

26. Consider Emerging Technologies and Other Important Policies

1. Introduction

The previous chapters offer a wide array of options to reduce greenhouse gas (GHG) emissions from the electric power sector through existing technology-based and policy-oriented solutions. The electricity sector is undergoing dramatic change, however, morphing from an analog unidirectional system to a digital multidirectional system. Traditional unidirectional systems are characterized by centralized electric generating units (EGUs) providing electricity to end-users through radial transmission and distribution grid networks. These systems have historically managed supply in order to meet demand. By contrast, currently emerging digital multidirectional systems will utilize distributed grid networks and manage both supply and demand through two-way communications and smart devices.

These changes will profoundly alter the electric power system as we have known it for the last century. Neither the form these changes take, nor their impacts and ramifications, are predictable or understandable at this point in any accurate or comprehensive way. However, several technology and policy trends and developments are increasingly evident. Although some may not achieve material penetration in the existing electric power system for a decade or more, many are already becoming widely commercialized. Because major air quality regulatory processes often operate on decadal timescales,¹ it is important to introduce several of these developments for regulators' awareness in air quality planning. The sections that follow do so, first for technology considerations and then for policy considerations.

It is also important to note that new technologies and new policy ideas regularly arise over the course of time. Those that follow do not represent a compilation of all such considerations, let alone a prediction of future ones. Furthermore, this list is intended to serve merely as an introduction to each of these developments rather than an exhaustive treatment of each.

2. Other Technology Considerations

Many new capabilities and increased efficiencies in the entire electric power system – from generation through end-uses – are being driven by the application of advanced digital and communications technologies. Others are emerging from enhanced data capture and analysis, better imaging and research capabilities, and new scientific discoveries and their application. Several of these technologically driven developments are covered in this chapter. Note that their order does not represent any kind of prioritization in terms of commercialization likelihood, time frame, or importance.

2.1. Energy Storage

Recent improvements in energy storage and power electronics technologies coupled with changes in the electricity marketplace are expanding opportunities for electricity storage as a cost-effective electric energy resource. Some analysts suggest, in fact, that we are nearing an inflection point in battery storage, with the economics of lithium-ion batteries unlocking new business opportunities that were unavailable just a few years ago. These in turn drive development efforts to, among other things, evaluate storage solutions as alternatives to future peaking needs. In conjunction with improving component costs, declining costs of capital, and the potential for utilities to rate-base the investment, factors are ripe for continued growth in storage as the market nears a tipping point on storage deployment.² Figures 26-1 and 26-2 illustrate the breadth

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- 1 For example, the interval necessary for revising a National Ambient Air Quality Standard (NAAQS), adopting regulations to attain it, implementing and enforcing those regulations, and conducting the research necessary for the next periodic NAAQS review regularly exceeds ten years.
 - 2 Dumoulin-Smith, J. (2014, December 8). *US Electric Utilities & IPPs: The Storage Inflection Point?* UBS.

Figure 26-1

New Storage Opportunities Are Beginning to Proliferate in Front of the Meter³

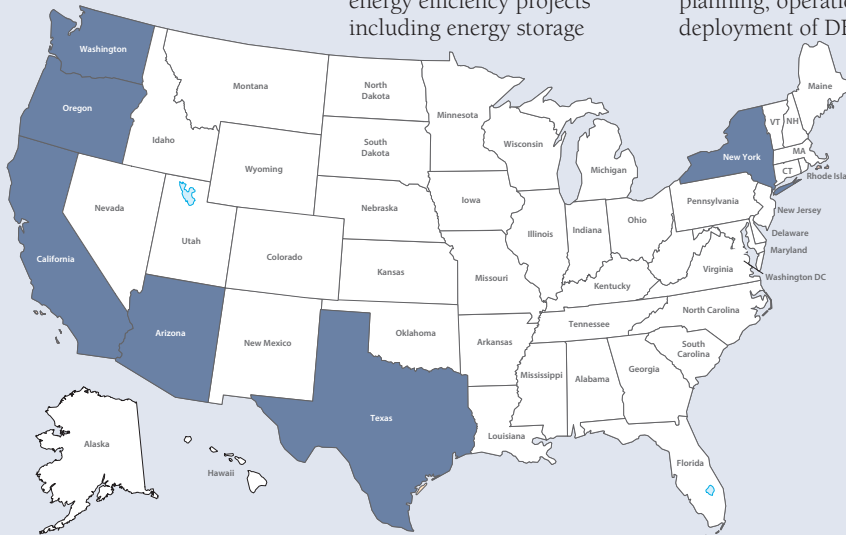
Oregon: Department of Energy sought comments to assist with development of storage demonstration RFP

Washington: Department of Energy awarded \$15 million to three utilities for storage demonstration projects

US: DOE announced a \$2.5 million solicitation (with additional funding up to \$4 billion) in loan guarantees toward renewable energy and energy efficiency projects including energy storage

New York: Con Edison and PSEG Long Island procuring storage for T&D deferral; NYSERDA providing funding for storage technology startups in addition to microgrid projects; New York PSC reforming regulation to facilitate planning, operations, and market-based deployment of DERs, including storage

California: CPUC mandating 1.3 GW of storage by 2020; SCE, PG&E and SDG&E issued relevant RFOs; SCE also procured 100.5 MW through LCR and SDG&E issued LCR RFOs (which count toward the mandate), capacity requirements driving more procurements than the mandate so far; PG&E and SCE issued RPS RFOs for utility-scale renewables paired with storage; CPUC proceeding to improve utility distribution resource planning in 2015



Arizona: APS to procure upward of 10 MW of storage; TEP to procure up to 10 MW

Hawaii: HECO considering three battery storage projects of 60 MW to 200 MW

ERCOT: Undertaking comprehensive redesign of ancillary service market to allow participation in the market and appropriately value fast-acting resources such as storage within three years; Oncor sponsored study showing value of utility-controlled distributed energy storage in Texas

PJM: Seeing consistent deployments for ancillary services; developing new capacity performance requirements for resources including storage

of storage opportunities now being explored both “in front of the meter” and “behind the meter.”³

Energy storage incorporates a variety of technology types that deliver four broad categories of energy services:

1. *Bulk energy services* (e.g., supply capacity, utility-scale time-shifting);
2. *Ancillary services* (e.g., regulation, spinning, non-spinning, and supplemental reserves, voltage support, black start, and the like);
3. *Transmission and distribution infrastructure services* (e.g., transmission/distribution upgrade deferral, avoided investments, reduced congestion); and
4. *Customer energy management services* (e.g., enhanced quality and reliability, retail time-shifting, and so forth).⁴

In what is known as stacked services, a single storage system can provide a combination of services, allowing it to become economically viable by capturing multiple revenue streams. These stacked configurations can be designed on a case-by-case basis, depending on location within the grid

and the specific technology capabilities.⁵

Energy storage could be a key component of a comprehensive strategy to reduce GHG emissions from the power sector. Storage can reduce GHG emissions directly by providing bulk energy and ancillary services to replace

3 GTM Research and Energy Storage Association. (2015, February 20). *US Energy Storage Monitor: 2014 Year In Review: Executive Summary*. Available at: <http://www.greentechmedia.com/research/us-energy-storage-monitor>

4 Eyer, J., & Corey, G. (2010, February). *SAND2010-0815 Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide: A Study for the DOE Energy Storage Systems Program*. Sandia National Laboratories. Available at: <http://www.sandia.gov/ess/publications/SAND2010-0815.pdf>

5 See: California Public Utilities Commission. R.10-12-007, *Rulemaking to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems*. Available at: <http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm>

Figure 26-2

New Storage Opportunities Are Beginning to Proliferate Behind the Meter⁶

US: DOE reviewing applications for \$15 million funding opportunity targeting behind-the-meter PV and solar integration

California: CPUC's SGP program to continue through 2020 on \$83 million annual budget, 4 MW of non-residential and 0.15 MW of residential projects have received upfront incentive; SCE procured 160.6 MW of behind-the-meter storage (135 MW battery storage) through LCR

New York: Con Edison soliciting 85 MW of load management including battery and thermal storage across two programs; PSEG Long Island may issue similar RFP; NYSERDA providing funding for microgrid projects; New York PSC reforming regulation to facilitate market-based deployment of DERs including storage

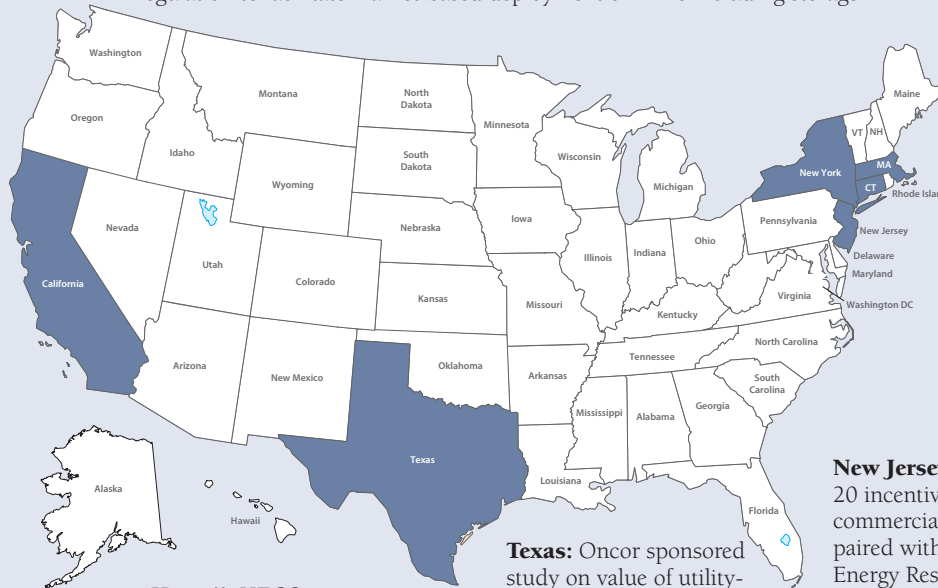
Massachusetts: \$25.8 million grant awarded to various microgrid projects, many including battery storage; MassCEC awarded \$150,000 for demonstration of utility-controlled residential battery systems

Connecticut: \$2.9 million grant awarded to municipal microgrid project including 100 kW of battery storage

New Jersey: BPU reviewing 20 incentive applications for commercial storage systems paired with renewable generation; Energy Resiliency Bank accepting applications for backup power systems for critical facilities

Texas: Oncor sponsored study on value of utility-controlled distributed (including behind-the-meter) energy storage in Texas

Hawaii: HECO contracted with Stem for 1 MW of storage for C&I customers with PV



high-emitting resources, such as fossil fuel peaking units and conventional load-following/ramping units. Storage can also help mitigate emissions indirectly by providing ancillary services to help integrate variable renewable energy resources into the grid. Storage can provide time-shifting services by charging devices when electricity prices are low – including when renewables are producing excess energy that would otherwise be curtailed – and discharging from them when prices are high. This can help reconcile the discrepancy between peak demand and peak renewable output, which can become an issue for portfolio managers at high penetrations of variable renewable generation.

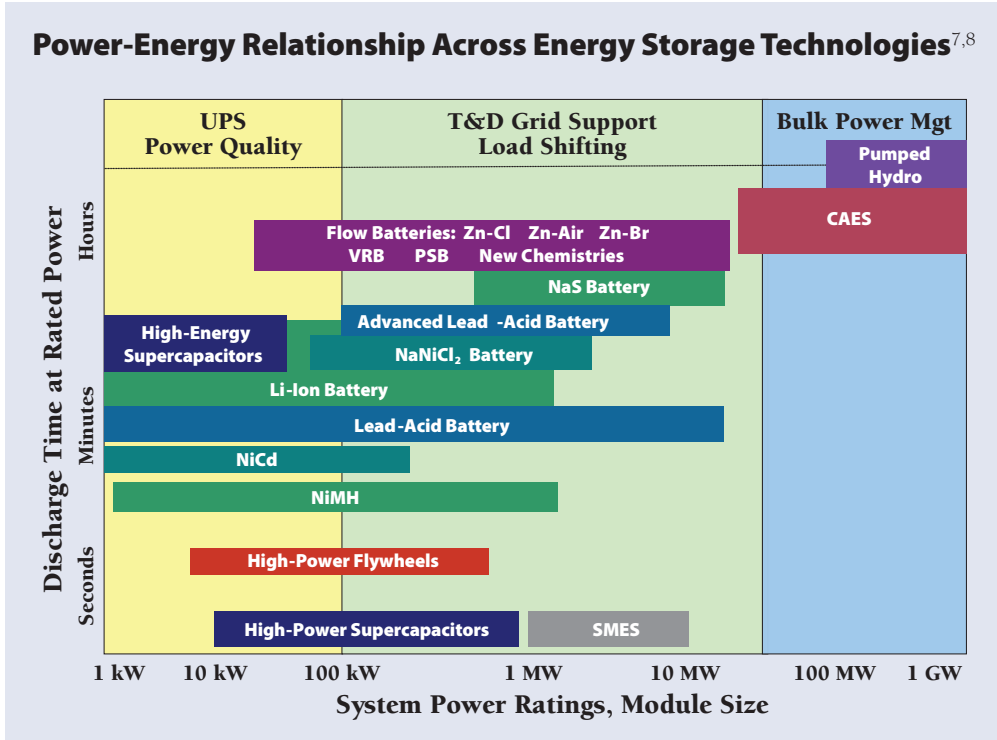
At present, viable storage opportunities have been primarily limited to pumped hydro and compressed air. Pumped hydro is a mature, utility-scale technology that takes advantage of off-peak electricity to pump water to a high elevation reservoir, from where it can be released and run through a hydroelectric turbine to generate electricity in peak hours. Compressed air energy storage (CAES) uses off-peak electricity to compress and store air, either belowground in manmade or natural caverns, or

aboveground in tanks. When needed, the compressed air can be heated and expanded to generate electricity via an expansion turbine or in conjunction with a conventional gas turbine. To date, there are two existing commercial CAES plants, one in Germany and the second in Alabama. A number of second-generation facilities are currently planned or under development.

CAES and pumped hydro fit a similar profile of bulk storage services, capable of long discharge durations (>10 hours) at large sizes (15 to 1000 megawatts [MW]). Storage technologies can be classified according to this relationship between discharge time and power rating, as demonstrated conceptually in Figure 26-3, which shows that the majority of storage technologies (e.g., electrochemical batteries and flywheels) are better suited to shorter and rapid discharge times at lower power ratings.

⁶ Supra footnote 3.

Figure 26-3



Note that Figure 26-3 is intended as an illustration of this relationship and that many of the technology options shown can have broader applications than the figure characterizes.⁹ Storage for utility-scale time-shifting (energy

arbitrage) or storage tied to large variable power facilities (or groups of facilities) would fall in the upper right on Figure 26-3 at the higher end of the size and duration times. Alternatively, storage used for time-shifting smaller-scale wind farms or solar photovoltaic (PV) applications would fall on the left, at the lower end of size and duration times.

