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Articles

The Regulatory Future of Clean, Reliable Energy: Increasing Distributed Generation
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This article examines the policy and regulatory issues surrounding the implementation of distributed generation. It is important for the United States to implement an effective regulatory framework right to avoid falling further behind in global efforts to de-carbonize electric power.

In 2010, carbon dioxide (CO2) emissions from energy production were the highest in history.[1] The International Energy Agency (IEA) estimates that 44% of CO2 emissions in 2010 came from coal, 36% from oil, and 20% from natural gas.[2] The IEA estimates that 80% of the power sector emissions are locked in for 2020 and will arise from existing central generation and new central generation construction.[3] One alternative to centralized generation from these fossil fuels is distributed generation (DG) from renewable energy.

DG can be defined as electric power generation occurring within distribution networks or on the customer side of the substation, as opposed to occurring in the large, centralized generation facilities built outside the distribution network on the transmission grid. The main DG electric-generating technologies include combined heat and power (CHP), small wind installations, small solar plants, fuel cells, and other forms of decentralized power sources that either generate electricity or displace fossil fuel generation. DG has three key aspects: storage, renewable generation, and renewable following natural gas plants.

DG has the potential to support the future of clean, reliable energy and the de-carbonization of electric power by increasing the feasibility of local renewable generation and offering benefits, such as additional overall system generation capacity and increased transmission efficiency. DG encounters barriers in the current regulatory framework, which does not allow the full realization of DG's benefits. Because state policies and incentives drive renewable energy generation,[4] the regulatory scheme plays an important role in helping or hindering the implementation of DG.

These DG resources constitute what one author calls one of the promising "Great Power Shifts" away from centralized fossil fuel generation.[5] However, the regulatory framework for DG is still in flux. This article addresses several current DG projects and the DG regulatory framework in the United States, and suggests future policies to enable DG resources.

DG Background

Historically, central station power plants generate the majority of electricity used in the United States. Electricity is transferred from power plants by the transmission and distribution (T&D) system to customers. Electricity comes predominately from fossil fuels: in 2009, coal provided 45% of centralized electricity generation, natural gas provided 23%, nuclear power provided 20%, and hydroelectric provided 7%.[6] The remaining 5% of generation came from other sources, some of which are renewable resources.[7]

In 2009, approximately 2,115 million metric tons (mmt) of CO2 were produced as a result of the electric power generation from coal (1,742 mmt) and natural gas (373 mmt).[8] Total emissions from electric power generation were approximately 2,160 mmt,[9] making coal and natural gas responsible for more than 97% of the CO2 emissions produced from electricity. Demand for renewable energy generation grows as the awareness of environmental benefits from clean generation spreads. Due to increased pressure for clean generation, a 2% decrease in the share of electricity produced by burning coal is expected by 2035.[10]

Accordingly, the U.S. Energy Information Administration (EIA) expects electricity generated from renewable distribution to increase to a total share of 14% to 16% by 2035.[11] Sophisticated "Active Distributed Power Networks" projects in Denmark, "Localized Portfolio Standards" in Boulder, and increasing city and citizen pressures in the United States suggest that local or distributed renewable generation could provide up to 50% of electricity to particular areas of the country by 2020.[12] Colorado clean energy businesses are actively engineering DG projects throughout the world. One example is Fort Collins's Fort ZED, which has a goal of a net Zero Energy District of DG by 2020.[13]

Similarly, Spirae, Inc., a Fort Collins renewable and distributed energy company, has proven through its work in Fort ZED and in Denmark that 50% renewable DG by 2030—and even 100% renewable DG—is achievable:

> [A] 100 percent renewable energy supply based on domestic resources is physically possible, and . . . the first step toward 2030 is feasible to Danish society.[14]

The EIA's projected 14% to 16% share of overall 2035 U.S. electricity generation still falls significantly behind the 50% projected capabilities in Denmark, Fort Collins, Boulder, California, and other parts of the United States.

DG would involve shifting the local, state, and federal policy focus away from centralized power and transmission facilities and toward distributed, localized resources to increase efficiency and decrease CO_2 emissions and costs. Although most states and the federal government already have implemented policies aimed at facilitating the growth of renewable resources, a lack of regulatory uniformity remains for DG.[15] This regulatory uncertainty poses a challenge not only to continued implementation of new renewable energy facilities, but also to the integration of one of the most dynamic methods of reducing greenhouse gases (GHGs)—electricity storage.

As the technology of electric storage evolves, the regulatory regime will be playing catch-up to be effective. Similarly, although the current regulatory regime contains some interconnection standards, many of these standards have resulted in long wait lists and imposed restrictions on applicability.[16] To promote and encourage renewable DG, this article examines the regulatory, legislative, and policy initiatives available and necessary to enhance the full use of DG capabilities.

Benefits and Technical Challenges

The Los Angeles Department of Water & Power (LADWP) touted DG in its 2010 Power Integrated Resource Plan. It stated:

> The promise of DG is to provide electricity to customers at a reduced cost and more efficiently than the traditional utility central generating plant with transmission and distribution wire losses. Other benefits that DG could potentially provide, depending on the technology, include reduced emissions, utilization of waste heat, improved power quality and reliability and deferral of transmission or distribution upgrades.[17]

Itron's 2010 "Impacts of Distributed Generation: Final Report" to the California Public Utility Commission (CPUC) states:

> Compared to the rest of the United States, California has a significant amount of DG installed on the grid, particularly solar. . . . [A]s yet there are no noticeable impacts on the distribution and transmission infrastructure, based on performed studies.[18]

Itron then identified future issues for continued evaluation of DG's impacts on distribution feeders and DG's contribution to reducing peak demand through both existing technology and technologies under development. Lists of potential benefits and technical challenges appear below.

Potential benefits include:

- directly connecting DG into substations or behind the meter
- adding generation capacity at the customer site for continuous power and backup supply
- adding overall system generation capacity
- freeing up additional system generation, transmission, and distribution capacity
- relieving transmission and distribution bottlenecks
- supporting maintenance and restoration for power system operations by providing potential generation of temporary backup power
- reducing load and replace peakers
- providing greater control of the grid
- providing greater localized power and local ownership of energy issues
- improving efficiency
- providing greater capacity control
- democratizing the electricity system
- allowing local control over the economics of power supply.

