U.S. DEPARTMENT OF ENERGY

2014/2015 Economic Dispatch and Technological Change

Report to Congress
September 2015

United States Department of Energy
Washington, DC 20585

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Message from the Assistant Secretary

In this report, the Department of Energy is responding to Sections 1234 and 1832 of the Energy Policy Act of 2005, which directed the Secretary of Energy to conduct an annual study of economic dispatch and potential ways to improve such dispatch to benefit American electricity consumers.

In this 2014/2015 economic dispatch report, the Department examines how technology and policy affect economic dispatch. This report looks at seven current topics that affect economic dispatch. They are: (1) variable generation resources; (2) energy storage; (3) the production tax credit; (4) market structure; (5) environmental regulations; (6) demand response; and (7) market power. The report is not intended to provide an in-depth study of these topics. Rather, the report gives a brief overview of the topics and their implications for economic dispatch, and in some cases suggests future actions that should be considered. Overall, the report stresses the need for grid flexibility and for a suite of solutions to address the complexities of economic dispatch as changes in policy and available technologies create new challenges for grid operators.

The ability to maximize the dispatch of low cost generation and to fully utilize the large investment already made in the electric system will depend on the flexibility of the system. A flexible system will use price signals, operational procedures, market structures, and technology to ensure that the lowest cost resources are dispatched first. Energy storage capacity, larger balancing areas, and shorter dispatch intervals are just some of the components a flexible electric system needs to better use the investments that we have made in the grid to date.

This report is being provided to the following Members of Congress:

- **The Honorable Joseph Biden**
  President of the Senate

- **The Honorable Thad Cochran**
  Chairman
  Senate Committee on Appropriations

- **The Honorable Barbara Mikulski**
  Ranking Member
  Senate Committee on Appropriations

- **The Honorable Lisa Murkowski**
  Chair
  Senate Committee on Energy and Natural Resources

- **The Honorable Maria Cantwell**
  Ranking Member
  Senate Committee on Energy and Natural Resources

- **The Honorable Lamar Alexander**
  Chairman, Subcommittee on Energy and Water Development
  Senate Committee on Appropriations

- **The Honorable Dianne Feinstein**
  Ranking Member, Subcommittee on Energy and Water Development
  Senate Committee on Appropriations

- **The Honorable John Boehner**
  Speaker
  U.S. House of Representatives

- **The Honorable Harold Rogers**
  Chairman
  House Committee on Appropriations

- **The Honorable Nita Lowey**
  Ranking Member
  House Committee on Appropriations

- **The Honorable Mike Simpson**
  Chairman, Subcommittee on Energy and Water Development
  House Committee on Appropriations

- **The Honorable Marcy Kaptur**
  Ranking Member, Subcommittee on Energy and Water Development
  House Committee on Appropriations

- **The Honorable Fred Upton**
  Chairman
  House Committee on Energy and Commerce

- **The Honorable Frank Pallone**
  Ranking Member
  House Committee on Energy and Commerce

- **The Honorable Ed Whitfield**
  Chairman, Subcommittee on Energy and Power
  House Committee on Energy and Commerce

- **The Honorable Bobby L. Rush**
  Ranking Member, Subcommittee on Energy and Power
  House Committee on Energy and Commerce

If you have any questions or need additional information, please contact me or Mr. Christopher King, Principal Deputy Assistant Secretary, Office of Congressional and Intergovernmental Affairs, at (202) 586-5450.

Sincerely,

Patricia A. Hoffman

Patricia A. Hoffman
Office of Electricity Delivery and Energy Reliability

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Executive Summary

Sections 1234 and 1832 of the Energy Policy Act of 2005 direct the U.S. Department of Energy (DOE, the Department) to conduct an annual study of economic dispatch and the potential benefits to American electricity consumers from improving such dispatch to use more non-utility generation. Today, economic dispatch in many parts of the country is being influenced by the increased use of non-traditional forms of utility generation to balance supply and demand.

In this report, the Department looks at how technology and policy affect economic dispatch. This report looks at seven current topics that affect economic dispatch. They are: (1) variable generation resources; (2) energy storage; (3) the production tax credit; (4) market structure; (5) environmental regulations; (6) demand response; and (7) market power. The report is not intended to provide an in-depth study of these subjects. Rather, the report gives a brief overview of the issues and their implications for economic dispatch, and in some cases suggests future actions that should be considered. Overall, the report stresses the need for grid flexibility and for a suite of solutions to address the complexities of economic dispatch as changes in policy and available technologies create new challenges for grid operators.

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ECONOMIC DISPATCH AND TECHNOLOGICAL CHANGE

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I. Statutory Language

This report responds to statutory language set forth in Sections 1234 and 1832 of the Energy Policy Act of 2005 which requires in subsection (c) that "on a yearly basis..., the Secretary shall submit a report to Congress and the States on the results of the [economic dispatch] study conducted under subsection (a)...." This study is described as follows:

(a) STUDY.—The Secretary, in coordination and consultation with the States, shall conduct a study on—
  (1) the procedures currently used by electric utilities to perform economic dispatch;
  (2) identifying possible revisions to those procedures to improve the ability of nonutility generation resources to offer their output for sale for the purpose of inclusion in economic dispatch; and
  (3) the potential benefits to residential, commercial, and industrial electricity consumers nationally and in each State if economic dispatch procedures were revised to improve the ability of nonutility generation resources to offer their output for inclusion in economic dispatch.

DOE's 2014/2015 Economic Dispatch Report finds that with respect to subsection (a)(1), there are no significant changes in utility practices regarding economic dispatch, and therefore this report focuses on subsections (a)(2) and (a)(3).

There are about 2730[1] non-utility power plants in the United States. Non-utility power plants include Qualifying Facilities established under the Public Utility Regulatory Policies Act of 1978. Qualifying Facilities include combined heat and power plants and small power producers. Non-utility power generators also include independent power producers that produce and sell electricity on the wholesale market at market-based rates. Independent power producers generated 1,516,000 gigawatt hours in 2013 as compared to 2,388,000[2] gigawatt hours generated by electric utilities.

II. Introduction to Economic Dispatch

The term "economic dispatch" refers to the practice of operating an electric system so that the lowest-cost generators are used first, followed by the more expensive generators. As demand increases, more expensive generators are brought into production, and then ramped down again when loads decrease. However, this theoretically simple economic optimization task is complicated by several factors—the complexity of the generation fleet being optimized; the size and configuration of the fleet's geographic footprint; the need to coordinate the differing

[1] See the GeneratorY2012file in EIA-860 Dataset, http://www.eia.gov/electricity/data/eia860/

[2] Energy Information Administration, "Electric Power Annual 2012" Data Table 1.3. http://www.eia.gov/electricity/annual/html/epa_01_03.html.

characteristics and operating costs of different generation technologies and sources; the need to account for significant variations in load over daily and seasonal cycles; and the need to operate the system reliably and within transmission line operating limits.[3]

Thus, the practice of economic dispatch is influenced by several factors other than price. Security-constrained economic dispatch, for example, is the operation of generation facilities producing energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities and the possibility of unexpected generator or transmission outages (contingencies). This report will use the term economic dispatch, which is inclusive of the term security-constrained economic dispatch.

Economic dispatch must manage generation and demand resources efficiently over time. Electricity demand varies greatly, in daily, weekly and seasonal patterns. Because bulk electricity cannot be stored inexpensively at present, generation must be available to follow changes in load almost instantaneously, as well as respond to sudden, unplanned contingencies, such as generator outages and changes in variable resource production levels.

Different generators have different costs, production capabilities, and operating characteristics. A generator's production level at a point in time will be affected by how quickly it can safely move between output levels; whether it is operating in a high- or lower-fuel efficiency zone; fuel availability; and whether there is sufficient transmission capacity available to deliver its output across the grid. Grid operators adjust the output of dispatchable generators (including fossil, nuclear, geothermal and dam-impounded hydro) to reflect changing grid conditions frequently, sometimes relying on automatic controls.[4]

The costs associated with ramping large fossil generators up and down can be significant. Increasingly, operators are looking to automatically dispatched demand-side resources and distributed storage devices, such as batteries and flywheels, to help manage small, short-term fluctuations in variable resource output. Some regions allow for temporarily operating transmission assets above nominal ratings—but still within the limits of reliability rules—to avoid using costly ramping or generator commitments to accommodate short-term conditions. Continued investment and innovation in both equipment and policies is needed to develop a flexible grid that can respond to traditional fluctuations in consumer demand as well as new

[3] Where multiple utilities are using the same transmission network to serve customers, the various dispatches or outputs from generators meeting the demand must be coordinated, either through a centralized market operator or other mechanisms.