Bulk storage is especially complementary to solar generation. In a 2014 study examining strategies for integrating large amounts of variable energy resources, researchers at Lawrence Berkeley National Laboratory found that the value of PV and wind increase dramatically with availability of low-cost bulk power storage on the system.^{10,11}

Discussion about “storage” often defaults to mean “storage of electricity,” but electricity is used to provide energy services (heating, cooling, lighting, driving motors, and so on). Rather than storing electricity to provide such energy services

7 Sandia National Laboratories. (2013, July). *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA*. Available at: <http://www.sandia.gov/ess/publications/SAND2013-5131.pdf>

8 CAES = Compressed Air Energy storage; Li-Ion = Lithium Ion battery; NaNiCl₂ = Sodium Tetrachloroaluminate battery; NaS = Sodium Sulfur battery; NiCd = Nickel Cadmium battery; NiMH = Nickel Metal Hydride battery; PSB = Polysulfide Bromide battery; SMES = Superconducting Magnetic Energy Storage; T&D = Transmission and Distribution; UPS = Uninterruptible Power Supply; VRB = Vanadium Redox Battery; Zn-Air = Zinc Air battery; ZnBr = Zinc Bromine battery; ZnCl = Zinc Chloride battery.

9 For greater technical detail on storage technology types, see full report: supra footnote 7. See also: State Utility Forecasting Group. (2013, June). *Utility Scale Energy Storage Systems: Benefits, Applications, and Technologies*. Available at: <http://www.purdue.edu/discoverypark/energy/assets/pdfs/SUFG/publications/SUFG%20Energy%20Storage%20Report.pdf>

10 Wisner, R., & Mills, A. (2014, March). *Strategies for Mitigating the Reduction in Economic Value of Variable Generation With*

Increasing Penetration Levels. Lawrence Berkeley National Laboratory. Available at: <http://eetd.lbl.gov/sites/all/files/lbnl-6590e.pdf>

11 Among other strategies considered (e.g., flexible conventional generation, real-time pricing, and variable resource diversity), low-cost bulk power storage was found to increase marginal values of PV by 80 percent at a 30-percent penetration level. The bulk power storage analyzed – modeled on pumped hydro storage with ten hours of storage capacity – would be charging during times with PV generation and have the effect of driving up prices during those times. Results for wind were positive but less substantial than solar. Lawrence Berkeley National Laboratory modeling found an 11-percent increase in the value of wind at a 40-percent penetration level, in comparison to a scenario without low-cost storage. The low-cost bulk storage mitigation measure assumes that pumped-hydro storage with ten hours of storage capacity can be built with a much lower investment cost than was assumed in the reference scenario, \$700/kilowatts-year, based on the cost of new pumped-hydro storage from the Energy Information Administration (2011).

at a later time, electricity can be converted to an alternative energy carrier and then stored in that form for direct use later. One of the most promising opportunities along these lines is thermal storage (e.g., water heating) in homes and businesses to shift electricity use from peak periods and/or to capture and store solar and wind generation when it is available. With water heating responsible for more than 17 percent of residential energy demand, the tens of millions of electric water heaters across the country represent a large opportunity for load control.¹² As is already being done by many rural cooperatives and other utilities, grid operators can shift water heating from morning and evening peak demand times to mid-day and overnight, when wind and solar may be underutilized. Using existing capacity, water can be “supercharged” to higher temperatures during off-peak times, and moderated through blending valves to achieve desired temperatures.¹³ One million electric water heaters are roughly equivalent to 4000 MW of dispatchable load, yielding as much as 10,000 megawatt-hours (MWh) per day that could be shifted as needed.¹⁴

Another promising load-shifting strategy involves thermal storage associated with air conditioning units

under grid operator control. Central air conditioners and large cooling systems can incorporate two hours of thermal storage in the form of chilled water and ice. Commercially available and being deployed today, these units allow ice-making during the hours of maximum solar output to meet demand for cooling later in the evening.¹⁵

Over a longer-term horizon, electrical batteries will offer opportunities for storage, but at the 2014 cost of \$700 to \$3000 per kilowatt-hour (kWh) of installed electricity storage, they remain expensive.¹⁶ Some analysts predict 50-percent declines in cost over the next three years; other analysts forecast even larger cost reductions.¹⁷ Initial market transformation is being driven by activities at the state level, including notably a 2013 energy storage mandate by the California Public Utility Commission requiring the state’s three investor-owned utilities to add 1.3 gigawatts (GW) of cost-effective energy storage to their grids by 2020.¹⁸ In the first competitive procurement process by Southern California Edison, storage proposals exceeded expectations, with 264 MW of storage capacity selected, including a 100-MW lithium-ion battery (with four-hour output duration) to replace older conventional peaking units.¹⁹

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- 12 US Department of Energy. (2011). *Residential Energy Consumption Survey 2009*. Available at: <http://www.eia.gov/consumption/residential/>
- 13 Lazar, J. (2015, February 15). *Thermal Energy Storage: A Low-Cost Option for Electricity Storage*. Presentation at NARUC’s 2015 Winter Committee Meetings. Montpelier, VT: The Regulatory Assistance Project. Available at: <http://www.narucmeetings.org/Presentations/Winter2015%20Lazar.pdf>
- 14 Lazar, J. (2014, January). *Teaching the “Duck” to Fly*. Montpelier, VT: The Regulatory Assistance Project. Available at: <http://www.raponline.org/document/download/id/6977>
- 15 In accordance with CPUC D.13-02-015, Southern California Edison selected 25.6 MW offered through 16 contracts in the West Los Angeles Basin for behind-the-meter thermal energy storage from Ice Energy Holdings, Inc. Gross, D. (2015, January 9). Long May You Run. *Slate*. Available at: http://www.slate.com/articles/business/the_juice/2015/01/battery_and_storage_infrastructure_is_the_next_growth_area_for_energy_here.html
- 16 UBS Global Research. (2014, October 2). *US Electric Utilities & IPPs: The Storage Opportunity*. Available at: <https://neo.ubs.com/shared/d1vn32UwCm8eh>; Supra footnote 7.
- 17 Byrd, S., Radcliff, T., Lee, S., Chada, B., Olszewski, D., Matayoshi, Y., Gupta, P., Rodrigues, M., Jonas, A., Mackey, P. J., Walsh, P. R., Curtis, M., Campbell, R., & Gosai, D. (2014, July 28). *Morgan Stanley Blue Paper – Solar Power & Energy Storage: Policy Factors vs. Improving Economics*. Available at <http://energystorage.org/resources/morgan-stanley-blue-paper-solar-power-energy-storage-policy-factors-vs-improving-economics>
- 18 California Public Utilities Commission. (2013, October 17). *Decision 13-10-040: Decision Adopting Energy Storage Procurement Framework and Design Program*. Available at: <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF>
- 19 Southern California Edison. *Pursuant to D. 13-02-015, Local Capacity Requirements Request for Offers, Selected Resource List*. Available at: https://www.sce.com/wps/portal/home/procurement/solicitation/lcr!/ut/p/b1/rVTBcpswEP0VXzzTHmQtSIB0JDVjw3jsJqSTwMU-jZJnQAsJA4rhfX0zcyfQQ43Ssk3bn6Wn37ZvFMX7Ec-SleslS0mS5Ffoxjex34U9eYUDNf3RgeuKHPpt7cg3Bld-4CoA8AHx4Vz778tbPyAYxzLsq3aJxw1Uq2LLtVtmtVjuF-0H4MqVZ0eRlWt5XOtij7X6DyTWdtX2owh11Lklykq-0SUPo1rtnrM3aDP6k6sv66_GjSmYbHBFbqLmRCbISCxA-IJEObAniwhaUc5IYpnFq7EzLA8L0jQ0w9ACDzdy5H4I-PzoKdF_P9zuP3nDCHnAB8Bt48WIE_u78l4JNbWiauSwD-MpxRP8Bxmuukn2TklglhKY5rtVW1qidPumnx436_n6Rap-7maSF3gqOvb-bDqqYnDdyEdJoQSRoIgsQmiwCliDt0g-SR3TlnlLhDhNa1CZ1PEwZDg-q0y37udrHbWfVoyddOtv_36vkGQvqPxBd5dYDQujah82nC4II9ckWJL1kHvFgYOSAft3Nfy-2yyUSCQNi5S9FsX6LDvs_7AAmZw!!/dl4/d5/L2dBI-SEvZ0FBIS9nQSEh/#/accordionGrp2-4

Other developments in Texas bode well for the growing viability of battery storage. Building on the results of a study by the Brattle Group, which found broad benefits to Electric Reliability Council of Texas customers from grid-integrated distributed electricity storage,²⁰ Texas utility Oncor is seeking regulatory approval to invest in 5 GW of energy storage, including \$2 billion in battery storage predicated on declining battery costs.²¹ Another commercial project underway in Illinois uses two 19.8-MW batteries to provide real-time frequency regulation service to the PJM Interconnection ancillary services market.²²

As greater segments of the transportation sector are electrified, electric vehicle (EV) batteries are another grid-integrated storage application that holds promise for low-cost grid support services.²³ With high ramping capabilities and the ability to shift loads over many hours, aggregated EV batteries can offer demand response and ancillary services to help accommodate variable energy resources and replace fossil fuel consumption in the transportation sector. Various pilot projects around the country, including those spearheaded by the Department of Defense (e.g., at Los Angeles Air Force Base, California; Joint Base Andrews, Maryland; Fort Hood Army Base, Texas; Joint Base McGuire-Dix-Lakehurst, New Jersey; and Fort Carson, Colorado) are exploring the benefits and costs of EV grid support across different utility and market environments.²⁴

As the costs of many of these technologies steadily

decline and storage becomes an increasingly important component of resource portfolios, market and regulatory frameworks also need to follow suit to allow the benefits of energy storage, both distributed and centralized, to be adequately evaluated and compensated. This may mean allowing utilities to include energy storage investments in their rate base, giving the right to own storage assets to transmission and distribution utilities, modifications to ancillary service markets, or other things in different utility market structures. These issues are explored in recent studies by the National Renewable Energy Laboratory (NREL), which provides more detail on valuing energy storage and overcoming related market and policy barriers.²⁵

2.2. Smart Grid

The term “smart grid” refers to a vision of a future power grid in which new types of information technology and other technological improvements are integrated into the existing power delivery system to enable more visibility, control, coordination, and management of both the existing grid and new assets, such as increased levels of renewables, customer-sited resources, electricity storage, and others. This information technology is envisioned to be provided by high-speed, two-way communications networks between utilities and customers, improved sensing systems, advanced metering infrastructure, energy management and

20 Chang, J., Pfeifenberger, J., Spees, K., Davis, M., Karkatsouli, I., Regan, L., & Mashal, J. (2014, November). *The Value of Distributed Electricity Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments*. The Brattle Group, Prepared for Oncor. Available at: http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf?1415631708

21 Klump, E. (2014, November 12). Texas Utility Sees Benefit in Potential \$2B Battery Storage Rollout. *EnergyWire*. See: <http://www.eenews.net/stories/1060008712>

22 PV Magazine. (2014, November 11). *RES Americas to Build 40 MW of Energy Storage System in Illinois*. Available at: http://www.pv-magazine.com/news/details/beitrag/res-americas-to-build-40-mw-energy-storage-system-in-illinois-_100017126/#ixzz3SaInSmbS

23 Energy and Environmental Economics, Inc. (2014, October 23). *California Transportation Electrification Assessment, Phase 2: Grid Impacts*. Available at: http://www.caetc.com/wp-content/uploads/2014/10/CalETC_TEA_Phase_2_Final_10-23-14.pdf

24 Morse, S., & Glitman, K. (2014, April). *Electric Vehicles as Grid Resource in ISO-NE and Vermont*. Vermont Energy Investment Corporation. Available at: <https://www.veic.org/documents/default-source/resources/reports/evt-rd-electric-vehicles-grid-resource-final-report.pdf>; California Independent System Operator. (2014, February). *California Vehicle Grid Integration Roadmap: Enabling Vehicle-Based Grid Services*. Available at: <http://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf>

25 Denholm, P., Jorgenson, J., Hummon, M., Jenkin, T., & Palchak, D., Kirby, B., Ma, O., & O'Malley, M. (2013, May). *The Value of Energy Storage for Grid Applications*. NREL. Available at: <http://www.nrel.gov/docs/fy13osti/58465.pdf>; Cappers, P., MacDonald, J., & Goldman, C. (2013, March). *Market and Policy Barriers for Demand Response Providing Ancillary Services in the US Market*. Lawrence Berkeley National Laboratory. Available at: <http://emp.lbl.gov/sites/all/files/lbnl-6155e.pdf>; Ela, E., Milligan, M., Bloom, A., Botterud, A., Townsend, A., & Levin, T. (2014, September). *Evolution of Wholesale Electricity Market Design With Increasing Levels of Renewable Generation*. NREL. Available at: <http://www.nrel.gov/docs/fy14osti/61765.pdf>

control systems in buildings, and other technologies that will better coordinate all the pieces of the power delivery system. When fully operational, the technologies will increase the use of and enable the better integration and control of:

- Demand response on end-use devices and systems to reduce the demand for electricity at certain times (discussed in Chapter 23);
- Behavior responses of customers who change their electricity use in response to feedback they receive through smart technologies (discussed in Chapter 13);
- Distributed generation, such as small engine or turbine generator sets, wind turbines, and solar electric systems connected at the distribution level;
- Distributed storage, such as batteries, flywheels, superconducting magnetic storage, and other electric and thermal storage technologies (discussed earlier in this chapter);
- Distribution/feeder automation, such as expanded communications in substations and other parts of the distribution network with remotely actuated switches, dynamic capacitor bank controllers, better transformer-management systems, and so forth;
- Transmission control systems that rapidly sense and respond to disturbances;
- Microgrids, which can disconnect from the traditional grid when it is stressed and thus improve system resiliency; and
- Electric and plug-in electric hybrid vehicles that charge and discharge energy stored in the batteries of the vehicles at appropriate times (discussed elsewhere in this chapter).

Operators of the smart grid (and customers and devices themselves), through the technologically improved electricity delivery system, will be able to actively control and respond in real time to grid conditions by adjusting usage and improving efficiencies in order to meet one or more of several goals. Those goals are varied, but some of the most important are: energy savings and emissions reductions; integrating renewables and other distributed sources into the grid; managing peak load capacity; operating ancillary services; and improving costs, reliability, resiliency, and security.

The potential applications of the smart grid are varied and diverse. For example, a smart grid application could allow a utility to have better awareness and communication of outages, allowing for faster recovery. During capacity-constrained periods, a smart grid application could help

deploy distributed energy resources to a greater extent or interrupt commercial and industrial customer loads. Large buildings could use whole-building control systems that would integrate all the energy-using devices within the building and allow building energy managers and utilities to control the devices in real time for optimal energy efficiency or other goals. Large customers that can't afford long outages, such as hospitals and some manufacturers, could use microgrids, increasing the resiliency and security of the grid. The smart grid also could make evaluation, measurement, and verification of energy efficiency and demand response programs easier, because smart meters and other technologies can more accurately record, track, and measure the energy savings impact of the programs.

In order to make the smart grid fully operational, several things need to occur: the improvement and modernization of the grid infrastructure; the addition of the digital communications layer onto the grid; and the business approaches and policy transformations necessary to capitalize on the investments and bring about the other goals of the smart grid. These many parts of the smart grid have been rolling out in pieces in different jurisdictions since the late 1990s and early 2000s. The rate of smart grid adoption varies across the United States, and depends on state policies, regulatory incentives, and technology experience within utilities.