Potential technical challenges include:

- problems and/or delays with interconnection regulations
- problems attempting to connect with the utility transmission system or grid
- problems seeking to net meter, particularly with multiple DG sources
- increased pressure on utilities to balance generation and demand
- Volt-Var management, Watt-Volt management, curtailment, Watt-frequency management, voltage Sag ride-through, and dynamic grid stabilization (inertia)
- potential to eventually strand existing centralized generation assets
- impacts of variable renewable resources on distribution feeder voltage and harmonic levels

- redesign of distribution system as a supply source.[19]

Despite a number of policies geared toward supporting renewable energy and DG, some of which are discussed below, the lack of uniformity and other regulatory issues may challenge implementation.[20] The new rules for electricity generation and distribution in the coming "age where households and businesses will be both producers and consumers of electricity" are still being developed.[21]

DG Regulatory Framework: Federal and State

The genesis of DG facilities in the United States was qualifying facilities (QFs) in the Public Utility Regulatory Policy Act (PURPA) of 1978. QFs include CHP facilities and other small power producers; QFs were the precursor to DG facilities. Most QFs interconnect to the utility high voltage transmission line. DG facilities, on the other hand, typically are located on the lower voltage distribution side—either at or inside the substation, or inside the meter.

Therefore, a useful definition for DG focuses on both the point of connection and the location. The Swedish Royal Institute of Technology's Department of Electric Power Engineering defines DG as "an electric power source connected directly to the distribution network or on the customer side of the meter."[22] DG facilities include solar, wind, hydroelectric, geothermal, engines, turbines, fuel cells, and batteries.

In 2010, Colorado HB 1001 amended a previous requirement for solar electricity within the wider renewable energy system. A Colorado investor-owned utility (IOU) must have a certain percentage of its retail sales come from either wholesale DG—30 megawatts (MW) or less—or retail DG (on customer property limited to 120% of customer's load), regardless of technology type, according to the following schedule:[23]

- 1% of its retail electricity sales in 2011 and 2012
- 1.25% of its retail electricity sales in 2013 and 2014
- 1.75% of its retail electricity sales in 2015 and 2016
- 2% of its retail electricity sales in 2017–19
- 3% of its retail electricity sales in 2020 and each following year.[24]

Beginning January 1, 2015, the Colorado Public Utility Commission (PUC) may reduce the DG requirement if a utility submits an application and the PUC finds that the requirement is no longer in the public interest. On the other hand, if the PUC finds that the public interest demands a higher DG requirement, it must report its findings to the General Assembly. By contrast, California has a goal to advance 12,000 megawatts (MW) of renewable DG onto its system by 2020 as part of its 33% Renewable Portfolio Standard mandate.[25]

Leadership for DG policies and programs has come from European Union countries such as Denmark, from the state of California, from the U.S. Department of Defense (DOD), and from several municipal utilities.[26] FortZED in Fort Collins is a DG innovator and currently represents approximately 10% to 15% of the Fort Collins municipal utilities' distribution system. This percentage is expected to grow to 50%. Spirae uses the term "Active Distributed Power Networks" in its worldwide distributed generation projects in Fort ZED and in Denmark.[27] The Austin, Texas municipal utility, Austin Energy, has a similar DG project called the Pecan Street Project:

> Our Smart Grid 2.0 is about managing and leveraging Distributed Generation (Solar PV, Micro Wind, etc [*sic*]), Storage, Plug-In Hybrid Vehicles, Electric Vehicles and Smart Appliances on the customer side of the meter. . . . The vision . . . is to solve the energy problem . . . by reinventing the power sector via moving into new energy models, including interconnecting with the transportation sector.[28]

Sacramento Municipal Utility District today has 20 MW of installed DG, with a goal of 130 MW net-metered solar by 2016.[29] LADWP is another municipal utility that is a DG innovator; it currently has 350MW of customer-installed DG, with thousands of DG installations planned.[30] Boulder is looking to increase renewable DG through either its franchise agreement or municipalization.[31] Boulder uses the term Localization Portfolio Standard to describe the city's future distributed renewable generation efforts.[32] Other municipal utilities focusing efforts on DG include Riverside, California and Jacksonville, Florida.

Regulation Depends on the State or City

The regulation of electricity generation is split between the federal government and the states. Pursuant to the Federal Power Act, the Federal Energy Regulatory Commission (FERC) regulates the wholesale electric markets, including interstate transmission.[33] Generally, FERC oversees the interconnection of generators connected to the higher-voltage transmission system. States, on the other hand, regulate the retail electric markets and oversee the interconnection of generators connected to the lower-voltage distribution lines through a PUC. Most DG systems connect via the lower-voltage distribution grid, and are regulated by PUCs rather than FERC. FERC's policies, however, can still drive change at the state level.

Federal Integration of DG

Historically, FERC has had little jurisdictional authority over small generation facilities. However, Section 210 of PURPA provided a legal framework for mostly smaller, privately owned QFs to interconnect to the transmission system and sell electricity to a regulated utility.[34] PURPA mandated that local utilities purchase excess power generated by the QFs at the utility's avoided cost rate.[35] This reform created largely unregulated sources of electricity to compete with existing regulated utilities.

Congress passed the Energy Policy Act of 2005 (EPAct) and tightened certain restrictions of PURPA.[36] Under the EPAct, a public utility is no longer obligated to enter into a new contract with or purchase power from a QF that has nondiscriminatory access to certain types of developed markets, including the FERC-regulated Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). RTOs and ISOs are independent transmission companies that manage transmission facilities owned by public utilities; they ensure that no class of generators is favored by the transmission system.

