BACKGROUNDER

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The Effects of State Laws and Regulations on the Development of Renewable Sources of Electric Energy

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RESOURCES FOR THE FUTURE

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1. Executive Summary

Purpose

This paper identifies and assesses the state laws, regulations, and regulatory actions having the greatest potential to affect the rate at which renewable sources of electric energy are brought online. The paper is prepared as a background resource for a broader study, entitled *Toward a New National Energy Policy—Assessing the Options*, which is being undertaken by Resources for the Future and the National Energy Policy Institute.

Geographical Coverage

It was impractical to assess the laws, regulations, and regulatory actions of all 50 states. So this paper covers 17 of the 18 most populous states (the subject states), in which about 70 percent of the nation's population resides, see United States Census Bureau, *Annual Estimates of the Resident Population for the United States, Regions, States, and Puerto Rico: April 1, 2000 to July 1, 2008 (NST-EST2008-01)*, http://www.census.gov/popest/states/NST-ann-est.html (accessed August 15, 2009). In order of their population, from highest to lowest, these states include California, Texas, New York, Florida, Illinois, Pennsylvania, Ohio, Michigan, Georgia, North Carolina, New Jersey, Virginia, Washington, Arizona, Massachusetts, Indiana, and Missouri. Tennessee, the nation's 17th most populous state, was excluded because of the inordinate impact of the Tennessee Valley Authority on its electric energy markets.

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Legal and Regulatory Coverage

The laws, regulations, and regulatory actions covered in this paper include the following:

- Renewable electric energy purchasing and pricing mandates
  - Renewable portfolio standards (RPS)
  - Net energy metering
  - Green purchasing requirements
  - Public benefits funding to support renewable energy production
- Renewable electric energy purchasing incentives and opportunities represented by voluntary green purchasing initiatives
- Laws and regulatory decisions governing the permitting and siting of electric energy generators and electric transmission facilities
- Laws and regulatory decisions influencing the demand for electric energy
  - Demand-side management and energy efficiency
  - Decoupling

Coverage is limited to laws, regulations, and regulatory decisions that have statewide applicability. However, extensive coverage of federal laws and regulatory decisions is provided to establish the extent to which federal or state law will affect the development and use of renewable power generation.

Narrative Overview

Competitive Overlay

Renewable electric energy technologies are seeking a beachhead within electric energy markets that have been radically altered over the last 20 years. State and federal initiatives have attempted to create by regulation workably competitive retail and wholesale electric energy markets. To facilitate this goal, traditional fully integrated electric utility monopolists have been required to unbundle—so as to operate separately or to spin off to other entities—generation, transmission, and distribution.

In these disaggregated markets, competing unregulated electric energy generators may operate in broader, less obstructed markets that have been organized by regional transmission organizations (RTOs) and/or statewide independent systems operators (ISOs). These RTOs and

ISOs are governed by rules that require them to provide nondiscriminatory, open-access transmission service to all electric energy suppliers and purchasers who need it. Electric energy end users still receive energy delivery service from their local distribution companies, which in some states are the remnants of a vertically integrated electric energy monopolist that was required to unbundle in the cause of creating workably competitive retail choice markets.

To the extent that these state and federal competitive initiatives succeed in creating workably competitive wholesale and retail electric energy markets, they may keep the prices of electric energy generated from traditional fuel sources low enough to forestall emerging sources of renewable electric energy. However, design flaws and operational difficulties have caused these new markets to be less competitive than their creators envisioned. As a result, these markets have often produced high and unstable electric energy prices that reduce the cost gap between traditional and renewable sources of electric energy. To the extent that federal initiatives to extend nondiscriminatory, open-access transmission services over huge areas of the country succeed, persons wishing to help the environment by buying and selling electric energy generated from renewable sources will have more competitive alternatives.

Market Descriptions

The electric energy markets in the states subject to this study have a variety of market structures, depending on whether (a) they have restructured their electric energy markets to provide for retail choice and/or (b) RTOs or ISOs operate within their territories. These structural attributes are correlated with the level of retail electric energy prices prevailing in each state. They also are correlated with the mix of fuel used in a state to generate electric energy.

Because of cost and other advantages, the traditional fuels—coal, natural gas, and nuclear power—dominate the fuel mixtures of the subject states. Renewable sources of electric energy other than traditional hydroelectric power are just emerging. In these states, the leading nonhydro renewable sources are wind, wood and wood waste, and municipal solid waste/landfill gas.

Retail electric energy prices are highly correlated with the percentage of coal and natural gas in a state's fuel mixture: the more coal, the lower the price; the more natural gas, the higher the price. Nevertheless, in terms of total costs imposed on society, coal may be the most expensive because its use is highly correlated with emissions of major air pollutants. If these costs are internalized, coal will lose its cost advantage over natural gas, which is a cleaner fuel, and the cost gap between renewable electric energy and carbon fuels will be narrowed.

State Renewable Energy Initiatives

Not content to wait for market forces and national environmental policy to bring about significant production of electric energy from renewable sources, the subject states have undertaken market-leveling initiatives to promote renewable sources of electric energy. Two of the most important such initiatives are RPS and net metering.

RPS are conceptually simple; they mandate that a certain percentage of electric energy, or a certain number of megawatt-hours (MWh), be generated. In practice, the forms of RPS adopted by the subject states are very complex and not uniform. They also tend to favor parochial interests in ways that detract from the express goal of promoting the development and use of renewable sources of electric energy. Nevertheless, RPS provide a mechanism that enables renewable energy generators to receive a price that covers their generating costs.

Net metering is a way of promoting renewable distributed generation (DG). As applied to renewable energy sources that are intermittent, net metering enables customer–generators to sell back to the grid electric energy that their generating facilities generate in excess of their needs. It also enables customer–generators to receive backup power on normal, nondiscriminatory terms. In essence, net metering permits customer–generators to “bank” electric energy in the grid for withdrawal at a later time, thereby avoiding the need to install expensive electric energy storage devices. Unlike RPS, net metering does not provide customer–generators with above-market prices that cover their generating costs. States have also imposed low-capacity limits on the individual generating device and the aggregate capacity for the state or the utility service area. As a consequence, net metering is not a robust means of promoting renewable sources of electric energy.

Some of the subject states have also initiated programs to promote the purchase of electric energy generated from renewable sources. Green purchasing requirements mandate that government institutions purchase a certain percentage of renewable electric energy from renewable resources. Public benefits funding involves imposing a mandatory charge on electric bills for purposes of creating a fund to be used to promote renewable energy. Voluntary green purchasing initiatives harness altruism by requiring utilities to offer their customers programs that enable them to purchase renewable electric energy at a remunerative price.

Permitting and Siting Generating and Transmission Facilities

The process of permitting and siting generating and transmission facilities can negatively affect the development of renewable electric energy projects. Renewable energy resources are likely to be remote from population centers of areas covered with adequate transmission grids.

Transmission facilities are environmentally controversial even if they are used to make renewable electric energy generation possible. Therefore, it is more difficult to develop renewable electric energy projects in states that permit every local government to apply its zoning and siting rules. Having a statewide one-stop siting mechanism that could preempt these local siting authorities may become a necessary means of signaling the importance of developing renewable electric energy projects.

Similarly, states that have continued with the traditional cost-of-service, rate-of-return regulation still require those who would build power plants to obtain a certificate of convenience and necessity. Obviously, such an approach is not compatible with the theory of retail choice. So those states tend to leave any power plant siting issues to local authorities that wish to apply their zoning and environmental protection rules. Again, a statewide one-stop preemptive certification–siting–permitting approach would facilitate the development of priority energy projects. Where such mechanisms exist, they may exclude renewable energy projects because of size limitations.

Competitive Procurement

Even in retail choice states, some utilities are still serving a number of "captive" customers who have been unwilling or unable to secure competitive electric energy services. As a consequence, the distribution company that provides them with electric energy delivery service is still subject to the traditional duty of securing electric energy on their behalf. If these companies have not totally divested their generating facilities, they have an incentive to provide the captive customers with electric energy generated by those facilities whether or not they are the least-cost generators. Importantly, in states where the traditional cost-of-service, rate-of-turn regulation is still applied to electric energy monopolies, competitive procurement standards should be created and applied to make sure that the monopolists do not build their own generating facilities when less costly generating alternatives are available in wholesale markets or less costly efficiency initiatives should be pursued. Given the current cost disadvantages of renewable electric energy, this emphasis on least-cost alternatives could cause competitive procurement to be an impediment to developing renewable electric energy projects.

Efficiency and Demand-Side Management

Energy efficiency involves a reduction in energy consumption, whereas demand-side management involves reducing or eliminating electric energy demand at times of high-cost peak periods or times when the grid faces problems in balancing its loads. Thus, energy efficiency causes electric energy providers to lose sales. The problem of lost electric energy sales is most acute in states where the affected company is still regulated under traditional cost-of-service, rate-of-return methods. Faced with such losses, companies will try to recoup them by increasing the rates on the remaining projected electric energy demand or fight efficiency measures to prevent such losses.

Some states have experimented with decoupling electric energy revenues from the production of kilowatt-hours (kWh) as a means of encouraging electric energy and delivery companies to support aggressive energy efficiency programs. Decoupling is controversial, however, because it does shift the cost of lost sales onto customers' remaining purchases. It also seems to be a concept that is not workable in retail choice and market-based wholesale markets because there efficiency is just one more competitor in what is supposed to be deregulated markets.

Demand-side management conceptually helps electric energy and transmission service providers more effectively and efficiently operate their facilities and manage the grid. The Federal Energy Regulatory Commission (FERC) has taken steps to put demand response assets on an equal footing with electric energy generators in supplying resources to help balance loads on the transmission grid.

2. Baseline Information

Introduction

Current state laws and regulations affecting the development and use of renewable electric energy generation emerged from an evolving electric energy regulatory structure. To gauge the prospects for renewable sources of electric energy to constitute an increasing percentage of the nation's electric energy generation mix, it is necessary to have a basic understanding of the current electric energy regulatory structure and its effects on the configuration of the nation's electric energy grids. Accordingly, this section contains

- an extensive history of how the electric energy regulatory structure evolved over the last 30 years into its current configuration;
- a succinct comparison of the key characteristics of the two regulatory models (traditional cost-of-service regulation and regulated competition) currently affecting the electric power industry; and
- descriptions of current electric energy market conditions within the subject states.

The Historical Evolution of Electric Energy Regulatory Structure

The Natural Monopoly Theory and Cost-of-Service Regulation

After the New Deal reforms of the 1930s, the electric energy industry evolved into a highly fragmented industry featuring many vertically integrated electric energy utilities.[1] This industrial structure was in part the result of regulation under the Public Utility Holding Company Act of 1935 (PUHCA), which "reduced holding companies generally to an electric or gas utility system confined to a single area or region, with interconnected utility assets capable of coordinated and efficient operation."[2] The vertically integrated electric energy utilities were predominantly regulated at the state level under a cost-of-service regulation model premised on the natural monopoly theory.[3]

The natural monopoly theory holds that some industries naturally devolve into monopolies because their producers have economies of scale so large that marginal costs of production fall throughout the relevant range of demand.[4] As a consequence, competition drives prices below all the competitors' breakeven points until a monopoly emerges because all but one competitor goes out of business, or the competitors merge into one entity, or the competitors form a cartel.[5]

Once the natural monopoly emerges, absent regulation or the reemergence of competition, it tends to reduce output to a level that interacts with demand for its services to set a price above its marginal and average costs.[6] The resulting high profitability eventually attracts competitors, and the cycle of destructive competition leading to the reemergence of a monopoly repeats itself.[7]

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[1] Markian M.W. Melnyk & William S. Lamb, *PUHCA's Gone: What Is Next For Holding Companies?*, 27 Energy L.J. 1, 11, 12 (2006).

[2] *Id.* at 7.

[3] David B. Spence, *Can Law Manage Competitive Energy Markets?*, 93 Cornell L. Rev. 765, 767–770 (2008) [hereinafter Spence].

[4] PAUL A. SAMUELSON & WILLIAM D. NORDHAUS, ECONOMICS 506, 523–525 (12th ed. 1985) [hereinafter Samuelson].

[5] ALFRED E. KAHN, II, THE ECONOMICS OF REGULATION: INSTITUTIONAL ISSUES 118 (1988) [hereinafter Kahn II].

[6] *See* Spence, *supra* note 3, at 767 & n. 11; *Samuelson*, *supra* note 4, at 517–520, 522; Harold Demsetz, *Why Regulate Utilities*, 11 J. L. & Econ. 55, 56 (1968) [hereinafter Demsetz].

[7] Kahn II, *supra* note 5, at 2.

Cost-of-service regulation has been the traditionally prescribed regulatory antidote to the economic ills produced by natural monopolies. As applied to the electric energy industry, individual electric energy utilities were permitted by the states in which they operated to be the single suppliers of electric energy service within prescribed service areas.[8] In return, they were regulated by state public utility commissions (PUCs) under standards requiring them to provide reliable and efficient electric energy service on a nondiscriminatory basis at just and reasonable rates.[9] The just and reasonable rates were to be set at levels that enabled the electric energy utility to pay its operating expenses and obtain the capital needed to acquire and maintain sufficient plant and equipment for providing reliable and efficient electric energy service.[10] The Federal Power Commission (now FERC) regulated, largely on a cost-of-service basis, electric energy utilities' interstate transmission services and wholesale electric energy transactions.[11]

Development of Regulated Competition

Critiques of Natural Monopoly Regulation

Since the 1960s, economic regulation of electric utilities has come under increasing criticism and erosion. In his seminal article, *Why Regulate Utilities?*,[12] Harold Demsetz argued persuasively that the natural monopoly theory did not in and of itself provide justification for government regulation. If economies of scale dictate that only one firm serve a market, that market could be organized to set up competitive bidding by all firms seeking to serve it.[13] The outcome of the bidding could produce prices and outputs near perfect competitive levels if "(1) the inputs required to enter production [were] available to many potential bidders at prices

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[8] *See* Spence, *supra* note 3, at 768–769.

[9] Federal Power Act, § 205, 16 U.S.C. § 824d(a), (b); Spence, *supra* note 3, at 769 & nn. 21–22.

[10] This standard was established in the natural gas case of *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1994), but it has been applied generally to other types of regulated utilities for the proposition that "Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid . . . .", *id.* at 605. *See In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed To Realize a Reasonable Rate of Return on the Fair Value of Its Operations throughout the State of Arizona*, 2008 Ariz. PUC LEXIS 201 *78–*87 (Ariz. Corp. Comm'n 2008); Spence, *supra* note 3, at 769 & n. 21.

[11] Federal Power Act, § 201, 16 U.S.C. § 824; see Spence, *supra* note 3,. at 769 & n. 23; Federal Energy Regulatory Commission (FERC), What FERC Does, http://www.ferc.gov/about/ferc-does.asp (last visited Sept. 6, 2009).

[12] Harold Demsetz, *Why Regulate Utilities?*, 11 J. L. & Econ. 55 (1968).

[13] *Id.* at 56–62.

determined in open markets[, and] (2) the cost of colluding by bidding rivals [was] prohibitively high."[14]

Demsetz further argued that the problem of undesirable facilities duplication could also be handled by market transactions. Governments could either set appropriate market-clearing prices for the rights of way through publicly owned corridors[15] or build the facilities themselves by awarding construction contracts to the lowest-bidding construction firm and then award the right to use the facilities to the lowest-bidding supplier of utility services.[16]

Finally, Demsetz asserted that the problem of windfall profits or losses arising from long-term commitments to utility providers using durable equipment result not from economies of scale but rather from poor predictions about technology advances and the prices of important production inputs.[17] Such predictions must be made, and there is no way to know whether they will be handled better by negotiators of long-term bilateral utility service contracts or government regulators who oversee the technology choices and operational costs of utility monopolists.[18]

In fact, cost-of-service regulation has often been criticized as ineffective in meeting its chief goal of "replicat[ing] prices that would exist in well-functioning competitive markets."[19] United States Supreme Court Justice Stephen Breyer cogently summarized these critiques in a 1979 article entitled *Analyzing Regulatory Failure: Mismatches, Less Restrictive Alternatives, and Reform*.[20] Competitive markets determine returns to shareholders based on reproduction costs, but regulators must do so on the basis of historical costs because reproductive costs cannot be measured administratively.[21] Methods for determining what rates of return should be allowed poorly estimate the rates of return necessary to attract adequate investments in competitive

[14] *Id.* at 58.

[15] *Id.* at 62–63.

[16] *Id.* at 63.

[17] *Id.* at 63–64.

[18] *Id.* at 64–65.

[19] Stephen Breyer, *Analyzing Regulatory Failure: Mismatches, Less Restrictive Alternatives, and Reform*, 92 Harv. L. Rev. 552, 562 (1979).

[20] *Id.*

[21] *Id.* at 562–563.

markets.[22] Setting cost-based rates strips firms of incentives to be efficient, because their cost-savings are passed through to the ratepayers.[23] Historical-year investments and costs are used to set rates, so the rates set often fail to anticipate changes in costs and technologies likely to occur in the near future.[24] It is all but impossible to estimate demand elasticity accurately, so regulators often fail to anticipate how price changes will affect revenues or how best to allocate fixed and joint costs among various classes of ratepayers.[25]

Events Leading to Regulatory Change

Beginning in the 1960s, a perfect storm of unfortunate circumstances seemed to expose serious flaws in the way the electric energy industry was regulated. Many electric utilities built relatively large power plants from the late 1960s through the 1970s, a time of higher inflation and interest rates, thereby causing significant increases in their rate bases.[26] Two energy shocks also produced much higher fuel costs during this period.[27] Operational problems of expensive new nuclear plants, most dramatically the incident at Three Mile Island, drove up nuclear power plants' construction and operational costs.[28]

Forecasted electricity demand growth used to justify the construction of large, new power plants did not materialize because of energy conservation efforts and a sluggish economy.[29] As a consequence, there was not much need for additional generating capacity at the time the new expensive baseload power plants were coming online.[30]

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[22] *Id.* at 563 & n. 62.

[23] *Id.* at 563 & n. 63.

[24] *Id.* at 563.

[25] *Id.* at 563–564.

[26] Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 60 Fed. Reg. 17,662, 17,668–17,669 (proposed April 7, 1995) [hereinafter OATS NOPR].

[27] MATTHEW H. BROWN & RICHARD P. SEDANO, A COMPREHENSIVE VIEW OF U.S. ELECTRIC RESTRUCTURING WITH POLICY OPTIONS FOR THE FUTURE, 7–8 (National Council on Electricity Policy, 2003), http://www.ncouncil.org/Documents/restruc.pdf (last visited Sept. 7, 2009) [hereinafter NCEP OPTIONS].

[28] OATS NOPR, *supra* note 26, at 17,669 & n. 47.

[29] *Id.* at 17,669.

[30] *Id.*

The combination of these factors caused electricity prices to substantially increase in real and nominal terms between 1970 and 1985.[31] "[A]verage residential electricity prices more than tripled in nominal terms, and increased by 25% after adjusting for general inflation[;] . . . average [industrial] electricity prices . . . more than quadrupled in nominal terms . . . and increased 86% after adjusting for inflation."[32]

Customer responses to these rate increases included demands that regulatory agencies more strictly judge the prudence of utility investments and expenditures.[33] These demands resulted in regulators disallowing significant amounts of utility expenditures and investments, thereby creating disincentives for utilities to undertake the construction of new power plants.[34]

Industrial users began seeking special below-fully allocated average-cost rates, such as economic development rates and load retention rates.[35] They also began to self-generate and explore competitive alternatives.[36] The resulting loss of revenue from industrial users drove residential and commercial rates even higher.[37]

Development of Competitive Nonutility Generators

Seeking to spawn alternatives to expensive electricity generated by vertically integrated utilities and to diversify the mix of fuels used to generate electricity, Congress enacted in 1978 the Public Utility Regulatory Policies Act (PURPA), which in part created new classes of generators:[38] small generators and cogenerators owned by persons not primarily engaged in the generation and sale of electric energy except through the operation of small generators and cogenerators.[39] Small generators generally were required to be no larger than 80 MW and fueled

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[31] *Id.*

[32] *Id.*

[33] *Id.*

[34] OATS NOPR, *supra* note 26, at 17,669.

[35] NCEP OPTIONS, *supra* note 27, at 3. Economic development rates are used to induce firms to locate new businesses within a utility's service area. Load retention rates are used to keep existing companies in business or from moving out of the utility's service area. These rates are high enough to cover the utility's marginal costs of serving their recipients but less than fully allocated average costs. *See id*.

[36] OATS NOPR, *supra* note 26, at 17,669.

[37] *Id.*

[38] *Id.* at 17,670; NCEP OPTIONS, *supra* note 27, at 8.

[39] Public Utility Regulatory Policies Act of 1971, Pub. L. No. 95-617, §§ 201, 210, 92 Stat. 3117, 3134, 3135, 3144–3147 (Nov. 9, 1978) (hereinafter PURPA).

by alternative energy sources.[40] Cogenerators were required to generate electric energy plus steam or other useful forms of energy "used for industrial, commercial, heating or cooling purposes."[41]

Vertically integrated electric utilities were required to purchase electric energy from qualifying small generators and cogenerators (qualifying facilities [QFs]) at a price no higher than what their incremental cost of purchasing or generating electric energy would have been had they not purchased electric energy from the QFs.[42] The utilities were also required to sell QFs backup power at nondiscriminatory rates.[43]

Despite their size, technology, and ownership limitations, QFs soon occupied a significant portion of the wholesale electric energy market, expanding from 576 facilities with an aggregate capacity of 27,429 MW in 1989 to more than 1,200 facilities with an aggregate capacity of 47,774 MW by 1993.[44] QF success soon encouraged other nonutility generators to enter the wholesale electric energy market with generating facilities ineligible for QF status and benefits. These independent power producers (IPPs) employed new electric generating technologies, such as gas-fired, combined-cycle generators and conventional steam units with circulating fluidized bed combustion boilers, which enabled them to build much smaller, less expensive facilities to achieve the scale economies previously attained only by more expensive, larger baseload plants.[45] As a consequence, by the end of 1994, the '"optimum size [of generation plants] . . . shifted from [more than 500 MW (10-year lead time) to smaller units (one-year lead time) [in the 50- to 150-MW range]."'[46]

The IPPs could produce electric energy at lower costs than the vertically integrated incumbent utilities.[47] Moreover, advanced transmission technology emerged that facilitated efficient long-distance, high-voltage electric energy transmission, thus making it technically

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40 PURPA § 201, 92 Stat. 3134.

41 PURPA § 201, 92 Stat. 3135.

42 PURPA § 210(b), (d), 92 Stat. 3144, 3145.

43 PURPA § 210(c), 92 Stat. 3144–3145.

44 OATS NOPR, *supra* note 26, at 17,670.

45 *Id.* at 17,669.

46 *Id.* & nn. 58, 59, quoting Charles E. Bayless, *Less Is More: Why Gas Turbines Will Transform Electric Utilities*, PUB. UTIL. FORT. 21 (Dec. 1, 1994).

47 OATS NOPR, *supra* note 26, at 17,669–17,670.

possible for IPPs to serve far away captive customers of vertically integrated utilities that were saddled with high-cost generating facilities.[48] This developing bulk power market also induced some vertically integrated utilities to form affiliated power producers (APPs) through which they sought to sell electric energy generated by facilities not included in their rate bases under cost-of-service regulation.[49] Power marketers also entered this market.[50]

However, two significant obstacles impeded the expansion of a competitive bulk market: PUHCA's ownership restrictions[51] and a lack of generally available, nondiscriminatory transmission services.[52]

In 1992, Congress removed some of the barriers imposed by PUHCA by creating an exempt wholesale generator category of generation owners who were exempted from PUHCA's ownership restrictions.[53] As discussed below, FERC has been trying ever since the enactment of PURPA to reduce or eliminate discriminatory transmission service practices that impede the development of a fully competitive wholesale bulk electric energy market.

Despite the PUHCA and transmission access barriers, nontraditional generators other than QFs expanded significantly, from 249 generating facilities with an installed capacity of 9,216 MW in 1989 to 634 generating facilities with an installed capacity of 13,004 MW in 1993.[54] In 1992, IPPs accounted for more new generating capacity than the vertically integrated utilities.[55]

QF, IPP, and APP facilities had to be financed outside of the cost-of-service rate structure through project financing,[56] which often had to be backed by long-term contracts.[57] FERC aided in this financing effort by establishing policies and procedures that enabled QFs, IPPs, and APPs

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[48] *Id.* at 17,670.

[49] *Id.*

[50] *Id.*

[51] *Id.* at 17,670–17,672.

[52] *Id.* at 17,670–17,678.

[53] Energy Policy Act of 1992, Pub. L. No. 486, § 711, 106 Stat. 2776, 2905–2910 (Oct. 24, 1992).

[54] OATS NOPR, *supra* note 26, at 17,671.

[55] *Id.*

[56] NCEP OPTIONS, *supra* note 27, at 8.

[57] *Id.*

to receive market-based rates (MBRs).[58] Many vertically integrated utilities willingly entered into long-term contracts to purchase electric energy from QFs, IPPs, and APPs at prices that anticipated increasingly higher energy prices.[59]

Unfortunately, foresight as to future energy prices and electric energy market conditions by those who bought and sold electric energy in the post-PURPA competitive wholesale markets was no better than the foresight of regulators and vertically integrated utilities during the late 1960s and early 1970s. Once again, high energy prices stimulated energy conservation efforts and stifled economic growth.[60] As a consequence, demand for electric energy slowed in the face of significant new capacity being brought online by QFs, IPPs, and APPs.[61] Wholesale electric energy prices fell, but many vertically integrated companies could not lower their retail electric energy prices because they were contractually bound to pay QFs, IPPs, and APPs higher-than-market electric energy wholesale prices.[62] Captive customers of the high-priced vertically integrated utilities began to demand access to lower-cost electric energy available in some regions of the United States,[63] and restructuring of the electric energy industry to achieve competitive retail markets was increasingly viewed as necessary to satisfy these demands.[64]

State Retail Choice Initiatives

Commencing in California and expanding to 22 states, state legislators and regulators restructured the electric energy industries in their states.[65] The goal was to free end users to seek the most efficient electric generation service from an array of competitive electric energy suppliers.

To achieve this goal, integrated electric energy utilities were required to financially or functionally unbundle their generation, transmission, and distribution services. Typically, these

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58 OATS NOPR, sup*ra* note 26, at 17,670, 17,671, 17,674.

59 NCEP OPTIONS, *supra* note 27, at 8.

60 *Id.* at 10.

61 *Id.*

62 *Id.* at 10–11.

63 OATS NOPR, *supra* note 26, at 17,675.

64 *Id.*; NCEP OPTIONS, *supra* note 27, at 11.

65 American Bar Association, *Section on State and Local Government Law and Section of the Environment, Energy, and Resources*, *in* CAPTURING THE POWER OF ELECTRIC RESTRUCTURING 28–29 (Joey Lee Miranda, ed., 2009) [hereinafter RESTRUCTURING].

utilities turned over the operation of their transmission systems to ISOs or RTOs to ensure that transmission services were provided on an equal basis to all potential electric energy suppliers.[66] The integrated utilities also either sold much or all of their generating capacity to other companies or turned over the operation of their generating assets to affiliates charged with operating independently from the utilities' remaining operations. From this disaggregation process, electric energy generators emerged from which electric energy end users could purchase their electric energy within a deregulated retail electric energy market.[67]

At the commencement of retail choice initiatives, it was not possible to get all end users to shift immediately to the newly emerging retail electric energy market. As a consequence, the states had to extend traditional electric energy service to most residential and many other small end users. They did so under provider of last resort (POLR) plans, which provided end users who did not seek a competitive substitute with discounted rates so they would share in the presumed benefits of lower retail electric energy rates emerging from the new competitive retail electric energy markets.[68] Over time, these discounted POLR rates set prices below those that eventually emerged from the newly created retail electric energy markets.[69] These low prices have discouraged new competitors from entering the market, thereby creating the need to maintain POLR service for the foreseeable future.[70] Some retail choice states initiated auctions as the means of acquiring electric energy for POLR customers in a manner that exposes them to rates more equivalent to those being set by market forces.[71]

In 2000–2001, California's retail electric energy market was buffeted by rising natural gas prices, the loss of contracted-for electric energy from hydroelectric facilities resulting from drought conditions, and a flawed retail electric energy spot market design that facilitated the endeavors of some generators to manipulate it in ways that drove up electric energy prices.[72] California's experience with electric power shortages and much higher electric energy prices led to an abandonment of retail choice in California and elsewhere.

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66 *Id.* at 29–30.

67 *Id.*

68 The Electric Energy Market Competition Task Force, REPORT TO CONGRESS ON COMPETITION IN WHOLESALE AND RETAIL MARKETS FOR ELECTRIC ENERGY 98–102 (2006).

69 *Id.*

70 *Id.* at 103–106.

71 *Id.* at 107.

72 RESTRUCTURING, *supra* note 65, at 42–45.

It is fair to say that retail choice has not brought to most states the widespread benefits they anticipated receiving. Small and residential customers continue to lack good competitive alternatives to the POLR service they have been receiving. As a consequence, electric energy prices have been volatile and much higher than anyone anticipated. This has led some retail choice states to extend their POLR service past their planned discontinuance dates and discuss the possibility of reregulating.[73]

FERC's Electric Energy Competition Initiatives

Given the laws of physics and today's generating and transmission technologies, electric grids can interconnect electric energy generators and electric energy end users within great territorial expanses.[74] Indeed, currently in the continental United States, electric energy generators are interconnected with electric energy end users within three huge electric networks: the Western Interconnect, the Eastern Interconnect, and the Texas Interconnect.[75]

If the owners and operators of electric energy generation facilities and electric transmission facilities lack market power, electric energy end users, and/or those who procure electric energy on their behalf, should have ready access to a large enough number of electric energy generation service options to enable them to acquire the best possible service at the lowest possible prices.[76] However, transmission facilities have natural monopoly characteristics because entry into transmission markets is difficult and transmission facilities possess scale economies.[77] External costs (environmental and aesthetic) of providing transmission service can be minimized if one or a few large transmission facilities are built within a service area in place of a large number of smaller competing facilities.[78]

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73 *Supra* notes 70, 71.

74 Amicus Curiae Brief of Electrical Engineers, Energy Economist, and Physicists in Support of Respondents at 5–20, *New York v. Federal Energy Regulatory Comm'n*, No. 00-568 (May 31, 2001), which explains the phenomenon of electromagnetic unity of response of interconnected electrical systems, *id.* at 5–17, and describes the evolution of the U.S. electric energy industry as evolving from a time when electric energy utilities consisted of isolated unconnected grids to the present circumstance where most electric energy users and electric energy generators are interconnected within two large interstate grids. ***Id.*** at 17–20.

75 U.S. Department of Energy, U.S. Power Grids, http://www.eere.energy.gov/de/us_power_grids.html (last visited Sept. 18, 2009).

76 *See* NCEP OPTIONS, *supra* note 27, at 2–5.

77 OATS NOPR, *supra* note 26, at 17,675.

78 *Id.*

In addition, competition among competing but interconnected transmission systems operating parallel facilities is inevitably skewed. Because of impedance, the electricity flows each system contracts to handle will partially flow over both systems. Thus, under their transmission contracts, each system receives all of the transmission service revenues but bears only part of the transmission costs.[79]

Utilities that own and operate both electric energy generation and transmission facilities have an incentive to discriminate in the provision of transmission service against those who would offer electric energy generation competition.[80] Similarly, utilities that serve retail end users by purchasing electric energy from wholesale markets rather than generating it have an incentive to discriminate in the provision of transmission service against those who might compete with them for access to sources of low-cost electric energy generation.[81]

In attempting to prevent transmission facilities from being used as anticompetitive weapons, FERC has encountered a variety of discriminatory tactics, including:[82]

- outright refusals to serve;
- protracted negotiations;
- protracted delays in implementing negotiated deals; and
- providing access on a discriminatory basis, including
    - denial of network service,
    - discriminatory pricing,
    - unequal service priority,
    - unreasonable scheduling and balancing provisions,
    - overly restrictive access to firm transmission capacity,
    - inferior ancillary services,
    - unreasonable credit and security terms,

[79] *Id.*

[80] *Id.* at 17,675–17,676.

[81] *Id.*

[82] These discriminatory methods are described at *Id.* at 17,677.

- burdensome reciprocity arrangements, and
- collusion among transmission facility owners to discriminate against those without transmission facilities.

To combat the market power and discriminatory tactics of transmission owners and operators, FERC has pursued two major regulatory initiatives: (a) open-access transmission tariffs (OATTs) that specify rules to reduce market power and discrimination[83] and (b) the formation of ISOs and RTOs that are structured to reduce the potential for discrimination and market power.[84] To further ensure that transmission facilities and their operations facilitate competitive wholesale electric energy markets, FERC has also taken steps to establish a structure of incentives for investing in transmission facilities[85] and to facilitate the acquisition of long-term firm transmission rights within transmission networks managed by RTOs or ISOs.[86]

Inadequate or uncompetitive operation of transmission facilities is not the only means of creating uncompetitive wholesale electric energy markets. Accordingly, FERC has established rules and mechanisms for preventing anticompetitive market behavior and manipulation,[87]

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[83] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmission Utilities (Order No. 888), 61 Fed. Reg. 21,540 (1996) [hereinafter Order 888]; Standardization of Generator Interconnection Agreements and Procedures (Order No. 2003), 68 Fed. Reg. 49,846 (July 24, 2003) [hereinafter Order 2003]; Standardization of Small Generator Interconnection Agreements and Procedures (Order No. 2006), 70 Fed. Reg. 34,190 (May 12, 2005) [hereinafter Order 2006]; Interconnection for Wind Energy (Order No. 661), 70 Fed. Reg. 34,993 (June 2, 2005) [hereinafter Order 661]; Preventing Undue Discrimination and Preference in Transmission Service (Order No. 890), 72 Fed. Reg. 12,266 (Feb. 16, 2007) [hereafter Order 890]; Standards of Conduct for Transmission Providers (Order No. 717), 73 Fed. Reg. 63,796 (Oct. 16, 2008) (hereinafter Order 717].

[84] Regional Transmission Organizations (Order No. 2000), 65 Fed. Reg. 809 (Dec. 20, 1999) [hereinafter Order 2000].

[85] Promoting Transmission Investment through Pricing Reform (Order No. 679), 71 Fed. Reg. 43,294 (July 20, 2006) [hereinafter Order 679].

[86] Long-Term Firm Transmission Rights in Organized Markets (Order No. 681), 71 Fed. Reg. 43,564 (July 20, 2006) [hereinafter Order 681].

[87] Conditions for Public Utility Market Based Rate Authorization Holders (Order 674), 71 Fed. Reg. 9,695 (Feb. 16, 2006) [hereinafter Order 674]; Prohibition of Energy Market Manipulation (Order No. 670), 71 Fed. Reg. 4,244 (Jan. 19, 2006) [hereinafter Order 670] ; *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 105 F.E.R.C. ¶ 61,218 (Nov. 17, 2003) [hereinafter *Market Behavior Order*].

identifying and mitigating nontransmission-related sources of market power,[88] and improving the design of regional wholesale electric energy markets.[89]

OATTs

Despite restrictions on its authority to regulate interstate transmission facilities, from the late 1970s to the mid-1990s FERC granted blanket approval of market-based wholesale electric energy generation rates and permission to merge only on the condition that the entities seeking such benefits, and any of their affiliates that owned or operated transmission facilities, filed OATTs.[90] The nature of the OATT mandate evolved from requiring transmission service providers to treat third parties equally with respect to point-to-point transmission service to requiring them to provide third parties with transmission services, including network service, comparable to the transmission services they and their affiliates enjoyed.[91]

By April 1995, FERC's case-by-case OATT efforts had resulted in only 21 utilities having any form of OATT, and none of these OATTs were of the nondiscriminatory, fully open type that FERC believed was necessary to promote more effective interstate wholesale electric energy competition.[92] As noted above, FERC was aware that discriminatory practices were rife among transmission service providers that had not voluntarily filed OATTs in conjunction with pursuing market-based wholesale electric energy generation rates or mergers.[93] Redressing complaints about discrimination involved a process so time consuming that the relief often came too late to enable the victims to exploit their market opportunities.[94] FERC also believed that continuing with this case-by-case approach would produce a national grid consisting of a patchwork of transmission systems, some with and some without OATTs, that would produce inefficiencies in the provision of transmission service and the construction of new transmission

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88 Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities (Order No. 697), 72 Fed. Reg. 39,904 (June 21, 2007) [hereinafter Order 697].

89 Wholesale Competition in Regions with Organized Electric Markets (Order No. 719), 73 Fed. Reg. 64,100 (Oct. 17, 2008) [hereinafter Order 719]; Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (NOPR), 67 Fed. Reg. 55,452 (Aug. 29, 2002) [hereinafter SMD NOPR].

90 OATS NOPR, *supra* note 26, at 17,671–17,672.

91 *Id.* at 17,672–17,674.

92 *Id.* at 17,671, 17,675 text & n. 140.

93 *Id.* at 17,675–17,677.

94 *Id.* at 17,672, 17,677–17,678.

facilities.[95] Among the inefficiencies feared by FERC was the potential inability to address "pricing parallel flows on a sensible regional basis . . . [through t]he formation of effective regional transmission groups."[96]

Pro Forma OATT (Order No. 888)

On April 24, 1996, FERC issued its pathbreaking Order No. 888.[97] Public utilities engaged in providing interstate transmission service were ordered to file a pro forma OATT containing "minimum terms and conditions of non-discriminatory service."[98] These utilities were also ordered to functionally unbundle their wholesale merchant functions (buying and selling electric energy in wholesale markets) from their transmission function by taking transmission and ancillary services for their new wholesale sales and purchases on the same basis as third parties under the OATT.[99] Entities engaged in providing interstate transmission service that were not subject to FERC's jurisdiction were prohibited from accessing OATT services from jurisdictional public utilities until they agreed to offer the same OATT services.[100] To facilitate functional unbundling, the utilities were required to state separately their rates for wholesale generation, transmission, and ancillary services.[101] FERC claimed jurisdiction over unbundled interstate retail transmission, but it declined to assert jurisdiction over transmission services associated with bundled retail sales of electric energy.[102] Seeking more regional efficiencies and effective prevention of discrimination, FERC encouraged, but did not require, the formation of ISOs.[103]

The OATT provided wholesale electric energy customers with opportunities to use the transmission facilities of their current wholesale electric energy providers to access lower-cost electric energy generators. If wholesale electric energy customers pursued these opportunities, the firms that previously served them faced stranded costs as a result of making investments and

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[95] *Id.* at 17,676.

[96] *Id.*

[97] Order 888, *supra*. note 83.

[98] Order 888, *supra* note 83, at 21,597–21,616.

[99] *Id.* at 21,552.

[100] *Id.* at 21,610–21,615.

[101] *Id.*

[102] *Id.* at 21,624–21,627.

[103] *Id.* at 21,595–21,597.

incurring purchase obligations in anticipation of continuing to serve them.[104] Viewing these potential stranded costs as the consequence of unforeseeable legal and regulatory changes,[105] in Order 888 FERC created mechanisms by which they could be recovered by the firms that suffered them from the departing customers that caused them.[106]

OASIS (Order No. 889)

To ensure that OATTs and Order 888's functional unbundling mandate provided meaningful competitive opportunities, FERC issued a companion order, Order No. 889,[107] to ensure that everyone in need of transmission services had equal access to timely information about transmission operations and that firms truly separated their wholesale merchant function from their transmission function.[108] Public utilities engaged in providing interstate transmission services were required to either establish an Open Access Same-Time Information System (OASIS) or participate in one.[109] Technical standards and protocols were established to ensure the effective and fair operation of OASISs.[110] Detailed standards of conduct governing the behavior of and communications between personnel engaged in wholesale merchant functions and those engaged in interstate transmission functions were established so that a public utility's wholesale merchant arm could not obtain useful transmission operations information that was not equally available to competitors.[111]

The availability of transmission capability is the most important information to be provided transmission customers by OASIS. Accordingly, FERC grappled in Order 889 with how to provide transmission customers with data concerning available transmission capability (ATC) and total transmission capability (TTC).[112] In light of the technical difficulties in providing these data, FERC asked that the industry come up with "consistent methods for

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104 *Id.* at 21,628.

105 Order 888, *supra* note 83, at 21,629–21,630.

106 *Id.* at 21,633–21,664.

107 Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct (Order No. 889), 61 Fed. Reg. 21,737 (1996) [hereinafter Order 889].

108 *Id.* at 21,740–21,741.

109 *Id.* at 21,748–21,755.

110 *Id.* at 21,755–21,760.

111 *Id.* at 21,743–21,748.

112 Order 889, *supra* note 107, at 21,749–21,750.

calculating ATC and TTC" and required transmission providers to calculate them by "a methodology described in . . . [their] tariff[s]" in accordance with "current industry practices, standards and criteria."[113]

Interconnection Rules (Order Nos. 2003, 2006, 661)

"Order . . . 888 did not directly address generator interconnection issues."[114] However, the ability of firms owning or operating generating resources (generators) to interconnect with interstate transmission systems in an effective, efficient, nondiscriminatory manner is essential to developing and maintaining competitive wholesale electric energy markets.[115] In many cases, generators seeking such interconnection faced delays that undermined their competitiveness in the form of "complex, time consuming technical disputes about interconnection feasibility, cost, and cost responsibility."[116] At first, FERC attempted to deal with these disputes on a case-by-case basis, but as the number of such disputes rose, FERC decided that it was necessary to develop a standardized set of interconnection procedures and a standardized interconnection agreement.[117] Accordingly, on October 25, 2001, FERC issued an Advance Notice of Proposed Rulemaking that commenced a nearly five-year endeavor that culminated in the establishment of standard interconnection procedures and agreements for large generation facilities (> 20 MW) in 2003,[118] small generation facilities (≤ 20 MW) in 2005,[119] and wind generators (with capacities > 20 MW) in 2005.[120]

In *Order 2003*, FERC established the standardized interconnection procedures and agreement for large generators, thereby setting a model from which variations were made in 2005 to accommodate the unique aspects of small generators and wind generators. The standardized interconnection procedures include the following steps.[121]

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113 *Id.* at 21,750.

114 Order 2003, *supra* note 83, at 49,848.

115 *Id.*

116 *Id.*

117 *Id.*

118 Order 2003, *supra* note 83.

119 Order 2006, *supra* note 83.

120 Order 661, *supra* note 74.

121 *See* discussion in Order 2003, *supra* note 83, at 49,851–49,852.

- The generator submits an interconnection request to the transmission provider.
- Upon completion of a valid interconnection request, the transmission provider puts it in the queue of outstanding interconnection requests and assigns it a queue position based on when it was received.
- The generator and transmission provider will then participate in a scoping meeting during which they will exchange technical data and discuss technical issues that could affect the selection of a point of interconnection.
- Thereafter, a series of studies will be undertaken by, or at the direction of, the transmission provider to determine the feasibility of the interconnection, assess its impact on the reliability of all affected transmission systems, and develop a list of facility additions or modifications that will be needed to complete the interconnection successfully.
- At the conclusion of the studies, the transmission provider and generator will negotiate a schedule for completing all the necessary construction and system modifications.
- The transmission provider and generator will then enter into an interconnection agreement based on the standardized interconnection agreement established by *Order 2003*, which will specify, among other things, that the generator will pay up front for the costs of completing the interconnection.