Advanced metering infrastructure has been one of the most frequently deployed elements of the smart grid. Advanced metering infrastructure refers to three components: the smart meters at the point of energy end-use, the communications networks that transmit metered data, and the information management systems used to receive and process these data at utility offices. By 2015, an estimated 65 million smart meters will be installed across the country, representing more than one-third of the US meters of all types in use today.²⁶ Thirty of the largest utilities in the United States have fully deployed smart meters to their customers.²⁷ The smart meters so far are being used to produce operational savings for the

26 US Department of Energy. (2014, August). *2014 Smart Grid System Report: Report to Congress*. Available at: <http://energy.gov/sites/prod/files/2014/08/f18/SmartGrid-SystemReport2014.pdf>

27 Institute for Electric Innovation. (2014, September). *Utility-Scale Smart Meter Deployments: Building Block of the Evolving Power Grid*. Available at: http://www.edisonfoundation.net/iei/Documents/IEI_SmartMeterUpdate_0914.pdf

utilities; to roll out new services such as bill management tools, dynamic pricing, and energy use notifications; to improve outage management systems and restoration services; and to integrate new distributed resources. When combined with customer-based technologies such as programmable thermostats, in-home displays, and building energy management systems, smart meters have the potential to produce higher levels of energy savings. For example, at Oklahoma Gas and Electric, advanced metering infrastructure, time-based rates, and in-home displays are reducing peak demand by an amount that will potentially allow the utility to defer building a 170-MW peaking power plant.²⁸

Grid modernization within the distribution system includes the use of smart sensor, communications, and control technologies that create highly responsive and efficient grid operations. These technologies allow operators to locate and isolate faults using automated feeder switches and reclosers, optimize voltage and reactive power levels, and monitor the health of the system. Investments in distribution automation technology are now exceeding investments in smart metering, according to industry analysts.²⁹

An important piece of the smart grid is a modernized transmission grid. Investor-owned utilities have substantially increased their transmission investments in the past 15 years. In 2000, annual investment in the transmission infrastructure was less than \$4 billion; in 2013, annual investment had jumped to a record \$16.9 billion.³⁰ Although much of this investment was targeted at new transmission infrastructure and replacement of old infrastructure, some of it was targeted at advanced technologies and other grid modernization projects. For example, synchrophasors³¹ are an important element in a future resilient smart grid and have received increased

attention as a technology that can improve grid reliability and resilience. There were roughly 1700 synchrophasors connected to the US grid in 2014, up from only 200 in 2009.³² There are a number of other emerging transmission-related technologies that will help monitor and control operations within high-voltage substations and wide-area operations across the transmission grid, including dynamic line ratings, grid-scale energy storage, volt-VAR optimization, high-voltage direct current transmission, high-temperature low-sag transmission lines, and smart solar inverters. Some of these technologies are described in more detail in Chapters 5, 10, and 18.

More smart grid applications are also being deployed and required as a result of the growth in distributed energy resources that has occurred during the past several years, including rooftop solar, combined heat and power, EVs, energy storage, and demand response practices. Two-way power flows are required to optimally use such assets. Interest in microgrids also has increased with growing resilience and sustainability concerns. North American microgrid capacity may reach almost 6 GW by 2020, up from 992 MW in 2013, according to industry analysts.³³

Many smart grid projects have been deployed since 2010 as a result of the US Department of Energy's American Recovery and Reinvestment Act (ARRA) Smart Grid Program, which facilitated more than \$9 billion in public and private investments for smart grid applications. In total, the electric industry spent an estimated \$18 billion for smart grid technology deployed between 2010 and 2013 (ARRA and non-ARRA applications).³⁴ However, there is still a long way to go before the smart grid is fully built out. Estimates of the cost of full build-out vary, and range from \$338 to \$476 billion over a 20-year period (Electric Power Research Institute estimate) to nearly \$900 billion (nominal) for the transmission and distribution investment

28 Supra footnote 26.

29 Ibid.

30 US Energy Information Administration. (2014, September 3). Electricity transmission investments vary by region. Available at: <http://www.eia.gov/todayinenergy/detail.cfm?id=17811>; Edison Electric Institute. (2015, January 8). *Actual and Planned Transmission Investment by Shareholder-Owned Utilities (2008-2017)*. Available at: http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf

31 A synchrophasor is a device that measures the electrical waves on an electricity grid, using a common time source

for synchronization, allowing for real-time measurements of multiple remote measurement points on the grid. This provides grid operators with a better image of the grid in real time, helping to alert them to grid stress early on, potentially avoiding power outages and maintaining power quality.

32 Chaudhry, U. M. (2014, July). *Survey of Emerging Transmission Technologies*. Americans for a Clean Energy Grid. Available at: <http://cleanenergytransmission.org/transmission-technology-series/>

33 Supra footnote 26.

34 Ibid.

by 2030 (The Brattle Group estimate).³⁵

Smart grid applications, when combined with smart policy and business decisions, have the potential to enable more energy and emissions savings than would otherwise be possible. A 2008 estimate that examined seven smart grid mechanisms found that the applications, if deployed across the United States, could potentially reduce annual energy use by 56 to 203 billion kWh and GHG emissions equivalent to 60 to 211 million metric tons of carbon dioxide (CO₂) by 2030.³⁶ A 2010 analysis that considered nine smart grid applications found that electricity use and CO₂ emissions in 2030 could be reduced by 12 percent directly through the implementation of smart grid applications, and by a further 6 percent indirectly if cost savings from energy and avoided capacity were further invested in energy efficiency.³⁷ The many smart grid applications that are now underway will be providing real-life assessments of their impacts during the upcoming years.

2.3. Electric Vehicles

Powering vehicles with electricity offers the chance to reduce or eliminate emissions coming from a vehicle's tailpipe. As a result, steps have been taken by governments and manufacturers to encourage growth in the market for plug-in hybrid EVs (PHEVs) and battery EVs. But the uptake of EVs has been slow, because high initial costs of the vehicles make them less attractive than conventional vehicles with internal combustion engines (ICEs). Moreover, current battery technology does not store enough energy to give EVs the same range as ICE vehicles

without the help of an additional source of energy, such as an onboard gasoline-powered engine. In 2013, there were about 70,000 battery EVs and 104,000 PHEVs registered in the United States, a small number compared to the total of 226 million registered vehicles. Nevertheless, the market for EVs has expanded in recent years as manufacturers introduced new EVs and electric versions of existing models.³⁸ US sales of PHEVs represented about 0.7 percent of new vehicle sales in 2014, up from 0.6 percent in 2013 and 0.4 percent in 2012.³⁹

Transportation accounts for 32 percent of total CO₂ emissions from all uses, and passenger vehicles represent the largest share of transportation CO₂ emissions.^{40,41} Compared to ICE vehicles, which depend on the combustion efficiency and sophistication of onboard emissions control systems and fuel quality, the emissions attributable to an EV depend on the fuel source, efficiency, and emissions controls on the electric power sources used to charge them. An EV might be charged by solar panels on an adjacent rooftop, or electricity from a coal or nuclear plant hundreds of miles away.

As a result, emissions from EV electricity use vary widely based on the local grid mix, which varies by the time of day and, in certain cases, the time of year. Electricity from high-emitting generators reduces the comparative emissions benefits of EVs over ICE vehicles. EVs move emissions from the tailpipe to the power source (typically an EGU), reducing localized mobile-source emissions where vehicles are driven, but increasing the need to generate electricity elsewhere. Therefore, a robust understanding of the emissions implications of charging strategies is necessary to

35 Supra footnote 26.

36 Electric Power Research Institute. (2008, June). *The Green Grid: Energy Savings and Carbon Emissions Reductions Enabled by a Smart Grid*. Available at: http://www.smartgridnews.com/artman/uploads/1/SGNR_2009_EPRI_Green_Grid_June_2008.pdf

37 Pratt, R. G., Balducci, P. J., Gerkenmeyer, C., Katipamula, S., Kintner-Meyer, M. C. W., Sanquist, T. F., Schneider, K. P., & Secrest, T. J. (2010, January). *The Smart Grid: An Estimation of the Energy and CO₂ Benefits*. Pacific Northwest Laboratory for the US Department of Energy. Available at: https://www.smartgrid.gov/document/smart_grid_estimation_energy_and_co2_benefits

38 M. J. Bradley & Associates for The Regulatory Assistance Project and the International Council on Clean

Transportation. (2013, June). *Electric Vehicle Grid Integration in the U.S., Europe, and China: Challenges and Choices for Electricity and Transportation Policy*. Available at: <http://www.raonline.org/document/download/id/6645> June 2013.

39 EIA. (2014). *California Leads in the Adoption of Electric Vehicles*. Available at: <http://www.eia.gov/todayinenergy/detail.cfm?id=19131>

40 US Environmental Protection Agency. (2014). *Overview of Greenhouse Gases, 2014*. Available at: <http://www.epa.gov/climatechange/ghgemissions/gases/co2.html>

41 E3/ICF (2014, September). *California Transportation Electrification Assessment, Phase 1: Final Report*. Available at: http://www.caletc.com/wp-content/uploads/2014/09/CalETC_TEA_Phase_1-FINAL_Updated_092014.pdf

ensure net emissions reductions from EVs.^{42,43}

A Texas EV study found that if vehicle charging is optimized, an EV fleet of up to 15 percent of light duty vehicles could actually decrease EGU nitrogen oxides (NO_x) emissions, even while increasing load. This is because selectively increasing system load allows EGUs to run more efficiently, and allows system operators to deploy more efficient units. The same study found that using the batteries in the EVs to provide “vehicle-to-grid” (V2G) services could also reduce the sulfur dioxide (SO₂) and CO₂ emissions impacts of increased load from charging EVs. V2G services include using EV batteries for spinning reserves, frequency regulation, and energy storage to address peak load.⁴⁴ The study did not compare EVs to conventional vehicles, however.^{45,46}

EV charging strategies would typically seek to use off-peak electricity from the grid (i.e., nights and weekends). This would enhance the efficiency of the grid by shifting electricity use to off-peak nighttime hours, reducing the difference between off-peak and peak demand levels and allowing EGUs to operate more steadily and efficiently. As noted in Chapter 5, EVs can also be managed to help meet ancillary service needs on the grid as power supply market conditions change (e.g., by turning them off and on, drawing upon them as power “sources,” or charging them

as power “sinks”). Applying this V2G approach, a large number of EVs – plugged in and aggregated together as a single resource – could serve as a large battery for the grid, balancing variations in load and correcting for short-term changes in electricity use that might otherwise affect the stability of the power system.⁴⁷

The wise application of EV charging strategies can provide benefits beyond peak shifting and the provision of ancillary services to the grid. Through their storage capabilities, EVs can also improve the ability of the grid to absorb higher levels of renewable generation.^{48,49} EVs interfaced with the grid in a smart way can help meet balancing requirements associated with growing renewable energy deployment and maximize the amount of renewable energy that can be exploited without compromising grid robustness. Ultimately EVs and V2G could serve as twin pillars to boost renewables and simultaneously improve the overall performance of the grid.^{50,51}

As also noted in Chapter 5, several questions associated with the Environmental Protection Agency’s (EPA) proposed Clean Power Plan (CPP) must be addressed before EVs will contribute fully to grid optimization. States choosing a mass-based pathway for complying with the CPP, for example, could be discouraged from pursuing large-scale EV penetration because emissions from EGUs (which

42 Supra footnote 38.

43 US EPA. (2014). *Greenhouse Gas Emissions for Electric and Plug-In Hybrid Vehicles*. Available at: <http://www.fueleconomy.gov/feg/Find.do?zipCode=82001&year=2014&vehicleId=34699&action=bt3>

44 “Spinning reserves” are generation resources that are kept on standby and are able to provide capacity to the grid when called by the system operator. “Frequency regulation” is a service, typically provided by a power plant, which system operators use to maintain a target frequency on a power grid. Signaled, a frequency-regulating unit will either increase or decrease its output or load to rebalance system frequency.

45 Supra footnote 38.

46 Sioshansi, R., & Denholm, P. (2009, January). Emissions Impacts and Benefits of Plug-In Hybrid Electric Vehicles and Vehicle-to-Grid Services. *Environ Sci Technol* 43(4):1199–1204. Available at: <http://pubs.acs.org/doi/abs/10.1021/es802324j>

47 PJM Interconnection Fact Sheet. (2015, March 31). *Electric Vehicles and the Grid*. Available at: <http://www.pjm.com/~media/about-pjm/newsroom/fact-sheets/electric-vehicles-and-the-grid-fact-sheet.ashx>

48 Keay-Bright, S. (2014). *EU Power Sector Market Rules and Policies to Accelerate Electric Vehicle Take-Up While Ensuring Power System Reliability*. Montpelier, VT: The Regulatory Assistance Project. Available at: <http://www.raponline.org/document/download/id/7441>

49 E3/ICF. (2014, October 23). *California Transportation Electrification Assessment, Phase 2: Grid Impacts*. Available at: http://www.caletc.com/wp-content/uploads/2014/10/CalETC_TEA_Phase_2_Final_10-23-14.pdf

50 Peças Lopes, J. A., Rocha Almeida, P. M., & Soares, F. J. (2009, June). *IEEE 2009 International Conference on Clean Electrical Power: Using Vehicle-to-Grid to Maximize the Integration of Intermittent Renewable Energy Resources in Islanded Electric Grids*. Available at: http://www.researchgate.net/profile/Joao_Abel_Lopes/publication/224581302_Using_vehicle-to-grid_to_maximize_the_integration_of_intermittent_renewable_energy_resources_in_islanded_electric_grids/links/53fc5c7c0cf22f21c2f3cc0a.pdf

51 Tuffner, F., & Kintner-Meyer, M. (2011, July). *Using Electric Vehicles to Meet Balancing Requirements Associated With Wind Power*. Pacific Northwest National Laboratory for the US Department of Energy. Available at: http://energyenvironment.pnnl.gov/pdf/PNNL-20501_Renewables_Integration_Report_Final_7_8_2011.pdf

are covered by the CPP) could rise owing to additional charging load, even though GHGs from motor vehicles (which the CPP does not cover) would decline.⁵²

2.4. The Internet of Things

The “*Internet of Things*” (IoT) is a term used to describe an increasingly interconnected, responsive, and dynamic world in which many millions of new devices capable of two-way communication are being connected to the Internet every year. This interconnectedness offers convenience and comfort, but can also be designed to reduce costs and improve efficiency economy-wide.