[4] Different techniques are used on different time scales to manage or direct generators output for different purposes: on the time scale of millisecond to seconds, turbine governors are used to automatically adjust power output for frequency response; on the time scale of seconds to minutes, automatic generation control signals are sent to generators from a central location for load following; on the time scale of minutes and greater, operators communicate with generators through electronic dispatch instructions in order to dispatch the system economically based on a centralized market or dispatch stack. In electricity systems, the shorter-time frame controls are typically services, where generators (with preferable physical and economic characteristics) are compensated for being available to provide these capabilities when directed by grid operators.

and growing fluctuations from variable resources, while simultaneously reducing the need to run higher-cost ramping resources.

The practice of economic dispatch has become more complex as grid operators seek to incorporate public policy changes, technological innovation and growing amounts of variable generation. To dispatch electricity at the lowest cost possible, grid operators are incorporating a broader set of tools and resources to operate the grid. These tools and resources are components of a flexible electric system.

III. A Flexible Electric System

The underlying theme throughout this report is that the development of a flexible electric system or grid is necessary to ensure that generation resources are dispatched in the most economic manner possible. The International Energy Agency (IEA) considers a power system to be flexible if it can, "within economic boundaries... respond rapidly to large fluctuations in demand and supply, both scheduled and unforeseen variations and events, ramping down production when demand decreases, and upwards when it increases."[5] A flexible system prices the individual services needed to balance the grid on the basis of the value they add to the system. This allows technologies that are cost-effective to meet certain needs, but perhaps not to meet other needs, to compete in the market. This increased competition to provide the various services leads toward the lowest cost system and the most efficient use of resources.[6] The body of the report will discuss some of the specific components of a flexible electric system, both operational and technological.

IV. Variable Generation and Economic Dispatch

Variable generation resources, both utility and non-utility—primarily wind and solar photovoltaic—have been some of the fastest-growing sources of capacity being added to the grid in the past decade.[7] Twenty-nine states, the District of Columbia, and two U.S. territories have enacted renewable portfolio standards, which typically place binding requirements on electric utilities, generators, or consumers to purchase certain amounts of electricity generated by renewable sources.[8] In addition, eight states and two U.S. territories have legislatively

[5] International Energy Agency, "Empowering Variable Renewables: Options for Flexible Electricity Systems." 2008.
[6] The lowest cost system exists within the larger context of allocation or responsibility of cost. For instance, subsidies to particular types of fuel or generation may impact the marginal costs of producers in a way that changes the dispatch stack. On the other hand, other costs, such as some health impacts of emissions or bird kills from wind or solar installations, may not be internalized into the economic dispatch of the system.
[7] Energy Information Administration, "Electric Power Annual 2012." Data Table 4.2.A http://www.eia.gov/electricity/annual/
[8] Database of State Incentives for Renewables and Efficiency. "RPS Policies." March 2013. http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf

established, non-binding renewable-related goals.[9] These state policies, coupled with the production tax credit,[10] other state programs, and market conditions, have catalyzed the development of renewable generation resources.[11]

Between 2007 and 2013, installed capacity of wind generators grew from 16,515 MW to 59,973 MW (from 1.7% to 5.7% of total net summer capacity of all fuel sources) and solar thermal and photovoltaic generation grew from 502 to 6,623 MW (<1% of net summer capacity).[12] In 2013, wind generators produced over 167 billion kWh of electricity and solar produced 9.0 billion kWh; together these amounted to 4.4percent of total U.S. electricity generation.[13] The U.S. Energy Information Administration (EIA) projects continued significant growth of wind and solar generation over the coming decades, as shown in Figure 1.

[9] Some of these goals do not exclusively require the use of renewable generation. In particular, West Virginia has a broader "clean energy" goal which can be satisfied with non-renewables (including natural gas).

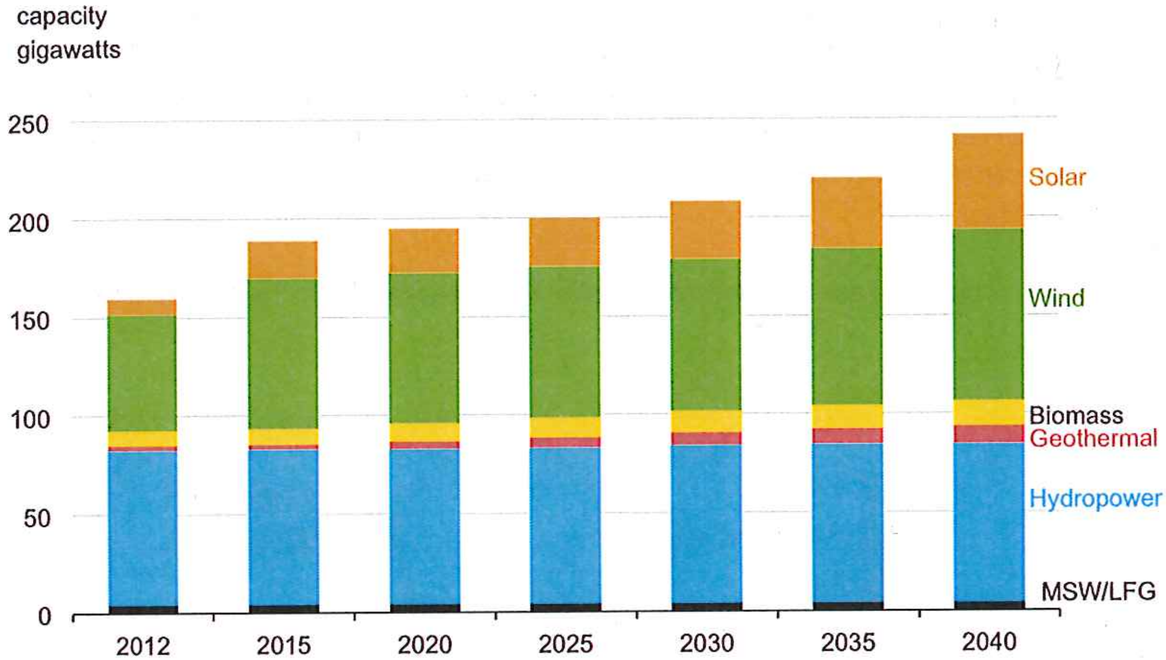
[10] The production tax credit for wind has expired, but projects that were under construction by the end of 2014 may be eligible to receive them. There have been legislative proposals to extend the eligibility deadline (e.g., projects that begin construction before the end of 2015) as well as proposals to phase out the production tax credit.