Subsequently, FERC issued a rulemaking, known as Order 2006, establishing standardized procedures for the electrical interconnection of small QF generators with all FERC-jurisdictional public utilities (as well as some non-jurisdictional utilities, such as publicly owned cooperatives or federal power agencies though reciprocity access to FERC-jurisdictional markets).[37] FERC specifically noted that it was issuing the "Small Generator Interconnection Procedures" and "Small Generator Interconnection Agreement" to "facilitate development of non-polluting alternative energy sources."[38] In Order 2006, FERC acknowledged that it had limited jurisdiction but expressed a desire for states to adopt similar policies modeled after Order 2006:

> [T]he Final Rule applies only to interconnections to facilities that are already subject to a jurisdictional [Open Access Transmission Tariff (OATT)] at the time the interconnection request is made and that will be used for purposes of jurisdictional wholesale sales. Because of the limited applicability of this Final Rule, and because the majority of small generators interconnect with facilities that are not subject to an OATT, this Final Rule will not apply to most small generator interconnections. Nonetheless, our hope is that states may find this rule helpful in formulating their own interconnection rules.[39]

Order 2006 includes three levels of review developed by FERC for DG systems generating up to 20 MW. The standard procedures provide the methods by which a utility must evaluate a request for interconnection.[40] First, any small generator request may be evaluated through a default study process. Second, generators 2 MW or less certified by a "nationally recognized certification laboratory" may be evaluated through a "fast track" process. Third, "certified inverter-based generators" of 10 MW or less may be evaluated through a special process.

The methods described above are FERC's attempts to streamline the integration of renewables while still ensuring the safety and reliability of the grid. They also attempt to remove any potential burdens placed on DG owners or installers by transmission owners.

As with Order 2006, FERC can influence state regulations by creating model interconnection and compensation arrangements for energy storage. The advent of technologies that make electric storage a reality goes against one of the hoary principles of electric market design—that electricity cannot be stored.

Supply and demand must always be balanced, and transmission operators must ensure that adequate reserves (typically 15%) are available to meet demand. DG electric storage has many potential applications and could transform the electricity markets by modifying this 15% redundancy in generation. Storage also will assist in the integration of intermittent renewable resources such as wind and solar.[41] Finally, it has the potential to reduce GHGs when used as a "ramp up" resource in lieu of coal or gas.[42]

FERC is beginning to create model energy storage standards, albeit at a slow pace. Electric storage is unique to the regulatory regime because it has characteristics of generation, transmission, a commodity, and "auxiliary services." Auxiliary services are services that support electric transmission, such as electricity reserve (spinning or non-spinning), voltage support, and load regulation.

In June 2010, FERC issued a Request for Comment Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies.[43] Numerous commentators responded to Commission questions regarding how to treat energy storage and what changes in rate design are necessary. FERC has issued some notices of proposed rulemaking (NOPR) relating to renewables,[44] but it has not yet proposed a specific rule relating to electric storage. Recently, however, FERC has started exploring how it can encourage the integration of renewables through its regulatory scheme.

In February 2011, FERC issued a NOPR relating to compensation for frequency regulation in the RTOs and ISOs.[45] In it, FERC acknowledged that new technologies such as electric storage can "provide frequency regulation services more accurately than traditional resources" and that the "current compensation methods for regulation service in ISO and RTO markets may not acknowledge the inherently greater" accuracy of storage in frequency regulation.[46] Frequency regulation is the "injection or withdrawal of real power by facilities capable of responding appropriately" to a mismatch of electric supply and demand.[47]

FERC proposes that RTOs and ISOs compensate providers of frequency regulation in two parts—the first for capacity and the second for performance. The performance portion of the compensation will take into consideration the increased accuracy of technologies such as electric storage.[48] FERC has not yet issued a final rule and currently is reviewing comments.

In June 2011, FERC issued a Notice of Inquiry (NOI) relating to auxiliary services.[49] As described above, ancillary services are needed to keep supply and demand on the grid in balance. Current FERC policy restricts the sale of ancillary services at market-based rates (compared to traditional cost-of-service rates).[50] FERC inquired whether this restriction is impeding the development of a competitive ancillary service market. Also, FERC sought comment on accounting and reporting requirements for energy storage devices.[51] Although the NOI did not propose changes to current FERC policy, comments in response to the NOI may lead to an energy storage NOPR.

FERC could issue an order providing certainty to storage providers in recovering their costs and setting an example to the states. Some comments received in the previous request for comment regarding electric storage encouraged FERC to create a separate category of resource, similar to the category of demand response in the organized electricity markets, which includes the lowering of use during periods of high demand.[52]

However, there is uncertainty about jurisdiction; who will regulate energy storage depends on how it is viewed. Policymakers would need to clarify the jurisdictional issues between state and federal regulation and determine when storage is federally regulated transmission or state-regulated DG. Energy storage also has rate-related cost recovery issues depending on what type of service the energy storage provides. While these regulatory issues are being worked out, municipally owned utilities are proceeding with DG and energy storage projects.

State Integration of DG through PUCs

FERC Order 2006, discussed above, has influenced the development of state rules and regulations. A FERC order on energy storage could similarly influence state regulations. Order 2006 has prompted states to design their own standardized interconnection agreements for their systems. Colorado could look to California, New York, Minnesota, and model agreements for the best policy outcomes and potentially revise its existing procedures to allow for more uniformity to encourage investment in DG, including energy storage.

Many states have modeled their interconnection after the model interconnection standards developed by Interstate Renewable Energy Council, FERC, the Mid-Atlantic Distributed Resources Initiative (MADRI), or rules developed by California. The use of many models instead of one or two presents challenges.

One solution is for FERC to revise Order 2006 to conform to one of the model agreements adopted by most of the states.[53] Well-designed interconnection standards facilitate the integration of renewables by standardizing and simplifying the technical and regulatory requirements, as well as the commercial terms by which utilities and DG system owners must abide in the context of state regulation. Standardized interconnection agreements ostensibly limit utilities from favoring their own generation, reduce unfair impediments to market entry for small generation, and encourage investment electric infrastructure.