In the industrial sector, smart manufacturing systems are connecting productivity on the factory floor with the business domain, permitting greater market responsiveness, reductions in lead times, and minimized material waste. In logistics, smart tagging of pallets and parcels is being deployed and piloted to enable a standardized, open transportation platform in global supply chains. These new models in transportation offer enormous potential improvements in freight utilization and associated reductions in GHG emissions.⁵³

In the building sector, heating, ventilation, and air conditioning systems are being integrated with energy storage and distributed generation, such as ice storage, rooftop solar, and combined heat and power.^{54,55} Networked locally, these systems can be optimized to incorporate renewable generation output and load forecasting. They can be controlled internally by building managers to respond to time-of-use (TOU) pricing and otherwise reduce energy costs. And they can be controlled remotely by grid operators to provide aggregated peak shaving and load-shifting benefits as well as ancillary services. Commercial and institutional buildings designed with this kind of interoperability are envisioned as key building blocks of a more resilient and distributed electric grid.⁵⁶

In the residential sector, smart thermostats – notably the learning thermostat developed by Nest Labs and brought to media attention in 2014 after its acquisition by Google – are already gaining market share, reducing energy for heating and cooling by 10- to 15-percent, according to field studies.⁵⁷ Following smart thermostats, a new wave of lighting, water heating, and other smart appliances and automation platforms are making their way

52 Toor, W., & Nutting, M. (2014, November 30). *Southwest Energy Efficiency Project (SWEET) and the Electric Vehicle Industry Coalition (EVIC), Comments on the Treatment of Electricity Used by Electric Vehicles in the EPA's Proposed Clean Power Plan Rule Docket ID No. EPA-HQ-OAR-2013-0602*. Available at: <http://www.seealliance.org/wp-content/uploads/SWEET-EVs.pdf>

53 A National Science Foundation-supported analysis by the Center for Excellence in Logistics and Distribution estimated that smart-tagging enabled innovations in logistics (a vision for modern freight transport coined the physical Internet) applied to only a 25-percent subset of freight flows in the United States could reduce the total freight transportation emissions by 200 teragram (Tg), or 39 percent of a total of 517 Tg CO₂ per year. Meller, R. D., Ellis, K. P., & Loftis, B. (2012, September 24). *From Horizontal Collaboration to the Physical Internet: Quantifying the Effects on Sustainability and Profits When Shifting to Interconnected Logistics Systems*. Final Research Report of the CELDi Physical Internet Project, Phase 1. Available at: <http://faculty.ineg.uark.edu/rmeller/web/CELDi-PI/Final%20Report%20for%20Phase%20I.pdf>

54 US Department of Energy & Pacific Northwest National Laboratory. (2015). *Transactional Network and Rooftop Units Project Overview*. Available at: <http://transactionalnetwork.pnnl.gov/overview.stm>

55 Such integration can build on and be coupled with direct improvements to building energy use through benchmarking

and annual disclosure of energy use, also called transparency. Benchmarking measures a building's energy use and compares it to the average for similar buildings, allowing owners and occupants to understand their building's relative energy performance and helping to identify opportunities to cut energy waste. More information is available at: <http://www.imt.org/policy/building-energy-performance-policy>

56 US Department of Energy, Building Technologies Office. *Sustainable and Holistic Integration of Energy Storage and Solar PV (SHINES)*. Available at: <http://energy.gov/eere/buildings/building-technologies-office-load-control-strategies>

57 Three studies of the Nest Learning Thermostat have been conducted, one by Nest Labs and the other two by independent groups. Results generally agree, suggesting heating savings of about 10 percent to 12 percent and electric savings of about 15 percent of cooling use in homes with central air conditioning. Apex Analytics. (2014, October 10). *Energy Trust of Oregon Nest Learning Thermostat Heat Pump Control Pilot Evaluation*. Available at: http://energytrust.org/library/reports/Nest_Pilot_Study_Evaluation_wSR.pdf; Aarish, C., Perussi, M., Rietz, A., & Korn, D. (2015). *Evaluation of the 2013–2014 Programmable and Smart Thermostat Program*. Prepared by Cadmus for Vectren Corporation; Nest Labs. (2015, February). *Energy Savings from the Nest Learning Thermostat: Energy Bill Analysis Results* (white paper). Available at: <https://nest.com/downloads/press/documents/energy-savings-white-paper.pdf>

to consumers and promising further interoperability.⁵⁸ The future of demand response-enabled homes will rely on the proliferation of interconnected hardware and compatible software tools, but also – and probably more importantly for energy saving – it will rely on dynamic or TOU pricing plans being offered to residential utility customers.

In the power sector, IoT applications will increasingly combine greater situational awareness on the grid, and at the point of final energy use, with the interoperability of distributed energy resources. The influence of communicating and computing technologies going forward will represent a quantum change. It will enable complex interactions that integrate millions of customers with grid operations to manage end-use load and maximize the performance of variable resources like wind and solar and storage resources. This interconnectivity can bring about emissions reductions through overall reductions in demand, as well as improved system efficiency in matching demand with cleaner, more cost-effective supply through load shifting, peak shaving, and the provision of regulation services – all of which are required for the integration of large shares of intermittent renewable energy.

Although product developers are at the cusp of envisioning, testing, and piloting these IoT developments today, how market forces, enabling regulation, and consumer demand will interact to realize the potential for greater efficiency and cost savings – and precisely how large that potential is – remains to be determined.

2.5. The Water-Energy Nexus

Large amounts of power are used in managing water resources, including pumping, treatment, distribution, and increasingly desalination; and likewise, large amounts of water are used in energy production, especially for boiler feedwater and cooling purposes at thermal power stations, as well as in extractive activities such as hydraulic fracturing of oil and natural gas wells. These linkages mean that water efficiency saves energy, and energy efficiency saves water.

With parts of the country facing growing water stress, as in California and other western states, the linkages between water and energy have attracted attention in recent years. However, these interconnections deserve consideration across the country, where nationwide, water pumping, treatment, and distribution account for a substantial portion of total electricity consumption – between 4 and 13 percent, according to various estimates.^{59,60} For GHG mitigation planning, water efficiency – whether in the form of water conservation or improved energy efficiency in water systems – represents an important opportunity that can be factored into state compliance plans for the EPA's CPP rule.

Opportunities are especially ripe at the municipal level, where drinking water and wastewater treatment facilities are often the largest energy consumers. They account for 30 to 40 percent of energy consumed by municipal governments, according to the EPA.⁶¹ Because energy comprises the lion's share of water system costs – for drinking water and wastewater utilities, energy is typically

58 For examples, see GE: <http://www.geappliances.com/connected-home-smart-appliances/>; Belkin Home Automation: <http://www.belkin.com/us/Products/home-automation/c/wemo-home-automation/>; Philips: <http://www2.meethue.com/en-us/>; Whirlpool 6th sense appliances and my smart appliances app: <http://www.whirlpool.com/smart-appliances/>; <https://www.mysmartappliances.com/>

59 Estimates vary widely. An EPRI study from 2002 estimated that drinking water and wastewater systems accounted for four percent of national electricity demand. A 2009 study by the River Network, which includes commercial and residential water heating, places it closer to 13 percent. Another investigation by researchers at the University of Texas Austin in 2011 found energy use associated with public water supply to be 6.1 percent of national electricity consumption. Regional differences can be significant. For example, in California, as much as 19 percent of the electricity is consumed in pumping, treating, collecting, and discharging water and wastewater. See: Electric Power Research Institute. (2002, March). *Water & Sustainability*

(Volume 4): *US Electricity Consumption for Water Supply & Treatment*. Available at: <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=00000000001006787>; Griffiths-Sattenspiel, B., & Wilson, W. (2009, May). *The Carbon Footprint of Water. River Network*. Available at: <http://www.rivernetwork.org/resource-library/carbon-footprint-water>; Twomey, K., & Webber, M. (2011, August). *Evaluating the Energy Intensity of the US Public Water System*. Proceedings of the ASME 2011 5th International Conference on Energy Sustainability. Available at: <http://proceedings.asmedigitalcollection.asme.org/proceeding.aspx?articleid=1636857>

60 A survey of current estimates is included in: Copeland, C. (2014, January 3). *Energy-Water Nexus: The Water Sector's Energy Use*. Congressional Research Service. Available at: <http://fas.org/sgp/crs/misc/R43200.pdf>

61 US EPA. *Energy Efficiency for Water and Wastewater Utilities*. Available at: <http://water.epa.gov/infrastructure/sustain/energyefficiency.cfm>

the second-largest expense after labor⁶² – improvements in water efficiency can yield substantial economic returns for local government.

Utilities and jurisdictions around the country have existing water conservation policies and programs. Program evaluation in many cases already involves quantification of associated energy savings,⁶³ allowing the programs to be readily incorporated as a mitigation strategy in GHG reductions plans.⁶⁴ Take, for example, an energy-management pilot project targeting drinking water and wastewater facilities in Massachusetts that was framed around a 20-percent GHG mitigation goal.⁶⁵ The state of Massachusetts also provides guidance on emissions calculations for water and wastewater treatment facilities on the basis of an average energy cost per volume of treated water (e.g., within the territory of Massachusetts Water Resources Authority: 1.3 kWh/1000 gallons treated for wastewater treatment; 0.2 kWh/1000 gallons treated for water treatment).⁶⁶

As in the case of the Massachusetts project, efficiency investments in the water sector are often designed to improve performance of motors and pumps in the treatment and distribution systems, or to produce onsite electric generation from methane biogas or other renewable energy sources.⁶⁷ Another inquiry by researchers at The Analysis Group and American Water Works Association examined the carbon emissions associated with lost water recovery and found significant energy and emissions benefits associated with infrastructure upgrades to reduce leaks.⁶⁸ Their findings suggest that general infrastructure

spending in the water sector could also be tied to GHG reduction strategies. The authors recommend further consideration of using generalized versions of ratepayer-funded energy efficiency cost-effectiveness tests to compare water infrastructure investments with other carbon reduction options.

3. Other Policy Considerations

Advancing technology has led and is leading to profound changes in the entire electric power system. At the same time, new technologies often create new policy issues and opportunities as well. Technology often makes possible, for instance, the measurement, management, and control of system processes where it was previously infeasible to do so. Resources can be identified and enlisted in ways that were previously inconceivable. Several of the most basic and traditional policy considerations for public utility regulators may need to be re-examined in light of these new developments. These include the core issues of reliability, rate design and pricing, and utility business models.

3.1. Reliability

No attribute of the electric power system garners more attention from public utility regulators than reliability. Many regulators consider “keeping the lights on” to be their most important job, if not a near-sacred duty. When the lights go out, utility employees and utility regulators endure harsh criticism and enormous political pressure, and may even fear for their jobs. Enormous economic

62 Supra footnote 60.

63 American Council for an Energy Efficient Economy. *Local Technical Assistance Toolkit: Energy Efficiency Opportunities in Municipal in Water and Wastewater Treatment Facilities*. Available at: <http://aceee.org/sector/local-policy/toolkit/water>

64 Tierney, S. (2014, July 21). Analysis Group's Tierney Says States Ready to Comply With Carbon Rule. *OnPoint: E&ETV Interview*. Available at: <http://www.eenews.net/tv/videos/1856/transcript>

65 US EPA. (2009, December). *Massachusetts Energy Management Pilot Program for Drinking Water and Wastewater Case Study*. Available at: http://water.epa.gov/aboutow/eparecovery/upload/2010_01_26_eparecovery_ARRA_Mass_EnergyCaseStudy_low-res_10-28-09.pdf

66 Massachusetts Energy and Environmental Affairs. *Greenhouse Gas Emissions Policy and Protocol. Guidance for GHG Emissions*

Calculations for Water and Wastewater Treatment. Available at: <http://www.mass.gov/eea/agencies/mepa/greenhouse-gas-emissions-policy-and-protocol-generic.html>

67 US EPA. (2010). *Evaluation of Energy Conservation Measures for Wastewater Treatment Facilities*. Available at: <http://water.epa.gov/scitech/wastetech/upload/Evaluation-of-Energy-Conservation-Measures-for-Wastewater-Treatment-Facilities.pdf>; California Energy Commission. *Process Energy – Water/Wastewater Efficiency*. Available at: <http://www.energy.ca.gov/process/water/index.html>

68 Aubuchon, C., & Roberson, J. (2013). *Embodied Energy of Lost Water: Evaluating the Energy Efficiency of Infrastructure Investments*. The Analysis Group and American Water Works Association. Available at: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/2013_Aubuchon_EconomicsOfWater.pdf

losses to businesses and individuals may occur from lost or spoiled production, as well as losses in service and Internet connectivity. Very real public health and environmental problems can also occur – for example, if water treatment or wastewater operations are interrupted, power to hospitals is lost, and so on. Simply stated, when reliability is raised as a concern against a particular regulation or compliance strategy, it must be taken seriously.

Reliability is a function of generation, transmission, distribution, and load interactions, and it may be measured on the local or regional level. Changes in one state or utility may impact the reliability or deliverability of power in another state or utility. As a result, generation and transmission projects must be assessed through regional processes to determine whether other upgrades are necessary and whether the benefits outweigh the costs overall. Resource adequacy and reserve margins are key elements of reliability, but they must also be supplemented with power flow studies. Reliability is maintained by a complex web of responsibilities at the utility, the balancing area, and authorities at the state, regional, and national levels. There are established procedures to assess reliability, to choose preferred solutions, and then to get solutions engineered, permitted, built, and operational. These processes can take several years, and they often involve significant tradeoffs for decision-makers.

Ensuring reliability is a fundamental constraint in reducing carbon emissions in the power sector, and it is a central concern of the EPA in developing the Carbon Pollution Emission Guidelines for Existing Stationary Power Sources (i.e., the proposed CPP). Accompanying the proposed rule, the EPA's Regulatory Impact Analysis used

the Integrated Planning Model framework to assess impacts on the power sector, including reliability impacts.^{69,70} The Integrated Planning Model is constrained by the need to maintain resource adequacy and meet reserve margin requirements in each of the 64 modeling regions.⁷¹ It does this through existing sources or new construction, and limits interregional energy and capacity transfers such that the reliability of the bulk transmission system is ensured and the specific regional reserve requirements are met first.

Considering a policy scenario with state-specific goals (as opposed to goals associated with potential regional, multistate efforts), the EPA's modeling indicates that 49 GW of coal and 16 GW of oil-gas steam capacity would be uneconomic by 2020 as a result of its proposed CPP regulations. Where needed for reserves, the EPA's modeling assumes these retirements are replaced by 35 GW of new capacity, consisting of 23 GW of natural gas combined-cycle, 2 GW of combustion turbine capacity, and 10 GW of wind, and the equivalent of four percent of current reserve capacity. Retirements are also offset by energy efficiency, which reduces total operational capacity requirements by 35 GW, further reducing the capacity required to meet reserve margins and the burden on transmission infrastructure.⁷² Given these results, the EPA concludes that the rule will not pose regional reliability risks that cannot be mitigated through standard planning processes within the timeline allowed.

The North American Electric Reliability Corporation (NERC) is an international regulatory authority responsible for assuring the reliability of the bulk power system in North America. In the United States, NERC acts under the oversight of the Federal Energy Regulatory Commission (FERC). In its *Initial Reliability Review*⁷³ of the proposed

69 US EPA. (2014, June). *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*. Available at: <http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf>

70 US EPA. (2014, June). *EPA Analysis of the Proposed Clean Power Plan: Supplemental Documentation and IPM (v5.13) Run Files*. Available at: <http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html>

71 Reserve margins are based on reliability assessments of NERC or state requirements, where they may be more stringent. For more on IPM, see: US EPA. (2013, November 27). *EPA's Power Sector Modeling Platform v.5.13: Documentation*. Available at: <http://www.epa.gov/airmarkets/programs/ipm/psmodel.html>

72 Greater detail on the resource adequacy analysis, including a regional breakdown of results, is provided in the Regulatory Impact Analysis and supplemental documents on resource adequacy. See: US EPA. (2014, June). *Technical Support Document: Resource Adequacy and Reliability Analysis*. Available at: <http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf>

73 NERC. (2014, November). *Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review*. Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf

CPP, NERC questioned some of the EPA's assumptions and emphasized the importance of additional research and analysis to better understand how the CPP may affect reliability. Several independent system operators (ISOs) and regional transmission organizations (RTOs) published analyses of the impacts of the proposed rule on their systems as well.^{74,75} Concerns raised by these groups generally focus on the following potential risks to reliability:

1. Insufficient reserve margins owing to retirements of fossil-fueled generators;
2. Inadequate *Essential Reliability Services*, for example, ramping flexibility, load following, reactive power, voltage control, frequency response, and so on, to accommodate increased supply of both utility-scale and distributed non-hydro renewable energy;
3. Insufficient planning time for expansions and enhancement to transmission infrastructure; and
4. Strained natural gas infrastructure owing to increased gas-fired generation.

NERC's preliminary assessment also questions specific assumptions in the EPA's CPP Regulatory Impact Analysis, namely that the EPA may have overstated the reductions achievable through heat rate improvements at fossil-fueled generators, increased natural gas generation, and reductions in demand through energy efficiency (i.e., what the EPA refers to as Building Blocks 1, 2, and 4 of its assessment of the Best System of Emission Reduction for existing fossil

fuel-fired EGUs).