The standardized interconnection agreement addresses a number of matters, including:

> the effective date and termination costs; regulatory filings, scope of service, . . .; generator provided services; Interconnection Facilities engineering, procurement, and construction; testing and inspection, . . .; emergency, and disconnect obligations; metering and communications; operations and maintenance; Defaults and indemnifications; transmission crediting; audits; and Dispute Resolution.[122]

Order 2003 also established interconnection service pricing policies designed to promote the construction of new generation facilities, encourage efficient siting decisions, and reduce the ability of nonindependent transmission providers (those who own or operate their own integrated generation facilities) to discriminate against competing generators.[123] Firms seeking to

[122] Order 2003, *supra* note 83, at 49,873.

[123] *Id.* at 49,900–49,904.

interconnect new generation facilities (interconnection customers) are required to pay all interconnection costs up front.[124] Interconnection costs include the costs of constructing interconnection facilities, which are facilities and equipment constructed between the generating facilities and their point of interconnection with the transmission network, and network upgrades needed to accommodate the new generation facilities, which are facilities and equipment constructed at or beyond the point of interconnection between the generation facilities and the transmission network.[125]

For ratemaking purposes, FERC mandated that the costs of interconnection facilities be directly assigned to interconnection customers instead of being rolled into the transmission rate base where they would be shared by all transmission service customers.[126] Assigning these costs directly to the interconnection customers is both fair and efficient because interconnection facilities benefit only those who operate the newly interconnected generation facilities and their generation service customers.[127] Directly assigning interconnection facilities costs also eliminated a discriminatory practice of some nonindependent transmission providers—rolling into the transmission rate base the interconnection facility costs associated with their own new generation facilities while directly assigning such costs to competing generators.[128]

Determining whether network upgrades are required solely to accommodate the interconnection of a new generation facility, who benefits from such upgrades, and how to allocate the costs of such upgrades involves controversial, subjective judgements.[129] Out of fear that the subjectivity of such decisions could facilitate discrimination against competing generators by nonindependent transmission providers, FERC mandated that nonindependent transmission providers refund within five years the interconnection customers' costs of making network upgrades in the form of credits to the interconnection customers' transmission service charges.[130] This mandate not only reduced the ability of nonindependent transmission providers

[124] *Id.* at 49,901.

[125] *Id.*

[126] *Id.*

[127] *Id.*

[128] Order 2003, supra note 83, at 49,901.

[129] *Id.* at 49,901, 49,903–49,904.

[130] *Id.* at 49,903–49,904.

to discriminate in the assignment of network upgrade costs,[131] it also facilitated FERC's continuation of its traditional practice of rolling into the transmission rate bases the costs of network upgrades.[132]

FERC recognized, however, that the rebate and rolled-in network upgrade pricing policy could lead interconnection customers to make inefficient siting decisions and state regulators to reject siting authority for transmission expansions designed to remove transmission congestion outside of the state—expansions that would impose costs on the state's retail customers but provide them with little or no benefits.[133] As a consequence, FERC authorized independent transmission providers (those without their own integrated generation facilities) to experiment with participant funding policies that would directly assign the costs of network upgrades to the transmission service customers who would benefit from them rather than roll those costs into the transmission rate base. It did so because of its belief that independent transmission providers did not have incentives to discriminate in favor of or against any particular interconnection customer.[134]

Upgrades to distribution systems do not benefit all transmission network customers.[135] For that reason, in *Order 2003* FERC mandated that the costs of upgrading jurisdictional distribution facilities to accommodate the interconnection of new generation facilities should be directly assigned to interconnection customers.[136]

In *Order 2006*, FERC established standardized small generator interconnection procedures (SGIP) and a standardized small generator interconnection agreement (SGIA) for generators producing no more than 20 MW.[137] The SGIP and SGIA are essentially modified versions of the standardized interconnection procedures and standardized interconnection agreement established for large generators in *Order 2003*.[138] Thus, *Order 2006* adopts a default

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[131] *Id.*

[132] *See id.* at 49,901, 49,903–49,904.

[133] *Id.* at 49,901, 49,903–49,904.

[134] Order 2003, *supra* note 83, at 49,903–49,904.

[135] *Id.* at 49,904.

[136] *Id.*

[137] Order 2006, *supra* note 83.

[138] *Id.* at 34,194–324,195.

study process (SP) covering the same scoping meeting and study steps applicable to large generators with some simplification and shorter time frames.[139]

Order 2006 establishes fast-track procedures for very small generators ($\leq$ 2 MW) and small inverter-based generators ($\leq$ 10 MW), such as those with solar panels, which produce direct current that must be converted to alternating current.[140] Each procedure applies only to generators that have been certified as safe and reliable by "a nationally recognized testing and certification laboratory."[141] In lieu of the SP, the generators undergo certain technical screens to determine whether they meet reliability and safety prerequisites for being interconnected to the transmission system.[142] Supplemental reviews may be held if the generators do not pass the screens and the transmission provider has lingering concerns about their safety or reliability.[143]

The two processes differ only in that those seeking interconnection of small inverter-based generators receive an "all-in-one" document incorporating aspects of a procedures document and an interconnection agreement that contains some interconnection terms and conditions.[144] Once a generator passes the screens or a supplemental review, the transmission provider extends an interconnection agreement to the small generator before authorizing the interconnection, but it will directly authorize interconnection of a small inverter-based generator.[145] Small inverter-based generators receive a faster track because they can be quickly disconnected from the transmission system if safety and reliability problems occur.[146]

The SGIA adopted by FERC in *Order 2006* is a simplified version of the interconnection agreement used for large generators.[147] It features a reduced insurance obligation and a streamlined dispute resolution process that is sensitive to the fact that small generator projects are unlikely to be completed if they are the subject of expensive and time-consuming

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139 *Id.*

140 *Id.* at 34,190 text & nn. 6, 7.

141 Order 2006, *supra* note 83, at 34,190 n. 6, 34,194–34,196, 34,224.

142 *Id.* at 34,194–34,195, 34,224.

143 *Id.* at 34,195–34,196.

144 *Id.*

145 *Id.* at 34,195–34,196, 34,224.

146 *Id.* at 34,224.

147 *Id.* at 34,194–34,195, 34,197.

arbitration.[148] Both the SGIA and the interconnection terms and conditions applicable to small inverter-based generators adopt the pricing policy mandated by FERC in *Order 2003*.[149]

In recognition that large wind generating facilities (> 20 MW) have distinct operating characteristics that impose unique safety and reliability risks on transmission systems, FERC adopted a special set of interconnection requirements for large wind generators in *Order 661*.[150] Wind generating facilities are distinctly different from conventional generators in that they:

- are nonsynchronous;[151]
- "use induction generators;"[152]
- "consist of several . . . small generators connected to a collector system;"[153]
- respond differently to grid disturbances;[154]
- may shut down when there is "a sudden change in voltage on the transmission system;"[155]
- "can[,in most instances,] only provide reactive power through the addition of external devices;"[156]
- are located in remote areas;[157]
- are usually unmanned;[158]
- have unpredictable rates of output;[159] and
- lack a standard design so that their electrical characteristics vary in relation to their size, location, and the location of other generators.[160]

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[148] Order 2006, *supra* note 83, at 34,194–34,195, 34,200–34,201.

[149] *Id.* at 34,195.

[150] Order 661, *supra* note 83, at 34,994.

[151] *Id.* at 34,994 text & n. 4.

[152] *Id.* at 34,996.

[153] *Id.*

[154] *Id.*

[155] *Id.*

[156] *Id.* at 34,999 n. 27.

[157] *Id.* at 35,003 n. 31, 35,005.

[158] *Id.* at 35,003 n. 31.

[159] Order 661, *supra* note 83, at 35,003 n. 31.

As wind generation facilities have grown in size and number, it has become increasingly important for grid reliability purposes to determine whether they must have the capability of remaining online during times of low voltage[161] and producing reactive power that is dynamic.[162] However, the design changes needed to achieve these capabilities can be expensive. Accordingly, to balance the desire not to impose unnecessary expense on wind generators and the need to preserve grid reliability and safety, FERC mandated in *Order 661* that wind generators achieve the ability to ride out low-voltage occurrences, operate within a power factor range of ± 0.95, and produce dynamic reactive power capability only if the need for these abilities is determined during the System Impact Study.[163]

Historically, wind generators have not had remote supervisory control and data acquisition capability.[164] In light of their increasing numbers, FERC mandated in *Order 661* that wind generators have, at minimum, the capability to receive instructions from transmission providers, but did not require them to achieve the capability of being remotely controlled by transmission providers unless they agreed to do so after good faith negotiations with transmission providers.[165]

OATT Antidiscrimination Modifications (Order No. 890)

By May 2006, FERC had identified flaws in the OATT that it feared were undermining its efforts to remedy discrimination in the provision of transmission services.[166] In February 2007, FERC issued Order No. 890[167] to remedy these flaws[168] and to reinforce the core elements of Order 888.[169] Major concerns addressed in Order 890 included the continued existence of

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160 *Id.* at 35,005.

161 *Id.* at 34,996.

162 *Id.* at 35,000–35,002.

163 *Id.* at 34,998 (low voltage ride-through), 35,000–35,001 (reactive power through a power factor range of ± 0.95), 35,002 (dynamic reactive power).

164 Order 661, *supra* note 83, at 35,002–35,003 & n. 31.

165 *Id.* at 35,003.

166 Preventing Undue Discrimination and Preference in Transmission Service (NOPR), 71 Fed. Reg. 32,636 (June 6, 2006).

167 Order No. 890, *supra* note 83.

168 *Id.* at 12,271–12,278.

169 *Id.* at 12,281–12,285.

opportunities for undue discrimination,[170] transmission congestion and inadequate transmission infrastructure investment,[171] the continued lack of a consistent method for calculating and reporting ATC,[172] discriminatory pricing of imbalances,[173] and inequality in the provision of redispatch and conditional firm service in conjunction with point-to-point transmission service.[174] FERC addressed these concerns with major reforms to promote consistent and transparent ATC calculations;[175] ensure coordinated, open, and transparent transmission planning;[176] provide fairer calculation of energy and generator imbalance charges;[177] and improve point-to-point transmission services.[178]

In addressing the ATC problem, FERC found that the failure of the transmission service providers to develop collectively a consistent method for calculating ATC and to make transparent their individual ATC calculation methodologies created "the potential for undue discrimination in the provision of open access transmission service."[179] FERC also noted its concern that inconsistency in ATC calculation standards threatened the reliability of the "bulk-power system."[180] Accordingly, FERC ordered jurisdictional transmission providers to work with the North American Electric Reliability Corporation (NERC) and the North American Energy Standards Board to improve the consistency and transparency of ATC calculations.[181] To facilitate this collaboration, FERC provided detailed assessments of, and frameworks for dealing with, various aspects of calculating and reporting ATC.[182]

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[170] *Id.* at 12,271–12,274.

[171] *Id.* at 12,275–12,276.

[172] *Id.* at 12,276–12,277 (note, in Order 888, ATC was referred to as available transmission capability).

[173] *Id.* at 12,277.

[174] *Id.* at 12,277–12,278.

[175] Order No. 890, *supra* note 83, at 12,279, 12,294–12,317.

[176] *Id.* at 12,279, 12,317–12,341.

[177] *Id.* at 12,279, 12,344–12,356.

[178] *Id.* at 12,280, 12,381–12,415 (primarily through assuring more equality in the provision of redispatch and conditional firm service).

[179] *Id.* at 12,294.

[180] *Id.*

[181] *Id.* at 12,294.

[182] *Id.* at 12,294–12,317.

FERC justified the need to mandate coordinated, open, and transparent transmission planning by noting the consequences of a national "decline in transmission investment relative to load growth in the ten years since Order No. 888 was issued."[183] These consequences include declines of "transmission capacity per MW of peak demand . . . in every NERC region," widespread reductions in ATC, higher numbers of transmission request denials, increased transmission service interruptions and curtailments, dramatic increases in transmission load relief events, and rising congestion costs in RTO markets.[184] After reiterating how public utilities providing both generation and transmission services had incentives to ignore the transmission capacity needs of potential competitors, FERC documented that the OATT facilitated this discrimination because it does not require transmission service providers to include customers, competitors, and state commissions in their transmission planning process or to make available to customers "the key assumptions and data that underlie [their] transmission plans."[185]

To combat this discrimination and its consequences, FERC required transmission service providers "to submit . . . a proposal for a coordinated and regional planning process that complies with the [nine] planning principles [coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, congestion studies, cost allocation for new projects[186]] and other requirements in this Final Rule. . . . In the alternative, . . . transmission provider[s were permitted to] . . . show that th[eir] existing process[es were] consistent with or superior to the requirements in this Final Rule."[187]

Energy imbalances are the hourly differences "between the scheduled and the actual delivery of energy to a load located within [a transmission service provider's] control area."[188] "[T]he amount of energy taken by load in an hour is variable and not subject to the control of either a wholesale seller or a wholesale requirements buyer."[189] By contrast, generator imbalances are the hourly differences between electric energy scheduled to be delivered by a

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183 Order No. 890, *supra* note 83, at 12,318.

184 *Id.* text & n. 228.

185 *Id.* at 12,318.

186 FERC discussed in detail the nine planning principles at Order 890, *supra* note 74, at 12,322–12,336.

187 Order 890, *supra* note 83, at 12,318.

188 *Id.* at 12,344.

189 Order 890, supra note 83, at 12,344.

generator and the actual electric energy generated.[190] With the exception of generation from intermittent sources such a wind generators,[191] a generator "should be able to deliver its scheduled hourly energy with precision . . . ."[192] To preserve system reliability, both types of imbalances must be corrected by ramping other generation up or down.[193]

FERC has permitted transmission service providers to impose charges on transmission customers who cause energy and generation imbalances. However, FERC found that transmission service providers were in the aggregate imposing a confusingly wide array of imbalance charges,[194] and that many of these charges were higher than necessary to provide incentives to keep energy and generation schedules accurate.[195] Therefore, in Order 890, FERC modified the OATT to include a three-tier imbalance charge provision that "recognizes the link between escalating deviations and potential reliability impacts on the system,"[196] and takes into account that many intermittent generators are "'not dispatchable[,] . . . cannot store [their] fuel[,] and therefore cannot respond to changes in system demand or respond to transmission security constraints.'"[197] The tiers are represented in the following table.[198]

Imbalance Charges by Tiers

			imbalance charge	
	± bandwidth: the greater of		overscheduled	underscheduled
tier	% scheduled energy	MW	% decremental costs	% incremental costs
1	1.5	2	100	100
2	1.5 to 7.5	2 to 10	90	110
3	> 7.5	10	75	125

Under this imbalance charge provision, "intermittent resources are exempt from the third-tier deviation band and . . . pay the second-tier deviation band charges for all deviations greater

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190 *Id.*

191 *Id.* at 12345 text & n. 385, 12,349.

192 *Id.* at 12,344.

193 *Id.* at 12,349.

194 *Id.* at 12,345.

195 Order 890, *supra* note 83, at 12,345.

196 *Id.* at 12,349.

197 *Id.* (citation to internal quote omitted).

198 Data for table taken from a narrative description of the tiers at Order 890, *supra* note 83, at 12,349.

than the larger of 1.5 percent or two megawatts."[199] FERC found that this imbalance charge provision was consistent with the three imbalance charge principles it adopted in Order 890, which are: "(1) The charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger; and (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as waiving the more punitive adders associated with higher deviations."[200]

As transmission capacity declines relative to load, the ability of the transmission provider to grant new requests for long-term firm point-to-point service (long-term service) also declines because, for some hours of the year, transmission capacity will be unable to accommodate both the new customer and all existing customers.[201] Until transmission upgrades capable of handling increased loads are made, the transmission provider could possibly accommodate new long-term firm point-to-point service through planning redispatch or conditional long-term firm point-to-point service (conditional service).[202] "Planning redispatch involves an ex ante determination of whether out-of-merit order generation resources can be used to maintain firm service. Conditional service involves an ex ante determination of whether there are limited conditions or hours under which firm service can be curtailed to allow firm service to be provided in all other conditions or hours."[203]

In proceedings prior to issuing Order 890, FERC found that transmission providers that also provide bundled retail electric energy service have used planning redispatch to accommodate new long-term firm bundled retail electric service (bundled service) customers until such time as transmission upgrades necessary for handling new customers were made.[204] FERC further found that such transmission providers may plan for new bundled retail service in a manner more accommodating than the way it plans, or fails to plan, for new long-term

[199] Order 890, *supra* note 83, at 12,349.

[200] Order 890, *supra* note 83, at 12,349.

[201] *See id.* at 12,381.

[202] *Id.* at 12,380–12,381.

[203] *Id.* at 12,382.

[204] *Id.* at 12,380–12,381.

service.[205] To rectify this discrepancy in treatment, in Order 890, FERC modified the terms under which planned redispatch is offered under the OATT, and mandated that both planned redispatch and conditional service be offered to prospective long-term service customers until transmission upgrades for fully handling them and existing customers are completed.[206]

Under the then-existing OATT, transmission providers were required to accommodate requests for long-term service by either expanding or upgrading its transmission system or planning to redispatch its resources, whichever option was the most economical.[207] Regardless of its economic merit, redispatch was not to be offered if it would "(1) degrade or impair the reliability of service to native load customers, network customers and other transmission customers taking firm point-to-point service or (2) interfere with the transmission provider's ability to meet prior firm contractual commitments to others."[208] In assessing whether planned redispatch would be the most economical and reliable way of accommodating a new long-term service customer, the transmission provider performs a system impact study and a facilities study to identify system constraints on accommodating the new long-term service and redispatch options for overcoming them.[209] "The Commission proposed to modify the existing planning redispatch option by (1) accelerating the study of planning redispatch in the transmission request study process, (2) requiring an estimate of the number of hours of redispatch that may be required to accommodate the requested service, (3) requiring a preliminary estimate of the cost of planning redispatch, and (4) pricing planning redispatch services to facilitate increased availability of the service."[210]

Long-term forecasts of conditions on a transmission system are inherently uncertain and subjective.[211] As a consequence, unless great care is taken, providing long-term planning redispatch and conditional service may detrimentally affect the reliability of service to historic customers.[212] In Order 890, FERC took this uncertainty into consideration by "limit[ing] the

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205 *Id.*

206 Order 890, *supra* note 83, at 12,382–12,383.

207 *Id.* at 12,380.

208 *Id.*

209 *Id.*

210 *Id.* at 12,380–12,381.

211 *Id.* at 12,382.

212 Order 890, *supra* note 83, at 12,382.

availability of [planning redispatch and conditional service] so that their duration is for a time period over which service can be reasonably provided without impairing reliability."[213] In addition, new long-term service customers may receive planning redispatch or conditional service only under "conditions . . . specified in the initial service agreement."[214] New long-term service customers willing to pay their fair share of the expenses of upgrading or expanding the transmission system may receive planning redispatch or conditional service only until the transmission system upgrades or expansions are completed.[215] Transmission providers may review biennially the efficacy of continuing to provide planning redispatch or conditional service to new long-term service customers who will not pay to upgrade or expand the transmission system.[216]

In imposing the modified planning redispatch and conditional service mandates, FERC noted that not only would these mandates and their limits reduce the potential for discrimination in the provision of long-term firm point-to-point service, they would also "help integrate new generation more quickly."[217] FERC believed that the latter benefit would be especially important to bringing renewable generation, such as wind, online as quickly as possible because such facilities "can be constructed more quickly than the transmission upgrades necessary to deliver their power on a firm basis over the long-run."[218]

Modified Standards of Conduct (Order No. 717)

The standards of conduct for electricity transmission providers were changed considerably after they were first established in *Order 889*. In particular, FERC combined the electricity standards with the natural gas standards and required transmission providers to function independently from their marketing and energy employees and affiliates through corporate separation rather than the functional separation required by *Order 889*.[219] These changes made the standards "difficult to enforce and apply." As a consequence, on October 16,

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[213] *Id.* at 12,383.

[214] *Id.*

[215] *Id.*

[216] *Id.*

[217] *Id.* at 12,382.

[218] *Id.*

[219] Order 717, *supra* note 83, at 63,797.

2008, FERC issued *Order 717* in which it ". . . eliminate[d] the concept of energy affiliates[,] eliminate[d] the corporate separation approach in favor of the employee functional approach . . .[,] and . . . refocus[ed the Standards] on areas where there is greatest potential for affiliate abuse."[220] The refocused standards establish three broad rules designed to ensure that transmission providers that also engage in electric energy sales do not interact with their marketing personnel and affiliates in ways that disadvantage competitors: (a) the independent functioning rule,[221] (b) the no conduit rule,[222] and (c) the transparency rule.[223]

Under the independent functioning rule, employees personally engaged in the "planning, directing, organizing or carrying out of day-to-day transmission operations . . ."[224] are prohibited from interacting with the transmission provider's and its affiliates' employees, contractors, consultants, or agents who engage day-to-day[225] in interstate selling (for resale or otherwise) "of electric energy or capacity, demand response, virtual transactions, or financial or physical transmission rights . . . ."[226] However, bundled retail sales of electric energy, including those made by firms designated as POLRs, are excluded from the definition of marketing functions.[227] The no conduit rule reinforces the independent functioning rule by prohibiting transmission providers' marketing function employees from receiving nonpublic transmission function information from persons who are not transmission function employees, including those who may act as conduits for transmission providers as well as employees, contractors, consultants, and agents of transmission providers and their marketing affiliates.[228]

Finally, *Order 717's* transparency rule requires transmission providers to post on their websites in a timely fashion information that could be relevant in mitigating or preventing anticompetitive exchanges of information between employees performing transmission functions

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220 Order 717, *supra* note 83, at 63,797–63,798.

221 *Id.* at 63,801–63,816.

222 *Id.* at 63,816–63,817.

223 *Id.* at 63,817–63,822.

224 *Id.* at 63,801.

225 *Id.* at 63,807–63,808.

226 *Id.* at 63,802.

227 *Id.* at 63,802, 63,805–63,806.

228 Order 717, *supra* note 83, at 63,816–63,817.

and employees and affiliate employees engaged in marketing functions.[229] Important data to be posted include:

- nonpublic transmission information that has been disclosed to marketing function personnel;[230]
- notice of tariff waivers that the transmission provider "grants in favor of an affiliate;"[231]
- notice of a transmission customer's consent to allow the transmission provider to disclose the transmission customer's nonpublic transmission information to the transmission provider's marketing function personnel, plus a statement that the transmission provider did not provide the transmission customer with any benefits in return for the consent;[232]
- "names and addresses of all the transmission provider's affiliates that employ or retain marketing function employees;"[233] and
- names and job titles of all the transmission provider's transmission function employees.[234]

RTOs and ISOs: Structural Remedies

Nearly four years after establishing the OATT in *Order 888*, FERC issued *Order 2000* to promote vigorously the creation of RTOs as structural remedies to emerging engineering and economic inefficiencies and continued opportunities for discrimination within the nation's wholesale electricity markets.[235] The engineering and economic inefficiencies resulted from stresses being placed on the nation's transmission grids by many vertically integrated utilities divesting their generating facilities, significant public utility mergers, increasing numbers of new market participants, significant increases in the volume of trade in wholesale electricity markets, and state experiments with retail competition.[236] Discrimination, real or perceived, continued

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229 *Id.* at 63,817–63,822.

230 *Id.* at 63,820–63,821.

231 *Id.* at 63,818–63,819.

232 *Id.* at 63,821.

233 *Id.*

234 *Id.* at 63,821–63,822.

235 Order 2000, *supra* note 75, at 823–825.

236 *Id.* at 813–815.

despite the introduction of the OATT by *Order 888* because vertically integrated utilities still had incentives to use their transmission facilities in ways that protected their generation facilities from competition, and the functional unbundling required by the OATT was proving to be difficult to implement, monitor, and enforce.[237] Manifestations of these problems included:

- increasing numbers of transmission line loading relief procedures to remedy grid overloading;[238]
- slowing rates of increase in transmission capacity in the face of growing generation capacity and electricity demands;[239]
- an unprecedented price spike in Midwest spot market wholesale electric energy prices in 1998;[240] and
- a lack of market confidence that inhibited market participants from
    - sharing information crucial to maintaining grid reliability with integrated transmission providers,
    - seeking competitive alternatives among existing generation facilities, and
    - investing in new generation capacity.[241]

In light of the foregoing problems, FERC found that the formation of "[a]ppropriate regional transmission institutions could (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation."[242] To promote the formation of appropriate RTOs, FERC established four minimum characteristics and eight minimum functions of effective RTOs; a collaborative process to bring together all interested parties in the quest for voluntarily forming RTOs; and guidance for transmission ratemaking policies with respect to *pancaked* rates, access charges, congestion

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237 *Id.* at 823–825.

238 *Id.* at 814.

239 *Id.*

240 *Id.*

241 *Id.* at 824–825.

242 Order 2000, *supra* note 75, at 811.

pricing, performance-based regulation (PBR), and incentive pricing).[243] FERC also required all jurisdictional public utilities that were not yet participating in a regional transmission entity to file either a proposal for forming or participating in an RTO conforming to Order 2000 requirements or a description of efforts exerted, plans made, and obstacles encountered in attempting to join or create an RTO.[244] However, FERC did not make joining an RTO mandatory.[245]

According to FERC, the four minimum characteristics of an effective RTO are (a) independence, (b) scope and regional configuration, (c) operating authority, and (d) short-term reliability.[246] The effective RTO must be able to perform the following eight minimum functions: (a) tariff administration and design; (b) congestion management; (c) parallel path flow; (d) ancillary services; (e) OASIS, TTC, and ATC; (f) market monitoring; (g) planning and expansion; and (h) interregional coordination.[247]

RTO Minimum Characteristics (Order No. 2000)

The *independence* characteristic is designed to insulate the RTO from control by any market participant or class of market participant.[248] A market participant is essentially any entity with interests that could be significantly affected by an RTO's activities.[249] To ensure this independence, FERC established limits on ownership and standards for independent decisionmaking.[250]

An RTO possesses the *scope and regional configuration* characteristic if it has sufficient size to "achieve the regulatory, reliability, operational, and competitive objectives [established

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243 *Id.* at 811–812.

244 *Id.* at 812.

245 *Id.* at 834–836.

246 *Id.* at 811 (list), 841–859 (discussion of Independence), 859–864 (discussion of Scope and Regional Configuration), 864–867 (discussion of Operational Authority), 867–875 (discussion of Short-Term Reliability).

247 *Id.* at 811 (list), 876–877 (discussion of Tariff Administration and Design), 877–888 (discussion of Congestion Management), 888–890 (discussion of Parallel Path Flow), 890–897 (discussion of Ancillary Services), 897–898 (discussion of OASIS, TTC, and ATC), 898–905 (discussion of Market Monitoring), 905–910 (discussion of Planning and Expansion), 910–911 (discussion of Interregional Coordination).

248 Order 2000, *supra* note 75, at 850.

249 *Id.*

250 *Id.* at 850–859.

by *Order 2000*].”[251] FERC stated that in evaluating the adequacy of an RTO’s boundaries, it would “consider the extent to which the boundaries:”

- facilitate the performance of essential RTO functions and the achievement of RTO goals,
- encompass one contiguous geographic area,
- encompass a highly interconnected portion of the grid,
- deter the exercise of market power,
- recognize trading patterns,
- take into account existing regional boundaries (e.g., NERC regions) to the extent consistent with the Commission’s goals for RTOs,
- encompass existing regional transmission entities,
- encompass existing control areas, and
- take into account international boundaries.[252]

An RTO has sufficient *operational authority* if it has the authority to control the key transmission functions of the transmission facilities under its control and assumes the responsibility for being the security coordinator for its region.[253] Key transmission functions over which the RTO must have operational authority include “switching transmission elements into and out of operation in the transmission system (e.g., transmission lines and transformers), monitoring and controlling real and reactive power flows, monitoring and controlling voltage levels, and scheduling and operating reactive resources…. As security coordinator, the RTO will assume responsibility for: (1) performing load-flow and stability studies to anticipate, identify and address security problems; (2) exchanging security information with local and regional entities; (3) monitoring real-time operating characteristics such as the availability of reserves, actual power flows, interchange schedules, system frequency and generation adequacy; and (4) directing actions to maintain reliability, including firm load shedding.”[254]

[251] *Id.* at 862–863.

[252] *Id.* at 863–864.

[253] Order 2000, *supra* note 75, at 866.

[254] *Id.* at 867.

An adequate "RTO must have exclusive authority for maintaining the short-term reliability of the grid that it operates."[255] This means that the RTO must have exclusive authority over interchange scheduling,[256] redispatching to ensure grid reliability,[257] and transmission maintenance approval.[258]

RTO Minimum Functions (Order No. 2000)

The *tariff administration and design* function calls on the RTO to "be the sole provider of transmission service and sole administrator of its own open access tariff."[259] This means that the RTO has exclusive authority to approve requests for transmission service and new interconnections.[260]

An RTO performs the *congestion management* function adequately by establishing congestion market mechanisms,[261] which must "ensure that (1) the generators that are dispatched in the presence of transmission constraints are those that can serve system loads at least cost, and (2) limited transmission capacity is used by market participants that value that use most highly."[262] In this regard, FERC extolled the virtues of locational marginal pricing (LMP) hedged with a system of financial transmission rights (FTRs).[263]

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[255] *Id.* at 874.

[256] *Id.* at 874.

[257] *Id.* at 874–875.

[258] *Id.* at 875.

[259] *Id.* at 877.

[260] *Id.*

[261] Order 2000, *supra* note 75, at 887.

[262] *Id.*

[263] *Id.*

Locational marginal pricing is a mechanism for providing price signals in areas experiencing transmission congestion that prevents loads from receiving electric energy from the least-cost generators. The LMP contains an energy component equal to the cost of providing the last increment of electric energy demand from the least-cost generator available in the system plus a congestion component equal to the difference between the energy component and the cost of supplying electric energy from the least-cost generator that could actually deliver energy to the congested location. See discussion of locational marginal pricing on the ISO-NE website, http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/lmp/index.html (last visited May 11, 2010).

Financial transmission rights are financial instruments entitling holders to receive a share of any excess congestion payments collected by an RTO. The congestion revenue equals the remainder left after subtracting the congestion component paid to the generator from the congestion component paid by the load. FTRs enable market participants to hedge against congestion charges they may encounter resulting from congestion at various locations within the transmission system. See discussion of financial transmission rights on the ISO-NE website, http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/ftrs_arrs/index.html (last visited May 11, 2010).

FERC mandated that RTOs establish procedures for addressing parallel flow problems.[264] In this regard, FERC warned that such procedures were likely to reduce contract path options within RTO regions.[265]

RTOs are called upon to be the ancillary service POLRs under the *ancillary service* function.[266] This means that the RTO must have control over ancillary service issues within its region, including the amounts of each service needed, the location where they are to be provided, and the operations of all facilities that provide ancillary services.[267] In addition, FERC required RTOs to develop competitive ancillary service markets and real-time balancing markets.[268]

Under the *OASIS–TTC–ATC* function, RTOs are to be their regions' sole OASIS operators.[269] They are also required to calculate all ATC values for transmission facilities under their control.[270]

FERC mandated that RTOs engage in extensive market monitoring.[271] To adequately perform the *market monitoring* function, the RTO must develop and implement a market monitoring plan that:

- captures and reports objective market information;
- contains mechanisms for improving the efficiency, design, and competitiveness of all markets;

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264 *Id.* at Order 2000, *supra* note 84, at 889.

265 *Id.* at 889–890.

266 *Id.* at 895. In Order 888, FERC mandated that six ancillary services be offered in the OATT, including (a) Scheduling, System Control, and Dispatch Service; (b) Reactive Supply and Voltage Control from Generation Sources Service; (c) Regulation and Frequency Response Service; (d) Energy Imbalance Service; (e) Operating Reserve-Spinning Reserve Service; and
(f) Operating Reserve-Supplemental Reserve Service. Order 888, *supra* note 83, at 21,580. For a detailed discussion of these ancillary services, see *id.* at 21,580–21,585. Transmission providers were required to offer the first two ancillary services to all of their transmission service customers, but they were required to offer the remaining four ancillary services to their transmission customers that served loads within their transmission control areas. *Id.* at 21,587–21,588.

267 *Id.* at 896.

268 *Id.*

269 Order 2000, *supra* note 75, at 898.

270 *Id.*

271 *Id.* at 904–905.

- identifies all markets that the RTO will monitor, and examine their structure and the degree to which market participants comply with rules, possess market power, or abuse market power; and
- assesses how the RTO markets affect the markets operated by others and vice-versa.[272]

Under the *planning and expansion* function, RTOs have the responsibility for transmission planning and for encouraging expansion of the transmission grid.[273] To fulfill this function, the RTO must "(1) [e]ncourage market-motivated operating and investment actions for preventing and relieving congestion; (2) accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities, coordinated with programs of existing Regional Transmission Groups (RTGs) where necessary; and (3) file a plan with the Commission with specified milestones that will ensure that it meets the overall planning and expansion requirement . . . ."[274]

The *interregional coordination* function requires RTOs to assume active leadership in coordinating their activities with those of other electric energy markets and transmission grids in other regions.[275] To do this, the RTO must help integrate "reliability practices within an interconnection and market interface practices among regions."[276]

RTO Ratemaking Policies (Order No. 2000)

If they are to provide a valuable service, RTOs must adopt ratemaking policies that make the use of their transmission grids more economical and efficient. To that end, in *Order 2000*, FERC adopted ratemaking policies calling on RTOs to "eliminate regional rate pancaking; manage congestion; internalize parallel flow paths; deal effectively and fairly with transmission owning utilities that choose not to participate in RTOs; and provide incentives for transmission owning utilities to efficiently operate and invest in their systems."[277]

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272 *Id.*

273 *Id.* at 909.

274 *Id.*

275 Order 2000, supra note 75, at 911.

276 *Id.*

277 *Id.* at 913.

Without RTOs, transmission customers face multiple access charges for transmission services that must use more than one transmission system.[278] These pancaked rates so increase the cost to load-serving entities (LSEs) of accessing remote generators that the areas within which generators can effectively compete are significantly reduced.[279] Thus, FERC mandated that RTOs should strive, as much as possible, to establish a single rate for transmission services throughout the area covered by the transmission systems they operate.[280]

The area of effective competition for electric energy could be even more expanded if RTOs with contiguous areas of control would cooperate so that transmission service customers could use generators within the control area of one RTO to provide electricity to load located within the control area of another RTO without paying multiple access charges. [281] To that end, FERC encouraged RTOs to engage in reciprocal waivers of access charges in ways that "are reasonable in terms of cost recovery, cost shifting, efficiency, and discrimination."[282]

Order 2000 also mandates that RTOs achieve a uniform access charge applicable throughout the region within which they operate.[283] Given that the individual transmission systems that the RTO manages may have differing cost structures, this is a difficult task.[284] As a consequence, FERC authorized the use of transitional license plate rates.[285] License plate rates allow transmission service customers who access an RTO's grid at a particular location within the grid to pay a single access charge to gain the use of the entire grid. However, the access charge could vary among locations.[286]

In mandating that RTOs perform the function of congestion management, FERC extolled the virtues of LMP used in conjunction with FTRs.[287] FERC continued to do so in its discussion

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[278] *Id.* at 915.

[279] *Id.*

[280] Order 2000, *supra* note 75, at 915.

[281] *Id.* at 916.

[282] *Id.*

[283] *Id.* at 917.

[284] *Id.*

[285] *Id.*

[286] *Id.*

[287] *Id.* at 887. For definitions of locational marginal pricing and financial transmission rights, see *supra* note 263.

of congestion pricing, but declined to mandate its use and instead encouraged RTOs to experiment with congestion management techniques.[288]

For a variety of reasons, owners and operators of transmission systems located within an RTO's operational region may refuse to join the RTO. Allowing these non-RTO transmission systems to access the RTO-managed systems at the RTO's uniform access rate would allow them to receive RTO benefits without "accepting any of the burdens of participation in the RTO."[289] Accordingly, FERC announced that it would "permit an RTO and its transmission-owning public utility members to make the case that it is just and reasonable to charge individual system rates to a transmission customer who is a nonparticipating transmission owner in its RTO region."[290]

To encourage RTOs to make efficient operating and investment decisions, FERC announced that transmission rates should increasingly be set through the use of PBR.[291] PBR involves setting cost and performance benchmarks that will reward or penalize the RTO on the basis of whether its performance fails to meet or exceeds the benchmarks.[292] In recognition of the difficulty of creating PBR frameworks, FERC did not require RTOs to file PBR proposals.[293] It did, however, establish five guidelines for RTOs that did wish to file PBR proposals.[294]

- "PBR should not be applied piecemeal.
- PBR should encompass both rewards and penalties.
- PBR rewards and penalties should create incentives for an RTO to make efficient operating and investment decisions, and should not compromise system reliability.
- The benefits of PBR should be shared between the RTO and its customers.
- To the extent possible, the rewards and penalties should be prescribed in advance based on known and measurable benchmarks."

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288 Order 2000, *supra* note 84, at 917.

289 *Id.* at 919.

290 *Id.*

291 *Id.* at 920–922.

292 *Id.* at 920.

293 *Id.* at 921.

294 *Id.* at 921–922.

Standard Market Design Initiative

As of July 31, 2002, FERC had fully approved only one RTO.[295] Discouraged by the slow rate of RTO formation and the continued prevalence of discrimination in the provision of transmission services, FERC initiated proceedings to bring the transmission component of retail bundled electric energy service under its jurisdiction, modify the OATT to require all transmission providers to offer a network access service similar to the type of transmission service it expected RTOs to offer, and require all transmission owners and operators who had not joined an RTO to turn over operations of their transmission systems to an independent entity.[296] Through this initiative, known as the Standard Market Design (SMD) initiative, FERC also provided a vision of an SMD for wholesale electric markets.[297] The SMD was well received by most independent generators, independent marketers, and market participants in regions where RTO-style business patterns were emerging.[298] It was, however, controversial in areas where RTOs and ISOs had not been formed. Bending to political pressure generated by the controversy, FERC ultimately terminated the SMD initiative in mid-2005.[299]

Currently, four RTOs—ISO New England (ISO-NE), PJM, Midwest ISO (MISO), and Southwest Power Pool (SPP)—operate large regional transmission grids.[300] ISO-NE operates within the entirety of six New England States,[301] one of which, Massachusetts, is one of this study's subject states. PJM operates within 13 states located mainly in the Mid-Atlantic and Midwest regions, including the entirety of 5 states, 2 of which, New Jersey and Virginia, are subject states;[302] in most of 2 subject states, Ohio and Pennsylvania; in parts of 3 subject states,

295 SMD NOPR, *supra* note 89, at 44,458.

296 *Id.* at 55,454–55,458.

297 *Id.* at 55,455.

298 *See* CAPTURING THE POWER OF ELECTRIC RESTRUCTURING 13 (Joey Lee Miranda ed., 2009) [hereinafter RESTRUCTURING POWER].

299 Order Terminating Proceeding, 70 Fed. Reg. 43,140, 43,140–43,141 (July 19, 2005).

300 *See* Information about these RTOs on their own websites, as follows: MISO, http://www.midwestiso.org/home (last visited May 11, 2010); PJM, http://www.pjm.com/home.aspx (last visited May 11, 2010); SPP, http://www.spp.org/index.asp (last visited May 11, 2010); and ISO-NE, http://www.iso-ne.com/ (last visited May 11, 2010). In addition, specific information as to the states in which these RTOs operate are found at FERC, Regional Transmission Organizations(RTO)/Independent System Operators (ISO), http://www.ferc.gov/industries/electric/indus-act/rto.asp (last visited May 11, 2010); FERC: Map-Regional Transmission Organizations, http://www.ferc.gov/market-oversight/mkt-electric/overview/elec-ovr-rto-map.pdf (last visited May 11, 2010).

301 Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

302 The other states are Delaware, Maryland, and West Virginia.

Illinois, Indiana, and North Carolina; and in fragmentary parts of 3 states, 1 of which, Michigan, is a subject state.[303] MISO operates in 15 states, ranging from the Mid-Atlantic to the upper Northwest, including the entirety of 1 state, Wisconsin; in most of 6 largely Midwest states, 3 of which, Illinois, Indiana, and Michigan, are subject states;[304] in parts of 3 states, 1 of which, Missouri, is a subject state;[305] and in fragmentary parts of 5 states, 2 of which, Ohio and Pennsylvania, are subject states.[306] SPP operates within eight states, including the entirety of two states;[307] in most of one state;[308] and in parts of five states, two of which, Missouri and Texas, are subject states.[309]

In each of the nation's three most populous states, all of which are subject states, an ISO unique to that state operates in the entirety or most of the state. These ISOs are the California Independent System Operator Corp. (CAISO), which operates in most of California; the New York Independent System Operator (NYISO), which operates in the entirety of New York; and the Electric Reliability Council of Texas (ERCOT), which operates in most of Texas.[310]

No RTOs or ISOs operate in large areas of the United States encompassing all or parts of 28 states in the South, West, and Great Plains. None operates in the entirety of 12 states, 4 of which, Arizona, Florida, Georgia, and Washington, are subject states;[311] in most of 9 states, 1 of which, North Carolina, is a subject state;[312] in parts of 3 states, 2 of which, California and Missouri, are subject states;[313] and in fragmentary parts of 4 states, 1 of which, Texas, is a subject state.[314]

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303 The other two states are Kentucky and Tennessee.

304 The other three states are Iowa, Minnesota, and North Dakota.

305 The other two states are Montana and South Dakota.

306 The other three states are Arkansas, Kentucky, and Wyoming.

307 Kansas and Oklahoma.

308 Nebraska.

309 The other three states are Arkansas, Louisiana, and New Mexico.

310 *See* information about the three ISOs on their own websites, as follows: NYISO, http://www.nyiso.com/public/index.jsp (last visited May 11, 2010); CAISO, http://www.caiso.com/ (last visited May 11, 2010); and ERCOT, http://www.ercot.com/ (last visited May 11, 2010).