[11] Energy Information Administration, "Most states have Renewable Portfolio Standards." *Today in Energy*. February 3, 2012. http://www.eia.gov/todayinenergy/detail.cfm?id=4850

[12] Energy Information Administration, "Electric Power Annual 2013" Data Table 4.2b. http://www.eia.gov/electricity/annual/html/epa_04_02_b.html

[13] Energy Information Administration, "Electric Power Annual 2013" Data Table 1.1. http://www.eia.gov/electricity/annual/html/epa_01_01.html

Figure 1: U.S. Renewable electricity capacity projections from EIA Annual Energy Outlook reference case, 2012-2040 (GW)



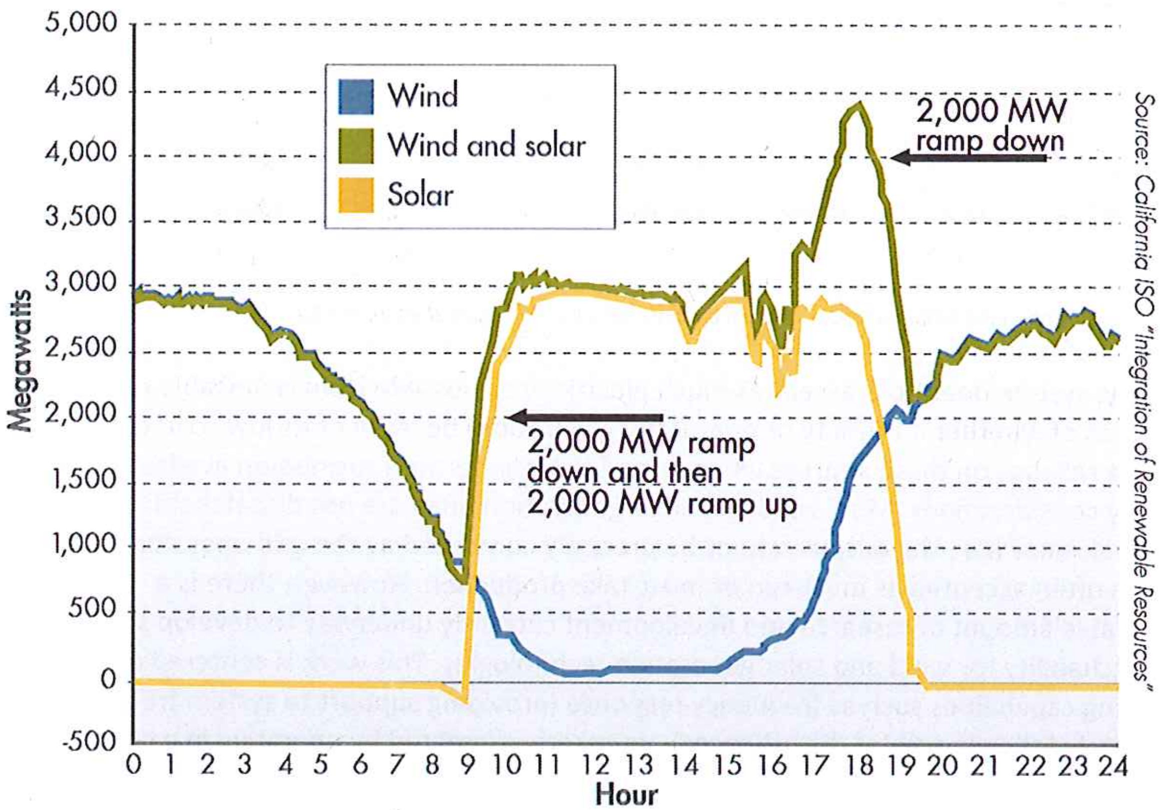
Source: Energy Information Administration, "Annual Energy Outlook 2014," April 2014, p. MT-19.

Generally, system operators accept as much electricity as possible from renewable resources (regardless of whether it is utility or non-utility generation) because of its low cost, only curtailing reliance on these sources when forced to by limits on transmission availability or reliability considerations. Most wind and solar generation units are not dispatchable in the traditional sense (i.e., the output cannot be precisely controlled by the grid operator), and their output is often accepted as must-run or must-take production. However, there is a considerable amount of research and development currently underway to develop some level of dispatchability for wind and solar generation technologies. This work is centered on developing capabilities such as frequency response (providing support to system frequency immediately following major disturbances); up-reserves (created by operating in a curtailed mode so production can be increased when required); ramp control (limiting how quickly production is increased); and variable generation curtailment. These are all components of a flexible electric grid. Some of these components have been implemented in the MISO (the Midcontinent Independent System Operator). MISO has introduced a Dispatchable Intermittent Resources product that requires wind to be treated like other generation resources.[14] This will allow wind to participate in the MISO real-time market and help in setting market-clearing prices.

[14] https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/WindIntegration.aspx

The characteristics of renewable generation differ from that of fossil generation. Renewable generation adds variability and uncertainty to the system because the wind does not blow at a given speed, nor does the sun shine with uniform intensity (variability); and while forecasting techniques are improving, we cannot predict exactly when these changes in wind speed or solar intensity will occur (uncertainty).[15] CAISO (the California Independent System Operator) observes that "the variability of wind and solar generation somewhat offset each other, but production of both resources can swing dramatically." CAISO projects that within a few years, wind generation serving California could swing by thousands of megawatts within a single hour, as illustrated in Figure 2.

Figure 2: CAISO's projected ramping extremes under 20% Renewable Portfolio Standard conditions

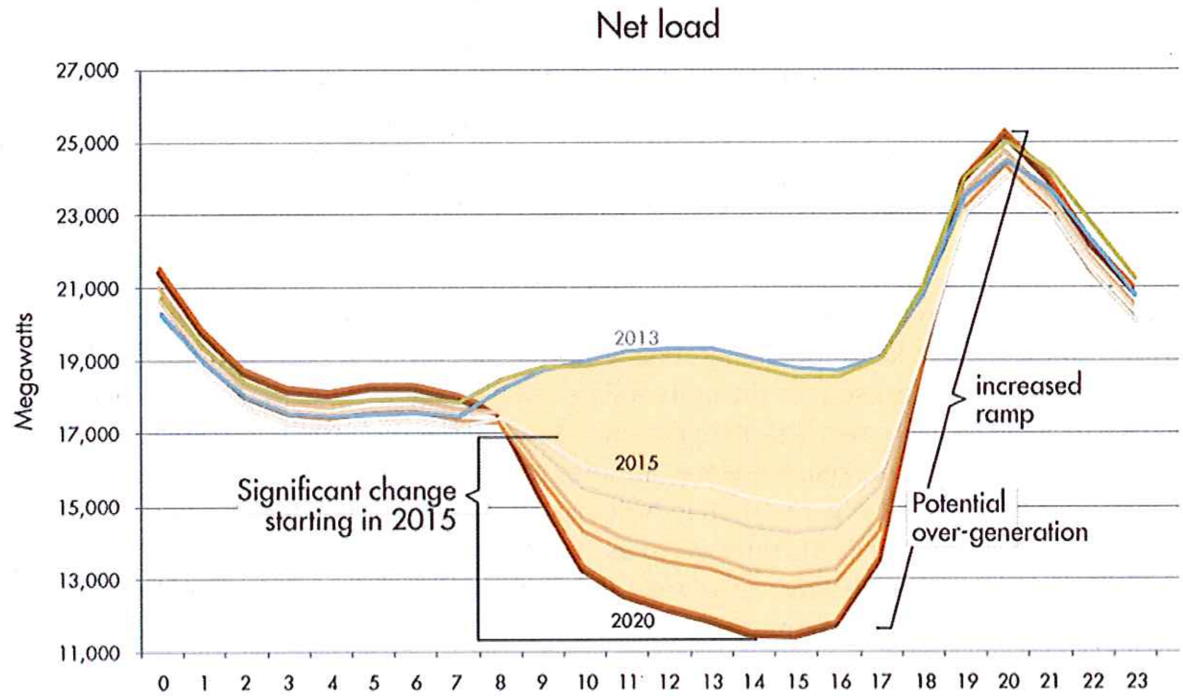


Source: CAISO, "2011 Annual State of the Grid," August 8, 2011, p. 24.

This variability in wind production, and the temporal correlation combining wind, solar product, and load, is expected to result in a dramatically increased need for ramping during certain hours of the day commonly referred to as the "duck curve" (see Figure 3 below).

[15] The grid and its operators have always had to deal with variability and uncertainty due to daily load variation and the unexpected loss of generation or transmission facilities, but the scale of the projected variability and uncertainty associated with wind and solar—at high levels of penetration of these technologies—is dramatically greater than that experienced earlier.

Figure 3: CAISO's growing need for flexibility starting 2015



Source: Rothleder, VP Market Quality and Renewable Integration CASIO. "Long Term Resource Adequacy Summit", February 26, 2013.

The need for more flexibility with respect to ramping is one of several challenges the California ISO faces as they integrate variable renewable resources with the traditional fossil/hydro fleet:

- Increased frequency, speed, and magnitude of ramps.
- Increased procurement of regulation-up and regulation-down energy.
- Increased load-following requirements, leading to the need for additional operating and supplemental reserves.[16]
- Increased stresses on generation fleet from ramping and cycling; and
- Increased frequency and magnitude of over-generation conditions.[17]

To address these issues, greater operational flexibility and improved resource forecasting are needed to integrate higher levels of variable generation resources. Currently, CAISO and its regulators have not implemented renewable generation curtailment as a strategy for providing

[16] Increased load-following requirements can arise from changes in variable generation and the prediction of variable production. See California ISO, "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS." August 31, 2010.