A study released in February 2015 by the Brattle Group reached very different conclusions. It found that, although the EPA may have moderately overestimated potential reductions in some areas, it underestimated, or altogether excluded, potential reductions in other areas.⁷⁶ For example, Brattle noted that the EPA did not explicitly consider the emissions reductions that could be achieved by states through non-utility energy efficiency programs, appliance standards, or building codes (as explained in Chapters 12, 14, and 15, respectively). The potential for demand response programs to reduce emissions and maintain reliability was also not considered by the EPA or NERC (demand response is considered in detail in Chapter 23). The Brattle Group also evaluated several ideas that could potentially alleviate reliability problems. For example, higher-emitting facilities are expected to scale down hours of operation, but they may not need to retire, or not immediately. Some of these EGUs could perhaps be maintained on an emergency-capacity-only basis for two to three years to meet reserve margin requirements until other capacity resources such as combustion turbines, demand response, and energy efficiency can be built. The Brattle study also found that regional solutions to fuel switching, versus state-by-state solutions, could help offset short-term constraints in natural gas infrastructure. On balance the study found the CPP would not create major risks to reliability.⁷⁷

74 Midcontinent Independent System Operator. (2014, November 23). *MISO Comments on Docket ID No. EPA-HQ-OAR-2013-0602*. Available at: <https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/MISO%20Comments%20to%20EPA%20on%20Proposed%20CPP%2011-25-14.pdf>; New York ISO. (2014, December 19). *Comments of the NYISO on the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*. Available at: http://www.nyiso.com/public/webdocs/markets_operations/documents/Legal_and_Regulatory/Other_Filings/Other_Filings/20141201_IRC_Cmmnts_CLEAN_POWER_PLAN.pdf; SPP. (2014, October 8). *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan*. Available at: <http://www.spp.org/publications/Cpp%20Reliability%20Analysis%20Results%20Final%20Version.pdf>; ERCOT. (2014, November 17). *ERCOT Analysis of the Impacts of the Clean Power Plan*. Available at: <http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf>

75 Comments submitted to the EPA from many ISOs and RTOs have requested that the final rule include a reliability safety valve to provide a process for undertaking reliability

assessments and through which to be granted leniency to implement any requisite reliability solutions. ISO/RTO Council. (2014). *EPA CO₂ Rule – ISO/RTO Council Reliability Safety Value and Regional Compliance Measurements and Proposals*. Available at: http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-CO2Rule.pdf

76 The Brattle Group. (2015, February). *EPA's Clean Power Plant and Reliability: Assessing NERC's Initial Reliability Review*. Available at: <http://info.aee.net/hs-fs/hub/211732/file-2486162659-pdf/PDF/EPA-Clean-Power-Plan--Reliability-Brattle.pdf>

77 EGUs are also subject to new Maximum Achievable Control Technology (MACT) standards for mercury, Clean Water Act Section 316(b) cooling water regulations, and possible additional regulations associated with the Cross-State Air Pollution Rule (CSAPR). Some analysts have suggested that these requirements and other issues may create a greater impact on bulk or local electric grid reliability – at least in terms of coal shutdowns – than the CPP. See, for instance: Dumoulin-Smith, J. (2015, March 16). *U.S. IPP Power Shock: The Next Capex Cycle?* UBS.

A May 2014 report from the Analysis Group also considered the reliability impacts of GHG reduction strategies, and enumerated a number of approaches that can be applied in different market structures to balance reliability requirements with environmental compliance.⁷⁸ Restricting the operating permits of specific high-emitting facilities or using multiyear compliance periods are two mechanisms that would allow a fossil fuel-fired EGU to continue to serve reliability purposes. The Analysis Group study presents a range of emissions trading schemes that could be instituted, from bubbling of emissions across units at a single station, to interstate trading across various power plant owners. Inter-facility averaging, for instance, would allow a utility holding multiple plants to determine the best set of actions through which to maintain reliability while bringing its fleet into overall compliance (e.g., by limiting operations of certain high-polluting units, increasing capacity factors at underutilized natural gas combined-cycle units, investing in renewables, and reducing demand through energy efficiency programs).⁷⁹ Further modeling of the power system would be needed to properly understand reliability impacts, but these examples show how states could tailor their implementation plans to help manage those impacts.

A common finding of the Brattle Group and Analysis Group studies is that the flexibility afforded through Section 111(d) of the Clean Air Act allows states to use a broad range of options, both inside and outside the fenceline, to develop compliance strategies that can account for the unique factors affecting system reliability in a particular state or region. Both organizations conclude that existing institutions, operational tools, procedures, and planning processes are likely sufficient for regulators, market participants, and system operators to work together to resolve any reliability challenges that compliance strategies may present, and in some cases these efforts are already underway. In addition, the industry has a

demonstrated track record of effectively responding to environmental regulations – where most regulations have been less flexible than the current ones – without sacrificing reliability.

If the EPA has overestimated potential carbon reductions from heat rate improvements, coal-to-gas fuel switching, and energy efficiency, as NERC asserts, greater reliance would fall on renewable energy (in the CPP, Building Block 3) to achieve compliance. This raises the question of what risks there are to regional reliability from integrating variable energy resources at levels comparable to those established by the Best System of Emission Reduction. NERC expressed concern that variable energy resources significantly impact reliability, require build-out of transmission, and require additional ancillary services. However, the EPA's targets for 2020 are based on levels of renewable energy deployment that many states are already expecting and planning to accommodate. Of the 34 states that have already adopted renewable portfolio standards, only three have set levels that would be exceeded by the assumptions the EPA used in setting state targets for 2020.

In fact, the EPA's analysis suggests only a minor incremental increase in average renewable generation by states over its base-case scenario – from seven percent of generation from renewables in 2020 without policy intervention, to eight percent with policy intervention. The Brattle Group study concluded that this minor incremental increase is unlikely to disrupt reliability, even if renewables need to provide a greater share of total emissions reductions than the EPA assumes (as would be the case for states planning Renewable Portfolio Standard goals that exceed the EPA's targets).

The EPA sets renewable penetration levels below 20 percent by 2020 for all but two states, with a maximum penetration of 25 percent in Maine (a rate that state already exceeds, according to the EPA).⁸⁰ With Germany at 27 percent, Denmark at 39 percent (wind only), and California

78 The Analysis Group. (2014, May). *Greenhouse Gas Emission Reductions from Existing Power Plants: Options to Ensure Electric System Reliability*. Available at: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Tierney_Report_Electric_Reliability_and_GHG_Emissions.pdf

79 Inter-facility averaging, if conducted across facilities in multiple states operated by a multistate utility holding company, may require the relevant states to enter into a specific understanding that would enable each state's CPP

compliance plan to appropriately account for the fleet-wide controls established for the multistate holding company.

80 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units*. Docket ID No. EPA-HQ-OAR-2013-0602. Available at: <http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf>

on track to meet 33 percent of electricity from renewables by 2020,⁸¹ experiences from around the world demonstrate that comparable rates of renewables do not inherently compromise reliability.

A number of operational practices have been proven to facilitate cost-effective integration of intermittent resources.⁸² These include conventional techniques such as re-dispatch, curtailment, and adding additional flexible reserve capacity, as well as incorporating newer resources such as storage and demand response. Impacts of intermittency can also be mitigated by improving forecasting and scheduling, expanding balancing areas, and – where available and cost-effective – capturing a diversified portfolio of renewables, including resources with varying intermittency profiles and dispatchable resources such as geothermal, biomass, and biogas. These topics are addressed in more detail in Chapters 18 and 20 of this document.

Taking integration techniques like these into account, a number of recent analyses suggest that intermittent resources at higher levels than those set by the EPA in the CPP could be reliably accommodated. A study commissioned by Minnesota in collaboration with the Midcontinent Independent System Operator concluded that the state's electric power system could accommodate 40 percent variable renewable-energy resources without risking reliability.⁸³ Another study found that 30 percent of generation from wind and solar across the PJM Interconnection's territory would not have significant effects on reliability.⁸⁴ An additional study for California found levels of penetration of up to 50 percent were possible.⁸⁵ NREL has also conducted significant renewables integration

work, including multiple phases of its Eastern Wind Integration and Transmission Study, Western Wind and Solar Integration Study, and Eastern Renewable Generation Integration Study.⁸⁶

NERC's preliminary assessment and the other comments and studies discussed earlier agree that as states and regions develop implementation plans to comply with the EPA's CPP, additional modeling and analysis will be needed to ensure reliability. Some parties have suggested that some form of "reliability safety valve" should be built into the CPP or the state plan approval process, whereby detailed modeling could be conducted to ensure that state compliance strategies do not jeopardize reliability. In the CPP technical conferences that FERC held in early 2015, parties raised several possible iterations of such a safety valve, including broad-brush studies conducted using the EPA Building Blocks as a whole, followed by more detailed modeling after state plans are submitted. Actual power flow studies cannot be completed until regional groups have a clearer understanding of what individual states might propose in their compliance plans. These studies may indicate a need for more detailed regional assessment and possible adjustments to the timelines or to preferred methods in order to maximize benefits. Other parties recommend that the EPA build a step into the compliance process only if and when reliability issues arise and plan adjustments become necessary. Because reliability impacts cross state lines, no individual state is in a position to address this issue on a standalone basis. Safety valve studies, if conducted, must be transparent and include stakeholder participation, review periods, and opportunity for debate.

81 California Public Utilities Commission. (2014). *Renewables Portfolio Standard Quarterly Report: 3rd Quarter 2014*. Available at: <http://www.cpuc.ca.gov/NR/rdonlyres/CA15A2A8-234D-4FB4-BE41-05409E8F6316/0/2014Q3RPSReportFinal.pdf>

82 For discussion of costs of ancillary services, see: (1) NREL. (2013, September). *The Western Wind and Solar Integration Study Phase 2: Executive Summary, Technical Report*, NREL/TP-5500-58798. Available at: <http://www.nrel.gov/docs/fy13osti/58798.pdf>; (2) ERCOT. (2013, November 1). *Future Ancillary Services in ERCOT, Concept Paper, Draft Version 1.1*. Available at: <http://www.ercot.com/committees/other/fast>; (3) Porter, K., Mudd, C., Fink, S., Rogers, J., Bird, L., Schwartz, L., Hogan, M., Lamont, D., & Kirby, B. (2012, June 10). *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*. Western Governors' Association. Available at: <http://www.uwig.org/variable2012.pdf>

83 GE Energy Consulting and MISO for Minnesota Department of Commerce. (2014, October 31). *Minnesota Renewable Energy Integration and Transmission Study: Final Report*. Available at: <http://www.minnelectrans.com/documents/MRITS-report.pdf>

84 GE Energy Consulting for PJM Interconnection, LLC. (2014, March 31). *PJM Renewable Integration Study: Executive Summary Report*. Available at: <http://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx>

85 Energy and Environmental Economics. (2014, January). *Investigating a Higher Renewables Portfolio Standard in California*. Available at: https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf

86 Additional information on these projects is available at: www.nrel.gov

The flexibility of Section 111(d) of the Clean Air Act gives states the opportunity to draw on a wide range of options – including operational practices, technological applications, pricing strategies, and market-based policies, among other approaches – which they can use to help mitigate potential reliability impacts while achieving compliance.

3.2. Rate Design and Pricing

The rate structure that electric utilities apply to residential, commercial, and industrial customers has a direct impact on the *amount* of electricity that customers consume and *when* they consume it. The impact occurs in at least five different ways:

- **Conservation.** Customers who face a higher price per kWh will be more likely to participate in energy efficiency programs or acquire more efficient appliances and equipment to save money;
- **Time-Shifting.** Customers who face time-varying rates may choose to schedule energy use, such as laundry and dishwashing (for residential customers), business activities or production processes (for commercial or industrial customers), or EV charging (for both) into lower-cost time periods;
- **Fuel-Switching.** Customers who face a higher price per kWh may be more likely to choose fuels other than electricity to meet needs, including natural gas for space heat and water heat, and natural gas or a clothesline for clothes drying;
- **Economic Curtailment.** Customers who face a higher price per kWh may choose to change their thermostat settings, be more attentive to turning off lights and appliances when not in use, or wash clothes in cold water; and
- **Onsite Generation.** Customers who face a higher price per kWh may be more likely to choose to install a solar PV system or other onsite generating facility.⁸⁷

Although it is difficult to measure exactly which of these impacts causes the reduction in usage in response to a higher price (or an increase in response to a lower price), it is generally accepted that there is a price elasticity for electricity. Elasticity measures the change in the quantity demanded with respect to a change in price. That elasticity is generally recognized to be small in the short-run (one to three years) and higher in the long-run (over a period when appliances, lighting, and other energy-consuming equipment are replaced).

Although the techniques used to set prices are complex, the result is not. Customers deal with price-driven decisions every day. For example, an ice cream parlor entices customers to eat more ice cream with simple pricing tools, making additional scoops cheaper than the initial scoop. In electricity, this is known as a “declining block” rate design.

Residential rates are the best-understood rate designs, and they can have a dramatic impact on residential electricity consumption. Across the country, higher-cost utilities have lower usage per customer than lower-cost utilities. And there is plentiful evidence that the design of rates, within the constraint of the utility revenue requirement, also affects usage.

Residential prices generally include:

- **Customer Charge.** A fixed monthly charge, usually to cover billing and collection costs, but sometimes including distribution system costs as well.
- **Energy Charge.** A price per kWh for all usage; this may be in multiple blocks, differentiated by season, or differentiated by time of day.
- **Tariff Riders.** These are adjustments applied to rates that operate between general rate cases. The most common are for fuel and purchased-power recovery, but some regulators have allowed multiple riders that amount to one-third of the total bill or more.

Impact of Price Level on Usage

In general, the higher the per-kWh charge, the more incentive there is for customers to find alternatives to consumption. Economists use a concept known as “price elasticity” to estimate the change in usage in response to a change in price. An elasticity factor of -0.1 means that a one-percent increase in price is expected to produce a 0.1-percent decrease in the quantity demanded. Most estimates of the elasticity of demand for electricity are in the range of -0.2 to -0.7 , with the expected price response greater over the long-term. For illustrative purposes below,

87 Rate designs may increasingly impact customers who face low kWh prices as well, as when an excess of low-cost renewable power exists. Such situations present an opportunity to specifically target electricity use for some industrial production, water pumping or heating, car charging, and so on. For instance, a standby desalinization facility could be operated when an excess of solar or wind generation might otherwise cause their use to be curtailed.

Table 26-1

| Illustrative Residential Rate Design | | | |
|--------------------------------------|-----------|----------------------|----------------------|
| | Flat Rate | Inclining Block Rate | High Customer Charge |
| Customer Charge | \$ - | \$ - | \$25.00 |
| First 250 kWh | \$0.15 | \$0.1160 | \$0.1025 |
| Over 250 kWh | \$0.15 | \$0.1740 | \$0.1025 |
| Usage Change With Elasticity of -0.2 | | -2.6% | +6.3% |

we use an elasticity of -0.2.⁸⁸

Table 26-1 shows three alternative residential rate designs, all designed to produce the same total revenue from a given mix of customer usage. The first is a simple rate, with only a per-kWh charge that applies to all usage. The second divides these into two blocks, usage before 250 kWh, and a higher price for usage above that level. The third collects \$25 per month in a customer charge, independent of usage, and the balance in a uniform price per kWh. Because the overwhelming majority of usage is by customers whose monthly usage exceeds 250 kWh per month, this “end block” price is the primary determinant upon which elasticity is measured; only a few customers using a very small percentage of power face the initial block rate for their marginal consumption. Therefore, a reduction in the price for the first 250 kWh has a very small effect increasing consumption, whereas a higher price for usage above 250 kWh affects a much larger percentage of total usage.

