review Stakeholder Meeting #12: Newark, NJ Electricity Transmission and Distribution – East, September 8, 2014. Retrieved From: http://energy.gov/sites/prod/files/2014/09/f18/qer_transcript_newark_.pdf

use, will require ratemaking policies (primarily at the state level) to evolve so that rates more clearly distinguish grid costs, which are attributable to all customers (including those relying, in part, on DER resources), from energy costs. Estimation of these grid costs applicable to all customers, at least for distributed resource users, is essential if grid and power supply prices are to be based on the cost causation and fairness principles necessary to assure that the electric system is operated, maintained, and expanded in a cost-effective manner. This can and should be done without undermining other policy goals.

Approaches to DER compensation and cost recovery should be fair and on par with the methods used to price utility grid investments. For example, DER should only be compensated for net benefits provided to the system, recognizing that their addition could result in additional costs to the grid. Given that the grid must be built to meet peak demand on a circuit-by-circuit basis, DER resources may not actually contribute to avoided grid costs; and in fact may increase fixed and variable operating costs as well as capital costs needed to support the highly variable nature of the resource.[56] Benefits of DER will vary regionally. For example, many existing studies rely on relatively stable solar irradiance data such as that observed in western states like Arizona or California. Much higher variability of solar irradiance exists in many of the eastern and mid-west states. This higher variability can translate to higher grid costs rather than deferring grid investment.

[56] The bulk transmission grid is built to meet coincident peak demand, while the distribution system is built to meet non-coincident demand. Coincident Peak demand is the sum of two or more demands that occur in the same demand interval. Non Coincident demand is the sum of two or more individual demands which do not occur in the same demand interval. This term is meaningful only when considering demands within a limited period of time, such as day, week, month, heating or cooling season, and usually for not more than one year. *See* Edison Electric Institute: Glossary of Electric Industry Terms, 2005.

Overcompensating DER harms the grid in two ways. First, it promotes uneconomic investments, usually in unplanned locations, that increase the cost and complexity of the distribution grid itself. Second, because of subsidies and rate structures, currently existing costs, as well as the increased grid costs associated with DER, are unfairly passed on to those without DER resources.

The QER should recognize that consistent pricing, planning, and evaluation approaches are essential to achieving a safe, reliable, and environmentally desirable electric system that properly incorporates the best new technologies in a cost-effective manner to the benefit of all electricity customers.

B. Storage

Storage will be key in integrating variable energy resources (e.g., wind, solar, and other DER), while maintaining resiliency and reliability. Currently, there are many types of storage technologies, but only a few of them are cost-effective, and in very limited applications.[57] Each storage technology has a unique set of characteristics – there is no "one size fits all" solution. There may be niche applications that could provide value for customer, commercial, agricultural, industrial, or utility grid applications.

[57] Several types of electric storage that have been developed, including: Solid State Batteries, Flow Batteries, Thermal Storage, Grid Interactive Thermal Storage, Flywheels, Compressed Air Energy Storage (CAES), and Pumped Hydroelectric Power Storage

Generally speaking, the smaller localized storage applications consisting of batteries are currently not yet cost competitive and have not been widely implemented. From a large grid perspective, hydroelectric pumped storage is the only commercially-proven, cost competitive bulk energy storage resource available. Additional large-scale solutions, such as compressed air energy storage (CAES) and large scale lithium ion batteries are being added to the grid, though their cost competitiveness is still being studied.[58]

EEI and its members suggest DOE and the QER focus on the following priorities:

-Improve the performance and cost-effectiveness of large electric storage systems for grid-scale applications.

Many types of battery systems cost more than $500 per kilowatt-hour, which limits their use for many applications. Research that focuses on reducing costs and improving performance (in terms of cycles of operation, longevity, durability, etc.) will provide the most value.

-Improve the performance and cost-effectiveness of electric storage systems for light-duty and medium/heavy duty transportation applications.

Plug-in electric vehicles provide economic and energy security, and environmental benefits over conventionally fueled vehicles. They also have the potential to directly improve the electric grid, as noted by DOE.[59] By October 2014, there will be approximately 250,000

[58] For example, Pathfinder, Magnum Energy and Dresser-Rand propose to install a $1.5 billion compressed air energy storage system in southwest Utah, which would use four vertical caverns, carved out of an underground salt formation at the site. The caverns would be capable of storing the energy equivalent of 60,000 MWh of electricity. Retrieved From: http://www.duke-energy.com/news/releases/2014092301.asp

[59] And the deployment of electric vehicles (EV) is another form of customer storage of electricity. Co-optimized charging can be conducted in a manner that supports improved grid reliability and economics. Studies are underway now to examine the potential for using EVs as power sources for the grid, essentially in the same manner that utility storage would be. Once retired (nominally when their energy capacity reaches 80% of their initial value), EV batteries can see secondary use, repackaged for providing stationary grid storage (currently being demonstrated by DOE). *Grid Energy Storage,* Department of Energy, December 2013. Retrieved from: http://energy.gov/sites/prod/files/2013/12/f5/Grid%20Energy%20Storage%20December%202013.pdf

plug-in electric vehicles on the roads in the United States. While this is a tremendous success story, further improvements in battery technology in the areas of cost reduction, energy density, and weight will help to increase the market penetration of these clean and advanced vehicles.

- Improve Permitting and siting

Depending on the technology and space requirements, long lead times may be necessary to develop, permit, and construct projects, such as large pumped storage hydro facilities and CAES. Efforts should be made to reduce the time it takes to permit and site projects. For example, aligning agency schedules, allowing permitting processes to run concurrently, as opposed to sequentially, and ensuring that all agencies are using the same basic data sets and assumptions for analytic purposes can help to reduce permitting timelines and the potential for permit challenges.[60]

- Improve our understanding of the environmental impacts of storage.

Some energy storage technologies can present unique environmental issues that should be understood and addressed early in the regulatory process. Regulatory certainty regarding future handling of environmental impacts will help facilitate the financing and building of projects and reduce risks therefore reducing the cost of capital. For example, many battery technologies may contain hazardous materials during operation and after the facility is

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[60] See Written Comments of Geisha Williams, Executive Vice President for Electric Operations, Pacific Gas & Electric, before the QER Energy Review Task Force on Electric Transmission, Storage and Distribution – West July 11, 2014. Retrieved from: http://energy.gov/sites/prod/files/2014/07/f17/portland_williamsgeisha_statement_qer.pdf

decommissioned. Clear rules for managing any hazardous materials associated with a project are important so that parties can better manage costs and risks.[60]

Working with domestic vehicle manufacturers, utilities, and research organizations such as EPRI and IEEE, DOE research and development of advanced electric storage technologies will result in an improved electric grid and improved technologies that are used by end-use individual and corporate consumers.

C. Price Responsive Demand and Energy Efficiency

The growth of price responsive demand, also referred to as Demand Response (DR), and Energy Efficiency (EE) affects load growth, and thus, planning for long-lived capital intensive energy assets such as transmission and generation. DOE and the industry should work together to better understand issues such as customer fatigue for DR, how DR, DER, and EE affect planning, and how DR, DER, and EE can be best integrated to optimize Grid operations. Other questions could include, will DR and EE continue to materialize in a way that does not cause a potential resource shortage given long lead times for generation and transmission assets?

VII. Business Models and Regulation

EEI members fully support a clean energy future and are committed to building a sustainable energy future. EEI believes that states and utilities should be free to consider business model reforms as appropriate, and our members look forward to working with the states to update regulations, where needed. The business model and regulatory challenges the industry faces was well-framed by a study commissioned earlier this year to analyze issues related to the President's clean energy agenda:

> The nation's energy technologies and needs are advancing faster than the rules, rates and administrative processes that govern how America's utilities operate. Rules and procedures need to be streamlined, modernized and reformed to help utilities respond to changes in technology and markets, and to achieve the President's policy objectives for a clean energy economy…
>
> Utilities recognize the challenge before them and the increasing role of technology. At the heart of this challenge is the application of a 20th century regulatory model for a 21st century economy…Utilities are not the barrier to the path forward.. they are the linchpins to implementing a low-carbon energy economy by using cleaner fuels to generate electricity, helping to electrify the transportation sector and providing the enhanced services that customers are increasingly demanding. Utilities provide more than just power and energy. They are fundamental to our economy…Utilities make life happen.[61]

Utilities can and will play a key role in enabling least-cost development of DER (and other new technologies), new services, and the integrated grid. While utilities will continue to provide primary generation from central station power, they should be allowed to compete freely and fairly in DER markets, and engage in partnerships with third parties to provide DER, new technologies, and new services to customers while remaining the provider and operator of the distribution network. This is the optimal strategy for integrating diverse energy sources in a way that supports customer choice, while maintaining high levels of reliability and power quality.

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[61] *Powering Forward: Presidential and Executive Agency Actions to Drive Clean Energy in Amer*ica, Center for the New Energy Economy, January 2014. Note: citing this report does not imply endorsement of all the recommendations in it.

Where necessary and appropriate, Utilities will work with state and local regulators to modify state laws and local franchise agreements to encourage new service opportunities created through grid modernization and the growth of DER. As DER grows, distribution systems will become critical hubs between customers' resources, the distribution utility, and bulk power markets. Continued and increased flexibility under state law and local franchise agreements could allow utilities to offer customers choices among sophisticated new grid services (e.g. reliability services, network management services, and transaction management services).

Utilities are ideal business partners. Utilities have skills related to engineering, installation, maintenance, and operational services that can be of great value to customers and business partners alike. By partnering with third parties who bring specific technologies and skills to the market, synergies can reduce the cost of serving customers, compared to the cost of either utilities or third parties operating alone. Additionally, utilities can typically access investor capital under better, more reasonable terms than other entities. This uniquely enables utilities to facilitate cost-effective investments at utility scale, on the customer side of the meter ("behind the meter"), and in 3rd party partnerships. Utilities could provide 3rd party financing as a service to customers, make funds available to consumers directly, or collaborate with finance syndicators.

To ensure adequate infrastructure investments and preserve access to capital in an environment of flat to declining sales, utilities and state regulators will continue to work together to mitigate regulatory lag (e.g., future test years, construction cost trackers, formula rates, multi-year rate plans).[62] Utilities and State regulators will also continue to develop flexible rate designs and cost allocation methodologies that equitably and fully recover costs within reasonable time horizons.

VIII. Conclusions

In conclusion, EEI notes that customers are demanding increasingly more flexibility, reliability, and greener resources from the nation's electric grid, as discussed herein and in EEI's Initial Comments. But in meeting these desires, reliability and safety cannot be compromised. Electricity should also be affordable and have minimal impact on the environment. Finally, electricity business models and policies should be equitable, ensuring that customers, shareholders, and stakeholders are treated fairly. EEI believes that the traditional flow of power from centralized generation resources through bulk transmission and distribution infrastructure to load will continue to be a predominate supply for our nation's electricity needs, providing the foundation to both access diverse generation resources and transition to new technologies.

EEI recognizes the scope of the QER is broad, but DOE's role is limited in some areas. EEI requests that conclusions and recommendations resulting from the QER:

- Promote regulatory certainty and the consistent application of supportive policies that are paramount to encouraging necessary needed investment in the

[62] See *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, EEI, January 2013.

Grid with compensatory returns, particularly transmission and distribution infrastructure.

- Recognize that there is no “one size fits all” approach to meeting our national energy goals; innovation will take on many faces.
- Encourage policy makers and stakeholders to simultaneously assure reliability, minimize costs, ensure level playing fields, and minimize environmental impact.
- Recommendations made as a result of the QER process should be thoroughly assessed by states, regulators, and industry stakeholders to avoid unintended and costly consequences; costs and benefits should be included.
- Improve federal agency processes in the siting, permitting, and maintenance of transmission on public lands.
- Policies that may fundamentally change the distribution system will be made at the state and local levels and may require revisiting state laws and local franchise agreements.
- Recognize how new technologies (DER and microgrids) at high penetration levels will affect both the bulk electric and distribution grids including safety, operability, cost, and power quality.
- Support consistent principles for compensation of DER resources (and other new technologies) and more traditional resources, and parity in how their utility rates are determined
- Recognize that utilities and state and local regulators may need to revisit regulations to provide increased flexibility to develop new business models,

support innovation, and allow utilities to fairly compete in the evolving DER markets.

EEI appreciates the opportunity for participation in the QER process, and supports this effort to examine the nation's energy infrastructure, identify vulnerabilities, and develop policy recommendations to address these matters. To that end, we submit these additional comments for the public record and look forward to participating in the dialogue for this and future installments of the QER.

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Appendix A. List of Acronyms

Acronym	Definition of Acronym
BMPs	Best Management Practices
CAES	Compressed Air Energy Storage
CURE	Consumers United for Rail Equity
CWA	Clean Water Act
DER	Distributed Energy Resources
DMS	Distribution Management Systems
DOE	Department of Energy
DSO	Distributed System Operators
DR	Demand Response
EE	Energy Efficiency
EEI	Edison Electric Institute
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EIS	Environmental Impact Statement
EISPC	Eastern Interconnection States Planning Council
EPAct 2005	Energy Policy Act of 2005
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESA	Endangered Species Act

Acronym	Definition of Acronym
EV	Electric Vehicles
FPA	Federal Power Act
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
IEEE	Institute of Electrical and Electronic Engineers
IIP	Integrated Interagency Pre-Application Process
ISO	Independent System Operator
IVM	Integrated Vegetation Management
KW	Kilowatt
LTC	Load Tap Changers
MISO	Midcontinent Independent System Operator
MSTI	Mountain States Transmission Intertie
NEB	National Energy Board of Canada
NERC	North American Electric Reliability Corporation
NESCOE	New England State Committee on Electricity
NPS	U.S. National Park Service
NREL	National Renewable Energy Laboratory
PCC	Point of Common Coupling
PV	Photovoltaic
PNUCC	Pacific Northwest Utilities Conference Committee
PJM	PJM Regional Transmission Operator

Acronym	Definition of Acronym
QER	Quadrennial Energy Review
REV	Reforming the Energy Vision
RRTT	Rapid Response Team for Transmission
RTOs	Regional Transmission Organizations
RD&D	Research Development and Demonstration
SPP	Southwest Power Pool
STB	Surface Transportation Board
TOV	Temporary Overvoltage
TS&D	Transmission Storage and Distribution
USFS	U.S. Forest Service
VR	Voltage Regulators
WOTUS	Waters of the United States

IHS **Energy**

The Value of US Power Supply Diversity

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Contents

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IHS™ **Energy**

The Value of US Power Supply Diversity

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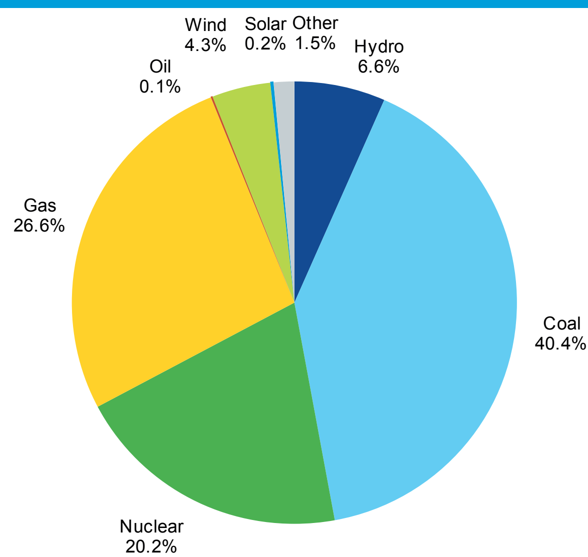
Executive summary

Engineering and economic analyses consistently show that an integration of different fuels and technologies produces the least-cost power production mix. Power production costs change because the input fuel costs—including for natural gas, oil, coal, and uranium—change over time. The inherent uncertainty around the future prices of these fuels translates into uncertainty regarding the cost to produce electricity, known as production cost risk. A diversified portfolio is the most cost-effective tool available to manage the inherent production cost risk involved in transforming primary energy fuels into electricity. In addition, a diverse power generation technology mix is essential to cost-effectively integrate intermittent renewable power resources into the power supply mix.

The current diversified portfolio of US power supply lowers the cost of generating electricity by more than $93 billion per year, and halves the potential variability of monthly power bills compared to a less diverse supply. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power (see Figure ES-1). In this less diverse scenario, called the *reduced diversity case,* wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas–fired power plants account for the remaining 61.7% of installed capacity and 73.7% of generation.

FIGURE ES-1

US generation mix, 2013



Source: IHS Energy

Power supply in the reduced diversity case increases average wholesale power prices by about 75% and retail power prices by 25%. Energy production costs are a larger percentage of industrial power prices, and many industrial consumers buy power in the wholesale power market. Thus a loss of power supply diversity will disproportionally affect the industrial sector. These higher electricity prices impact the broader US economy by forcing economic adjustments in production and consumption. If the US power sector moved from its current diverse generation mix to the less diverse generating mix, power price impacts would reduce US GDP by nearly $200 billion, lead to roughly one million fewer jobs, and reduce the typical household's annual disposable income by around $2,100. These negative economic impacts are similar to an economic downturn. Additional potential negative impacts arise from reducing power supply diversity by accelerating the retirement of existing power plants before it is economic to do so. For example, a transition to the reduced diversity case within one decade would divert around $730 billion of capital from more productive applications in the economy. The size of the economic impact from accelerating power plant turnover and reducing supply diversity depends on the deviation from the pace of change dictated by the underlying economics.

Maintaining and preserving a diverse US power supply mix is important to consumers for two reasons:

- Consumers reveal a strong preference for not paying more than they have to for reliable electricity.
- Consumers reveal preferences for some degree of predictability and stability in their monthly power bills.

The economic benefits of diverse power supply illustrate that the conventional wisdom of not putting all your eggs in one basket applies to power production in much the same way as it does to investing. This is the *portfolio effect*. In addition, diversity enables the flexibility to respond to dynamic fuel prices by substituting lower-cost resources for more expensive resources in the short run by adjusting the utilization of different types of generating capacity. This ability to move eggs from one basket to another to generate fuel cost savings is the *substitution effect*. Looking ahead, the portfolio and substitution effects remain critically important to managing fuel price risks because of the relative fuel price dynamics between coal and natural gas.

The shale gas revolution and restrictions on coal are driving an increased reliance on natural gas for power generation and provide strong economic benefits. However, this past winter demonstrated the danger of relying too heavily on any one fuel and that all fuels are subject to seasonal price fluctuations, price spikes, and deliverability and infrastructure constraints. The natural gas price spikes and deliverability challenges during the past winter were a jolt for a number of power systems that rely significantly on natural gas in the generation supply. These recent events demonstrated that natural gas deliverability remains a risk and natural gas prices continue to be hard to predict, prone to multiyear cycles, strongly seasonal, and capable of significant spikes. The root causes of these price dynamics are not going away anytime soon. The best available tool for managing uncertainty associated with any single fuel or technology is to maintain a diverse power supply portfolio.

Maintaining power supply diversity is widely supported—the idea of an all-of-the-above approach to the energy future is supported on both sides of the aisle in Congress and at both ends of Pennsylvania Avenue. Four decades of experience demonstrate the conclusion that government should not pick fuel or technology winners, but rather should create a level playing field to encourage the economic decisions that move the power sector toward the most cost-effective generation mix.

Maintaining a diverse power supply currently is threatened by three emerging trends:

- **Awareness.** The value of fuel diversity is often taken for granted because United States consumers inherited a diverse generation mix based on decisions from decades ago.

- **Energy policy misalignment.** Legislation and regulatory actions increasingly dictate or prohibit fuel and technology choices. The resulting power supply is increasingly at odds with the underlying engineering/economic principles of a cost-effective power supply mix.

- **Power market governance gridlock.** Market flaws produce wholesale power prices that are chronically too low to produce adequate cash flows to support and maintain investments in a cost-effective power generation mix. This "missing money" problem is not being addressed in a timely and effective way through the stakeholder governance processes found in most power markets. As a result, the loss of power supply diversity is accelerating because too many power plants are retiring before it is economic to do so. Consequently, they will be replaced with more costly sources of supply.

US power consumers are fortunate to have inherited a diverse power supply based on fuel and technology decisions made over past decades. Unfortunately, the current benefits of US power supply diversity are often taken for granted. This undervaluation of power supply diversity means there is no counterweight to current pressures moving the United States toward a future generation mix without any meaningful contribution from nuclear, coal, or oil and a diminished contribution from hydroelectric generation.[1]

The United States needs to consider the consequences of a reduced diversity case involving no meaningful contribution from nuclear, coal-fired, or oil-fueled power plants, and significantly less hydroelectric power. A reduced diversity case presents a plausible future scenario in which the power supply mix has intermittent renewable power generation capacity of 5.5% solar, 27.5% wind, and 5.3% hydro and the remaining 61.7% of capacity is natural gas–fired power plants. Comparing the performance of current US power systems to this possible reduced diversity case provides insights into the current nature and value of diversity in the US generation mix.

IHS Energy assessed the current value of fuel diversity by using data on the US power sector for the three most recent years with sufficient available data: 2010 through 2012. IHS Energy employed its proprietary Power System Razor (Razor) Model to create a base case by closely approximating the actual interactions between power demand and supply in US power systems. Following this base case, the Razor Model was employed to simulate the reduced diversity case over the same time period. The differences between the base case and the reduced diversity case provide an estimate of the impact of the current US power supply fuel and technology diversity on the level and variance of power prices in the United States. These power sector outcomes were fed through to the IHS US macroeconomic model to quantify the broader economic impacts of the resulting higher and more varied power prices along with the shifts in capital deployment associated with premature retirements that accelerate the move to the reduced diversity case.

The difference between the base case and the reduced diversity case is a conservative estimate of the value of fuel diversity. The portfolio and substitution values would be greater over a longer analysis time frame because uncertainty and variation in costs typically increase over a longer time horizon. In addition, the estimate is conservative because it excludes indirect feedback effects from a higher risk premium in the reduced diversity power supplier cost of capital. This feedback is not present because the analysis alters only the generation capacity mix and holds all else constant. This indirect cost feedback would increase capital costs in this capital-intensive industry and magnify the economic impact of current trends to replace power plants before it is economic to do so by moving shifting capital away from applications with better risk-adjusted returns.

The United States is at a critical juncture because in the next decade the need for power supply to meet increased customer demands, replace retiring power plants, and satisfy policy targets will require fuel and

1. Oil-fired power plants account for about 4% of US capacity and 0.2% of US generation but can play a critical role in providing additional electricity when the system is under stress.

technology decisions for at least 150 gigawatts (GW)—about 15% of the installed generating capacity in the United States. However, current trends in energy policy could push that power plant turnover percentage to as much as one-third of installed capacity by 2030. The implication is clear: power supply decisions made in the next 10–15 years will significantly shape the US generation mix for decades to come.

The results of this study indicate seven key factors that will shape US power supply diversity in the years to come:

- **Energy policy development.** US policy heavily influences the US power supply mix. Implementing an all-of-the-above energy policy requires properly internalizing the value of fuel diversity.

- **Market structure.** Market flaws distort wholesale power prices downward and result in uneconomic retirement and replacement of existing cost-effective generation resources. This issue and any market structure changes to address it will significantly shape future power plant development.

- **Energy policy discourse.** Preserving the value of fuel diversity depends on public awareness and understanding. The extent and nature of public education regarding the value of power supply diversity may strongly influence public opinion.

- **Planning alignment.** Alignment of fuel and technology choices for power generation with engineering and economic principles is critical to efficient and reliable supply. There is no single fuel or technology of choice for power generation, and all forms of power production have economic, environmental, and reliability impacts.