[17] California ISO, "2011 Annual State of the Grid," August 8, 2011, p. 21, and Keith E. Casey, CAISO VP – Market and Infrastructure Development, "Renewable Integration – CAISO Perspective," NARUC Summer Committee Meetings, July 18-21, 2010.

flexibility, although they are developing a flexible ramping market product as well as requiring load-serving entities to acquire certain amounts of flexible ramping capacity.[18]

Typically, changes in variable renewable resource output are met by ramping up and down dispatchable generation resources. Gas turbines and hydroelectric units are the most flexible and fastest responding units in the generation fleet and are therefore often used to follow load and provide balancing services.[19] Coal and nuclear units are generally less flexible, but are still able to ramp up and down to some degree to replace variable resources and match changes in load.

To ensure that some coal and nuclear generation units will be available for peak hours, grid operators often need to keep them operating at low output levels during minimum load conditions (e.g., overnight) so that the units will be readily available the next day to meet peak loads and provide ancillary services. Keeping some fossil generation running during the night to ensure next-day operational reliability may at times require operators to "spill" (i.e., curtail) low-cost wind or run-of-river generation in order to keep generation in balance with low off-peak load levels.[20] This practice is referred to as "out-of-merit dispatch."[21] A more flexible electric system will allow operators to address fluctuations in supply and demand through means other than traditional generation and has the potential to reduce the need for out-of-merit dispatch.

V. Energy Storage and Economic Dispatch

Energy storage has the potential to provide significant flexibility to the modern grid. It can provide both energy arbitrage, by absorbing excess power when it is low in cost and discharging when it is more valuable, and fast ramping response, to support the system in situations where system conditions change more quickly than can be satisfied by traditional generator ramping and demand management.

Several energy storage technologies are applicable in the bulk power context, and they fall into two broad groups. One group stores bulk energy and then transfers it back to the grid over long periods of time (e.g., several hours), such as pumped hydro storage, rechargeable batteries, concentrated solar thermal, ice storage, water heaters (particularly large capacity grid-interactive models), and compressed air storage. These technologies consume electricity

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[18] California Energy Commission, "Tracking Progress: Resource Flexibility." Last updated July 16, 2014, http://www.energy.ca.gov/renewables/tracking_progress/documents/resource_flexibility.pdf; Platts, "California PUC approves first-ever flexible capacity requirement," June 26, 2014, http://www.platts.com/latest-news/electric-power/portland-maine/california-puc-approves-first-ever-flexible-capacity-21822184.

[19] The physical flexibility of hydroelectric units is often constrained by other factors such as environmental concerns or competing uses such as irrigation and flood control.

[20] For a review of curtailment in the U.S., see Bird, Cochran and Wang, "Wind and Solar Energy Curtailment: Experiences and Practices in the United States." NREL Technical Report TP-6A20-60983, March 2014.

[21] Also see Section VI of this report for issues related to curtailing renewable resources.

produced in one time period—typically when it is abundant, low in price, and not needed to meet immediate demand—and feed it back into the grid in a controlled fashion at later periods when electricity is scarce and it is more valuable. These longer-duration storage technologies perform an electricity arbitrage function by buying electricity when it is low in price and releasing it when it is expensive. By doing so, they flatten out variability by increasing demand when electricity is plentiful, and serve as dispatchable resources that can be used to meet on-peak and other grid demands and, therefore, may address several of the variable renewable integration issues discussed above.

One circumstance under which this type of storage could be valuable is when paired with or on the same system as variable renewable sources. Storage could absorb excess electricity produced by non-dispatchable wind or solar when production is high but demand (and prices) are low, and then feed electricity back into the grid when prices are higher.

The second group of energy storage technologies produces and delivers large amounts of electric energy in very short periods of time (seconds or a few minutes). Such devices include high-speed flywheels, certain types of batteries, and advanced power electronics. They can provide vital fast-response services needed for reliability such as regulation capability and voltage support.

These technologies are promising in the economic and operational value they could bring to the grid, and thus they are potentially very compatible with the fundamental purpose of economic dispatch. Storage could also give grid operators new tools and capabilities for responding to the operational needs of integrating variable wind and solar resources, and a possible reduction in some regions in the amount of dispatchable fossil generation needed. Currently, the main barrier to storage is that the technologies are frequently not economically competitive.[22] However, with continuing investments in research and development for storage technologies, they could become more competitive as components of the future flexible electric system. It should be noted that the strategy of implementing thermal storage capacity to achieve operational flexibility of the electric grid has been adopted in several places, including the Pacific Northwest and PJM regions.

In October 2013, California adopted the first energy storage mandate in the United States. The California Public Utilities Commission required California's three investor-owned utilities to procure 200 MW of storage capacity by the end of 2014(these procurements are in progress) and 1,335 MW by 2020, with installation by the end of 2024.[23] This mandate, which would

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[22] The economic potential of storage projects rely not only on the cost of the technology, but also on whether the project developer can capture all the value the project provides and on how often the storage must by cycled and at what price difference. See Northwest Power and Conservation Council, "Sixth Northwest Conservation and Electric Power Plan." Chapter 6. https://www.nwcouncil.org/energy/powerplan/6/plan/

[23] California Public Utilities Commission, *Decision Adopting Energy Storage Procurement Framework and Design Program*. October 17, 2013. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M078/K929/78929853.pdf

double storage capacity in the country, was intended to help the state integrate and maximize the value of the anticipated increase in renewables generation.[24]

VI. Negative Pricing, the Production Tax Credit, and Economic Dispatch

Electricity markets set prices by matching aggregations of offers from suppliers with demand through market-clearing processes. There are a variety of circumstances when offered prices from suppliers can be quite low, zero, or even negative: generators with out-of-market agreements to sell their power (power purchase agreements); generators that must run for reliability reasons; mandatory releases through hydro-electric dams;[25] and output from variable renewable resources whose operating costs are very low and may benefit from production tax credits.[26] In some areas, certain system conditions exist where low, zero, or negative price offers converge with low demand, resulting in low, zero, or negative market prices. These situations result from over-abundant low-priced offers and in some cases, transmission constraints or other physical limits preventing the export of power.

Low, zero, and negative prices provide an economic signal to reduce generation or increase consumption from price-responsive demand. However, at times it is in a generation operator's best interest to continue producing electricity even though the market price is much lower than the unit's marginal cost of producing the electricity. This can occur for many reasons, including physical limitations on the unit (e.g., minimum shut-down times) and production tax credits. For example, many coal units and almost all nuclear units have large steam boilers, which are slow to reheat once they have been shut down. As a result, they are typically kept in operation all night at or above their minimum operating level, even if prices are low or negative, so that they will be available the next day when energy prices are more favorable.[27] Prices for some variable resources can frequently be negative during periods when production is high but demand is low. During negative pricing periods, wind generators may find it cost effective to continue operation if the negative prices are more than offset by the production tax credits—the amount of which are based on the kilowatt hours of electricity generated and sold to unrelated parties (rather than based on the price for which the electricity is sold).

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[24] The Energy Daily. "CPUC approves nation's first mandate for utilities to deploy energy storage." October 18, 2013.

[25] For example, in the spring of 2011, Bonneville Power Authority expected unusually high spring snow melt, which would result in large river flows that would harm protected salmon if that water were "spilled," or not directed through the hydro-electric dams. See The Energy Daily, "Wind Industry Claims BPA Grid Curtailments Are Discriminatory," May 23, 2011.

[26] The production tax credit provides qualifying wind installations tax credits for power that is produced. This can effectively reduce the prevailing market price at which these producers are willing to sell power.

[27] This was presented above in the discussion of variable generation as a reason variable generation is sometimes curtailed.

Low, zero, and negative prices arise from the combination of economic dispatch (meeting load with the lowest cost power available), economic incentives (including the production tax credit), and physical system constraints (such as minimum shut-down time or transmission constraints preventing low-cost power from flowing to a wider market). These prices have a major impact on the generators exposed to them, and can require out-of-market payments to resources to ensure they are kept financially whole.