By applying the economic concept of elasticity, we estimate that, compared to the flat rate, the inclining block rate would result in about 2.6 percent *less* consumption, whereas the high customer charge (and lower per-kWh price) would result in 6.3 percent *more* consumption. This shows that the type of residential rate design *to produce the same revenue* can cause a swing of nine percent in total customer usage. This does not inform us as to whether the reduced usage is the result of conservation, curtailment, fuel switching, or other options the customer may choose.

Commercial and Industrial Prices

Prices for commercial and industrial customers are generally more complex. They often include a “demand charge” that is based on the customer’s peak demand, usually measured as the highest hour (or even the highest

Table 26-2

| Illustrative Commercial Rate Design With Demand Charge | |
|--|------------|
| Rate Element | Price |
| Monthly Customer Charge | \$20.00 |
| Demand Charge (\$/kW/month) | \$10.00 |
| Energy Charge | \$0.08/kWh |

15 minutes) of the billing period. Although demand charges can be designed to fairly price the cost of providing adequate capacity for peak periods, they generally result in lower per-kWh prices, and can thus result in higher consumption. An illustrative commercial rate is shown in Table 26-2.

Because the typical commercial customer has usage of about 300 kWh per peak kW of demand, this rate design collects about \$0.03 per kWh of the total revenue requirement through the demand charge.⁸⁹ Without the demand charge, the energy charge would have to be about \$0.11 per kWh. The principal adverse impact of a demand charge is that once the customer had “hit their peak” for the month, they no longer see the demand charge as an incremental cost, and make consumption decisions based solely on the \$0.08 per kWh energy price.

An alternative to imposing a commercial demand charge is to convert this into a TOU rate design. For example, if the \$10.00 per kW demand charge were applied only to the 100 highest-use hours of the month (3:00 PM to 8:00 PM, Monday to Friday, for example), it would add about \$0.06 per kWh to the energy price in those hours (the

88 For a detailed discussion of price elasticity, see: Lazar, J. (2013, April). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed*, Appendix A. Montpelier, VT: The Regulatory Assistance Project. Available at: <http://www.raonline.org/document/download/id/6516>

89 A typical commercial customer using 300 kWh per peak kW means that its normal operations may reflect electricity use of about 40 percent of its peak, not surprising for a retail or office environment or a one-shift, light-manufacturing operation. The \$10.00 per-kW demand charge, if amortized over these 300 kWh, would equate to about \$0.03 per kWh. Meeting the utility’s revenue requirements without the demand charge would require the energy charge to be the \$0.08 per kWh plus this \$0.03 per kWh, or about \$0.11 per kWh.

Table 26-3

| Illustrative Commercial Rate Design Without Demand Charge | |
|---|------------|
| Rate Element | Price |
| Monthly Customer Charge | \$20.00 |
| On-Peak Energy (3:00 PM to 8:00 PM Monday to Friday) | \$0.18/kWh |
| Off-Peak Energy (other hours) | \$0.09/kWh |

actual calculation requires dividing the demand charge revenue by the expected kWh consumed during that period). The resultant rate design is shown in Table 26-3.

This TOU rate would provide a strong incentive to conserve during the on-peak hours, whereas a higher energy rate for off-peak usage would encourage somewhat more conservation during the off-peak hours as well. But it could result in a higher customer peak demand during some normally off-peak hours of the month.

Another alternative would be to confine the demand charge to the few hours of the month when peak demands are expected to occur, in order to constrain usage during those particular hours. An example of this is shown in Table 26-4. This is known as a “coincident peak” demand charge, because it applies only when the *system* peak is likely to occur, rather than applying to the *customer’s* individual demand, whenever it occurs. This would serve to constrain demands on the utility system during peak periods. Because it would apply to a lower total number of kW (because some customers have their individual peaks outside of these hours), the energy charge would need to be a little higher, leading to more incentive to conserve energy at all hours. Note that with a demand charge of this type, there would be no on-peak versus off-peak energy charge differential.

Table 26-4

| Illustrative Coincident Peak Demand Charge Rate Design | |
|---|------------|
| Rate Element | Price |
| Customer Charge \$/month | \$20.00 |
| Demand Charge (4:00 PM to 8:00 PM, Monday to Friday) | \$10.00/kW |
| Energy Charge | \$0.09/kWh |

There are a few electric utilities that impose residential demand charges. Most of these are based on the customer’s non-coincident peak (highest usage, whenever it occurs during the month). These tend to increase usage (because of the correspondingly lower energy charge) without having a meaningful impact on peak demand. If narrowly focused on the highest hours of the day (for example, 4:00 PM to 7:00 PM), they may result in load-shifting out of those hours, similar to the effect of a TOU rate design, but with a lower level of customer understanding, and thus less impact.

Rate design concepts that result in lower usage include:

- **Inclining Block Rates.** Prices that apply higher per-kWh charges to usage over a baseline that generally reflects what is deemed to be essential-needs level of usage.
- **Low or Zero Customer Charges.** If the fixed charge per month is lower, then the per-kWh price must be higher to produce the utility’s allowed revenue. A low customer charge thus results in lower expected usage.

Rate design concepts that generally result in higher usage include:

- **High Fixed Charges.** If a utility recovers a greater portion of its revenue requirement in a fixed charge or customer charge, the price per-kWh will be lower, and usage will increase.
- **Demand Charges.** If a separate charge is imposed based on the customer’s highest usage for a short period during the month (15 minutes or 1 hour, typically), the price per kWh will be lower, and usage during hours other than those when the customer’s highest demand occurs will increase.

Rate design concepts that may increase or decrease usage include:

- **Time-Varying Rates.** Prices that are higher during peak periods will reduce usage during those periods, but will be offset by lower prices at off-peak times, increasing usage during these periods. If time-varying rates are used to reduce or eliminate demand charges, they will likely result in reduced usage.⁹⁰

90 For more discussion of time-varying pricing, see: Faruqui, A., Hledik, R., & Palmer, J. (2012, July). *Time Varying and Dynamic Rate Design*. The Regulatory Assistance Project and the Brattle Group. Available at: <http://www.raponline.org/document/download/id/5131>

- **Critical Peak Pricing.** Many utilities have implemented what is known as critical peak pricing, where in the highest 50 to 100 hours of the year, a much higher price is implemented, with customers notified by text, email, or telephone. These result in higher collection during the highest hours, and slightly lower rates in all other hours, and the overall impact on usage varies from circumstance to circumstance.
- **Peak-Time Rebates.** Many utilities have implemented a different form of peak load pricing that provides a rebate when usage is curtailed during the highest-cost hours. Although not shown separately, these require a slightly higher base rate in order to fund the rebates.

Clarity and Transparency

Many electric bills are either impossibly complex or hopelessly opaque. They have become more of a litigator’s scorecard or an accountant’s worksheet than a price that consumers can respond to. Improving clarity enables customers to take appropriate actions to save energy and

Table 26-5

| Illustrative Elements of an Electric Bill With Multiple Tariff Riders | | | |
|--|-------------|--------------|---------------|
| <i>Your Usage: 1,266 kWh</i> | | | |
| Base Rate | Rate | Usage | Amount |
| First 500 kWh | \$0.04000 | 500 | \$20.00 |
| Next 500 kWh | \$0.06000 | 500 | \$30.00 |
| Over 1,000 kWh | \$0.08000 | 266 | \$21.28 |
| Fuel Adjustment Charge | \$0.03456 | 1,266 | \$43.75 |
| Infrastructure Tracker | \$0.00789 | 1,266 | \$9.99 |
| Decoupling Adjustment | \$(0.00057) | 1,266 | \$(0.72) |
| Conservation Program Charge | \$.00123 | 1,266 | \$1.56 |
| Nuclear Decommissioning | \$.00037 | 1,266 | \$0.47 |
| Subtotal | | | \$126.33 |
| State Tax | 5% | | \$6.32 |
| City Tax | 6% | | \$7.96 |
| Total Due | | | \$140.60 |

money, based on an informed perspective on the benefits. In addition, the more clarity there is in the electric bill, the more likely consumers are to understand the price and to respond to it. Table 26-5 provides an example of how one electric bill is calculated – and Table 26-6 shows what that rate design really means.

Table 26-6

| Distillation of an Electric Bill With Multiple Tariff Riders | | | |
|---|-------------|--------------|---------------|
| <i>Effective Rate Including All Adjustments</i> | | | |
| Base Rate | Rate | Usage | Amount |
| First 500 kWh | \$0.09291 | 500 | \$46.46 |
| Next 500 kWh | \$0.11517 | 500 | \$57.59 |
| Over 1,000 kWh | \$0.13743 | 266 | \$36.56 |
| Total Due: | | | \$140.60 |

Table 26-6 distills these multiple elements into a more understandable inclining-block structure.

Consumers do not generally value the additional information provided in the example shown in Table 26-5. This can be seen in gasoline pricing, for example. Gasoline prices also include numerous components, from crude oil and refining to tankers and retailers. But consumers respond to a single per-gallon price in choosing where to buy gasoline. They aren’t asked or expected to consider the fixed and variable costs of each component.

Encouraging utility regulators to simplify, condense, and improve the presentation of the effective prices that customers will incur or save with changed usage is important. There is no problem providing detailed information in a tariff published on the utility website, or even printed on the reverse side of the bill. But what consumers really need to know to make rational decisions is how much their bill will increase or decrease in response to a change in usage.

Load Shifting

Most time-varying pricing is designed to shift load from on-peak periods to lower-use periods, in order to improve the use of transmission and distribution system capacity, and to avoid the high costs of securing resources to meet short durations of high demand. The impact of this pricing structure on total usage, and on emissions, is a complex calculation.

Sometimes it will increase usage; for example, if a

commercial building is pre-cooled in the early afternoon to a lower temperature, in order to be able to comfortably “ride through” a higher rate in the late afternoon, there may be a net increase in kWh usage. Conversely, if a residential customer chooses to raise the thermostat to reduce cooling costs during an on-peak period, the customer is unlikely to make this up by lowering the thermostat below a comfortable level at night.

There is an environmental issue with load shifting as well. If the effect of load shifting is to shift load from hours when natural gas is the marginal resource to hours when coal is the marginal resource, then criteria and CO₂ emissions may increase. If the effect of load shifting is to increase usage of natural gas power plants with better heat rates, and decrease usage of less-efficient natural gas power plants, then emissions will decrease. This topic is covered in detail in Chapter 23.

However, load shifting also affects transmission and distribution line losses. As noted in Chapter 10, line losses are highest during peak hours. Shifting loads to lower-use periods will reduce line losses, and thus reduce the total number of kWh that are needed.⁹¹

3.3. Utility Business Models

The traditional electric utility business model is based on “cost of service” regulation. The essence of this model is that the rates utilities charge to customers are designed to recover the utility’s costs of serving those customers. In the case of investor-owned utilities, rates also allow utilities the opportunity to replenish their capital stock and to earn a reasonable rate of return on capital invested by shareholders. Implicit in this model is the fact that investor-owned utilities earn profits by making capital investments in generation, transmission, and distribution system assets. Where a third party or a customer invests in similar assets, the utility’s shareholders lose the opportunity to enjoy that return. Finally, as noted in the preceding section, rates have typically been designed in such a way that utilities collect most of their revenue based on volumetric sales (i.e., per-kWh and

per-kWh). Absent any mitigating policies, this gives utilities an inherent interest in maximizing their sales volume.

It is widely agreed that the US electric industry is at the cusp of a fundamental transformation, which is both challenging the traditional utility business model and offering significant opportunities to reduce the carbon intensity of the power sector. The transformation at hand is from a twentieth century model of central power generation and unidirectional delivery, toward a decentralized model in which the provision and management of electric services are distributed across end-users, for which the grid serves as a transactive platform.

This shift is being driven by a number of factors, notably the improved performance and availability of distributed energy resources. Distributed energy resources incorporate both demand- and supply-side resources deployed across the grid, including, for example, small-scale generation, combined heat and power, energy storage, microgrids, sensors, smart inverters, and load control technologies. Siting generation at the point of consumption, be it residential solar PV or commercial combined heat and power, cuts into retail sales of electricity, and therefore bypasses traditional cost recovery mechanisms for the regulated utility. Reducing demand, whether through demand response or energy efficiency programs, similarly cuts into utility sales. Therefore, even though distributed energy resources have been demonstrated to provide a broad variety of system benefits, such as resilience, electric reliability, congestion relief, and other ancillary services, many of which directly enhance the grid, utility incentives still typically discourage customer-owned assets.

The more recent technological advances in distributed energy resources are occurring against a backdrop of steadily declining growth in electricity demand, another factor driving industry transformation. Growth in electricity consumption has dropped from 9.8 percent per year in the 1950s to 0.7 percent per year since 2000,⁹² and demand has begun to level off over the last decade, with sales having declined in six out of the last seven years (2007 to 2014).⁹³ Reduced demand further undermines

91 See: Lazar, J., & Baldwin, X. (2011, August). *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*. Available at: <http://www.raponline.org/document/download/id/4537>

92 US Energy Information Administration. (2014, May 7). *Annual Energy Outlook 2014. Market Trends: Electricity Demand*. Available at: http://www.eia.gov/forecasts/aeo/MT_electric.cfm

93 US Energy Information Administration. (2015, February). *Electric Power Monthly With Data for December 2014*. Available at: <http://www.eia.gov/electricity/monthly/pdf/epm.pdf>; US Energy Information Administration. (2015, February). *Monthly Energy Review. Table 7.6 Electricity End Use*. Available at: <http://www.eia.gov/totalenergy/data/monthly/pdf/sec7.pdf>; US Energy Information Administration. (2014, April 30). *Implications for Low Electricity Demand Growth*. Available at: http://www.eia.gov/forecasts/aeo/elec_demand.cfm

utility revenue and is contributing to the upward pressure on rates seen across the country.⁹⁴ The traditional utility model may have been well suited for planning investment in large facilities and infrastructure projects at economies of scale, where continuous growth in demand was all but guaranteed. Today, not only are the economies of scale in power generation known to be limited,⁹⁵ but owing to structural economic changes and improvements in end-use efficiency, large capacity additions are no longer needed in the same way to meet planning requirements.

This evolution, from a natural monopoly to a participatory network that relies more on customer interaction, energy services, and information management, will require a redefinition of the utility profit regime. What exactly this will look like is the subject of debate.

Numerous research efforts have investigated the issue, representing a broad array of perspectives, including those of regulators, consumer advocates, environmental advocates, as well as the utility industry⁹⁶ and investors.⁹⁷

The Electricity Markets and Policy Group at Lawrence Berkeley National Laboratory has been working in this space since the 1990s, analyzing business models, quantifying financial impacts of distributed energy resources on shareholders and ratepayers, and providing technical assistance to utilities across the country. A library of related resources is available online.⁹⁸ With funding from the US Department of Energy, Lawrence Berkeley National Laboratory began convening a high-level advisory group of regulators, utilities, experts, and other stakeholders in late

2014, with the objective of exploring a vision for utility models that can enable distributed energy resources. The initial round of issue papers is scheduled for release in 2015.⁹⁹

One of the forerunners on the subject was Peter Fox-Penner's *Smart Power*, a 2010 book widely praised for presenting a rigorous yet accessible account of the challenges to electric utilities posed by smart grid technologies, energy efficiency, and related policy goals of reducing carbon emissions.¹⁰⁰ Fox-Penner envisions the utility of the future as a "smart integrator" of upstream supply, local supply, and storage, whose chief role is one of network operator, rather than commodity retailer.