- **Risk assessment.** To incorporate system considerations into plant-level decisions, prudent fuel price uncertainties must be used with probabilistic approaches to decision making.

- **Flexibility.** Flexibility and exemptions in rule making and implementation allow for the balancing of costs and benefits in power supply systems and may help preserve highly valuable diversity in systemwide decisions as well as on a small but impactful individual plant scale.

- **Scope.** Including fuel price risk and additional storage and transportation infrastructure costs is crucial when evaluating reduced diversity scenarios in comparison to the cost of maintaining and expanding fuel diversity.

The Value of US Power Supply Diversity

Overview

The power business is customer driven: consumers do not want to pay more than necessary for reliable power supply, and they want some stability and predictability in their monthly power bills. Giving consumers what they want requires employing a diverse mix of fuels and technologies in power production. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power. In this less diverse scenario, called the *reduced diversity case,* wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas–fired power plants account for the remaining 61.7% of installed capacity and 73.7% of generation.

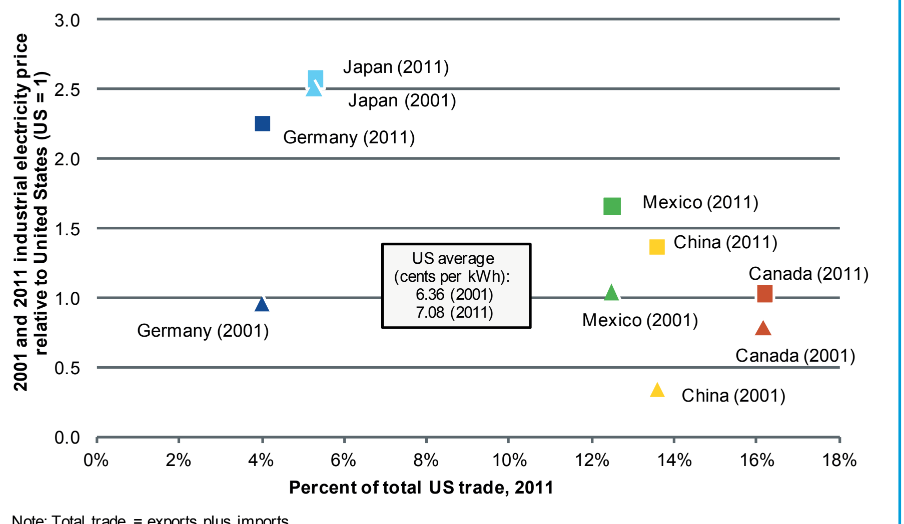
The current diverse US power supply reduces US consumer power bills by over $93 billion per year compared to a reduced diversity case. In addition, the current diversified power generation mix mitigates exposure to the price fluctuations of any single fuel and, by doing so, cuts the potential variability of monthly power bills roughly in half.

Power prices influence overall economic performance. For example, since the recovery of the US economy began in the middle of 2009, manufacturing jobs in the 15 states with the lowest power prices increased by 3.3%, while in the 15 states with the highest power prices these jobs declined by 3.2%. This job impact affected the overall economic recovery. The average annual economic growth in the 15 states with the lowest industrial power prices was 0.6 percentage points higher than in the 15 states with the highest power prices.

Higher and more varied power prices can also impact international trade. In the past decade, the competitive position for US manufacturers improved thanks to lower relative energy costs, including the improving US relative price of electric power (see Figure 1). Although power prices are only one of a number of factors that influence competitive positions in the global economy, there are clear examples, such as Germany, where moving away from a cost-effective power generating mix is resulting in significant economic costs and a looming loss of competitiveness. German power prices increased rapidly over the past decade because Germany closed nuclear power plants before it was economic to do so and added too many wind and solar power resources too quickly into the generation mix. IHS estimates that Germany's net export losses

FIGURE 1

Relative industrial electricity prices for top five US trading partners



Note: Total trade = exports plus imports.
Source: IHS Energy, US Census Bureau, OECD/IEA

directly attributed to the electricity price differential totaled €52 billion for the six-year period from 2008 to 2013.[2]

A less diverse US power supply would make power prices higher and more varied and force a costly adjustment process for US consumers and businesses. The price increase associated with the reduced diversity case produces a serious setback to US economic activity. The value of goods and services would drop by nearly $200 billion, approximately one million fewer jobs would be supported by the US economy, and the typical household's annual disposable income would go down by over $2,100. These economic impacts take a few years to work through the economy as consumers and producers adjust to higher power prices. The eventual economic impacts are greater if current trends force the closure and replacement of power plants before it is economic to do so. Regardless of the replacement technology, it is uneconomic to close a power plant when the costs of continued operation are less than the cost of a required replacement. Premature power plant turnover imposes an additional cost burden by shifting capital away from more productive applications. A closure and replacement of all nuclear and coal-fired generating capacity in the next 10 years would involve roughly $730 billion of investment. An opportunity cost exists in deploying capital to replace productive capital rather than expanding the productive capital base.

The United States currently faces a key challenge in that many stakeholders take the current benefits of power supply diversity for granted because they inherited diversity based on fuel and technology decisions made decades ago. There is no real opposition to the idea of an all-of-the-above energy policy in power supply. Yet, a combination of factors—tightening environmental regulations, depressed wholesale power prices, and unpopular opinions of coal, oil, nuclear, and hydroelectric power plants—are currently moving the United States down a path toward a significant reduction in power supply diversity. A lack of understanding of power supply diversity means momentum will continue to move the United States toward a future generation mix without any meaningful contribution from nuclear, coal, or oil, and a diminishing contribution from hydroelectric generation.

The United States is at a critical juncture because power plant fuel and technology decisions being made today will affect the US power supply mix for decades to come. These decisions need to be grounded in engineering, economic, and risk management principles that underpin a cost-effective electric power sector. Comparing the performance of the current generation mix to results of the reduced diversity case provides key insights into the current nature and value of diversity. An assessment and quantification of the value of power supply diversity will help achieve a more cost-effective evolution of US power supply in the years ahead.

Generation diversity: A cornerstone of cost-effective power supply

If power consumers are to receive the reliable and cost-effective power supply they want, then cost-effective power production requires an alignment of power supply to power demand. Engineering, economic, and risk management assessments consistently show that an integration of fuels and technologies produces the least-cost power production mix. A cost-effective mix involves integrating nondispatchable power supply with dispatchable base-load, cycling, and peaking technologies. This cost-effective generating mix sets the metrics for cost-effective demand-side management too. Integrating cost-effective power demand management capabilities with supply options requires balancing the costs of reducing or shifting power demand with the incremental cost of increasing power supply. Appendix A reviews the principles of engineering, economics, and risk management that lead to the conclusion that cost-effective power supply requires fuel and technological diversity.

2. See the IHS study *A More Competitive Energiewende: Securing Germany's Global Competitiveness in a New Energy World,* March 2014.

The underlying principles of cost-effective power supply produce five key insights:

- There is no single fuel or technology of choice for power generation. Reliably and efficiently supplying consumers with the amounts of electricity they want when they want it requires a diverse generation mix.
- A cost-effective generation mix involves diversity but does not involve maximizing diversity by equalizing generation shares from all available supply options.
- A cost-effective mix of fuel and technologies for any power system is sensitive to the uncertainties surrounding the level and pattern of consumer power demands as well as the cost and performance of alternative power generating technologies and, in particular, the delivered fuel prices.
- A cost-effective generating mix will differ from one power system to the next because of differences in aggregate consumer demand patterns as well as in the cost and performance of available generating options.
- The best type of capacity to add to any generation portfolio depends on what types of capacity are already in the mix.

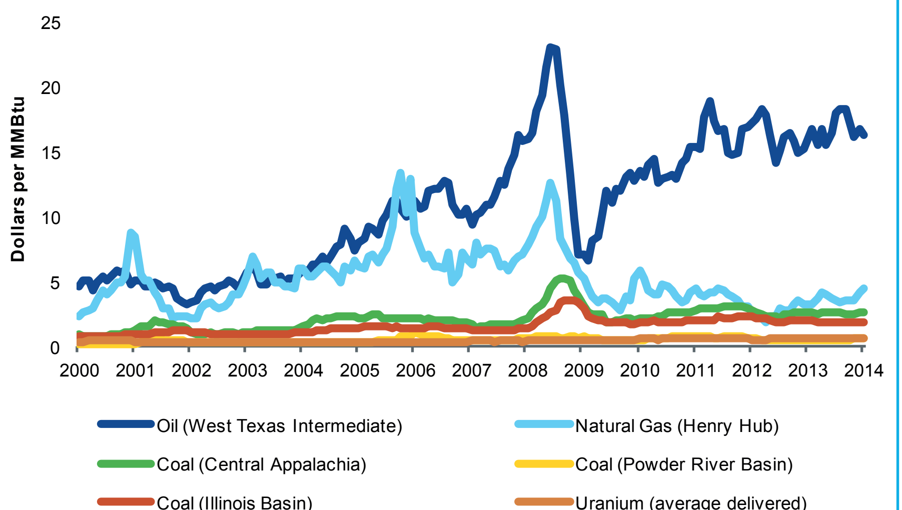
Power production cost fluctuations reflect inherent fuel price uncertainties

Power consumers reveal preferences for some degree of predictability and stability in their monthly power bills. These consumer preferences present a challenge on the power supply side because the costs of transforming primary energy—including natural gas, oil, coal, and uranium—into electric power is inherently risky. Experience shows that the prices of these fuel inputs to the power sector are difficult to anticipate because these prices move in multiyear cycles and fluctuate seasonally (see Figure 2). In addition, this past winter showed that dramatic price spikes occur when natural gas delivery systems are pushed to capacity (see Figure 3).

The recent volatility in the delivered price of natural gas to the US Northeast power systems demonstrates the value of fuel diversity. During this past winter, colder-than-normal weather created greater consumer demand for natural gas and electricity to heat homes and businesses. The combined impact on natural gas demand strained the capability of pipeline systems to deliver natural gas in the desired quantity and pressure. Natural gas prices soared, reflecting the market forces allocating available gas to the highest valued end uses. At some points in time, price allocation was

FIGURE 2

Monthly spot oil, natural gas, and coal prices, 2000–14 year to date



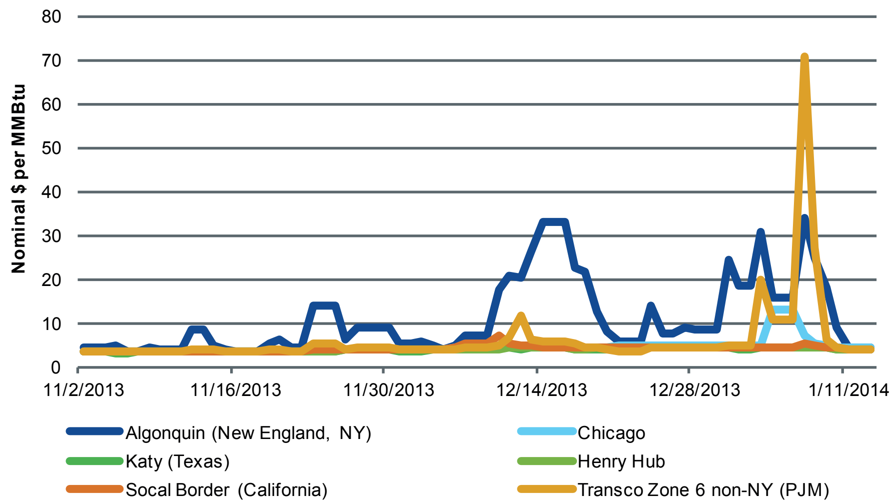
Source: IHS Energy
Data Sources: Energy Information Administration, Platt's and Natural Gas Intelligence, Platts Coal Outlook, SNL Energy Coal

not enough and additional natural gas was not available at any price, even to power plants holding firm supply contracts.

As high as the natural gas price spikes reached, and as severe as the natural gas deliverability constraints were, things could have been worse. Although oil-fired power provided only 0.35% of generation in the Northeast in 2012, this slice of power supply diversity provided an important natural gas supply system relief valve. The oil-fired power plants and the dual-fueled oil- and natural gas–fired power plants were able to use liquid fuels to generate 12% of the New England power supply during the seven days starting 22 January 2014 (see Figure 4). This oil-fired generation offset the equivalent of 327,000 megawatt-hours (MWh) of natural gas–fired generation and thus relieved the natural gas delivery system of about 140 million cubic feet per day of natural gas deliveries. This fuel diversity provided the equivalent to a 6% expansion of the daily delivery capability of the existing natural gas pipeline system.

FIGURE 3

Delivered daily gas prices, November 2013–January 2014



Source: IHS Energy, Ventyx Velocity Suite

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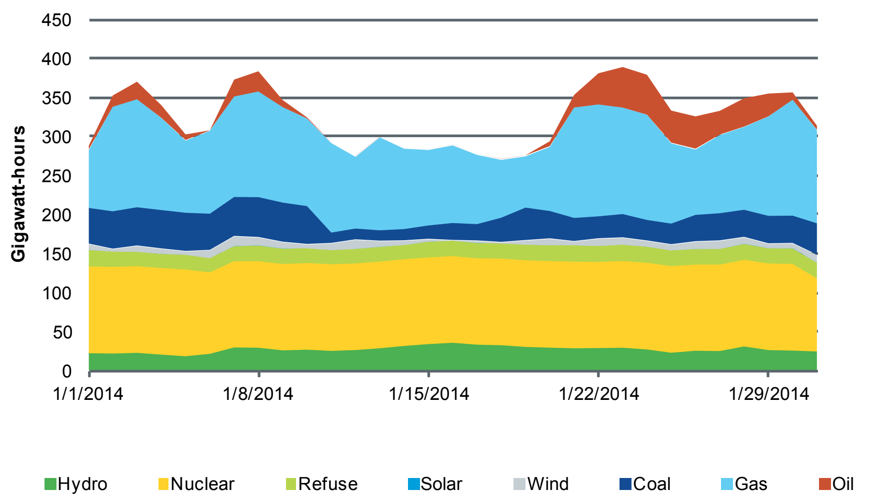
FIGURE 4

ISO New England generation, January 2014



Source: IHS Energy

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The lesson from this past winter was that a small amount of oil-fired generation in the supply mix proved to be highly valuable to the Northeast energy sector despite its production costs and emission rates. Many of these oil-fired power plants are old and relatively inefficient at converting liquid fuel to power. However, this relative inefficiency does not impose a great penalty because these power plants need to run very infrequently to provide a safety valve to natural gas deliverability. Similarly, these units have emissions rates well above those achievable with the best available technology, but the absolute amount of emissions and environmental impacts are small because their utilization rates are so low. Although the going forward costs and the environmental impacts are relatively small, the continued operation of these oil-fired power plants is at risk from tightening environmental regulations.

Oil-fired power plants were not the only alternative to natural gas–fired generation this past winter. Coal played a major role. As the *New York Times* reported on 10 March 2014, 89% of American Electric Power Company, Inc.'s 5,573 megawatts (MW) of coal-fired power plants slated for retirement in 2015 owing to tightening environmental regulations were needed to keep the lights on during the cold snap this past winter in PJM.[3]

The critical role fuel diversity played during the recent polar vortex affected power systems that serve over 40 million US electric consumers and almost one-third of power supply. This widespread exposure to natural gas price and deliverability risks is becoming increasingly important because the share of natural gas in the US power mix continues to expand. The natural gas–fired share of power generation increased from 16% to 27% between 2000 and 2013. Twelve years ago, natural gas–fired generating capacity surpassed coal-fired capacity to represent the largest fuel share in the US installed generating mix. Currently, natural gas–fired power plants account for 40% of the US installed capacity mix.

The increasing dependence on natural gas for power generation is not an accident. The innovation of shale gas that began over a decade ago made this fuel more abundant and lowered both its actual and expected price. But the development of shale gas did not change the factors that make natural gas prices cyclical, volatile, and hard to forecast accurately.

Factors driving natural gas price dynamics include

- Recognition and adjustment lags to market conditions
- Over- and under-reactions to market developments
- Linkages to global markets through possible future liquefied natural gas (LNG) trade
- Misalignments and lags between natural gas demand trends, supply expansions, and pipeline investments
- "Black swan" events—infrequent but high-impact events such as the polar vortex

Natural gas price movements in the shale gas era illustrate the impact of recognition and adjustment lags to changing market conditions. Looking back, natural gas industry observers were slow to recognize the full commercialization potential and magnitude of the impact that shale gas would have on US natural gas supply. Although well stimulation technologies date back to the 1940s, today's shale gas technologies essentially began with the innovative efforts of George Mitchell in the Barnett resource base near Fort Worth, Texas, during the 1980s and 1990s. Mitchell Energy continued to experiment and innovate until eventually proving the economic viability of shale gas development. As a result, shale gas production expanded (see Figure 5).

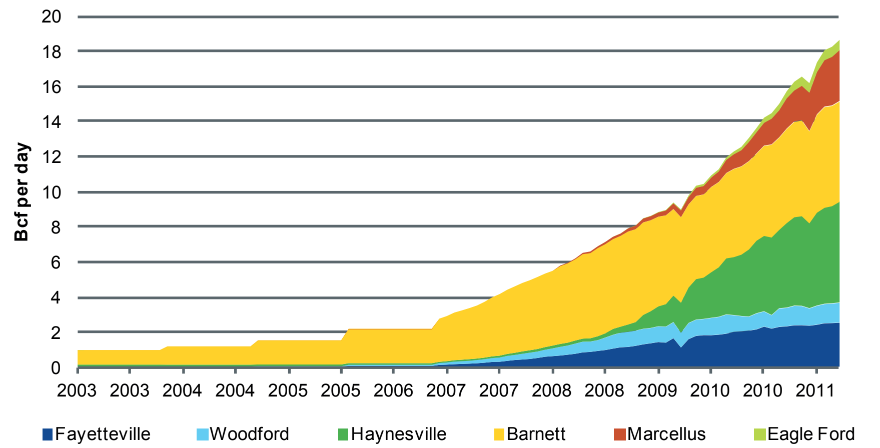
Although shale gas had moved from its innovation phase to its commercialization phase, many in the oil and gas industry did not fully recognize what was happening even as US shale gas output doubled from 2002 to 2007 to reach 8% of US natural gas production. The belief that the United States was running out of natural gas persisted, and this recognition lag supported the continued investment of billions of dollars to expand LNG import facilities (see Figure 6).

3. *New York Times*. "Coal to the Rescue, But Maybe Not Next Winter." Wald, Matthew L. 10 March 2014: http://www.nytimes.com/2014/03/11/business/energy-environment/coal-to-the-rescue-this-time.html?_r=0, retrieved 12 May 2014.

Eventually, evidence of a shale gas revolution became undeniable. However, recognition and adaptation lags continued. Productivity trends in natural gas–directed drilling rigs indicate that only about 400 gas-directed rigs are needed to keep natural gas demand and supply in balance over the long run. Yet operators in the natural gas industry did not fully anticipate this technological trend. Bullish price projections caused the US natural gas–directed rig count to rise from 690 to 1,600 rigs

FIGURE 5

Growth in major US shale plays



Note: Bcf = billion cubic feet.
Source: IHS Energy, Lippmann Consulting

FIGURE 6

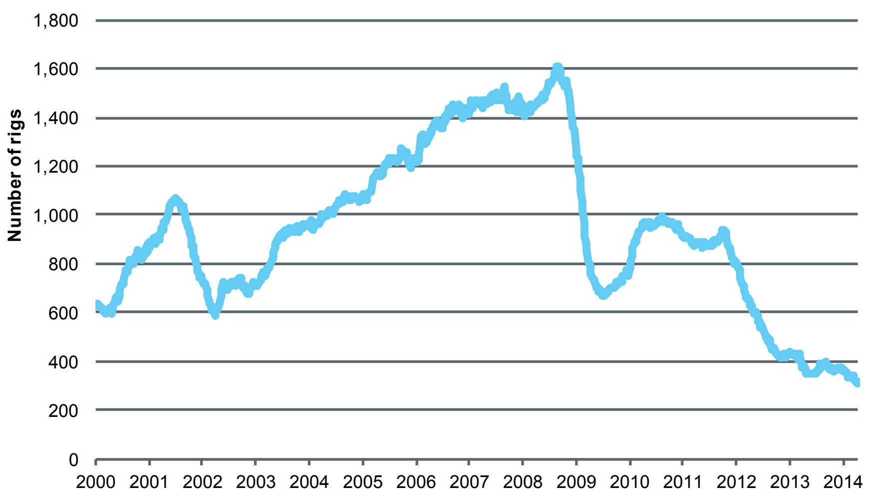
LNG facilities in North America—Existing and proposed (October 2006)

40609-1Source: IHS Energy

between 2002 and 2008. This level of drilling activity created a supply surplus that caused a precipitous decline of up to 85% in the Henry Hub natural gas price from 2008 to 2012. From the 2008 high count, the number of US natural gas–directed rigs dropped over fivefold to 310 by April 2014 (see Figure 7).

FIGURE 7

US gas-directed rig count, 2000–14 YTD



Source: IHS Energy, Baker Hughes © 2014 IHS

Natural gas investment activity also lagged market developments. During this time, the linkage between North American natural gas markets and global markets reversed from an investment hypothesis supporting an expansion of LNG *import* facilities, as shown in Figure 6, to an investment hypothesis involving the expansion of LNG *export* facilities (see Figure 8). At the same time, investment in natural gas pipelines and storage did not keep pace with the shifts in domestic demand, supply, and trade. This asymmetry created vulnerability to low frequency but high impact events, such as colder-than-normal winters that expose gas deliverability constraints and launch record-setting delivered price spikes, as happened in the Northeast in the winters of 2012/13 and 2013/14.