311 The other eight states are Alabama, Colorado, Idaho, Mississippi, Nevada, Oregon, South Carolina, and Utah.

312 The other eight states are Arkansas, Kentucky, Louisiana, Montana, New Mexico, South Dakota, Tennessee, and Wyoming.

313 The other state is Iowa.

314 The other three states are Minnesota, Nebraska, and North Dakota.

Long-Term Transmission Rights (Order No. 681)

On August 8, 2005, the Energy Policy Act of 2005 (EPA of 2005) was enacted into law.[315] Section 1233 of this act required FERC to ensure that LSEs with long-term power supply arrangements could obtain long-term firm transmission rights in transmission organizations (TOs), defined as entities approved by FERC for the operation of transmission facilities, with organized electric markets.[316] Demand for this mandate arose from the uncertainty as to the availability and cost of long-term firm transmission service caused by RTOs/ISOs with organized electric markets managing congestion through the use of LMP coupled with FTRs. [317] FTRs help transmission customers hedge against the costs of paying the congestion component of LMPs.[318] When the EPA of 2005 was enacted, FTRs were not made available for terms longer than one year.[319] LSEs alleged that the uncertainty caused by the lack of long-term FTRs made it difficult for them to finance long-term power arrangements.[320]

To comply with the EPA of 2005's long-term transmission right mandate and address the concerns of LSEs desiring to obtain and retain long-term power supply arrangements, FERC issued *Order 681* on July 20, 2006.[321] TOs with organized markets were required to make available long-term firm transmission rights, support the expansion or upgrade of grid transfer capacity so it will be sufficient to accommodate new long-term firm transmission rights, and "explain how their transmission system planning and expansion policies will ensure that long-term firm transmission rights . . . remain feasible over their entire term."[322] *Order 681* applies only to TOs that operate "auction-based day ahead and real-time wholesale [electric energy]

315 Pub. L. No. 109-58, 119 Stat. 594 (August 8, 2005) [EPA of 2005].

316 EPA of 2005, § 1233(b), 119 Stat. 960, which required FERC to carry out the mandate of the newly created FPA § 217(b)(4), codified at 16 U.S.C. § 824q(b)(4), to enable "load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to [satisfy their service obligations."

317 Long-Term Firm Transmission Rights in Organized Electricity Markets (Order No. 681), *supra* note 86, at 43,564, 43,565–43,566.

318 *Id.* at 43,566.

319 Order 681, *supra* note 294, at 43,566.

320 *Id.*

321 Order 681, *supra* note 86.

322 *Id.* at 43,567.

market[s]" and use LMPs and FTRs to manage congestion.[323] Thus, SPP is excluded because it does not offer a day-ahead market.[324]

The long-term transmission rights supported by *Order 681* are firm point-to-point long-term transmission rights that will enable LSEs to "hedge particular long-term power supply arrangements."[325] TOs must offer long-term FTRs, even though the way they manage the transmission facilities under their control provides the equivalent of long-term physical transmission rights because FERC interpreted *firm* to apply to "quantity and price".[326] The duration of long-term FTRs must be sufficient to support LSEs' long-term power supply arrangements.[327] Accordingly, FERC required TOs to be able to offer FTRs with at least a 10-year term and to set term and renewal policies such that the LSEs' long-term supply arrangements are adequately supported.

To ensure that long-term transmission rights, especially long-term FTRs, remain feasible throughout their terms, and to provide new long-term transmission rights that cannot be accommodated by the TOs' current transmission systems, FERC required TOs to include in their long-term expansion plans any expansions and upgrades that will enable existing long-term transmission rights to remain feasible without their holders having the costs of these expansions and upgrades assigned directly to them.[328] However, in the short-term, TOs are not required to favor LSEs with long-term power arrangements over other LSEs,[329] and they may deny requests that prove to be infeasible given current system and market conditions and "place reasonable limits on the amount of capacity [they] will offer as long-term rights."[330] LSEs requiring more long-term transmission rights than can be accommodated in the short term may obtain them by agreeing to support any necessary expansions and upgrades, and in return TOs must award them long-term transmission rights for the newly created transfer capability.[331] Once long-term FTRs

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323 *Id.* at 43,568–43,569.

324 *Id.* at 43,568–43,569.

325 *Id.* at 43,579.

326 *Id.* at 43,575.

327 *Id.* at 43,591–43,592.

328 Order 681, *supra* note 86, at 43,612–43,613.

329 *Id.* at 43,567–43568, 43,597–43,598.

330 *Id.* at 43,566–43,567.

331 *Id.* at 43,566–43,567, 43,613.

are awarded, they must be fully funded so they truly provide cost certainty.[332] TOs are given discretion as to how to allocate the start-up costs of the fully funded mandate and provide equivalent cost security to holders of short-term FTRs.[333]

Recognizing the technical difficulties of providing long-term firm transmission rights, FERC did not establish exact specifications for these rights. Instead it issued seven guidelines that long-term firm transmission rights must meet,[334] as follows:[335]

1. The long-term firm transmission right should specify a source (injection node or nodes), sink (withdrawal node or nodes), and quantity (MW).
2. The long-term firm transmission right must provide a hedge against day-ahead LMP congestion charges or other direct assignment of congestion costs for the period covered and the quantity specified. Once allocated, the financial coverage provided by a financial long-term right should not be modified during its term (the "full funding" requirement) except in the case of extraordinary circumstances or through voluntary agreement of both the holder of the right and the TO.
3. Long-term firm transmission rights made feasible by transmission upgrades or expansions must be available upon request to any party that pays for such upgrades or expansions in accordance with the TO's prevailing cost allocation methods for upgrades or expansions.
4. Long-term firm transmission rights must be made available with term lengths (and/or rights to renewal) that are sufficient to meet the needs of LSEs to hedge long-term power supply arrangements made or planned to satisfy a service obligation. The length of term of renewals may be different from the original term. TOs may propose rules specifying the length of terms and use of renewal rights to provide long-term coverage, but must be able to offer firm coverage for at least a 10-year period.
5. LSEs must have priority over non-LSEs in the allocation of long-term firm transmission rights that are supported by existing capacity. The TO may propose

[332] *Id.* at 43,567, 43,583–45,585.

[333] *Id.* at 43,567, 43,583–45,585.

[334] *Id.* at 43,567–43,568.

[335] 18 C.F.R. § 42.1(d)(1)-(7).

reasonable limits on the amount of existing capacity used to support long-term firm transmission rights.

6. A long-term transmission right held by an LSE to support a service obligation should be reassignable to another entity that acquires that service obligation.
7. The initial allocation of the long-term firm transmission rights shall not require recipients to participate in an auction.

Transmission Investment Incentives

Thriving wholesale electric energy markets cannot be sustained without available, reliable, and congestion-free transmission facilities. As of 2003, investment in transmission facilities was less in real dollars than it had been in 1975, yet the electric load on the nation's grid had more than doubled during this time frame.[336] In 2005, Congress enacted a new transmission incentive provision, § 219 of the Federal Power Act (FPA),[337] as a part of the EPA of 2005.[338]

Section 219 directed FERC to establish within a year rules providing jurisdictional transmission utilities with "incentive-based (including performance-based) rate treatments . . . for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[339] Congress required that these rate incentive rules:

- promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;
- provide a return on equity (ROE) that attracts new investment in transmission facilities (including related transmission technologies);

[336] Order 679, *supra* note 85, at 43,296.

[337] 16 U.S.C. § 824s.

[338] EPA of 2005, § 1241, 119 Stat. 961.

[339] 16 U.S.C. § 824s(a).

- encourage the deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and
- allow recovery of
    - all prudently incurred costs necessary to comply with mandatory reliability standards . . .
    - all prudently incurred costs related to transmission infrastructure development.[340]

FERC was also directed to provide incentives to encourage transmitting and electric utilities to join a TO[341] and to make sure that all incentive rates approved are "just and reasonable and not unduly discriminatory."[342]

On July 20, 2006, FERC complied with the incentive rate mandate by issuing new transmission incentive rate rules in *Order 679*.[343] To qualify for incentive rates, applicants must establish a nexus between their projects and either improving transmission reliability or reducing transmission congestion.[344] Transmission projects enjoy a rebuttable presumption that they qualify for incentive rates if they are approved through a fair and open regional planning process that considered whether they would improve reliability or reduce congestion, are located in a National Interest Transmission Corridor, or have received construction approval from a state commission or siting authority.[345]

FERC offered applicants for incentive rates two time-saving and risk-reducing procedures. They can seek, preconstruction, a declaratory order that the project qualifies for incentive rates and that particular rate incentives are justified.[346] Favorable findings on these issues cannot be reopened in the subsequent rate approval proceeding after the project is completed.[347] Alternatively, incentive rate applicants can seek to have their incentive rates

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340 16 U.S.C. § 824s(b)(1)–(4).

341 16 U.S.C. § 824s(c).

342 16 U.S.C. § 824s(d).

343 Order 679, *supra* note 85.

344 *Id*. at 43,300.

345 *Id*. at 43,302.

346 *Id*. at 43,304.

347 *Id*.

approved through a single-issue rate proceeding that examines only the merits of the incentive rates.[348] The single-issue option is a departure from FERC's past practice of requiring transmission utilities to file comprehensive rate cases whenever they want a change in their rates.[349] As a consequence, FERC noted that, in some circumstances, the need to harmonize the sought-after incentive rates is pressing enough to require the applicant to commence a comprehensive rate proceeding or to do so by a date-certain.[350]

Order 679 does not guarantee that any utility will receive incentive rates, "but rather identifies specific incentives that the [FERC] will allow when justified in the context of individual declaratory orders or [rate proceedings] . . . ."[351] The incentives available to all jurisdictional utilities in conjunction with their qualified projects are:

- ROE in the upper range of reasonableness on projects for which normal rates of return are inadequate;[352]
- 100 percent construction work in progress in the rate base for prudently incurred transmission construction costs;[353]
- expensing precommercial operations costs;[354]
- hypothetical rate bases;[355]
- accelerated depreciation;[356]
- 100 percent recovery of prudently incurred construction costs for plants abandoned for reasons beyond the applicants' control, including projects that were rejected outright by local, state, and federal regulatory bodies;[357] and

348 *Id*. at 43,304–43,305.

349 Order 679, *supra* note 85, at 43,305.

350 *Id*. at 43,317.

351 *Id*. at 43,295.

352 *Id*. at 43,306–43,307.

353 *Id*. at 43,308–43,309.

354 *Id*.

355 *Id*. at 43,310–43,311.

356 *Id*. at 43,312–43,313.

357 *Id*. at 43,314–43,315.

- deferred recovery of costs associated with new transmission investments that could not be recovered in a normal time frame because of rate freezes.[358]

Transcos are "stand-alone transmission company[ies], approved by the Commission, which sell[ ] transmission service at wholesale and/or on an unbundled retail basis, regardless of whether [they are] affiliated with another public utility."[359] *Order 679* provides two incentives to encourage the formation of Transcos and to encourage Transcos to make new transmission investments:

- ROE in the upper range of reasonableness[360] and
- accumulated deferred income taxes to offset capital gains taxes that could discourage firms from selling transmission facilities to Transcos at book value.[361]

FERC stated that it would consider the level of the Transcos' independence from other market participants when determining where in the range of reasonableness to set their ROEs.[362]

Order 679 makes available, on a case-by-case basis, all of the previously discussed investment incentives to those who would deploy advanced transmission technologies.[363]

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358 Order 679, *supra* note 85, at 43,315–43,316.

359 *Id*. at 43,318.

360 *Id*. at 43,320–43,321.

361 *Id*. at 43,322–43,323.

362 *Id*. at 43,322.

363 *Id*. at 43,326–43,327. FERC stated that advanced technologies included 18 that were identified as such in the EPA of 2005 plus any other emerging transmission technology FERC finds to be appropriate for rate incentives. *Id*. at 43,327. The 18 advanced technologies identified in the EPA of 2005 include:

- high-temperature lines (including superconducting cables);
- underground cables;
- advanced conductor technology (including advanced composite conductors, high-temperature low-sag conductors, and fiber optic temperature-sensing conductors);
- high-capacity ceramic electric wire, connectors, and insulators;
- optimized transmission line configurations (including multiple phased transmission lines);
- modular equipment;
- wireless power transmission;
- ultra high-voltage lines;
- high-voltage DC technology;
- flexible AC transmission systems;
- energy storage devices (including pumped hydro, compressed air, superconducting magnetic energy storage, flywheels, and batteries);
- controllable load;
- distributed generation (including solar photovoltaic, fuel cells, and microturbines);
- enhanced power device monitoring;

However, FERC declined to provide incentives unique to these technologies.[364] It also declined to provide incentives for undertaking advanced transmission technology research and development.[365] But FERC required firms seeking transmission investment rate incentives to file a technology statement describing what advanced technologies had been considered and explaining why those technologies not pursued were rejected.[366]

To encourage membership in TOs,[367] FERC stated that it would consider, on a case-by-case basis, providing ROE-based rate incentives to utilities that would become or remain TO members.[368] It declined to establish a specific incentive to encourage public utilities to join regional planning organizations.[369]

Competitive Wholesale Electric Energy Markets

Market-Based Rates (Order No. 697)

Bilateral wholesale electric energy contracts featuring MBRs have been the hallmark of the nation's interstate wholesale market since FERC began using MBRs as an incentive for vertically integrated utilities to provide OATTs.[370] To be just and reasonable, MBRs must not be the product of electric energy providers exercising market power or engaging in market manipulation.[371] To deal with these potential market abuses, FERC developed a four-pronged analysis to assess "whether

8. . . . the seller and its affiliates lack, or have adequately mitigated, market power in generation;

- direct system state sensors;
- fiber optic technologies;
- power electronics and related software (including real-time monitoring and analytical software); and
- mobile transformers and mobile substations.

EPA of 2005, § 1223, 119 Stat. 953, codified at 42 U.S.C. § 16422.

364 *Id*. at 43,327.

365 *Id*. at 43,328.

366 Order 679, *supra* note 85, at 43,327.

367 *Id*. at 43,330.

368 *Id*.

369 *Id*.

370 *See* OATS NOPR, *supra* note 26, at 17,671–17,672; SMD NOPR, *supra* note 89, at 55,455.

371 *See* Order 697, *supra* note 88, at 39,907; *Market Behavior Order*, *supra* note 87, at 62,142–62,143.

9. . . . the seller and its affiliates lack, or have adequately mitigated, market power in transmission;
10. . . . the seller or its affiliates can erect other barriers to entry; and
11. . . . there is evidence involving the seller or its affiliates that relates to affiliate abuse or reciprocal dealing."[372]

Concerned that this framework might not be adequate for ensuring just and reasonable wholesale electric energy prices, FERC commenced proceedings to assess whether and how it should be modified in April 2004.[373]

On June 21, 2007, FERC issued *Order 697*, which revised its standards for granting MBRs for "wholesale sales of electric energy, capacity, and ancillary services."[374] *Order 697* addressed measures to identify and mitigate[375] horizontal market power (i.e., competition within the wholesale electric energy market),[376] vertical market power (i.e., the ability to leverage market power in transmission or with respect to a resource critical to power generation),[377] and affiliate abuse (i.e., transactions between a franchised public utility with captured customers and an affiliate that disadvantages the captured customers).[378]

In *Order 697*, FERC stated that sellers of wholesale electric energy will be presumed to have market power in their relevant wholesale electric energy market if they fail either of two screens: the *market share indicative screen* or the *pivotal supplier indicative screen*. The market share screen measures "whether a seller has a dominant position in the market based on the number of megawatts of uncommitted capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire relevant market."[379] A seller's market share is deemed to be dominant if it is at least 20 percent.[380] The pivotal supplier screen measures whether, at the

[372] Order 697, *supra* note 88, at 39,907.

[373] *Id*.

[374] *Id*.

[375] *See* discussion of Mitigation issues at *id.* at 39,975–39,402.

[376] *Id*. at 39,909–39,952.

[377] Order 697, *supra* note 88, at 39,952–39,960.

[378] *Id*. at 39,960–39,975.

[379] *Id*. at 39,909.

[380] *Id*. at 39,916.

time of the annual peak for the balancing authority area, "demand cannot be met without some contribution of supply by the seller or its affiliates."[381]

FERC also held that a seller who fails a screen may demonstrate, through the use of a *delivered price test* (DPT) that it does not have market power.[382] The DPT identifies potential suppliers to a market by assessing their economic capacity based on "market prices, input costs and transmission availability."[383] Market shares and market concentration are calculated based on each supplier's economic capacity and available economic capacity in relation to the sum of all suppliers' economic capacity.[384] Market concentration is calculated using the Herfindahl–Hirschman Index (HHI), which is the sum of the squares of each seller's market share (e.g., in a market with six sellers, one with a 30 share, one with a 20 share, two with a 15 share, and two with a 10 share, the HHI will be $1950 = 30^2 + 20^2 + 2(15^2) + 2(10^2)$).[385] A market is deemed not to be concentrated if the HHI is less than 2500.[386] The seller is deemed to be pivotal if the sum of the rival seller's economic capacity is less than the load level of the destination market.[387] A seller that is not pivotal with a market share less than 20 percent in a market with an HHI less than 2500 will be deemed to lack market power.[388]

With respect to vertical market power, FERC stated that it will continue to rely on the filing of OATTs to mitigate any potential market power arising out of the ownership and control of transmission facilities.[389] However, violations of the OATT can lead to an assertion that the violator has used its transmission facilities to gain a competitive advantage in the electric energy market so as to affect its right to charge MBRs.[390]

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381 *Id*. at 39,909.

382 *Id*. at 39,917–39,919.

383 *Id*. at 39,918.

384 Order 697, *supra* note 88, at 39,917–39,918.

385 *Id*. at 39,918.

386 *Id*. at 39,918, 39,920.

387 *Id*. at 39,918.

388 *Id*.

389 *Id*. at 39,953.

390 *Id*. at 39,954.

FERC will continue to assess whether a seller can erect other barriers to entry.[391] In that regard, FERC has conclusively determined that sellers cannot erect barriers to entry into the electric energy market by owning or controlling or being affiliated with an owner or controller of natural gas and oil supply, including interstate natural gas transportation and oil transportation.[392] Therefore, sellers will not have to file a description or statement about their ownership or control over these inputs.[393] But FERC will continue to require such descriptions and statements about their ownership or control over intrastate natural gas transportation, intrastate natural gas storage or distribution facilities, sites for generation capacity development, and sources of coal supplies and the transportation of coal supplies such as barges and rail cars.[394]

FERC announced that it would no longer consider affiliate abuse when doing an MBR analysis, but sellers authorized to receive MBRs must comply with a code of affiliate restrictions.[395] These restrictions apply to franchised public utilities with captive customers and their market-regulated power sales affiliates.[396] FERC will scrutinize power sales between the covered entities using such criteria as direct head-to-head competition between the affiliate and its rivals; prices that nonaffiliates were willing to pay or receive; benchmarks set by prices; terms and conditions of sales made by rival nonaffiliates; and participation in a truly competitive solicitation process that is transparent, involves well-defined products, evaluates bids evenhandedly, and "is designed and evaluated by an independent entity."[397] The covered entities must, as much as possible, function separately from one another.[398] If the covered entities share market information of a nature that could cause harm to the captured customers, they must disclose it to the public immediately.[399] Sales of nonpower goods and services must be at prices that are either at cost or the market price, whichever is higher.[400]

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391 *Id*. at 39,957.

392 *Id*.

393 Order 697, *supra* note 88, at 39,957.

394 *Id*. at 39,957–39,958.

395 *Id*. at 39,960.

396 *Id*. at 39,969.

397 *Id*. at 39,967–39,968.

398 *Id*. at 39,970–39,971.

399 *Id*. at 39,971–39,974.

400 *Id*. at 39,974–39,975.

Order 697 continues FERC's past policy of mitigating market power with cost-based default mitigation prices.[401] These default mitigation prices are the incremental cost plus 10 percent for sales no more than one week,[402] an embedded "up to" rate for sales greater than one week but less than one year,[403] and a embedded cost rate for sales over one year.[404] However, sellers subject to mitigation may sell at MBRs in markets where they do not have market power, including sales for export at the metered boundary of the market in which they are subject to mitigation.[405]

Bid-Based Spot Markets

In its SMD proceeding, FERC presented a vision of bid-based spot markets for electric energy and certain ancillary services.[406] The markets included a day-ahead market and a real-time market.

Buyers and sellers participating in the day-ahead market would place bids for the volumes of electric energy they believed they would buy or sell the following day.[407] A market-clearing price would be set at the bid of the seller with the highest-cost generation facilities needed to serve the last willing purchaser.[408] All sellers would receive that price regardless of their bids, and all buyers would pay that price regardless of their bids.[409]

In the real-time market, buyers and sellers would make bids based on differences between the amount of electric energy they scheduled to buy or sell the day before and the amount of electric energy they would actually be willing or able to buy or sell in real time.[410] In effect, this

[401] Order 697, *supra* note 88, at 39,985.

[402] *Id*. at 39,977–39,978.

[403] *Id*. at 39,980–39,981.

[404] *Id*. at 39,981.

[405] *Id*. at 39,994–39,998, 40,001–40,002.

[406] SMD NOPR, *supra* note 89, at 55,487–55,551. The ancillary service markets proposed were for regulation and frequency response, spinning operating reserve, and supplemental operating reserve. *Id*. at 55,491.

[407] *Id*. at 55,487.

[408] *Id*. at 55,490–55,492.

[409] *Id*.

[410] *Id*. at 55,493, 55,495.

market would function as a bid-based balancing service market.[411] The market-clearing price would be set the same way it was in the day-ahead market.[412]

Concerned that market manipulation or design flaws could make the markets uncompetitive or inefficient, FERC proposed market mitigation tools with which to approximate the results of competitive markets and the establishment of market monitoring units (MMUs) to monitor market performance and the behavior of market players.[413] Although FERC did not finalize its SMD initiative, today, four RTOs (MISO, PJM, SPP, and ISO-NE) and three ISOs (NYISO, CAISO, and ERCOT) operate organized energy and ancillary service markets more or less along the lines envisioned in the SMD.[414]

Market Behavior Rules

After analyzing the causes of the 2000–2001 disturbances in the western electric market, FERC promulgated six market behavior rules and attached them to all MBR tariffs.[415] These rules are as follows.[416]

> 1. Unit Operation: Seller will operate and schedule generating facilities, undertake maintenance, declare outages, and commit or otherwise bid supply in a manner that complies with the Commission-approved rules and regulations of the applicable power market. Compliance with this Market Behavior Rule 1 does not require Seller to bid or supply electric energy or other electricity products unless such requirement is a part of a separate Commission-approved tariff or requirement applicable to Seller.

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411 SMD NOPR, *supra* note 89, at 55,493.

412 *Id.* at 55,493–55,495.

413 *Id.* at 55,503–55,510.

414 *See* Information about these RTOs on their own websites, as follows: MISO, http://www.midwestiso.org/home (last visited May 11, 2010); PJM, http://www.pjm.com/home.aspx (last visited May 11, 2010); SPP, http://www.spp.org/index.asp (last visited May 11, 2010); and ISO-NE, http://www.iso-ne.com/ (last visited May 11, 2010). *See* information about the three ISOs on their own websites, as follows: NYISO, http://www.nyiso.com/public/index.jsp (last visited May 11, 2010); CAISO, http://www.caiso.com/ (last visited May 11, 2010); and ERCOT, http://www.ercot.com/ (last visited May 11, 2010). For good overviews of these markets, see RESTRUCTURING POWER, *supra* note 298, at 45–53 (PJM), 53–56 (NYISO), 56–62 (ISO-NE), 63–68 (MISO), 68–74 (CAISO), 74–77 (SPP), and 77–80 (ERCOT).

415 *Market Behavior Order*, *supra* note 87, at 62,173.

416 *Id.* at 62,170–62,171.

2. Market Manipulation: Actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products are prohibited. Actions or transactions undertaken by Seller that are explicitly contemplated in Commission-approved rules and regulations of an applicable power market (such as virtual supply or load bidding) or taken at the direction of an ISO or RTO are not in violation of this Market Behavior Rule. Prohibited actions and transactions include, but are not limited to:

a. prearranged offsetting trades of the same product among the same parties, which involve no economic risk and no net change in beneficial ownership (sometimes called “wash trades”);

b. transactions predicated on submitting false information to transmission providers or other entities responsible for operation of the transmission grid (such as inaccurate load or generation data; or scheduling non-firm service or products sold as firm), unless Seller exercised due diligence to prevent such occurrences;

c. transactions in which an entity first creates artificial congestion and then purports to relieve such artificial congestion unless Seller exercised due diligence to prevent such an occurrence; and

d. collusion with another party for the purpose of manipulating market prices, market conditions, or market rules for electric energy or electricity products.

3. Communications: Seller will provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, or Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercised due diligence to prevent such occurrences.

4. Reporting: To the extent Seller engages in reporting of transactions to publishers of electricity or natural gas price indices, Seller shall provide accurate and factual information, and not knowingly submit false or misleading information or omit material information to any such publisher, by reporting its transactions in a manner consistent with the procedures set forth in the Policy Statement issued by the Commission in Docket No.PL03-3 and any clarifications thereto. Seller shall notify the Commission within 15 days of the effective date of this tariff provision of

> whether it engages in such reporting of its transactions and update the Commission within 15 days of any subsequent change to its transaction reporting status. In addition, Seller shall adhere to such other standards and requirements for price reporting as the Commission may order.
>
> 5. Record Retention: Seller shall retain, for a period of three years, all data and information upon which it billed the prices it charged for the electric energy or electric energy products it sold pursuant to this tariff or the prices it reported for use in price indices.
>
> 6. Related Tariffs: Seller shall not violate or collude with another party in actions that violate Seller's market-based rate code of conduct or Order No. 889 standards of conduct, as they may be revised from time to time.

Market Manipulation Rules (Order No. 670)

Section 1283 of the EPA of 2005 made it "unlawful for any entity . . . directly or indirectly, to use or employ, in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission, any manipulative or deceptive device or contrivance . . . in contravention of such rules and regulations as the Commission may prescribe as necessary or appropriate in the public interest or for the protection of electric ratepayers."[417] On January 16, 2006, FERC issued *Order 670*, in which it promulgated new energy market manipulation rules, as follows.

> (a) It shall be unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission,
>
> (1) To use or employ any device, scheme, or artifice to defraud,
>
> (2) To make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or

[417] EPA of 2005, § 1283, codified at 16 U.S.C. § 824v.

> (3) To engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity.[418]

After promulgating these rules, FERC then rescinded Market Behavior Rules 2 and 6 after finding that the new antimanipulation rules of *Order 670* made them superfluous.[419] FERC also moved Market Behavior Rules 1, 3, 4, and 5 from MBR tariffs to the Code of Federal Regulations.[420]

RTO and ISO Energy Market Improvements (Order No. 719)

In October 2008, FERC issued *Order 719* to improve the performances of the organized electric energy markets operated by four RTOs and two ISOs.[421] Specifically, FERC mandated reforms to improve the operations of these markets "in the areas of demand response, long-term power contracting, market monitoring policies," and the responsiveness of RTOs and ISOs to their stakeholders and customers.[422]

Demand response resources involve the willingness and ability of electric energy consumers to reduce or curtail their electric energy consumption during times of potential shortages in response to economic incentives. Finding that demand resources were encountering barriers to participation in the organized electric markets, FERC issued mandates requiring the RTOs and ISOs operating those markets to treat demand response resources in ways comparable to their treatment of energy supply resources.[423] To that end, it required the RTOs and ISOs to accept bids from demand resources to supply ancillary services if they are capable of providing the services and submit bids at or below the market-clearing price.[424]

To ensure comparability of treatment, FERC required the RTOs and ISOs "to allow demand response resources to specify limits on the duration, frequency, and amount of their service in their bids."[425] FERC opined that this mandate put demand resources on the same level

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418 Order 670, *supra* note 87, at 4258. These rules are now found at 18 C.F.R. § 1c.2.

419 Order 674, *supra* note 87, at 9,695–9,697.

420 *Id.*; Market Behavior Rules 1, 3, 4, & 5 are now found at 18 C.F.R § 35.37(a)–(d).

421 Order 719, *supra* note 89.

422 *Id.* at 64,101.

423 Order 719, *supra* note 89, at 64,103.

424 *Id.* at 64,107.

425 *Id.* at 64,110.

as generators because generators are allowed to specify "price, quantity, startup and no-load costs, and minimum downtime between starts."[426] RTOs and ISOs were also required to exempt buyers from deviation charges if they consumed less during a real-time market period than their day-ahead market bids in response to an RTO or ISO declaration of an operating reserve shortage or a call for load reductions to prevent operating reserve shortages.[427] To facilitate participation by demand resources in the bidding process, FERC ordered the RTOs and ISOs to permit aggregators of retail customers (ARCs) to enter demand response bids on behalf the retail customers they represent. However, ARC bids have to meet a fairly lengthy set of criteria designed to make sure that they meet the same requirements as others, are verifiable, and do not run afoul of legal prohibitions.[428]

In times of shortage, market mitigation price caps may be imposed. FERC found that, during times of operating reserve shortages, the capped prices did not reflect enough of the value of electric energy. Accordingly, it ordered the RTOs and ISOs to change their market rules for times of operating reserve shortages and evaluate them as to whether they will:

- improve reliability by reducing demand and increasing generation during periods of operating reserve shortage;
- make it more worthwhile for customers to invest in demand response technologies;
- encourage existing generation and demand resources needed during an operating reserve shortage to remain in business;
- encourage the entry of new generation and demand resources;
- provide comparable treatment and compensation to demand resources during periods of operating reserve shortages; and
- have provisions for mitigating market power and deterring gaming behavior, including, but not limited to, the use of demand resources to discipline bidding behavior to competitive levels during periods of operating reserve shortages.[429]

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426 *Id.*

427 *Id.* at 64,114.

428 Order 719, *supra* note 89, at 64,119-64,120.

429 *Id.* at 64,130.

FERC considers the ability of buyers and sellers to enter into long-term electric energy contracts essential to having well-functioning electric energy markets.[430] To facilitate these negotiations, FERC ordered each RTO and ISO to dedicate a portion of its website to publishing the offers of market participants to enter into long-term electric energy contracts.[431]

Order 719 contains reforms for strengthening the market monitoring capabilities of the MMUs of RTOs and ISOs. RTOs and ISOs were ordered to provide their MMUs with the resources and information needed to perform their functions, including full access to RTO or ISO databases and the right of exclusive control over MMU-created data.[432] To foster MMU independence, FERC required (a) MMUs to report to RTO or ISO boards instead of to management[433] and (b) RTOs and ISOs to relieve MMUs of tariff administration and mitigation duties.[434] FERC updated the MMUs' core tasks to include evaluating "market rules, tariff provisions and market design elements;" reviewing and reporting on electric energy market performance; and identifying and reporting the behavior of market participants that warrants an investigation.[435] To ensure that MMU personnel have no conflicts of interest that would compromise their ability to perform their duties, FERC required RTOs and ISOs to adopt ethical standards largely geared toward prohibiting MMU personnel from having financial or professional interest in, or affiliations with, market participants.[436] FERC also imposed some MMU communications requirements, including requiring MMUs to prepare state-of-the-market reports annually and quarterly, respond to tailored information requests from state agencies unless they are designed to aid state enforcement actions, and keep confidential their referrals to FERC.[437]

Under *Order 719*, RTOs and ISOs are required to "establish a means for customers and other stakeholders to have a form of direct access to the board of directors."[438] The goal is to

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430 *Id.* at 64,133.

431 *Id.* at 64,134.

432 Order 719, *supra* note 89, at 64,139.

433 *Id.* at 64,140.

434 *Id.* at 64,143.

435 *Id.* at 64,141.

436 *Id.* at 64,144-64,145.

437 *Id.* at 64,148-64,153.

438 *Id.* at 64,154.

make RTOs and ISOs more responsive to their constituents. To that end, FERC ordered RTOs and ISOs to submit compliance filings that will be assessed in terms of their inclusiveness, fairness in balancing diverse interests, representation of minority positions, and ongoing responsiveness.[439]

Descriptions of Current Electric Energy Markets in the Subject States

Key characteristics of the electric energy markets of each subject state include:

- the electric energy market structure in terms of
    - the degree to which RTOs and ISOs operate within the state;
    - the degree to which the state has mandated restructuring of the electric power industry to help end users select the entities that generate the electric energy they consume from deregulated retail electric energy markets;
- the capacity of electric generators operating within the state;
- the net generation of electric energy within the state;
- the electric energy available to end users and its disposition;
- the composition of retail electric energy sales;
- the composition of retail electric energy purchases; and
- the levels of emissions of important air pollutants, including
    - carbon dioxide (CO_2),
    - sulfur oxides (SO_x), and
    - nitrogen oxides (NO_x).

Data reported are for 2007 because this was the last year of "normal" economic activity before the nation's recent great recession. Therefore, the electric energy data reported are likely to be more reflective of electric energy capacity, production, consumption, and pricing in normal economic times than are the data for more recent years.

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439 *Id.* at 64,157.

Market Structure

The two most important aspects of market structure influencing the range of electric energy supply choices of wholesale electric energy purchasers and electric energy end users are:

- the degree to which RTOs and ISOs operate in the states in which they are located and
- whether those states have, by law, restructured the electric power entities operating therein to unbundle the electric energy generation function from the electric energy transmission and distribution functions so that electric energy end users can choose which entity shall generate the electric energy they consume from an array of competing LSEs.

As noted in part 2.2.2.5.2 above, to the extent that RTOs and ISOs remove obstacles to transmitting electric energy over long distances free from congestion, pancake rates, and discriminatory practices, the most efficient electric energy generators will have a wider wholesale market within which sell their services, and wholesale electric energy purchasers will have access to lower-cost electric energy generation services that previously were unavailable because of dysfunctional transmission markets. As noted in part 2.2.2.4 above, in those states where restructuring has opened up good retail choice options for all retail electric energy end users, electric energy generators may seek to serve electric energy end users directly or through mediating LSEs on the basis of their generating efficiencies free from obstacles erected by a local electric utility monopoly.

RTOs and ISOs

Four interstate RTOs (ISO-NE, PJM, MISO, and SPP) operate within the United States. Each of these entities organizes wholesale competitive electric energy markets with varying degrees of success by performing the RTO functions and complying with the RTO mandates described in the discussion under the heading of RTOs & ISOs: Structural Remedies (pages 36 – 50).

Table 1 shows the degree to which RTOs and ISOs operate within the states subject to this study. They operate within the entirety of nine subject states, with four states involving just one RTO or ISO (Massachusetts: ISO-NE; New York: NYISO; New Jersey: PJM; Virginia: PJM) and five states involving PJM and MISO (Ohio and Pennsylvania: mostly PJM with MISO in fragmentary parts; Illinois and Indiana: mostly MISO with PJM in parts; and Michigan: mostly MISO with PJM in fragmentary parts). RTOs and ISOs operate in most of three subject states—California (CAISO); Missouri (MISO and SPP); and Texas (ERCOT)—but no RTO or ISO operates in parts of California or Missouri or in fragmentary parts of Texas. PJM operates in parts of North Carolina, but no RTO or ISO operates in most of North Carolina or all of Arizona, Florida, Georgia, and Washington.

Table 1. RTO and ISO Operation in the Subject States

	RTOs/ISOs							
States	ISO-NE	NYISO	PJM	MISO	SPP	ERCOTT	CAISO	None
Massachusetts	A							
New York		A						
New Jersey			A					
Virginia			A					
Ohio			M	Sf				
Pennsylvania			M	Sf				
Illinois			S	M				
Indiana			S	M				
Michigan			Sf	M				
Texas					S	M		Sf
California							M	S
Missouri				S1	S2			S3
North Carolina			S					M
Arizona								A
Florida								A
Georgia								A
Washington								A

Notes: A, all; M, most; S, some; Sf, fragmentary. Missouri has designations S1 through S3 because some areas are not covered by an RTO and other areas are covered by two different RTOs, neither of which is dominant.

Sources: Federal Energy Regulatory Commission (FERC), Regional Transmission Organizations (RTO)/Independent System Operators (ISO), http://www.ferc.gov/industries/electric/indus-act/rto.asp; FERC: Map—Regional Transmission Organizations, http://www.ferc.gov/market-oversight/mkt-electric/overview/elec-ovr-rto-map.pdf.

Retail Choice

As noted in the earlier discussion of State Retail Choice Initiatives, some 22 states engaged in the process of restructuring the electric energy markets within their borders in an attempt to achieve meaningful retail choice for their resident electric energy end users.[440] Table 2

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[440] U.S. Energy Information Administration, Electricity Restructuring by State, http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html (January, 2010) (last visited February 27, 2010).

shows that 8 subject states—Illinois, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania, and Texas—are among the 12 still actively pursuing deregulation of retail electric energy markets and retail choice.[441] Three subject states—Arizona, California, and Virginia—have suspended their deregulation and retail choice efforts. Six subject states—Florida, Georgia, Indiana, Missouri, North Carolina, and Washington—have not been active in pursuing deregulation and retail choice.

In the nine states without retail choice, electric energy end users generally receive electricity from a traditional electric utility monopoly (investor-owned utilities [IOUs], electric cooperatives [or, coops], or municipal electric energy systems). These LSEs may not have ready access to interstate wholesale electric energy generation services, in part because they may be able to control their in-state transmission grid so as to maximize their wholesale selling and purchasing opportunities at the expense of other LSEs.

Table 2. Electricity Restructuring by State

State	Active, not active, or suspended	Deregulation (yes, no, suspended)	Retail choice (yes, no, suspended)	Last activity
Illinois	A	Y	Y	Dec-07
Massachusetts	A	Y	Y	Apr-09
Michigan	A	Y	Y	Jun-08
New Jersey	A	Y	Y	Feb-08
New York	A	Y	Y	Jul-08
Ohio	A	Y	Y	Jan-09
Pennsylvania	A	Y	Y	Jan-10
Texas	A	Y	Y	May-09
Florida	N	N	N	Dec-01
Georgia	N	N	N	Jun-98
Indiana	N	N	N	Nov-00
Missouri	N	N	N	Jul-02
North Carolina	N	N	N	Mar-02
Washington	N	N	N	Dec-07
Arizona	S	S	N	Jun-07
California	S	S	S	Dec-08
Virginia	S	S	S	Apr-07

441 *Id.*

Source: http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html

RTO, ISO, and Retail Choice Market Patterns

In combination, the decisions of electric energy utilities, IPPs, and transmission companies to join RTOs or ISOs, as well as the decisions of state legislators and regulators to provide resident electric energy end users with meaningful retail choice, have produced seven different RSO, ISO, and Retail Choice Market Patterns among the 17 subject states. Three of these patterns feature retail choice—total RTO coverage, total statewide ISO coverage, and mostly statewide ISO coverage. The other four patterns lack retail choice—mostly RTO coverage, mostly statewide ISO coverage, some RTO coverage, and no RTO or ISO coverage.

Retail Choice Market Patterns

Six subject states—Illinois, Massachusetts, Michigan, New Jersey, Ohio, and Pennsylvania—are still actively pursuing retail choice and have interstate RTO or ISO operations throughout their territories. To the extent that interstate RTOs and ISOs and retail choice function well, end users in these states have access, directly or through the services of mediating LSEs, to a broader array of electric energy generating services.

New York has implemented a statewide ISO (NYISO) and retail choice. As a consequence, New York electric energy wholesale purchasers should have less obstructed access to competitive generation services provided by entities operating in New York, and electric energy end users should have the same opportunities as wholesale purchasers to access these competitive generation services directly. The absence of RTO operations within New York deny New York wholesale purchasers and electric energy end users less restricted access to generation services on a regional basis.

Texas has implemented retail choice and has its own intrastate RTO operating throughout most of the state. Although Texas electric energy end users do not have access to electric service generators in other states, through ERCOT they should have broader access to electric service generators within the nation’s largest state by territory.

No Retail Choice Market Patterns

Virginia has suspended its retail choice efforts, and Indiana has not actively pursued retail choice. But LSEs serving their resident electric energy end users should have access to a broad array of interstate wholesale electric generating service options because of RTO operations throughout their territories.

RTOs operate in most of Missouri and some of North Carolina. So LSEs serving electric energy end users in most of Missouri and part of North Carolina should have opportunities similar to those of wholesale purchasers in Virginia and Indiana.

In California, the suspension of retail choice efforts and the operation of only an intrastate ISO in most of the state may limit somewhat the ability of LSEs serving resident electric energy end users to access interstate wholesale electric energy generating options. But CAISO operations should make it easier for these LSEs to access wholesale electric energy generating options in most of California.

Finally, in the four subject states without retail choice or RTOs or ISOs—Arizona, Florida, Georgia, and Washington—electric energy end users are served by LSEs that do not have ready access to interstate wholesale markets for generating services. These LSEs also may be traditional electric utility monopolists that manipulate access to their transmission to limit the wholesale sales and purchase opportunities of other entities. In the worst case scenario, LSEs in these states are inefficient monopolists that serve captive customers who cannot pursue less costly sources of electric energy if they are dissatisfied with the electric energy services they are receiving.

Market Structure Implications for Renewable Sources of Electric Energy

Some end users are so philosophically dedicated to helping to reduce the greenhouse gas emissions that are driving climate change that they are willing to pay higher prices for electric energy service to promote renewable sources of electric energy. RTOs, ISOs, and retail choice markets should facilitate the aggregation of these climate change warriors across vast interstate distances so that entities wishing to build and operate electric energy generators fueled by renewable sources will have enough customers to secure financing and operate profitably.

Similarly, RTO and ISO wholesale markets should be able to facilitate the aggregation of LSEs seeking to satisfy renewable energy portfolio standards or other renewable energy mandates if the states that imposed these standards and mandates permit them to be satisfied by purchases of electric energy from out-of-state generators fueled by renewable sources. In addition, RTO and ISO markets are more likely than smaller wholesale markets to have the load-balancing generating resources needed to handle the intermittent operations of renewable sources of electric energy generation, such as wind and solar. However, to the extent that RTOs, ISO, retail choice, and RTO or ISO wholesale markets operate as intended to promote vigorous price competition, they will impose competitive disadvantages on high-cost electric energy generated from renewable sources.

As noted previously, in states without RTOs or ISOs and retail choice, electric energy end users may continue to be served by traditional electric utility monopolists who are subject to traditional cost-of-service or rate-of-return rate regulation. These monopolists could, if permitted or ordered to by state regulators or state laws, pass on to their captive customers the higher costs of generating electric energy from renewable sources by including such generators in their rate bases.

Electric Energy Generating Capacity

Electric energy generating capacity is the maximum amount of electric energy that a power plant can instantaneously generate. The aggregate capacity of all power plants connected to an electric grid determines the maximum aggregate demand for electric energy that can be handled by the grid at any moment in time. Below are data detailing aggregate capacities within each state of power plants fueled by various sources of primary energy.

Aggregate Electric Energy Generating Capacity from All Primary Energy Sources

With respect to total aggregate generating capacity, Texas has the most with 101,937 MW, and Massachusetts has the least with 13,558 MW (Table 3). For each primary fuel source, the range of the percentage of the state's aggregate generating capacity it accounts for is as follows.