Although many states have these agreements, variations and barriers to entry remain—including high fees and slow processing. Traditionally, public utilities are regulated by state PUCs and have rate-related and non-rate-related issues to integrating DG. Generally, rate-related impediments include potential for lost revenue by incumbent utilities, and undesirable practices by incumbent utilities such as standby charges, exit fees, and low sell-back rates.[54] There are also several non-rate-related impediments, such as utility fees charges to interconnect with the grid, application and study fees, insurance and liability requirements, and delays in the processing of interconnection requests by existing utilities.[55]

The integration of electric storage presents new challenges for states. Thirty-eight states and the District of Columbia have some sort of Renewable Portfolio Standard that requires a certain percentage of electricity to come from renewable sources.[56] Electric storage is a whole new world for state regulators. State regulators do not universally understand storage, so there is a growing need to educate and create standardized methods of integrating electric storage.[57]

The U.S. Department of Energy (DOE) has many energy storage programs funded in part by the American Recovery and Reinvestment Act (ARRA).[58] The DOE and to some extent FERC could ensure that energy storage projects go from pilot programs to implementation as technology permits. Also, large states such as California that have begun to investigate energy storage will provide models to other states, including Colorado.[59]

Local Integration of DG

Although federal and state regulations insufficiently support a system of DG, municipalities and local governments can step in and correct the shortcomings. IOUs comprise 75% of the electric utility industry.[60] These utility companies generally lack business incentive to implement DG and renewable generation; a reduction in the energy produced by the company results in reduced revenue.[61] Public utility districts (PUDs) or municipal utility districts (MUDs) make up the remaining 25% of the electric utility industry.[62] These districts typically are governed by an elected board of directors that implements policy on behalf of the public.

Public understanding of DG is increasing rapidly, as shown by a number of municipalities supporting feed-in tariffs. Consumers and utilities in Europe already are energy literate, which may be the reason DG is first being implemented in Germany, Denmark, and other Nordic countries. Both private and public utilities are subject to consumer pressure, indicating that to encourage implementation of DG at the local level, consumers—not federal or state policy—are the driving force. For example, DG results in shorter distribution routes, which eventually may allow approximately 30% in savings on electric bills.[63]

There are benefits and costs at the outset of incorporating DG, which are discussed later in this article. To counter the costs, some municipalities offer incentives, such as feed-in tariffs or the chance to buy shares in the proposed renewable energy facility (termed solar or wind gardens).[64] These methods allow integration of DG in areas where not everyone can afford the initial investment. Other municipalities institute a community choice aggregation (CCA) program, allowing local government to combine the buying power of its individual consumers to purchase electricity on their behalf from alternative energy sources.[65]

A CCA program lets the community determine its energy supply without taking on the cost of an entirely new infrastructure.[66] The program is generally promulgated statewide, but implemented by local governments. As of late 2010, six states—California, Illinois, Ohio, Massachusetts, New Jersey, and Rhode Island—have incorporated the concept of community choice into their energy legal regime.[67] There are a number of benefits to a CCA program, including halving generation costs and promoting the development of new, local renewable energy projects.[68]

Legislative and Policy Initiatives Supporting Implementation

Supporting federal and state policies are the primary drivers of growth in renewable energy generation.[69] For example, the EIA projects that if one incentive—the federal investment tax credit (ITC)—is not renewed when it expires in 2016, the growth in solar photovoltaic (PV) capacity would slow from 39% per year to less than 1% per year.[70] Similarly, the growth in wind capacity would slow from 48% per year to less than 1% per year.[71] These projections emphasize the importance of incentives to reach renewable energy goals.

In February 2009, the federal government promulgated the ARRA, which contained provisions aimed toward facilitating renewable energy development. This law extended the availability of production tax credits and investment tax credits and established a U.S. Treasury grant program, allowing parties interested in renewable energy to take advantage of these benefits.[72] The production tax credit allows eligible taxpayers to receive a per-kilowatt-hour tax credit for electricity generated by qualifying renewable resources and sold to an unrelated person.

Similarly, the investment tax credit can be taken in lieu of production credit, and allows eligible taxpayers to receive credits equal to 10% or 30% of expenditures, such as a credit for 30% of expenditures for a small wind turbine system. The grant can be taken in lieu of investment credit, and provides eligible taxpayers to receive a cash grant equal to 10% or 30% of the basis of property for qualified renewable energy technology, such as a cash grant for 30% of the basis of solar energy property.

A Renewable Portfolio Standard (RPS) program establishes future goals for state renewable electricity generation. An RPS program requires a minimum percentage of electricity to be supplied from renewable energy sources, allowing renewable energy to be economically competitive with other forms of electric power, such as coal.[73] Electricity suppliers can comply with these standards by owning a renewable energy facility or by purchasing renewable energy certificates (RECs) or electricity from a renewable energy facility.[74] As of May 2009, thirty-three states and the District of Columbia had established RPS programs (five of those states have non-mandatory goals).[75]

Growth in distributed generation is similarly driven by the federal and state policies in place to provide support. These policies include interconnection standards, net metering policies, public benefit/clean energy funds, feed-in tariffs, and other incentives. Additionally, certain states, including Colorado, have specifically allocated goals within their RPS programs to increase distributed generation.

Interconnection Standards

Interconnection standards allow distributed energy resources to connect to the grid, which is vital in supporting DG. Well-designed interconnection standards facilitate the integration of renewables by standardizing and simplifying the technical and regulatory requirements, as well as the commercial terms by which utilities and DG system owners must abide in the context of state regulation. Standardized interconnection agreements limit utilities from favoring their own generation, reduce unfair impediments to market entry for small generation, and encourage investment electric infrastructure.

As of December 2010, thirty-four states had statewide interconnection procedures.[76] EPA assessed that fewer than half of the states with statewide interconnection standards were favorable to implementation of DG.[77] Favorable standards had standard forms, a reasonable timeline for application approval, low or no additional insurance requirements, an allowance for less than 10 kW residential and more than 100 kW commercial DG units to interconnect, and/or other positive attributes.[78] Interconnection is projected to improve, supporting a growth in DG, as technology advances and the spread of RPS programs encourages relaxation on the limits on the maximum capacity that can be interconnected.[79]

Many states have modeled their interconnection after the model interconnection standards developed by the Interstate Renewable Energy Council, FERC, the Mid-Atlantic Distributed Resources Initiative (MADRI), or large states such as California. The DOE and the Institute of Electrical and Electronics Engineers (IEEE) also developed a uniform standard—IEEE standard 1547—for interconnecting DG with the existing electric power system.[80] Certain states will adopt interconnection policies and/or rules to further support DG and whatever model interconnection standard was used, such as California's Rule 21, which helped reduce DG interconnection times and costs.[81]