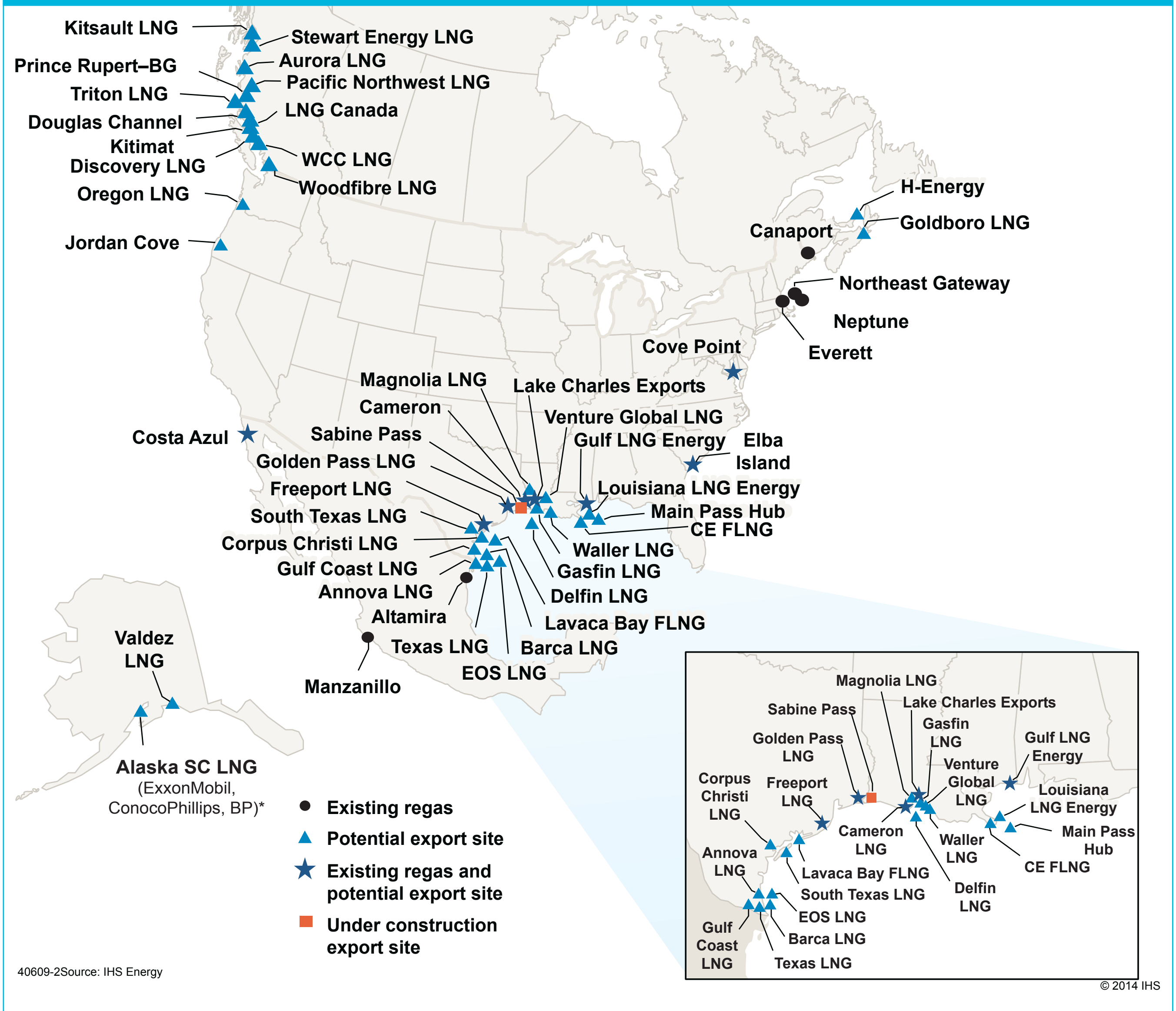
The Northeast delivered natural gas price spikes translated directly into dramatic power production cost run-ups. During the winter of 2013/14, natural gas prices delivered to the New York and PJM power system border hit $140 per MMBtu (at Transco Zone 6, 21 January 2014) and pushed natural gas–fired power production costs up 25-fold from typical levels and well beyond the $1,000 per MWh hourly wholesale power price cap in New York and PJM. This forced the New York Independent System Operator (NYISO) to allow exemptions to market price caps. The Federal Energy Regulatory Commission granted an emergency request to lift wholesale power price caps in PJM and New York. Lifting these price caps kept the lights on but also produced price shocks to 30% of the US power sector receiving monthly power bills in these power systems. The impact moved the 12-month electricity price index (a component of the consumer price index) in the Northeast up 12.7%—the largest 12-month jump in eight years.

The New York Mercantile Exchange (NYMEX) futures contract price strip illustrates how difficult it is to anticipate natural gas price movements. Figure 9 shows the price dynamics over the shale gas era and periodic examples of the NYMEX futures price expectations. The NYMEX future price error pattern indicates a bias toward expecting future natural gas prices to look like those of the recent past. Although these futures prices are often used as an indicator of future natural gas price movements, they have nonetheless proven to be a poor predictor.

The complex drivers of natural gas price dynamics continue to apply in the shale gas era. Prudent planning requires recognition that natural gas price movements remain hard to forecast, affected by multiyear

FIGURE 8

US lower-48 regasification facilities and filed liquefaction projects



investment cycles that lag market developments, subject to seasonality, and capable of severe short-run price volatility.

Natural gas price cycles during the shale gas era and the recent extreme volatility in natural gas prices are clear evidence that the benefits of increased natural gas use for power generation need to be balanced against the costs of natural gas's less predictable and more variable production costs and fuel availability.

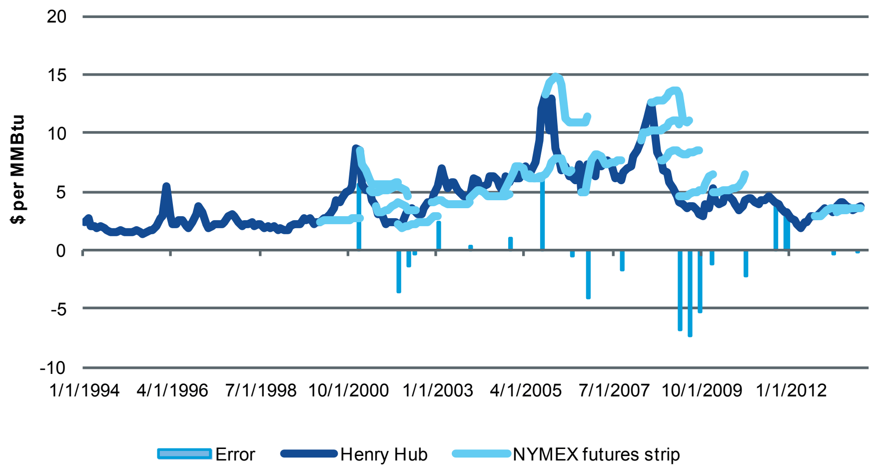
The natural gas–fired generation share is second only to the coal-fired generation share. One of the primary reasons that fuel diversity is so valuable is because natural gas prices and coal prices do not move together.

Significant variation exists in the price of natural gas relative to the price of coal delivered to US power generators (see Figure 10). The dynamics of the relative price of natural gas to coal are important because relative prices routinely change which power plants provide the most cost-effective source of additional power supply at any point in time.

The relative prices of natural gas to coal prior to the shale gas revolution did not trigger as much cost savings from fuel substitution as the current relative prices do. From 2003 to 2007 the price of natural gas was four times higher than the price of coal on a Btu basis. Under these relative price conditions, small changes in fuel prices did not alter the position of coal-fired generation as the lower-cost resource for power generation. The shale gas revolution brought gas prices to a more competitive level and changed the traditional relative relationship between gas and coal generation. As Table 1 shows, the 2013 dispatch cost to produce electricity at the typical US natural gas–fired power plant was equivalent to the dispatch cost at the typical US coal-fired power plant with a delivered natural gas price of \$3.35 per MMBtu, about 1.39 times the delivered price of coal. Current price changes move the relative price of natural gas to coal around this average equivalency level and create more generation substitution than has historically occurred.

FIGURE 9

Henry Hub and NYMEX futures, 1994–2013



Source: IHS Energy

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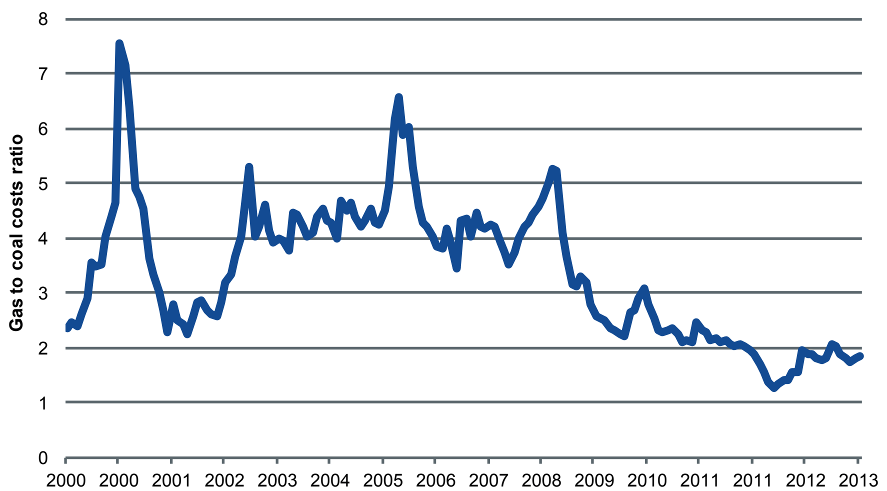
FIGURE 10

Ratio of delivered gas to delivered coal costs, 2000–13



Note: ratio of costs per MMBtu.
Source: IHS Energy, Ventyx Velocity Suite

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The average equivalency level triggers cost savings from substitution within the generation mix. Current relative prices frequently move above and below this critical relative price level. Consequently, slight movements in either coal or natural gas prices can have a big impact on which generation resource provides the most cost-effective source of generation at any given point in time.

Coal price dynamics differ from natural gas price movements. The drivers of coal price dynamics include rail and waterborne price shifts, changes in coal inventory levels, and mine closures and openings. In addition, international coal trade significantly influences some coal prices. For example, when gas prices began to fall in 2008–12, the natural gas displacement of coal in power generation caused Appalachian coal prices also to drop. However, the coal price drop was slower and less severe than the concurrent natural gas price drop because of the offsetting increase in demand for coal exports, particularly for metallurgical coal. Linkages to global coal market prices were significant even though only about one-quarter of Appalachian coal production was involved in international trade. The implication is that as global trade expands, the influence of international trade on domestic fuel prices may strengthen.

TABLE 1

Typical generating units

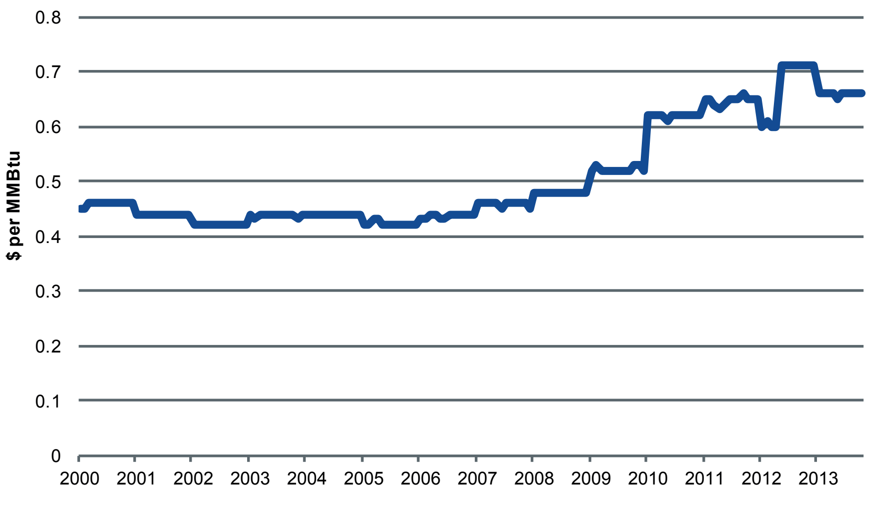
	Typical coal unit	Typical CCGT unit
Size, MW	218	348
Heat rate, Btu/kWh	10,552	7,599
Fuel cost, $/MMBtu	$2.41	$4.46
Fuel cost, $/MWh	$25.43	$33.89
Variable O&M, $/MWh	$4.70	$3.50
Lbs SO_2/MWh (with wet FGD)	1.16	0
SO_2 allowance price, $/ton	70	70
Lbs NO_X/MWh	0.74	0.15
NO_X allowance price, $/ton	252	252
SO_2,NO_X emissions cost, $/MWh	0.13	0.02
Short-run marginal cost, $/MWh	$30.26	$37.41
Breakeven fuel price, $/MMBtu	$2.41	$3.35

Note: kWh = kilowatt-hour(s); O&M = operation and maintenance (costs); SO_2 = sulfur dioxide; NO_X = nitrogen oxides; CCGT = combined-cycle gas turbine.

Source: IHS Energy

FIGURE 11

Nuclear fuel prices, 2000–13



Source: IHS Energy, Ventyx Velocity Suite

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Nuclear fuel prices are also dynamic, and are different from fossil fuel prices in two ways (see Figure 11). Nuclear fuel cost is a relatively smaller portion of a nuclear plant's overall cost per kilowatt-hour. Also nuclear fuel prices have a different set of drivers. The primary drivers of nuclear fuel price movements include uranium prices, enrichment costs, and geopolitical changes in nuclear trade. These drivers produce price dynamics dissimilar to those of either natural gas or coal. As a result, nuclear fuel price movements are not strongly correlated to fossil fuel price movements.

Diversity: The portfolio effect

A diverse fuel and technology portfolio is a cornerstone for an effective power production risk management strategy. If prices for alternative fuels moved together, there would be little value in diversity. But relative power production costs from alternative fuels or technologies are unrelated and inherently unstable. As a result, the portfolio effect in power generation exists because fuel prices do not move together, and thus changes in one fuel price can offset changes in another. The portfolio effect of power generation fuel diversity is significant because the movements of fuel prices are so out of sync with one another.

TABLE 2

Delivered monthly fuel price correlations, 2000–13	
Coal/natural gas	0.01
Natural gas/nuclear	(0.35)
Coal/nuclear	0.85

Source: IHS Energy

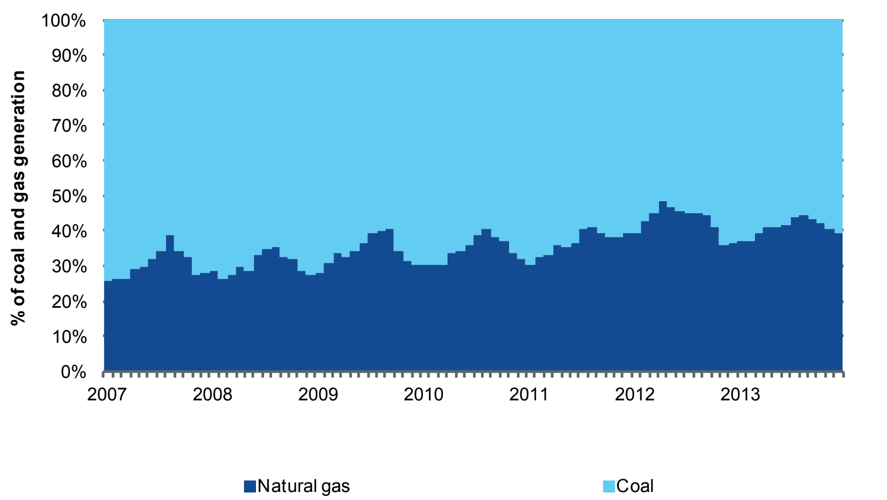
The "correlation coefficient" is a statistical measure of the degree to which fuel price changes are related to each other. A correlation coefficient close to zero indicates no similarity in price movements. Correlation coefficients above 0.5 are considered strong correlations, and values above 0.9 are considered very strong correlations. Power production input fuel price changes (natural gas, coal, and nuclear) are not highly correlated and consequently create the basis for a portfolio approach to fuel price risk management (see Table 2).

Diversity: The substitution effect

A varied portfolio mitigates power production cost risk because fuel diversity provides the flexibility to substitute one source of power for another in response to relative fuel price changes. Therefore, being able to substitute between alternative generation resources reduces the overall variation in production costs.

FIGURE 12

Coal and natural gas generation, 2007–13



Source: IHS Energy © 2014 IHS

Substitution benefits have proven to be substantial. In the past five years, monthly generation shares for natural gas–fired generation were as high as 33% and as low as 19%. Similarly, monthly generation shares for coal-fired generation were as high as 50% and as low as 34%. The swings were driven primarily by a cost-effective alignment of fuels and technologies to consumer demand patterns and alterations of capacity utilization rates in response to changing relative fuel costs. Generation shares shifted toward natural gas–fired generation when relative prices favored natural gas and shifted toward coal-fired generation when relative prices favored coal. Figure 12 shows the recent flexibility in the utilization share tradeoffs between only coal-fired and natural gas–fired generation in the United States.

Diversity benefits differ by technology

All types of generating fuels and technologies can provide the first dimension of risk management—the *portfolio effect*. However, only some types of fuels and technologies can provide the second dimension of risk management—the *substitution effect*. Power plants need to be dispatchable to provide the substitution effect in a diverse portfolio. As a result, the benefits of expanding installed capacity diversity by adding nondispatchable resources such as wind and solar generating technologies are less than the equivalent expansion of power capacity diversity with dispatchable power plants such as biomass, conventional fossil-fueled power plants, reservoir hydro, and nuclear power plants. Therefore, not all diversity in the capacity mix provides equal benefits.

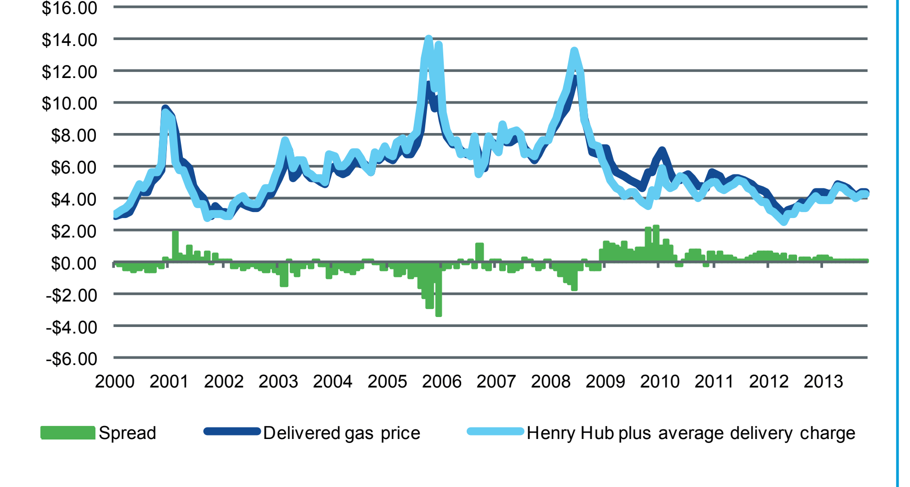
Diversity is the best available power cost risk management tool

A diverse portfolio is the best available tool for power generation cost risk management. Other risk management tools such as fuel contracts and financial derivatives complement fuel and technological diversity in power generation but fall far short of providing a cost-effective substitute for power supply diversity.

Contracts are tools available to manage power production cost risk. These tools include short-run contracts, including NYMEX futures contracts, as well as long-term contracts spanning a decade or more. Power generators have traditionally covered some portion of fuel needs with contracts to reduce the variance of delivered fuel costs. To do this, generators balance the benefits of using contracts or financial derivatives against the costs. With such assessment, only a small percentage of natural gas purchases are under long-term contracts or hedged in the futures markets. Consequently, the natural gas futures market is only liquid (has many buyers and sellers) for a few years out.

FIGURE 13

Power generation delivered gas price versus Henry Hub (plus delivery), 2000–13



Source: IHS Energy, Ventyx Velocity Suite © 2014 IHS

The degree of risk management provided by contracts is observed in the difference between the reported delivered price of natural gas to power generators and the spot market price plus a typical delivery change. Contract prices along with spot purchases combine to determine the reported delivered price of natural gas to power generators. Delivered prices are typically about 12% higher than the Henry Hub spot price owing to transport, storage, and distribution costs, so this percentage may be used to approximate a delivery charge. Figure 13 compares the Henry Hub spot price plus this typical delivery charge to the reported delivered price of natural gas to power producers.

A comparison of the realized delivered price to the spot price plus a delivery charge shows the impact of contracting on the delivered price pattern. Natural gas contracts provided some protection from spot price highs and thus reduced some variation of natural gas prices compared to the spot market price plus transportation. Over the past 10 years, contracting reduced the monthly variation (the standard deviation) in the delivered price of natural gas to the power sector by 24% compared to the variation in the spot price plus delivery charges at the Henry Hub. Although fuel contracts are part of a cost-effective risk management strategy, the cost/benefit trade-offs of using contracts limit the application of these tools in a cost-effective risk management strategy.

Using a contract to lock into volumes at fixed or indexed prices involves risks and costs. Contracting for fuel creates volume risk. A buyer of a contract is taking on an obligation to purchase a given amount of fuel, at a given price, and at a future point in time. From a power generator's perspective, the variations in aggregate power consumer demand and relative prices to alternative generating sources make predicting the amount of fuel needed at any future point in time difficult. This difficulty increases the further out in time the contracted fuel delivery date. If a buyer ends up with too much or too little fuel at a future point in time, then the buyer must sell or buy at the spot market price at that time.

Contracting for fuel creates price risk. A buyer of a fuel contract locks into a price at a future point in time. When the contract delivery date arrives, the spot market price for the fuel likely differs from the contract price. If the contract price ends up higher than the spot market price, then the contract provided price certainty but also created a fuel cost that turned out to be more expensive than the alternative of spot market purchases. Conversely, if the spot market price turns out to be above the contract price, then the buyer has realized a fuel cost savings.

Past price relationships also illustrate the potential for gains and losses from contracting for natural gas in an uncertain price environment. When the spot market price at Henry Hub increased faster than expected, volumes contracted at the previously lower expected price produced a gain. For example, in June 2008 the delivered cost of natural gas was below that of the spot market. Conversely, when natural gas prices fell faster than anticipated, volumes contracted at the previously higher expected price produced a loss. For example in June 2012, the delivered cost of natural gas was above that of the spot market purchases.

The combination of volume and price risk in fuel contracting makes buying fuel under contract a speculative activity, capable of generating gains and losses depending on how closely contract prices align with spot market prices. Therefore, cost-effective risk management requires power generators to balance the benefits of gains from contracting for fuel volumes and prices against the risk of losses.

Managing fuel price risk through contracts does not always involve the physical delivery of the fuel. In particular, a futures contract is typically settled before physical delivery takes place, and thus is referred to as a financial rather than a physical hedge to fuel price uncertainty. For example, NYMEX provides a standard contract for buyers and sellers to transact for set amounts of natural gas capable of being delivered at one of many liquid trading hubs at a certain price and a certain date in the future. Since the value of a futures contract depends on the expected future price in the spot market, these futures contracts are derivatives of the physical natural gas spot market.

The potential losses facing a fuel buyer that employs financial derivatives create a risk management cost. Sellers require that buyers set aside funds as collateral to insure that potential losses can be covered. Market regulators want these guarantees in place as well in order to manage the stability of the marketplace. Recently, as part of reforms aimed at improving the stability of the financial derivatives markets, the Dodd-Frank Act increased these collateral requirements and thus the cost of employing financial derivatives.

Outside of financial derivatives, fuel deliverability is an important consideration in evaluating power cost risk management. Currently, natural gas pipeline expansion requires long-term contracts to finance projects. Looking ahead, the fastest growing segment of US natural gas demand is the power sector and, as described earlier, this sector infrequently enters into long-term natural gas supply contracts that would finance new pipelines. Consequently, pipeline expansions are not likely to stay in sync with power generation natural gas demand trends.

The prospect of continued periodic misalignments between natural gas deliverability and natural gas demand makes price spikes a likely feature of the future power business landscape. The nominal volume of long-term fuel contracts and the costs and benefits of entering into such contracts limit the cost-effective substitution of contracts for portfolio diversity. Therefore, maintaining or expanding fuel diversity remains a competitive alternative to natural gas infrastructure expansion.

Striking a balance between the costs and benefits of fuel contracting makes this risk management tool an important complement to a diverse generation portfolio but does not indicate that it could provide a cost-effective substitute for power supply diversity.

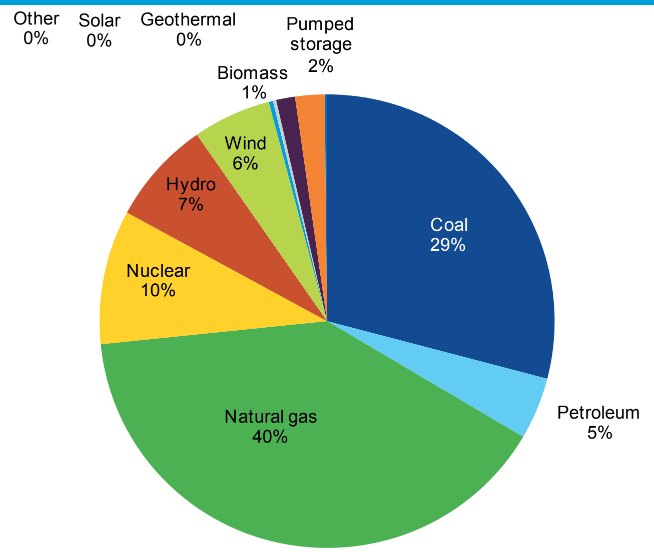
A starting point taken for granted

US power consumers benefit from the diverse power supply mix shown in Figure 14. Simply inheriting this diverse generation mix based on fuel and technology decisions made decades ago makes it easy for current power stakeholders to take the benefits for granted. This underappreciation of power supply diversity creates an energy policy challenge because if the value of fuel and technology diversity continues to be taken for granted, then the current political and regulatory process is not likely to properly take it into account when crafting legislation or setting regulations.