- Coal: High = 73.12% (Indiana); Low = 0.61% (California)
- Petroleum: High = 23.14% (Massachusetts); Low = 0.01% (Washington)
- Natural gas: High = 69.80% (Texas); Low = 10.25% (Washington)
- Other gases: High = 2.26% (Indiana); Low = 0.00% (10 states)
- Nuclear power: High = 26.63% (Illinois); Low = 0.00% (Indiana)
- Hydro power: High = 74.55% (Washington); Low = 0.02% (New Jersey)
- Other renewables: High = 8.99% (California); Low = 0.06% (Arizona)
- Pump storage: High = 13.75% (Virginia); Low = 0.00% (5 states)
- Other: High = 0.40% (Florida); Low = 0.00% (13 states)

Table 3. 2007 Capacity (MW and Percentage) by Primary Fuel Source for Subject States

State	Coal	Petroleum	N gas	O gases	Nuclear	Hydro	O renew	Pump st	Other	∑
	5,818	93	12,845		3,872	2,720	16	216		**25,580**
AZ	**22.74%**	**0.36%**	**50.22%**	**0.00%**	**15.14%**	**10.63%**	**0.06%**	**0.84%**	**0.00%**	
	389	754	38,556	262	4,390	10,041	5,734	3,688		**63,814**
CA	**0.61%**	**1.18%**	**60.42%**	**0.41%**	**6.88%**	**15.73%**	**8.99%**	**5.78%**	**0.00%**	
	10,297	11,671	28,312		3,902	55	993		222	**55,452**
FL	**18.57%**	**21.05%**	**51.06%**	**0.00%**	**7.04%**	**0.10%**	**1.79%**	**0.00%**	**0.40%**	
	13,275	2,169	12,652		3,995	2,032	675	1,675		**36,473**
GA	**36.40%**	**5.95%**	**34.69%**	**0.00%**	**10.95%**	**5.57%**	**1.85%**	**4.59%**	**0.00%**	
	15,582	1,097	13,709	47	11,379	33	884			**42,731**
IL	**36.47%**	**2.57%**	**32.08%**	**0.11%**	**26.63%**	**0.08%**	**2.07%**	**0.00%**	**0.00%**	
	19,759	503	6,048	612		60	39			**27,021**
IN	**73.12%**	**1.86%**	**22.38%**	**2.26%**	**0.00%**	**0.22%**	**0.14%**	**0.00%**	**0.00%**	
	1,744	3,137	5,789		685	259	301	1,643		**13,558**
MA	**12.86%**	**23.14%**	**42.70%**	**0.00%**	**5.05%**	**1.91%**	**2.22%**	**12.12%**	**0.00%**	
	11,910	673	11,242		3,969	249	390	1,872		**30,305**
MI	**39.30%**	**2.22%**	**37.10%**	**0.00%**	**13.10%**	**0.82%**	**1.29%**	**6.18%**	**0.00%**	
	11,259	1,287	5,553		1,190	552	60	657		**20,558**
MO	**54.77%**	**6.26%**	**27.01%**	**0.00%**	**5.79%**	**2.69%**	**0.29%**	**3.20%**	**0.00%**	
	2,054	1,345	10,298	44	3,984	4	211	400	11	**18,351**
NJ	**11.19%**	**7.33%**	**56.12%**	**0.24%**	**21.71%**	**0.02%**	**1.15%**	**2.18%**	**0.06%**	
	3,570	7,286	16,727		5,156	4,301	786	1,297		**39,123**
NY	**9.13%**	**18.62%**	**42.75%**	**0.00%**	**13.18%**	**10.99%**	**2.01%**	**3.32%**	**0.00%**	
	13,068	564	6,616		4,975	1,960	342	84	37	**27,646**
NC	**47.27%**	**2.04%**	**23.93%**	**0.00%**	**18.00%**	**7.09%**	**1.24%**	**0.30%**	**0.13%**	
	22,074	1,075	8,169	100	2,124	101	112			**33,755**
OH	**65.39%**	**3.18%**	**24.20%**	**0.30%**	**6.29%**	**0.30%**	**0.33%**	**0.00%**	**0.00%**	
	18,581	4,660	9,410	100	9,305	748	781	1,521		**45,106**
PA	**41.19%**	**10.33%**	**20.86%**	**0.22%**	**20.63%**	**1.66%**	**1.73%**	**3.37%**	**0.00%**	
	19,817	216	71,152	308	4,860	673	4,712		199	**101,937**
TX	**19.44%**	**0.21%**	**69.80%**	**0.30%**	**4.77%**	**0.66%**	**4.62%**	**0.00%**	**0.20%**	
	5,794	2,418	6,869		3,404	675	672	3,161		**22,993**
VA	**25.20%**	**10.52%**	**29.87%**	**0.00%**	**14.80%**	**2.94%**	**2.92%**	**13.75%**	**0.00%**	
	1,405	4	2,933		1,131	21,333	1,494	314		**28,614**
WA	**4.91%**	**0.01%**	**10.25%**	**0.00%**	**3.95%**	**74.55%**	**5.22%**	**1.10%**	**0.00%**	

Notes: Green cells represent the states with the highest percentage capacity from a particular renewable source; yellow cells represent the states with the lowest percentage capacity. N gas, natural gas; O gases, other gases; O renew, other renewables; Pump st, pump storage. Other gases includes blast furnace gas, propane, and other manufactured and waste gases derived from fossil fuels. Other renewables includes wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind. Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels, and miscellaneous technologies.

Sources: The data in the table and the notes are taken essentially verbatim from Energy Information Administration, State Electricity Profiles, Table 4. Electric Power Industry Capability by Primary Energy Source, 1990 through 2007 (MW), http://www.eia.doe.gov/fuelelectric.html.

Net Summer Renewable Capacity

Conventional hydroelectric power constitutes the primary renewable source for 12 subject states, including Arizona, California, Georgia, Indiana, Michigan, Missouri, New York, North Carolina, Ohio, Pennsylvania, Virginia, and Washington. Municipal solid waste (MSW) and bio-landfill gas constitutes the primary renewable fuel source for three states: Florida, Massachusetts, and New Jersey. Wind is the primary renewable source for Illinois and Texas.

With respect to total aggregate renewable generating capacity, Washington has the most with 22,828 MW and a national ranking of 1, and Indiana has the least with 99 MW and a national ranking of 48 (Table 4). With respect to the percentage of total generation capacity represented by renewable primary fuels, Washington leads with 79.8 percent and a national ranking of 1, and Indiana trails with 0.4 percent and a national ranking of 49. For each renewable primary fuel source, the range of the percentage of a state's aggregate renewable generating capacity is as follows.

- Geothermal: High = 12.30% (California); Low = negligible (16 states)
- Conventional hydro: High = 99.42% (Arizona); Low = 1.85% (New Jersey)
- Solar: High = 2.56% (California); Low = negligible (13 states)
- Wind: High = 83.36% (Texas); Low = negligible (6 states)
- Wood/waste: High = 36.21% (Michigan); Low = negligible (4 states)
- MSW/BLG: High = 84.26% (New Jersey); Low = 0.15% (Arizona)
- Other biomass: High = 16.79% (Florida); Low = negligible (10 states)

Table 4. 2007 Net Summer Renewable Capacity (MW and Percentage)

State	Renewable energy sources: Primary renew source	Geo-thermal	Convent hydro	Solar	Wind	Wood, wood waste	MSW, bio landfill gas	Other biomass	Total renew capacity	Rank total renew capacity	% Total state capacity	Rank % total state capacity
AZ	HydroCv	—	2,720	9	—	3	4	—	**2,736**	**9**	**10.7**	**18**
			99.42%	**0.33%**		**0.11%**	**0.15%**					
CA	HydroCv	1,940	10,041	404	2,312	596	380	102	**15,775**	**2**	**24.7**	**8**
		12.30%	**63.65%**	**2.56%**	**14.66%**	**3.78%**	**2.41%**	**0.65%**				
FL	MSW-LG	—	55	—	—	354	463	176	1,048	**24**	**1.9**	**44**
			5.25%			**33.78%**	**44.18%**	**16.79%**				
GA	HydroCv	—	2,032	—	—	621	10	44	**2,707**	**10**	**7.4**	**26**
			75.06%			**22.94%**	**0.37%**	**1.63%**				
IL	Wind	—	33	—	740	—	131	13	**917**	**25**	**2.1**	**41**
			3.60%		**80.70%**		**14.29%**	**1.42%**				
IN	HydroCv	—	60	—	—	—	39	—	**99**	48	**0.4**	**49**
			60.61%				**39.39%**					
MA	MSW-LG	—	259	—	2	26	264	9	**560**	**36**	**4.1**	**34**
		—	**46.25%**		**0.36%**	**4.64%**	**47.14%**	**1.61%**				
MI	HydroCv	—	249	—	2	231	156	—	**638**	**31**	**2.1**	**41**
			39.03%		**0.31%**	**36.21%**	**24.45%**					
MO	HydroCv	—	552	—	57	—	3	—	**612**	**32**	**3.0**	**39**
			90.20%		**9.31%**		**0.49%**					
NJ	MSW-LG	—	4	2	8	—	182	20	**216**	**46**	**1.2**	**47**
			1.85%	**0.93%**	**3.70%**		**84.26%**	**9.26%**				
NY	HydroCv	—	4,301	—	425	37	324	—	**5,087**	**5**	**13.0**	**15**
			84.55%		**8.35%**	**0.73%**	**6.37%**					
NC	HydroCv	—	1,960	—	—	324	18	—	**2,302**	**12**	**8.3**	**23**
			85.14%			**14.07%**	**0.78%**					
OH	HydroCv	—	101	—	7	64	41	—	**213**	**47**	**0.6**	**48**
			47.42%		**3.29%**	**30.05%**	**19.25%**					
PA	HydroCv	—	748	—	293	108	379	—	**1,528**	**18**	**3.4**	**37**
			48.95%		**19.18%**	**7.07%**	**24.80%**					
TX	Wind	—	673	—	4,490	130	72	21	**5,386**	**4**	**5.3**	**30**
			12.50%		**83.36%**	**2.41%**	**1.34%**	**0.39%**				
VA	HydroCv	—	675	—	—	418	254	—	**1,347**	**21**	**5.9**	**28**
			50.11%			**31.03%**	**18.86%**					
WA	HydroCv	—	21,333	1	1,162	296	36	—	**22,828**	**1**	**79.8**	**1**
			93.45%	**0.00%**	**5.09%**	**1.30%**	**0.16%**					

Notes: Green cells represent the states with the highest percentage capacity from a particular renewable source; yellow cells represent the states with the lowest percentage capacity. HydroCv, conventional hydroelectric power; MSW-LG, municipal solid waste-landfill gas, absolute percentage less than 0.05; —, no data reported. Conventional hydro does not include pumped storage. Solar includes solar thermal and photovoltaic. Other biomass includes agricultural byproducts and crops; sludge waste; and other biomass solids, liquids, and gases. MSW biogenic includes paper and paperboard, wood, food, leather, textiles, and yard trimmings. Totals may not equal the sum of the components because of independent rounding.

Sources: Most of the data in the table and the notes are taken essentially verbatim from Energy Information Administration, State Renewable Electricity Profiles, Table 1: Summary Renewable Electric Power Industry Statistics (2007). % Total state capacity was determined using data from Table 1 for all 50 states, http://www.eia.doe.gov/cneaf/solar.renewables/page/state_profiles/r_profiles_sum.html. Capacity: Energy Information Administration, Form EIA-860, Annual Electric Generator Report. Generation: Energy Information Administration, Form EIA-906, Power Plant Report, and EIA-920, Combined Heat and Power Plant Report.

Net Summer Nonhydro Renewable Capacity

Geothermal constitutes the primary nonhydro renewable source for California, and solar is the primary nonhydro renewable source for Arizona. For five subject states—Illinois, Missouri, New York, Texas, and Washington, wind is the primary nonhydro renewable source. Wood and wood waste is the primary nonhydro renewable source for five subject states—Georgia, Michigan, North Carolina, Ohio, and Virginia—and MSW/BLG constitutes the primary renewable fuel source for the five remaining subject states—Florida, Indiana, Massachusetts, New Jersey, and Pennsylvania.

With respect to total aggregate nonhydro renewable generating capacity, Texas has the most with 4,713 MW and a national ranking of 1, and Arizona has the least with 16 MW and a national ranking of 47 (Table 5). With respect to the percentage of total generation capacity represented by nonhydro renewable primary fuels, California leads with 6.77 percent and a national ranking of 10, and Arizona trails with 0.06 percent and a national ranking of 50. In terms of total aggregate MWs of capacity for each nonhydro renewable primary fuel source, the leading states are as follows.

- Geothermal: California—1,940 MW
- Solar: California—404 MW
- Wind: Texas—4,490 MW
- Wood/waste: Georgia—621 MW
- MSW/BLG: Florida—463 MW
- Other biomass: Florida—176 MW

Table 5. 2007 Net Summer Renewable Capacity—Less Hydro (MW and Percentage)

	Renewable energy sources										
State	Primary renew source	Geo-therm al	Solar	Wind	Wood/ wood waste	MSW-bio landfill gas	Other bio-mass	Total non-hydro renew capacity	Rank total nonhydro renew capacity	% total state capacity	Rank % total state capacity
AZ	Solar	—	9	—	3	4	—	**16**	**47**	**0.06**	**50**
CA	GeoTh	1,940	404	2,312	596	380	102	**5,794**	**1**	**9.08**	**3**
FL	MSW-LG	—	—	—	354	463	176	**993**	**8**	**1.80**	**28**
GA	Wood / Ws	—	—	—	621	10	44	**675**	**14**	**1.85**	**27**
IL	Wind	—	—	740	—	131	13	**884**	**9**	**2.02**	**23**
IN	MSW-LG	—	—	—	—	39	—	**39**	**44**	**0.16**	**47**
MA	MSW-LG	—	—	2	26	264	9	**301**	**25**	**2.20**	**20**
MI	Wood / Ws	—	—	2	231	156	—	**389**	**20**	**1.28**	**34**
MO	Wind	—	—	57	—	3	—	**60**	**42**	**0.29**	**45**
NJ	MSW-LG	—	2	8	—	182	20	**212**	**29**	**1.23**	**35**
NY	Wind	—	—	425	37	324	—	**786**	**10**	**1.18**	**36**
NC	Wood / Ws	—	—	—	324	18	—	**342**	**23**	**2.01**	**24**
OH	Wood / Ws	—	—	7	64	41	—	**112**	**37**	**0.32**	**43**
PA	MSW-LG	—	—	293	108	379	—	**780**	**11**	**1.74**	**29**
TX	Wind	—	—	4,490	130	72	21	**4,713**	**2**	**4.64**	**12**
VA	Wood / Ws	—	—	—	418	254	—	**672**	**15**	**2.94**	**19**
WA	Wind	—	1	1,162	296	36	—	**1,495**	**3**	**5.23**	**11**

Notes: Green cells represent the states with the highest percentage capacity from a particular renewable source; yellow cells represent the states with the lowest percentage capacity. GeoTh, geothermal; LG, landfill gas; Ws, waste; —, no data reported. Hydro conventional does not include pumped storage. Solar includes solar thermal and photovoltaic. Other biomass includes agricultural byproducts and crops; sludge waste; and other biomass solids, liquids, and gases. MSW biogenic includes paper and paperboard, wood, food, leather, textiles and yard trimmings. Totals may not equal the sum of components because of independent rounding.

Sources: Most of the data in the table and the notes are taken essentially verbatim from Energy Information Administration, State Renewable Electricity Profiles, Table 1: Summary Renewable Electric Power Industry Statistics (2007), http://www.eia.doe.gov/cneaf/solar.renewables/page/state_profiles/r_profiles_sum.html. All of the data under the last four headings were determined from data in Table 1 for all 50 states. Capacity: Energy Information Administration, Form EIA-860, Annual Electric Generator Report. Generation: Energy Information Administration, Form EIA-906, Power Plant Report, and EIA-920, Combined Heat and Power Plant Report.

Net Electric Energy Generation

Net electric energy generation constitutes electric energy production less line losses as measured in MWh. Below are data detailing aggregate net electric energy generation within each state by power plants powered by various sources of primary energy.

Net Electric Energy Generation by Primary Fuel Source

With respect to total aggregate net electric energy generation, Texas has the most with 405,492,296 MWh, and Massachusetts has the least with 47,075,975 MWh (Table 6). For each primary fuel source, the range of the percentage of the states' aggregate net electric energy generation is as follows.

- Coal: High = 94.00% (Indiana) Low = 1.09% (California)
- Petroleum: High = 8.96% (Florida) Low = 0.03% (Washington)
- Natural gas: High = 54.87% (California) Low = 2.56% (Ohio)
- Other gases: High = 0.89% (Texas) Low = 0.00% (eight states)
- Nuclear power: High = 51.08% (New Jersey) Low = 1.98% (Indiana)
- Hydro power: High = 73.68% (Washington) Low = 0.03% (New Jersey)
- Other renewables: High = 11.78% (California) Low = 0.03% (Missouri)
- Pump storage: High = 0.42% (Missouri) Low = –2.07% (Virginia)
- Other: High = 1.59% (Massachusetts) Low = 0.00% (two states)

Table 6. 2007 Net Generation (MWh and Percentage) by Primary Fuel Source for Subject States

ST	Coal	Petrol	N gas	O gases	Nuclear	Hydro	O renew	Pump St	Other	∑
AZ	41,275,362	49,276	38,469,221		26,782,391	6,597,671	41,639	125,411		**113,340,971**
	36.42%	**0.04%**	**33.94%**	**0.00%**	**23.63%**	**5.82%**	**0.04%**	**0.11%**	**0.00%**	
CA	2,298,306	2,333,974	115,700,470	1,818,106	35,792,490	27,327,751	24,845,257	309,779	421,447	**210,847,580**
	1.09%	**1.11%**	**54.87%**	**0.86%**	**16.98%**	**12.96%**	**11.78%**	**0.15%**	**0.20%**	
FL	67,908,115	20,202,867	100,307,183	15,162	29,289,289	154,446	4,302,818		3,236,180	**225,416,060**
	30.13%	**8.96%**	**44.50%**	**0.01%**	**12.99%**	**0.07%**	**1.91%**	**0.00%**	**1.44%**	
GA	90,297,529	788,227	16,078,944		32,544,998	2,236,188	3,415,422	−321,649	115,499	**145,155,158**
	62.21%	**0.54%**	**11.08%**	**0.00%**	**22.42%**	**1.54%**	**2.35%**	**−0.22%**	**0.08%**	
IL	95,264,914	131,667	7,541,527	134,271	95,728,845	153,727	1,284,752		20,978	**200,260,681**
	47.57%	**0.07%**	**3.77%**	**0.07%**	**47.80%**	**0.08%**	**0.64%**	**0.00%**	**0.01%**	
IN	122,802,897	169,977	4,011,824		2,591,406	449,936	231,247		380,711	**130,637,998**
	94.00%	**0.13%**	**3.07%**	**0.00%**	**1.98%**	**0.34%**	**0.18%**	**0.00%**	**0.29%**	
MA	12,024,347	3,051,604	24,925,043		5,119,789	797,482	1,240,224	−830,547	748,033	**47,075,975**
	25.54%	**6.48%**	**52.95%**	**0.00%**	**10.88%**	**1.69%**	**2.63%**	**−1.76%**	**1.59%**	
MI	70,810,599	698,525	13,140,984	282,414	31,516,953	1,269,989	2,416,747	−1,129,241	302,966	**119,309,936**
	59.35%	**0.59%**	**11.01%**	**0.24%**	**26.42%**	**1.06%**	**2.03%**	**−0.95%**	**0.25%**	
MO	75,084,154	60,401	4,979,379	3,400	9,371,955	1,204,326	29,309	383,473	36,685	**91,153,082**
	82.37%	**0.07%**	**5.46%**	**0.00%**	**10.28%**	**1.32%**	**0.03%**	**0.42%**	**0.04%**	
NJ	10,210,670	452,771	18,752,332	160,549	32,010,376	20,909	843,578	−268,934	488,994	**62,671,245**
	16.29%	**0.72%**	**29.92%**	**0.26%**	**51.08%**	**0.03%**	**1.35%**	**−0.43%**	**0.78%**	
NY	21,405,542	8,195,109	45,633,631		42,452,854	25,252,555	2,775,084	−768,380	932,292	**145,878,687**
	14.67%	**5.62%**	**31.28%**	**0.00%**	**29.10%**	**17.31%**	**1.90%**	**−0.53%**	**0.64%**	
NC	79,983,038	495,689	4,456,643		40,044,705	2,984,159	1,672,219	136,996	341,852	**130,115,301**
	61.47%	**0.38%**	**3.43%**	**0.00%**	**30.78%**	**2.29%**	**1.29%**	**0.11%**	**0.26%**	
OH	133,130,679	1,147,746	3,974,897	289,273	15,764,049	410,436	435,143		3,322	**155,155,545**
	85.80%	**0.74%**	**2.56%**	**0.19%**	**10.16%**	**0.26%**	**0.28%**	**0.00%**	**0.00%**	
PA	122,693,094	1,484,074	19,197,600	533,986	77,376,316	2,235,982	2,546,196	−722,855	743,948	**226,088,341**
	54.27%	**0.66%**	**8.49%**	**0.24%**	**34.22%**	**0.99%**	**1.13%**	**−0.32%**	**0.33%**	
TX	147,278,889	1,308,904	199,531,281	3,601,211	40,955,030	1,644,437	10,287,612		884,932	**405,492,296**
	36.32%	**0.32%**	**49.21%**	**0.89%**	**10.10%**	**0.41%**	**2.54%**	**0.00%**	**0.22%**	
VA	35,420,746	2,096,949	10,903,840		27,268,475	1,248,264	2,565,571	−1,620,283	476,945	**78,360,507**
	45.20%	**2.68%**	**13.91%**	**0.00%**	**34.80%**	**1.59%**	**3.27%**	**−2.07%**	**0.61%**	
WA	8,556,816	37,042	7,287,394	333,773	8,108,560	78,829,195	3,730,554	44,512	62,370	**106,990,216**
	8.00%	**0.03%**	**6.81%**	**0.31%**	**7.58%**	**73.68%**	**3.49%**	**0.04%**	**0.06%**	

Notes: Green cells represent the states with the highest percentage generation from a particular renewable source; yellow cells represent the states with the lowest percentage generation. N gas, natural gas; o gases, other gases; o renew, other renewables; pump st, pump storage. Other gases include blast furnace gas, propane, and other manufactured and waste gases derived from fossil fuels. Other renew includes wood, black liquor, other wood waste, MSW, landfill gas, sludge waste, agricultural byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Sources: Data in the table and the notes below are taken essentially verbatim from Energy Information Administration, State Electricity Profiles, Table 5. Electric Power Industry Generation by Primary Energy Source, 1990 through 2007 (MWh), http://www.eia.doe.gov/fuelelectric.html

Net Renewable Generation

For purposes of fueling net renewable generation, conventional hydro power constitutes the primary renewable source for nine subject states, including Arizona, California, Indiana, Missouri, New York, North Carolina, Ohio, Pennsylvania, and Washington. Wood and wood waste is the primary renewable source for four subject states—Florida, Georgia, Michigan, and Virginia. MSW/BLG constitutes the primary renewable fuel source for Massachusetts and New Jersey, and wind is the primary renewable fuel source for Illinois and Texas.

With respect to total aggregate renewable generation, Washington produced the most with 82,559,000 MWh and a national ranking of 1, and Indiana produced the least with 681,000 MWh and a national ranking of 47 (Table 7). With respect to the percentage of total net generation represented by renewable primary fuels, Washington leads with 77.2 percent and a national ranking of 1, and Indiana and Ohio trail with 0.5 percent and a national ranking of 49. For each renewable primary fuel source, the range of the percentage of the states' aggregate renewable generating capacity is as follows.

- Geothermal: High = 24.90% (California); Low = negligible (16 states)
- Conventional hydro: High = 99.37% (Arizona); Low = 2.43% (New Jersey)
- Solar: High = 1.07% (California); Low = negligible (15 states)
- Wind: High = 75.48% (Texas); Low = negligible (8 states)
- Wood/Waste: High = 59.49% (Georgia); Low = negligible (5 states)
- MSW/BLG: High = 95.14% (New Jersey); Low = 0.20% (Washington)
- Other biomass: High = 12.99% (Florida); Low = negligible (Indiana)

Table 7. 2007 RENEWABLE NET GENERATION (k MWH / %)[1]

EIA, 2007 State Renewable Electricity Profiles, table 1, http://www.eia.doe.gov/cneaf/solar.renewables/page/state_profiles/r_profiles_sum.html

	Renewable Energy Sources											
STATE	Primary Renew Source	Geo-Thermal	Convent Hydro	Solar	Wind	Wood / Wood Waste	MSW-Bio Landfill Gas	Other Bio-Mass	Total Renew Generat	Rank Total R Gen	% Total St Gen	Rank % Tot St Gen
AZ	HydroCv	-	6,598	9	-	-	29	4	**6,640**	**10**	**5.9**	**20**
			99.37%	**0.14%**			**0.44%**	**0.06%**				
CA	HydroCv	12,991	27,328	557	5,585	3,407	1,657	648	**52,173**	**2**	**24.7**	**7**
		24.90%	**52.38%**	**1.07%**	**10.70%**	**6.53%**	**3.18%**	**1.24%**				
FL	Wood.Ws	-	154	-	-	1,930	1,794	579	**4,457**	**18**	**2.0**	**41**
			3.46%			**43.30%**	**40.25%**	**12.99%**				
GA	Wood.Ws	-	2,236	-	-	3,362	16	37	**5,651**	**12**	**3.9**	**29**
			39.57%			**59.49%**	**0.28%**	**0.65%**				
IL	Wind	-	154	-	664	-	603	17	**1,438**	**36**	**0.7**	**47**
			10.71%		**46.18%**		**41.93%**	**1.18%**				
IN	HydroCv	-	450	-	-	-	231	-	**681**	**47**	**0.5**	**49**
			66.08%				**33.92%**					
MA	MSW-LG	**-**	**797**	**-**	**-**	**119**	**1,094**	**27**	**2,037**	**31**	**4.3**	**27**
			39.13%			**5.84%**	**53.71%**	**1.33%**				
MI	Wood.Ws	-	1,270	-	3	1,692	721	1	**3,687**	**22**	**3.1**	**34**
			34.45%		**0.08%**	**45.89%**	**19.56%**	**0.03%**				
MO	HydroCv	-	1,204	-	-	s	22	7	**1,233**	**39**	**1.4**	**45**
			97.65%				**1.78%**	**0.57%**				
NJ	MSW-LG	-	21	-	20	-	822	1	**864**	**43**	**1.4**	**45**
			2.43%		**2.31%**		**95.14%**	**0.12%**				
NY	HydroCv	-	25,253	-	833	492	1,442	7	**28,027**	**4**	**19.2**	**8**
			90.10%		**2.97%**	**1.76%**	**5.15%**	**0.02%**				
NC	HydroCv	-	2,984	-	-	1,585	86	1	**4,656**	**16**	**3.6**	**30**

			64.09%			**34.04%**	**1.85%**	**0.02%**				
OH	HydroCv	-	410	-	15	399	11	10	**845**	**45**	**0.5**	**49**
			48.52%		**1.78%**	**47.22%**	**1.30%**	**1.18%**				
PA	HydroCv	-	2,236	-	470	620	1,441	16	**4,783**	**15**	**2.1**	**40**
			46.75%		**9.83%**	**12.96%**	**30.13%**	**0.33%**				
TX	Wind	-	1,644	-	9,006	914	322	45	**11,931**	**5**	**2.9**	**36**
			13.78%		**75.48%**	**7.66%**	**2.70%**	**0.38%**				
VA	Wood.Ws	-	1,248	-	-	1,792	753	20	**3,813**	**20**	**4.9**	**23**
			32.73%			**47.00%**	**19.75%**	**0.52%**				
WA	HydroCv	-	78,829	-	2,438	1,116	163	13	**82,559**	**1**	**77.2**	**2**
			95.48%		**2.95%**	**1.35%**	**0.20%**	**0.02%**				

Notes: Green cells represent the states with the highest percentage generation from a particular renewable source; yellow cells represent the states with the lowest percentage generation. HydroCv, conventional hydro; Ws, waste; s, value is less than 0.5 of the table metric, but value is included in any associated total; —, no data reported.

Source: Energy Information Administration, 2007, State Renewable Electricity Profiles, Table 1, http://www.eia.doe.gov/cneaf/solar.renewables/page/state_profiles/r_profiles_sum.html

Net Nonhydro Renewable Generation

Geothermal constitutes the primary nonhydro renewable source for California, and wind is the primary nonhydro renewable source for Illinois, Texas, and Washington. For six subject states—Florida, Georgia, Michigan, North Carolina, Ohio, and Virginia, wood and wood waste is the primary nonhydro renewable source. MSW/BLG is the primary nonhydro renewable source for seven subject states—Arizona, Indiana, Massachusetts, Missouri, New Jersey, New York, and Pennsylvania.

With respect to total aggregate net nonhydro renewable generation, California has the most with 24,845,000 MWh and a national ranking of 1, and Missouri has the least with 29,000 MWh and a national ranking of 49 (Table 8). With respect to the percentage of total net generation represented by nonhydro renewable primary fuels, California leads with 11.76 percent and a national ranking of 2, and Missouri trails with 0.03 percent and a national ranking of 50. For each renewable primary fuel source, the range of the percentage of the states' aggregate net nonhydro renewable generation is as follows.

- Geothermal: High = 52.29% (California); Low = negligible (16 states)
- Solar: High = 21.43% (Arizona); Low = negligible (15 states)
- Wind: High = 87.55% (Texas); Low = negligible (8 states)
- Wood/waste: High = 98.45% (Georgia); Low = negligible (5 states)
- MSW/BLG: High = 100.0% (Indiana); Low = 0.47% (Georgia)
- Other biomass: High = 24.14% (Missouri); Low = negligible (Indiana)

Table 8. 2007 Renewable Net Generation—Nonhydro (Thousand MWh and Percentage)

State	Renewable energy sources							Total non-hydro renew gen	Rank total non-hydro renew gen	% total state gen	Rank % total state gen
	Primary renew source	Geo-thermal	Solar	Wind	Wood / wood waste	MSW-bio landfill gas	Other bio-mass				
AZ	MSW-LG	—	9	—	—	29	4	**42**	**47**	**0.04**	**49**
			21.43%			69.05%	9.52%				
CA	GeoTh	12,991	557	5,585	3,407	1,657	648	24,845	**1**	**11.76**	**2**
		52.29%	2.24%	22.48%	13.71%	6.67%	2.61%				
FL	Wood/Ws	—	—	—	1,930	1,794	579	**4,303**	**3**	**1.93**	**31**
					44.85%	41.69%	13.46%				
GA	Wood/Ws	—	—	—	3,362	16	37	**3,415**	**8**	**2.36**	**23**
					98.45%	0.47%	1.08%				
IL	Wind	—	—	664	—	603	17	**1,284**	**24**	**0.63**	**41**
				51.71%		46.96%	1.32%				
IN	MSW-LG	—	—	—	—	231	—	**231**	**41**	**0.17**	**47**
						100.00%					
MA	MSW-LG	—	—	—	119	1,094	27	**1,240**	**25**	**2.62**	**19**
					9.60%	88.23%	2.18%				
MI	Wood/Ws	—	—	3	1,692	721	1	**2,417**	**14**	**2.03**	**29**
				0.12%	70.00%	29.83%	0.04%				
MO	MSW-LG	—	—	—	s	22	7	**29**	**49**	**0.03**	**50**
						75.86%	24.14%				
NJ	MSW-LG	—	—	20	—	822	1	**843**	**29**	**1.37**	**36**
				2.37%		97.51%	0.12%				
NY	MSW-LG	—	—	833	492	1,442	7	**2,774**	**11**	**1.90**	**35**
				30.03%	17.74%	51.98%	0.25%				
NC	Wood/Ws	—	—	—	1,585	86	1	**1,672**	**18**	**1.29**	**33**
					94.80%	5.14%	0.06%				
OH	Wood/Ws	—	—	15	399	11	10	**435**	**39**	**0.26**	**45**
				3.45%	91.72%	2.53%	2.30%				
PA	MSW-LG	—	—	470	620	1,441	16	**2,547**	**13**	**1.12**	**38**
				18.45%	24.34%	56.58%	0.63%				
TX	Wind	—	—	9,006	914	322	45	**10,287**	**2**	**2.50**	**20**
				87.55%	8.89%	3.13%	0.44%				
VA	Wood/Ws	—	—	—	1,792	753	20	**2,565**	**12**	**3.30**	**13**
					69.86%	29.36%	0.78%				
WA	Wind	—	—	2,438	1,116	163	13	**3,730**	**7**	**3.49**	**12**

				65.36%	29.92%	4.37%	0.35%				

Notes: Green cells represent the states with the highest percentage generation from a particular renewable source; yellow cells represent the states with the lowest percentage generation. Hydro conventional does not include pumped storage. GeoTh, geothermal; LG, landfill gas; Ws, waste; s, value is less than 0.5 of the table metric, but value is included in any associated total; —, no data reported. Solar includes solar thermal and photovoltaic. Other biomass includes agricultural byproducts and crops; sludge waste; and other biomass solids, liquids, and gases. MSW biogenic includes paper and paperboard, wood, food, leather, textiles, and yard trimmings. Totals may not equal the sum of components because of independent rounding.

Sources: Most of the data in the table and the notes below are taken verbatim from Energy Information Administration, State Renewable Electricity Profiles, Table 1: Summary Renewable Electric Power Industry Statistics (2007), http://www.eia.doe.gov/cneaf/solar.renewables/page/state_profiles/r_profiles_sum.html. The data under the last four headings were determined using the data in Table 1 for all 50 states. Capacity: Energy Information Administration, Form EIA-860, Annual Electric Generator Report. Generation: Energy Information Administration, Form EIA-906, Power Plant Report, and EIA-920, Combined Heat and Power Plant Report.

Prices of Electric Energy Retail Sales and Purchase

Within each state, retail sales are made by several types of providers organized under two distinct classes of providers, as follows.

- Full service providers sell bundled electric energy service (energy and delivery) to end users. These providers include:
  - IOUs,
  - public (municipalities, state power agencies, and municipal marketing authorities),
  - federal (Fed; providers owned or financed by the federal government),
  - cooperatives (Coop; providers owned and operated by their end users), and
  - facility (direct electric energy sales from IPP to end user).
- Other providers involve the interactions of generators of electric energy and deliverers of electric energy to achieve the delivery of electric energy to end users. These providers include:
  - energy (providers that generate electric energy) and
  - delivery (providers that transmit and distribute electric energy).

At the other end of these transactions are retail electric energy purchases, which are attributed to five end-use sectors: residential, commercial, industrial, transportation, and other. The discussions below document the retail prices for these transactions within each of the covered states.

Retail Sales Price (¢ per kWh)

Among the subject states, New York had the highest weighted average retail sales price at 15.22¢ per kWh, the 3rd highest in the nation, and Washington had the lowest at 6.37¢ per kWh, the 45th highest (Table 9). The ranges of average price per provider type are as follows.

- IOUs: High = 16.63 (Massachusetts) Low = 6.21 (Missouri)
- Public: High = 15.75 (New York) Low = 5.48 (Washington)
- Fed: High = 7.06 (North Carolina) Low = 2.55 (California)
- Coop: High = 11.13 (New Jersey) Low = 6.08 (Washington)
- Facility: High = 13.83 (Massachusetts) Low = 5.46 (Missouri)
- Energy: High = 10.40 (Massachusetts) Low = 4.71 (Ohio)
- Delivery: High = 4.44 (New York) Low = 0.42 (Washington)
- Energy + Delivery Service Providers High = 14.80 (Massachusetts) Low = 6.09 (Washington)

Table 9. 2007 Retail Sales by Provider: Price (¢/kWh)

State	Full service providers					Other providers		Avg price	Rank hi to lo
	IOUs	Public	Fed	Coop	Facility	Energy	Delivery		
AZ	9.08	7.81	4.33	10.41	NA	NA	NA	8.54	18
CA	14.00	10.30	2.55	10.58	7.41	7.82	3.97	12.80	10
FL	10.50	9.66	NA	10.09	NA	NA	NA	10.33	14
GA	7.55	7.51	NA	8.63	NA	NA	NA	7.86	25
IL	9.78	7.65	NA	9.29	NA	5.93	1.02	8.46	21
IN	6.26	6.70	NA	8.12	NA	NA	NA	6.50	42
MA	16.63	11.76	NA	NA	13.83	10.40	4.40	15.16	4
MI	8.53	7.80	NA	10.50	6.31	5.68	1.46	8.53	19
MO	6.21	7.45	NA	7.36	5.46	NA	NA	6.56	41
NJ	13.28	12.63	NA	11.13	8.92	8.93	3.34	13.01	9
NY	16.36	15.75	NA	10.77	8.50	9.47	4.44	15.22	3
NC	7.25	8.96	7.06	10.17	NA	NA	NA	7.83	26
OH	7.84	8.37	NA	8.14	NA	4.71	3.46	7.91	24
PA	9.08	10.02	NA	10.46	NA	6.71	1.81	9.08	17
TX	10.59	8.02	NA	10.11	6.84	NA	NA	10.11	15
VA	6.68	7.66	4.40	11.05	NA	9.34	1.36	7.12	34
WA	7.82	5.48	3.65	6.08	NA	5.67	0.42	6.37	45

Notes: Green cells represent the states with the highest price for a particular provider type; yellow cells represent the states with the lowest price. Totals may not equal the sum of components because of independent rounding. Data are shown for all sectors. Full service providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full service providers may purchase electricity from others (such as IPPs or other full service providers) prior to delivery. Other providers sell either the energy or the delivery services, but not both. Sales volumes and customer counts shown for Other providers refer to delivered electricity, which is a joint activity of both energy and delivery providers; for clarity, they are reported only in the Energy column in this table. The revenue shown under Other providers represents the revenue realized from the sale of the energy and the delivery services distinctly. Public entities include municipalities, state power agencies, and municipal marketing authorities. Federal entities are either owned or financed by the federal government. Cooperatives are electric utilities legally established to be owned by and operated for the benefit of those using its services. A cooperative will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Facility sales represent direct electricity transactions from independent generators to end-use consumers.

Sources: Data in the table and the notes below are taken verbatim from Energy Information Administration, State Electricity Profiles, Table 9. Retail Electricity Sales Statistics, 2007, http://www.eia.doe.gov/fuelelectric.html. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Retail Purchase Price (¢ per kWh)

New York has the highest average retail purchase price, 15.22 ¢ per kWh, which is the 3rd highest in the nation, and Washington has the lowest, 6.37 ¢ per kWh, which is the 45th highest in the nation (Table 10). The range of average retail purchase prices for each end-use sector is as follows.

- Residential: High = 17.10 (New York) Low = 7.26 (Washington)
- Commercial: High = 15.92 (New York) Low = 6.34 (Missouri)
- Industrial: High = 13.03 (Massachusetts) Low = 4.57 (Washington)
- Transportation: High = 11.14 (New Jersey) Low = 5.74 (Washington)
- Other: none/negligible in every subject state.

Table 10. 2007 Retail Purchase Price (¢/kWh) by Sector

State	Res	Comm	Ind	Other	Trans	All	Rank
AZ	9.66	8.27	6.05	—		8.54	18
CA	14.42	12.82	9.98	—	8.37	12.80	10
FL	11.22	9.75	7.76	—	9.73	10.33	14
GA	9.10	8.07	5.53	—	6.42	7.86	25
IL	10.12	8.57	6.61	—	6.43	8.46	21
IN	8.26	7.29	4.89	—	10.09	6.50	42
MA	16.23	15.20	13.03	—	9.24	15.16	4
MI	10.21	8.77	6.47	—	9.76	8.53	19
MO	7.69	6.34	4.76	—	6.16	6.56	41
NJ	14.14	12.99	10.08	—	11.14	13.01	9
NY	17.10	15.92	8.71	—	10.96	15.22	3
NC	9.40	7.43	5.47	—	9.09	7.83	26
OH	9.57	8.67	5.76	—	9.98	7.91	24
PA	10.95	9.20	6.87	—	7.72	9.08	17
TX	12.34	9.87	7.79	—	8.40	10.11	15
VA	8.74	6.38	5.07	—	6.73	7.12	34
WA	7.26	6.55	4.57	—	5.74	6.37	45

Notes: Green cells represent the states with the highest price for a particular sector; yellow cells represent the states with the lowest price. —, data not available.

Sources: Data in table and notes taken essentially verbatim from Energy Information Administration, State Electricity Profiles, Table 8, Retail Sales, Revenue, and Average Retail Price by Sector, 1990 through 2007, http://www.eia.doe.gov/fuelelectric.html. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Air Pollution Emissions

The process of generating electric energy also produces certain air pollution emissions, the levels of which vary depending on the primary energy source used in the generating process. Below are data documenting the levels of CO2, SOx, and NOx emissions caused by electric energy generation within each subject state.

CO_2 Emissions

Texas's electric energy generators emit the most CO_2, 255,092,000 metric tons, and Washington's emit the least, 12,652,000 (Table 11). On a metric ton-per-MWh basis, Indiana's electric energy generators emit the most CO_2, 0.932 metric tons per MWh, and Washington's emit the least, 0.118 metric tons per MWh. The range of emissions levels for each primary energy source (in thousands of metric tons) is as follows.

- Coal: High = 150,595 (Texas) Low = 3,112 (California)
- Petroleum: High= 17,535 (Florida) Low = 40 (Arizona)
- Natural gas: High = 102,800 (Texas) Low = 2,121 (Ohio)
- Other: High = 2,477 (Florida) Low = none, negligible (Arizona, Texas)
- Geothermal: High = 330 (California) Low = none, negligible (16 states)

Table 11. 2007 CO_2 Emissions (Thousand Metric Tons) by Primary Fuel Source

State	Coal	Petrol	N gas	O gases	O renew	Other	Geoth	∑	Total gen (thousand MWh)	Metric tons / MWh
AZ	40,546	40	15,192					**55,779**	113,341	**0.492**
CA	3,883	3,112	55,105		—	350	330	**62,780**	210,849	**0.298**
FL	64,872	17,535	42,778		—	2,477		**127,662**	225,417	**0.566**
GA	85,948	1,522	7,145		—	633		**95,249**	145,155	**0.656**
IL	100,077	116	4,380		—	46		**104,620**	200,262	**0.522**
IN	119,056	152	2,461		—	56		**121,725**	130,638	**0.932**
MA	11,036	2,672	10,616		—	1,215		**25,539**	47,076	**0.543**
MI	70,431	1,222	6,884		—	554		**79,090**	119,310	**0.663**
MO	74,797	62	2,233			39		**77,131**	91,153	**0.846**
NJ	10,363	409	9,095		—	717		**20,585**	62,672	**0.328**
NY	21,800	7,234	22,570		—	1,658		**53,262**	145,878	**0.365**
NC	75,377	807	2,215		—	134		**78,533**	130,115	**0.604**
OH	126,182	2,082	2,121		—	23		**130,407**	155,155	**0.840**
PA	116,547	1,624	8,439		—	1,279		**127,888**	226,088	**0.566**
TX	150,495	1,797	102,800		—	—		**255,092**	405,493	**0.629**
VA	38,269	2,268	5,227		—	958		**46,722**	78,360	**0.596**
WA	9,018	299	3,218		—	116		**12,652**	106,989	**0.118**

Notes: Green cells represent the states with the highest emissions for a particular fuel source; yellow cells represent the states with the lowest emissions. N gas, natural gas; o gases, other gases; o renew, other renewables; —, data not available. O renew emissions include biogenic MSW and other renewable waste. Other includes nonbiogenic MSW, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels, and miscellaneous technologies.