The use of many models and variations presents its own challenges, as discussed above. One solution would be for FERC to revise Order 2006 to conform to one of the model agreements adopted by most of the states, and encourage all other states to adopt that model.[82]

Net-Metering Standards

Net-metering is a process by which states encourage DG by crediting customers, allowing them to offset their energy use by electricity they generate and feed back to the grid. Variations in net metering include the types of technologies that are eligible for net metering; the types of customer; the MWs that can be net metered; the size of the systems that may enroll; the treatment of net excess generation; and the types of utilities covered by a state policy (such as investor-owned utilities, municipal utilities, or cooperatives).[83] Net-metering policies had been implemented in forty-four states as of December 2010.[84]

Reimbursement policies for any excess generation also vary. For example, in Utah, utilities must net meter electricity produced by consumers and compensate consumers who supply more electricity than they receive.[85] In New York and Washington, utilities must provide credits on future use to residential and farm customers for excess generation.[86] Some states leave the policy on reimbursement up to the utility or do not allow refunds beyond nonmonetary credits.[8]7 Net metering in some states is limited to a small percentage above the customers' load. Net metering remains primarily a state issue, because FERC may regulate such generation only if the net sale of energy exceeds consumption of energy over the entire billing period.[88]

Public Benefit Funds and Clean Energy Funds

Public benefit funds (PBFs), and specifically clean energy funds, may provide funding for clean energy purposes such as DG programs, allowing acceleration of DG by reducing the competitive advantage held by other forms of energy generation, such as coal.[89] PBFs typically are funded through small fees (systems benefit charges) incurred by customers of electricity.[90] The fund then is allocated, typically by one of three models:

1) investment model, which provides a state loan or equity for initial investment in clean energy;

2) project development model, which provides production incentives and grants or rebates; or

3) industry development model, which facilitates market transformation through various methods, such as business development grants and consumer education.[91]

As of October 2008, twenty-three states and the District of Columbia had established some type of clean energy fund for renewable energy.[92]

Feed-in Tariffs

A feed-in tariff policy generally requires a utility to purchase either RECs or electricity from eligible renewable energy generators.[93] The purchase price generally comes from either a cost-based or a value-based approach.[94] The cost-based approach considers the cost of generation and helps ensure that renewable energy investors receive a reasonable rate of return.[95] In contrast, a value-based approach quantifies numerous benefits to the utility, society, and/or the environment, and involves a more complex determination.[96]

Feed-in tariff policies for renewable generation have been successfully implemented in numerous countries, typically with a purchase price that covers the cost and an estimated profit.[97] In the United States, however, the purchase price usually is determined with a value-based approach and appears to be less successful.[98] Feed-in tariff policies promote new renewable development by providing long-term consistency, whereas RPS policies merely mandate the percentage of total demand that must be provided by renewable energy.[99] Feed-in tariff policies are influential municipal policy programs in cities within the United States to further incentivize DG, beyond an RPS.

Other Policies and Incentives

Distributed generation can be enhanced by energy storage capabilities. For example, electricity consumers who implement DG to provide for their own needs can provide only between 50% and 70% of their peak load needs, and so DG systems can aggravate a utility's supply balance.[100] Energy storage capabilities provide load-following and voltage stability, which can allow a DG unit to operate reliably and efficiently.[101]

States also have implemented unique financial incentive programs to encourage progress in DG. For example, the California Energy Commission developed the Emerging Renewables Program to "stimulate market demand," in line with its primary goal of developing a self-sustaining market for "'emerging' renewable energy technologies in distributed generation applications."[102] The program provides a financial incentive to electricity consumers to install renewable energy systems and connect them to the utility distribution grid, and varies with the size, technology, and type of installation.[103] It is limited to particular types of renewable technology (currently, renewable fuels or small wind turbines).[104]

The program currently is suspended to address deficiencies with its requirements, because the program was not intended to fully eliminate the consumer's economic interest by covering the entire cost of the system, and many rebate reservations requested incentives near the total cost of the renewable system.[105] This decreases the incentive to locate renewable systems in resource-rich locations.[106] Proposed changes include a cap on the rebate, a performance-based incentive, or a hybrid approach.[107] States and local districts will need to provide such incentives to utility companies to counteract the negative incentive that will arise from decreased revenue, such as the ability to recover costs from energy efficiency and renewable energy gains.[108]

Conclusion

Achieving success to de-carbonize fossil fuel generation to clean DG will involve modifying some of the legal and policy energy frameworks within the United States at the federal, state, and local levels. Federal and state policies that enable speedy and fair interconnection processes of DG, net metering, favorable and fair rates, terms and conditions, and storage will decide whether DG is enabled or inhibited. If the United States does not establish an effective regulatory framework, it risks falling further behind in efforts to de-carbonize electric power. Local municipal utilities, the DOD, and European countries such as Denmark likely will continue to drive the technical implementation of DG until a business model is successfully developed for IOUs.

Notes

1. International Energy Agency, "Prospect of Limiting the Global Increase in Temperature to 2ºC Is Getting Bleaker" (May 30, 2011), available at www.iea.org/LatestInformation.asp?offset=10.

2. *Id.*

3. *Id.*

4. Colorado's Renewable Portfolio Standard (RPS) now requires each investor-owned utility to provide 30% of its retail electricity sales from renewable energy by the year 2020. CRS Ann. § 40-2-124. *See also* Database of State Incentives for Renewables & Efficiency, www.dsireusa.org/ (listing various RPSs and similar laws for all fifty states).

5. Fox-Penner, *Smart Power: Climate Change, the Smart Grid and the Future of Electric Utilities* 109-21 (Island Press, 2010). Fox-Penner also discusses new business models for investor-owned utilities (IOUs), which is beyond the scope of this article but is increasingly important.

6. U.S. Energy Information Administration (EIA), "Annual Energy Outlook 2011" 96 (2011).

7. *Id.* "Other" includes wind, petroleum, wood, waste, geothermal, solar, photovoltaic, and batteries, some of which is nonrenewable.

8. *Id.* at 150.

9. *Id*.

10. *Id.* at 73. The total share of coal is expected to decrease 2% by 2035.

11. *Id*.