As a result, the United States may move down a path toward a less diverse power supply without consumers realizing the value of power supply diversity until it is gone. For example, if the US power sector had been all natural gas–fired during the shale gas era to date, the average fuel cost for power would have been over twice as high, and month-to-month power bill variation (standard deviation) would have been three times greater (see Table 3). This estimate itself is conservative because the additional demand from power generation would have likely put significant upward pressure on gas prices.

FIGURE 14

US installed capacity (1,063 GW), 2012



Source: US Energy

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TABLE 3

The impact of fuel diversity: Power production fuel costs
(Actual versus all gas generation mix, 2000–13 YTD, cents per kWh)

	Henry Hub	All power sector fuel costs
Average	5.09	2.29
Maximum	11.02	4.20
Minimum	2.46	1.21
Standard deviation	1.63	0.55

Note: Converted the Henry Hub dollar per MMBtu price to cents per kWh using the average reported heat rate for all operating natural gas plants in the respective month.
Data source: Ventyx Velocity Suite.

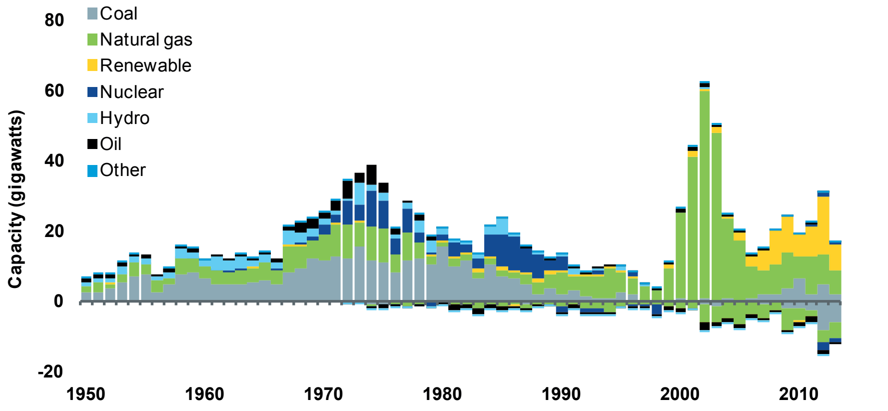
Source: IHS Energy

Trends in the US generation mix

The current diverse fuel and technology mix in US power supply did not come about by accident. The US generation mix evolved over many decades and reflects the fuel and technology decisions made long ago for power plants that typically operate for 30 to 50 years or more. Consequently, once a fuel and technology choice is made, the power system must live with the consequences—whatever they are—for decades.

FIGURE 15

US generating capacity additions and retirements, 1950–2013



Source: IHS Energy, Ventyx Velocity Suite

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US power supply does not evolve smoothly. The generation mix changes owing to the pace of power plant retirements, the error in forecasting power demand, price trends and other developments in the energy markets, and the impacts of public policy initiatives. All three of these factors unfold unevenly over time. The current diverse generation mix evolved from multiyear cycles of capacity additions that were typically dominated by a particular fuel and technology (see Figure 15). The swings in fuel and technology choice do not indicate a lack of appreciation for diverse power supply. Instead, they show that given the size of the existing supply base, it takes a number of years of homogenous supply additions to move the overall supply mix a small proportion. Therefore, altering the overall mix slightly required a number of years of adjustment.

The uneven historical pattern of capacity additions is important because the future pattern of retirements will tend to reflect the previous pattern of additions as similarly aged assets reach the end of their useful lives. For example, current retirements are disproportionately reducing the coal and nuclear shares in the capacity mix, reflecting the composition of power plants added in the 1960s through 1980s. Current power plant retirements are about 12,000 MW per year and are moving the annual pace of retirements in the next decade to 1.5 times the rate of the past decade.

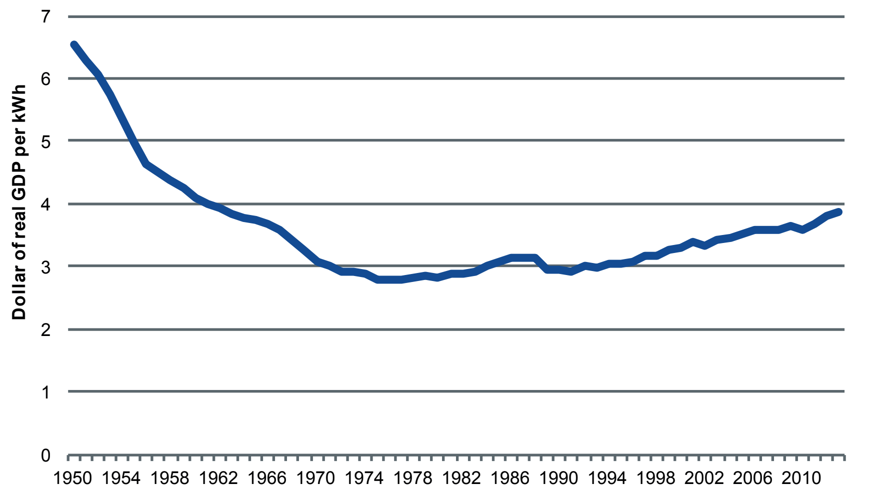
Power plant retirements typically need to be replaced because electricity consumption continues to increase. Although power demand increases are slowing compared to historical trends and compared to the growth rate of GDP, the annual rate of change nevertheless remains positive. US power demand is expected to increase between 1.0% and 2.5% each year in the decade ahead, averaging 1.5%.

The expected pace of US power demand growth reflects a number of trends. First, US electric efficiency has been improving for over two decades. Most appliances and machinery have useful lives of many years. As technology improves, these end uses get more efficient. Therefore, overall efficiency typically increases as appliances and machinery wear out and are replaced. On the other hand, the number of electric end uses keeps expanding and the end-use penetration rates keep increasing owing to advances in digital and communication technologies that both increase capability and lower costs. These trends in existing technology turnover and new technology adoption produce a steady rate of change in electric end-use efficiency (see Figure 16).

Underlying trends in power demand are often masked by the influences of variations in the weather and the business cycle. For example, US electric output in first quarter 2014 was over 4% greater than in the same period one year ago owing in part to the influence of the polar vortex. Therefore, trend rates need to compare power consumption increases either between points in time with similar weather conditions or on a weather-normalized basis. Similarly, power demand trends can be misleading if compared without taking the business cycle into account. Figure 17 shows the trend rate of growth in power use from the previous business cycle peak to peak and tough to trough. Overall, power consumption increased by between 0.5 and 0.6 of the rate of increase in GDP. Looking ahead, GDP is expected to increase on average 2.5% annually through 2025 and thus is likely to produce a trend rate of electric consumption of around 1.5% annually. This US power demand growth rate creates a need for about 9 GW of new power supply per year, for a total of 1,140 GW by 2025.

FIGURE 16

US electric efficiency, 1950–2013



Note: BEA reports Real GDP in 2009 dollars.
Source: IHS Energy, EIA, BEA

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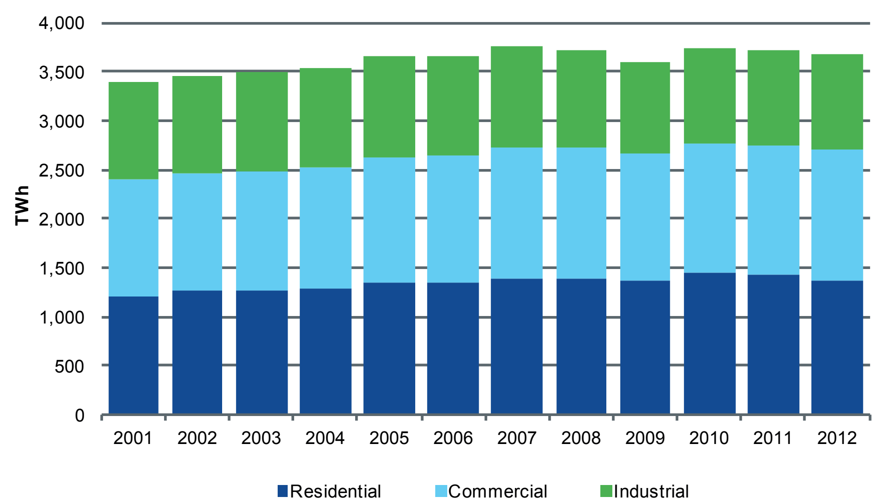
FIGURE 17

US electricity sales by customer class, 2001–12



Note: TWh = terawatt-hour(s).
Source: IHS Energy, EIA

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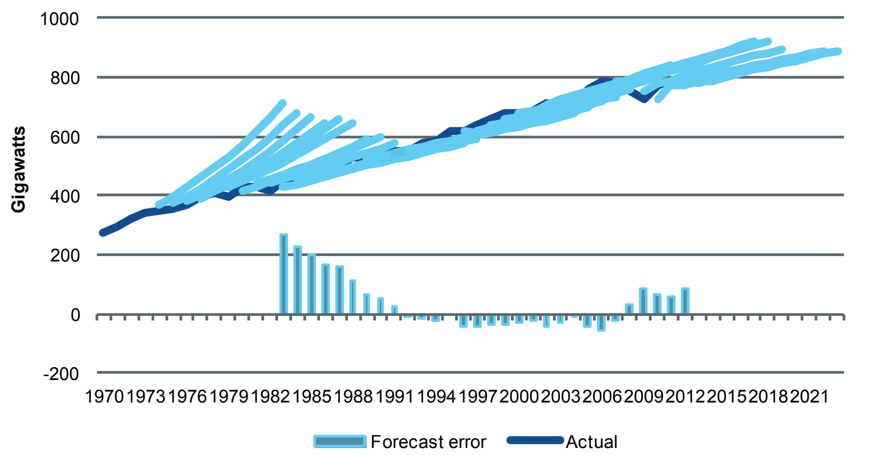
Annual power supply additions do not typically unfold simultaneously with demand increases. Historically, changes in power supply are much more pronounced than the changes in power demand. This uneven pace of change in the capacity mix reflects planning uncertainty regarding future power demand and a slow adjustment process for power supply development to forecast errors.

Future electric demand is uncertain. Figure 18 shows a sequence of power industry forecasts of future demand compared to the actual demand. The pattern of forecast errors indicates that electric demand forecasts are slow to adjust to actual conditions: overforecasts tend to be followed by overforecasts, and underforecasts tend to be followed by underforecasts.

FIGURE 18

US power demand: Projected versus actual, 1983–2012



Source: IHS Energy
Data source: North American Electric Reliability Corporation
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Forecasting uncertainty presents a challenge because fuel and technology decisions must be made years in advance of consumer demand to accommodate the time requirements for siting, permitting, and constructing new sources of power supply. As a result, the regional power systems are subject to momentum in power plant addition activity that results in capacity surpluses and shortages. Adjustment to forecast overestimates is slow because when a surplus becomes evident, the capital intensity of power plants creates an accumulating sunk-cost balance in the construction phase of power supply development. In this case, there is an economic incentive to finish constructing a power plant because the costs to finish are the relevant costs to balance against the benefits of completion. Conversely, if a shortage becomes evident, new peaking power plants take about a year to put into place under the best of circumstances. Consequently, the forecast error and this lagged adjustment process can produce a significant over/underinstallment of new capacity development versus need. These imbalances can require a decade or more to work off in the case of a capacity overbuild and at least a few years to shore up power supply in the case of a capacity shortage.

The pace and makeup of power plant additions are influenced by energy policies. The current installed capacity mix reflects impacts from the implementation of a number of past policy initiatives. Most importantly, 35 years ago energy security was a primary concern, and the energy policy response included the Fuel Use Act (1978) and the Public Utilities Regulatory Policy Act (1978). These policies limited the use of natural gas for power generation and encouraged utility construction of coal and nuclear generating resources as well as nonutility development of cogeneration. Public policy championed coal on energy security grounds—as a safe, reliable, domestic resource.

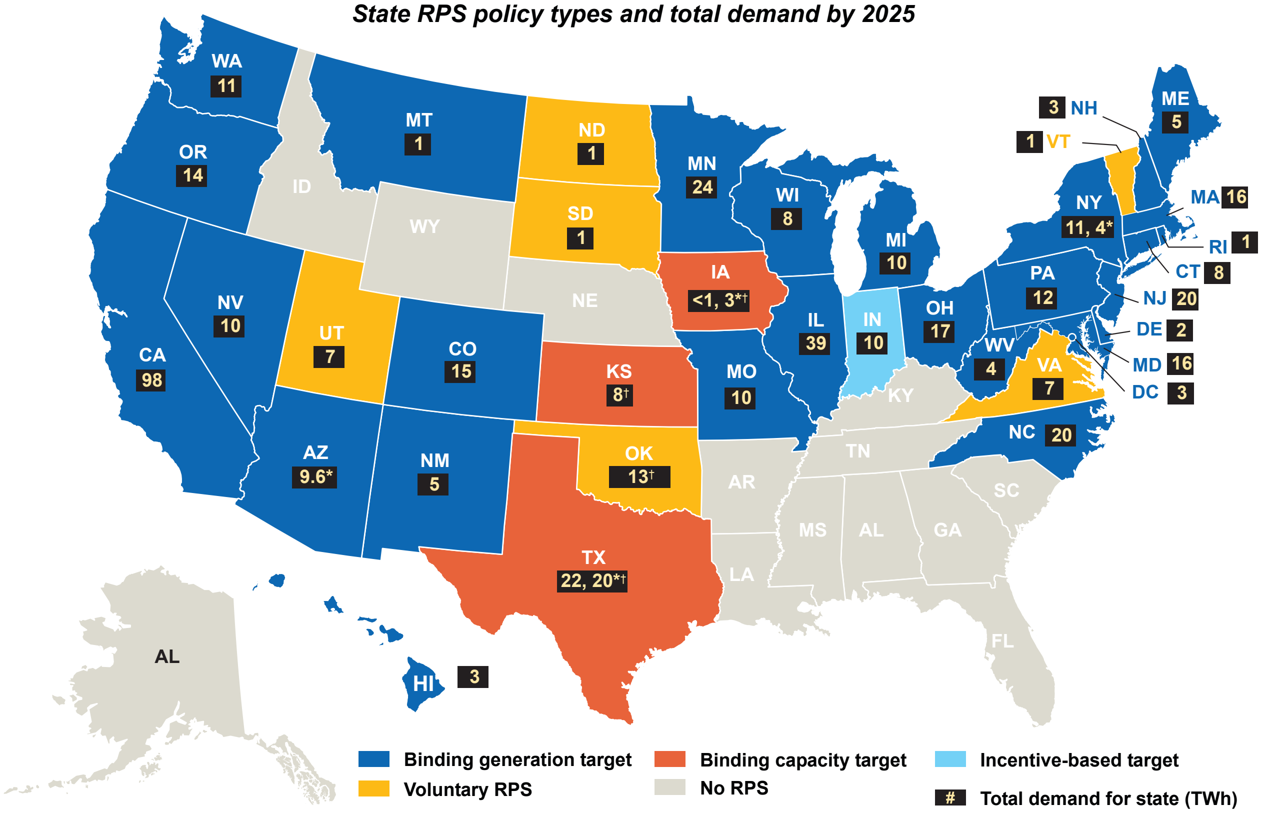
The influence of energy policy on power plant fuel and technology choice is dynamic. For example, as natural gas demand and supply conditions changed following the passage of the Fuel Use Act, the limits on natural gas use for power generation were eventually lifted in 1987. Whereas the Fuel Use Act banned a fuel and technology, other policy initiatives mandate power generation technologies. Energy policies designed to address the climate change challenge created renewable power portfolio requirements in 30 states (see Figure 19).

As states work to implement renewable generation portfolio standards, the complexity of power system operations becomes evident and triggers the need for renewable integration studies. These studies generally find that the costs to integrate intermittent power generation resources increase as the generation share of these resources increases. Some integration studies go so far as to identify the saturation point for wind resources based on their operational characteristics. A wind integration study commissioned by the

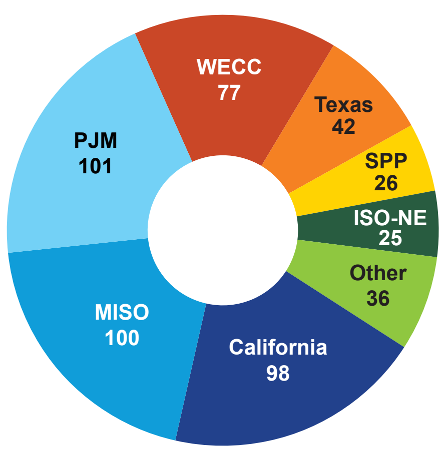
FIGURE 19

The outlook for US State RPS demand to 2025—Total demand: State policy and targets

State RPS policy types and total demand by 2025



Total RPS demand by region (TWh)



30 US states plus the District of Columbia have enacted binding renewable energy targets, and seven others have adopted incentive-based or voluntary targets. These 37 states account for 74% of US retail power sales.

40609-3

Note: *States include both mandatory and voluntary targets; first number reflects mandatory target, second number reflects additional voluntary targets (of state, municipalities, or other political divisions/utilities).

†Capacity targets have been converted to generation for comparison using estimated regional capacity factors. All quantities reflect primary renewables; see page 2 for additional notes

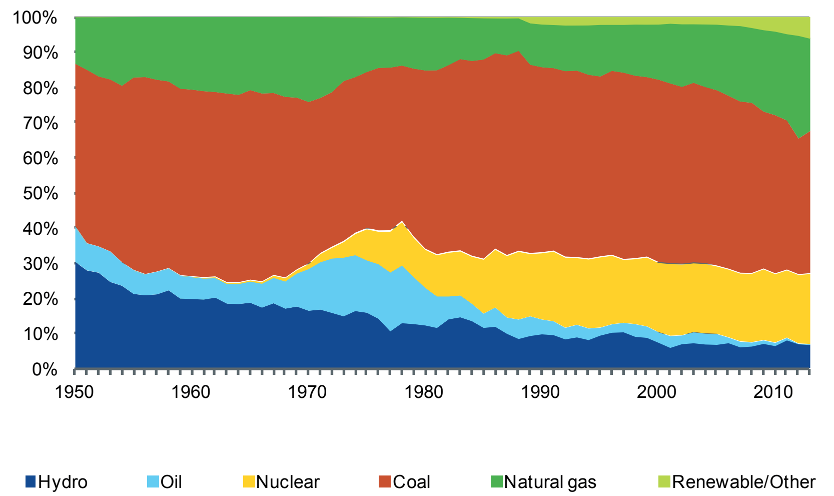
Source: IHS Emerging Energy Research

power system operator in New England estimated the saturation point for wind in the power system (24% generation share) as well as the additional resources that would be needed to integrate more wind resources.[4] Similarly, a wind integration study by the power system operator in California found that problems were ahead for the California power system because the number of hours when too much wind generation was being put on the grid was increasing. The study noted higher costs were ahead as well because additional resources would be needed to integrate expected additional wind resources planned to meet the renewable portfolio requirements in place.[5] Many of the impacts on the US generation mix from renewable power portfolio requirements are yet to come as higher generation or capacity share mandates become binding in many states in the next few years.

The United States is at a critical juncture because current trends in power plant retirements, demand and supply balances, and public policies are combining to accelerate change in the US generation mix, as shown in Figure 20. In 2013, increases in demand, power plant retirements, and renewable mandates resulted in around 15,800 MW of capacity additions. In the decade ahead, these increasing needs will require power supply decisions amounting to 15% of the installed generating capacity in the United States. In addition, public policies are expected to increase the share of wind and solar generation, and forthcoming regulations from the Environmental Protection Agency (EPA) regarding conventional power plant emissions as well as greenhouse gases (GHG) could significantly increase power plant retirements and accelerate changes further. Altogether, changes in US generating capacity in the next two decades could account for more than one-third of installed capacity.

FIGURE 20

US power generation: shares by fuel, 1950–2013



Source: IHS Energy, EIA

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Threat to power generation diversity: Complacency

Threats to maintaining diversity in power production do not come from opposition to the idea itself, but rather from the complacency associated with simply taking diversity for granted. The familiar adage of not putting all your eggs in one basket is certainly aligned with the idea of an all-of-the-above energy policy. Four decades of experience demonstrates the conclusion that the government should not be picking fuel or technology winners, but rather should be setting up a level playing field to encourage competitive forces to move the power sector toward the most cost-effective generation mix. Nevertheless, in a striking contrast,

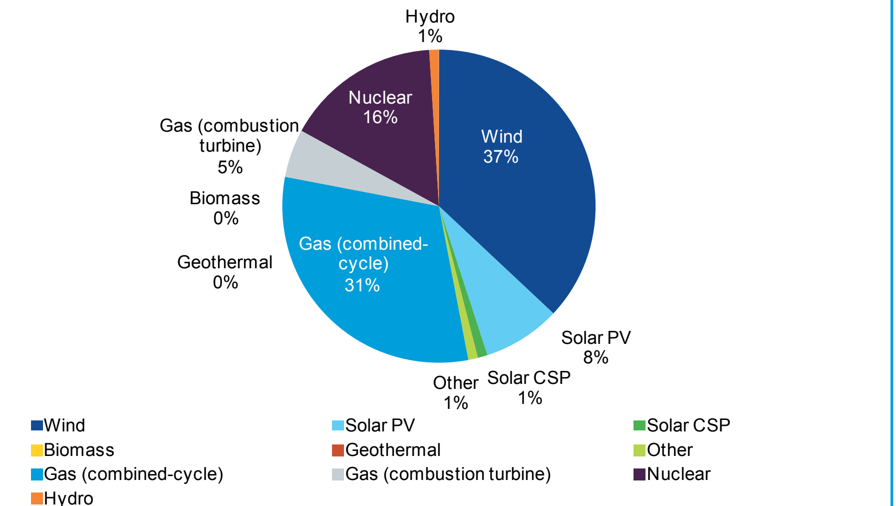
4. *New England Wind Integration Study* produced for ISO New England by GE Energy Applications and Systems Engineering, EnerNex Corporation, and AWS Truepower, 5 December 2010. Accessed 16 April 2014 (http://www.uwig.org/newis_es.pdf).

5. "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS." California ISO, 31 August 2010, downloaded from www.caiso.com/2804/2804d036401f0.pdf.

the value of fuel diversity to the end use consumer is not internalized in current power plant decision making. A 2013 review of over eighty integrated resource plans (IRPs) found that many reference fuel diversity but only a few of them refer to it as a risk, and none of them quantify the value of fuel diversity to incorporate it into the decision process.[6] Additionally, environmental policy initiatives do not seem to accommodate diversity issues. Therefore, one power plant decision after another is revealing a de facto energy policy to move away from oil, coal, and nuclear generation and reduce hydroelectric capability, and instead build relatively low utilization wind and solar resources backed up by natural gas–fired generating units (see Figure 21).