Sources: Data in table and notes below are taken essentially verbatim from Energy Information Administration, State Electricity Profiles, Table 7. Electric Power Industry Emissions Estimates, 1990 Through 2007 (Thousand Metric Tons), http://www.eia.doe.gov/fuelelectric.html. Calculations made by the Electric Power Division, Energy Information Administration.

SO_X Emissions

Ohio's electric energy generators emit the most SO_X, 958,000 metric tons, and Washington's emit the least, 10,000 (Table 12). On a metric ton-per-MWh basis, Ohio's electric energy generators emit the most SO_X, 0.006174 metric tons per MWh, and Washington's emit the least, 0.000093 metric tons per MWh. The range of emissions levels for each primary energy source is as follows.

- Coal: High = 928 (Ohio) Low = 2 (Washington)
- Petroleum: High = 116 (Florida) Low = none, negligible (3 states)
- Natural gas: High = 1 (Texas) Low = none, negligible (16 states)
- Other renewables: High = 28 (Georgia) Low = none, negligible (6 states)
- Other: High = 1 (4 states) Low = none, negligible (13 states)

Table 12. 2007 SO_x Emissions (Thousand Metric Tons) by Primary Fuel Source

State	Coal	Petrol	N gas	O gases	O renew	Other	Geoth	∑	Total gen (thousand MWh)	Metric tons per MWh
AZ	51	*	*		—	—		**51**	113,341	**0.000450**
CA	3	18	*	*	2	*		**23**	210,849	**0.000109**
FL	192	116	*	*	14	1		**322**	225,417	**0.001428**
GA	617	36	*		28	*		**682**	145,155	**0.004698**
IL	301	1	*	*	*	*		**302**	200,262	**0.001508**
IN	661	*	*	*	*	*		**662**	130,638	**0.005067**
MA	38	13	*		*	*		**51**	47,076	**0.001083**
MI	325	23	*	—	4	1		**353**	119,310	**0.002959**
MO	251	6	*		—	1		**258**	91,153	**0.002830**
NJ	45	1	*	*	*	*		**46**	62,672	**0.000734**
NY	93	24	*	—	6	*		**123**	145,878	**0.000843**
NC	356	2	*		6	1		**365**	130,115	**0.002805**
OH	928	28	*	*	2	*		**958**	155,155	**0.006174**
PA	870	16	*	*	3	*		**889**	226,088	**0.003932**
TX	449	13	1	*	6	*		**468**	405,493	**0.001154**
VA	172	12	*		13	*		**197**	78,360	**0.002514**
WA	2	*	*	*	7	*		**10**	106,989	**0.000093**

Notes: Green cells represent the states with the highest emissions for a particular fuel source; yellow cells represent the states with the lowest emissions. N gas, natural gas; o gases, other gases; o renew, other renewables; *, value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is 1, and values under 0.5 are shown as *); —, data not available. O renew emissions include biogenic MSW and other renewable waste. Other includes nonbiogenic MSW, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels, and miscellaneous technologies.

Sources: Data in the table and the notes are taken essentially verbatim from Energy Information Administration, State Electricity Profiles, Table 7. Electric Power Industry Emissions Estimates, 1990 through 2007 (Thousand Metric Tons), http://www.eia.doe.gov/fuelelectric.html. Calculations made by the Electric Power Division, Energy Information Administration.

NO_X Emissions

Texas's electric energy generators emit the most NO_X, 247,000 metric tons, and Washington's emit the least, 19,000 (Table 13). On a metric ton-per-MWh basis, Indiana's electric energy generators emit the most NO_X, 0.001493 metric tons per MWh, and Washington's emit the least, 0.000178 metric tons per MWh. The range of emissions levels for each primary energy source is as follows.

- Coal: High = 220 (Ohio) Low = 3 (California)
- Petroleum: High = 44 (Florida) Low = none, negligible (5 states)
- Natural gas: High = 105 (Texas) Low = 1 (North Carolina)
- Other gas: High = 14 (Texas) Low = none/negligible (13 states)
- Other renewables: High = 20 (California) Low = none, negligible (Arizona, Missouri)
- Other: High = 4 (Florida, Texas) Low = none, negligible (8 states)

Table 13. 2007 NO_x Emissions (Thousand Metric Tons) by Primary Fuel Source

State	Coal	Petrol	N gas	O gases	O renew	Other	Geoth	∑	Total gen (thousand MWh)	Metric tons / MWh
AZ	74	*	4	*	*	—		79	113,341	0.000697
CA	3	4	58	3	20	1		89	210,849	0.000422
FL	110	44	25	4	14	4		203	225,417	0.000901
GA	104	4	6		11	*		125	145,155	0.000861
IL	111	*	4	*	5	*		120	200,262	0.000599
IN	181	*	2	10	3	*		195	130,638	0.001493
MA	8	2	4		4	2		20	47,076	0.000425
MI	99	4	5	*	9	1		117	119,310	0.000981
MO	97	*	2		*	*		100	91,153	0.001097
NJ	12	1	5	*	3	1		21	62,672	0.000335
NY	27	13	10	—	8	2		60	145,878	0.000411
NC	57	1	1		2	*		61	130,115	0.000469
OH	220	4	2	*	1	*		227	155,155	0.001463
PA	163	8	4	*	6	2		183	226,088	0.000809
TX	113	3	105	14	8	4		247	405,493	0.000609
VA	51	3	3	—	6	2		64	78,360	0.000817
WA	11	*	4	*	4	*		19	106,989	0.000178

Notes: Green cells represent the states with the highest emissions for a particular fuel source; yellow cells represent the states with the lowest emissions. N gas, natural gas; o gases, other gases; o renew, other renewables; *, value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is 1, and values under 0.5 are shown as *); —, data not available. Other renewable emissions include biogenic MSW and other renewable waste. Other includes nonbiogenic MSW, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels, and miscellaneous technologies.

Sources: Data in the table and the notes below are taken essentially verbatim from Energy Information Administration, State Electricity Profiles, Table 7. Electric Power Industry Emissions Estimates, 1990 through 2007 (Thousand Metric Tons), http://www.eia.doe.gov/fuelelectric.html. Calculations made by the Electric Power Division, Energy Information Administration.

Correlations and Implications for Renewables

Correlations among some key characteristics of the subject states' electric energy markets reveal patterns that have implications for the ability of state laws and regulations to affect the development of renewable sources of electric energy generation. The correlations are among state retail choice market patterns, statewide average retail price of electric energy, the mix of primary fuels used within a state to generate electricity, and the emissions of CO_2, SO_X, and NO_X.

Correlations

Table 14 provides the essential data, sorted by each state's average retail price of electric energy (¢ per kWh). Among the subject states, Michigan's price of 8.53¢ per kWh is the median.

Table 14. Correlations between Market Patterns, Retail Price, Fuel Mix, and Air Emissions

	Market pattern				Primary fuel sources for electric energy generation									Air emissions		
St	RTO	ISO	R ch	Rtl price	Coal	Ptrl	N gas	O gas	Nuke	Hydro	O ren	Pmp St	Othr	CO_2	SO_X	NO_X
WA	N	N	N	6.37	8.00%	0.03%	6.81%	0.31%	7.58%	73.68%	3.49%	0.04%	0.06%	0.118	0.000093	0.000178
IN	A-M,P		N	6.50	94.00%	0.13%	3.07%	0.00%	1.98%	0.34%	0.18%	0.00%	0.29%	0.932	0.005067	0.001493
MO	M-M,S		N	6.56	82.37%	0.07%	5.46%	0.00%	10.28%	1.32%	0.03%	0.42%	0.04%	0.846	0.002830	0.001097
VA	A-P		S	7.12	45.20%	2.68%	13.91%	0.00%	34.80%	1.59%	3.27%	-2.07%	0.61%	0.596	0.002514	0.000817
NC	S-P		N	7.83	61.47%	0.38%	3.43%	0.00%	30.78%	2.29%	1.29%	0.11%	0.26%	0.604	0.002805	0.000469
GA	N	N	N	7.86	62.21%	0.54%	11.08%	0.00%	22.42%	1.54%	2.35%	-0.22%	0.08%	0.656	0.004698	0.000861
OH	A-P,M		Y	7.91	85.80%	0.74%	2.56%	0.19%	10.16%	0.26%	0.28%	0.00%	0.00%	0.840	0.006174	0.001463
IL	A-M,P		Y	8.46	47.57%	0.07%	3.77%	0.07%	47.80%	0.08%	0.64%	0.00%	0.01%	0.522	0.001508	0.000599
MI	A-M,P		Y	8.53	59.35%	0.59%	11.01%	0.24%	26.42%	1.06%	2.03%	-0.95%	0.25%	0.663	0.002959	0.000981
AZ	N	N	N	8.54	36.42%	0.04%	33.94%	0.00%	23.63%	5.82%	0.04%	0.11%	0.00%	0.492	0.000450	0.000697
PA	A-P,M		Y	9.08	54.27%	0.66%	8.49%	0.24%	34.22%	0.99%	1.13%	-0.32%	0.33%	0.566	0.003932	0.000809
TX	S-S	M-E	Y	10.11	36.32%	0.32%	49.21%	0.89%	10.10%	0.41%	2.54%	0.00%	0.22%	0.629	0.001154	0.000609
FL	N	N	N	10.33	30.13%	8.96%	44.50%	0.01%	12.99%	0.07%	1.91%	0.00%	1.44%	0.566	0.001428	0.000901
CA	N	M-C	S	12.80	1.09%	1.11%	54.87%	0.86%	16.98%	12.96%	11.78%	0.15%	0.20%	0.298	0.000109	0.000422
NJ	A-P		Y	13.01	16.29%	0.72%	29.92%	0.26%	51.08%	0.03%	1.35%	-0.43%	0.78%	0.328	0.000734	0.000335
MA	A-I		Y	15.16	25.54%	6.48%	52.95%	0.00%	10.88%	1.69%	2.63%	-1.76%	1.59%	0.543	0.001083	0.000425
NY	N	A-N	Y	15.22	14.67%	5.62%	31.28%	0.00%	29.10%	17.31%	1.90%	-0.53%	0.64%	0.365	0.000843	0.000411

Notes: Green cells represent the states with the highest percentage of generation from a particular fuel source; yellow cells represent the states with the lowest percentage of generation from a particular fuel source; blue cells represent state with the highest level of emissions for a given pollutant; orange cells represent the state with the lowest level of emissions for a given pollutant. N gas, natural gas; r ch, retail choice; o gas, other gases; o ren, other renewables; othr, other; pump st, pump storage. Market patterns: A-I = all-ISO-NE; A-M,P = all-MISO, PJM; A-N = all-NYISO; A-P = all-PJM; A-P,M = all-PJM, MISO; M-C = most-CAISO; M-E = most-ERCOT; M-M,S = most-MISO, SPP; N = None; S-P = some-PJM; S-S = some-SPP; R ch = retail choice. Retail price (¢ per kWh).

Retail prices are modestly correlated with whether an RTO functions in all or most of a state. Of the nine states for which RTOs operate in all or most of their territories, three are among the states with the eight highest retail prices, five are among the states with the eight lowest retail prices, and one has the median retail price.

A stronger correlation exists between high retail prices and ISOs that operate within a single state. New York (NYISO), Texas (ERCOT), and California (CAISO) are among the states with the eight highest retail prices.

There is also a strong correlation between retail price and whether a state permits retail choice. Six of the nine states without retail choice have retail prices below the median, and they have the six lowest retail prices. In contrast, of the eight states with retail choice, five have retail prices above the median, including the three states with the highest prices; two have retail prices below the median; and one has the median retail price.

When the combined effects of RTO and ISO operations and retail choice are examined, with one exception, there is little correlation among the various combinations that is not accounted for within the separate RTO, ISO, and retail choice correlations. The three states without retail choice that have RTOs operating in all or most of their territories are among the eight states with the lowest retail prices.

An even stronger correlation exists between a fuel mix with a relatively high percentage of coal and lower prices. Among the eight states with the highest percentage of coal in their fuel mixes, six have retail prices below the median, one has the median retail price, and one has a retail price greater than the median. In contrast, among the eight states that have the lowest percentage of coal in their fuel mixes, seven have retail prices higher than the median. The state with the median percentage of coal in its fuel mix has a retail price less than the median.

The correlation between the percentage of natural gas in the fuel mix and retail prices is the mirror image of coal's. Among the eight states with the highest percentage of natural gas in their fuel mixes, seven have retail prices greater than the median, and one has a retail price less than the median. In contrast, among the eight states with the lowest percentage of natural gas in their fuel mixes, six have retail prices less than the median, one has the median retail price, and one has a retail price greater than the median. The state with the median percentage of natural gas in its fuel mix has a retail price less than the median.

Nuclear-powered generation facilities seem to be the price levelers. Among the eight states with the highest percentage of nuclear power in their fuel mixes, four have retail prices greater than the median, three have retail prices less than the median, and one has the median retail price. Similarly, among the eight states with the lowest percentage of nuclear power in their fuel mixes, four have retail prices greater than the median and four have retail prices less than the median. The state with the median percentage of nuclear power in its fuel mix has a retail price less than the median.

As might be expected, the percentage of coal in a state's fuel mix is strongly and positively correlated with that state's air pollution emissions (tons per kWh). This is illustrated by the data in Table 15, which shows, for each state, its rank among the 17 (subject) states with respect to price, fuel mix, and air pollution emissions.

Table 15. Price, Fuel, and Emissions Correlations

	Rank					
St	**Price**	**Coal**	**CO_2**	**SO_x**	**No_x**	**N gas**
WA	1	16	17	17	17	12
IN	2	1	1	2	1	16
MO	3	3	2	6	3	13
VA	4	9	8	8	7	8
NC	5	5	7	7	12	15
GA	6	4	5	3	6	9
OH	7	2	3	1	2	17
IL	8	8	12	9	11	14
MI	9	6	4	5	4	10
AZ	10	10	13	15	9	5
PA	11	7	10	4	8	11
TX	12	11	6	11	10	3
FL	13	12	9	10	5	4
CA	14	17	16	16	14	1
NJ	15	14	15	14	16	7
MA	16	13	11	12	13	2
NY	17	15	14	13	15	6

Notes: Green cells represent the eight highest-ranking states, purple cells represent the eight lowest-ranking states, and orange cells represent the states with median values. N gas, natural gas.

Six of the eight states with the highest percentage of coal in their fuel mixes are also among the eight states with the highest CO_2 emissions. Conversely, six of the eight states with the lowest percentage of coal in their fuel mixes are also among the eight states with the lowest CO_2 emissions. The coal–NO_X pattern is the same as the coal–CO_2 pattern. There is an even more pronounced correlation between high coal use and high SO_X emissions: seven of the eight states with the highest percentage of coal in their fuel mixes are also among the eight states with the highest SO_X emissions, and the eight states with the lowest percentage of coal in their fuel mixes are also the eight states with the lowest emissions of SO_X.

Natural gas as a percentage of a state's fuel mix is significantly and inversely related to the level of air pollution emitted by electric energy generation within the state. Five of the eight states with the highest percentage of natural gas in their fuel mixes are among the eight states with the lowest CO_2 and NO_X emissions, and five of the eight states with the lowest percentage of natural gas emissions are among the eight states with the highest CO_2 and NO_X emissions. This inverse relationship is even more pronounced with respect to SO_X emissions: seven of the eight states with the highest percentage of natural gas in their fuel mixes are among the eight states with the lowest SO_X emissions, and six of the eight states with the lowest percentage of natural gas within their fuel mixes are among the eight states with the highest SO_X emissions.

Retail choice is modestly correlated with lower air pollution emissions in these states. Emissions among the eight states with retail choice are as follows:

- For CO_2,
  - three states are among the eight with the highest emissions and
  - five states are among the eight with the lowest emissions;
- for SO_X,
  - three states are among the eight with the highest emissions,
  - four states are among the eight with the lowest emissions, and
  - one has the median emissions; and
- for NO_X,
  - three states are among the eight with the highest emissions and
  - five states are among the eight with the lowest emissions.

Emissions among the nine states without retail choice are as follows:

- For CO_2,
  - five states are among the eight with the highest emissions,
  - three are among the eight with the lowest emissions, and
  - one has the median emissions;
- for SO_X,
  - five states are among the eight with the highest emissions and
  - four are among the eight with the lowest emissions; and

- for NO_X,
  - five states are among the eight with the highest emissions,
  - three are among the eight with the lowest emissions, and
  - one has the median emissions.

A more significant correlation exists between RTO or ISO operations and air pollution emissions. Emissions among the nine states for which RTOs operate within all or most of their territories are as follows:

- For CO_2,
  - five states are among the eight with the highest emissions and
  - four are among the eight with the lowest emissions;
- for SO_X,
  - six states are among the eight with the highest emissions,
  - two are among the eight with the lowest emissions, and
  - one has the median emissions; and
- for NO_X,
  - six states are among the eight with the highest emissions and
  - three are among the eight with the lowest emissions.

Emissions in the three states for which an ISO operates exclusively within all or most of their territories are as follows:

- For CO_2,
  - one state is among the eight with the highest emissions and
  - two are among the eight with the lowest emissions, and
- for SO_X and NO_X,
  - no state is among the eight with the highest emissions,
  - two states are among the eight with the lowest emissions, and
  - one has the median emissions.

The one state for which an RTO operates within some of its territory is among the eight states with the highest emissions for CO_2 and SO_X and is among the eight states with the lowest emissions for NO_X.

Emissions from the four states without RTO or ISO functions are as follows:

- For CO_2,
  - one state is among the eight with the highest emissions,
  - two are among the eight with the lowest emissions, and
  - one has the median emissions;
- for SO_X,
  - one state is among the eight with the highest emissions and
  - three are among the eight with the lowest emissions; and
- for NO_X,
  - two states are among the eight with the highest emissions,
  - one is among the eight with the lowest emissions, and
  - one has the median emissions.

Finally, there are mixed correlations with respect to RTO, ISO, and retail choice market patterns. There is little correlation between market pattern and emissions in the five states without retail choice that have few or no RTOs or ISOs operating within their territories. However, a modest correlation between market pattern and emissions exists in the six states with retail choice that have an RTO operating within all of their territories. Among these states, the emissions are as follows:

- For CO_2,
  - four states are among the eight with the highest emissions and
  - two are among the eight with the lowest emissions;
- for SO_X,
  - three states are among the eight with the highest emissions,
  - two are among the eight with the lowest emissions, and

    - one has the median emissions; and

- for NO_X,
    - three states are among the eight with the highest emissions and
    - three are among the eight with the lowest emissions.

Emissions are mixed among the three states without retail choice that have RTOs operating in all or most of their territories. All three are among the eight states with the highest CO_2 emissions, but all three are also among the eight states that have the lowest SO_X and NO_X emissions.

Among the three states with ISOs operating exclusively within all or most of their territories, all are among the eight states with the lowest SO_X and NO_X emissions, and only the one without retail choice is among the eight states with the highest CO_2 emissions.

Retail choice is not correlated with fuel mix in these states. Among the states with the highest percentage of coal in their fuel mixes, four have retail choice and four do not, and among the states with lowest percentage of coal in their fuel mixes, four have retail choice and four do not. The state with the median percentage of coal in its fuel mix does not have retail choice. This pattern is identical for natural gas.

RTO or ISO operations are correlated with fuel mix. Of the nine states that have an RTO operating within all or most of their territories, six are among the eight states with the highest percentage of coal in their fuel mixes, two are among the eight states with the lowest percentage of coal in their fuel mixes, and one has the median percentage of coal in its fuel mix. For these states, the pattern is reversed for natural gas: three of these states are among the eight states with the highest percentage of natural gas in their fuel mixes and six are among the eight states with the lowest percentage of natural gas in their fuel mixes. Similarly, all three states with only a single ISO operating within all or most of their territories are among the eight states with the lowest percentage of coal in their fuel mixes, and all three are among the eight states with the highest percentage of natural gas in their fuel mixes. The five states with few or no RTO or ISO operations within their borders have more balanced fuel mixes. There is little or no correlation between RTO–ISO–retail choice combinations and fuel mix.

Implications for Renewable Electric Energy Generation

End-use prices and air pollution emissions are important determinants of renewable electric energy potential. The analyses above show that the fuel type most associated with lower retail prices, coal, is also the fuel type most associated with higher CO_2, SO_X, and NO_X air pollutants. Natural gas, a fuel that is moderately associated with lower CO_2, SO_X, and NO_X air pollutants, is, unfortunately, strongly associated with higher retail prices. This suggests a price gap that could close if coal's greater external costs were somehow internalized into the price of generating electric energy from coal. Closing that price gap would not only make cleaner burning natural gas more competitive, it would also reduce the gap between carbon-based fuels and renewable fuels.

Indeed, as seen in Table 16, the Energy Information Administration's estimate of levelized costs of new generation resources in 2016 shows how this gap is likely to be reduced if the external costs of generating electric energy from coal are reduced by the introduction of more expensive "clean" coal technology.

Table 16. Estimated Levelized Cost of New Generation, 2016

Electric energy generation plant type		$/MWh
Coal	Conventional	100.40
	Advanced	110.50
	Advanced with CCS	129.30
Natural gas	Conventional combined cycle	83.10
	Advanced combined cycle	79.30
	Advanced combined cycle with CCS	113.30
	Conventional combustion turbine	139.50
	Advanced combustion turbine	123.50
Nuclear		119.00
Wind	Onshore	149.30
	Offshore	191.10
Solar	Photovoltaic	396.10
	Thermal	256.60
Geothermal		115.70
Biomass		110.00
Hydro		119.90

Note: CCS, carbon capture and sequestration.

Source: Energy Information Administration, Annual Energy Outlook 2010, December 2009, DOE/EIA-0383(2009), http://www.eia.doe.gov/oiaf/aeo/pdf/2016levelized_costs_aeo2010.pdf.

It would be difficult for individual states to undertake the task of internalizing the costs of coal's high air pollution emissions levels. So this is a task that ultimately must be undertaken by the federal government enacting a carbon policy such as carbon taxes, cap and trade, or new air pollution mandates.

High retail prices were also found in the three states wherein a single ISO operated exclusively. This price effect seems to be driven by the fuel mix in those states, for each of them has a relatively high percentage of natural gas in its fuel mixture.

States with retail choice also tend to have high retail prices. The presence or absence of retail choice did not have much, if any, correlation with state fuel mixtures. It would therefore appear, as previously discussed, that competitive options have not developed to the extent that would allow many end users in retail choice states to keep prices near or below rates set by traditional cost-of-service, rate-of-return regulation. Continuing high prices in these markets could cause renewable sources of electric energy to become more cost competitive.

3. State Laws and Regulations Affecting Renewable Power Generation

Renewable Electric Energy Purchasing and Pricing Mandates

Renewable Energy Portfolio Standards

Many states have adopted goals or requirements to utilize renewable energy sources for a specified portion of the state's electricity demand. Although terminology may vary somewhat from state to state, the industry generally refers to these goals or requirements as RPS.

Of the 17 states analyzed, 15 have statewide RPS programs.[442] Florida recently passed a statewide program. However, Florida's commission is still in the process of establishing goals that must be approved by the legislature.[443] Georgia and Indiana currently have no state-initiated RPS program.[444]

The states analyzed differ on the state action that originated the state's RPS program. Three basic trends exist in the 15 states analyzed with RPS programs.

- The public utilities commission took the first and only lead in creating the RPS.

442 *See* Appendix RPS-1 of this report.

443 34 FLA. ADMIN. WEEKLY 6708 (Dec. 19, 2008).

444 Energy Information Administration, Renewable Portfolio Standards and State Mandates by State, http://www.eia.doe.gov/cneaf/solar.renewables/page/trends/table28.html (April 2009) (last visited May 10, 2010).

- The legislature took the lead, and the implementation of RPS was then delegated to (a) the traditional public utilities commission, (b) a newly created agency, or (c) a combination of the two.[445]
- The citizenry took the lead by voting for RPS programs in a statewide popular initiative.

Table 17 below outlines the actions originating RPS programs in the 17 states analyzed.

Table 17. Origins of RPS Programs

Originated by legislation	Originated by statewide vote	Originated by state utility commission	No statewide RPS program
California[446] Florida[447] Illinois[448] Massachusetts[449] Michigan[450] New Jersey[451] North Carolina[452] Ohio[453] Pennsylvania[454] Texas[455] Virginia[456]	Missouri[457] Washington[458]	Arizona[459] New York[460]	Indiana[461] Georgia[462]

445 *See* APPPENDIX RPS-4 of this report.

446 CAL. PUB. UTIL. CODE §§ 399.11-399.20 (Deering 2009) (enacted 2002).

447 FLA. STAT. ANN. §366.92 (209) (enacted 2008).

448 20 ILL. COMP. STAT. ANN. 3855 et. seq. (LexisNexis 2009) (enacted 2007).

449 MASS. GEN. LAWS cha. 25A ,§ 11F. (2009) (enacted 1997).

450 MI. PUBLIC ACT 295 OF 2008 (enacted 2008).

451 N.J. STAT. §48:3-49 et. seq.(2009) (enacted 1999).

452N.C. GEN. STAT. § 62-133.8 et. seq. (enacted 2007).

453 OHIO REV. CODE §4828.64 et. seq. (enacted 2008).

454 73 PA. STAT. § 1648 et. seq. (enacted 2004).

455 TEX. UTIL. CODE § 39.904 (enacted 1999).

456 VA. CODE §56-585.2 (enacted 2009).

457 Proposition C (passed 2008) http://www.sos.mo.gov/elections/2008petitions/2008-031.asp (last visited May 11, 2010).

458 Initiative 937 (passed 2006) http://www.secstate.wa.gov/elections/initiatives/text/I937.pdf (last visited May 11, 2010).

459 AZ. ADMIN. CODE R14-2-1801et. seq.(2009) (adopted 2006).

All 15 statewide RPS programs set the minimum amount of power that should be generated using renewable energy sources. Most set standards that incrementally increase over time to a specific overall goal. Beyond the general structure of setting a renewable goal, the states differ greatly in implementation strategy.

All but 2 of the 15 states set their RPS goals as a percentage goal for renewable energy use in that state.[463] The only two exceptions are Texas and Michigan. Texas expresses its goal as a total number of MW of installed renewable generation capacity instead of a percentage (although a percentage goal was used in the decision setting the MW goal).[464] Michigan set a hybrid goal that involves a certain MW goal plus a percentage goal.[465]

The other 12 states analyzed with statewide goals calculated their goals based on percentages of a particular load. It is important to note that the percentage goal expressed in the RPS goals does not normally equate to a percentage of the total actual electrical load of the state.[466]

Although similar in purpose, the states with RPS programs have implemented those programs in differing ways using very different structures. These differences make state-to-state comparisons of statewide RPS programs very difficult. This analysis identified five major factors that must be considered when comparing state goals in a consistent manner. The five major factors are:

- goal calculation methodology,
- a definition of what is a renewable energy source,
- differences in who administers the program,
- differences in implementation and enforcement, and
- differences in cost recovery mechanisms.

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460 NYPSC ORDER 03-E-0188 (adopted 2004).

461 Energy Information Administration, Renewable Portfolio Standards and State Mandates by State, http://www.eia.doe.gov/cneaf/solar.renewables/page/trends/table28.html (April 2009) (last visited May 10, 2010).

462 *Id.*

463 *See* Appendix RPS-1 of this report.

464 TEX. UTIL. CODE §39.904(a) and 16 TAC §25.173(a)(1).

465 MICH. COMP. LAWS SERV. § 460.1027 (LexisNexis 2009).

466 *See* the "Goal Calculation Methodology" section of this report.

Goal Calculation Methodology

As in any calculation, the baseline against which the percentage is applied plays a crucial role. From the analysis of the 14 subject states with RPS programs, the following two major factors were considered:

- How did the state define the baseline against which the percentage would be applied?
- Which electric suppliers were included in the RPS requirements?

Baseline

In defining the baseline, the states used one of three major approaches: (a) current year approach, (b) an average of prior periods' loads, or (c) a modified prior load.[467] Table 18 summarizes the differing baseline approaches by state.

Table 18. Baseline Comparison for State RPS Programs[468]

State	Approach
Arizona	Current year for each "affected utility"
California	Current year for each utility
Florida	Rulemaking underway
Georgia	—
Illinois	Previous year for each utility
Indiana	—
Massachusetts	Current year
Michigan	Utility can choose to whether to normalize or take the average of three prior years; also based on utility's number of customers. The utility has a minimum number of MW required from a renewable source.
Missouri	Current year for each utility
New Jersey	Current year
New York	Based on growth load in 2002 State Energy Plan
North Carolina	Current year
Ohio	For utilities: average of the total kWh sold under standard service offered For service companies: average of the three preceding years of the total annual number of kWh sold to all retail electric consumers in the state
Pennsylvania	Current year
Texas	Not applicable—MW goal rather than percentage
Virginia	Total electric energy in the base year, which is calculated by determining a participating utility's average jurisdictional retail load in 2007 and

467 *See* Table 17.

468 *See* Appendix RPS-1 for authority citing.

	subtracting the average energy supplied from nuclear power to that utility in 2004–2006
Washington	Average load for the utility for the previous two years

Electric Suppliers Included

In addition to the different baseline methodologies, the group to whom the baseline applies also differs by state. In applying the percentage goal to the baseline, all states (except Texas) applied the percentage goal to the baseline loads of a defined group of power suppliers (e.g., *affected utility*, *public utility*, or *electric distribution company*).[469] Texas set a statewide goal of a certain number of MW that is distributed to the various suppliers.

In the majority of states, the RPS requirements are restricted to specified providers of electricity, not to every LSE in the state. This application means that the RPS required percentage will not necessarily equate to the same percentage of a state's electric consumption. For instance, Washington's use of the term *qualifying utility* (which involves cascading references to seven different code sections to discern a final definition) includes about 17 of the state's 62 utilities for about 84 percent of the state load.[470] Therefore, an important aspect for assessing the effectiveness of state RPS programs is to identify the entities to which the baseline applies.

In states where the traditional utility structure remains in place, the RPS requirements are normally confined to the regulated utility level.[471] However, each state differently defines the extent to which utilities are included in the RPS programs. In some states, all providers (IOUs, electric cooperatives, and municipal utilities) must meet the requirements. In others, only certain utilities are required to meet the requirements. If the traditional regulatory commission has been assigned to implement the program or directly created the RPS program through regulation, the regulatory commission's authority will typically extend only to those utilities already under its jurisdiction, thus limiting the extent of the RPS program's application.

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469 *See* Appendix RPS-1.

470 Database of State Incentives for Renewables & Efficiency, Washington: Incentives/Policies for Renewable Energy, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=WA15R&re=1&ee=0 (Sept. 21, 2009) (last visited May 10, 2010).

471 *Id.*

Further complicating an analysis applying the baseline to power suppliers is differences in the level of electric "deregulation" (market competition in supplying retail electricity) in each state. In states such as Massachusetts and New Jersey, where electric deregulation is very advanced, the requirement has been transferred from the traditional utility to an array of power suppliers and the default service provider of the traditional distribution company. In those states, the RPS requirement is calculated as a percentage times the sales (kWh) to end-use customers by each supplier or provider.[472] Table 19 sets out the application of this principle by state.

Table 19. Entities to Which RPS Requirements Apply

State	Entities
Arizona	"Affected utilities"—any public service corporation serving retail load with at least half its customers in Arizona.[473] Some electric power cooperatives are affected utilities.[474]
California	All retail sellers of electricity.[475] Retail sellers do not include: (a) cogeneration parties, (b) Department of Water Resources, or (c) a local publicly owned electric utility under Section 387.[476]
Florida	"Provider" means an IOU in Florida[477]
Georgia	No RPS program.
Illinois	Illinois Power Agency has procurement directive for "electric utilities that on December 5, 2005 had at least 100,000 customers."[478] Alternative retail electric suppliers have the same requirements as the electric utilities pertaining to the percentage of renewable sources and clean coal.[479] Electric utilities serving retail customers outside of their service areas are subject to the requirements of Section 16-115 (including renewables goals).[480]
Indiana	No RPS program.
Massachusetts	Class I (in service after December 31, 1997) on "all retail electricity suppliers."[481]

472 *See* Table 19.

473 AZ. ADMIN. CODE R14-2-1801.

474 AZ. ADMIN. CODE R14-2-1814.

475 CAL. PUB. UTIL. 399.12(e).

476 CAL. PUB. UTIL. 399.12(G).

477 FLA. STAT. ANN. §366.92(2)(B).

478 20 ILL. COMP. STAT. ANN. 3855 §1-75(a) (LexisNexis 2009).

479 220 ILL. COMP. STAT. ANN. 5/16-115 (LexisNexis 2009).

480 220 ILL. COMP. STAT. ANN. 5/16116(c) (LexisNexis 2009).

	Class II (in service before December 31, 1997) on all retail electric suppliers providing service under contracts executed on or after January 1, 2009.[482]
Michigan	Electric providers whose rates are regulated by the Michigan Public Service Commission.[483] Alternative electric suppliers and coops that have elected to become member-regulated under the electric cooperative member-regulation act.[484] Municipal-owned electric utilities.[485]
Missouri	"Electric utilities" as defined by 386.020.[486]
New Jersey	Each supplier or provider means electric power supplier or a basic generation service provider, as defined at NJAC 14:4-1.2.[487]
New York	Surcharge imposed on retail electric rates—requirements are imposed on NYSERDA for centrally administered, incentive-based procurement.[488] "Revenue necessary to support this program will be raised through a non-bypassable volumetric wires charge on the delivery customers of each of the State's investor-owned utilities."[489] "Because of our adoption of a central procurement model, it is not necessary to create an alternative compliance mechanism to ensure individual load serving entities' compliance with RPS targets."[490] RPS program exempts from paying: those customers currently exempt from SBC contribution (reduced rate customers for economic development objectives).[491] Municipalities are exempt but NYC and LIPA encouraged to voluntarily participate—if LIPA participates, it can administer its portion of the goal rather than NYSERDA.[492]

481 MASS. GEN. LAWS cha. 25A §11F(a) (2009); 225 CMR 14.07.

482 MASS. GEN. LAWS cha. 25A §11F(d) (2009); 225 CMR 15.07.

483 MICH. COMP. LAWS SERV. §460.1021(1) (LexisNexis).

484 MICH. COMP. LAWS SERV. §460.1023(1) (LexisNexis).

485 Id. §460.1025(1).

486 MO. REV. STAT. §393.1030.1 and 393.1025.3 for definition of utility (2009).

487 N.J. ADMIN. CODE §14.8-2.1 and 14.8-1.2 "supplier/provider" (2009).

488 NYPSC Case 030E-0188 p.5.

489 *Id.* at 11.

490 *Id.* at 10.

491 *Id.* at 55.

492 *Id.*

	Explicitly imposed upon Central Hudson Gas & Electric Corp., Consolidated Edison Company of NY, Inc., Niagara Mohawk Power Corp., New York State Electric & Gas Corp., Rochester Gas & Electric Corp., and Orange and Rockland Utilities, Inc.[493]
North Carolina	"Each electric public utility."[494] Electric membership corporations and municipal-owned utilities.[495]
	North Carolina Admin Rule R8-60 on integrated resource planning only applies to: "Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; Virginia Electric and Power Company, d/b/a Dominion North Carolina Power; the North Carolina Electric Membership Corporation; and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources."[496]
Ohio	Electric distribution utility.[497]
Pennsylvania	"[T]he electric energy sold by an electric distribution company or electric generation supplier to retail electric customers in this Commonwealth…."[498]
Texas	The Texas PUC "shall adopt rules" that "establish the minimum annual renewable energy requirement for each retail electric provider, municipally owned utility, and electric cooperative in this state" so that the goals are met.[499] The Commission created a "program administrator"—an independent entity to serve as the trading program administrator.[500]
Virginia	"Any investor-owned utility *may* [emphasis added] apply to the Commission to participate in the renewable portfolio standard programs…" *and* the Commission must agree that the utility has a reasonable expectation of achieving 12% renewable by 2022. Note: The IOU would do so to get a higher ROE in its rate case.[501]
Washington	Applies to any "qualifying utility," which means an electric utility per RCW 19.29.010 serving more than 25,000 customers.[502] Where "electric utility" per RCW 19.29.010 means "a consumer-owned or investor-owned utility as defined in this section."[503] Where a "consumer-owned utility" means "a municipal electric utility formed

493 *Id.* at 83–4 (Commission orders # 4 to 9).

494 N.C. GEN. STAT. §62-133.8(b).

495 N.C. GEN. STAT. §62-133.8(c).

496 N.C. ADMIN. CODE §R8-60(b).

497 OHIO REV. CODE ANN. §4928.64 (LexisNexis 2009).

498 73 PA. STAT. ANN. §1648.3(a)(1) (2009) AND PA. CODE §75.61 (2009).

499 TEX. UTIL. CODE ANN. §39.904(c) (2009).

500 16 TEX. ADMIN. CODE §25.173(g).

501 VA. CODE ANN. §56-585.2.B (2009).

502 WASH. REV. CODE §19.285.030(16) (LexisNexis 2009).

503 WASH. REV. CODE §19.29.010(12) (LexisNexis 2009).

	under Title 35 RCW, a public utility district formed under Title 54 RCW, an irrigation district formed under chapter 87.03 RCW, a cooperative formed under chapter 23.86 RCW, or a mutual corporation or association formed under chapter 24.06 RCW, that is engaged in the business of distributing electricity to more than one retail electric customer in the state."[504] And where an "investor-owned utility" means a "company owned by investors that meets the definition of RCW 80.04.010 and is engaged in distributing electricity to more than one retail electric customer in the state."[505] In which, "electrical company" per RCW 80.04.010 includes "any corporation, company, association, joint stock association, partnership and person, their lessees, trustees or receivers appointed by any court whatsoever (other than a railroad or street railroad company generating electricity solely for railroad or street railroad purposes or for the use of its tenants and not for sale to others), and every city or town owning, operating, or managing any electric plant for hire within this state. 'Electrical company' does not include a company or person employing a cogeneration facility solely for the generation of electricity for its own use or the use of its tenants or for sale to an electrical company, state or local public agency, municipal corporation, or quasi municipal corporation engaged in the sale or distribution of electrical energy, but not for sale to others, unless such company or person is otherwise an electrical company."[506]

Notes: LIPA, Long Island Power Authority; NJAC, New Jersey Administrative Code; NYSERDA, New York State Energy Research and Development Authority; RCW, Revised Code of Washington; SBC, System Benefits Charge.

Certain other peculiarities affect the application of the RPS goals. For instance, Pennsylvania's RPS requirements do not begin until a power supplier has finished cost recovery from electric restructuring. Both Illinois[507] and California[508] provide for goal adjustment for cost reasons. The Pennsylvania commission can excuse for force majeure events.[509]

Definitions of Renewable Energy Source

In addition to understanding the differences in how each state defines and calculates the RPS goal, a full analysis of the RPS requirements also requires consideration of the different resource options that each state allows to fulfill the goal. Unfortunately, the approaches taken by the states tend to vary tremendously. Analyzing the differing approaches to defining a *renewable* requires considering two major components: (a) the definitions of *renewable energy* within the

504 WASH. REV. CODE §19.29.010(6) (LexisNexis 2009).

505 WASH. REV. CODE §19.29.010(19) (LexisNexis 2009).

506 WASH. REV. CODE §80.04.010 (LexisNexis 2009).

507 20 Ill. COMP. STAT. §3855/1-75(c)(2) (LexisNexis 2009).

508 CAL. PUB. UTIL. CODE §399.15(d) (2009).

509 PA. CODE §75.66 (2009).

context of the RPS programs And (b) the subgoals into which the RPS requirements may be divided.

Defining Renewable

The 15 subject states with RPS programs have many similarities in the definition of a renewable energy source for RPS-qualified generation resources. All include a general acceptance of biomass, hydropower, solar thermal and photovoltaic, and wind as renewable energy sources. Appendix RPS-2 summarizes the definitions of renewable energy source by state.

However, even within those generally accepted renewable energy sources, the states differ in which resources qualify. The definition of biomass (and biogas) has a wide array of sources and restrictions. Those are summarized into general categories in Table 20.

Table 20. Biomass and Biogas Comparison[510]

State	Biogas	Biomass	Exclusions
Arizona	Gas derived from plants or municipal waste[511]	Raw or processed plant-derived organic matter[512]	Painted or treated wood or tires[513] Wood stoves, furnaces, and fireplaces[514]
California	Digester gas[515]	General waste[516]	All MSW combustion (except one grandfathered unit)[517]
Florida	Gases derived from biomass[518]	Forest, municipal, and agricultural wastes[519]	—

510 Note: the definitions of biomass are extremely detailed in some states; comparisons provided in Table 20 do not necessarily include all details of the state definitions and are for illustrative purposes only.

511 AZ. ADMIN. CODE R14-2-1802.A.1 (2009).

512 AZ. ADMIN. CODE R14-2-1802.A.2 (2009).

513 *Id.*

514 AZ. ADMIN. CODE R14-2-1802.B.2 (2009).

515 CAL. PUB. RES. §25741 (2009).

516 *Id.*

517 CAL. PUB. UTIL. CODE §399.11(c)(2) (2009).

518 FLA. STAT. ANN. §366.29(2)(C) USING §366.91(2)(A).

Georgia	—	—	—
Illinois	Not mentioned	Biodiesel; crops and organic waste such as trees and tree trimming[520]	Burning of trees, garbage, office waste, or treated wood[521]
Indiana	—	—	—
Massachusetts	Included in biomass[522]	Must be "low emission"[523]	—
Michigan	Included in biomass[524]	Organic matter; must replenish over human, not geological, time; municipal waste is listed as its own category[525]	Must not be derived from fossil fuels[526]
Missouri	Wastewater treatment gas[527]	Crops grown for energy, agriculture residues, untreated wood[528]	—
New Jersey	Not mentioned	Biomass cultivated in a sustainable manner; municipal waste if resource recovery and environmentally sound[529]	—
New York	Sewage and manure digestion[530]	Direct combustion (may be combined with fossil fuels but only credit for renewable portion)[531]	—
North Carolina	Included in biomass[532]	Agricultural, animal, and wood wastes; energy	—

519 FLA. STAT. ANN. §366.29(2)(C) USING §366.91(2)(A).

520 20 ILL. COMP. STAT. 3855/1-10 (LexisNexis 2009).

521 *Id.*

522 22 MASS. CODE REGS. 14.05(1)(a)(7) and 225 MASS. CODE REGS. 15.05(1)(a)(8) (2009).

523 *Id.*

524 MICH. COMP. LAWS SERV. 460.1003(f) (LexisNexis 2009).

525 *Id.*

526 *Id.*

527 393 MO. REV. STAT. §1025 (2009).

528 *Id.*

529 N.J. REV. STAT. 48:3-51 "Class I Renewable Energy" (2009).

530 NY Pub. Service Comm. Order, Case 03-E-0188 Appendix B.

531 *Id.*

532 N.C. GEN. STAT. §62-133.8(a)(8) (2009).

		crops[533]	
Ohio	Anaerobic digestion of organic material[534]	Organic material from plants or animals on a renewable basis[535]	Must not use direct combustion[536]
Pennsylvania	Anaerobic digestion of organic material methane[537]	MSW; pulping byproducts[538]	—
Texas	Included in biomass[539]	Generally, "biomass or biomass-based waste products"[540]	—
Virginia	Anaerobic decomposition of animal waste[541]	Must be sustainable biomass; MSW[542] Requirement to use not more than 1.5 million tons of wood waste[543]	—
Washington	From sewage treatment facilities[544]	Animal waste, wood, dedicated energy crops[545]	Treated wood, municipal waste, old-growth forests, black liquor[546]

Note: —, no applicable statutory references.