12. *See* "The Cell Project" (Aug. 12, 2010), available at www.energinet.dk/EN/FORSKNING/Energinetdk-research-and-development/The-Cell-Project/Sider/The-Cell-Project.aspx; Fenn *et al.*, "Boulder's Energy Future—Localization Portfolio Standard—Electricity" (June 4, 2011), available at www.bouldercolorado.gov/files/Energy/June14_StudySession/EF_July14_SS_AttH.pdf.

13. *See* Fort ZED, "Smart Grid," available at fortzed.com/what-is-fortzed/smart-grid.

14. *See* Lund and Mathiesen, "Energy System Analysis of 100 Percent Renewable Energy Systems: The Case of Denmark year 2030 and 2050," 34 *Energy* 524 (2009), available at www.ewp.rpi.edu/hartford/~ernesto/F2010/EP2/Materials4Students/Farrell/Lund2009.pdf.

15. *See* "Database of State Incentives for Renewables & Efficiency," available at www.dsireusa.org.

16. For example, the standard may allow only small units to interconnect or require significant liability insurance.

17. Los Angeles Department of Water and Power (LADWP), "2010 Power Integrated Resource Plan: Appendix G, Distributed Generation" (Dec. 15, 2010), available at www.lapowerplan.org/documents/final_irp/Appendix_G_Distributed_Generation.pdf.

18. Itron, Inc., "Impacts of Distributed Generation: Final Report" 2-3 (Jan. 2010), available at www.cpuc.ca.gov/NR/rdonlyres/750FD78D-9E2B-4837-A81A-6146A994CD62/0/ImpactsofDistributedGenerationReport_2010.pdf.

19. California Public Utilities Commission (PUC)/California Energy Commission (CEC) Workshop, "1990 Electricity Sector Baseline, Current Entity-Specific GHG Emissions Levels and Policy Issues Related to Allowance Allocation" (June 22, 2007), available at www.cpuc.ca.gov/PUC/energy/climate+change/news.htm.

20. *See* Rose *et al.*, "Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures" (Network for New Energy Choices, 2010), available at www.newenergychoices.org/uploads/FreeingTheGrid2010.pdf.

21. Farrell, "Democratizing the Electricity System—A Vision for the 21st Century Grid," *The New Rules Project* (June 2011), available at www.newrules.org/energy/publications/democratizing-electricity-system-vision-21st-century-grid.

22. Ackermann *et al.*, "Distributed Generation: a Definition," 57 *Electric Power Systems Research* 195, 201 (2001), available at paginas.fe.up.pt/~cdm/DE2/DG_definition.pdf.

23. CRS Ann. § 40-2-124(1)(c)(I)(C) to (E). At least one-half of the distributed generation (DG) requirement must be generated by retail DG systems.

24. HB 1001, 67th General Assembly, 2d Reg. Sess. (Colo. 2010).

25. *See* CEC, "Committee Workshop on Distribution Infrastructure Challenges and Smart Grid Solutions to Advance 12,000 Megawatts of Distributed Generation" 1-2 (2011). California Clean Energy Future includes 2020 target goals of adding 8,000 megawatts (MW) of utility-scale renewable resources; 12,000 MW of renewable DG; and 1,000 MW of energy storage. *See* "California Clean Energy Future," available at www.cacleanenergyfuture.org.

26. The California Public Utilities Commission (CPUC) opened R.98-12-015 "to develop specific policies and rules to facilitate the deployment of distributed generation and distributed energy resources in California." CPUC, Order Instituting Rulemaking into Distributed Generation: R. 99-10-025 at 2 (1999), available at ftp://ftp.cpuc.ca.gov/gopher-data/distgen/OIR9910025-dg-oir.rtf. *See* CPUC, CPUC Decision D.00-12-037, Decision Adopting Interconnection Standards (2000), available at docs.cpuc.ca.gov/Published/Final_decision/4117.htm. In 2004, eleven states were identified as moving aggressively toward DG and California was the leader. *See* Ritchie, "The Top 11 States for Distributed Energy," *Distributed Energy* (2004), available at www.distributedenergy.com/march-april-2004/top-11-states.aspx. Denmark is a leading implementer of DG, and provides substantial information to the public through Energinet.dk, a nonprofit enterprise owned by the Danish Climate and Energy Ministry. *See* Energinet.dk, www.energinet.dk/EN/Sider/default.aspx. The U.S. Department of Defense (DOD) also has been a leader in the implementation of DG. *See, e.g.*, Heininger Schwerin, "Army Deploys Microgrids in Afghanistan for 'Smart' Battlefield Power" (June 28, 2011), available at www.army.mil/article/60709/Army_deploys_microgrids_in_Afghanistan_ for____smart____battlefield_power; Hightower, "Energy Surety Microgrids for Critical Mission Assurance to Support DOE and DOD Energy Initiatives" (2010), available at events.energetics.com/SmartGridPeerReview2010/pdfs0/ presentations/day2/am/16_Energy_Surety_Microgrids_and_SPIDERS_NEW.pdf.

27. Spirae, Inc., "Energinet.dk Project Description" 7 (2011), available at www.spirae.com/Energinet.php.

28. Carvallo, "Austin Energy Plans Its Smart Grid 2.0," *CIO and Smart Grid Master* (April 18, 2009), available at www.ciomaster.com/2009/04/austin-energy-plans-its-smart-grid-20.html.

29. The Sacramento Municipal Utility District (SMUD) adopted a feed-in tariff for solar, which was rolled out on January 4, 2010 and fully subscribed within one week. *See* SMUD, "SMUD's Feed-In Tariff," available at www.smud.org/en/community-environment/solar-renewables/pages/feed-in-tariff.aspx.

30. The LADWP has both a feed-in tariff for solar and a "Standard Energy Credit." *See* LADWP, "2010 Power Integrated Resource Plan: Appendix G, Distributed Generation" (Dec. 15, 2010), available at www.lapowerplan.org/documents/final_irp/Appendix_G_Distributed_Generation.pdf.

31. City of Boulder: Certified Ballot Measures, Ballot Issue Nos. 2B and 2C (adopted Aug. 16, 2011), available at www.bouldercolorado.gov/files/Elections/2011/2011_Ballot_Measure_Certification.pdf.