FIGURE 21

US capacity under construction: 34,620 MW



Notes: Note: CSP = concentrating solar power, PV = photovoltaic. Data as of April 2014.
Source: IHS Energy and Ventyx Velocity Suite

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Threat to power generation diversity: The "missing money"

Fuel diversity is threatened as well by the inability of power markets to evolve market rules and institutions to address the "missing money" problem in competitive power generator cash flows. The missing money problem in power markets is the latest manifestation of a long-standing problem in a number of industries, including railroads, airlines, and power, where competitive markets fail to balance demand and supply at market-clearing prices high enough to support the full cost of supply.

Power markets have a missing money problem because they do not have all of the necessary conditions to produce a textbook competitive marketplace. The textbook marketplace has suppliers who maximize their profits by expanding output up to the point where their short-run marginal cost (SRMC) of production equals the market-clearing price. This means that an aggregation of rival suppliers' SRMC curves produces the market supply curve. If this market supply curve intersects the market demand curve at a price too low to support the full cost of new supply (long-run marginal cost [LRMC]), then suppliers will not expand productive capacity. Instead, they will meet increases in demand by adding more variable inputs to the production process with a fixed amount of capacity. However, doing so increases SRMC, and eventually the market-clearing price rises to the point where it covers the cost of expanding productive capacity. This produces the textbook market equilibrium where demand and supply are in balance at the unique point where market-clearing prices are equal to both SRMC and LRMC.

Several characteristics of the technologies that make up a cost-effective power supply create a persistent gap between SRMCs and LRMCs as production varies. As a result, market-clearing wholesale power prices are below the level needed to support the full cost of power supply when demand and supply are in balance with the desired level of reliability.[7] Consequently, the stable textbook market equilibrium does not exist in an electric power marketplace.

6. See the IHS Energy Insight *Reading the Tea Leaves: Trends in the power industry's future plans.*

7. See the IHS Energy Private Report *Power Supply Cost Recovery: Bridging the missing money gap.*

A simple example of a competitive power market made up entirely of rival wind generators illustrates the missing money problem. The cost profile of wind turbine technologies comprises nearly exclusively upfront capital costs (LRMCs). SRMCs for wind technologies equal zero because the variable input to the power production process is wind, and this input is free. In a competitive market, if wind conditions allow for power production, then rival wind generators will be willing to take any price above zero to provide some contribution to recovering the upfront capital costs. If there is adequate supply to balance demand in a competitive marketplace, then rival wind suppliers will drive the market-clearing price to zero. This is not just a theoretical example. When power system conditions create wind-on-wind competition, then zero or negative market-clearing prices (reflecting the cost of losing the production tax credit) are typically observed. Wind generating technologies are a simple and extreme example of a power generating technology with a persistent gap between SRMCs and LRMCs. But this problem exists to some degree with other power generation technologies.

This technology-based market flaw means that periodic shortage-induced price spikes are the only way for market-clearing prices to close the gap between the SRMC and LRMC. This market outcome does not work because of the inherent contradiction—periodic shortages are needed to keep demand and supply in balance.

The missing money problem threatens cost-effective power supply because when market-clearing power prices are chronically too low to support new power plants, then lower expected cash flows at existing plants cause retirements before it is economic to do so, given replacement costs. It is cost effective to retire and replace a power plant only when its cost of continued operation becomes greater than the cost of replacement. Therefore, a market-clearing power price that reflects the full cost of new power supply is the appropriate economic signal for efficient power plant closure and replacement. Consequently, when this price signal is too low, power plant turnover accelerates and moves power supply toward the reduced diversity case.

"Missing money" and premature closing of nuclear power plants

The Kewaunee nuclear plant in Wisconsin is an example of a power plant retirement due to the missing money problem. Wholesale day-ahead power prices average about $30 per MWh in the Midwest power marketplace. This market does not have a supply surplus, and recently the Midwest Independent System Operator (MISO), the institution that manages the wholesale market, announced that it expects to be 7,500 MW short of generating capacity in 2016.[8] The current market-clearing power price must almost double to send an efficient price signal that supports development of a natural gas–fired combined-cycle power plant.

The Kewaunee power plant needs much less than the cost of a new plant, about $54 per MWh, to cover the costs of continued operation. Kewaunee's installed capacity was 574 MW, and the plant demonstrated effective performance since it began operation in 1974. The plant received Nuclear Regulatory Commission approval for life extension through 2033. Nevertheless, the persistent gap between market prices and new supply costs led Dominion Energy, the power plant's owner, to the October 2012 decision to close the plant because of "low gas prices and large volumes of wind without a capacity market."

Kewaunee is not an isolated case. Other nuclear power plants such as Vermont Yankee provide similar examples. Additionally, a significant number of coal-fired power plants are retiring well before it is economic to do so. For example, First Energy retired its Hatfield's Ferry plant in Ohio on 9 October 2013. This is a large (1,700 MW) power plant with a $33 per MWh variable cost of power production.[9] The going-forward

8. Whieldon, Esther. "MISO-OMS survey of LSEs, generators finds resource shortfall remains likely in 2016." SNL Energy, 6 December 2013. Accessed on 14 May 2014 http://www.snl.com/InteractiveX/ArticleAbstract.aspx?id=26168778. Note: LSE = load-serving entity.

9. Source: SNL Financial data for 2012 operations, accessed 5 May 2014. Available at http://www.snl.com/InteractiveX/PlantProductionCostDetail.aspx?ID=3604.

costs involved some additional environmental retrofits, but the plant had already invested $650 million to retrofit a scrubber just four years prior to the announced retirement.

Reducing diversity and increasing risk

Proposed EPA regulations on new power plants accommodate the carbon footprint of new natural gas–fired power plants but do not accommodate the carbon footprint of any new state-of-the-art conventional coal-fired power plants that do not have carbon capture and storage (CSS). Since the cost and performance of CSS technologies remain uneconomic, the United States is now on a path to eliminating coal-fired generation in US power supply expansion. This move toward a greatly reduced role for coal in power generation may accelerate because the EPA is now developing GHG emission standards for existing power plants that could tighten emissions enough to dramatically increase coal-fired power plant retirements.

The impact of a particular fuel or technology on fuel diversity depends on overall power system conditions. As a general rule, the benefits of fuel diversity from any source typically increase as its share in the portfolio decreases. Oil-fired generation illustrated this principle when it proved indispensable in New England in keeping electricity flowing this past winter. Despite only accounting for 0.2% of US generation, it provided a critical safety valve for natural gas deliverability during the polar vortex. Yet, these oil-fired power plants are not likely to survive the tightening environmental regulations across the next decade. The implication is clear: there is a much higher cost from losing this final 0.2% of oil in the generation mix compared to the cost of losing a small percentage of oil-fired generation back in 1978, when oil accounted for 17% of the US generation mix. Losing this final 0.2% of the generation mix will be relatively expensive because the alternative to meet infrequent surges in natural gas demand involves expanding natural gas storage and pipeline capacity in a region where geological constraints make it increasingly difficult to do so.

Public opinion is a powerful factor influencing the power generation mix. The loss of coal- or oil-fired power plants in the generation mix is often ignored or dismissed because of public opinion. Coal- or oil-fired power plants are generally viewed less favorably than wind and solar resources. In particular, labeling some sources of power as “clean energy” necessarily defines other power generating sources as “dirty energy.” This distinction makes many conventional power supply sources increasingly unpopular in the political process. Yet, all sources of power supply employed to meet customer needs have an environmental impact. For example, wind and solar resources require lots of land and must be integrated with conventional grid-based power supply to provide consumers with electricity when the wind is not blowing or the sun is not shining. Therefore, integrating these “clean energy” resources into a power system to meet consumer needs produces an environmental footprint, including a GHG emission rate. The arbitrary distinctions involved in “clean energy” are evident when comparing the emissions profiles of integrated wind and solar power production to that of nuclear power production. A simplistic and misleading distinction between power supply resources is a contributing factor to the loss of fuel diversity.

Edison International provides an example of the impact of public opinion. Antinuclear political pressures in California contributed to the decision in 2013 to prematurely close its San Onofre nuclear power plant. This closure created a need for replacement power supply that is more expensive, more risky, and more carbon intensive.

The going-forward costs of continued operation of the San Onofre nuclear plant were less than the cost of replacement power. Therefore, the closure and replacement of the San Onofre power plant made California power supply more expensive in a state that already has among the highest power costs in the nation. A study released in May 2014 by the Energy Institute at Haas at the University of California Berkeley estimated that closing the San Onofre nuclear power station increased the cost of electricity by $350 million during the first twelve months.[10] This was a large change in power production costs, equivalent to a 13% increase in the total generation costs for the state.

Closing San Onofre makes California power costs more risky. California imports about 30% of its electricity supply. Prior to the closure, nuclear generation provided 18.3% of California generation in 2011, and the San Onofre nuclear units accounted for nearly half of that installed nuclear capacity. The Haas study found that imports increase with system demand but not much, likely owing to transmission constraints, grid limitations, and correlated demand across states. The results imply that the loss of the San Onofre power plant was primarily made up through the use of more expensive generation, as much as 75% of which was out-of-merit generation running to supply energy as well as voltage support. The report's analysis found that up to 25% of the lost San Onofre generation could have come from increased imports of power. The substitute power increases California consumers' exposure to the risks of fossil fuel price movements as well as the risks of low hydroelectric generation due to Western Interconnection drought cycles.

Closing San Onofre makes California power production more carbon intensive. Nuclear power production does not produce carbon dioxide (CO_2) emissions. These nuclear units were a major reason that the CO_2 intensity of California power production was around 0.5 pounds (lb) per kilowatt-hour (kWh). Replacement power coming from in-state natural gas–fired power plants has associated emissions of about 0.9 lb per kWh. Replacement power coming from the rest of the Western Interconnection has associated emissions of 1.5 lb per kWh. Even additional wind and solar power sources in California with natural gas–fired power plants filling in and backing them up have a 0.7 lb per kWh emissions profile. The Haas study found that closing San Onofre caused carbon emissions to increase by an amount worth almost $320 million, in addition to the $350 million in increased electricity prices in the first year. In the big picture, California CO_2 emissions have not declined in the past decade, and the closure of the San Onofre nuclear units will negate the carbon abatement impacts of 20% of the state's current installed wind and solar power supply.

The path toward a less diverse power supply

The relative unpopularity of coal, oil, nuclear, and hydroelectric power plants (compared to renewables), combined with the missing money problem, tightening environmental regulations, and a lack of public awareness of the value of fuel diversity create the potential for the United States to move down a path toward a significant reduction in power supply diversity. Within a couple of decades, the US generation mix could have the following capacity characteristics:

- No meaningful nuclear power supply share
- No meaningful coal-fired power supply share
- No meaningful oil-fired power supply share
- Hydroelectric capacity in the United States reduced by 20%, from 6.6% to 5.3% of installed capacity
- Renewables power supply shares at operational limits in power supply mix: 5.5% solar, 27.5% wind
- Natural gas–fired generation becoming the default option for the remaining US power supply of about 61.7%

10. http://ei.haas.berkeley.edu/pdf/working_papers/WP248.pdf, accessed 30 May 2014.

Comparing the performance of current diverse power supply to this reduced diversity case provides a basis for quantifying the current value of fuel and technology diversity in US power supply.

Quantifying the value of current power supply diversity

A number of metrics exist to compare and contrast the performance of power systems under different scenarios. Three power system performance metrics are relevant in judging the performance of alternative generation portfolios:

- SRMC of electric production (the basis for wholesale power prices)
- Average variable cost of electric production
- Production cost variability

IHS Energy chose a geographic scope for the diversity analyses at the interconnection level of US power systems. The United States has three power interconnections: Electric Reliability Council of Texas (ERCOT), Eastern, and Western. These interconnections define the bounds of the power supply network systems that coordinate the synchronous generation and delivery of alternating current electrical energy to match the profile of aggregate consumer demands in real time.

Analysis at the interconnection level is the minimum level of disaggregation needed to analyze the portfolio and substitution effects of a diverse fuel and technology generation mix. In particular, the substitution effect involves the ability to shift generation from one source of power supply to another. The degree of supply integration within an interconnection makes this possible, whereas the power transfer capability between interconnections does not. The degree of power demand and supply integration within these interconnections creates the incentive and capability to substitute lower-cost generation for higher-cost generation at any point in time. These competitive forces cause the incremental power generation cost-based wholesale power prices at various locations within each interconnection to move together. An average correlation coefficient of monthly average wholesale prices at major trading hubs within each interconnection is roughly 0.8, indicating a high degree of supply linkage within each interconnection.

IHS Energy assessed the current value of fuel diversity by using the most recently available data on the US power sector. Sufficient data were available for 2010 to 2012, given the varied reporting lags of US power system data.

IHS employed its Razor Model to simulate the interactions of demand and supply within each of these US power interconnections from 2010 to 2012. The 2010 to 2012 backcasting analysis created a base case of the current interactions between power demand and supply in US power systems. Appendix B describes the IHS Razor Model and reports the accuracy of this power system simulation tool to replicate the actual performance of these power systems. The high degree of predictive power produced by this model in the backcasting exercise establishes the credibility of using this analytical framework to quantify the impacts of more or less fuel and technology diversity. The macroeconomic impact analysis used the most recently available IHS simulation of the US economy (December 2013) as a base case.

Once this base case was in place, the Razor Model was employed to simulate an alternative case involving a less diverse generation mix. The current generation mix in each of the three interconnections—Eastern, Western, and ERCOT—were altered as follows to produce the reduced diversity case generation:

- The nuclear generating share went to zero.
- The coal-fired electric generating share went to zero.
- The hydroelectric generation share dropped to 3.8%.
- Intermittent wind and solar generation increased its combined base case generation share of about 2% to shares approximating the operational limits—24% in the East, 45% in the West, and 23% in ERCOT—resulting in an overall wind generation share of 21.0% and a solar generation share of 1.5%.
- Natural gas–fired generation provided the remaining generation share in each power system, ranging from about 55% in the West to over 75% in the East and ERCOT, for an overall share of nearly 74%.

Differences between the performance metrics of the current diverse generating portfolio simulation and the reduced diversity case simulation provide an estimate for the current value of fuel diversity. The differences in the level and variance of power prices were fed through to the IHS US macroeconomic model to quantify the broader economic impacts of the higher and more varied power prices and shifts in capital deployment associated with the reduced diversity case.

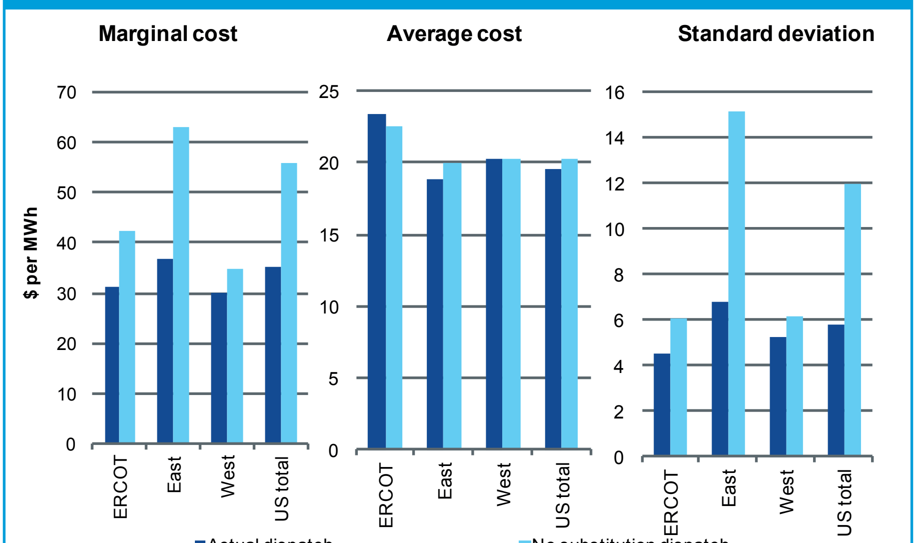
Quantification of the impact of fuel diversity within the US power sector involved a two-step process. The first step quantifies the current value of the substitution effect enabled by a diverse power generating portfolio. The second step quantified the additional value created by the portfolio effect.

The value of the substitution effect

The first step alters the base case by holding relative fuel prices at the average level across 2010 to 2012. Doing this removes the opportunity to substitute back and forth between generation resources based on changes to the marginal cost of generation. This case maintains a portfolio effect but eliminates the substitution effect in power generation. The difference between this constant relative fuel price case and the base case provides an estimate of the current value of the substitution effect provided by the current diverse power generation fuel mix. The results show significantly higher fuel costs from a generation mix deprived of substitution based on fuel price changes. The substitution effects in the current diverse US power generating portfolio reduced the fuel cost for US power production by over $2.8 billion per year. In just the three years of the base case, US power consumers realized nearly $8.5 billion in fuel savings from the substitution effect. Figure 22 shows the results of this first step in the analysis for each interconnection and the United States as a whole.

FIGURE 22

Actual dispatch versus no substitution dispatch: Cost results



Source: IHS Energy

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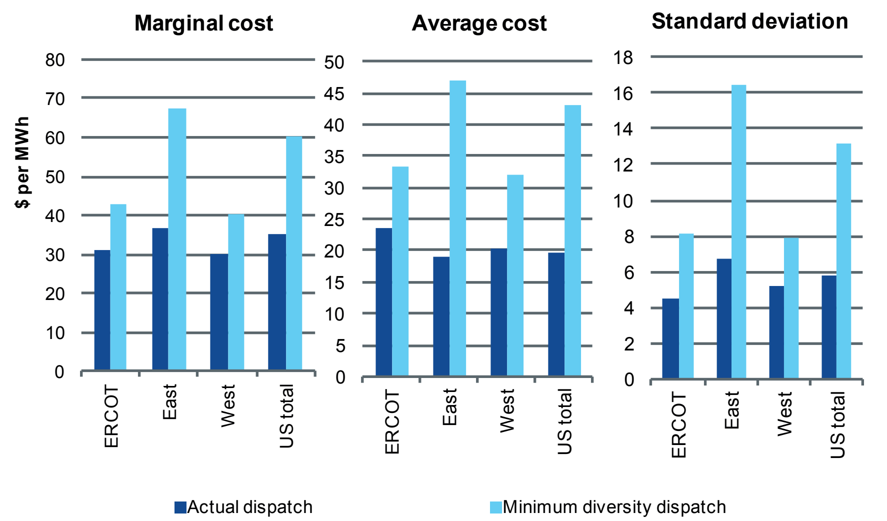
The value of the portfolio effect

The second step quantifies the portfolio value of the current generation mix. To measure this, the base case is altered by replacing the actual current generation mix with the less diverse generation mix. All else is held constant in this reduced diversity case, including the actual monthly fuel prices. Therefore, this reduced diversity simulation reduces the portfolio effect of diverse generation and allows any economic generation substitution to take place utilizing this less diverse capacity mix.

Figure 23 shows the performance metrics for each interconnection and the United States as a whole in the less diverse portfolio case compared to the base case.

FIGURE 23

Actual dispatch versus minimum diversity dispatch: Cost results



Source: IHS Energy

The portfolio effect reduces not only costs, but also the variation in costs. This translates into a reduction in the typical monthly variation in consumers' power bills of between 25% and 30%.

The differences in average power production costs between the reduced diversity case and the current supply case indicate that fuel and technology diversity in the base case US generation mix provides power consumers with benefits of $93 billion per year. This difference between the reduced diversity case and the base case includes both the substitution and portfolio effects. Using the results of step one allows separation of these two effects, as shown in Table 4.

Figures 24 and 25 show the progression from the base case to the reduced diversity case. The results indicate that the Eastern power interconnection has the most to lose from a less diverse power supply because it faces more significant increases in cost, price, and variability in moving from the base case to the reduced diversity case. The Eastern interconnection ends up with greater variation in part because its delivered fuel costs are more varied than in Texas or the West. In addition, the natural endowments of hydroelectric power in the Western interconnection generation mix continue to mitigate some of the fuel price risk even at a reduced generation share.

In the past three years, generation supply diversity reduced US power supply costs by $93 billion per year, with the majority of the benefit coming from the portfolio effect. These estimates are conservative because they were made only across the recent past, 2010 to 2012. An evaluation over a longer period of history would show increased benefits from managing greater levels of fuel price risk.

The estimates of the current value of power supply diversity are conservative as well because they do not include the feedback effects of higher power cost variation on the cost of capital for power suppliers, as outlined in Appendix A. The analyses indicate that a power supplier with the production cost variation equal to the current US average would have a cost of capital 310 basis points lower than a power supplier

TABLE 4

Diversity cases cost results

		Substitution effect	Portfolio effect	Total
ERCOT	Output (2011, TWh)	334	334	334
	Marginal cost increase ($/MWh)	$11.10	$0.35	$11.45
	Average cost increase ($/MWh)	($0.91)	$10.62	$9.71
	Marginal cost increase split	97%	3%	100%
	Average cost increase split	-9%	109%	100%
	Marginal cost increase percentage	35.40%	1.10%	36.50%
	Average cost increase percentage	-3.90%	45.20%	41.40%
	Marginal cost increase (total)	$3,708,970,847	$116,702,120	$3,825,672,967
	Average cost increase (total)	($302,604,000)	$3,547,080,000	$3,244,476,000
Eastern interconnection	Output (2011, TWh)	2,916	2,916	2,916
	Marginal cost increase ($/MWh)	$26.01	$4.73	$30.74
	Average cost increase ($/MWh)	$1.10	$26.92	$28.02
	Marginal cost increase split	85%	15%	100%
	Average cost increase split	4%	96%	100%
	Marginal cost increase percentage	70.70%	12.80%	83.50%
	Average cost increase percentage	5.80%	142.70%	148.50%
	Marginal cost increase (total)	$75,840,639,098	$13,791,489,884	$89,632,128,981
	Average cost increase (total)	$3,207,600,000	$78,498,720,000	$81,706,320,000
Western interconnection	Output (2011, TWh)	728	728	728
	Marginal cost increase ($/MWh)	$4.94	$5.27	$10.21
	Average cost increase ($/MWh)	($0.10)	$11.67	$11.57
	Marginal cost increase split	48%	52%	100%
	Average cost increase split	-1%	101%	100%
	Marginal cost increase percentage	16.50%	17.60%	34.10%
	Average cost increase percentage	-0.50%	57.50%	57.00%
	Marginal cost increase (total)	$3,593,597,137	$3,837,638,788	$7,431,235,926
	Average cost increase (total)	($72,800,000)	$8,495,760,000	$8,422,960,000
US total	Output (2011, TWh)	3,978	3,978	3,978
	Marginal cost increase ($/MWh)	$20.90	$4.46	$25.36
	Average cost increase ($/MWh)	$0.71	$22.76	$23.47
	Marginal cost increase split	82%	18%	100%
	Average cost increase split	3%	97%	100%
	Marginal cost increase percentage	59.50%	12.70%	72.20%
	Average cost increase percentage	3.60%	116.70%	120.30%
	Marginal cost increase (total)	$83,143,207,082	$17,745,830,792	$100,889,037,874
	Average cost increase (total)	$2,832,196,000	$90,541,560,000	$93,373,756,000

Source: IHS Energy

with the production cost variation associated with the generation mix of the reduced diversity case. Since 14% of total power costs are returned to capital, this difference accounts for 1–3% of the overall cost of electricity. This cost-of-capital effect can have a magnified impact on overall costs if more capital has to be deployed with an acceleration of power plant closures and replacements from the pace that reflects underlying economics.