Further, each state also treats hydropower very differently. Generally, the states use one or a combination of three approaches: (a) hydro is included or excluded based on the date of installation, (b) hydro is included based on the total number of MW, or (c) hydro is included or excluded based on its environmental impact. In general, the majority of states qualify

533 *Id.*

534 OHIO REV. CODE ANN. §4901:1-40-01(D) (LexisNexis).

535 OHIO REV. CODE ANN. §4901:1-40-01(E) (LexisNexis).

536 *Id.*

537 PA . STAT. ANN. §1648.2(8) (2009).

538 PA. STAT. ANN §1648.2(7) (2009).

539 TEX. UTIL. CODE §39.904(e) (2009).

540 *Id.*

541 VA. CODE ANN. §56-585.2(F) (2009).

542 VA. CODE ANN. §56-576 (2009).

543 *Id.*

544 WASH. REV. CODE §19.285.030(18) (LexisNexis).

545 *Id.*

546 *Id.*

hydropower for RPS programs only when the hydropower is relatively new and includes no new dams or other flow impairments in the waterway. Appendix RPS-3 provides a summary of how each state treats hydropower.

Because of the large capacity of existing hydropower facilities, the manner in which states treat hydropower in their RPS programs can have a significant impact on the overall goal. For example, compare New York and Washington states. In both of these heavily hydro-dependent states, the raw percentage goal would appear to have New York leading with a stated RPS goal of 24 percent by 2013 compared to Washington's 2013 RPS goal of 3 percent. However, New York's RPS guidelines include the 19.3 percent of existing hydro as a renewable energy source under its RPS program, whereas Washington explicitly excludes existing hydro from its RPS program.

Resource availability restrictions have also influenced the states' definitions of renewable energy under the RPS. All coastal states studied included ocean resources, such as ocean wave, ocean thermal, and tidal resources. States without large water bodies (oceans or the Great Lakes) did not include these resources. Interestingly, in the Great Lakes area, Illinois did not list wave energy as a potential resource, whereas Michigan did.

The coal-producing states in the analysis (Illinois, Ohio, and Pennsylvania) have all included some type of provision for coal. The Illinois provision for clean coal runs parallel to the RPS standards with similar goals.[547] Ohio includes clean coal as a renewable resource.[548] Pennsylvania includes waste coal as renewable resource.[549]

Further complicating an analysis of what is considered renewable power for RPS standards is the differences among states in whether energy efficiency programs are counted toward renewable goals. The Table 21 shows the differences in approach.

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547 20 ILL. COMP. STAT. 3855/1-10 (LexisNexis 2009).

548 OHIO REV. CODE ANN. §4928.01(A)(34)(c) (LexisNexis 2009).

549 PA. STAT. CODE ANN. §1648.2 (2009).

Table 21. Includes Efficiency as Way to Meet RPS

State	Approach
Arizona	Not included in definition or allowed in pilots for renewable energy; however, several efficiency products are allowed under the distributable definitions.[550]
California	Efficiency is separate from renewables in legislative intent.[551] Separate legislative directive for CPUC to administer efficiency programs.[552]
Florida	Not included in legislation; rulemaking underway.
Georgia	No statewide RPS program.
Illinois	Included in definitions section[553] but does not count toward RPS goals.[554]
Indiana	No statewide RPS program.
Massachusetts	No reference to energy efficiency programs in statutes[555] or administrative code[556] authorizing RPS program.
Michigan	Energy optimization plan mirrors RPS program;[557] optimized energy credits and renewable energy credits are interchangeable.[558]
Missouri	Energy efficiency is separate from RPS goals.[559]
New Jersey	None of the definitions of renewable energy in the RPS program includes efficiency programs.[560]
New York	Energy efficiency cannot be used to meet RPS goals,[561] but the NYPSC does state that reducing the overall load increases the overall proportion of renewables in the energy mix.[562] Whether to add efficiency to meet RPS goals is to be addressed in the 2009 Report.[563]

550 AZ ADMIN. CODE R14-2-1802(d) (2009).

551 CAL. PUB. UTIL. CODE §399(3) "energy efficiency" and §399(4) "renewable energy" (2009).

552 CAL. PUB. UTIL. CODE §399.4 (2009).

553 20 ILL. COMP. STAT. 3855/1-5(4) (LexisNexis 2009).

554 ILL. COMP. STAT. 3855/1-5 (LexisNexis 2009).

555 MASS. ANN. LAWS cha. 25 §11.F (LexisNexis 2009).

556 225 MASS. CODE REGS. 14.01-16.12 (2009).

557 MICH. COMP. LAWS SERV. §460.1071 (LexisNexis 2009).

558 MICH. COMP. LAWS SERV. §460.1083(2)(b) (LexisNexis 2009).

559 MO. REV. STAT. §393.1040 (2009).

560 N.J. ADMIN CODE 14:8-2.1 et. seq. (2009).

561 NYPSC ORDER 03-E-0188 (Sept. 24, 2004) at 12.

562 *Id.* at 9.

563 NYPSC ORDER 03-E-0188 (April 14, 2005).

North Carolina	Definitions make a distinction between energy efficiency and demand-side management.[564] Energy efficiency may be used for up to 25% of the RPS goal before 2021 and up to 40% of the RPS goal after 2021.[565]
Ohio	Up to half of RPS requirement may be met by "advanced energy resource," which includes "demand side management and energy efficiency improvement."[566]
Pennsylvania	Alternative energy source definition includes demand-side management.[567]
Texas	No mention of efficiency in RPS provisions.
Virginia	No mention of efficiency in RPS provisions.
Washington	Energy conservation goals are set separately from RPS. Each qualifying utility is to identify and pursue all conservation that is cost-effective, reliable, and feasible.[568]

Notes: CPUC, California Public Utilities Commission; NYPSC, New York Public Service Commission.

Subgoals

Many states have used certain defined subgoals to drive implementation toward a particular type of renewable energy. Table 22 provides a brief overview of the main subgoals by state.

Table 22. Subgoals to Drive Certain State Objectives

State	Subgoals
Arizona	o Distributed generation (generation behind distribution system) o Solar
California	—
Florida	o Statute allows for greater weight to wind and solar; rulemaking underway [569]
Georgia	o No statewide RPS program
Illinois	o Clean coal initiative runs parallel with RPS initiative
Indiana	—
Massachusetts	o Initiative to keep older renewable projects in operation o Initiative for energy from municipal waste
Michigan	—

564 N.C. GEN. STAT. §62.133.8(a)(4) (2009).

565 N.C. GEN. STAT. §62-133.8(b)(2)c and (c)(2)b (2009).

566 OHIO ADMIN. CODE §4901:1-40-03(A)(1); using definition in OHIO ADMIN. CODE ANN. §4928.01(A)(34 (LexisNexis 2009); OHIO ADMIN. CODE §4901:1-40-04(B)(7).

567 73 PA. CONST. STAT. §1648.2(12) (2009); 73 PA. CONST. STAT. §1648.8 (2009) (for rural electric coops).

568 WASH. REV. CODE §19.285.040(1) and (2) (2009).

569 FLA. STAT. ANN. §366.92(b)(3).

Missouri	o Solar
New Jersey	o Solar o Municipal waste
New York	o Plan is to transition to a market-based program
North Carolina	o Solar o Swine waste o Poultry waste
Ohio	o Solar o Clean coal technology
Pennsylvania	o Solar
Texas	o Limits dependence on wind but does not dictate source
Virginia	o Lumber industry waste
Washington	—

Note: —, no subgoals for a particular state

The states use these goals within a goal to drive certain development within the state. For instance, Arizona has encouraged the deployment of renewable energy sources at the customer level by creating a classification known as *Distributable Renewable Energy Resources* and requiring that a portion (X percent) of its total RPS goals be met with the Distributable category.[570] This classification includes all the renewable technologies available on a nondistributed basis with the exception of existing hydropower and new landfill gas generators.[571] Arizona also encourages the installation of many nongenerating technologies by including them as renewable energy resources (and thus making them eligible for renewable energy credits [RECs]). These nongeneration technologies include:[572]

- commercial solar heaters (commercial or municipal swimming pools);
- geothermal space heating and process heating systems;
- renewable heat and power systems (the heat from a generation process can also be counted toward the distributed renewable goal);
- solar daylighting (nonresidential);
- solar industrial process heating and cooling (industrial and commercial);
- solar heating (residential, industrial, and commercial);

570 AZ. ADMIN. CODE R14-2-1805.B (2009).

571 *Id.* at R14-1802.B.

572 *Id.*

- solar cooling (residential, industrial, and commercial); and
- solar water heating (residential, industrial, and commercial).

Another good example is New Jersey, which has an aggressive subgoal to implement solar power in the state.[573] To illustrate the impact of these subgoals, the maps of solar power potential in New Jersey show only modest potential.[574] However, New Jersey ranks behind only California in the percentage of solar power for summer generation of the 17 subject states.[575]

North Carolina has addressed its agricultural waste issues with specific RPS subgoals, each dedicated to a waste stream. Of North Carolina's 7 percent overall goal in 2012, 0.07 percent must come from swine waste.[576] North Carolina set a specific goal of 170,000 MW to be generated from poultry waste by 2012, increasing to 700,000 MW by 2013.[577]

In response to concerns that older renewable projects would not be used because of economic impacts, Massachusetts created a two-tiered system designed to promote the use of older projects.[578]

RPS Program Structure

The structure of the RPS programs varies greatly by state. Three appendices summarize different structural aspects of the RPS programs by state. Appendix RPS-4 summarizes who administers the RPS program by state. Appendix RPS-5 summarizes the major approach of each state in its creation and use of RECs in its implementation plan. Appendix RPS-6 summarizes the major characteristics of the implementation and enforcement provisions of each state.

With the exception of Illinois and New York, the role of implementing a strategy to meet RPS goals resides with the power supplier.[579] In nearly every state where the strategy in meeting

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573 N.J. ADMIN. CODE §14:8-2.3 (2009).

574 Energy Information Administration, Renewable Potential Maps, Middle Atlantic Division: New Jersey, New York, and Pennsylvania, http://www.eia.doe.gov/emeu/reps/rpmap/rp_mid-atl.html (Dec. 22, 2005) (last visited May 10, 2010).

575 ENERGY INFORMATION ADMINISTRATION, STATE RENEWABLE ELECTRICITY PROFILES, Table 1: Summary of Renewable Electric Power Industry Statistics (2007).

576 N.C. GEN. STAT. §62-133.8(e) (2009).

577 N.C. GEN. STAT. §62-133.8(f) (2009).

578 225 MASS. CODE REGS. 14.07 and 225 MASS. CODE REGS. 15.07.

579 *See* Appendix RPS-6.

the RPS requirements falls to the power supplier, each power supplier must file a plan or make a compliance filing with the appropriate state authority.[580]

In Illinois, the legislature decided that a centralized agency would administer the state's procurement plan for renewable energy and conduct a competitive procurement process.[581] Interestingly, the Illinois Commerce Commission must revoke an alternative energy provider's certification if the supplier has not met renewable or clean coal goals.[582]

In New York, the New York Public Service Commission (NYPSC)-directed New York State Energy Research and Development Authority also acts as a centralized administrator for renewable energy purchases.[583] The eventual goal in New York is to create a competitive market for green power when the RPS program ends.[584]

Overall, the state approaches to enforcement range from completely voluntary to punishments such as fines and license revocation.[585] Only Virginia has attempted to implement an RPS program in a voluntary fashion. Virginia's approach allows for an increase in the fair combined rate of return on common equity for each utility participating in the RPS program.[586] Some states use a default payment method with a preset charge imposed on those not meeting specified goals. For instance, both Ohio and Pennsylvania charge $45 per MWh[587] for any RPS shortage other than solar. Failing to meet the solar goal in Ohio results in a $450-per-MWh (in 2009)[588] payment, whereas in Pennsylvania a solar shortfall is calculated as 200 percent of the average market area for solar RECs within the PJM area.[589] Washington charges a flat $50 per MWh for any shortfall.[590]

580 *Id.*

581 20 ILL. COMP. STAT. 3855/1-5(A) (LexisNexis 2009).

582 220 ILL. COMP. STAT. 5/16-115(d-5) (LexisNexis 2009).

583 NYPSC ORDER 03-E-0188 (Sept. 2004).

584 *Id.* at 4.

585 *See* Appendix RPS-6.

586 VA. CODE ANN. §56-585.2.C (2009).

587 OHIO ADMIN. CODE 4901:1-40-08(A)(2); 73 PA. COMP. STAT. §1648.3(f)(3) (LexisNexis 2009).

588 OHIO ADMIN. CODE 4901: 1-40-08 (2009).

589 73 PA. COMP. STAT. §1648.3(f)(4) and PA. CODE §75.65 (2009).

590 WASH. REV. CODE §19.285.060 and WASH. ADMIN. CODE 480-109-050.

Cost Recovery

The idea of competition and lowest-cost electricity is at odds with renewable energy requirements because (at least for now) renewable energy is more expensive.[591] Therefore, in all states (except Illinois and New York), any power supplier implementing the RPS goals will experience an increase in the overall cost of power. In Illinois and New York,[592] where centralized agencies conduct the purchasing of renewable energy, those increased costs are experienced by the central purchasing agency.

All states allow for some type of recovery mechanism or cost coverage for the power supplier to remain whole on the increased costs.[593] All states without central purchasing authorities allow recovery by the power supplier via a pass-through in the rates.[594] All states use a *reasonable and prudent* standard with either review or potential review by a state governmental entity (normally the utility commission).[595] In addition to the reasonable and prudent standard, California[596] and Illinois[597] take an active role in monitoring costs and setting limits based on markets. Illinois continues with a provision that allows for a decrease in the RPS goal if it will exceed certain benchmarks. Michigan,[598] Missouri,[599] and Ohio[600] all set hard rate caps on the impact that renewable programs may have on consumers. In California, the PUC retains the authority to reject contract prices and force a rebid.[601]

Conclusion

The RPS programs of the 15 subject states illustrate a hodgepodge of overlapping and sometimes conflicting approaches. Comparing state requirements requires a greater analysis than

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591 THE MASSACHUSETTS RENEWABLE PORTFOLIO STANDARD: CONTEXT AND CONSIDERATIONS. THE AIM FOUNDATION, Oct. 2004.

592 NYPSC ORDER 03-E-0188 at 65, 83.

593 *See* Appendix RPS-7.

594 *Id.*

595 *Id.*

596 CAL. PUB. UTIL. CODE §399.15(d) (2009).

597 20 ILL. COMP. STAT. 3855/1-75(c)(1) (LexisNexis 2009).

598 MICH. COMP. LAWS SERV. §45(2) (LexisNexis 2009); Note: rate caps set by customer class.

599 MO. REV. STAT. 393.1030.2(a) and (d) (2009).

600 OHIO REV. CODE ANN. 4928.64(C)(3) (LexisNexis 2009).

601 CAL. PUBL. UTIL. CODE §399.14 (Deering 2009).

just comparing percentages. Further, state interests (such as coal mining) have influenced the approach in implementing RPS programs. The current state approaches reflect the priorities as set forth in that state. But it is unclear whether this eclectic collection of approaches meshes together to create an energy policy that is wise for the nation to follow.

From the experimentation of the different states, some favorable provisions can be gleaned. For instance, North Carolina statute requires solar contracts be "of sufficient length to stimulate the development of solar energy."[602] Texas shows great strength in overall planning "after consultation with each appropriate independent organization, electric reliability council or regional transmission organization shall: (1) designate competitive renewable energy zones in the state; (2) develop a plan to construct needed transmission for renewables; and (3) consider the level of financial commitment in whether to grant a certificate of convenience and necessity."[603] Further, Texas legislation grants the commission the authority to establish rules requiring renewable power facilities to have reactive power control capabilities.[604] Michigan includes an interesting provision for ensuring that entrepreneurial development of renewable energy resources occurs. The statute provides that electric providers with one million or more retail customers on January 1, 2008, are allowed to self-supply (including affiliates) only 50 percent of its renewable energy requirement. The remainder must come from third parties.[605] This type of provision forces utilities to look to other renewable projects beyond their internal work and provides the opportunity for anchor contracts for competitive projects.

Net Metering

Net metering service (NMS) is a mandated business arrangement between an electric energy consumer (net metering customer [NMC]) who has installed an electric energy generator at his, her, or its own premises (a net metering generator [NMG]) and an LSE required by law to purchase electric energy from the NMC when the NMC's NMG produces excess electric energy and to supply electric energy to the NMC when the NMC's NMG cannot meet his, her, or its

602 N.C. GEN. STAT. § 62-133.8(d) (2009).

603 TEX. UTIL. CODE §39.904(g) (2009).

604 TEX UTIL. CODE §39.904(l) (2009).

605 MICH. COMP. LAWS SERV. §33 (2009).

needs (such an LSE is referred to as a net metering provider [NMP]).[606] The legally mandated business arrangement has several important components, including:

- who is eligible to be an NMC,
- who is required to be an NMP,
- what types of generating facilities are eligible to be NMGs,
- what capacity limits in general are imposed on NMGs,
- what aggregate capacity limits are imposed on prospective NMCs, and
- the billing rules.

Net Metering Customers

NMC eligibility is mainly framed in terms of eligible electric energy customer classes or in catchall terms, such as customers owning qualifying NMGs (QNMGs). In a few instances, very specific and somewhat unusual eligibility criteria are enacted. Table 23 shows those eligible to be NMCs in the covered states.

606 *See* State Net Metering Laws Appendix of this report, which contains in outline form the legal parameters of the net metering laws and regulations of each covered state. Every statement or assertion made in this section is supported directly by these legal and regulatory summaries. So footnoting will be discontinued at this point for this section because all of the citations will be to the same material unless a specific state has an aberrational law or regulation that needs to be highlighted.

Table 23. NMC Eligibility in the Subject States

	Eligible NMCs					
States	Res	Comm	Ind	Agri	Owns QNMG	Other
Arizona					x	
California	x	x	x	x		
Florida					x	
Georgia	x	x				
Illinois					x	
Indiana	x					K–12 schools
Massachusetts						Distribution company customer[a] Neighborhood[b]
Michigan					x	
Missouri					x	
New Jersey					x	
New York	x	x	x	x		
North Carolina					x	
Ohio					x	Hospitals
Pennsylvania					x	
Virginia					x	
Washington					x	

[a] Massachusetts treats owners and operators of NMGs who are customers of a particular distribution company as NMCs. In addition, an NMC may designate other distribution company customers as persons with whom he, she, or it will share any net metering credits earned by the operation of the NMG. [b] Massachusetts recognizes a joint ownership/beneficial use customer category, *neighborhood*, which involves 10 or more residential customers within the same neighborhood being served by a single NMG.

All but three of the covered states add the qualifying purpose that the NMCs must have installed the NMG to meet all or part of their electric energy needs or to offset their electric energy purchases. Massachusetts, New Jersey, and New York do not specify such a purpose. Massachusetts did this explicitly to permit NMCs to become net sellers of electric energy to the grid.

Net Metering Providers

The designation of mandatory NMPs has been complicated by state electric industry restructuring to provide retail electric energy customers with the opportunity to choose which entity should serve their electric energy needs. In retail choice states, the individual retail electric energy customer may receive electric energy generation services from a competitive generator, which is usually an IPP, power broker, power marketer, or power aggregator (referred to collectively as independent load-serving entities [ILSEs]), rather than the distribution company that provides them with electric energy delivery service. As a consequence, as will be discussed in more detail below, in some retail choice states there is some confusion about whether retail electric energy customers who have elected to receive generating services from an entity other than their delivery service providers may receive NMS.

Similarly, in many states, some persons receive electric energy services from cooperatives, quasi-governmental energy districts, or municipalities instead of a traditional IOU. These other electric energy providers may or may not be covered by a state NMS mandate, and even if they are, there is some question about how the mandate will be enforced when these entities are not subject to state PUC regulation. The answer tends to be that the governing body of these other entities has the duty to make sure that NMS mandates are honored, but it is not clear what recourse is available if they do not do so. This issue should not be too disturbing where electric energy coops are involved because, by definition, the members of the coop are its electric energy customers who have the opportunity to select coop board members and instruct them about their needs and desires. However, recourse for the denial of NMS may only be through the political system when municipalities and energy districts are involved. Table 24 below shows the entities covered by a state NMS mandate for each of the covered states.

Table 24. State-Mandated NMPs

States	NMPs				
	IOUs	COOPs	E Dists	Munis	ILSEs
Arizona	x	x			
California	x	x	x	except LA W&P Dept	
Florida	x			x	
Georgia	x	x		x	
Illinois	x				x
Indiana	x				
Massachusetts	distrib				
Michigan	distrib	if chose PUC reg			x
Missouri	x	x		x	
New Jersey	x				x
New York	major				
North Carolina	major				
Ohio	distrib				x
Pennsylvania	x			as comp gen	x
Virginia	x			if chose PUC reg or as comp gen	x
Washington	x	x	x	x	

Notes: Green cells represent states with retail choice, red cells represent states without retail choice, and yellow cells represent states with suspended retail choice. comp gen, competitive generator; COOP, cooperative; distrib, distribution company; E Dist, energy district; LA W&P Dept, Los Angeles Department of Water and Power; Muni, municipality; PUC, public utility commission.

Net Metering Generators

Technology determines what types of generating facilities are QNMGs. Most states have defined QNMGs to be only those generating facilities that use renewable energy (see Table 25). But some covered states have designated QNMGs that do not use renewable energy—Georgia (fuel cells), North Carolina (combined heat and power [CHP]), Ohio (fuel cells and microturbines), and Pennsylvania (waste coal and methane derived from mines). All of the covered states designate wind and solar photovoltaic as QNMGs, and all but two states designate solar thermal. Hydro, biomass, and landfill gas are also popular.

Table 25. State-Designated QNMGs

QNMG technologies	States															
	AZ	**CA**	**FL**	**GA**	**IL**	**IN**	**MA**	**MI**	**MO**	**N J**	**NY**	**NC**	**OH**	**PA**	**VA**	**WA**
Wind	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Solar photovoltaic	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Solar thermal	x	x	x		x		x	x	x	x		x	x	x	x	x
Hydro small							x									
Hydro any scale	x		x		x	x			x			x	x	x	x	
Biomass	x		x		x			x		x		x	x	x	x	
Biogas	x										6					10
MSW	x		x					x						x	x	
Geothermal	x							x		x		x			x	
H_2O kinetics*			a				a,c			a,c		a,b			a,c	
Landfill gas			x				x	4		x		x	x	x		
Fuel cell, renew source	x				x					x						
Fuel cell, any source				x									x			
CHP, renew source	x															
CHP, any source												x		x		
Ocean thermal							x									
Other		1	2		3				5			7	8	9		11

Notes: *, includes wave, current, and tidal; a, wave; b, current; c tidal; 1, solar–wind hybrid; 2, waste heat from sulfuric acid manufacturing; 3, microturbines using renewable fuel; 4, produced by MSW; 5, emerging renewables certified by the Department of Natural Resources; 6, only for persons engaged in farming who use anaerobic digestion of farm wastes; 7, hydrogen derived from a renewable source; 8, microturbines; 9, waste coal and mine-based methane; 10, farm animal waste; 11, water, but does not define the water sources.

Net Metering Capacity Limits

The subject states have imposed two types of net metering capacity limits. The first type affects the capacity of individual NMGs, and the second type affects the total amount of net metering capacity that can, in the aggregate, be installed within a state.

Individual NMG Capacity Limits

Among the covered states, six different standards have been used to set capacity limits on individual NMGs.

- Six states set a limit common to all NMGs and NMCs (see Table 26).
- Five states set limits based on NMC type (see Table 27).
- Two states set limits based on NMG technology (see Table 28).
- One state, Massachusetts, sets limits that vary by NMC class and NMG type and class (see Table 29).
- One state, New Jersey, sets a MW limit for all NMGs at 2 MW, but this is capped by an NMC kW or MW ceiling calculated on the basis of the NMC's annualized consumption.
- One state, Arizona, sets limits for each NMC at 125 percent of his, her, or its connected load (or estimated drop capacity if connected load cannot be determined).

Table 26. Common Limit Approach

States	NMG capacity limit
Florida	≤ 2 MW
Illinois	≤ 2 MW
Indiana	≤ 10 MW
Missouri	≤ 100 kW
North Carolina	≤ 1 MW
Washington	≤ 100 kW

Table 27. Limit by NMC Class

NMC type	States				
	Georgia	New York	Ohio	Pennsylvania	Virginia
Residential	≤ 10 kW	≤ 25 kW		≤ 50 kW	≤ 10 kW

Nonresidential	≤ 100 kW	≤ (< of 2 MW or peak load)		≤ 3 MW	≤ 500 kW
Farm service		≤ 500 kW			
Standard			= cust need		
Hospital			None		
Critical infrastructure[a]				> 3 ≤ 5 MW	

[a] Emergency use microgrids for certain purposes: homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants, and telecommunication facilities.

Table 28. Limit by NMG Type

NMG type	States	
	California	**Michigan**
Solar	≤ 1 MW	
Wind	≤ 1 MW	
Solar–wind hybrid	≤ 1 MW	
N biodigester	≤ 1 MW	
L biodigester	> 1 MW ≤ 10 MW	
Fuel cell	≤ 1 MW	
Methane digester		550 kW
QF renewables		150 kW

Table 29. Massachusetts's Capacity Limit: by NMG Class, NMG Type, and NMC Class

NMG class	NMG type	NMC class	
		Nonagricultural	**Agricultural**
Class I NMG	Solar	≤ 60 kW	≤ 60 kW
	Wind	≤ 60 kW	≤ 60 kW
	All other NMGs	≤ 60 kW	≤ 60 kW
Class II NMG	Solar	> 60 kW ≤ 1 MW	> 60 kW ≤ 1 MW
	Wind	> 60 kW ≤ 1 MW	> 60 kW ≤ 1 MW
	All other NMGs	N/A	> 60 kW ≤ 1 MW
Class III NMG	Solar	> 1 MW ≤ 2 MW	> 1 MW ≤ 2 MW
	Wind	> 1 MW ≤ 2 MW	> 1 MW ≤ 2 MW
	All other NMGs	N/A	> 1 MW ≤ 2 MW

The subject states vary widely in capacity limits. Obviously, the smaller the capacity limit, the less likely the NMC will be able to generate the amount of electric energy that will produce a net metering billing credit (NMBC). For comparison purposes, Table 30 shows, for each state, the maximum NMG capacity for residential customers and nonresidential customers.

Table 30. States Ranked by NMG Capacity Limits

States—for residential	Capacity limits		States—for other NMC
	Residential	Other NMCs	
Arizona	≤ 125% load	≤ 125% load	Arizona
Ohio[a]	≤ Need	No limit	Ohio[a]
Georgia	≤ 10 kW	≤ 100 kW	Georgia
Virginia	≤ 10 kW	≤ 100 kW	Missouri
New York	≤ 25 kW	≤ 100 kW	Washington
Pennsylvania	≤ 50 kW	≤ 500 kW	Virginia
Missouri	≤ 100 kW	≤ 550 kW	Michigan
Washington	≤ 100 kW	≤ 1 MW	North Carolina
Michigan	≤ 550 kW	≤ 2 MW	Florida
California[b]	≤ 1 MW	≤ 2 MW	Illinois
North Carolina	≤ 1 MW	≤ 2 MW	Massachusetts
Florida	≤ 2 MW	≤ 2 MW	New Jersey
Illinois	≤ 2 MW	≤ 2 MW	New York
Massachusetts	≤ 2 MW	≤ 3 MW	Pennsylvania
New Jersey	≤ 2 MW	≤ 10 MW	California[b]
Indiana	≤ 10 MW	≤ 10 MW	Indiana

[a] Other NMC is the hospital class. [b] Other NMC limit based on using a digester.

Aggregate Net Metering Capacity Limits

The subject states also vary by whether and how they impose aggregate capacity limits on prospective NMCs. Aggregate capacity limit variations include the following.

- None (Florida, North Carolina, Ohio, and Pennsylvania).
- None initially, but individual NMPs can seek approval from the PUC to impose aggregate capacity limits (Arizona).
- None initially, but all NMPs may discontinue offering NMS to new NMCs when the aggregate capacity of all QNMGs equals 2.5 percent of the most recent statewide peak demand (New Jersey).

- An aggregate capacity limit for each NMP based on a fixed percentage of its latest statewide or summer peak demand:
    - 1 percent (Illinois, Massachusetts, and Virginia).
    - 0.1 percent (Indiana).
- An aggregate capacity limit for each NMP based on a fixed percentage of its latest statewide peak demand that is applied to the aggregate capacity of all renewable generators covered by all state renewable programs, not just the state's NMS program: 0.2 percent (Georgia).
- An aggregate capacity limit for each NMP plus an annual limit on additional new QNMG capacity based on a fixed percentage of its latest statewide peak demand (Missouri):
    - 5 percent aggregate.
    - 1 percent annual QNMG capacity additions.
- An aggregate capacity limit for each NMP based on a fixed percentage of its latest statewide peak demand that is broken down into specific aggregate capacity limits based on the size of QNMGs (Michigan):
    - 1 percent aggregate.
    - 0.5 percent for QNMGs ≤ 20 kW.
    - 0.25 percent for QNMGs ≤ 150 kW.
    - 0.25 percent for QNMGs > 150 kW.
- An aggregate capacity limit for each NMP based on a fixed percentage of its statewide peak demand for a specific year that is broken down into specific aggregate capacity limits based on QNMG technology (Washington):
    - Peak demand year—1996.
    - Aggregate capacity limit—0.25 percent until 2013, then 0.5 percent.
    - QNMG technology limits—50 percent of aggregate capacity must be dedicated to renewable QNMGs.
- An aggregate capacity limit for each NMP based on a fixed percentage of the statewide peak demand for a specific year for each QNMG technology (New York):
    - Peak demand year—2005.

  - QNMG technology limits:
    - 1 percent shared by solar and farm waste QNMGs.
    - 0.3 percent for wind NMGs.
- An aggregate capacity limit for each QNMG technology, some based on aggregate statewide demand, some based on an overall MW total, with one QNMG also broken down by the size of the NMP (California):
  - Solar, wind, solar–wind hybrid NPGs:
    - Share 2.5 percent of latest statewide peak demand.
    - Applies statewide regardless of the NPC involved.
  - Biogas digester NPGs:
    - Aggregate capacity = 50 MW.
    - Applies to the combined service territories of the state's largest NMPs.
  - Fuel cell NPGs:
    - Aggregate statewide capacity = 112.5 MW.
    - NMP aggregate capacity limits:
      - 22.5 MW for NMPs with system peak demands ≤ 10,000 MW.
      - 45.0 MW for NMPs with system peak demands > 10,000 MW.

The aggregate capacity limits for each state are summarized in Table 31.

Table 31. Aggregate Capacity Limit Summary

	Aggregate capacity limit			NMG > last year	NMG	
State	**Size**	**Basis**	**Year**		**Type**	**Limit**
Florida	None					
North Carolina	None					
Ohio	None					
Pennsylvania	None					
Arizona	None[a]					
New Jersey	None[b]					
Illinois	1%	NMP sys peak	Last		All share	

Massachusetts	1%	NMP sys peak	Last		All share	
Virginia	1%	NMP sys peak	Last		All share	
Indiana	0.10%	NMP sys peak	Last		All share	
Georgia	0.20%[c]	NMP sys peak	Last		All share	
Missouri	5%	NMP sys peak	Last	1%	All share	
Michigan	1%	NMP sys peak	Last		≤ 20 kW ≤ 150 kW > 150 kW	0.5% 0.25% 0.25%
New York		NMP sys peak	2005		Solar, farm waste Wind	1% 0.3%
Washington	0.25% to 2013 0.50% aft 2013	NMP sys peak	1996		Renewable	≥ 50% aggregate limit
California					Solar, wind, solar–wind hybrid Biogas digester[d] Fuel cell	2.5% statewide peak 50 MW[d] 112.5 MW[e] 22.5 MW 45.0 MW

[a] NMP can ask PUC for permission to impose a limit. [b] NMP can seek limits when aggregate NMG capacity is 2.5 percent of statewide demand. [c] Aggregate capacity is shared by all renewable generators, not just NMGs. [d] Aggregate capacity with service territories of three largest NMPs. [e] Statewide capacity wherever the fuel cells are located: 22.5-MW limit applies for NMPs with system peak ≤ 10,000 MW; 45.0-MW limit applies for NMPs with system peak > 10,000 MW.

Net Metering Billing Rules

State net metering laws specify how an NMC's net excess generation (NEG) is credited. The two major aspects of how NEGs are handled are (a) how NEG is credited and (b) whether the NMC or the NMP will be allocated the RECs associated with the NMC's NMGs. Below, a verbal explanation of this process and Table 32 summarize how the covered states do it.

NEG is the number of kWh produced by the NMC's NMG that are fed back into the grid less the number of kWh the NMC received from the NMP. Key attributes of NEG crediting include the basis by which NEG is credited each month, whether the NMC or the NMP receives any NEG credits that remain at the end of a billing year, and the relationship between the NMC and the NMP.

NEG crediting each month is done either on a dollar or kWh basis. If it is done on a kWh basis, the NEG kWh are carried forward and applied to the next monthly billing period. If it is done on a dollar basis, the NEG kWh are multiplied by a state-prescribed rate, which most often is either the full retail rate charged by the NMP, the energy component of the NMP's billing rate, or some version of the NMP's avoided cost of not producing the electric energy supplied by the NMC.

State net metering laws most often specify an annual reconciliation period based on a calendar year or a billing year and whether the NMP or the NMC gets the financial advantage of any NEG credits remaining at the reconciliation date. If the NMC is awarded the NEG credits, he, she, or it most often receives a monetary refund at some specified rate. Alternatively, the credits are applied to the NMC's billing in the next billing period. If the NMP is awarded the NEG credits, the credits are simply zeroed out.

In many states, persons who develop, own, or operate renewable NMGs receive RECs that can be marketed for additional income. State net metering laws sometimes specify whether the NMP or the NMC controls those RECs.

Table 32. Summary of Net Excess Credit Billing Rules

	Rate basis		Monthly net billing credit basis				Yr/term reconcil[b]			
State	**Reg**	**TOU[a]**	**NMC type**	**NMG type**	**$**	**kWh**	**Expires**	**$**	**C/F**	**REC[b]**
Arizona	x	x	All	All		x	Y & T	Avoided		
California	x		Co-energy[c] All other		Energy Full retail	or x	Y & T			
Florida	x		All	All		kWh	Y & T	Avg yr rate		NMC
Georgia	x		All	All	≤ avoided					
Illinois	x x	x x	All	≤ 40 kW ≤ 40 kW >40 kW ≤ 2 MW >40 kW < 2 MW	Full retail Avoided Full retail	x	Y & T			NMC
Indiana	x					x	T			
Massachusetts	x	x	All	Class I regular[d] Class I other[e] Class II Class III gov[f] Class III nongov	Full retail1[g] Avoided[h] Full retail1[g] Full retail1[g]		T		x	NMC

					Full retail2[i]					
Michigan			All	≤ 20 kW > 20 kW	Full retail Energy		T	Refunded		NMC
Missouri	x		All	All	Avg kWh Fuel cost		Y & T			
New Jersey[j]	x		All	All		x		Energy		NMC
New York	x	x	Residential Others	All		x	T	Avoided	x	
North Carolina	x	x	All	All		x	Y & T			NMC NMP
Ohio	x		All	All		x		Full retail[k]		
Pennsylvania	x		Distr cust ILSE cust	All		x		Avg retail K rate		NMC
Virginia			ILSE cust IOU-PJM IOUxPJM COOP	All				K price Zone LMP Sys LMP Avoid		NMC
Washington	x		All	All		x	Y & T			

Notes: C/F, carried forward to the next billing year or period; TOU, time of use.

[a] When TOU are in use, excess off-peak generation cannot be used to credit peak consumption. [b] Blank cells indicate where net metering laws did not address either reconciliation, RECs, or both. [c] Co-energy is a particular way of metering some customers in California. [d] Class I NMGs that are solar or wind or are used by an agricultural NMC. [e] Class I NMGs that are not solar or wind and are not used by an agricultural NMC. [f] Class III NMGs owned or operated by municipalities or other governmental entities. [g] Full retail rate plus transition charges. [h] Average monthly clearing price at applicable ISO-NE. [i] Full retail rate without transition charges. [j] New Jersey, by statute, offers other NMBC choices, but regulations so far specify the one documented. [k] NMCs can request a refund, but it is not clear what happens if no request is made.

Evaluation of State Net Metering Rules

Net metering is not a goal unto itself. The Network for New Energy Choices (NNEC) has identified several important energy, environmental, and economic goals that can be furthered by well-designed net metering laws and regulations:

- promoting the development and use of renewable electric energy generation,
- promoting customer-sited DG,
- helping electric energy customers achieve energy self-reliance,

- reducing demands on strained electric grids,
- improving air quality,
- reducing greenhouse gas emissions, and
- promoting economic development through the creation of green jobs.[607]

By assessing outcomes produced by the net metering laws and regulations of each state, the NNEC has been able to identify which net metering practices are conducive to helping states maximize the energy, environmental, and economic goals described above. These practices include:

- setting high individual NMG capacity limits of at least 2 MW so that "customer load and demand" will "determine the system's design parameters;"[608]
- eliminating aggregate net metering capacity limits or setting them at a high level (at least 5 percent of peak demand) so that customer-sited renewable DG and markets for renewable energy systems will not be curtailed artificially;[609]
- allowing indefinite rollover of NEG at the full retail rate to reduce net metering administrative costs and maximize NMCs' financial benefits;[610]
- allowing NMCs to retain existing meters or requiring the utility to pay for new or additional metering equipment so that net metering and other means of achieving reductions in electric energy demand and consumption are treated more equally;[611]
- ensuring that NMCs retain full ownership of any RECs they earn for developing, owning, or operating a renewable NMG so that they will achieve the maximum financial benefit for investing in renewable energy systems;[612]

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607 NETWORK FOR NEW ENERGY CHOICES, FREEING THE GRID: BEST AND WORST PRACTICES IN STATE NET METERING POLICIES AND INTERCONNECTION PROCEDURES 22 (2009), http://www.freeingthegrid.org (last visited Feb. 10, 2010) [hereinafter BEST PRACTICES].

608 *Id.* at 11, 24.

609 *Id.* at 11, 25.

610 *Id.* at 11, 25, 26.

611 *Id.* at 26.

612 BEST PRACTICES, *supra* note 609 at 11, 27.

- defining eligible NMGs as all renewable and zero-emissions technologies to preclude any artificial exclusion of a renewable source of electric energy or a nonrenewable source of electric energy that eliminates greenhouse gas emissions;[613]
- having no restrictions on customers eligible to be NMCs so that nonresidential customers with the greatest capacity for installing eligible NMGs are not excluded;[614]
- allowing aggregate (group, neighborhood) net metering so that NMCs with multiple meters on large, contiguous properties (such as farms) can take maximum advantage of net metering and NMCs can pool their resources to share the benefits of net metering by siting large NMGs in the most optimum location within an area;[615]
- providing NMCs with assurances through safe harbor provisions that they will not be subject to standby charges or other fees and expenses that are not imposed on other customers so that they are relieved of discriminatory financial burdens that often make it uneconomical to engage in net metering;[616]
- extending net metering mandates to all LSEs (IOUs, coops, energy districts, municipalities, and ILSEs) so that all of the state's electricity consumers will have net metering opportunities;[617] and
- ensuring that net metering rules will not exclude from net metering NMGs that have been installed on prospective NMCs' premises by third parties who finance and operate them.[618]

NNEC also has graded each state's net metering laws and regulations on the basis of how closely they follow the best net metering practices. Of the 43 states with some form of net metering, NNEC awarded an "A" to 11 states (raw scores 20 to 15), a "B" to 15 states (raw scores 13.5 to 9.0), a "C" to 8 states (raw scores 8.5 to 6.0), a "D" to 6 states (raw scores 5.5 to

613 *Id.*

614 *Id.*

615 *Id.* at 28.

616 *Id.* at 11, 28.

617 *Id.* at 11, 29.

618 BEST PRACTICES, *supra* note 609 at 29.

3.0), and an "F" to 3 states (raw scores 1.5 to 0.5).[619] Below is a spreadsheet showing the grades of the 16 states subject to this study with their raw scores on each best practice.[620]

Evaluation of Subject States' Net Metering Programs

Interstate Renewable Energy Council, *Freeing the Grid*, App A at 102–103 (2009)																
Scoring Categories	**AZ**	**CA**	**FL**	**GA**	**IL**	**IN**	**MA**	**MI**	**MO**	**NJ**	**NY**	**NC**	**OH**	**PA**	**VA**	**WA**
IREC Grade	A	A	A	F	B	F	B	B	C	A	D	D	B	A	B	C
System Capacity[a]	5.0	3.0	5.0	1.0	0.0	–1.0	5.0	2.0	1.0	5.0	0.0	3.0	5.0	5.0	2.0	1.0
Program Capacity[b]	2.5	2.0	2.5	0.0	1.0	0.0	1.0	1.0	2.5	2.5	1.0	2.5	2.5	2.5	1.0	0.5
NEG Rollover[c]	0.5	1.5	0.5	0.0	0.0	1.5	1.0	–1.0	–2.0	0.5	1.0	0.0	–1.0	0.5	1.5	0.0
Metering Issues[d]	2.0	2.0	2.0	0.0	1.0	1.0	2.0	1.5	0.0	2.0	2.0	1.0	0.0	2.0	2.0	0.0
REC Ownership[e]	1.0	1.0	1.0	–1.0	1.0	–1.0	1.0	1.0	–1.0	1.0	–1.0	–2.0	–1.0	1.0	1.0	–1.0
Eligible NMG[f]	1.0	1.0	1.0	0.5	1.0	1.0	0.5	1.0	1.0	1.0	0.5	1.0	0.5	0.5	1.0	1.0
Eligible NMC[g]	2.0	2.0	2.0	1.0	2.0	0.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.0	2.0
Meter Aggregation[h]	0.5	0.5	0.5	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	1.0
Safe Harbor[i]	0.0	3.0	3.0	–1.0	3.0	0.0	0.0	3.0	3.0	3.0	0.0	–1.0	3.0	3.0	3.0	3.0
Utilities Covered[j]	0.5	0.5	0.0	1.0	0.0	0.0	0.0	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.5	1.0
3d Party Ownership[k]	0.0	1.0	–1.0	–1.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	–1.0	0.0	0.0	0.0	0.0
IREC Scoring Total	**15.0**	**17.5**	**16.5**	**0.5**	**9.0**	**1.5**	**13.5**	**11.5**	**7.5**	**18.0**	**5.5**	**5.5**	**11.0**	**17.5**	**13.0**	**8.5**

Highest Score =

Lowest Score =

619 *Id.* at 12, 102, 103. In numeric order, the "A" states include (in numeric order) Colorado, Delaware, Maryland, ***New Jersey***, ***California***, Oregon, ***Pennsylvania***, ***Florida***, Utah, Connecticut, and ***Arizona***, *id.* at 102; the "B" states include ***Massachusetts***, ***Virginia***, Nevada, ***Michigan***, Maine, ***Ohio***, Kentucky, Wyoming, New Mexico, Rhode Island, Vermont, ***Illinois***, Kansas, Louisiana, and Nebraska, *id.* at 102–103; the "C" states include Hawaii, New Hampshire, ***Washington***, Arkansas, Iowa, ***Missouri***, Montana, and Minnesota, *id.* at 103; the "D" states include ***New York***, ***North Carolina***, Wisconsin, Oklahoma, West Virginia, and North Dakota, *id.*, and the "F" states include ***Indiana***, Idaho, and ***Georgia***, *id.* The bold-italicized states are those that are subjects of this study.