The opportunity for new renewable generation sources to receive multi-year production tax credits—which contribute to wind generators' incentives to offer power into the market at very low, zero, or negative prices—expired as of the beginning of 2014. In December 2014, an extension was granted to include all projects under construction by the end of 2014. This does not change the production incentives for existing or eligible installations. However, wind installations that were not under construction by the end of 2014 are currently not eligible for the credits and thus may have different production incentives under low, zero, or negative market prices. There are legislative proposals to extend the eligibility date, but as of the writing of this report those have not been successful.[28]

In some areas, expansion of the transmission system could allow more electricity to be delivered to load centers while enabling the lowest-cost resources to be fully utilized. Economic and engineering analysis of the particular situation would be needed in order to determine whether an investment in transmission would be a relevant or cost-effective solution. In some cases the benefits of restoring merit order in the economic dispatch may not outweigh the cost of building additional transmission capacity. In other cases, transmission capacity is not the actual bottleneck, and an operational issue such as availability of reserves is the problem.

VII. Market Structure and Economic Dispatch

Market structure and operational procedures can affect economic dispatch. Markets can be highly organized and centralized Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), or consist of more decentralized procedures for trading, as in the non-ISO/RTO regions. In both cases, structures and rules exist to facilitate economic dispatch. Two market structure strategies that can improve operating flexibility, and thus economic dispatch, include larger balancing areas and sub-hourly markets. These can be particularly effective in addressing the variable output of renewable generation resources.

There are several reasons larger balancing areas can have an effect on economic dispatch. In a large balancing area changes in both load and variable resources will generally be non-coincident, meaning that they will generally not experience their peaks or other key operating conditions at the same time. Also, larger balancing areas typically have a larger and more diverse suite of generation units to dispatch, which can help reduce the cost to meet load and manage transmission congestion and variability. Sub-hourly markets or shorter market periods

[28] The Energy Daily, "Senate discord stalls legislation to extend tax subsidies for renewables." May 16, 2014.

can match generator flexibility to real-time conditions more closely than longer market periods. Thus, both larger balancing areas and shorter dispatch intervals give operators more options for meeting real-time system conditions and achieving a more economically-efficient dispatch. Both are components of the new energy imbalance market plan by the California ISO and PacifiCorp, approved by FERC in June 2014,[29] which will dispatch generation across the combined footprint—spanning California and five other Western states—every five minutes. The new market became fully operational November 1, 2014, and NV Energy plans to join in October 2015. Supporters of the market anticipate improvements in reliability, cost of system dispatch, and integration of variable resources.[30]

Some grid operators have adopted, are testing, or are considering a variety of new operational procedures and tools that could improve economic dispatch and increase system flexibility, including:

- Scheduling and dispatching resources to follow net load (customer load minus variable generation), to reduce overall variability and operations costs.
- Improving forecasting of day-ahead, hour-ahead and near-real-time variable resource generation, to reduce the difference between predicted and actual renewable generation and reduce the likelihood of a large mismatch between scheduled supplemental resources and actual generation needs in real time.
- Integrating variable renewable resource forecasting into control centers and decision-support tools for grid operations.
- Creating incentives for more flexible, load-following resources available to provide regulation and reserve requirements.
- Increasing the flexibility of dispatchable generation resources such as gas turbines, to have faster starts, faster ramp rates, and efficient fuel use across a wider operational range.
- Using monitoring and communications technologies such as synchrophasors and SCADA[31] to track variable generation and grid conditions and improve the use of available transmission capacity.
- Using redispatch and "conditional firm transmission service"[32] to reduce the impact of transmission constraints on variable generation's access to transmission services.
- Using more demand response and interruptible load for load following and ancillary services, including the aggregation of flexible loads like refrigerated warehouses,

[29] CAISO, "FERC actions support expansion of real-time markets in the West." Press Release, June 19, 2014. http://www.caiso.com/Documents/FERCActionsSupportExpansion-Real-TimeMarket-West.pdf

[30] CAISO, "Energy Imbalance Market Draft Final Proposal." September 23, 2013; http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarket.aspx

[31] Supervisory control and data acquisition

[32] Conditional firm transmission service is a way for more generators to use existing transmission lines under long-term contracts. Transmission lines are often "sold out" contractually but have physical capacity available in all but a small percentage of the year. Conditional firm is a service that would make that physical capacity available for use on a long-term basis. http://www.nationalwind.org/assets/blog/WGA_NWCC_Conditional_Firm_Factsheet.pdf

agricultural water pumping, and others to meet additional load-following needs due to variable resources and intelligent building energy management systems to support on-site photovoltaic resources.

- Backing down (curtailing, also known as "over-generation mitigation") variable resources when necessary to ensure that needed load-following generators remain on-line during minimum load periods for next-day reliability support.[33]
- Using technologies such as power electronics, dynamic voltage support, and storage to improve the controllability of intermittent generators and their impact on the grid.
- Developing energy storage technologies to serve as buffers and reduce the need for instantaneous balancing of load and generation. Storage technologies that absorb bulk energy can be used to store intermittent generation in one time period and release it into another (e.g., take in on-peak photovoltaic generation and shift it for night-time use, or absorb off-peak wind production for on-peak use), while short-duration storage technologies can be used to mitigate short, fast generation changes.[34]
- Developing and incentivizing new operational capabilities for variable resources such as self-provision of regulation and other active power controls.

VIII. Environmental Regulations and Economic Dispatch

The U.S. Environmental Protection Agency (EPA) is in the process of establishing several environmental regulations that will affect the electric utility sector. Of the regulations discussed in this section, many are still awaiting finalization. The following table lists the current major regulations that will affect the electric utility sector and denotes their status and expected compliance dates.

Depending on their configuration, owners of generators that are affected by the rules may need to undertake some degree of operational modifications (e.g., switching fuels to limit emissions) or retrofit with control technologies or purchase allowances (in the case of CSAPR) to meet the new requirements. In some cases, generator owners may choose to retire units instead of investing in such measures. Timely coordination among stakeholders will be necessary to maintain reliability while implementing these environmental regulations when retirements are expected.[35]

[33] See sections IV and VI above for more on variable generation curtailment.
[34] More detail about energy storage can be found in Section V of this report.
[35] NERC "2013 Long-Term Reliability Assessment." December 2013. pg 29-30.

Table 1: EPA Electric Utility Sector Environmental Regulations

	Federal Regulation	Impacts	Status
Air	**Cross-State Air Pollution Rule (CSAPR)**	• Establishes pollution caps for SO_2, annual NO_x and seasonal NO_x for 28 states in the eastern half of the U.S. to reduce transported pollution that significantly affects downwind nonattainment and maintenance problems with National Ambient Air Quality Standards (NAAQS).	Rule: finalized 7.6.2011 and published in the *Federal Register* 8.8.2011; supplemental rule finalized 12.15.2011 and published in the *Federal Register* 12.27.2011; technical revisions finalized 2.7.2012 and 6.5.2012 and published in the *Federal Register* 2.21.2012 and 6.12.2011, respectively; vacated 8.21.2012 by U.S. Court of Appeals, D.C. Circuit; vacatur reversed by the Supreme Court 4.29.2014, remanded to the D.C. Circuit; stay of the rule lifted by the D.C. Circuit on 10.23.2014; compliance deadlines were extended in an interim final rule signed 11.21.2014 and published in the *Federal Register* 12.3.2014.[36] Compliance: CSAPR became effective 1.1.2015. The Phase 1 emissions budgets apply in 2015 and 2016 (instead of 2012 and 2013), and the Phase 2 emissions budgets apply in 2017 and beyond (instead of 2014 and beyond).
	Mercury and Air Toxics Standards (MATS) Rule for Electric Generation Units[37]	• Establishes national emission standards for hazardous air pollutants (HAPs), including mercury, heavy metals and acid gases • Will affect existing and new coal- and oil-fired plants	Rule: finalized 12.21.2011 and published in the *Federal Register* 2.16.2012; updated standards for new plants finalized 3.28.2013 and published in the *Federal Register* 4.24.2013, except for certain startup/ shutdown issues, which were finalized 11.7.2014 and published in the *Federal Register* 11.19.2014. Compliance: sources have until April 2015 to comply or April 2016 if granted an additional year by permitting authority. Additional time possible if needed to maintain reliability through an Administrative Order;[38] new facilities will need to comply upon construction.