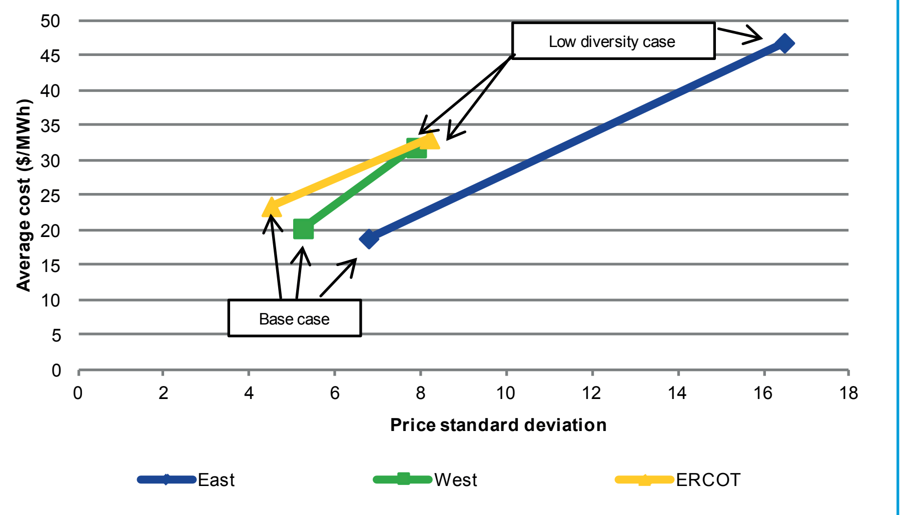
The cost of accelerating change in the generation mix

Current trends in public policies and flawed power market outcomes can trigger power plant retirements before the end of a power plant's economic life. When this happens, the closure creates cost impacts beyond the level and volatility of power production costs because it requires shifting capital away from a productive alternative use and toward a replacement power plant investment.

All existing power plants are economic to close and replace at some point in the future. The economic life of a power plant ends when the expected costs of continued operation exceed the cost of replacement. When this happens, the most cost-effective replacement power resource depends on the current capacity mix and what type of addition creates the greatest overall benefit—including the impact on the total cost of power and the management of power production cost risk.

FIGURE 24

Average cost: Base case versus low diversity case

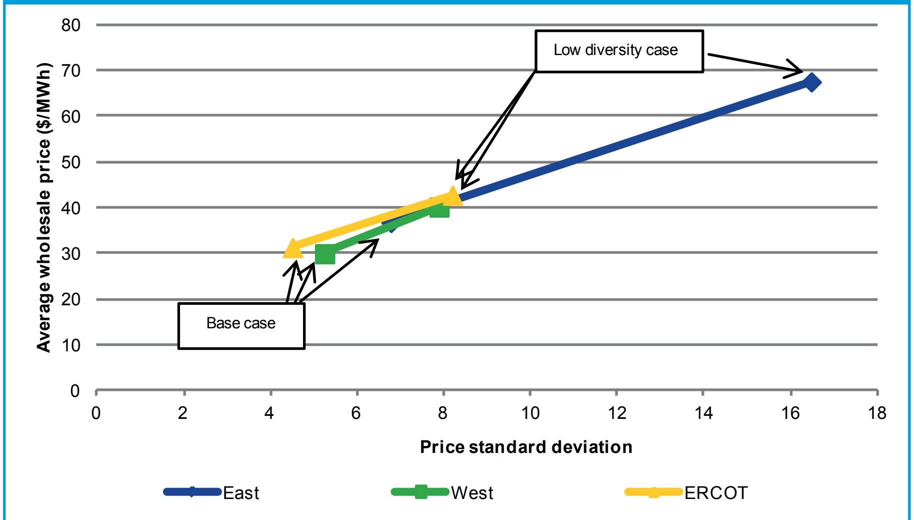


Source: IHS Energy © 2014 IHS

Figure 26 shows the current distribution of the net present value (NPV) of the going-forward costs for the existing US coal-fired generation fleet on a cents per MWh basis in relation to the levelized NPV of replacement power on a per MWh basis.

FIGURE 25

Average wholesale price: Base case versus low diversity case



Source: IHS Energy © 2014 IHS

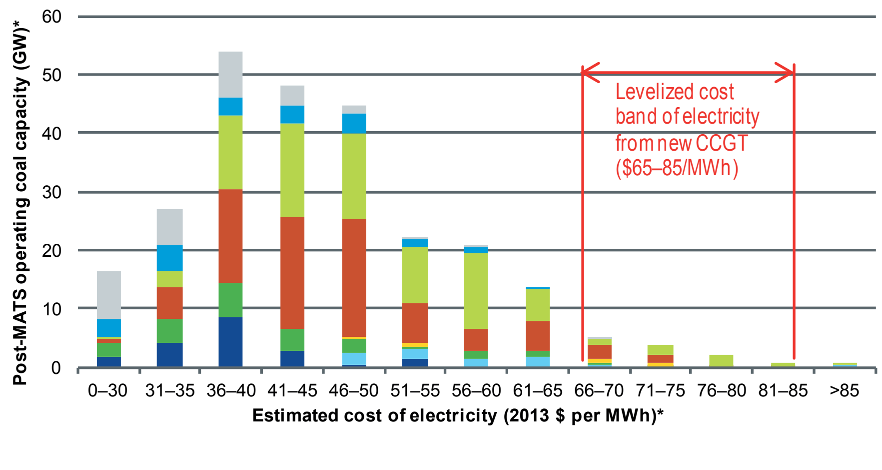
As the distribution of coal-fired power plant going-forward costs indicates, there is a significant difference between the going-forward costs and the replacement costs for the majority of plants. As a result, a substantial cost exists to accelerate the turnover of coal-fired power plants in the capacity mix. For example, closing coal-fired power plants and replacing them as quickly as possible with natural gas–fired power plants would impose a turnover cost of around $500 billion.

Figure 27 shows the going-forward costs of the existing US nuclear power plant fleet. As with the coal units, there is currently a high cost associated with premature closure. As a point of comparison, closing all existing nuclear power plants and replacing them as quickly as possible with natural gas–fired power plants would impose a turnover cost of around $230 billion. Unlike the coal fleet, where a nominal amount of older capacity has a going-forward cost that exceeds the expected levelized cost of replacement, none of the US nuclear capacity is currently more expensive than the lowest of projected replacement costs.

Closing a power plant and replacing it before its time means incurring additional capital costs. The average depreciation rate of capital in the United States is 8.3%. This implies that the average economic life of a capital investment in the United States economy is 12 years. Altering the amount of capital deployed in the US economy by $1 in Year 1 results in an equivalent impact on GDP as deploying a steady stream of about $0.15 of capital for each of the 12 years of economic life. This annual levelized cost approximates the value of the marginal product of capital. Therefore, each dollar of capital deployed to replace a power plant that retires prematurely imposes an opportunity cost equal to the value of the marginal productivity of capital in each year.

FIGURE 26

Going-forward costs of the existing coal fleet

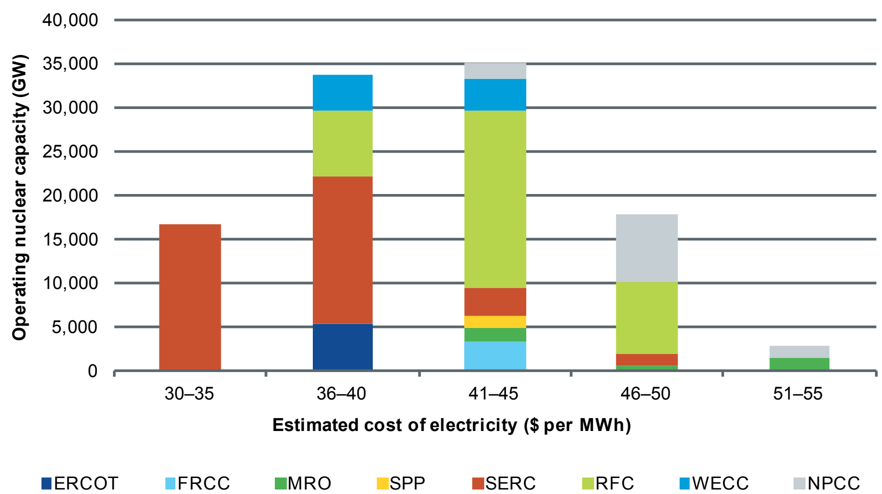


*Only includes those coal units that are forecasted to operate beyond 2020 in our reference case scenario. These coal units are retrofitted with conventional pollution controls.
Source: IHS Energy

Economywide impacts

FIGURE 27

Going-forward costs of the existing nuclear fleet



Source: IHS Energy

In addition to the $93 billion in lost savings from the portfolio and substitution effects, depending upon the pace of premature closures, there is a cost to the economy of diverting capital from other productive uses. The power price increases associated with the reduced diversity case would profoundly affect the US economy. The reduced diversity case shows a 75% increase in average wholesale power prices compared to the base case. IHS Economics conducted simulations using its US Macroeconomic Model to assess the potential impact of the change in the level and variance of power prices between the base case and the reduced diversity case. The latest IHS base line macroeconomic outlook in December 2013 provides a basis for evaluating the impacts of an electricity price shock due to a reduced diversity case for power supply. Subjecting the current US economy to such a power price increase would trigger economic disruptions, some lasting over a multiyear time frame. As a result, it would take several years for most of these disruptions to dissipate. To capture most of these effects, power price changes were evaluated over the period spanning the past two and the next three years to approximate effects of a power price change to the current state of the economy. Wholesale power price increases were modeled by increasing the

Producer Price Index for electricity by 75% in the macroeconometric model; consumers were affected by the resulting higher prices for retail electricity and other goods and services.

Economic impacts of the power supply reduced diversity case are quantified as deviations from the IHS macroeconomic baseline simulations of the US economy. The major impacts within the three years after the power price change would include

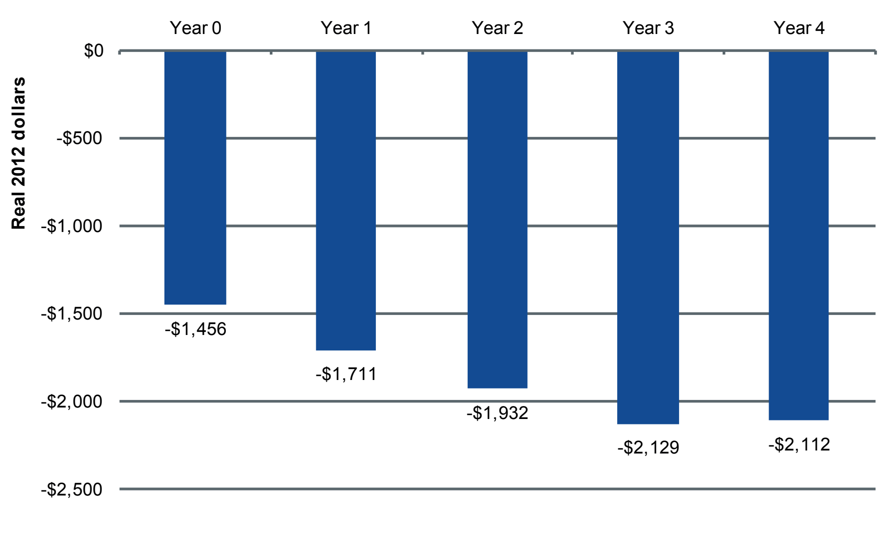
- A drop in real disposable income per household of about $2,100
- A reduction of 1,100,000 jobs
- A decline in real GDP of 1.2%

Consumers will bear the brunt of the impact of higher power prices. The higher price of electricity would trigger a reduction in power use in the longer run (10 or more years out) of around 10%. Yet even with such dramatic reductions in consumption, the typical power bill in the United States would increase from around $65 to $72 per month.

Not only will consumers face higher electric bills, but some portion of increases in manufacturers' costs ultimately will be passed on to consumers through higher prices for goods and services. Faced with lower purchasing power, consumers will scale back on discretionary purchases because expected real disposable income per household is lower by over $2,100 three years after the electric price increase (see Figure 28). Unlike other economic indicators (such as real GDP) that converge toward equilibrium after a few years, real disposable income per household does not recover, even if the simulations are extended out 25 years. This indicates that the price increases will have a longer-term negative effect on disposable income and power consumption levels.

FIGURE 28

Impact of reduced diversity on real disposable income



Source: IHS Economics © 2014 IHS

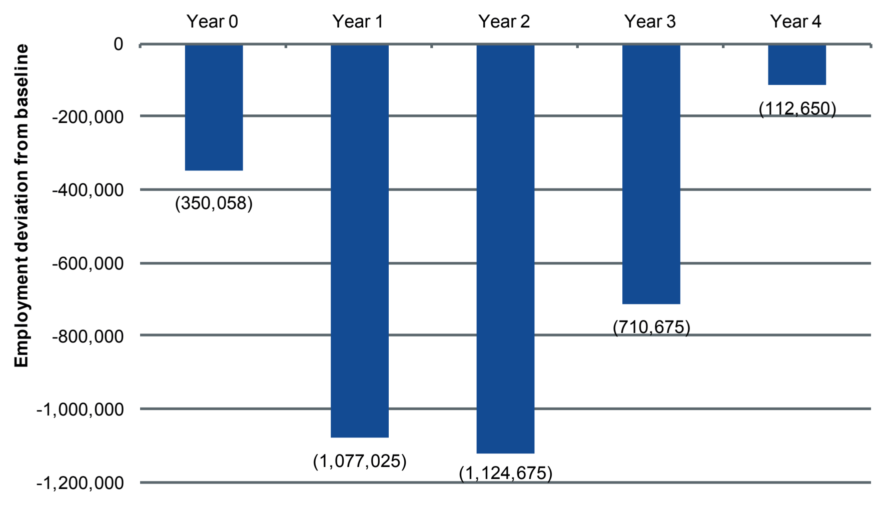
Businesses will face the dual challenge of higher operational costs coupled with decreased demand for their products and services. Industrial production will decline, on average, by about 1% through Year 4. This will lead to fewer jobs (i.e., a combination of current jobs that are eliminated and future jobs that are never created) within a couple of years relative to the IHS baseline forecast, as shown in Figure 29, with the largest impact appearing in Year 2, with 1,100,000 fewer jobs than the IHS baseline level.

Impact on GDP

The US economy is a complex adaptive system that seeks to absorb shocks (e.g., increases in prices) and converge toward a long-term state of equilibrium. Although the simulations conducted for this study do not project that the US economy will fall into a recession because of power price increases, it is informative to gauge the underperformance of the US economy under the reduced diversity case. In essence, the higher power prices resulting from the reduced diversity conditions cause negative economic impacts equivalent to a mild recession relative to the forgone potential GDP of the baseline. The economic impacts of the reduced diversity case set back GDP by $198 billion, or 1.2% in Year 1 (see Figure 30). This deviation from the baseline GDP is a drop that is equivalent to about half of the average decline in GDP in US recessions since the Great Depression. However, the impacts on key components of GDP such as personal consumption and business investment will differ.

FIGURE 29

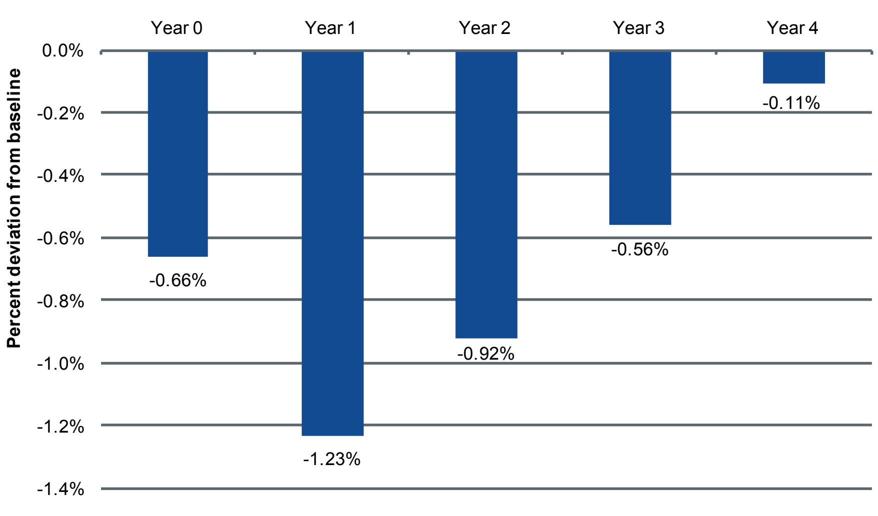
Impact of reduced diversity on employment (deviation from baseline)



Source: IHS Economics © 2014 IHS

FIGURE 30

Impact of reduced diversity on real GDP



Source: IHS Economics © 2014 IHS

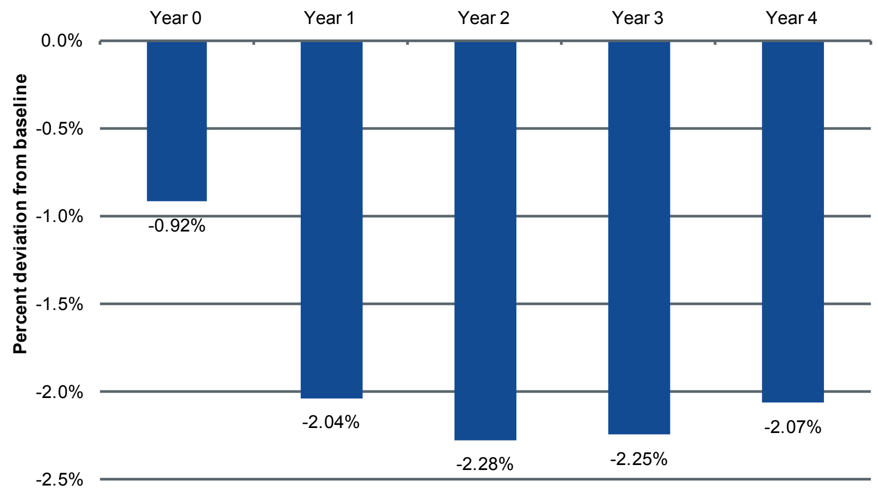
Consumption

Analyzing personal consumption provides insights on the changes to consumer purchasing behavior under the scenario conditions. Consumption, which accounts for approximately two-thirds of US GDP, remains lower over the period with each of its three subcomponents—durable goods, nondurable goods, and services—displaying a different response to the reduced power supply scenario conditions. In contrast with overall GDP, consumer spending shows little recovery by Year 4, as shown in Figure 31. This is due to continued higher prices for goods and services and decreased household disposable income. About 57% of the decline will occur in purchases of services, where household operations including spending on electricity will have a significant impact.

In the early years, lower spending on durable goods (appliances, furniture, consumer electronics, etc.) will account for about 33% of the decline, before moderating to 25% in the longer term. This indicates that consumers, faced with less disposable income, will simply delay purchases in the early years. The US macro simulations also predict moderate delays in housing starts and light vehicle sales, ostensibly due to consumers trying to minimize their spending.

FIGURE 31

Impact of reduced diversity on consumption



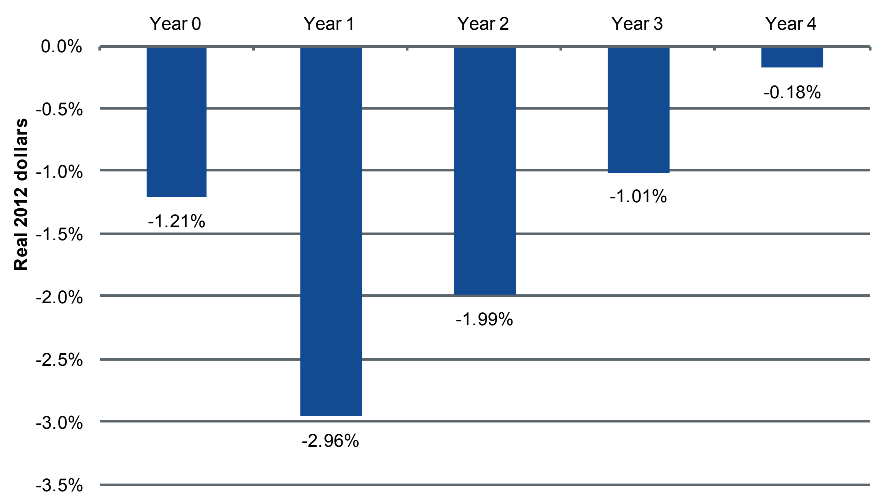
Source: IHS Energy © 2014 IHS

Investment

Following an initial setback relative to the baseline, investment will recover by the end of the forecast horizon. Nonresidential investment will initially be characterized by delays in equipment and software purchases, which will moderate a few years after the electric price shock. Spending on residential structures will remain negative relative to the baseline over the four years, as shown in Figure 32. The net effect in overall investment is a recovery as the economy rebounds back to a long-run equilibrium.

FIGURE 32

Impact of reduced diversity on investment



Source: IHS Energy © 2014 IHS

In the longer term, if current trends cause the reduced diversity case to materialize within the next decade, then the premature closure and replacement of existing power plants would shift billions of dollars of capital from alternative deployments in the US economy.

Conclusions

Consumers want a cost-effective generation mix. Obtaining one on the regulated and public power side of the industry involves employing an integrated resource planning process that properly incorporates cost-effective risk management. Obtaining such a mix on the competitive side of the power business involves employing time-differentiated market-clearing prices for energy and capacity commodities that can provide efficient economic signals. The linkage between risk and cost of capital can internalize cost-effective risk management into competitive power business strategies. Regardless of industry structure, a diverse generation mix is the desired outcome of cost-effective power system planning and operation.

The results of this study indicate seven key factors that will shape US power supply diversity in the years to come:

- **Energy policy development.** US policy heavily influences the US power supply mix. Implementing an all-of-the-above energy policy requires properly internalizing the value of fuel diversity.

- **Market structure.** Market flaws distort wholesale power prices downward and result in uneconomic retirement and replacement of existing cost-effective generation resources. This issue and any market structure changes to address it will significantly shape future power plant development.

- **Energy policy discourse.** Preserving the value of fuel diversity depends on public awareness and understanding. The extent and nature of public education regarding the value of power supply diversity may strongly influence public opinion.

- **Planning alignment.** Alignment of fuel and technology choices for power generation with engineering and economic principles is critical to efficient and reliable supply. There is no single fuel or technology of choice for power generation, and all forms of power production have economic, environmental, and reliability impacts.

- **Risk assessment.** To incorporate system considerations into plant-level decisions, prudent fuel price uncertainties must be used with probabilistic approaches to decision making.

- **Flexibility.** Flexibility and exemptions in rule making and implementation allow for the balancing of costs and benefits in power supply systems and may help preserve highly valuable diversity in systemwide decisions as well as on a small but impactful individual plant scale.

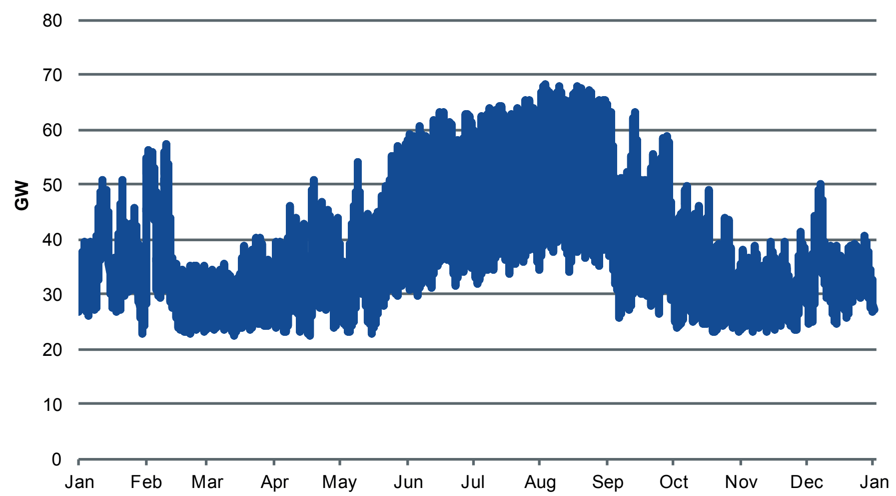
- **Scope.** Including fuel price risk and additional storage and transportation infrastructure costs is crucial when evaluating reduced diversity scenarios in comparison to the cost of maintaining and expanding fuel diversity.