620 This spreadsheet is a modified version of BEST PRACTICES, *supra* note 609 at 102–103, App. A: *State Scoring Spreadsheets—net metering*.

Interstate Renewable Energy Council, *Freeing the Grid* at 24–29 (2009)

[a] 5 = ≥ 2 MW; 4 = ≥ 1 MW; 3 = ≥ 500kW; 2 = ≥ 100 kW; 1 = ≥ 50 kW; 0 = < 50kW; –1 = Res only ≤ 20 kW
[b] 2.5 = ≥ 5 percent; 2.0 = ≥ 2 percent; 1.5 = ≥ 1 percent; 1.0 = ≥ 0.5 percent; 0.5 = ≥ 0.2 percent; 0 = ≥ 0.1 percent; –0.5 = < 0.1 percent
[c] 1.5 = Indef@RetRate(RR); 1.0 = Monthly(M)@RR-AnnPay(AP)@RR; +0.5 = M@RR, AP@WhsaleR(WR) or AvCost (AC); 0 = M@RR, AnEx(AE) to Util; –2.0 M@WR or AC; –4.0 = no Rov, ME to Util
[d] 2.0 = No Meter Δ or Util Pays (UP) or TOU w/time carryover; 1.0 = Dual met/reg-UP or TOU with seg time periods; 0 = Dual met/reg-Cust Pays (CP); –1 Fixed TOU Rate disadv small NMC
[e] 1 = Owned by NMC; –1 Not Addressed; –2 Given to Util for Exported Elec; –5 Given to Util w/o Incent
[f] 1.0 = all renew (r)/0 emiss Gen; +0.5 Solar & Wind, at least 1 other r excl or all r + at least 1 non-r
[g] 2.0 = no restrictions; 1.0 = Comm @ max limit & Res ≥ 10 kW; 0 = Res only; –1.0 = all other restrict
[h] 1.0 = NMC may aggregate all meters on his/her/its contiguous property
[i] 3.0 = No add equip, fees, requirements; 0 = not addressed; –1.0 = Fees c/b imposed or minor NM fees; –5.0 = large add charges/fees or per kW fee on production + fees
[j] 1.0 = NM Rules apply to all Utilities; 0 = NM Rules apply only to IOUs
[k] 1.0 = Presumably Allowed; 0 = Not specified; –1.0 = Presumably Not Allowed

Although NNEC has given an "A" or "B" grade to about 60 percent of the states with net metering policies, it is clear from the analyses above of the 16 states with net metering that are subjects of this study that net metering practices vary widely even among states that receive the same grade. In surveying the outcomes produced by this checkerboard of best to worst practices, NNEC has concluded that: "[I]nconsistency is the enemy of clean energy development[, increas[ing] customer confusion, undermin[ing] the ability of renewable energy developers to operate across utility territories or state lines, and increas[ing] the costs to all program participants—utilities, potential customer–generators, renewable energy developers, and commission staff . . . ."[621] To promote the adoption of uniform laws and regulations incorporating best net metering practices, the Interstate Renewable Energy Council (IREC) has issued a 2009 edition of its Net Metering Model Rules,[622] and NNEC is encouraging states to adopt them virtually verbatim. However, if the United States is to realize the maximum energy,

621 Best Practices, supra note 609 at 22.

622 Interstate Renewable Energy Council, Net Metering Model Rules: 2009 Edition, at http://irecusa.org/wp-content/uploads/2009/10/IREC_NM_Model_October_2009-1.pdf (last visited Feb. 20, 2010).

environmental, and economic benefits of renewable DG, IREC's Model Rules must find their way into federal renewable energy policy legislation.[623]

Green Purchasing Requirements

Similar to RPS programs that require the use of renewable energy per established goals, some states and localities have set renewable energy purchasing goals for state and local government. Among the subject states, five states have statewide green power purchasing requirements.[624] Those states are:

- Illinois (5 percent by 2009),[625]
- Indiana (10 percent by 2010 but only for state building in capitol county),[626]
- Massachusetts (15 percent by 2012 and 30 percent by 2020),[627]
- New York (20 percent by 2010),[628] and
- Pennsylvania (50 percent by 2010).[629]

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623 BEST PRACTICES, *supra* note 609 at 101.

624 Database of State Incentives for Renewables & Efficiency, Rules, Regulations & Policies for Renewable Energy, http://www.dsireusa.org/summarytables/rrpre.cfm (last visited May 10, 2010).

625 Illinois Government News Network press release, Lt. Gov. Pat Quinn Challenges Local Governments To Purchase Renewable Energy: "It's as Easy as 3-4-5," http://www.illinois.gov/PressReleases/ShowPressRelease.cfm?SubjectID=18&RecNum=5902 (Apr. 23, 2007) (last visited May 10, 2010).

626 Database of State Incentives for Renewables & Efficiency, Indiana: Incentives/Policies for Renewable Energy, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=IN07R&re=1&ee=0 (Apr. 7, 2010) (last visited May 10, 2010).

627 The Commonwealth of Massachusetts Exec. Order No. 484: Leading by Example—Clean Energy and Efficient Buildings, http://www.mass.gov/Agov3/docs/Executive%20Orders/Leading%20by%20Example%20EO.pdf (Apr. 18, 2007) (last visited May 10, 2010).

628 State of New York Exec. Order No. 111: Directing State Agencies To Be More Energy Efficient and Environmentally Aware, http://www.nyserda.org/programs/exorder111orig.asp (last visited May 10, 2010).

629 Database of State Incentives for Renewables & Efficiency, Pennsylvania: Incentives/Policies for Renewable Energy, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=PA05R&re=1&ee=0 (Jul. 7, 2009) (last visited May 10, 2010); *see also* Jeffrey Olsen, Commonwealth of Pennsylvania's Green Electricity Purchases, http://www.responsiblepurchasing.org/UserFiles/File/Green_Power/Webcast/Pennsylvania.pdf (Apr. 8, 2008) (last visited May 10, 2010); *see also* Commonwealth of Pennsylvania press release, State Government Reduces Energy Use 18 Percent, Saving Taxpayers $2.2 Million Annually: Aggressive Conservation Efforts on Track To Shatter 20 Percent Energy Reduction Goal, http://www.portal.state.pa.us/portal/server.pt/gateway/PTARGS_0_2_12691_1354_505925_43/http%3B/pubcontent.state.pa.us/publishedcontent/publish/cop_general_government_operations/dgs/community_content/dgs_homepage/portlets/dgs_home_page_news_and_media/articles/state_reduces_energy_consumption_4.pdf (Apr. 30, 2009) (last visited May 11, 2010).

Each statewide program originated in the state executive branch.[630]

Additionally, local governments in Arizona, California, Massachusetts, Michigan, New York, Texas, Virginia, and Washington also have established green purchase power requirements.[631]

Public Benefits Funding

Of the 17 subject states, 7 imposed a charge on utility customer bills to raise revenues for public funds to support renewable energy or efficiency.[632] Those states are:

- California,
- Illinois,
- Massachusetts,
- Michigan,
- New Jersey,
- New York, and
- Pennsylvania.

With the exceptions of New York and Pennsylvania, each of the subject states' trust funds is the product of electric restructuring legislation in the respective state.[633] New York's fund was created by the NYPSC as part of the retail restructuring order.[634] Pennsylvania's four funds resulted from a series of settlements with the five major power distribution utilities.[635]

All the funds distribute millions of dollars each year from mandatory payments by utility customers to renewable and energy efficiency programs through grants and loans. Notably, Michigan dedicates 75 percent of the fund income to low-income residents, with 25 percent

630 Database of State Incentives for Renewables & Efficiency, Rules, Regulations, & Policies for Renewable Energy, http://www.dsireusa.org/summarytables/rrpre.cfm (last visited May 11, 2010) (compare each state).

631 *Id.*

632 *Id.*

633 Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org (last visited May 11, 2010) (see summary of each state program).

634 NYPSC ORDER Case 94-E-0952 at 62.

635 Pennsylvania Public Utility Commission, Sustainable Energy Fund, http://www.puc.state.pa.us/electric/electric_renew_sus_energy.aspx (last visited May 11, 2010).

dedicated to energy efficiency.[636] Illinois reserves 50 percent of the fund for coal-related projects with the "exclusive purpose of (1) capturing or sequestering carbon emissions produced by coal combustion; (2) supporting research on the capture and sequestration of carbon emissions produced by coal combustion; and (3) improving coal miner safety.[637]

Voluntary Green Purchasing Initiatives

Allowing the consumer the opportunity to make a voluntary green-friendly decision represents one funding option for renewable energy programs. Of the subject states, only three have a statewide program under which customers are engaged in such a voluntary program.[638]

Two of the subject states, Washington and Virginia, have legislation that requires utilities to offer a voluntary option for consumers to purchase green power.[639] Since January 1, 2002, Washington has required each electric utility to provide its retail electricity customers a voluntary option to purchase qualified alternative energy resources.[640] A "qualified alternative energy resource" means: power produced with "(a) Wind; (b) solar energy; (c) geothermal energy; (d) landfill gas; (e) wave or tidal action; (f) gas produced during the treatment of wastewater; (g) qualified hydropower; or (h) biomass energy based on animal waste or solid organic fuels from wood, forest, or field residues, or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives, such as creosote, pentachlorophenol, or copper–chrome–arsenic."[641] The statute also calls for a restricted opportunity to use hydropower.[642] Rates must be approved by the commission (or, for consumer-owned utilities, their boards).[643] Virginia also requires that retail customers be permitted to purchase electric energy from a portfolio of 100 percent renewable energy.[644]

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636 Michigan Public Service Commission, Low Income and Energy Efficiency Fund (LIEEF), http://www.michigan.gov/mpsc/0,1607,7-159-16370_27289-79463--,00.html (last visited May 11, 2010).

637 N.Y.PSC, Opinion No. 96-12, at 62 (May 20, 1996).

638 Database of State Incentives for Renewables & Efficiency, www.dsireusa.org (last visited May 11, 2010) (see summary tables).

639 Database of State Incentives for Renewables & Efficiency, Rules, Regulations & Policies for Renewable Energy, http://www.dsireusa.org/summarytables/rrpre.cfm (last visited May 11, 2010).

640 REV. CODE WASH. §19.29A.090(1)

641 *Id.* §19.29A.090(3)

642 *Id.* §19.29A.090(4)

643 *Id.* §19.29A.090(5)

644 VA. CODE §56-577.C.5.

Even though North Carolina lacks the legislative requirement to offer a green option to customers, North Carolina customers may still participate in a green purchase program. Developed from a legislative initiative[645] directing the commission to study a voluntary "green" check-off program,[646] NC GreenPower serves North Carolina renewable energy programs. Under the commission-approved option, customers may make voluntary payments directly NC GreenPower, a nonprofit corporation. NC GreenPower will, in turn, make payments that supplement the power purchase agreements between the renewable generator and the utilities. All NC Green funding is based on voluntary contributions made from electric customer choosing to voluntarily pay an additional charge, so the supplemental payment from NC GreenPower is not guaranteed for the generator.[647]

Permitting and Siting Generators and Transmission Facilities

Overview

As discussed in Section 2, the evolving interface between state and federal authority creates a complex situation. This is especially true for the siting of generation and transmission facilities. Given that large-scale renewable resources, such as wind and geothermal, are normally located away from load centers, transmission facilities will play an important role in implementing a renewable strategy.[648] Against the backdrop of increasing federal control over

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645 NC Session Laws 2002-167, ss. 6(a) through (c).

646 NORTH CAROLINA UTILITIES COMMISSION, FINAL REPORT OF THE NORTH CAROLINA UTILITIES COMMISSION TO THE STUDY COMMISSION ON THE FUTURE OF ELECTRIC SERVICE IN NORTH CAROLINA AND THE ENVIRONMENTAL REVIEW COMMISSION REGARDING INVESTIGATION OF VOLUNTARY "GREEN" CHECK-OFF PROGRAM AND OTHER EFFORTS TO STIMULATE RENEWABLE ENERGY PRODUCTION IN THE STATE (March 2003), http://www.ncuc.commerce.state.nc.us/reports/finalrpt.pdf (last visited May 11, 2010).

647 Database of State Incentives for Renewables & Efficiency, North Carolina: Incentives/Policies for Renewable Energy, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC05F&re=1&ee (Feb. 16, 2010) (last visited May 11, 2010); *see also* NORTH CAROLINA UTILITIES COMMISSION, FINAL REPORT OF THE NORTH CAROLINA UTILITIES COMMISSION TO THE STUDY COMMISSION ON THE FUTURE OF ELECTRIC SERVICE IN NORTH CAROLINA AND THE ENVIRONMENTAL REVIEW COMMISSION REGARDING INVESTIGATION OF VOLUNTARY "GREEN" CHECK-OFF PROGRAM AND OTHER EFFORTS TO STIMULATE RENEWABLE ENERGY PRODUCTION IN THE STATE (March 2003), http://www.ncuc.commerce.state.nc.us/reports/finalrpt.pdf (last visited May 11, 2010).

648 The California Energy Commission, Renewable Energy Transmission Initiative, http://www.energy.ca.gov/reti/index.html (last visited May 11, 2010) (for California); FERC news release, FERC Grants Incentives for Midwest "Green" Transmission Superhighway, http://www.ferc.gov/news/news-releases/2009/2009-2/04-13-09.asp (Chairman Jon Wellinghoff, April 13, 2009) (last visited May 11, 2010).

wholesale power generation and interstate transmission,[649] the 17 subject states have taken a variety of approaches in regulating the siting of power plants and transmission lines. From the state-by-state data, a division in approaches appears:

- a centralized "one-stop" permitting approach,
- a traditional regulated industry "public need and necessity" scheme, or
- a market-oriented ("hands-off") approach or lack of any specific authority.

Generally the subject states fall into the three general trends as shown in Table 33.

Table 33. General Trends in Siting by State

Central siting	Traditional	Market/lack of authority
Arizona	Georgia	Illinois
California	Indiana	Michigan
Florida	Missouri	New York (plant only)
Massachusetts	New Jersey	Ohio
New York (transmission only)	North Carolina	Texas (plant only)
Washington	Virginia	
Texas (transmission only)		

Although the states may follow one of these generalized trends, the specifics involved in the implementation of each trend differ greatly by state. With the exception of Texas, Washington, and Indiana, none of the state siting regimes specifically addresses renewable energy resources.

Central Siting

Power Plants

Each of the subject states applying the centralized siting approach created a centralized authority that supersedes all other state and local regulations.[650] This approach provides for the "one-stop" ease and certainty of dealing with a single state authority. In New York, the state's

649 The EPA of 2005 provided for federal intervention for certain power transmission issues, 42 USC 1221(a); *see also* FERC Stats. & Regs. ¶ 31,234 (2006).

650 *See* Appendix GTS-1; specifically, for Arizona: AZ REV. STAT. 40–360.11; Florida: FLA. STAT. §403.511; Massachusetts: MASS. ANN. LAWS §69K1/2; Washington: WASH. REV. CODE §80.50.110 and §80.50.130.

centralized siting law for power generation expired on January 1, 2003, and has yet to be replaced.[651] This lapse has been cited as an impediment to power plant development.[652]

For facilities contemplated under centralized authority, all subject states other than Massachusetts and Washington require some type of environmental compatibility and need showing.[653] Massachusetts amended its statute in its 1997 Restructuring Act to eliminate any showing of need, leaving that determination to market forces.[654] Washington recognizes in its statute that demand is growing and presumes the need for new resources.[655] Therefore, Washington requires no showing of need.[656]

All subject states with centralized authority (except Massachusetts, Florida, and Washington) limit the application of centralized siting authority to thermal plants.[657] Therefore, in those states, wind, solar, and the other nonthermal renewable energy sources would not be included within the auspices of the centralized siting authority. The renewable developer must deal with local permitting and applicable state environmental permits.

Massachusetts does not restrict the definition of *facility* to thermal generators, but sets a size restriction of at least 100 MW.[658] Even though Washington's siting statute is specific to thermal generators, a special provision in the statutes makes the centralized siting authority available to nonthermal renewable projects on an optional basis.[659] An interview with the Washington Energy Facility Siting Council (EFSC) indicates that at least two wind projects have

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651 NYPSC, The New York State Board on Electric Generation Siting and the Environment, http://www.dps.state.ny.us/articlex.htm (last visited May 11, 2010).

652 *The Business Review (Albany)*, March 24, 2009.

653 See Table 34 for each state. Specifically, for Arizona: AZ. REV. STAT. §40–360.03 (2002); California: CAL. CODE REGS. tit. 20 §1726 (2009); Florida: FLA. STAT. ANN. §403.519(3) (LexisNexis 2009); Massachusetts: MASS. GEN. LAWS §69K; New York: NY. PUB. SERV. LAW §85-2.1(d).

654 MASS. GEN. STAT. §69J1/4; *see also*, *Alliance To Protect Nantucket Sound, Inc. v. Energy Facility Siting Board*, 858 N.E. 2d 294,

297 (Mass. Sup. Ct, Dec. 18, 2006).

655 WASH. REV. CODE §80.50.010 (2009).

656 WAC § 463-60-021 (2009).

657 *See* Appendix GTS-1.

658 MASS GEN. LAWS §69G.

659 WASH. REV. CODE §80.50.020(14)(a)

availed themselves of the centralized process rather than go through the local permitting process.[660]

Even for thermal renewable projects such as biomass incinerators or biogas power generators, the majority will fall outside of the centralized siting authority because of their small generation capacity. All states with centralized siting authority set a maximum capacity point at which the centralized authority must be used. Of these states, only Florida[661] (for smaller thermal) and Washington[662] (for renewables) allow for capacities smaller than those set. See Table 34 for a summary of capacities.

Table 34. Power Plant Capacities for Centralized Siting Authority

State	Capacity	Renewable energy provisions
Arizona[663]	Greater than 100 MW	No provision for smaller or renewable
California[664]	Greater than 50 MW	No provision for smaller; explicitly excludes wind, hydro, and solar photovoltaic
Florida[665]	Greater than 75 MW	Option to use for smaller thermal
Massachusetts	Greater than 100 MW	No provision to use for smaller
Washington	Greater than 350 MW	Option to use for renewables

Florida requires all thermal and solar electrical generation of 75 MW or more to apply with the centralized siting agency.[666] Because most solar generation projects are less than 75 MW and wind and other nonthermal generation is not included, the majority of renewable energy resources is not affected by the plant siting law and would fall to local permitting and an array of state environmental permitting.

660 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons, and Joshua Carson (Oct. 1, 2009).

661 FLA. STAT. §403.503(14).

662 WASH. REV. CODE §80.50.060(2).

663 AZ. REV. STAT. §40-360.9 (LexisNexis 2009).

664 CAL. PUB. RES. §25120 (2009).

665 FLA. STAT. §403.503(14).

666 FLA. STAT. §403.52 to §403.5365.

Transmission Facilities

For linear facilities, such as transmission lines, where the length of the facility may involve more than one local permitting entity, the centralized approach can speed and ease permitting.

The plant siting provisions discussed above include the transmission facilities associated with specific generation facilities. However, if centralized authority is not available for the renewable generator (see the discussion above), is it available for the transmission required? Basically, can the transmission associated with renewable energy projects use centralized authority independently of the plant? Only the California statute ties the plant and transmission together for renewables.[667] The remainder of the states either provide for renewable generation and associated facilities (Massachusetts and Washington) or allow for independent transmission permitting.

For transmission lines to be built independently of a specified power plant project, New York[668] and Florida[669] have provisions specific to transmission. In Florida, the centralized process is available only for "electric utilities," which are defined as "cities, towns, counties, public utility districts, electric cooperatives, RTO operators and other organizations approved by FERC."[670] Florida also specifically excludes transmission facilities associated with a generation plant from its transmission statute.[671] Arizona[672] and Massachusetts[673] both allow for transmission independent of the power plant. All states with permitting for power transmission set a minimum size for the transmission line for centralized siting authority, as summarized in Table 35.

667 Cal. Pub. Res. § 25120 (2009).

668 NYPSC REGS. §85 et. seq. (2009).

669 FLA. STAT. §403.501 et. seq. (2009).

670 FLA. STAT. §304.522(12).

671 FLA. STAT. §403.524(1).

672 AZ. REV. STAT. §40-360.10.

673 MASS. GEN. LAWS §69G.

Table 35. Minimum Transmission Line Size for Centralized Permitting

State	Transmission line size
Arizona	115 kV or more[674]
Florida	230 kV or more[675]
Massachusetts	69 kV or more[676]
New York	125 kV or more for at least 1 mile[677] 100 kV to 124 kV for at least 10 miles
Texas	Not applicable
Washington	115 kV or more can opt into EFSC[678]

Texas's approach is completely different from that of all of the other states. Texas focuses its approach on directly addressing the transmission issues associated with renewable energy projects. Although centralized, Texas directs the PUC to establish Competitive Renewable Energy Zones in which sufficient resources and suitable land are available. The Commission is further directed to develop a plan to construct transmission capacity to support generation development.[679] The Commission then examines expressions of interest submitted to it concerning proposals for constructing the transmission expansions.[680]

Traditional Approach

For the states analyzed with the more traditional approach, all statutory authority is targeted at public utilities. All states require the public utility to show public convenience and necessity (or need).[681] In some states, like North Carolina, the definitions are so broad that nearly all generation facilities are included in the certification process.[682] In these states, interviews with the commissions indicate that the majority of thermal power plants (coal, nuclear, or gas) are

674 AZ. REV. STAT. §40-360.10.

675 FLA. STAT. § 403-522(12).

676 MASS. GEN. LAWS §69G.

677 PUB. SERVICE LAW §85.2.1(e)(1).

678 Interview with EFSC staff conducted by Nathan Taylor, Holly Hammons, and Joshua Carson (Oct. 1, 2009).

679 TEX. UTIL. CODE §39.904 (2009).

680 16 Tex. Admin. Code §25.714(c) (2009).

681 *See* Appendix GTS-1; specifically for Georgia: GA. CODE ANN. §46-3A-3; for Indiana: IURC 8-1-8.5-2; for North Carolina: NC STAT. §62-110.1(a) (2009).

682 NC STAT. § 62.110.1 (2009).

being included in the rate base under traditional rate base theory.[683] Wind, the only renewable mentioned in the interviews, is being developed independently.[684]

Market "Hands-Off" or Lack of Authority

For states either taking a hands-off approach or lacking any specific authority, no state statutory or regulatory process exists for siting power plants other than environmental and local permitting. Illinois, Michigan, New York, New Jersey, Illinois, and Texas all take a hands-off approach for generation. For instance, in Illinois, interviews with the PUC indicate that utilities have not owned power plants since 1988, and thus no commission regulation is required. Interestingly, nearly all of these states have remained involved at the state level in transmission activities.

Conclusion

The siting of renewable energy generation falls mostly within the purview of local permitting. The state approaches differ, but only Washington has directly addressed the issue of siting renewable generation at the state level. The remainder leave siting mainly to local permitting authorities and the applicable state environmental agencies.

Transmission follows a similar path where only Texas has directly addressed the issue of transmission as it applies to renewable energy resources on the state statutory level. The interplay of RTOs, ISOs, and the relatively new federal authority and activity in permitting transmission lines also makes the situation even more complex.

Oversight of Distribution Companies' Electric Energy Procurement

Regardless of market or regulatory structure, most utilities that have any load-serving obligation will conduct some type of long-range planning process for supply. Some states take a formalized approach often supervised by the state utility commission known as an *integrated resource plan*.[685] Typically, this planning process is the first stage in the procurement process for electrical utilities by which they identify projected needs and timing.[686]

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683 *See* "Interviews" sections by state in Appendix GTS-1.

684 *Id.*

685 SUSAN F. TIERNEY AND TODD SCHATZKI, COMPETITIVE PROCUREMENT OF RETAIL ELECTRIC SUPPLY: RECENT TRENDS IN STATE POLICIES AND UTILITY PRACTICES 17 (National Association of Regulatory Commissioners, 2008).

686 *Id.*

Procurement of electric energy supply by utilities differs based on the state regulatory structure. In July 2008, the National Association of Regulatory Commissioners released a study of the procurement process for all states.[687] This study focused primarily on states with formal requirements and on the large IOUs. It excluded states with unregulated competitive retail markets (e.g., Texas).[688] Approximately 40 percent of the states have formal regulations or guidance that either encourages or requires utilities to use some type of competitive process in procuring supply.[689] Of the 17 states analyzed for this purpose, 10 states, or 59 percent, have formal processes (Arizona, California, Florida, Georgia, Illinois, Massachusetts, New Jersey, New York, Ohio, Pennsylvania, and Washington). [690]

In general, the states have taken three different approaches to structuring power market regulation:[691]

- a traditional approach, where the utility is responsible for service obligations to retail customers and retains the responsibility for adding additional supply (with no divestiture of power plants by the utilities);
- a restructured scenario with no retail choice (with no or partial divestiture of power plants by the utilities); and
- a restructured scenario with retail choice (with complete or almost complete divestiture of power plants by the utilities).

The study found that, for competitive procurement to be effective in any of the three market regulation approaches, states must design and implement processes that foster competition among market participants. To achieve effective competition, procurement should strive to meet to the following criteria.[692]

- The procurement process must be fair and objective.

687 *Id*. at i.

688 *Id*. at 3.

689 *Id.* at i.

690 *Id*. at 1, footnote 5; for Georgia, see p. 4.

691 *Id*. at iii.

692 *Id.* at ii, 4.

- The procurement should be designed to encourage a robust competitive offering and a creative proposal from market participants.
- The procurement should select winning offers bases on an appropriate evaluation of all relevant price and nonprice factors.
- The procurement should be conducted in an efficient and timely manner.
- When using a competitive procurement process, regulators should align their own procedures and actions to support the development of a competitive response.

In those states where utilities still own generation assets, the utility will procure *incremental resources*,[693] which are shaped around utility needs and typically do not necessarily follow a standard design. Some of these parameters include:[694]

- physical characteristics of the resources (such as fuel type, location, and availability);
- operation commitments;
- development status;
- service provided;
- supplier obligations; and
- risk allocation.

A key issue in incremental resources is preventing the potential for improper self-dealing by the utility.[695] In this situation, the utility is tempted because a greater financial benefit might accrue to the utility in an ownership scenario. Therefore, the utility would always favor a self-build procurement proposal over an alternative, thereby thwarting the competitive process. In states where utilities still own their generation facilities, the study indicates that regulators must design processes to protect against this situation. The study identifies the following as possible safeguards:[696]

- using a third-party independent monitor or evaluator;

693 *Id*. at 10.

694 *Id*. at 10.

695 *Id.* at iv.

696 *Id.* at iv.

- creating measures to increase the transparency of the process;
- providing potential bidders with detailed information needed to prepare competitive bids; and
- prohibiting the flow of market information between utilities and affiliates under codes of conduct.

States with retail competition and where generation divestiture has occurred often use a *full requirements service*. Under this service, the distribution utility obtains all or most of its electricity supply for its basic-service customer from suppliers that are responsible for assembling and managing services for the retained customers.[697]

The study notes two interesting factors in procurement. First, despite a great deal of experience in designing procurement plans, states have limited experience in implementing such plans.[698] Second, most competitive experience to date has been for supplies from natural gas–fired facilities.[699] Only recently have proposals been introduced for other commodities. In some instances, high-cost coal and nuclear options have been exempted from the competitive process.[700]

A determination of the winning bid can rely on many variables, including:

- how the economic modeling reflects the costs and benefits;[701]
- how the economic and financial risks are assessed to each party;[702]
- who has to post performance credit and how those are valued;[703]
- how the deal structure affects the credit capabilities of the utility (e.g., both a tolling agreement and building a power plant create credit chew for the utility);[704]

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697 *Id*. at 5.

698 *Id*. at vi.

699 *Id.* at 19.

700 *Id*.

701 *Id.* at 29.

702 *Id.* at 30, 38.

703 *Id.* at 34.

704 *Id.* at 35.

- the costs and timing associated with associated with obtaining transmission from the supply to the market;[705] and
- other nonprice criteria and bid requirements[706] (such as developmental risks, environmental benefits, and operational flexibility).

The study notes that the nonprice criteria and bid requirements are the most likely culprits in creating preferential treatment for the utility-sponsored project.[707]

As with most other aspects of the electric industry, the states follow a fragmented approach. The National Association of Regulatory Utility Commissions study does point to a number of best practices that states should consider when attempting to create a competitive supply environment. Most notably, states must control the incumbent utility's ability to create a preference for its own projects. To some extent, the accounting processes where nonutility contracts for power supplies affect utility credit ratings in a manner similar to a self-build situation also create a preference for the utility's projects. If the utility must undergo a credit hit with regard to contracts with third parties, the utility's response is likely to be, why not just build it myself and earn a return? Given the state of deregulation of the industry and fears created from past attempts, it appears unlikely that any additional deregulation will occur to create more states in which the incumbent utility does not control the generation asset. Therefore, state commissions will need to continue to refine the process for ensuring a fair, competitive supply scenario in which most of the 17 states studied have utilities owning the generation facilities.

4. State Laws and Regulations Affecting Electric Energy Use Efficiency

Efficiency and Demand-Side Management

The "nega-watt" (avoiding the need to generate power) plays an important role in the nation's energy future. Energy efficiency and demand-response programs will generate those nega-watts. Efficiency projects result in an actual decrease in energy consumption; demand-side management, on the other hand, affects the ability to change the time of use behavior to avoid peaks.[708] For instance, efficiency would involve replacing an air conditioner with one that

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705 *Id.* at 41.

706 *Id.* at 45.

707 *Id.* at 46.

708 N.C. GEN. STAT. §62.133.8(a)(4).

consumes less energy. Demand-side management would simply involve turning the existing air conditioner off during a peak demand time. Both slow the need for additional power infrastructure by counteracting demand growth.

Under the current administration, the federal government has been very active in providing funding for energy efficiency programs. For example, on October 01, 2009, Energy Secretary Steven Chu announced the awarding of nearly $72 million from the American Recovery and Reinvestment Act to seven states and territories to support energy efficiency and conservation activities.[709]

Although all subject states have some type of energy efficiency program, fewer than half have established a statewide quantitative goal. The states with such goals use one of two methods. They have either (a) incorporated efficiency as a way to meet the requirements of their statewide RPS requirements or (b) established an efficiency requirement independent of the RPS program.

The following subject states have incorporated energy efficiency as a way to meet the state RPS requirement: Arizona, North Carolina, Ohio, Pennsylvania, and Michigan. These states vary in the manner in which they have incorporated energy efficiency into their RPS programs.

Although Arizona does not allow for efficiency in its pilot program or include it in the definitions of a renewable energy source, it does allow several energy efficiency products, such as solar lighting, to count toward its RPS goals.[710]

North Carolina allows for meeting up to 25 percent of the RPS requirements before 2021 and 40 percent after 2021 with energy efficiency gains.[711] North Carolina makes an important distinction between energy efficiency and demand-side management. To count toward the RPS goals, all gains come only from efficiency projects—a gain from a demand-side management project will not count toward the RPS goals. Therefore, to count toward RPS requirements in North Carolina, an energy efficiency project must result in an actual decrease in consumption.

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709 U.S. Department of Energy, Energy Efficiency & Renewable Energy News, DOE Delivers Nearly $72 Million for Projects in 7 States and Territories, http://apps1.eere.energy.gov/news/daily.cfm/hp_news_id=206 (Oct. 1, 2009) (last visited May 11, 2010).

710 AZ. ADMIN. CODE R14-2-1802.

711 N.C. GEN. STAT. §62.133.8(a).

Ohio[712] and Pennsylvania [713] allow for half of their respective RPS requirements to be met with demand-side management and energy efficiency gains. Note the difference in approach compared to North Carolina, where demand-side management does not count toward RPS goals.

Michigan[714] possesses a very comprehensive energy efficiency statute, which mirrors the state's RPS program and ties to it. This statute requires energy providers to file a proposed energy optimization (EO) plan with the PUC.[715] The EO plan is to "delay the need for constructing new electric generating facilities…."[716] The energy providers are charged with the task of providing practical and effective administration of their proposed EO programs.[717] To entice electric providers, the statute provides financial incentives capped at 25 percent of net cost reductions by their efficiency programs or 15 percent of efficiency expenditures for the year. Like the RPS program, Michigan sets minimum annual goals for its efficiency program, as shown in Table 36.[718]

Table 36. Michigan Goals for Energy Efficiency

Time period	Goals
2008 and 2009	0.3% of total retail sales in 2007
2010	0.5% of total retail sales in 2009
2011	0.75% of total retail sales in 2010
2012 to 2015	1.0% of total retail sales of the previous year

Michigan structures the program like RPS in its implementation as well. Michigan has created an optimized energy credit (OEC) very similar to a REC under the RPS programs.[719] In fact, an electric service provider may use RECs from the RPS programs to meet the OEC

712 OHIO. ADMIN. RULE §4901:1-40-03(A)(1) using definition in §4928.01(A)(34).

713 73 PA. COMP. STAT. §1648.2(12); 73 PA. COMP. STAT. §1648 (for rural electric cooperatives).

714 MICH. COMP. LAWS. SERV. §460.1071 et. seq.

715 MICH. COMP. LAWS. SERV. §460.1071.

716 *Id.* §460.1071(2).

717 *Id.* §460.1071(3)(h).

718 *Id.* §460.1077.

719 *Id.* §460.1083.

requirements.[720] As with the RPS program, the statute also establishes alternative compliance payments for energy efficiency[721] and an enforcement provision.[722]

Other states do not allow efficiency gains to count toward the state's RPS requirements. However, the NYPSC provides an interesting observation concerning the interplay between RPS and efficiency gains. The commission notes that when the total power load is decreased by an efficiency project, the calculation of MWs required for the RPS goal will also decrease because the total load against which the percentage RPS goal is multiplied will also be less.[723]

Although not included in their RPS programs, California and Missouri direct their respective commissions to encourage energy savings. California directs its commission to implement cost-effective energy efficiency programs. These include demand-side management and actual load reduction.[724] Missouri's statute establishes a policy "to encourage electrical corporations to develop and administer energy efficiency initiatives that reduce the annual growth in energy consumption and the need to build additional electric generation capacity."[725]

Texas and Washington (like Michigan) possess a comprehensive, standalone energy efficiency statute and program. However, neither of these states ties their efficiency program to their RPS goals. Texas directs its utilities to create market-based incentives to acquire cost-effective savings of 20 percent of the growth in annual demand.[726] The Texas PUC is charged with implementing those plans. The statute allows for the costs of implementation to be passed through to customers or electric suppliers.[727] Washington directs each qualifying utility to identify its "achievable cost-effective conservation potential through 2019."[728] Beginning in 2010, each qualifying utility must establish its biennial target.[729] These programs represent the statewide energy efficiency programs imposed at the utility level for the 17 subject states.

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720 *Id.* §460.1077(7).

721 *Id.* §460.1091.

722 *Id.* §460.1073.

723 NYPSC ORDER 03-E-0188 (Sept. 24, 2004) at 12.

724 CAL. PUB. UTIL. CODE §399.4.

725 MO. REV. STAT.§393.1040.

726 TEX. UTILITIES CODE §39.905(a)(3).

727 *Id.* §39.905(b)(3); 16 TEX. ADMIN. CODE §25.181(f).

728 WASH. REV. CODE §19.285.040(a).

729 *Id.* §19.285.040(b).

In addition to the statewide programs above, a great many other programs have been created at the state and local levels to encourage individuals and companies to reduce energy consumption. Given the grassroots nature of these efficiency programs and their diverse local flavor, these incentives and requirements were determined to be outside the scope of this article. A brief description of the legislative programs follows.

- All subject states have implemented some type of building codes requirement at the state level.[730]
- All subject states have enacted energy standards for public buildings.[731]
- Of the 17 states, 6 have implemented appliance and equipment standards.[732]

The states also employ financial incentives in working to increase energy efficiency. The main programs and the participation level by state follow:[733]

- personal tax incentives (7 of 17 states)
- corporate tax incentives (4 of 17 states)
- sales tax incentives (5 of 17 states)
- property tax incentives (3 of 17 states)
- rebates (3 states directly involved; all states have at least one utility)
- grants (9 of 17 states; utilities in 5 of 17 states participating)
- loans (10 of 17 states; utilities in 13 of 17 states participating)
- bonds (only Illinois)

The Department of Energy provides an excellent overview these initiatives on its DSIRE website at www.dsireusa.org.

Energy efficiency will continue to receive a great deal of attention considering the recent influx of federal funds. The most widespread emphasis appears to be on the use of incentives at

730 Database of State Incentives for Renewables & Efficiency, www.dsireusa.org (last visited May 11, 2010) (each is available by state, or see summary tables).

731 *Id.*

732 *Id.*

733 *Id.*

the local and customer level to promote these goals. Only a few states have implemented energy efficiency as a requirement within their RPS goals. Michigan, Texas, and Washington have standalone programs requiring energy efficiency goals at the electric provider level.

Decoupling

Traditional rate design penalizes utilities for a lack of sales volume because utility recovery is based on a volumetric approach. Unfortunately, this rate recovery theory conflicts with the concepts of energy efficiency and demand-side management. In theory, if the utility helps its customers lower their usage, the utility will not be able to recover the lost revenues without a rate case.[734] The concept of *decoupling* attempts to strike a balance of providing utilities with revenue recovery assurance while still promoting energy efficiency and demand-side management programs.[735]

California has been a leader in this area. For California, decoupling has been a part of an overall plan to increase energy efficiency. "Over the years, successive CPUC decisions have created a policy framework to motivate IOUs to develop and continuously expand energy efficiency programs on behalf of their customers. This policy framework is composed of a number of elements including: the State's adopted loading order; aggressive goals set based upon up-to-date potential studies; decoupling of sales from revenues for electric and gas utilities; performance-based incentive mechanisms; and a robust dual funding stream comprised of a public goods charge and procurement funding."[736]

Decoupling creates a division in opinions. Some groups, like the Illinois Climate Change Advisory Group, have supported decoupling to promote conservation.[737] On the other hand, Wal-Mart (speaking as an advocate for consumers and commercial entities) does not necessarily oppose decoupling, but has expressed the opinion that decoupling should only be applied to actions taken by the utility to promote conservation. Actions by individual consumers or

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734 Rebecca Smith, Less Demand, Same Great Revenue: with Decoupling, Utilities Can Promote Efficiency and Not Fear Losing Money, THE WALL STREET JOURNAL, Feb. 8, 2009, http://online.wsj.com/article/SB123378473766549301.html (last visited May 11, 2010).

735 Wikipedia, Decoupling, http://en.wikipedia.org/wiki/Decoupling (last visited May 11, 2010).

736 2008 Cal. PUC LEXIS 417 (2008).

737 Memo from Illinois Climate Change Advisory Group, http://www.epa.state.il.us/air/climatechange/documents/subgroups/power-energy/decoupling-of-utility-rates-and-profits.pdf (last visited May 11, 2010).

nonconservation occurrences such as weather or economic downturns should not qualify for decoupling consideration.[738] Although some, such as the Residential Utility Consumer Office in Arizona, consider decoupling to be a "very slippery slope that could easily lead to a situation where monopoly enterprises could operate in the absence of any effective or meaningful regulation."[739]

5. Conclusion

The main obstacle facing renewable sources of electric energy is their cost disadvantage vis-à-vis coal and natural gas. If the United States wants the development of renewable electric energy to occur more rapidly than evolving market conditions will allow, it must find ways to reduce the cost gap or mandate the use of renewables despite their cost disadvantages. This is especially true at a time when state and federal regulators are trying to create workably competitive electric energy markets that reward the least-cost generators.

Perhaps the best way to equalize costs among electric energy sources is to require each source of electric energy to internalize the external costs of the pollution they produce. Not only would it reduce the cost gap between traditional and renewable energy sources, it also would contribute to addressing our climate change challenges. Such a policy would most likely raise the cost of generating electricity with coal, which has been the low-cost option for some time.

States are ill-equipped, by the nature of their limited jurisdictions and their inability to coordinate with one another, to produce uniformly consistent laws and regulations. State RPS and net metering programs are steps in the right direction, but they do not have enough financial impact and they certainly do not constitute a body of consistent law. The states' other renewable energy incentive programs are likewise not sufficiently robust.

Moreover, assuming that some combination of federal and state renewable energy initiative will begin to succeed in more rapidly developing renewable electric energy projects, it all could be for naught if state certification and siting procedures prevent these projects or their companion transmission projects from getting underway. If states are not willing to develop statewide certification and siting processes capable of preempting local government certification and siting mechanisms, and then use them on behalf of renewable energy projects, the federal

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738 Walmart Customer Insight to Decoupling in an Era of Declining Customer Energy Use. This document is a white paper produced by Walmart to be used in regulatory proceedings to question the merits of decoupling.
739 2008 Ariz. PUC LEXIS 239.

government must consider extending its National Interest Transmission Corridor authority to cover priority renewable electric energy projects that are endangered by state and local government certification and siting procedures.