[36] On April 29, 2014, the Supreme Court issued its decision reversing the vacatur and remanding the case back to the D.C. Circuit Court of Appeals. On October 23, 2014, the D.C. Circuit granted EPA's motion to lift its stay of the CSAPR rule. On November 21, 2014, EPA signed an interim final rule revising the deadlines for compliance with the rule to reflect the action of the D.C. Circuit. (http://www.epa.gov/crossstaterule/)

[37] Additional information at: http://www.epa.gov/mats/

[38] The Clean Air Act provides three years for compliance. Additionally, under the Clean Air Act, state permitting authorities can also grant an additional year as needed for technology installation. EPA expects this option to be

	Carbon Pollution Standards for New Power Plants[39]	• Establishes new source performance standards which set national limits on CO2 emissions from new power plants	Rule: final rule released 8.3.2015 (as Carbon Pollution Standard for New Power Plants)[40] for publication in the *Federal Register*. Compliance: New sources must meet the standards.
	Carbon Pollution Standard for Existing Power Plants[41]	• Establishes limits for CO_2 emissions from existing power plants[42]	Rule: final rule released 8.3.2015 for publication in the *Federal Register* (see FN 40). Compliance: Proposed rule provides up to 15 years to come into compliance.
	Carbon Pollution Standards for Modified and Reconstructed Power Plants	• Established limits for CO_2 emissions from modified or reconstructed fossil fuel-fired electric utility steam generating units and natural	Rule: final rule released 8.3.2015 for publication in the *Federal Register.* Compliance: modified or reconstructed facilities will be expected to comply upon completion of triggering upgrade(s).[43]

broadly available. Sources may extend compliance deadline by yet an additional year by seeking an administrative order from EPA.

[39] The Carbon Pollution Standard was formerly known as the Greenhouse Gas New Source Performance Standard (NSPS) for Electric Generating Units; for additional information, see http://www.epa.gov/carbonpollutionstandard/actions.html

[40] EPA originally released a proposed rule on March 27, 2012 (77 FR 22392). On June 25, 2013, President Obama introduced his Climate Action Plan, which includes reductions in carbon output for new and existing electric power generators, and a Presidential Memorandum (PM) to EPA, which includes direction to achieve this. The PM called for a proposed rule for greenhouse gas regulation of new power plants by September 20, 2013; the PM also addresses existing power plants, calling for a proposed rule by June 2014 and a final rule by June 2015, followed by state plan submission for EPA approval by June 30, 2016 (see FN 37). EPA released its Greenhouse Gas NSPS for Electric Generating Units proposed rule September 20, 2013, which replaces the March 2012 proposal. See http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf; http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards; http://www2.epa.gov/carbon-pollution-standards.

[41] This regulation is also referred to as the Section 111(d) rule or Clean Power Plan, referencing the Clean Air Act authority under which it is being promulgated. EPA proposed a Federal Plan and model trading rules on 8.3.2015, in conjunction with its release of the Clean Power Plan. See http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants for more information.

[42] In the proposed rule, EPA has calculated a rate-based goal for each state's CO_2 emissions that must be met by 2030. In addition, EPA calculated an interim goal for each state to be met on average between 2020 and 2029. Meeting the state goals is expected to achieve overall national carbon emissions reductions of 30 percent below 2005 levels. EPA calculated the state goals based on a four "building block" strategy representing the so-called best system of emissions reduction (BSER): (1) improving efficiency of existing fossil plants; (2) using low-emitting power source more; (3) using more zero- and low-emitting power source portfolio; and (4) using electricity more efficiently. For more information see http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule.

[43] EPA is proposing technology-based standards for reconstructed steam units and natural gas-fired turbines and for modified natural gas-fired turbines. EPA is co-proposing two potential standards for modified steam units, one that sets one standard for all modified steam units, and another that has different standards for steam units based on whether they are modified before or after implementation of a state plan for existing power plants. For more

		gas-fired stationary combustion turbines	
Waste	**Coal Combustion Residuals (CCR) Rule from Coal-Fired Electric Utilities and Independent Power Producers**[44]	• Regulates the disposal of CCR, commonly known as coal ash, in existing and new landfills and surface impoundments. • Establishes technical requirements for disposal units, including location restrictions, liner design criteria, structural integrity requirements, operating criteria, groundwater monitoring and corrective action, closure and post-closure care requirements, and recordkeeping, notification, and internet posting requirements. • Addresses the risks from coal ash disposal, including reducing the risk of catastrophic failure of CCR surface impoundments, protecting groundwater thru a groundwater monitoring and corrective action program, and protecting against the blowing of CCR into the air as dust.	Rule: final rule signed by the Administrator on 12.19.2014 and submitted for publication in the *Federal Register*. Compliance: Rule will become effective 6 months after publication in the *Federal Register*; however, the rule establishes timeframes for certain technical criteria based on the amount of time determined to be necessary to implement the requirements.
Water	**CWA §316(b) – Cooling Water Intake Structures**	• Establishes national standards for impingement mortality and entrainment, with latter determined through a site-specific process • Affects certain existing fossil and nuclear steam units	Rule: finalized 5.19.2014 and published in the *Federal Register* 8.15.2014.[45] Compliance: after issuance of a final permit establishing the entrainment requirements, both impingement and entrainment compliance is expected as soon as practicable, based on schedules of requirements established by the state permitting authority, which may include intermediate milestones.

information see http://www2.epa.gov/carbon-pollution-standards/proposed-carbon-pollution-standards-modified-and-reconstructed-power

[44] For more information, see http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/ccr-rule/index.htm.

[45] http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm

Steam Electric Power Generating Effluent Guidelines	• Strengthens national controls on pollutant discharges from certain steam electric power plants.[46]	Rule:proposed rule finalized 4.19.2013 and published in the *Federal Register* 6.7.2013; final rule expected 9.30.2015 (consent decree).[47] Compliance: compliance timing uncertain until rule is finalized.

As of November 2014, only three of the above tabulated rules have been finalized: the Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), and the Cooling Water Intake Structures (316(b)). Compliance with MATS is well underway, with some plants retrofitting their pollution control technologies and others retiring.[48] 316(b) has just recently been finalized, and compliance will be determined by the state permitting authority. Numerous studies were conducted when these rules were first proposed to project their potential impact upon retirements and electric system reliability.[49]

The remaining rules are still uncertain with respect to their requirements, implementation, and compliance deadlines because the rules have not yet been finalized. Two of these proposed rules may have significant effect on carbon emissions from new and existing power plants. In September 2013, EPA released the Carbon Pollution Standards for New Power plants for public comment; this rule would establish limits on the amount of carbon that new power plants can emit.[50] In June 2014, EPA proposed the Carbon Pollution Standard for Existing Power Plants, a proposed rule that would limit carbon emissions from existing power plants.[51] The proposal proposed rate-based state goals based on EPA's determination of the best system of emissions reduction (BSER), but also proposes flexibility in how states comply, including allowing extensions for plan submissions and multi-state plans and the option to use mass-based goals. The BSER used to calculate the individual state goals comprises (1) making fossil plants more efficient; (2) using low-emitting power sources more; (3) using more zero- and low-emitting power sources; and (4) using electricity more efficiently. Each of these strategies could have some impact on economic dispatch, by raising or lowering the cost of producing the same

[46] See http://water.epa.gov/scitech/wastetech/guide/steam-electric/proposed.cfm.

[47] See the April 9, 2014 modified consent decree: http://water.epa.gov/scitech/wastetech/guide/steam-electric/proposed.cfm.

[48] The Energy Daily, "Survey suggests most plants on track with MATS compliance." July 2, 2013. While some coal plants are being closed to avoid the costs of complying with MATS (see The Energy Daily, "Analyst: FirstEnergy move may signal more coal plant closures," July 11 ,2013), others are being retrofitted to burn natural gas (see The Energy Daily "NRG Energy to retool Ohio, Pa. coal plants to run on gas," July 2, 2013). In some cases it is economic to retrofit large coal plants but not small ones. (Smith, "Turning Away from Coal," The Wall Street Journal, September 13, 2010).