Appendix A: Cost-effective electric generating mix

The objective of power supply is to provide reliable, efficient, and environmentally responsible electric production to meet the aggregate power needs of consumers at various points in time. Consumers determine how much electricity they want at any point in time, and since the power grid physically connects consumers, it aggregates individual consumer demands into a power system demand pattern that varies considerably from hour to hour. For example, Figure A-1 shows the hourly aggregate demand for electricity in ERCOT.

FIGURE A-1

2011 hourly electric loads—ERCOT



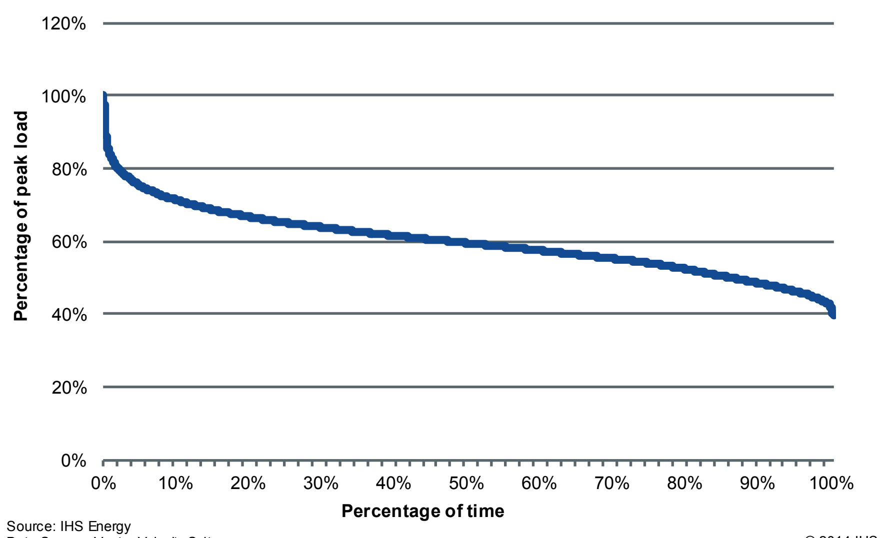
Source: IHS Energy © 2014 IHS

In order to reliably meet aggregate power demands, enough generating capacity needs to be installed and available to meet demand at any point in time. The overall need for installed capacity is determined by the peak demand and a desired reserve margin. A 15% reserve margin is a typical planning target to insure reliable power supply.

The chronological hourly power demands plus the required reserve margin allow the construction of a unitized load duration curve (see Figure A-2). The unitized load duration curve orders hourly electric demands from highest to lowest and unitizes the hourly loads by expressing the values on the y-axis as a percentage of the maximum (peak) demand plus the desired reserve margin. The x-axis shows the percentage of the year that load is at or above the declining levels of aggregate demand.

FIGURE A-2

Load duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite © 2014 IHS

This unitized load duration curve has a load factor—the ratio of average load to peak load—of 0.60. Although load duration curve shapes vary from one power system to another, this load factor and unitized load duration curve shape is a reasonable approximation of a typical pattern of electric demand in a US power system. The objective of any power system would be to match its demand pattern with cost-effective power supply.

There are a number of alternative technologies available to produce electricity. These power supply alternatives have different operating characteristics. Most importantly, some power generating technologies can produce electricity on demand that aligns with the pattern of consumer demand through time, while others cannot. For example, solar PV panels can only provide electric output during hours of sunlight and thus cannot meet aggregate demand during the night. In contrast, thermal generation such as coal and natural gas can ramp up and down or turn on and off to match output with customer demand. Technologies such as coal and natural gas are considered dispatchable, while technologies such as solar and wind are considered nondispatchable. A number of combinations of technologies can together provide electric output that matches the pattern of consumer needs.

The lowest-cost generating technologies that can meet the highest increases in demand are peaking technologies such as combustion turbines (CTs). CTs are the most economical technology to meet loads that occur for only a small amount of time. These technologies can start-up quickly and change output flexibly to meet the relatively infrequent hours of highest power demand. They are economic even though they are not the best available technology for efficiently transforming fuel into electricity. CTs have relatively low upfront capital costs and thus present a trade-off with more efficient but higher capital cost generating technology alternatives. Since these resources are expected to be used so infrequently, the additional cost of more efficient power generation is not justified by fuel savings, given their expected low utilization rates.

Cycling technologies are most economical to follow changes in power demand across most hours. Consequently, utilization rates can be high enough to generate enough fuel savings to cover the additional capital cost of these technologies over a peaking technology. These intermediate technologies provide flexible operation along with efficient conversion of fuel into power. A natural gas–fired combined-cycle gas turbine (CCGT) is one technology that is suitable and frequently used for this role.

Base-load technologies are the lowest-cost power supply sources to meet power demand across most hours. These technologies are cost-effective because they allow the trading of some flexibility in varying output for the lower operating costs associated with high utilization rates. These technologies include nuclear power plants, coal-fired power plants, and reservoir hydroelectric power supply resources.

Nondispatchable power resources include technologies such as run-of-the-river hydroelectric, wind, and solar power supplies. These technologies produce power when external conditions allow—river flows, wind speeds, and solar insolation levels. Variations in electric output from these resources reflect changes in these external conditions rather than changes initiated by the generator or system operator to follow shifts in power consumer needs. Some of these resources can be economic in a generation mix if the value of the fuel they displace and their net dependable capacity are enough to cover their total cost. However, since nondispatchable production profiles do not align with changes in consumer demands, there are limits to how much of these resources can be cost-effectively incorporated into a power supply mix.

Alternative power generating technologies also have different operating costs. Typical cost profiles for alternative power technologies are shown in Table A-1. Both nuclear and supercritical pulverized coal (SCPC) technologies are based on steam turbines, whereby superheated steam spins a turbine; in coal's case, supercritical refers to the high-pressure phase of steam where heat transfer and therefore the turbine itself is most efficient. Natural gas CTs are akin to jet engines, where the burning fuel's exhaust spins the turbine. A CCGT combines both of these technologies, first spinning a CT with exhaust and then using that exhaust to create steam which spins a second turbine.

TABLE A-1

Typical cost profiles for alternative power technologies

	CCGT	SCPC	Nuclear	CT
Capital cost (US$ per kW)	1,350	3,480	7,130	790
Variable O&M cost (US$ per MWh)	3.5	4.7	1.6	4.8
First year fixed O&M cost (US$ per kW-yr)	13	39	107	9
Property tax and insurance (US$ per kW-yr)	13	36	78	8
Fuel price (US$ per MMBtu)	4.55	2.6	0.7	4.55
Heat rate (Btu per kWh)	6,750	8,300	9,800	10,000
CO_2 emission rate (lbs per kWh)	0.8	1.73	0	1.18

Total capital cost figures include owner's costs: development/permitting, land acquisition, construction general and administrative, financing, interest during construction, etc.

Source: IHS Energy

Power production technologies tend to be capital intensive; the cost of capital is an important determinant of overall costs. The cost of capital is made up of two components: a risk-free rate of return and a risk premium. Short-term US government bond interest rates are considered an approximation of the risk-free cost of capital. Currently, short-term US government bond interest rates are running at 0.1%. In order to attract capital to more risky investments, the return to capital needs to be greater. For example, the average cost of new debt to the US investor-owned power industry is around 4.5%.[11] This indicates an average risk premium of 4.4%.

Power generating technologies have different risk profiles. For example, the fluctuations in natural gas prices and demand levels create uncertainty in plant utilization and the level of operating costs and revenues. This makes future net income uncertain. Greater variation in net income makes the risk of covering debt obligations greater. In addition, more uncertain operating cost profiles add costs by imposing higher working capital requirements.

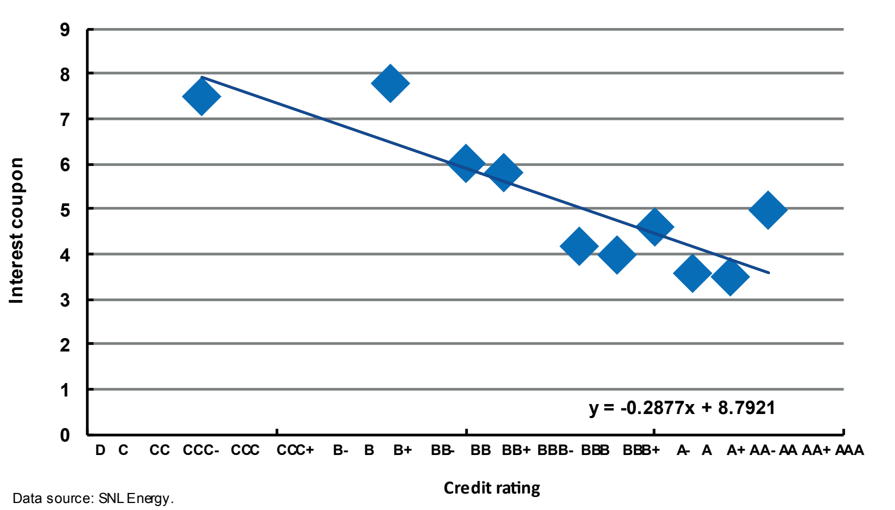
Risk profiles are important because they affect the cost of capital for power generation projects. If a project is seen as more risky, investors demand a higher return for their investment in the project, which can have a significant impact on the overall project cost.

Credit agencies provide risk assessments and credit ratings to reflect these differences. Credit ratings reflect the perceived risk of earning a return on, and a return of, capital deployments. As Figure A-3 shows, the higher credit ratings associated with less risky investments have a lower risk premium, and conversely lower credit ratings associated with more risky investments have a higher risk premium.

Lower credit ratings result from higher variations in net

FIGURE A-3

2010 shareholder-owned utilities senior debt offerings average interest coupon versus credit rating



Data source: SNL Energy.
Source: IHS Energy

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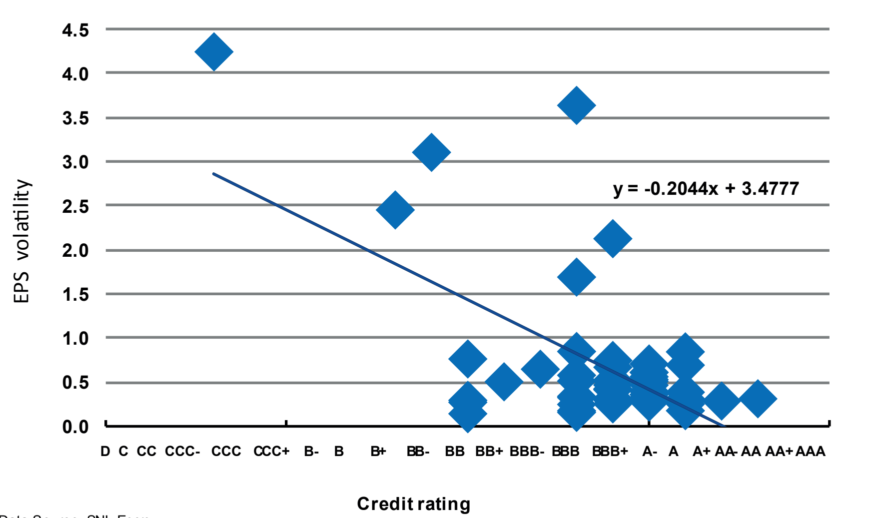
11. Data collected by Stern School of Business, NYU, January 2014. Cost of Capital. Accessed at http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/wacc.htm.

income, as shown in Figure A-4.

FIGURE A-4

Earnings per share volatility versus credit ratings



Data Source: SNL Energy
Notes: EPS = earnings per share.
Volatility is measured by standard deviation.

Source: IHS Energy © 2014 IHS

Sometimes the cost of capital is directly related to the power plant when project financing is used. In other cases, power companies raise capital at the corporate level with a capital cost that reflects the overall company risk profile rather than just the power plant risk profile. Utilities typically have diverse power supply portfolios, whereas merchant generators tend to be much less diverse—typically almost entirely natural gas-fired. As a result of the different supply mixes and associated risk profiles, utilities and merchant generators have different costs of capital. This difference in the cost of capital provides an approximation of the difference in risk premium.

Overall, the cost of capital for merchant generators is higher than that for utilities broadly. While the power industry has an average cost of debt of roughly 4.5%, merchant generators with significant natural gas holdings tend to have a cost of debt of around 8%. As many of these firms have gone through bankruptcies in the past, this number may be lower than the cost of debt these firms had prior to restructuring.[12] The implied risk premium of a merchant generator to a utility is 3.5%, which is similar to the cost of capital analysis results discussed in the body of the report, where the reduced diversity case generator was calculated to have a cost of capital 310 basis points (3.1%) higher than that of the current US power sector as a whole.

Merchant generators with majority natural gas holdings have higher costs of capital because of the increased earnings volatility and risk of an all natural gas portfolio. In contrast, a generator with a more diverse portfolio needing to secure financing for the same type of plant would have costs of capital more in line with the industry as a whole. This can have a significant impact on the overall cost of the plant. This is not due specifically to the properties of natural gas as a fuel, but rather to the diversity of generating resources available. If a merchant generator were to have an exclusively coal-fired generating fleet or an exclusively nuclear generating fleet, its cost of capital would also increase owing to the higher uncertainty in generation cash flows.

The expected annual power supply costs can be calculated over the expected life of a power plant once the cost of capital is set and combined with the cost and operating profile data. These power costs are uneven through time for a given utilization rate. Therefore, an uneven cost stream can be expressed as a levelized cost by finding a constant cost in each year that has the same present value as the uneven cost stream. The discount rate used to determine this present value is based on the typical cost of capital for the power

12. Based on analysis of the "Competitive" business strategy group, defined by IHS as businesses with generation portfolios that are over 70% nonutility, based on asset value and revenue. Cost of debt based on coupon rates of outstanding debt as of May 2014.

industry as a whole. Dividing the levelized cost by the output of the power plant at a given utilization rate produces a levelized cost of energy (LCOE) for a given technology at a given utilization rate (see Figure A-5).

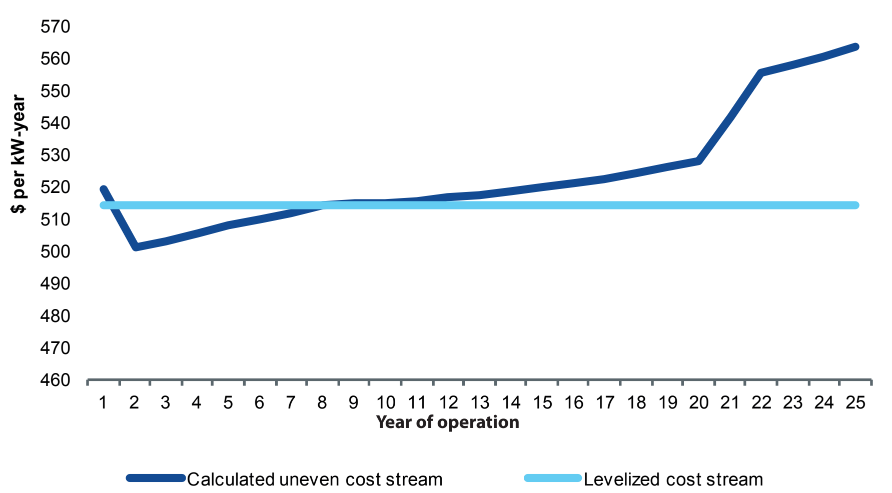
A levelized cost stream makes it possible to compare production costs at different expected utilization rates. A lower utilization rate forces spreading fixed costs over fewer units of output and thus produces higher levelized costs (see Figure A-6).

Figure A-7 adds the LCOE of a CT. Since the LCOE of the CT is lower than that of the CCGT at high utilization rates, adding CTs shows the point at which the savings for a CCGT's greater efficiency in fuel use are enough to offset the lower fixed costs of a CT.

There is a utilization rate at which a CCGT is cheaper to run than a CT. Below a utilization rate of roughly 35%, a CT is more economical. At higher utilization rates, the CCGT is more economical. When referring back to the load duration curve, it can be calculated that a generation mix that is 37% CT and 63% CCGT would produce a least-cost outcome. This can be demonstrated by comparing the LCOE graph with the load duration curve: the intersection point of CT and CCGT LCOEs occurs at the same time percentage on the LCOE graph at which 63% load occurs on the load duration curve (see Figure A-8).

FIGURE A-5

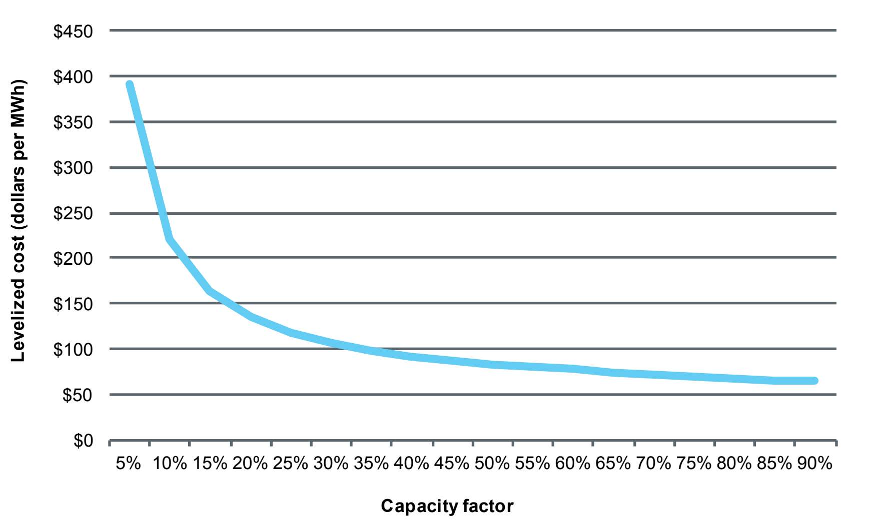
Cost stream comparisons—CCGT, 85% utilization rate



Source: IHS Energy © 2014 IHS

FIGURE A-6

LCOE of CCGT generation



Source: IHS Energy © 2014 IHS

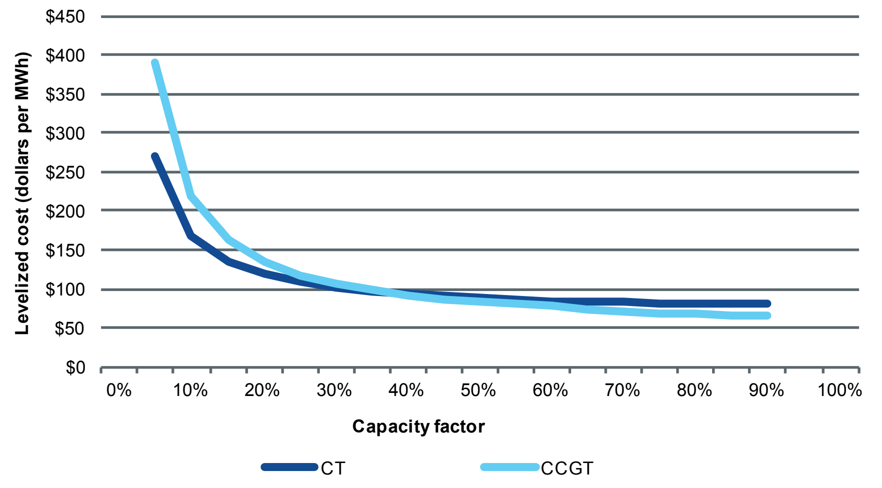
The levelized cost of production for each technology can be determined by finding the average load (and corresponding utilization rate) for the segment of the load duration curve (LDC) that corresponds to each technology (in this example, the two segments that are created by splitting the curve at the 35% mark). Loads that occur less than 35% of the time will be considered peak loads, so the average cost of meeting a peak load will be equivalent to the cost of a CT operating at a 17.5% utilization rate, the average of the peak loads. Cycling loads will be defined as loads occurring between 35% to 80% of the time, with base loads occurring more than 80% of the time. As the CCGT is covering both cycling and base loads in this example, the average cost of meeting theses loads with a CCGT will be equivalent to the levelized cost of a CCGT at a 57.5% utilization rate. A weighted average of the costs of each technology is then equivalent to an average cost of production for the power system. For this generation mix, the levelized cost of production is equal to 9.6 cents per kWh.

The generating options also can be expanded to include fuels besides natural gas. Stand-alone coal and stand-alone nuclear are not lower cost than stand-alone gas, as shown in Figure A-9, and all have a high-risk premium associated with the lack of diversity. However, when combined as part of a generation mix, the cost of capital will be lower owing to the more diverse (and therefore less risky) expected cash flow.

Based on the LDC, in this example base-load generation was modeled at 52.5% of capacity and was composed of equal parts gas, coal, and nuclear capacity. This combination of fuels and technology produces a diverse portfolio that can reduce risk and measurably lower the risk premium in the cost of capital. The point at which a CCGT becomes cheaper than a CT changes slightly from the previous example owing to the change in cost of capital, but the result is similar, with a 30% utilization rate the critical point and 36% CT capacity the most economical. Cycling loads with utilization

FIGURE A-7

LCOE of CCGT and CT generation



Source: IHS Energy

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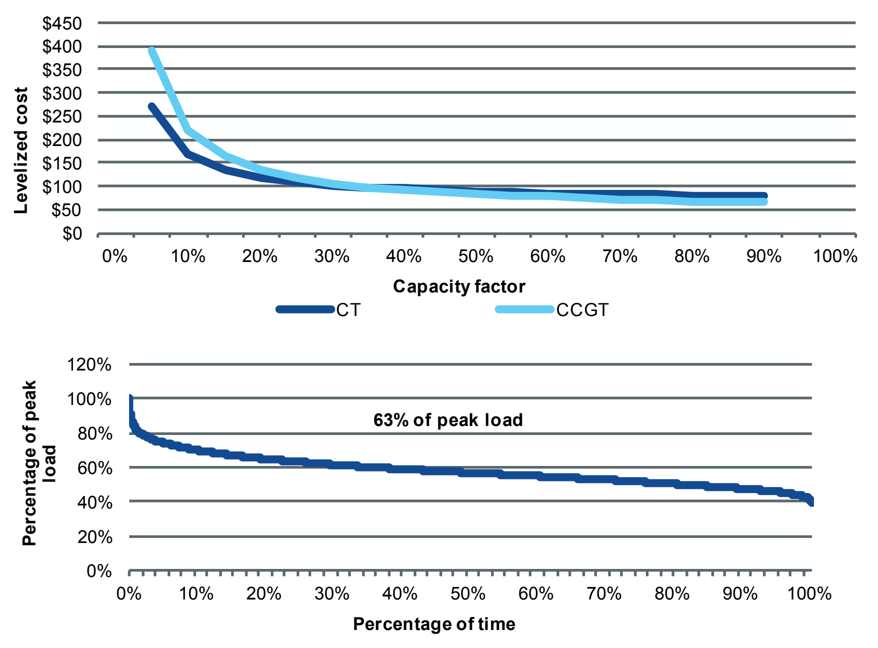
FIGURE A-8

Determination of generation mix based on load duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite, National Renewable Energy Laboratory

Source:

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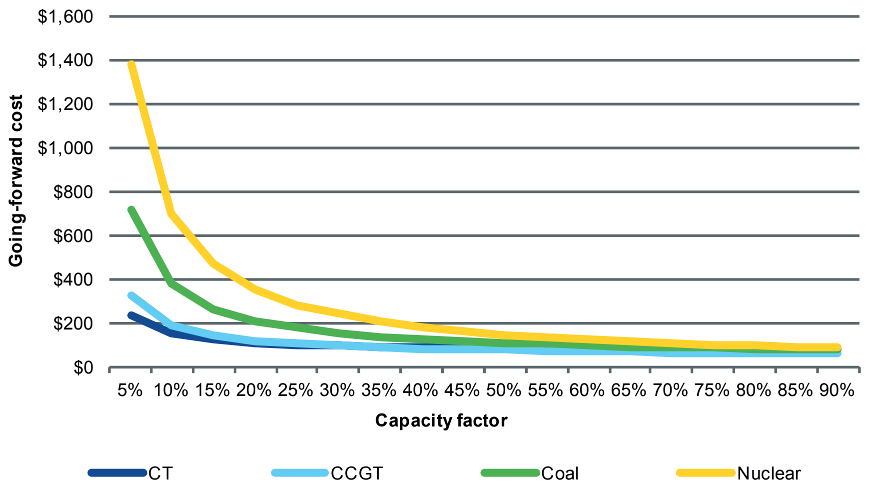
rates between 30% and 80% can be covered by CCGTs, equaling 11.5% of capacity. The levelized cost of production for this more diverse portfolio is equal to 9.3 cents per kWh. Even though coal and nuclear have higher levelized costs than gas, all else being equal, the reduced cost of capital is more than enough to offset the increased costs of generation. The implication is that a least-cost mix to meet a pattern of demand is a diverse mix of fuels and technologies.