The first wave of changes to the traditional business model has been less visionary, consisting instead of incremental variations to cost-of-service regulation. The most common example of this kind of regulatory fix is *revenue decoupling*, an approach that originated in the 1980s and has been instituted for electric utilities in 16 states as of 2013 (22 states have decoupling for gas utilities).¹⁰¹ Decoupling separates revenue from volumetric sales and allows utilities to recover fixed costs even when pursuing public policy objectives that may reduce sales.

Work by the Rocky Mountain Institute (RMI) through its eLab collaboration¹⁰² outlines additional incremental steps that utilities and regulators can take to create the price signals needed to optimize the deployment and operation of distributed energy resources. RMI frames pricing reforms in terms of three objectives:

94 Satchwell, A. (2014, April 2). *Utility Business Models in a Low Load Growth/High DG Future*. Presentation to the California Municipal Utilities Association. Lawrence Berkeley National Laboratory. Available at: http://cmua.org/wpcmuawp-content/uploads/2014/04/Utility-Bus-Mods-of-FutureCMUA_20140327_Andy.pptx

95 Burger, C., & Weinmann, J. (2013). *Small Is Beautiful: Decentralized Energy Revolution: Business Strategies for a New Paradigm*. Palgrave Macmillan.

96 Kind, P. (2013, January). *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*. Energy Infrastructure Advocates for Edison Electric Institute. Available at: <http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf>

97 Small, F., & Frantzis, L. (2010, July). *The 21st Century Electric Utility: Positioning for a Low-Carbon Future*. Navigant Consulting for Ceres. Available at: [http://www.ceres.org/resources/reports/the-21st-century-electric-utility-](http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1)

[positioning-for-a-low-carbon-future-1](http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1)

98 Lawrence Berkeley National Laboratory, Electricity Markets and Policy Group. *Utility Business Models, Research Area*. Available at: <http://emp.lbl.gov/ubm>

99 Lawrence Berkeley National Laboratory, Electricity Markets and Policy Group. (2015, forthcoming). *Future Electric Utility Regulation Series Reports*. Available at: <http://emp.lbl.gov/future-electric-utility-regulation-series>

100 Fox-Penner, P. (2010). *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities*. Island Press. Available at: <http://www.smartpowerbook.com/>

101 Natural Resources Defense Council. (2013, August). *Map of Gas and Electric Decoupling in the US*. Available at: <http://www.nrdc.org/energy/decoupling/files/Gas-and-Electric-Decoupling-Maps.pdf>

102 Rocky Mountain Institute eLab. Available at: <http://www.rmi.org/elab>

1. **Attribute unbundling** — shifting from fully bundled pricing to rate structures that break apart energy, capacity, ancillary services, environmental attributes, and other components;
2. **Temporal granularity** — shifting from flat or block rates to pricing structures that differentiate the time-based value of electricity generation and consumption (e.g., peak versus off-peak, hourly pricing); and
3. **Locational granularity** — shifting from pricing that treats all customers equally regardless of their location on the distribution system to pricing that provides geographically differentiated incentives for distributed energy resources.¹⁰³

By unbundling attributes and increasing temporal and locational resolution, rate design monetizes the system benefits provided by specific applications of distributed energy resources. As a result, prices can more effectively steer investment toward the areas, hours, and technologies that offer the greatest public benefit.¹⁰⁴ To achieve these objectives, RMI lays out six specific options for rate design, as shown in Table 26-7.

Ultimately prices would be highly differentiated to fully

incorporate a two-way exchange of value and services. But interim rate structures offer actionable options over the near-term, which can help optimize the investment flows that are already being made in distributed energy resources and set pricing on a trajectory toward greater sophistication in reflecting marginal costs and benefits over the load curve.

In addition to adequately valuing and incenting distributed energy resources, another looming challenge is how to organize multiple third-party service providers at the distribution level. In one model, an independently reviewed Integrated Resource Planning (IRP) process would be undertaken for the distribution network. The IRP would be used to identify least-cost procurement needs, for which proposals would be solicited from third-party service providers, aggregators, and consumer advocates. Utilities could provide financing or invest directly in owning and operating assets on the customer side. In another model, the distribution utility would offer customer outreach and on-bill financing for qualifying distributed energy resources, which would be installed and managed by approved third-party service providers. Rates could be designed to reflect the attributes and performance of specific assets.¹⁰⁶

Table 26-7

| Rate Design Reforms as Proposed by RMI¹⁰⁵ | |
|---|--|
| Near-Term Option | Longer-Term Option |
| <p>Energy + Capacity Pricing Unbundling energy and capacity (demand) values helps differentiate prices, but leaves many elements still bundled. Time- and location-based differentiation is still minimal.</p> | <p>Attribute-Based Pricing Attribute-based pricing more fully unbundles electricity prices, and doing so could also add time- and location-based sophistication.</p> |
| <p>Time-Of-Use Pricing Relatively basic TOU pricing (e.g., off-peak, peak, critical peak) begins to add time-based differentiation, but could still allow attributes to remain fully bundled with no location-based differentiation.</p> | <p>Real-Time Pricing Real-time pricing, with prices dynamically varying by one-hour or sub-hour increments, adds much time-based sophistication, but could still allow attributes to remain fully bundled with no location-based differentiation.</p> |
| <p>Distribution System Hot Spot Pricing Identifying distribution system “hot spots” begins to add location-based differentiation, but could still allow fully bundled attributes and little or no time-based differentiation.</p> | <p>Distribution Locational Marginal Pricing Distribution locational marginal pricing adds location-based sophistication, and in turn a high degree of temporal sophistication.</p> |

103 Rocky Mountain Institute. (2014, August). *Rate Design for the Distribution Edge: Electricity Pricing for the Distributed Resource Future*. Available at: http://www.rmi.org/elab_rate_design

104 Linvill, C., Lazar, J., & Shenot, J. (2013, November). *Designing Distributed Generation Tariffs Well: Ensuring Fair Compensation in a Time of Transition*. Montpelier, VT: The Regulatory Assistance Project. Available at: <http://www.>

raponline.org/press-release/designing-distributed-generation-tariffs-well-ensuring-fair-compensation-in-a-time-of

105 Supra footnote 103.

106 Rocky Mountain Institute. (2013, April). *New Business Models for the Distribution Edge: The Transition From Value China to Value Constellation*. Available at: http://www.rmi.org/New_Business_Models

These models are attractive on the one hand, because they could be implemented within the existing utility structure. However, utilities would still be subject to conflicts of interest, and ensuring oversight and transparency in acquisition and valuation would remain a challenge. To enable a fully transactive platform, the logical extension of these models would require the more disruptive intervention of separating the ownership and operational roles of the distribution utility.

Former Chairman of the FERC Jon Wellinghoff is among those who have come out in support of imposing reforms on the distribution utility that would transfer its operational authority to an independent distribution system operator, not unlike RTOs and ISOs in the bulk transmission system.^{107,108} A 2014 article by James Tong and Jon Wellinghoff in *Public Utilities Fortnightly* makes the case that the separation of assets from operations would be the best way for distribution utilities to embrace new innovation in consumer-based energy resources and eliminate the conflict of interest with grid management. The new independent distribution system operator would be responsible for: “maintaining the safety and reliability of the distribution system; (2) providing fair and open access to the distribution grid and information from the system; (3) promoting appropriate market mechanisms; and (4) overseeing the optimal deployment and dispatching of distributed energy resources.”¹⁰⁹ This opening at the distribution level to competitive forces would be designed to create greater customer choice, facilitate a broad deployment and integration of distributed resources, and ultimately “spur the development of the ‘Transactive Energy Framework’ in which independent energy agents in the

distribution system can trade and combine their services to meet increasingly disparate customer needs.”

Without the burden of operations, the distribution utilities would retain ownership of assets and continue to be compensated through rates for the value of service provided. Distribution utilities would also continue to be responsible for maintaining and upgrading the system, which could potentially include investment in distributed energy resources on the utility side of the meter to capture associated grid services and public benefits, where appropriate as subject to state laws.

This model of reform is similar to the course that is being set in New York’s Reforming the Energy Vision proceedings.¹¹⁰ In April 2014, the New York Public Service Commission launched an ambitious initiative to modernize the institutions and incentives that govern the electric utility industry to better promote energy efficiency, renewable energy, and distributed energy resources. Central to this effort is the task of redefining the distribution utility as a platform that serves as an interface between energy products, services, and market participants, including producer-consumers (“prosumers”).¹¹¹ The commission envisions this as a Distributed System Platform (DSP) provider, defined as follows:

*The DSP is an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers’ and society’s evolving needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system.*¹¹²

On February 26, 2015, the New York Public Service

107 Wellinghoff, J., Hamilton, K., & Cramer, J. (2014, September 22). *Comments Submitted Before the State of New York Department of Public Service, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision Case No. 14-M-0101.*

108 Others have proposed this model of reform as well. See, for example: Rehim, F., & Mokhtari, S. (2014, June). From ISO to DSO: Imagining a New Construct – An Independent System Operator for the Distribution Network. *Public Utilities Fortnightly*. Also see: Kristov, L., & De Martini, P. (2014, May). *21st Century Electric Distribution System Operations* [discussion paper]. Available at: <http://resnick.caltech.edu/docs/21st.pdf>

109 Tong, J., & Wellinghoff, J. (2014, August). Rooftop Parity: Solar for Everyone, Including Utilities. *Public Utilities Fortnightly* 152, 8:18. Available at: <http://www.fortnightly.com/fortnightly/2014/08/rooftop-parity>

110 New York Department of Public Service. *Case 14-M-0101. REV: Reforming the Energy Vision Proceedings*. Available at: <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument>

111 New York Department of Public Service. (2014, April 24). *Case 14-M-0101. Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal*. Available at: [http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/\\$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20\(REV\)%20REPORT%204.25.%2014.pdf](http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf)

112 New York Department of Public Service. (2014, August 22). *Case 14-M-0101. Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues*, p. 12. Available at: http://energystorage.org/system/files/resources/nyrev_dpstaffproposal_8_22_14.pdf

Commission issued its Reforming the Energy Vision order,¹¹³ determining that the DSP function be filled by incumbent utilities, as opposed to an independent entity. The main reason for this is to avoid creating redundancy in system planning and operations.¹¹⁴ The order put forward transitional steps, requiring each utility to undertake an IRP-like, least-cost planning exercise, called a Distributed System Implementation Plan (DSIP), which:

[S]hould present the utility's proposed investment plan for the next five years, and should reflect an integrated view of (transmission and distribution) investment needs and DER [distributed energy resources] resource alternatives. Beyond resource investments, the DSIP should include the utility's plan for implementing DSP platform and market components in the plan period. The actions proposed in the DSIP should be evaluated via a business plan that includes a benefit-cost assessment, a qualitative assessment of non-quantifiable benefits, and a risk assessment.

Extending the transactive energy market into the retail domain, the DSP would need to be in an unbiased position in order to optimize across all available distributed energy resources. To eliminate the conflict of interest in using the existing utilities to host the DSP platforms, New York is proposing to move away from cost-of-service regulation toward an outcome-oriented, performance-based regulation.

In performance-based regulation, utility profits are tied to achieving specific goals determined by the regulator. These can be a composite framework of environmental

targets, service quality metrics, price caps, reliability goals, or other goals based on related indices. If carefully designed, performance-based metrics can harness the utility profit motive to inspire innovation in targeted areas of public interest. The challenge lies in framing the goals, however, which may include a system of penalties and rewards for under- and over-achievement, respectively, and require extensive financial modeling.^{115,116} New York will be looking to the United Kingdom, where performance-based regulation is the basis of the new “Revenues = Incentives plus Innovation plus Outputs” (RIIO) framework. RIIO is a major reform effort to align utility business models with the policy-driven investment required to transition the nation to a low-carbon economy.¹¹⁷ One potential impact of RIIO of relevance to readers is that it intends over time to diminish and eliminate any bias favoring utility capital investments over operating expenses. This step is important if emissions-reducing demand-side investments by customers are motivated by utility expenses to support assets they will not own. A focus on total expenses assures attention to overall rate levels. New York is exploring this approach with Consolidated Edison's Brooklyn-Queens reliability project.¹¹⁸

Whether utility transformation is being advanced by consumer demand (as in Hawaii and Arizona, for instance), by utilities (as in the case of Duke Energy in North Carolina), or by regulators (as in New York and Minnesota),¹¹⁹ different models will work in different regulatory environments. And although near-term

113 New York Department of Public Service. (2015, February 26). *Case 14-M-0101. Order Adopting Regulatory Policy Framework and Implementation Plan*. Available at: <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b0b599d87-445b-4197-9815-24c27623a6a0%7d>

114 Supra footnote 112.

115 Goldman, C. A., Satchwell, A., Cappers, P., & Hoffman, I. M. (2013, April 10). *Utility Business Models in a Low Load Growth/High DG Future: Gazing Into the Crystal Ball?* Presentation Before the Committee on Regional Electric Power Cooperation (CREPC)/State-Provincial Steering Committee (SPSC) Meeting. Lawrence Berkeley National Laboratory. Available at: <http://emp.lbl.gov/publications/utility-business-models-low-load-growth-high-dg-future-gazing-crystal-ball>

116 Goldman, C. (2014, September 24). *Utility Regulatory Models: LBNL Technical Assistance Analysis and Tools. Presentation Before DOE OE Electricity Advisory Committee Meeting*. Available

at: <http://energy.gov/sites/prod/files/2014/10/f18/02d-CGoldman.pdf>

117 Fox-Penner, P., Harris, D., & Hesmondhalgh, S. (2013, October). *A Trip to RIIO in Your Future? Public Utilities Fortnightly*. Available at: http://www.brattle.com/system/publications/pdfs/000/004/958/original/A_Trip_to_RIIO_in_Your_Future.pdf?1386706496

118 Whited, M., Woolf, T., & Napoleon, A. (2015, March 9). *Utility Performance Incentive Mechanisms: A Handbook for Regulators*. Synapse Energy Economics, Inc. Available at: http://synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

119 GTM Research. (2015). *Evolution of the Grid Edge: Pathways to Transformation: A GTM Research Whitepaper*. Available at: <http://www.greentechmedia.com/research/report/evolution-of-the-grid-edge-pathways-to-transformation>

modifications to traditional cost-of-service regulation will be appropriate as interim solutions in many markets, thought leaders are converging on a vision of the future utility as a transactive energy platform that will eventually require dramatic changes to the role of the distribution utility.

3.4. Carbon Offsets

A carbon offset is a certificate or credit that is created to represent the reduction of a fixed amount of GHG emissions (generally, one metric ton of CO₂ or CO₂-equivalent) through an activity that is not directly regulated or is supplemental to regulatory requirements. These can be activities that reduce emissions, avoid emissions, or sequester carbon. Offsets are registered, tracked, traded, and retired in a manner similar to the renewable energy credits described in Chapter 16. Offsets can be used to assist in compliance with California's AB-32 requirements, in the European Union's Emissions Trading Scheme, in Clean Development Mechanism (CDM) and Joint Implementation (JI) projects under the United Nations Framework Convention on Climate Change, and in voluntary markets, among other purposes.