[49] A partial list of references to these studies and summaries of their conclusions can be found in the 2011/2012 Economic Dispatch report to Congress.

[50] For more information see http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

[51] For more information see http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule. EPA concurrently released a draft rule limiting carbon emissions from modified and reconstructed plants.

amount of power, changing the dispatch stack to use more low-emitting power sources, changing the profile of installed capacity, or decreasing demand for power by improving the efficiency of consumption. The actual impacts on economic dispatch will depend on the state (or, potentially, multi-state) compliance plans which are expected in the 2016-2018 time frame; these plans will reflect EPA's final Carbon Pollution Standard for Existing Power Plants [111(d)], which is expected in summer 2015. Per the Presidential Memorandum (see FN 40), the final Carbon Pollution Standard for New Power Plants is expected in summer 2015.

Recent studies have focused on the potential impacts of—and regulatory and policy responses to—the Carbon Pollution Standards for Existing Power Plants.[52]

Compliance decisions are being made in the context of a number of trends in markets for electricity that are affecting the economic viability of plants, and especially coal-fired plants. These trends include changing relative prices of fuels, in particular gas becoming less expensive; demand for electricity not growing at the same pace as in the past; and the increased use of renewable power which requires balancing with flexible plants that can cycle on and off relatively quickly. These trends tend to make coal plants less profitable.[53] Owners of the more marginal coal plants may decide to retire the plants rather than invest in them.[54] Between 2013 and 2017, 180 coal-fueled generators, with a combined net summer capacity of over 26 GW, are slated for retirement.[55] These retirements are located in many areas of the United States, but are concentrated in the eastern part of the country.

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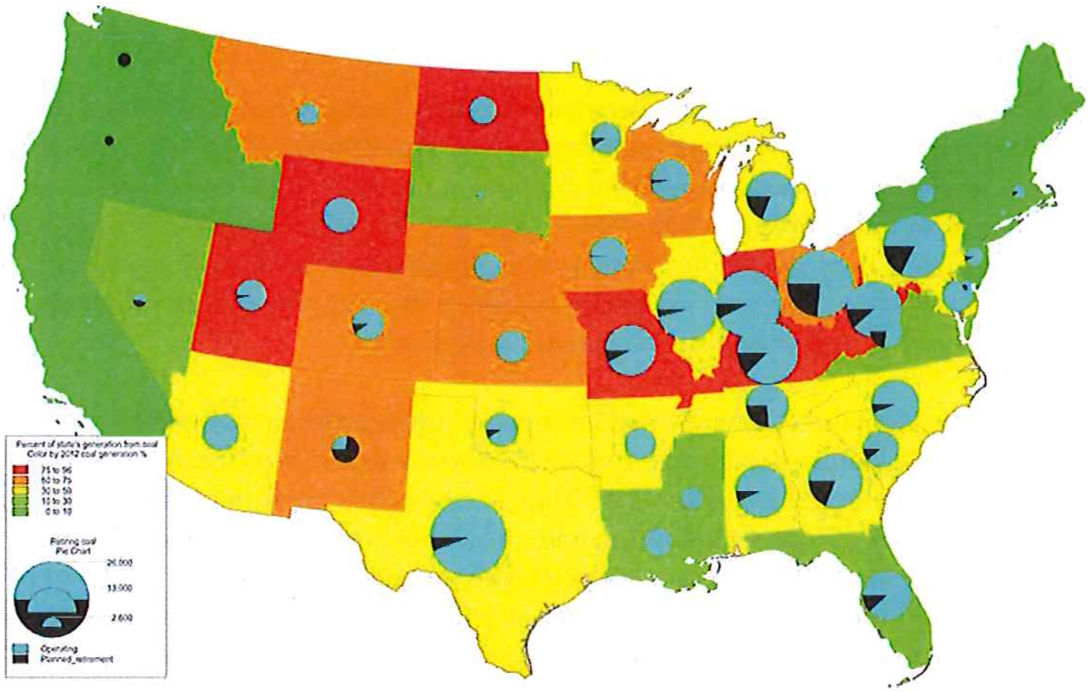
[52] See, e.g., Analysis Group, "Greenhouse Gas Emissions Reductions from Existing Power Plants: Options to Ensure Electric System Reliability." May 2014; Navigant Economics "Market Matter: Expect a Bumpy Ride on the Road to Reduced CO2 Emissions." *Perspectives*. May 2014. The Regulatory Assistance Project, "Clean Air Act Section 111(d): Legal Foundations, Policy Issues, and How States are Preparing." Presentation and discussion, Arkansas Public Service Commission and Arkansas Department of Environmental Quality. April 17, 2104; Environmental Defense Fund, "Section 111(d) of the Clean Air Act." October 2013 (revised February 2014).

[53] For example, former Exelon Chairman John Rowe said that half of Exelon's expected coal plant retirements are due to the current economics of the plant and relative coal and natural gas prices, independent of the retrofit decision. Rowe said, "cheaper gas, not stricter regulation, is prompting companies to shut older, smaller coal units." (Eileen O'Grady, Reuters, "Cheaper gas forcing coal retirements," June 14, 2011).

[54] One alternative strategy to either operating coal plants as status quo or retirement is seasonal dispatch. Under a seasonal dispatch management strategy coal plants would only be online during higher-priced seasons (summer in most regions of the United States), thus saving operation and management costs during seasons with lower market price. Electricity Policy, "How to get older coal plants back in the money? Use them for seasonal dispatch." April 23, 2014.

[55] During these same years, 242 natural gas plants are planned to be built, for a combined net summer capacity of just over 34 GW. Energy Information Administration, "Electric Power Annual 2012," Data Table 4.5. http://www.eia.gov/electricity/annual/

Figure 4: 2012 U.S. Coal Generation and Existing and Retiring Coal Capacity



Source: Map produced by NETL using Ventyx's Energy Velocity. Data Sources were Ventyx and EIA's Electric Power Monthly. States are shaded according to the percentage of total 2012 generation output from coal; pie charts indicate the proportion of coal capacity to be retired.

In the short term, environmental regulations may affect economic dispatch in two ways. First, these regulations may change the relative cost of generating electricity by fuel type, which will affect economic dispatch of generators. Some believe the EPA Carbon Pollution Standard for Existing Power Plants [111(d)] proposal suggested or endorsed the use of "environmental dispatch," in which case generators would be dispatched based on environmental characteristics instead of cost. However, the proposed rule is intended to be implemented within existing economic dispatch systems. Environmental regulations often affect dispatch because they change variable costs. For example, if states choose to achieve compliance with 111(d) through allowances, those costs may be included in the variable costs used to determine economic dispatch, as is done currently in areas of the country where tradable pollution permits are used to control emissions (e.g., under the Regional Greenhouse Gas Initiative, California's AB32).

Second, a combination of plant retirements, temporary outages for retrofits, and the time required for construction of replacement capacity may leave fewer units available to be dispatched at any given point in time. Planning authorities and grid operators will need to carefully schedule power plant outages to assure that grid reliability is maintained. These retirements could make economic dispatch more difficult or expensive for affected sub-regions, particularly if those regions are already burdened by transmission congestion or other constraints. As new generation is built, these potential difficulties may be alleviated.

IX. The Role of Demand Response in Economic Dispatch

Demand response (DR)—the reduction of electricity usage by consumers during peak periods in response to financial incentives—has the potential to improve economic dispatch by making more resources available to balance supply and demand in the system, potentially reducing costs to consumers. As noted in FERC Order 745,[56] "demand response in organized wholesale energy markets can help improve the functioning and competitiveness of those markets."[57] Demand response currently plays a role in energy, ancillary services, and capacity markets (where they exist), with different impacts on economic dispatch.

In electricity systems, demand response provides an additional resource that grid operators can dispatch to manage the system flexibly and reduce production prices, which can (directly or indirectly) reduce rates charged to customers.[58] That is, when the cost of demand response is lower than the cost of the marginal generation unit, or the next resource that would otherwise be dispatched, that demand response can displace higher priced resources, resulting in net savings to customers.[59] This phenomenon can happen whether the DR is being bid directly into the energy market or load-serving entities are managing DR as part of a larger energy procurement strategy. In the latter case, a load-serving entity can deploy their own DR programs in real time when wholesale energy prices are high to reduce their load and re-sell their positions to wholesale buyers willing to pay the high real-time price. In either case, deployment of DR in energy markets can affect economic dispatch.