32. "Boulder's Energy Future—Localization Portfolio Standard—Electricity" (June 4, 2011), available at www.bouldercolorado.gov/files/Energy/June14_StudySession/EF_July14_SS_AttH.pdf.

33. *See, e.g.*, 16 U.S.C. §§ 792 *et seq.* Federal regulation of the electricity markets began in 1935 with the passage of the Public Utility Holding Company Act (PUHCA) and the Federal Power Act (FPA). PUHCA required interstate utility holding companies to register with the Securities and Exchange Commission (SEC) and was intended to prevent utilities from investing in non-utility businesses. PUHCA was repealed by the Energy Policy Act of 2005 (EPAct). EPAct, Pub. L. No. 109-58, 119 Stat. 594. Section 201 of the FPA contains the core of the Federal Energy Regulatory Commission's (FERC) jurisdiction. It grants FERC jurisdiction over "transmission of electric energy in interstate commerce" but denies jurisdiction over facilities used in "local distribution." 16 U.S.C. § 824. Sections 205 and 206 of the FPA outline FERC's regulatory authority over rates and charges collected by a public utility in transmitting or selling electric energy in interstate commerce. Under the FPA, rates and charges "shall be just and reasonable, and any such rate or charge that is not just and reasonable" shall be unlawful. 16 U.S.C. § 824d (a). Section 205 requires that a public utility file a rate schedule with FERC, and § 206 provides for FERC review of rate schedules already in effect.

34. *See* 16 U.S.C. §§ 2601 to 2645.

35. *See Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 406 (1983).

36. EPAct, Pub. L. No. 109-58, 119 Stat. 594.

37. Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006, FERC ¶ 31,180, *order on reh'g*, Order No. 2006-A, FERC ¶ 31,196 (2005) (Order 2006).

38. *Id.* at 1-2.

39. *Id.* at 5.

40. *Id.* at 3.

41. Utilities across the country use coal, gas, and nuclear energy to firm renewable generation. Numerous utilities are testing battery storage to firm renewable generation. In Luverne, Minnesota, Xcel Energy is installing and testing a 1MW sodium-sulfide battery integrated with an 11.5 MW wind project. Himelic and Novachek, "Sodium Sulfur Battery Energy Storage And Its Potential To Enable Further Integration of Wind" 7 (Xcel Energy, 2010).

42. KEMA, Inc., "Research Evaluation of Wind Generation, Solar Generation and Storage Impact on the California Grid, California Energy Commission" 6 (2010), available at www.energy.ca.gov/2010publications/CEC-500-2010-010/CEC-500-2010-010.PDF.

43. FERC, Request for Comments Regarding Rates, Accounting, and Financial Reporting for New Electric Storage Technologies, Docket No. AD10-13 (June 11, 2010).

44. *See, e.g.*, Integration of Variable Energy Resources, Docket No. RM10-11-000, 133 FERC ¶ 61,149 (Nov. 18, 2010).

45. Frequency Regulation Compensation in the Organized Wholesale Power Markets, 134 FERC ¶ 61,124 (Feb. 17, 2011).

46. *See id.* at 2.

47. *Id.* at 4.

48. *See* Integration of Variable Energy Resources, 75 Fed. Reg. 75336-01 (proposed Dec. 2, 2010) (to be codified at 18 C.F.R. pt. 35.28(g)(3)).

49. Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies, Docket Nos. RM11-24-000 and AD10-13-000, 135 FERC ¶ 61,240 (June 16, 2011).

50. *Id.* at 1-2.

51. *Id.* at 23-27.

52. Liddell, Motion to Intervene and Comments of the California Energy Storage Alliance on Request for Comments Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies (Aug. 9, 2010), available at storagealliance.org/workfilings/08-09-10_FERC_Staff_Energy_Storage_Request_Comments.pdf.

53. Baker-Branstetter, "Distributed Renewable Generation: The Trifecta of Energy Solutions to Curb Carbon Emissions, Reduce Pollutants and Empower Ratepayers," *SelectedWorks*, available at works.bepress.com/
shannon_baker_branstetter/2.

54. *See* U.S. Department of Energy (DOE), "The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Its Expansion: A Study Pursuant to Section 1817 of the Energy Policy Act of 2005" (June 2007), available at www.oe.energy.gov/DocumentsandMedia/1817_Study_Sep_07.pdf. The primary rate-related impediments to DG noted by its developers include: lost utility sales revenue; standby charges; retail natural gas rates for wholesale applications; exit fees and stranded costs; sell-back rates, including net metering, retail power prices/rate credits, and wholesale prices; locational marginal price payments/credits; capacity payments/credits; co-generation deferral rates; and payments/credits for line losses.

55. *Id.*

56. DOE, "EERE State Activities and Partnerships: States with Renewable Portfolio Standards" (June 16, 2009), available at apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm#chart.

57. Elkind *et al.*, "The Power of Energy Storage: How to Increase Deployment in California to Reduce Greenhouse Gas Emissions" 19 (2010), available at www.law.berkeley.edu/files/Power_of_Energy_Storage_July_2010.pdf.

58. DOE, "Energy Storage: Program Planning Document" 27 (2011).

59. Elkind, *supra* note 57 at 4.

60. Davis and Davis, "Municipalization and Subsidized Utility Competition: The Taxpayer's Perspective," *Cal-Tax Digest* 5 (April 1997), available at www.caltax.org/MEMBER/digest/apr97/apr97-3.htm.

61. *See* Colorado Smart Grid Task Force, "Deploying Smart Grid in Colorado: Recommendations and Options" 34 (2011), available at www.nationalelectricityforum.org/pdfs/DeployingSmartGrid.pdf.

62. Davis and Davis, *supra* note 60.

63. Center for Social Inclusion, "Solar Energy Development at the Community Level: Briefing Paper Five of Black, Brown and Green" 7 (Nov. 2009), available at www.centerforsocialinclusion.org/publications/wpcontent/plugins/
publications/uploads/Solar_Energy_Development.pdf.

64. *See id.* at 12 (discussing SMUD, "Solar Power for Your Home," available at

www.smud.org/en/community-environment/solar/Pages/solarshares.aspx).

65. *See* Community Choice, "For Residents" (Oct. 28, 2008), available at www.communitychoice.info/residents.