If the power system has a renewables mandate, this can be incorporated as well. Solar PV has a levelized cost of 14.2 cents per kWh, given a 4.5% cost of capital. If solar made up 10% of generating capacity, the load duration curve for the remaining dispatchable resources would change, as shown in Figure A-10. Using hourly solar irradiation data from a favorable location to determine solar output, the peak load of the power system does not change, as there is less than full solar insulation in the hour when demand peaks.[13] The load factor for this new curve is 0.58, a small decrease from the original curve. A lower load factor typically means that larger loads occur less often, so more peaking capacity is necessary.

FIGURE A-9

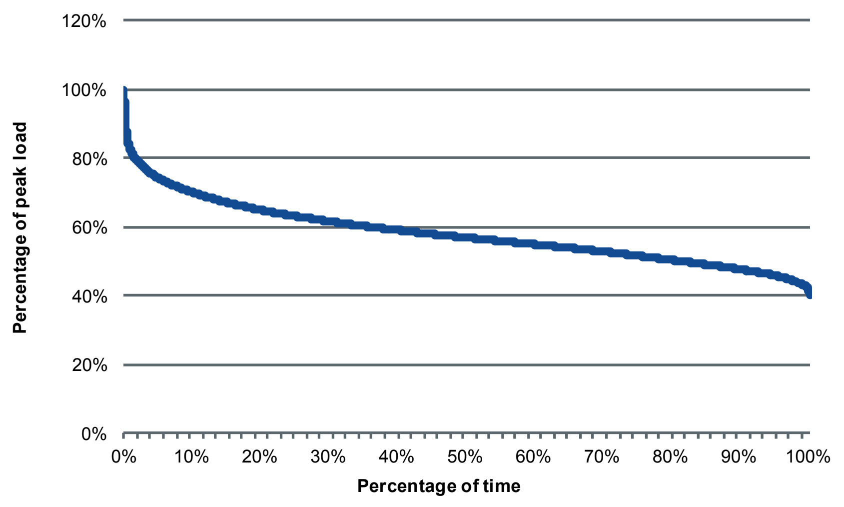
Levelized cost curves of generating resources



Source: IHS Energy © 2014 IHS

FIGURE A-10

Load duration curve, after solar additions



Source: IHS Energy
Data Source: Ventyx Velocity Suite, National Renewable Energy Laboratory © 2014 IHS

The needed dispatchable resources can be recalculated using the new curve, integrating the solar generation. The new curve increases the amount of peaking resources needed, but otherwise changes only very slightly. After solar is added, the total cost is 10.8 cents per kWh. Since the output pattern of solar doesn't match the demand pattern for the power system, adding solar does not significantly decrease the amount of capacity needed.

13. Solar data from National Renewable Energy Laboratory, Austin, TX, site. Data from 1991–2005 update, used for example purposes. http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/by_state_and_city.html accessed 13 May 2014.

Conclusion

- There is no single fuel or technology of choice for power generation. Reliably and efficiently supplying consumers with the amounts of electricity that they want, when they want it, requires a diverse generation mix.

- A cost-effective generation mix involves diversity but does not involve maximizing diversity by equalizing generation shares from all available supply options.

- The cost-effective mix of fuel and technologies for any power system is sensitive to the uncertainties surrounding the level and pattern of consumer power demands as well as expectations regarding the cost and performance of alternative power generating technologies and, in particular, the expectations for delivered fuel prices.

- The cost-effective generating mix will differ from one power system to the next because of differences in aggregate consumer demand patterns as well as the cost and performance of available generating options.

- The best type of capacity to add to any generation portfolio depends on what types of capacity are already in the mix.

Appendix B: IHS Power System Razor Model overview

Design

The IHS Power System Razor (Razor) Model was developed to simulate the balancing of power system demand and supply. The model design provides flexibility to define analyses' frequency and resolution in line with available data and the analytical requirements of the research investigation.

For this assessment of the value of fuel diversity, the following analytical choices were selected:

- **Analysis time frame**—Backcasting 2010 to 2012
- **Analysis frequency**—Weekly balancing of demand and supply
- **Geographic scope**—US continental power interconnections—Western, Eastern, and ERCOT
- **Demand input data**—Estimates of weekly interconnection aggregate consumer energy demand plus losses
- **Fuel and technology types**—Five separate dispatchable supply alternatives: nuclear, coal steam, natural gas CCGT, gas CT, and oil CT
- **Supply input data by type**—Monthly installed capacity, monthly delivered fuel prices, monthly variable operations and maintenance (O&M), heat rate as a function of utilization
- **Load modifiers**—Wind, solar, hydroelectric, net interchange, peaking generation levels, and weekly patterns

Demand

The Razor Model enables the input of historical demand for backcasting analyses as well as the projection of demand for forward-looking scenarios. In both cases, the Razor Model evaluates demand in a region as a single aggregate power system load.

For backcasting analyses, the model relies upon estimates of actual demand by interconnection. For forward-looking simulations, Razor incorporates a US state-level cross-sectional, regression-based demand model for each of the three customer classes—residential, commercial, and industrial. Power system composite state indexes drive base year demand levels by customer class into the future.

Load modifiers

Utilization of some power supply resources is independent of SRMC–based dispatch dynamics. Some power supply is determined by out-of-merit-order utilization, normal production patterns, or external conditions—such as solar insolation levels, water flows, and wind patterns. These power supply resources are treated as load modifiers.

Net load

Net load is the difference between power system aggregate electric output needs and the aggregate supply from load modifiers. It is the amount of generation that must be supplied by dispatchable power supply resources.

Calibration of the inputs determining net load is possible using data reporting the aggregate output of dispatchable power sources.

Fuel- and technology-specific supply curves

Supply curves are constructed for each fuel and technology type. The supply curve for each dispatchable power supply type reflects the SRMCs of the capacity across the possible range of utilization rates. Applying availability factors to installed capacity produces estimates of net dependable (firm, derated) capacity by fuel and technology type.

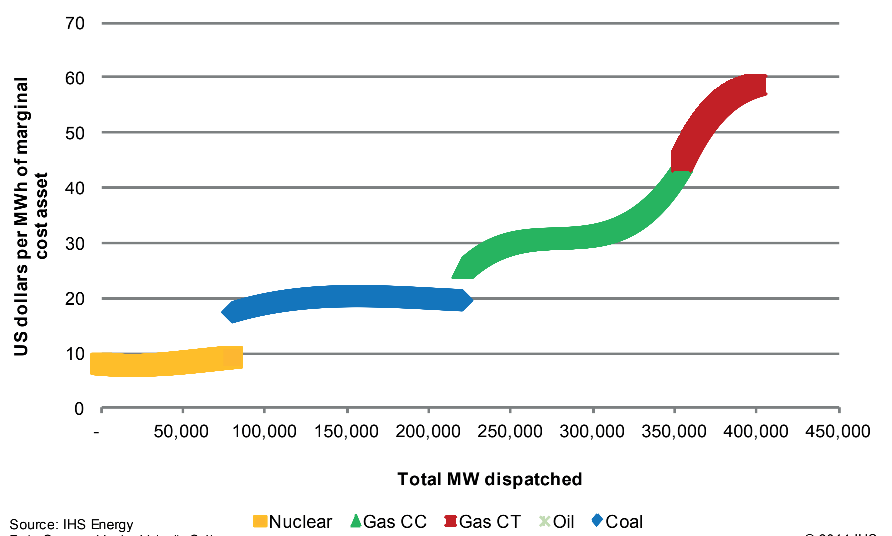
Each cost curve incorporates heat rate as a function of utilization rate.[14] *Heat rate* describes the efficiency of a thermal power plant in its conversion of fuel into electricity. Heat rate is measured by the amount of heat (in Btu) required each hour to produce 1 kWh of electricity, or most frequently shown as MMBtu per MWh. The higher the heat rate, the more fuel required to produce a given unit of electricity. This level of efficiency is determined primarily by the fuel type and plant design. Outliers are pruned from data to give a sample of heat rates most representative of the range of operational plants by fuel and technology type.[15]

Dispatch fuel costs are the product of the heat rate and the delivered fuel cost. Total dispatch costs involve adding variable operations and maintenance (VOM, or O&M) costs to the dispatch fuel costs. These O&M costs include environmental allowance costs.

The power system aggregate supply curve is the horizontal summation of the supply curves for all fuel and technology types. Figure B-1 illustrates the construction of the aggregate power system supply curve. The supply curve shows the SRMC at each megawatt dispatch level and the associated marginal resource.

FIGURE B-1

Representative supply curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite

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Balancing power system aggregate demand and supply

The Razor Model balances aggregate power system demand and supply by intersecting the demand and supply curves. At the intersection point, power supply equals demand; supply by type involves equilibrating the dispatch costs of available alternative sources of supply.

14. Power plant data sourced from Ventyx Velocity Suite.

15. Outliers are defined as plants with an average heat rate higher than the maximum observed fully loaded heat rate.

This power system–wide marginal cost of production is the basis for the wholesale power price level that clears an energy market.

The Razor Model results in the following outputs:

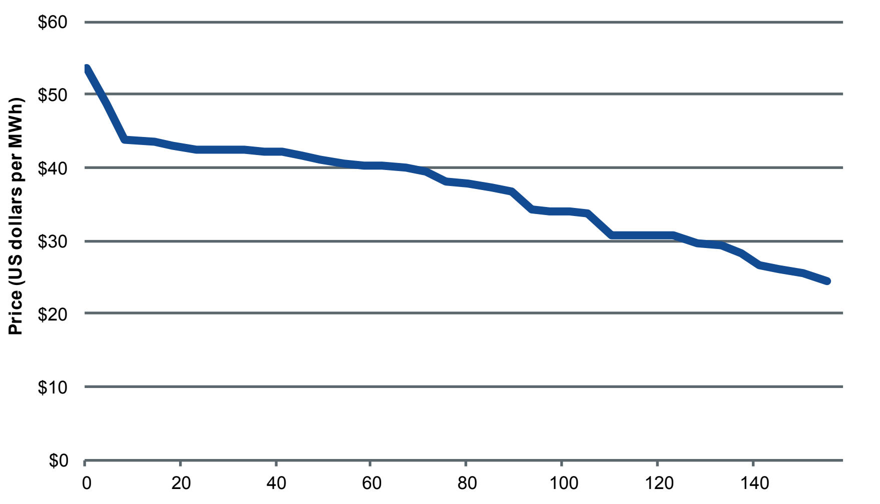
- **Power system SRMC/wholesale price**
- **Generation by fuel and technology type**
- **Average variable cost of production.** The average variable cost is calculated at each dispatch increment by taking the total cost at that generation level divided by the total megawatt dispatch.
- **Price duration curve.** The price duration curve illustrated in Figure B-2 provides an example of wholesale power price distribution across the weeks from 2010 through 2012.

Calibration

The predictive power of the Razor Model for portfolio and substitution analysis is revealed by comparing the estimated values of the backcasting simulations to the actual outcomes in 2010–12.

FIGURE B-2

Representative price duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite

The Razor Model backcasting results provide a comparison of the estimated and actual wholesale power prices. The average difference in the marginal cost varied between (3.8%) and +2.3% by interconnection region. A comparison of the average rather than marginal cost of power production also indicated a close correspondence. The average difference between the estimate and the actual average cost of power production varied between (4.7%) and (0.1%) by interconnection region. Table B-1 shows the assessment of the predictive power of the Razor Model for these two metrics across all three interconnections in the 2010 to 2012 weekly backcasting exercise.

TABLE B-1

IHS power system Razor Model analysis

	East	West	ERCOT
Average wholesale power price difference	2.3	0.3	-3.8
Average production cost difference	-0.2	-4.7	-0.1

Note: Differences reflect deviation averaged over backcasting period. Production cost difference reflects average of five power sources: Coal, gas combined-cycle, gas combustion turbine, nuclear, and oil.

Source: IHS Energy

July 10, 2014

The Honorable Harry Reid
Majority Leader
United States Senate
Washington, DC 20510

The Honorable Mitch McConnell
Minority Leader
United States Senate
Washington, DC 20510

Dear Majority Leader Reid and Minority Leader McConnell:

In April, a broad coalition of railroad customers representing a range of U.S. manufacturing, agricultural, and energy industries wrote to your office to highlight the need for rail policy modernization. Today, we write to you in support of the attached specific reforms that would increase competition among railroad companies and make the Surface Transportation Board (STB) a more effective and efficient regulatory body.

The lack of competition for rail services has become a critical problem for American industry, as more than three-quarters of U.S. rail stations are now served by just one major rail company. This consolidation has given the remaining railroads unprecedented market power, and has denied many rail-dependent companies the benefits of cost-effective and reliable rail transportation service. Unreasonable rate increases, service breakdowns, and diminishing competition, all act as headwinds on the many industries that require rail to do business in the United States.

In the past, the rail industry has inaccurately portrayed efforts to reform rail policy as "reregulation." This coalition does not support a return to the 1970's when all freight rates were automatically subject to strict government scrutiny. Because the nation's freight rail network is vital to the strength of the economy, this coalition supports policies to create a more competitive and market-based system, while ensuring the STB has procedures to settle disputes efficiently.

There is no question that the United States needs a strong rail network to compete globally. Railroads are a remarkably efficient means for transporting bulk commodities over long distances. According to the Association of American Railroads (AAR), rail companies can now move one ton of freight 476 miles on one gallon of diesel fuel. Surprisingly, these increases in productivity have coincided with sharp increases in rail rates and declining service performance.

Several factors have contributed to the increasing imbalance in railroad market power, most importantly the dramatic consolidation of the nation's freight rail network since Congress passed the Staggers Rail Act of 1980. There were 26 Class I rail companies in 1980; now, four corporations control more than 90 percent of the market. Staggers helped the industry regain profitability, but unchecked consolidation has led to dramatic increases in rates. In fact, according to AAR data, rates spiked 94.8 percent from 2002 to 2012, which outpaces increases in inflation and truck rates by about a factor of three. Furthermore, the STB held an emergency hearing and intervention this spring to address systemic rail service problems, while rates increases continue.

The STB process for rate cases can and should be improved by Congress. Although railroad rates may be challenged for being "unreasonably high", shippers large and small who desire to bring a rate case face tremendous economic barriers. A major case at the STB is extremely complex, involves a multimillion dollar investment in lawyers and consultants, and takes several years to obtain a decision. During the rate case, shippers are forced to pay extremely high tariff rates in the hopes of recouping those costs at the end of the case if they are successful. Many shippers cannot afford to challenge a rate at the STB under current procedures, and for those that can afford it, the economics of filing a complaint are dubious.

Simply put, the current policies do not achieve the goals that Congress established in 1980, including promoting effective competition between rail companies, maintaining reasonable rates where there is an absence of effective competition, and providing expeditious resolution of all proceedings. In our view, it is the responsibility of Congress to ensure that the STB is perceived as an effective and viable intermediary between railroads and their customers who currently have no truly competitive option to ship.

We hope you will take a look at the attached document where we have outlined specific policy proposals that would help to modernize the U.S. rail policy framework. We look forward to working with Congress and the rail industry to ensure the nation's freight rail works-- both for rail companies and the large and small American businesses that rely on them.

Sincerely,

Agricultural Retailers Association

Alliance for Rail Competition

American Architectural Manufacturers Association

American Chemistry Council

American Forest & Paper Association

American Public Power Association

Chlorine Institute

Consumers United for Rail Equity (CURE)

Edison Electric Institute

The Fertilizer Institute

Growth Energy

Institute of Scrap Recycling Industries, Inc.

Louisiana Chemical Association

Manufacture Alabama

National Association of Chemical Distributors

National Rural Electric Cooperative Association

Plastic Pipe and Fittings Association

Portland Cement Association

PVC Pipe Association

Resilient Floor Covering Institute

SPI: The Plastics Industry Trade Association

Steel Manufacturers Association

The National Industrial Transportation League

The Vinyl Institute

Enclosure

cc: The Honorable John Boehner
The Honorable Nancy Pelosi
The Honorable John Rockefeller, IV
The Honorable John Thune
The Honorable Richard Blumenthal
The Honorable Roy Blunt
The Honorable William Shuster
The Honorable Nick Rahall, II
The Honorable Jeff Denham
The Honorable Corrine Brown

RAIL POLICY PROPOSALS

ENHANCE EFFICIENCY OF STB OPERATIONS

- **Allow direct communication between STB Commissioners:** Government "sunshine laws" prohibit a quorum of the STB (currently, any two members) from discussing pending matters with each other, forcing members to work via staffs. Congress should address this problem by expanding the STB to five Commissioners or by providing a limited exception that allows appropriate discussions of pending issues by STB members.
- **Study STB staffing and resource requirements:** Congress should initiate a study to determine whether the STB has adequate resources to fulfill its statutory mission.
- **Eliminate railroad revenue adequacy determinations:** As demonstrated by the industry's high levels of capital investment and shareholder returns, the STB's annual "revenue adequacy" calculations for Class I carriers are no longer necessary and may inappropriately shield railroads' pricing power from STB scrutiny. Congress should eliminate this outdated requirement.
- **Publicly report the status of STB proceedings:** Rail stakeholders would benefit from regular reports from the STB detailing the status of pending rate cases, rulemakings, and complaints. Reports should include key STB actions and expected timelines for final resolution.

REFORM STB RATE CHALLENGE PROCEDURES

- **Review the STB's rate-reasonableness standards:** Congress should direct the STB to review its three types of rate-reasonableness reviews. Significant concerns involve not only the cost and length of STB reviews, but also the fundamental principles on which each standard is based. Reformed standards should recognize that the Staggers Rail Act's goal of restoring financial stability to the U.S. rail system has been achieved.
- **Provide arbitration as an alternative means to resolve rail rate challenges:** The STB's rate review procedures are costly for railroads and shippers and, therefore, are rarely used. Binding arbitration, which has been used successfully under Canadian law, could provide a quicker and less expensive approach to resolve rail rate disputes.
- **Prohibit "bundling" of contract rates that can prevent rate challenges:** In some instances, a railroad will "bundle" rates in a single contract proposal for a group of origin-destination pairs and *refuse* to quote tariff rates for individual movements. This all-or-nothing approach effectively forces a shipper to agree to the complete package of contract rates and deprives them of the ability to challenge specific rates that it believes are unreasonable. The STB must be empowered to address this problem and fulfill its mandate to resolve rate disputes.

- **Review STB commodity exemptions:** Since passage of the Staggers Rail Act, numerous categories of rail traffic have been exempted from STB oversight. The rail industry and the state of rail competition have changed significantly since many of these exemptions were granted. Congress should direct the STB to conduct a comprehensive review of existing commodity exemptions and remove any exemptions that are no longer appropriate.

REMOVE BARRIERS TO FREIGHT RAIL COMPETITION

- **Provide competitive switching to shippers:** Competitive switching agreements facilitate the efficient movement of traffic between carriers and are critical to a competitive rail system. Consistent with existing authority under the Staggers Rail Act, the STB should be directed to provide competitive switching service to shippers, without requiring evidence of anti-competitive conduct by a rail carrier from which access is sought. The availability of switching should not preempt STB authority to review rates.
- **Allow shippers to obtain service between interchange points on a rail carrier's system:** Current STB policies and precedents effectively block many shippers served by a single Class I railroad from obtaining competitive service. In order to provide effective competition among rail carriers, a Class I rail carrier should be required to quote a rate and provide service between points on that carrier's system where traffic originates, terminates, or may be reasonably interchanged.

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Power by Association℠

Edison Electric Institute

David K. Owens
Executive Vice President, Business Operations Group

May 28, 2014

Ms. Patricia Hoffman
Assistant Secretary, Office of Electricity Delivery and Energy Reliability
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Ms. Hoffman:

I am writing in regard to comments filed by the Canadian Electricity Association (CEA) in October 2013 to the Canada-U.S. Regulatory Cooperation Council (RCC). The RCC was established by President Obama and the Canadian Prime Minister in February 2011 to increase regulatory cooperation and alignment between the two countries.

CEA's comments responded to a solicitation issued by the RCC for public input on additional opportunities to reinforce, institutionalize and expand Canada-U.S. regulatory cooperation and alignment. In its comments, CEA recommends that the Department of Energy (DOE) and the National Energy Board of Canada (NEB) seek to align and modernize their respective permitting requirements for international power lines and electricity exports.

Edison Electric Institute (EEI) understands, as noted by the CEA, that both DOE and the NEB have already recognized the need to update their permitting processes, and are at various stages of proposing modifications. EEI agrees that significant value will be derived from these activities if they are performed in alignment with each other.

The U.S. and Canada enjoy a strong electricity trading relationship, and benefit from a high level of integration between their electric power systems. Enhanced regulatory cooperation and alignment will facilitate increased infrastructure investment and cross-border trade, which in turn will make the North American grid more reliable and secure.

EEI supports CEA's call for a more modernized, streamlined and complementary approach to permitting new cross-border transmission infrastructure and export transactions. CEA's comments are consistent with EEI's ongoing advocacy in support of more efficient regulatory and permitting processes for needed transmission project development to help ensure a reliable and efficient electric power grid. EEI believes that efforts to streamline permitting for cross-border transmission projects should be executed in a way to avoid delay or add regulatory uncertainty to pending projects. Thus, EEI believes that any changes that might be made should be prospective only.

EEI understands that the RCC may soon finalize plans for its subsequent phase of activity. EEI supports consideration of CEA's proposal in this next round of efforts.

Please do not hesitate to contact me at (202) 508-5527 if I can be of further assistance on this matter.

Sincerely,

David K. Owens

David K. Owens

cc: Mr. Jim Burpee, President and Chief Executive Officer, CEA
Mr. Robert Carberry, Assistant Secretary, Privy Council Office, RCC Secretariat
Mr. Andrei Greenawalt, Associate Administrator, Office of Information and Regulatory Affairs, Office of Management and Budget
Ms. Melanie Kenderdine, Director, Office of Energy Policy and Systems Analysis, Department of Energy
Mr. Jay Khosla, Assistant Deputy Minister, Natural Resources Canada
Ms. Sandy Lapointe, Strategic Leader, Regulatory, NEB