Demand response also potentially plays a role in reducing the exercise of generator market power in energy markets. Demand response can mitigate generator market power because "the more demand response that sees and responds to higher market prices, the greater the competition, and the more downward pressure it places on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high."[60]

A recent court decision invalidating FERC Order 745, which required demand response to be compensated at the same prices as generators in wholesale energy markets in certain

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[56] Federal Energy Regulatory Commission, *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 76 FR 16,658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011), *order on reh'g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011)

[57] Federal Energy Regulatory Commission. "Demand Response Compensation in Organized Wholesale Energy Markets." Order No. 745. 2011.

[58] DR can reduce wholesale prices (LMPs) in organized markets, though the cost savings may not accrue directly or immediately to customers. Typically retail rates are set through state regulatory processes and not necessarily linked directly to wholesale prices.

[59] See the Net Benefits Test in FERC Order No. 745 for details.

[60] Federal Energy Regulatory Commission, *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 76 FR 16,658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011), *order on reh'g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011)

circumstances, has created some uncertainty about how demand response will participate in these markets. In May 2014, a federal appeals court vacated FERC Order 745, finding that demand response is a retail product; thus compensation for demand response is under state jurisdiction, not FERC.[61] This ruling, as it stands, may change how demand response is compensated in energy markets and may have the effect of reducing their participation in wholesale energy markets. However, it does not change the theoretical ability of demand response to affect economic dispatch or increase flexibility in electricity systems, or its practical ability to be deployed in energy markets as part of a utility's strategy to meet its load.[62] Some believe that it also does not change the ability of demand response to participate in capacity or ancillary services markets—which may currently have more participation from demand response than energy markets.[63] Some states are exploring localized regulation as a path forward. For example, North Carolina is regulating demand response providers, who then offer the demand response into the organized markets.

In addition to wholesale energy markets, demand response resources may participate in capacity and ancillary services markets. Demand response can currently be offered into capacity markets in the MISO, PJM, New York ISO, and ISO New England, where they compete with generators to receive payment in exchange for offering their capacity into the energy market in future years. This may have the indirect effect on economic dispatch of changing which or what type of generators will be available when the system is dispatched.

Currently demand response can also provide several kinds of ancillary services. FERC Order 719 requires RTOs and ISOs to "accept bids from demand response resources in RTOs' and ISOs' markets for certain ancillary services on a basis comparable to other resources."[64] FERC Order 755 deals with how those providing frequency response are compensated, and will increase the value of fast-responding demand response resources providing frequency response.[65] Both Order 755 and Order 719 may increase competition in the market to provide ancillary services and appropriately compensate the services demand response can provide. Increased competition should lead to a downward price pressure for ancillary services, and possibly affect

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[61] See Electricity Policy, "D.C. Court vacates FERC Order 745." May 26, 2014. FERC and PJM petitioned for rehearing en banc, but the court rejected the request (Sept. 18, 2014). FERC has not indicated whether it will seek Supreme Court review.

[62] Some industry experts suggest the court ruling may "shift demand response initiation and rules to the states, but nonetheless this is not the end of demand response," and that there is "inherent value...in the ability to control demand." One possible option for FERC is to propose optional DR rules that states can adopt. See Beattie. "Experts: Ruling means bumpy road – but no cliff – for demand response." *The Energy Daily*, June 30, 2014.

[63] See EnerNOC, "EnerNOC Comments on Circuit Court Decision on FERC Order 745." Press release. May 27, 2014, http://investor.enernoc.com/releasedetail.cfm?ReleaseID=850532

[64] Federal Energy Regulatory Commission. *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[65] Federal Energy Regulatory Commission. *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 (2011), *order denying reh'g,* Order No. 755-A, 138 FERC ¶ 61,123 (2012). Also see http://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf

the trade-off decision generators make when offering their capacity in energy versus certain ancillary services markets. In addition, appropriate compensation could incentivize more valuable fast-ramping demand response that can be used for maintaining system frequency, in part to facilitate renewable integration.

X. Market Power and Economic Dispatch

As noted in the previous section, the exercise of market power can negatively affect economic dispatch because it can increase the cost of procuring electricity. Large firms, or ones with strategically located generation, can exercise market power by withholding output to drive up the market price for electricity. The price increases because a more expensive plant is satisfying the demand not met by the withholding plant. When generators withhold output it is a deviation from an economically efficient dispatch.

The possible increase of market power resulting from mergers continues to be a concern for FERC, state public utility commissions, and other stakeholders. As an example, in 2011 Duke Energy and Progress Energy filed a Merger Application with FERC. FERC "conditionally authorized the Proposed Transaction subject to Commission approval of market power mitigation measures" because in the absence of such measures, the merger could have adverse effects on competition in certain areas.[66] In particular, the merger application proposed a virtual divestiture of a certain amount of power from regulated sources, but dispatch of these sources was still under control of the parent company. The Commission commented that "The lack of detail regarding [Duke Energy's] reliability obligations provides [Duke] with too much discretion regarding when delivery [from virtually-divested, low cost sources] may be interrupted."[67]

The merger between Exelon and Constellation in March of 2012 was another example of the potential impact of market power on economic dispatch. A study conducted by the Independent Market Monitor for PJM shows that the merger would raise competitiveness concerns, and that the proposed market mitigation measures could either offset competitiveness issues or "greatly exacerbate the competitive issues."[68] The study examined three scenarios using PJM's own software and input assumptions for the operational characteristics of the facilities comprising the PJM system, and found that post-merger dispatch patterns could vary significantly, depending on the nature of the entity that would acquire certain generation assets proposed for divestiture. Using the so-called "three pivotal supplier test" that "makes explicit and direct use of" incremental dispatch under different merger conditions, the study tested "whether excess supply is adequate to offset other structural

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[66] *Duke Energy Corp.*, Order Rejecting Compliance Filing, 137 FERC ¶ 61,210, Docket No. EC11-60-001 (December 14, 2011).

[67] *Ibid.*, p. 37.

[68] Monitoring Analytics. "Review and Analysis of the Proposed Merger of Exelon and Constellation." September 16, 2011.

features of the market," and found that it was not.[69] Given the structural market issues that may lend themselves to the exercise of market power, ongoing monitoring is prudent to ensure that parties do not exercise market power to increase prices.

A third example of potential market power arose from a proposed merger of two merchant generation companies. In early 2014, concerns were raised by the Independent Market Monitor for PJM that NRG Energy's proposed acquisition of Edison Mission Energy would increase concentration in a local energy market in a region of PJM. Increased market concentration could allow the newly formed company to raise prices and disrupt efficient economic dispatch in that region. The proposed solution was "behavioral" mitigation as opposed to asset divestiture, and monitoring of the energy market after a year.[70]

XI. Conclusion

Increasingly, the electricity industry is being asked to balance a number of public policy goals such as reliability, low cost, and environmental sustainability. Economic dispatch is at the center of how the industry chooses which generators will meet demand and, thus, how the industry performs in terms of these goals. As discussed in this report, economic dispatch is affected by a wide array of factors. While efficient economic dispatch has always been an industry goal, changes in public policy on both the state and national levels promoting growth of variable renewable generation on the grid have forced grid operators to reassess both how they operate the grid and the resources necessary to operate the grid. The ability to maximize the dispatch of low-cost generation and to fully utilize existing infrastructure will depend on the flexibility of the physical system, operating procedures, and institutional policies. A flexible system will use price signals, operational procedures, market structures and technology to ensure that the lowest cost resources are dispatched first. Storage, larger balancing areas, and shorter dispatch intervals are just some of the components of the flexible electric system that are necessary to better utilize the investments that we have made in the grid to date.

[69] *Ibid*,. p. 12, 17, 84.

[70] Monitoring Analytics. "Comments of the Independent Market Monitor for PJM," FERC Docket No. EC14-14-000. January 6, 2014.