The carbon offset concept first arose more than a decade ago to serve the needs of individuals, businesses, and institutions that wanted to voluntarily reduce their contribution to climate change but found that the options to directly reduce their own emissions were limited in amount or unacceptably expensive. Recognizing that other parties often had more potential to reduce emissions and to do so at lower costs, but couldn't afford to or were not so inclined, some early entrepreneurs created carbon offsets as a means to put these two groups together. The buyers of offsets, in effect, finance the sellers' emissions reduction projects. For example, anaerobic digesters installed on dairy farms can capture methane from cow manure, burn it to generate electricity, and reduce GHG emissions. However, anaerobic digesters require a large upfront capital investment, and they can be complicated and expensive to maintain. As a result, few dairy farms in the United States have installed a digester. However, in recent years some farmers have financed digester projects by selling carbon offsets to willing buyers.

Today the market for carbon offsets is no longer limited only to voluntary buyers. Many of the established GHG cap-and-trade programs include provisions allowing for the use of carbon offsets as an alternative to emissions allowances. For example, under the current cap-and-trade

rules adopted by the nine Northeast states participating in the Regional Greenhouse Gas Initiative (RGGI), regulated power plants are allowed to meet up to 3.3 percent of their compliance obligation for each control period using CO₂ offset allowances. The RGGI states have thus far limited eligibility for offset allowances to just five project categories, each of which represents a project-based GHG emissions reduction outside of the capped electric power generation sector:

- Landfill methane capture and destruction;
- Reduction in emissions of sulfur hexafluoride in the electric power sector;
- Carbon sequestration in US forests (through reforestation, improved forest management, avoided conversion, or afforestation);
- Reduction or avoidance of CO₂ emissions from natural gas, oil, or propane end-use combustion owing to end-use energy efficiency in the building sector; and
- Avoided methane emissions from agricultural manure management operations.

Additionality requirements apply to all RGGI offset allowances, which means in this specific case that projects are not eligible for offsets if they are funded with utility ratepayer dollars or required under any statute, regulation, or order. A rigorous procedure has been developed for registering and verifying offset allowances. It is notable that no offset allowances had been awarded to any projects as of the end of 2013, in part because the low price of emissions allowances has not encouraged alternative investments.¹²⁰

The state of California has also opted to allow the use of registered and verified offsets for compliance with its GHG cap-and-trade program, but in its case more than 17 million offset credits have already been issued.¹²¹ Regulated entities in California can use offsets to meet up to eight percent of their compliance obligation. Projects in five categories are currently eligible for offset credits if they meet all program requirements:

- US Forest Projects;
- Urban Forest Projects;
- Livestock Projects;

120 Potomac Economics for RGGI. (2014, May). *Annual Report on the Market for RGGI CO₂ Allowances: 2013*. Available at: http://www.rggi.org/docs/Market/MM_2013_Annual_Report.pdf

121 See: http://www.arb.ca.gov/cc/capandtrade/offsets/issuance/arb_offset_credit_issuance_table.pdf

- Ozone Depleting Substances Projects; and
- Mine Methane Capture Projects.

At the international level, the Kyoto Protocol to the United Nations Framework Convention on Climate Change includes two offset programs, the CDM and JI. Countries that committed to limiting GHG emissions under the Kyoto Protocol are allowed to meet some of their commitment by funding and implementing emissions reduction projects in other countries. These projects can earn offset credits representing one metric ton of GHG emissions reductions, which can be counted toward meeting Kyoto Protocol targets. The list of eligible projects is much broader than the five categories approved for use in RGGI.

A CDM or JI project has to meet additionality requirements (i.e., provide emissions reductions that are additional to what would otherwise occur, and not result in the diversion of normal international development assistance). Verification and approval requirements also apply. Since the beginning of 2006, thousands of projects have registered and produced almost 2.5 billion credits.¹²² In Europe, where the European Union's Emissions Trading Scheme is used by most countries to comply with Kyoto Protocol commitments, CDM and JI credits can be used for Emissions Trading Scheme compliance purposes by regulated entities.

The voluntary offset market is now much smaller than the markets using offsets for compliance purposes. A recent report on the state of the voluntary market found that it encompassed 102.8 million metric tons of GHG emissions in 2012, and 76 million metric tons in 2013. Most of this decline is attributed to changes in California, where offset projects that had previously been registering credits for voluntary purposes instead began registering for the new, mandatory cap-and-trade program. Even so, the voluntary market in 2013 brought in \$379 million for offset projects that reduce GHG emissions.¹²³ A common criticism of voluntary offsets is that they are not regulated and thus

not subject to the same project eligibility, additionality, and verification standards as compliance market offsets. However, several voluntary standards administered by independent third-party verifiers have been introduced in recent years to bring more credibility to this market.

The EPA, in its 111(d) rulemaking, proposed that offsets from outside the US power sector could not be applied to demonstrate compliance by regulated sources. The rationale behind this decision appears to be based on the idea that out-of-sector offsets do not, by definition, reduce power sector emissions and may not be a legal option under the specific language of Section 111 of the Clean Air Act. However, the EPA tried to make clear that programs like the RGGI and California cap-and-trade programs, which allow for the use of offsets, will not run afoul of the regulations so long as the affected EGUs would not exceed their federal 111(d)-based emissions limits. Officials in some states feel that this does not go far enough, and have asked the EPA to afford states more flexibility to use offsets. For example, comments on the proposed rule that were submitted by officials in Kentucky and Georgia recommend that the EPA allow offsets from outside the power sector to be used for compliance.¹²⁴

4. Multi-Pollutant Planning

Most US states require utilities to plan for meeting forecasted annual peak and energy demand, plus an established reserve margin, considering all available supply- and demand-side resource options over a specified future period. Called "integrated resource planning" (IRP) and discussed at length in Chapter 22, such planning is often time- and resource-intensive, but its benefits are great – particularly to consumers. State public utilities commissions typically review and approve IRP plans submitted by utilities.¹²⁵

There is no similarly comprehensive consideration in air

122 Refer to: <http://cdm.unfccc.int/index.html> and http://ji.unfccc.int/statistics/2015/ERU_Issuance_2015_01_31_1200.pdf

123 Peters-Stanley, M., & Gonzalez, G. (2014). *Sharing the Stage: State of the Voluntary Carbon Markets 2014*. Forest Trends' Ecosystem Marketplace. Available at: http://www.forest-trends.org/documents/files/doc_4841.pdf

124 Refer to pp. 13–14 of the Kentucky cabinet's comments at <http://eec.ky.gov/Documents/Ky%20EEC%20>

111(d)%20Comments%20Nov.%202014.pdf, and p. 7 of the comments submitted by the Georgia Public Service Commission at <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-23535>

125 Wilson, R., & Biewald, B. (2013, January). *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*. Synapse Energy Economics, Inc. for The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6608

quality planning that takes into account the multiple public health and welfare threats of various air pollutant emissions and how collectively they might be addressed most cost-effectively and expeditiously. Instead, the Clean Air Act clearly delineates and separates different air pollutants and different ways in which they are to be regulated. This is unfortunate because sources often emit multiple pollutants, and control measures can often be selected that reduce emissions of multiple pollutants simultaneously.

The idea of addressing air quality from a holistic, multi-pollutant perspective is not new. Several papers and books have been written on this topic and several recommendations made for the EPA, state, and local air quality agencies to consider adopting multi-pollutant approaches. Economic models also conclude that reducing multiple air pollutants through root-of-pipe measures (e.g., at the beginning of industrial processes) is far more cost-effective than multiple pollutant-specific approaches focused only at the end of the pipe.¹²⁶

Two influential bodies in fact have recommended that the EPA explicitly enable and encourage states to develop multi-pollutant plans. In 2004, the National Research Council of the National Academies of Science published “Air Quality Management in the United States.” This comprehensive assessment identified five major recommendations for the EPA to consider and adopt. Among them were to “transform the [state implementation plan] SIP process into a more dynamic and collaborative performance-oriented, multi-pollutant air quality management planning (AQMP) process” and to “develop an integrated program for criteria pollutants and hazardous air pollutants.”¹²⁷ In 2010, the Clean Air Act Advisory Committee (CAAAC) developed a framework for a multi-pollutant strategy. The CAAAC’s objectives were to align four major Clean Air Act programs: National Emission Standards for Hazardous Air Pollutant Standards (NESHAPS), New Source Performance Standards (NSPS),

National Ambient Air Quality Standard (NAAQS), and New Source Review (NSR), and to coordinate – for the affected sources of pollution – the timing and obligations associated with these programs. CAAAC noted, “The Clean Air Act – read according to its express terms and without much of the intervening interpretative gloss of the past four decades – provides sufficient flexibility to achieve these objectives.”¹²⁸ These recommendations appear even more appropriate with the recent addition of proposed GHG emissions reduction requirements.

The National Academies of Science and CAAAC recommendations anticipate that, done correctly along the lines of an “air quality IRP,” states could develop comprehensive plans that meet existing NAAQS, as well as anticipate future NAAQS, hazardous air pollutant standards, and GHG reduction requirements. This concept has been explored further by The Regulatory Assistance Project under the rubric of Integrated Multi-Pollutant Planning for Energy and Air Quality (IMPEAQ).¹²⁹ IMPEAQ would identify all measures needed to meet a state’s long-term air quality goals. Each time a NAAQS, NSPS, or NESHAP is revised by the EPA, the state would identify, assign, and/or add appropriate elements from its IMPEAQ planning process and incorporate them into the required state implementation plan (SIP) or other compliance plan revision as needed for EPA approval. Unlike IRP as generally practiced in the power sector, IMPEAQ would seek to include “externalities” in air quality decisions (e.g., the societal benefits and costs associated with the adoption and implementation of air quality control measures).

Although the Clean Air Act generally applies a pollutant-by-pollutant approach, it does not restrict states to developing air quality plans that only address one pollutant or that only include measures to reduce a single pollutant. Economic models conclude that the costs to achieve a particular environmental end-point are lower when the selected control measures reduce several pollutants at the

126 James, C., & Colburn, K. (2013, March). *Integrated, Multi-Pollutant Planning for Energy and Air Quality (IMPEAQ)*. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raonline.org/document/download/id/6440

127 National Research Council, Committee on Air Quality Management in the United States. (2004). *Air Quality Management in the United States*. Available at: <http://www.nap.edu/catalog/10728/air-quality-management-in-the-united-states>

128 Clean Air Act Advisory Committee, Economic Incentives and Regulatory Innovation Subcommittee. (2010, September). *A Conceptual Framework for a Source-Wide Multi-Pollutant Strategy*. Available at: <http://www.eli.org/sites/default/files/docs/seminars/10.20.10dc/EPA-Attachment-4.pdf?q=pdf/seminars/10.20.10dc/EPA-Attachment-4.pdf>. CAAAC formally advises the EPA on air quality programs and regulatory standards.

129 Supra footnote 126.

same time and when both demand-side measures and end-of-pipe measures are applied. For example, modeling completed by the Bay Area Air Quality Management District for its 2010 Clean Air Plan indicated that public health benefits and reduced damages from climate change in the range of \$270 million to \$1.5 billion per year could be achieved from a suite of 55 control measures that would jointly reduce criteria, toxic, and GHG pollutants.¹³⁰

Similarly, work using the GAINS model demonstrates that the cost to reduce public health risk by 50 percent over 20 years can be reduced by one-third when the control measures include energy efficiency, combined heat and power, and end-of-pipe controls, as compared to only end-of-pipe controls.¹³¹ The EPA's regulatory impact analysis for the Mercury and Air Toxics Standards also showed that the costs of meeting the mercury standard were \$3 to \$12 billion lower when energy efficiency was an integral part of the control strategy, and that emissions of SO₂, NO_x, and CO₂ were also lower.¹³² Another EPA analysis performed for the cement industry indicated that compliance costs to meet NSPS and NESHAPs would be lower and provide greater environmental benefits if the various regulations were synchronized.¹³³

Among US states, Maryland is a leader in advancing multi-pollutant approaches. Working with the Northeast States for Coordinated Air Use Management, the University of Maryland, and Towson University, the Maryland Department of the Environment has leveraged Maryland's 2015 ozone SIP requirements and state-legislated 2012 GHG reduction requirements to build a multi-pollutant analytical framework. The Maryland Department of the Environment's framework allows it to:

- Quantify the emissions reductions of multiple pollutants for a broad suite of energy efficiency and renewable energy efforts;

- Model the reductions in ozone, fine particulate, and other pollutants;
- Estimate the public health benefits associated with those reductions; and
- Quantify the economic benefits and costs.¹³⁴

The Regulatory Assistance Project envisions IMPEAQ as an air quality planning process that builds upon the best components of utility IRP processes and also incorporates environmental, energy, and economic externalities that are not typically included in an IRP. Including externalities and their influence on the cost-effectiveness of control measures – and considering whether and how control measures may have unintended consequences – can help meet both air regulators' goals to attain and maintain compliance with NAAQS and other requirements of the Clean Air Act, and energy regulators' goals to assure reliable and affordable electric and gas service.

5. Conclusion

As noted in the introduction to this document, the EPA's proposed Clean Power Plan establishes state-specific CO₂ emissions standards using four building blocks. These building blocks are intended to reflect the degree of emissions limitation achievable through the application of the best system of emission reduction that the EPA believes has been adequately demonstrated, taking into account the cost of achieving such reductions and any non-air-quality health and environmental impacts and energy requirements.

The proposed CPP does not, however, compel states to use the same four building blocks to meet the state-specific emissions targets. Instead, states are free to identify other options to reduce CO₂ emissions and to submit compliance plans that incorporate any combination of measures in the

130 Bay Area Quality Management District. (2010, September 15). *2010 Clean Air Plan*. Available at: <http://www.baaqmd.gov/Divisions/Planning-and-Research/Plans/Clean-Air-Plans.aspx>

131 Bollen, J. C., van der Zwaan, B., Corjan, B., & Eerens, H. (2009). Local Air Pollution and Global Climate Change: A Combined Cost-Benefit Analysis. *Resource and Energy Economics* 31; 161–181. Available at: <https://ideas.repec.org/a/eee/resene/v31y2009i3p161-181.html>

132 US EPA. (2011, March). *Regulatory Impact of the Proposed Toxics Rule, Final Report (Chapter 8)*.

133 Witosky, M. (2010, May 26). *Sector-Based Multi-Pollutant Approaches for Stationary Sources*. Presentation to the Clean Air Act Advisory Committee. US EPA Office of Air Quality Planning and Standards. Available at: <http://www.eli.org/sites/default/files/docs/seminars/10.20.10dc/EPA-Attachment-1.pdf?q=pdf/seminars/10.20.10dc/EPA-Attachment-1.pdf>

134 Adburn, T. (2013, March 25). *Building Energy Efficiency and Renewable Energy Programs Into the Clean Air Planning Process: Taking Credit for Nontraditional Programs*. Presentation at ACEEE Market Transformation Symposium. Maryland Department of the Environment. Available at: aceee.org/files/pdf/conferences/mt/2013/Tad%20Aburn_D2.pdf

EPA's building blocks, as well as other options that in total reduce CO₂ emissions sufficiently to achieve compliance with the CPP's emissions targets. The broad variety of technology and policy options available for states to consider and incorporate in their CPP compliance plans is evident in the previous 25 chapters of this *Menu of Options* – a breadth that far exceeds the EPA's four building blocks.

This twenty-sixth chapter introduces a variety of rapidly emerging technologies and additional policy opportunities

that regulators may wish to consider as they formulate plans to reduce future power sector GHG emissions. With the dramatic evolution underway in the power sector, additional options – some not even conceived today – are likely to become available. Illustration of this rapid evolution is evident in the fact that many of the technologies and policies covered in this *Menu of Options* have advanced significantly during the year of its development and publication.