66. Marshall, "Forming a National Community Choice Aggregation Network: Feasibility, Findings and Recommendations" 3 (2010), available at www.galvinpower.org/sites/default/files/Community_ Choice_Aggregation_Report_Final_1-4-11.pdf.

67. *Id.* at 3.

68. *See* Community Choice, *supra* note 65.

69. EIA, *supra* note 6 at 65.

70. *Id.*

71. *Id.*

72. The production tax credit originally was enacted by the Energy Policy Act of 1992. The investment tax credit originally was enacted at 26 U.S.C. § 48. Both were subsequently extended and expanded by various acts until the most recent extension by the American Recovery and Reinvestment Act of 2009.

73. EPA, "Renewable Portfolio Standards Fact Sheet" (April 2009), available at www.epa.gov/chp/state-policy/renewable_fs.html.

74. *Id.*

75. *Id.*

76. Rose *et al.*, "Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures" 12 (Network for New Energy Choices, 2010), available at www.newenergychoices.org/uploads/FreeingTheGrid2010.pdf.

77. EPA, "Interconnection Standards" (July 5, 2011), available at www.epa.gov/chp/state-policy/interconnection.html.

78. *Id.*

79. EIA, *sup*ra note 6 at 67.

80. Itron, Inc., *supra* note 18 at 3-5.

81. *Id.* California's Rule 21 is for DG systems up to 10 MW. Each of the state's three major IOUs—Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company—have filed Rule 21 tariffs. Rule 21 is based on a screening process that determines the level of review process. The utility first performs an Initial Review Process (IRP) of the project plans. If all screens are passed, the system qualifies for "simplified interconnection," with no additional studies needed. If a system does not pass the IRP, it must go through additional processes. *See* CPUC, CPUC Decision D.00-12-037, Decision Adopting Interconnection Standards (2000), available at docs.cpuc.ca.gov/Published/Final_decision/4117.htm. *See also* CPUC, Rule 21 (June 24, 2011), available at www.cpuc.ca.gov/PUC/energy/DistGen/rule21.htm.

82. Baker-Branstetter, *supra* note 53.

83. Varnado and Sheehan, *Connecting to the Grid: A Guide to Distributed Generation Interconnection Issues* 11 (6th ed., 2009), available at irecusa.org/wp-content/uploads/2009/11/Connecting-to-the-Grid-Guide-6th-edition.pdf.

84. Rose, *supra* note 76 at 12.

85. Smoots, "Overview of State and Federal Incentives for the Use of Distributed Generation," 21 *Cogeneration & Distributed Generation J.* 7-8 (2006), available at www.igreenbuild.com/uploads/files/55.pdf.

86. *Id.*

87. *Id.*

88. Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003-A, 106 F.E.R.C. ¶ 61,220 (March 5, 2004):

[U]nder most circumstances [FERC] does not exert jurisdiction over a net energy metering arrangement when the owner of the generator receives a credit against its retail power purchases from the selling utility. Only if the Generating Facility produces more energy than it needs and makes a net sale of energy to a utility over the applicable billing period would [FERC] assert jurisdiction.

89. EPA, "State Clean Energy Funds Fact Sheet" (April 2009), available at www.epa.gov/chp/state-policy/funds_fs.html.

90. *Id.*

91. *Id.*

92. *Id.*

93. Cory *et al.*, "Feed-in Tariff Policy: Design, Implementation, and RPS Policy Interactions" 2 (National Renewable Energy Laboratory, March 2009), available at www.nrel.gov/docs/fy09osti/45549.pdf.

94. *Id.*

95. *Id.*

96. *Id.*

97. *Id.* at 2-3.

98. *Id.* at 3.

99. *Id.* at 8.

100. Baxter, "Energy Storage: An Expanding Role as a Distributed Resource," *Cogeneration and On-Site Power Production* 69, 71 (2003), available at www.energystoragecouncil.org/030501%20COSPP.pdf.

101. *Id.*

102. CEC, "Emerging Renewables Program" (June 15, 2011), available at www.energy.ca.gov/renewables/emerging_renewables/index.html.

103. *See* CEC, *Emerging Renewables Program: Final Guidebook* (10th ed. 2010). For instance, wind energy will incur a rebate of $2.50 or $3.00 per watt for the first 10 kW (depending on the date of generation).

104. *Id.* at 49.

105. *Id.*; CEC, *supra* note 102.

106. *Id.*

107. *Id.*

108. Colorado Smart Grid Task Force, *supra* note 61 at 20.

QUESTIONS

1. The Federal Energy Regulatory Commission (FERC) regulates:

    a. wholesale electric markets

    b. retail electric markets

    c. electric transmission

    d. local distribution

    e. a and c

2. FERC's Order 2006 related to:

    a. electric reliability

    b. small generation interconnection

    c. the standards of conduct

    d. regulation of electric storage

3. Recently, FERC issued the following:

    a. Request for Comment Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies

    b. Notice of Proposed Rulemaking relating to compensation for frequency regulation in the Regional Transmission Organizations and Independent System Operators

    c. Notice of Inquiry (NOI) relating to auxiliary services, including accounting changes for electric storage

d. all of the above

4. The majority of electricity in the United States is generated from which sources?

a. coal

b. natural gas

c. nuclear

d. wind

e. a and b

5. Which source of fuel was responsible for the highest carbon dioxide (CO2) emissions in the electric power sector?

a. coal

b. oil

c. natural gas

d. biomass

e. solar

6. Benefits of distributed generation (DG) include all but which of the following:

a. added system generation capacity

b. fewer problems and delays for interconnection

c. reduced load and replace peakers

d. improved efficiency

e. greater overall capacity and control

7. DG results in:

a. shorter distribution routes

b. increased CO2 emissions

c. importation of electricity from Canada

d. savings on electric bills

e. a and d

8. Colorado's DG law is regulated by:

a. the Governor

b. the Colorado Department of Public Health and Environment

c. the Colorado Public Utilities Commission (PUC)

d. FERC

e. the Governor's Energy Office

9. Incentives for integration of DG include which of the following?

a. net-metering standards

b. public benefit funds

c. feed-in tariffs

d. energy storage capabilities

e. all of the above

Click here for test answers.

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