Appendix 1. Renewable Portfolio Standards

APPENDIX RPS-1: GOALS BY STATE			
State	**Goal**	**Calculation**	**Source**
Arizona (DR=Distributed Resource)	2006: 1.25% 2007: 1.50% (5% DR) 2008: 1.75% (10% DR) 2009: 2.00% (15% DR) 2010: 2.50% (20% DR) 2011: 3.00% (25% DR) 2012: 3.50% (30% DR) 2013: 4.00% (30% DR) 2014: 4.50% (30% DR) 2015: 5.00% (30% DR) 2016: 6.00% (30% DR) 2017: 7.00% (30% DR) 2018: 8.00% (30% DR) 2019: 9.00% (30% DR) 2020: 10.00% (30% DR) 2021: 11.00% (30% DR) 2022: 12.00% (30% DR) 2023: 13.00% (30% DR) 2024: 14.00% (30% DR) 2025: 15.00% (30% DR)	% times retail kWh sold by the Affected Utility during that calendar year Distributed requirement must be met one-half from residential and one-half from non-residential, non-utility. Distributed requirement may be no more than 10% of requirement from non-utility owned generators selling at wholesale to affected utilities. Extra Credit for early installers and in-state criteria	Az. Admin. Code R14-2-1804 R14-2-1805 R14-2-1805.D R14-2-1805.E R14-2-1806
California	Increase % by at least 1% per year to reach at least 20% by end of 2010 with further goal of 33% by 2020.	% times the total kWh sold to the electric companies' retail end use customer each year, subject limits on the total costs above market	Cal. Pub. Ut. 399.11(a) Cal. Pub. Ut. 399.15
Florida	Rulemaking underway.	--	--
Georgia	No statewide goal	--	--
Illinois (by June 1 of each year)	2008: 2% 2009: 4% 2010: 5% 2011: 6% 2012: 7%	"include 'cost effective' renewable energy resources" % times "each utility's total supply to serve the load of eligible retail customers, as defined in Sec. 16-111.5(a) of the Public Utilities Act" for the previous year.	20 ILCS 3855 Sec. 1-75(c)

	2013: 8% 2014: 9% 2015: 10% 2016: 11.5% 2017: 13% 2018: 14.5% 2019: 16% 2020: 17.5% 2021: 19% 2022: 20.5% 2023: 22% 2024: 23.5% 2025: 25%	Total renewables acquired shall be reduced to meet limits on cost impacts on retail customers (see statute for limits)	
Indiana	No statewide goal	--	--
Massachusetts (by Dec. 31 of each year)	Class I requirements 2004: 1.5% 2005: 2.0% 2006: 2.5% 2007: 3.0% 2008: 3.5% 2009: 4.0% 2010: 5.0% 2011: 6.0% 2012: 7.0% 2013: 8.0% 2014: 9.0% 2015: 10.0% 2016: 11.0% 2017: 12.0% 2018: 13.0% 2019: 14.0% 2020: 15.0%, and an additional 1% of sales each year thereafter, with no stated expiration date	% times kWh sales to end-use customers	Mass. Gen. Laws Chap. 25A §11F(a) 225 CMR 14.07(1) 225 CMR 14.07(3) for post 2020 standards
	For Class I, Dept of Energy Resources to determine what portion should be from DR (in service after 12/31/07 and on-site	No established standard yet—“reserved” sections	Mass. Gen. Laws Chap. 25A §11F(g)&(h) 225 CMR 14.07(2)

	generation) OR make an alternative compliance payment.		
	Class II requirements: "in an amount approved by the Dept of Energy Resources o 3.6% annual o 3.5% annual from muni waste conversion plants NOTE: is waste generation additive to the other Class II requirement????		Mass. Gen. Laws Chap. 25A §11F(f) 225 CMR 15.07(1) 225 CMR 15.07(2)
Michigan	Electric Utilities with 1MM or more retail customer as of 1/1/2008: 12/31/2013: 200 MW 12/31/2015: 500 MW 2MM or more retail customers as of 1/1/2008: 12/31/2013: 300 MW 12/31/ 2015: 600 MW	Sets minimum amount of renewable MW capacity combined with % below	MCLS §460.1027(1) MCLS §460.1027(2)
		Can choose whether the RPS is weather-normalized or based on an average number of MW in previous 3 years; locked in once chosen	MCLS §460.1021(1)(b) MCLS §460.1023(1)(b) MCLS §460.1025(1)(b)
	10% total goal by 2015 Total goal phased in: 20% of Total in 2012 33% of Total in 2013 50% of Total in 2014 100% of Total in 2015 and beyond	Credit given for past renewable activity	MCLS §460.1027(3)(a)
Missouri	Minimum of: 2011to 2013: 2% 2014 to 2017: 5%	% if each utilities sales	RSMo. 393.1030.1

	2018 to 2020: 10% for after 2021: 15% for all years With minimum of 2% of above requirement from solar					
New Jersey	Solar %	Class I %	Class II %	Total %	% of electricity sold by each supplier/ provider	NJ Stat. §48:3-87(d) requires Board of Public Utilities to adopt rules
		0.74	2.5	3.25		
2004-2005	0.01	0.983	2.5	3.5		
2005-2006	.0017	2.037	2.5	4.5763		NJAC 14:8-2.3
2006-2007	0.0393	2.924	2.5	5.5057		
2007-2008	.00817	3.84	2.5	6.5		
2008-2009	0.16	4.685	2.5	7.406		
2009-2010	0.221	5.492	2.5	8.297		
2010-2011	0.305	6.320	2.5	9.214		
2011-2012	0.394	7.143	2.5	10.14		
2012-2013	0.497	7.997	2.5	11.098		
2013-2014	0.621	8.807	2.5	12.072		
2014-2015	0.765	9.649	2.5	13.077		
2015-2016	0.928	10.485	2.5	14.103		
2016-2017	1.118	12.325	2.5	16.158		
2017-2018	1.333	14.175	2.5	18.247		
2018-2019	1.572	16.029	2.5	20.365		
2019-2020	1.836	17.880	2.5	22.5		
2020-2021	2.120	BPUC to set	BPUC to set	BPUC to set		
2021 and beyond	BPUC to set					NJAC 14:8-2.3(j) and (k)
Years run June 1 to May 31	BPUC may adjust if solar costs exceed 2%				NOTE: An electric supplier or base generation service provider my satisfy the requirements of this subsection by participating in a renewable energy trading program approved by the BPU in consultation with the Dept. of Environmental Protection	NJAC 14:3-87(d)(2)
New York	24% by 12/31/2013 1% of which should come from voluntary green market programs for total of 25%			% retailed in NY 19.3% already derived from renewable sources Note: up for review in 2009 and NYSERDA to submit a plan for transition		NYPSC Case 03-E-0188 p.3, 4 p. 7

		to a market-based program	
	2006: 0.96% (1,369,424MWh) 2007: 1.95% (2,821,830 MWh) 2008: 2.94% (4,306,437 MWh) 2009: 3.90% (5,787,968 MWh) 2010: 4.86% (7,301,693 MWh) 2011: 5.83% (8,867,181 MWh) 2012: 6.76% (10,403,939 MWh) 2013: 7.71% (11,988,888 MWh) NOTE: Actual purchase is grossed up for losses	Based on projected growth load in the 2002 State Energy Plan	p. 80, p. 83 (Commisison order #2) Appendix 8, p.8
North Carolina By the year	2012: 3% of 2011 2015: 6% of 2014 2018: 10% of 2017 2020 and after: 12.5% of 2020	% of NC retail sales (each "public utility")	NC Gen. Stat. § 62-133.8(b)(1)
	2012: 3% of 2011 2015: 6% of 2014 2018 and after: 10% of 2017	% of NC retail sales (Electric Membership Corporations & Municipal Utilities)	NC Gen. Stat. § 62-133.8(c)
	Solar requirement 2010: 0.02% 2012: 0.07% 2015: 0.14% 2018: 0.2%	Included in RPS requirement ("sold to retail customers")	NC Gen. Stat. § 62-133.8(d)
	Swine waste requirement 2012: 0.07% 2015: 0.14% 2018: 0.2%	Included in RPS requirement ("sold to retail customers")	NC Gen. Stat. § 62-133.8(e)
	Poultry Waste requirement 2012: 170,000 MWh 2013: 700,000 MWh 2014: 900,000 MWh	Included in RPS requirement ("sold to retail customers")	NC Gen. Stat. § 62-133.8(f)
Ohio End of year	2009: 0.25% (0.004% solar) 2010: 0.50% (0.010% solar) 2011: 1% (0.030% solar) 2012: 1.5% (0.060% solar)	% of the total number of kilowatt hours of electricity sold by the subject utility or company to any and all retail electric consumers whose electric load centers are served by that utility and are located within the utility's certified territory or, in the case of an electric services company, are	Ohio Rev. Code Ann. 4928.64 And Staff Proposed Rules 4901:1-40-03

	2013: 2% (0.090% solar) 2014: 2.5% (0.12% solar) 2015: 3.5% (0.15% solar) 2016: 4.5% (0.18% solar) 2017: 5.5% (0.22% solar) 2018: 6.5% (0.26% solar) 2019: 7.5% (0.3% solar) 2020: 8.5% (0.34% solar) 2021: 9.5% (0.38% solar) 2022: 10.5% (0.42% solar) 2023: 11.5% (0.46% solar) 2024 and after: 12.5% (0.5% solar)	served by the company and are located within this state. For electric utilities: the baseline is computed as the average of the total kilowatt hours sold under its standard service offer to all retail customers with load centers served by the utility in its territory. For electric services companies: the baseline is computed as the average of the three preceding years of the total annual number of kWh sold to all retail electric consumers in the state.	Rule 4901:1-40-03(B)(1) Rule 4901:1-40-03(B)2
		Up to half may be generated from "advanced energy resources" Advanced energy resource means: "Advanced energy resource" means any of the following: (a) Any method or any modification or replacement of any property, process, device, structure, or equipment that increases the generation output of an electric generating facility to the extent such efficiency is achieved without additional carbon dioxide emissions by that facility; (b) Any distributed generation system consisting of customer cogeneration of electricity and thermal output simultaneously, primarily to meet the energy needs of the customer's facilities; (c) Clean coal technology that includes a carbon-based product that is chemically altered before combustion to demonstrate a reduction, as expressed as ash, in emissions of nitrous oxide, mercury, arsenic, chlorine, sulfur dioxide, or sulfur trioxide in accordance with the American society of testing and materials standard D1757A or a reduction of metal oxide emissions in accordance with standard D5142 of that society, or clean coal technology that includes the design capability to control or prevent the emission of carbon dioxide, which design capability the commission shall adopt by rule and shall be based on economically feasible best available technology or, in the absence of a	Rule 4901:1-40-03(A)(1) Ohio Rev. Code 4928.01(A)(34)

		determined best available technology, shall be of the highest level of economically feasible design capability for which there exists generally accepted scientific opinion; (d) Advanced nuclear energy technology consisting of generation III technology as defined by the nuclear regulatory commission; other, later technology; or significant improvements to existing facilities; (e) Any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell; (f) Advanced solid waste or construction and demolition debris conversion technology, including, but not limited to, advanced stoker technology, and advanced fluidized bed gasification technology, that results in measurable greenhouse gas emissions reductions as calculated pursuant to the United States environmental protection agency's waste reduction model (WARM). (g) Demand-side management and any energy efficiency improvement.	
Pennsylvania (Periods run from 6/1 to 5/31)	TIER I & SOLAR 2006-07: 1.5% 2007-08: 1.5% 2008-09: 2.0% 2009-10: 2.5% 2010-11: 3.0% 2011-12: 3.5% 2012-13: 4.0% 2013-14: 4.5% 2014-15: 5.0% 2015-16: 5.5% 2016-17: 6.0% 2017-18: 6.5% 2018-19: 7.0% 2019-20: 7.5% 2020 and after: 8.0%	% of electric energy sold by an electric distribution company or electric generation supplier to retail electric customers	73 Penn. Stat. §1648.3(b)(1) AND PAC §75.61

	Of the % above that must be from solar PV (time periods from June 1 to May 31 each year): 2006-7: 0.0013% 2007-8: 0.0030% 2008-9: 0.0063% 2009-10: 0.0120% 2010-11: 0.0203% 2011-12: 0.0325% 2012-13: 0.0510% 2013-14: 0.0840% 2014-15: 0.1440% 2015-16: 0.2500% 2016-17: 0.2933% 2017-18: 0.3400% 2018-19: 0.3900% 2019-2020: 0.4433% 2020 and after: 0.5000%		73 P.S. §1648.3(b)(2) AND PAC §75.61
	TIER II 2006-2010: 4.2% 2010-2015: 6.2% 2015-2020: 8.2% 2020 and after: 10.0%		73 Penn. Stat. §1648.3(c) AND PAC §75.61
	Requirement does not begin for an electric distribution company (or electric generation supplier) until finished with cost-recovery for restructuring BUT may bank credits during the exempt time		73 Penn. Stat. §1648.3(d) AND PAC §75.61(c)&(d)
	May be excused for Force Majeure	PA PUC determines if FM occurred	73 Penn. Stat. §1648.3(a)(2)
Texas (by January 1 of each year)	Cumulative installed renewable capacity in Texas: 2007: 2,280 MW 2009: 3,272 MW 2011: 4,264 MW 2013: 5,256 MW	No % must a MW goal.	Tex. Utilities Code §39.904(a) & 16 TAC §25.173(a)(1) Tex. Utilities Code §39.904(m-

	At least 500 MW of renewable capacity installed after 9/1/05 must be from a source other than wind. Goal as applied to a retail electric provider, muni or coop is reduced if customer receiving electric service at "transmission-level voltage" notifies the commission of its decision to opt out of the RPS goals. Such decision does NOT alter the statewide goal only the allocation. The program administrator does the allocation.		1) Tex. Utilities Code §39.904(m-3) 16 TAC §25.173(h)
Virginia	2010: 4% 2011-2015: 4% 2016: 7% 2017-2021: 7% 2022: 12% 2023 to 2024: 12% 2025: 15%	% times "total electric energy sold in the base year" which means: to VA jurisdictional retail customers by a participating utility in calendar year 2007 EXCLUDING average energy supplied to such customers from nukes for calendar years 2004-2006	VA Code 56-585.2.
	Utilities must install new facilities or retrofit existing to use no more than 1.5 MM tons of test wood waste as fuel	Collective effort by utilities participating in the RPS program.	VA Code 56-585.2.F.
Washington (by January 1 of each year)	2012: 3% 2016: 9 % 2020: 15%	% of each qualifying utilities annual load based on the average load for the utility for the previous 2 years	Rev. Code Wash. §19-285.040(2) and WAC 480-109-020

APPENDIX RPS-2: DEFINITION OF ELIGIBLE RENEWABLE RESOURCES

	Biogas	Biomass	Hydro	Fuel Cells	Geothermal	Landfill Gas	Water Kinetic	Solar	Wind	Date Restriction	Source
Arizona	Gas derived from plants or muni waste	Raw or processed plant-derived organic matter	Yes, see Hydro Table	Only for Hydrogen generated from water using renewable energy sources	Uses heat from earth to generate electricity	Yes	None	Thermal & PV	Yes	Installed after Jan. 1, 1997	Arizona Administrative Code R-14-2-1802
Distributed Renewable Energy Source—"located at a customer's premises and that displace Conventional Energy Resources…" (DG)	DG qualified	DG qualified excluding wood stoves, furnaces and fireplaces	New Hydro Gen of 10 MW or less	DG qualfied	DG qualified/ Geothermal Space Heating and Process Heating			DG Qualified/ Commercial Solar Pool Heaters/ Solar Daylighting/ Solar HVAC/ Solar Industrial Process Heating & Cooling/ Solar Space Cooling/ Solar Space Heating/ Solar Space Heating/ Solar Water Heater	1 MW or less		R-14-2-1802.B (Distributed Renewable Energy Resources)
California	Digester gas	* General * Muni solid waste conversion *combustion of muni solid waster excluded with one exception	Yes, see Hydro Table	Using renewable fuels	Yes	Yes	*ocean wave *ocean thermal * tidal current	Thermal & PV	Yes	In some instances must be installed after Jan. 1, 2005	Pub. Res. 25741 (Energy Commission must certify Pub. Ut. 399.13)
		PUC 399.12(C)(2) for muni waste combustion									
Florida	Included in biomass	Wood, muni & ag wastes	Yes	Yes	Yes	Yes	Yes	Yes	Yes		-- Fla. Stat. Ann.§366.91(2)(d)
Georgia	--	--	--	--	--	--	--	--	--	--	--

Illinois ** statute open ended " and other alternative sources of environmentally preferable energy		**	*Biodiesel *Crops & organic waste *Trees & tree trimming	Yes, see Hydro Table	**	**	Yes	**	Thermal & PV	Yes	--	20 ILCS 3855 Sec. 1-10
Indiana		--	--	--	--	--	--	--	--	--	--	
MASS.	Class I	Included in biomass	Low-emission	Yes, see Hydro Table	Using Class I renewable fuel	Yes	Yes, with location restrictions	*ocean wave *ocean thermal * tidal current	Thermal & PV	Yes	Commercial operations after 12/31/1997	225 CMR14.00
	Class II		Low-emission	Yes, see Hydro Table	Using Class II renewable fuel	Yes	Yes, if gas does not enter a common carrier	*ocean wave *ocean thermal * tidal current	Thermal & PV	Yes	Commercial operations BEFORE 12/31/1997	225 CMR 15.00
Michigan ** statute open ended "is not limited to"		Included in biomass	Organic matter not derived from fossil fuels; replenishes over a human not geological timeframe; Muni solid waste listed as a separate category	Yes, see Hydro Table	** (not directly mentioned)	Yes	Yes	* waves * tides * currents	Thermal and PV	Yes	Only date restriction is on hydro and muni incinerators	Pub. Util. 460.1003, 1007, 1011
Missouri ** statute open ended "other sources of energy"		Waterwater treatment gas	Crops grown for energy; ag residues; untreated wood	Yes, see hydro table	Yes, if fuel comes from a renewable source	**	Yes	**	Thermal & PV	Yes	No date restriction	Mo. St. 393.1025
NEW JERSEY	Class I	Yes, if biomass cultivated and harvested in a sustailable manner	--	--	Yes	Yes	Yes	Wave or tidal	Thermal & PV	Yes	No date restriction	N.J. Stat. § 48:3-49 et. seq.
	Class II	--	Resource recovery facility (a) in an area	Yes, see hydro table	--	--	--	--	--	--	--	N.J. Stat. § 48:3-49 et. seq.

			where retail competition is permitted and (b) meets highest environ standards									
NEW YORK	Main Tier	Sewage Gas; Manure digestion; Anaerobic digestion; Thermochemical gasification	Direct combustion; co-fired with fossil fuel (only biomass portion of gen eligible)	Yes, see hydro table	Yes (lists specific technologies)	--	Yes	*ocean wave *ocean thermal * tidal current	PV	Yes	Date restrictions only on “Maintenance Resources” installed prior to 1/1/2003 that require RPS financial support to operate	New York Pub. Service Comm. Case 03-E-188 Appendix B
	Customer-sited Tier	--	--	--	Yes (lists specific technologies)	--	--	--	PV	300 kWs or less	In-service date after 1/1/2003	Case 03-E-188 Appendix B
North Carolina		Included in biomass	Yes, agriculture, animal, wood wastes and energy crops	Yes, see hydro table	--	Yes	Yes	*ocean current *ocean wave	Thermal or PV	Yes	“New renewable energy facility” in-service date after 1/1/2007	NC Stat. 62-133.8 (also includes waste heat)
Ohio** (statute gives commission authority to accept other technologies)		Included in biomass	Yes, if not direct combustion	Yes, see hydro table	Yes	Yes	**	**	Thermal or PV	Yes	In-service after 1/1/1998	ORC 4928.64 and Rule 4901:1-40-04 Energy storage and distributed gen included as renewable energy resource
		Also includes “advanced energy resources” which include: (a) increases in efficiency of an electric generating facility without additional carbon dioxide emissions; (b) distributed generation consisting of customer cogeneration of electricity and thermal output simultaneously, primarily to meet the energy needs of the customer’s facilities; (c) Clean coal technology; (d) Advanced nuclear energy technology or significant improvements to existing facilities; (e) Any fuel cell used in the generation of electricity; (f) Advanced solid waste or construction and demolition debris conversion technology. (g) Demand-side management and any energy efficiency improvement.										ORC 4928.01(A)(34)
PENNSYLVA	Tier I	Biologically derived methane	Yes	Low-impact hydro, see hydro table	Yes	Yes, to drive steam turbine	Yes	--	Thermal or PV	Yes	--	PA Code s. 1648.2 (also includes coal mine methane)
	Tier II		Muni solid waste; Pulpling	Large Scale hydro, see hydro		--			--	--		PA Code s. 1648.2 (also includes waste coal; distributed generation systems;

N I A		byproducts	table								demand side management; integrated combined coal gasification technology)
Texas	Included in Biomass	Yes	Yes, see hydro table	--	Yes	Yes	*ocean wave * tidal current	Thermal or PV	Yes	No date restrictions	Tex Pub. Ut. 39.904(d)
Virginia	Included in Biomass	Sustainable; municipal solid waste	Yes, see hydro table	--	Yes	Not directly mentioned	*ocean wave * tidal current	Thermal or PV	Yes	No date restrictions	VA stat. § 56-576
Washington	From sewage treatment facilities	Animal waste, wood, dedicated energy crops (excludes municipal waste)	Yes, see hydro table		Yes	Yes	Wave, ocean or tidal power	Thermal & PV	Yes	In-service after 3/31/1999	Wash Stat. 19.285.030 Wash Admin. Code 480-109-007

APPENDIX RPS-3: Hydropower Restrictions

State	Description	Installation Date Restriction?	MW Limit?	Eligibility	Source
Arizona	Pre 1997 hydro units	Pre-1997	None	Increased capacity for technological & operational efficiency	AAC R-14-1802(4)a
				Amount of capacity used to firm intermittent renewables	AAC R-14-1802(4)b
	New Hydropower	After January 1, 2006	10 MW or less	Low-head or micro in stream that does not require damming	AAC R-14-1802(9)a
				Generation addition to existing dam with not adverse impacts	AAC R-14-1802(9)b
				Generation using canals or irrigation systems	AAC R-14-1802(9)c
California	Existing	Before 12/31/2005	30 MW or less	Retail seller or public-owned utility must own facility or purchased power	Cal. Pub. Ut. Code 399.12(C)1(A)

		Before 1/01/2006	30 MW or less	Generally eligible for conduit hydro	Cal. Pub. Ut. Code 399.12(C)1(B)
	New	After 12/31/2005	30 MW or less	Conduit hydro that must not adversely impact stream flow	Cal. Pub. Ut. Code 399.12(C)1(B)
Florida	No restrictions	--	--	No restrictions	Fla. Stat. Ann. §366.91(2)(d)
Georgia	--	--	--	--	--
Illinois	New	--	--	Must not require new construction or significant expansion of hydro dams	20 ILCS 3855/1-10 "Renewable Energy"
Indiana	--	--	--	--	--
Massachusetts	Class I	After 12/31/1997	New unit or efficiency improvement of 25 MW or less	Does not involve dam or diversion structure built after 12/31/1997 and does not adversely affect watershed	225 CMR 14.00
	Class II	12/31/1997	5 MW or less	Does not involve dam or diversion structure built after 12/31/1997 and does not adversely affect watershed	225 CMR 15.00
Michigan	Existing	Before 10/06/2008	No MW restrictions	Does not include pumped storage	MCLS §460.1011(k)
	New	After 10/06/2008	No MW restrictions	Efficiency gains by repairing or improving existing dams	MCLS §460.1011(k)
Missouri	New or Existing	No date restriction	10 MW or less	Does not require a new diversion or impoundment	RSMo §393.1025
New Jersey	Class II	No date restriction	No MW restriction	Must be where retail competition is permitted and meets highest environmental standards	NJ Stat. 48:3-51 "Class II Renewable Energy"
New York (Main Tier)	Upgrades	No date restriction	No MW restriction	Limited to the incremental production from the upgrade	NYPSC Order in Case 03-E-188
	New low-impact run of river	No date restriction	30 MW or less	No new storage impoundment	NYPSC Order in Case 03-E-188
North Carolina	Existing	Before 1/1/2007	10 MW or less		NC Stat. §62-1338
	"New"	After 1/1/2007	10 MW or less		NC Stat. §62-1338
Ohio	All	No date restriction	No MW restriction	Must meet environmental standards listed	Ohio. Rev. Code §4928.64
Pennsylvania	Large-scale hydro	No date restriction	No MW restriction		Penn. Stat. §1648.2
	Low-impact hydro	No date restriction	No MW restriction	No adverse impacts	Penn. Stat. §1648.2

Texas	All	No date restriction	No MW restriction		Tex. Pub. Utilities §39.904
Virginia	All	No date restriction	No MW restriction		Va. Code §56-576
Washington	All	After 3/31/1999	No MW restriction	Allows incremental efficiencies on existing hydropower and power using irrigation pipes and canals with no new impediments.	Wash. Admin. Code §480-109-007(9)(b)

APPENDIX RPS-4: Who Administers

Arizona	Arizona Corporation Commission (ACC)	R14-2-1801 et. seq.
California	California Air Resources Board was assigned is to implement the RPS program as of September 15, 2009 under a reassignment through an Executive Order; originally with the Energy Commission	Executive Order S-21-09, Sept. 15, 2009
	Energy Commission certifies compliance for publicly owned utility	Pub. Ut. C. 399.13(d)
	California Public Utilities Commission (CPUC) directs each electrical corporation to prepare a renewable energy plan	Pub. Ut. C. 399.14
Florida	Florida Public Service Commission	Fla. Stat. Ann. §366.92(3)
Georgia	--	--
Illinois	Illinois Power Agency is in charge of all procurement plans for energy including the renewable resources portion and given the charge to “develop procurement plans to ensure adequate, reliable, affordable, efficient and environmentally sustainable electric service. The Illinois Commerce Commission controls retail supplier certification and cost recovery review.	20 ILCS 3855 Sec. 1-5(A) and Sec. 1-20 220 ILCS 5/16-115
Indiana	--	--
Massachusetts	The MA Dept of Energy. Determines what facilities RPS Class I qualified Determine what facilities are RPS Class II qualified All Retail Electric Supplies must file annual reporting with MA Dept of Energy The Massachusetts Renewable Energy Trust is funded by a charge to consumers and is administered by the Massachusetts Technology Collaborative (MTC). MTC has a goal of 750 to 1000 MW renewable energy generation by 2009.	225 CMR 14.06 225 CMR 15.06 225 CMR 14.09 (Class I) & 15.09 (Class II) Aim Foundation Report, Oct. 2004 p.2.

Michigan	MI Pub Service Commission—utilities must submit plans	460.1021 Sec. 21(1)—regulated utilities 460.1023 Sec. 23(1)—coops 460.1025 Sec. 25(1) – munis
Missouri	Missouri Public Service Commission administers RPS program MO Dept Nat Resources (in consultation with MPSC) determines renewable certification process.	393.1030.1 and 1030.2 393.1030.4
New Jersey	NJ Board of Public Utilities	48:3-87(d)
New York	NYSPC issues surcharge while central renewable energy authority purchases energy—NY State Energy Research and Development Authority (NYSERDA) Staff to develop detailed procedures	NYSPC Case 030E-0188 p.3 p. 81
North Carolina	North Carolina Utility Commission	NC Gen. Stat. §62-133.8(h)(5)
Ohio	Public Utilities Commission	ORC Ann. 4928.64(C)
Pennsylvania	PA PUC (general compliance duties) Department of Environmental Protection of the Commonwealth (verify meet standards)	73 P.S. §§1648.1-1648.8 & 73 P.S. §1648.7 ARIPPA v. Pa. PUC, 966 A.2d 1204 (2009) 73 P.S. §1648.7(b) AND PAC §75.62
Tennessee		
Texas	The commission shall establish a REC trading program and any retail electric provider not meeting the RPS goal must purchase REC in lieu of capacity. Distributed Renewable Generation owners retain ownership of REC unless explicitly sold. Defined—one MWh of renewable energy that is physically metered and verified in Texas and meets the definition of renewable.	Tex. Utilities Code §39.904(b) Tex. Utilities Code §39.916(g) 16 TAC §25.173(c)(13) & (16-17)

Virginia	VA State Corporation Commission However, the VSCC has determined that no rules are currently needed.	VA Code §56-585.2.G 24 Va. Regs. Reg. 2468 (2008)
Washington	WA State Utilities and Transportation Commission for IOU WA State Dept. of Community, Trade and Economic Development for non-IOU qualifying utilities.	Rev. Code Wash. §19.285.080(1) Rev. Code Wash. §19.285.080(2)

APPENDIX RPS-5: RECs		
Arizona	One REC created per kW derived from Eligible Energy Resource One REC created per 3,415 Btus for DR RECs are owned by the owner of the Eligible Renewable Energy Resources and are Transferable Requires proof of transmission rights for delivery to customers	R14-2-1803.A R14-2-1803.B R14-2-1803.D&E R14-2-1803.F
	May use REC acquired in any year to meet the Annual Renewable Energy Requirement Must choose between environmental credits and REC—cannot double dip	R14-1804(C) R14-1804(E) R14-1805(E) DR
California	Certified by Energy Commission CPUC may authorize RECs to satisfy RPS requirements [look at CPUC rules for RECs] PURPA purchases are ineligible for RECs All revenues received by electrical corp under CPUC must be credited to ratepayers	Pub. Ut. 399.13 Pub. Ut. 399.16 Pub Ut 399.16(a)(6) Pub. Ut. 399.16(a)(4)
Florida	REC is equivalent to 1MWhr of electricity generated by a renewable source located in Fla.	Fla. Stat. Ann. §366.92(2)(d)
Georgia	--	--
Illinois	REC="A tradable credit that represents the environmental attributes of a certain amount of energy produced from a renewable energy resource."	20 ILCS 3851-10
Indiana	--	--
Massachusetts	Each Retail Electricity Supplier must make an annual Compliance Filing	225 CMR 14.09

	Class I "Renewable Generation Attributes" can be banked for two years up to a 30% excess Class II same as above Class I Compliance can be obtained by making an Alternative Compliance Payment to the MA Technology Park Corporation Class II same as above except rate is ½ Class II Waste Energy Alternative Compliance	225 CMR 14.08(2) 225 CMR 15.08(2) 225 CMR 14.08(3) 225 CMR 15.08(3) 225 CMR 15.08(4)
Michigan	Can meet requirements by (1) purchasing the energy; (2) acquiring RECs or (3) for 10% of requirement may substitute energy optimization credits (NOTE: limited tie of RPS to efficiency through this provision) 1 REC for each MWh to owner of renewable energy facility Additional RECs for "Michigan Incentive" o 2 RECs for solar o 1/5 REC other than wind o 1/5 REC for storage project (based on electric into storage—not out) o 1/10 REC for MI-made equipment o 1/10 REC for MI-resident workforce Good until used but expires within 3 years from creation date if still unused May be traded or sold per MPSC process	Sec. 27(5),(6), (7) Sec. 39 Sec. 39(2) Sec. 39(3) Sec. 41
Missouri	1 REC for each MWh generated from renewable resources Utility may comply all or part by purchasing RECs. 25% bonus for RECs created with in-state generation sources MPSC to create REC tracking system	393.1025.5 393.1030.1 393.1030.2
New Jersey	Solar: A supplier will meet either with Solar RECs or Solar Alternative Compliance Payment (SACP) Class I and Class II: A supplier will meet by submitting RECs in accordance with NJAC 14:8-2.8 Class I and Class II: Alternative compliance payments (ACP) can be used rather than RECs Solar RECs can be used to meet any classification; Class I for either Class I or II but not solar; Class II RECs only used for Class II.	NJAC 14:8-2.3(c) NJAC 14:8-2.3(d)

	REC requirements BPU issues RECs per guidelines in administrative code	NJAC 14:8-2.3(e) NJAC 14:8-2.3(f) NJAC 14:8-2.8 NJAC 14:8-2.9
New York	None—NYSERDA administers using funds collected from utilities; NYSERDA directed to consider a tracking system that will be compatible with a regional REC tracking and trading system.	NYSPC Case 030E-0188 p.10 p. 57
North Carolina	May purchase power or use RECs NC Utilities Commission to establish rules for RECs Owner of renewable facility must register with the NCUC for RECs Owner must certify that the facility meets the PRS guidelines REC must be purchased with three years of creation; must be used within seven years of cost recovery	NC Gen. Stat. §62-133.8(b)(2) NC Gen. Stat. §62-133.8(i) NCAC R8-66(b) NCAC R8-66(b)(4-5) NCAC R8-67(d)
	Note: Energy efficiency may count as much as 25% until 2021 and as much as 40% of the RPS goal in 2021	NC Gen. Stat. §62-133.8(b)(2)c.
Ohio	RECs good for five years from their purchase or acquisition The public utilities commission shall adopt rules specifying that one unit of credit shall equal one megawatt hour of electricity derived from renewable energy resources. The rules also shall provide for this state a system of registering renewable energy credits by specifying which of any generally available registries shall be used for that purpose and not by creating a registry. That selected system of registering renewable energy credits shall allow a hydroelectric generating facility to be eligible for obtaining renewable energy credits and shall allow customer-sited projects or actions the broadest opportunities to be eligible for obtaining renewable energy credits.	ORC Ann. 4928.65 Rules 4901:1-40-04(D)
Pennsylvania	PA UC to establish alternative energy credits (AEC) program by approving an independent entity to serve as administrator. An electric distribution company and electric generation supplier may bank AECs for use in the two subsequent years. May bank credits during the cost-recovery exemption period. Must use within the two reporting years following the end of the cost-recovery period.	73 P.S. §1648.3(e) AND PAC §75.64, §75.70 73 P.S. §1648.3(e)(6) AND PAC §75.69 73 P.S. §1648.3(e)(7)

	PA UC will track AEC transfers through a registry. PA UC to establish regs governing verification and tracking of energy efficient and demand-side management AEC creation. PA UC to develop a depreciation schedule for AEC created by demand-side management, efficiency & load management technologies. Owner of the alternative energy system owns the AEC Qualifications of alternative energy system (including must be within PA or PJM RTO)	73 P.S. §1648.3(e)(8) 73 P.S. §1648.3(e)(10) AND PAC §75.63 73 P.S. §1648.3(e)(11) 73 P.S. §1648.3(e)(12) PAC §75.62
Texas	The program administrator shall allocate the RPS requirements among retail entities through set out methodology (NOTE: opt-out provision for transmission level (60 kV or more) customers). Municipal-owned and distribution utilities that do not offer customer choice have NO RPS requirement (are excluded from allocation) Commission sets qualifications for RECs Program administrator (independent entity) administers REC trading program.	16 TAC §25.173(h) 16 TAC §25.173(d)(4) 16 TAC §25.173(e) 16 TAC §25.173(g)
Virginia	A utility may apply renewable energy sales achieved or RECs acquired in excess of an annual goal to future goals. Double credit toward meeting RPS goals with energy derived from sunlight or from wind.	VA Code § 56-585.2.D VA Code § 56-585.2.C
Washington	The requirements may be met with REC from that year, the preceding year or the subsequent year.	Rev. Code Wash. §19.285.040(2)(e)

APPENDIX RPS-6: Enforcement/Implementation		
Arizona	Annual Report filed with ACC Annual Implementation Plan filed with ACC	R14-2-1812 R14-2-1813
	ACC may deny cost recovery on meeting the shortfall or other traditional penalties available to the ACC Based entirely on RECs	R14-2-1815 R14-2-1804(A)
California	Energy Commission to establish a tracking system	Pub. Ut. 399.13
	CPUC to establish “flexible” rules for compliance for electric companies—flexible rules may take into account transmission constraints Electric companies must submit renewable procurement plan (least-cost, best fit) Electric companies must offer contracts of at least 10 years unless CPUC approves shorter Electric companies may give preference to project with benefits to low-income areas in analysis. CPUC may reject contract prices and force rebid	Pub. Ut. 399.14 (a)(2) (a)(5) (d)
	CPUC has enforcement authority over electrical companies	Pub. Ut. 399.14(e)
Florida	Rulemaking underway	--
Georgia	--	--
Illinois	Illinois Power Agency administers procurement plan and must conduct a competitive procurement process The Illinois Power Agency must report annually to the governor “the quantity, price and rate impact of all renewable resources purchased under the electricity procurement plans for electric utilities.” ICC must revoke alternative energy retail certification if supplier has not met renewable or clean coal goals.	20 ILCS 3855 Sec. 1-5(A) 20 ILCS 3855 Sec. 1-125(2) 220 ILCS 5/16-115 (d-5)
Indiana	--	--
Massachusetts	Each Retail Electricity Supplier must submit a compliance filing to the Dept. of Energy. Other than reporting, the enforcement is left to the MA Dept of Public Utilities who can suspend or revoke the retail license. Note: the civil penalty enforcement authority of the MDPU is not available for RPS enforcement.	225 CMR 14.08(1) for Class I 225 CMR 15.08 225 CMR 14.12(4) for Class I and 15.12(4) for Class II and 220 CMR 11.07(4)(c)1 for both

Michigan	MI Pub. Service Commission can grant good faith extensions including siting delays, equipment cost and availability delays, labor shortages MI Pub. Service Comm has right to review all contracts and reject for either REC or rate qualification Every electric provider must submit an annual report the MPSC. MPSC has direct authority over regulated utilities Civil action enforcement provisions for coops MPSC licensing revocation and civil fines for alternative electric providers Civil action enforcement provision for municipals	Sec. 31 Sec. 33 Sec. 51 Sec. 53(1) Sec. 53(2) Sec. 53(5) Sec. 53(6)
Missouri	Annual report required Penalties at twice the value of the REC shortage NOTE: MPSC to issue rules soon	393.1030.2 393.1030.2(c) 393.1030.2(b)
New Jersey	Solar: meet through solar RECs Class I: meet through listed energy types (see definitions) Class II: meet through list energy types (see definitions) Solar: A supplier will meet either with Solar RECs or Solar Alternative Compliance Payment (SACP) SACP schedule ($711/MWhr in 2009 down to $594/MWhr in 2016) Class I and Class II: A supplier will meet by submitting RECs in accordance with NJAC 14:8-2.8 Class I and Class II: Alternative compliance payments (ACP) can be used rather than RECs ACP amount to be set by ACP advisory committee to BPU Solar RECs can be used to meet any classification; Class I for either Class I or II but not solar; Class II RECs only used for Class II. Demonstrating and reporting compliance BPU can enforce using: (1) suspension or revocation of power license (2) financial penalties (3) disallowance of cost recovery prohibition of accepting new customers	NJAC 14:8-2.4 NJSC 14:8-2.5 NJAC 14:8-2.6 NJAC 14:8-2.3(c) NJAC 14:8-2.10(f) NJAC 14:8-2.3(d) NJAC 14:8-2.3(e) NJAC 14:8-2.3(b) NJAC 14:8-2.3(f) NJAC 14:8-2.11 NJAC 14:8:2.12
New York	RPS Program goal is create competitive market for green power (“green markets”) to replace gov. mandates when RPS program ends.	NYSPC Case 030E-0188 p.4

	No enforcement mechanism required due to centralized administration	p. 84 (Commission order #5 and 6)
North Carolina	North Carolina Utilities Commission (NCUC) to establish rules for compliance and enforcement NCUC can revoke the registration (ability to receive REC) Annual plan for current on next two years Electric utilities subject to R8-60 (very specific list) must file its RPS plan with its integrated resource plan filing for NCUC approval If not subject to R8-60, then the RPS compliance plan is for informational purposes only NCUC can delay implementation	NC Gen. Stat. §62-133.8(i)(1) NCAC R8-66(f) NCAC R8-67(b) NCAC R8-67(b)(3) and (c) NCAC R8-67(b)(4) and (c) NCAC R8-67(c)(5)
	NOTE: meeting the RPS requirements have different manners for utilities vs. cooperatives and municipal utilities	Compare NC Gen. Stat. §62-133.8(b)(2) vs. 133.8(c)(2)
Ohio	The Commission to do an annual review The Commission shall impose a renewable energy compliance payment on the utility or company for under or noncompliance. Chart setting out SOLAR compliance payments: 2009-- $450/MWh 2010-11-- $400/MWh 2012-13-- $350/ MWh 2014-15-- $300/ MWh 2016-17-- $250/ MWh 2018-19-- $200/ MWh 2020-21-- $150/ MWh 2022-23-- $100/ MWh 2024 +-- $50/ MWh Commission will set rate for other renewable compliance payments at a minimum of $45/ MWh Commission will review market to insure that compliance payments are punitive and not being used as an in lieu of method.	ORC Ann. 4928.64(C) Rule 4901:1-40-05 4928.64(C)(2) Rule 4901:1-40-08 Rule 4901:1-40-08(A)(2) Rule 4901:1-40-08(A)(3) 4928.64(C)(2)(c)

	Compliance payment may NOT be passed through rates. Force majeure provision	Rule 4901:1-40-08(D) 4928.64(C)(4) Rule 4901:1-40-06
Pennsylvania	Annual reports to Pennsylvania Utility Commission (PUC) PUC to conduct review and if finds failure to meet sections (b) & (c) shall impose an "alternative compliance payment" on that company or supplier. Alternative compliance payment excepting PV share compliance = $45 times the shortfall Alternative compliance payment for PV= 200% of the average market value for solar renewable credits within the reporting region of PJM. PUC must (at least) annually monitor the costs of Alternative Energy Credits (AECs), however authority to change pricing is reserved to the legislature. Payment made for alternative compliance to go to Penn. Sustainable Energy Fund. Cannot double dip in different state Only good for energy generated in PJM RTO May be excused for Force Majeure	73 P.S. §1648.3(f)(1) 73 P.S. §1648.3(f)(2) 73 P.S. §1648.3(f)(3) 73 P.S. §1648.3(f)(4) AND PAC §75.65 73 P.S. §1648.3(f)5) 73 P.S. §1648.3(g) 73 P.S. §1648.4 73 P.S. §1648.4 PAC §75.66
	Definition of AEC	PAC §75.1
Texas	The commission may establish an alternative compliance payment instead of using RECs with the parameters for payment a minimum of $2.50/ REC to a max of $20/ REC for wind based renewable energy with the Commission able to set other prices for alternative compliance for the 500MW goal other than wind.	Tex. Utilities Code §39.904(o)
Virginia	Voluntary with a carrot—meeting RPS goals yields increase in fair combined rate of return on common equity Each IOU to file an annual report to the Commission on its efforts (if any) to meet RPS goals.	VA Code 56-585.2.C VA Code 56-585.2.H
Washington	Either meet with using renewable energy resources or acquiring RECs. A qualifying utility that fails to comply with the energy conservation or renewable energy targets shall pay a $50/ MWh shortfall penalty. The commission will determine whether the penalty can be recovered in rates.	Rev. Code Wash. §19.285.040(2) Rev. Code Wash. §19.285.060 And WAC 480-109-050

	For qualifying utilities that are not IOUs, the auditor is responsible for auditing compliance the attorney general is responsible for enforcement. Annual reporting requirement for IOUs	Rev. Code Wash. §19.285.060(7) WAC 480-109-040
	A qualifying utility may count distributed generation at two times the output if the utility: (1) owns or has contracted for the Distributed Generation and the associated RECs; or (2) has contracted to purchase the associated RECs.	Rev. Code Wash. §19.285.040(2)(b)

APPENDIX RPS-7: Cost Recovery		
Arizona	Customer Self-Directed Renewable Energy Option Customer may self-direct if pays Tariff more than $25,000	R14-2-1801.D & R14-2-1801.H R14-2-1809
	Recovery through Tariff= Commission-approved rate design to recover reasonable and prudent costs of RPS program or an affected utility may file a rate case in the alternative	R14-2-1801.P R14-2-1808
California	Procurement and administrative costs associated with electric companies' long-term contacts are recoverable in rates CPUC to set limits on total costs above market	Pub. Ut. 399.14(g) Pub. Ut. 399.15(d)
Florida	Legislation directs for cost recovery. Rulemaking underway	Fla. Stat. Ann. §366.92(3)(b)1
Georgia	--	--
Illinois	Ability to take RPS renewables % goals down if it will break a cap on cost impacts—the Illinois Commerce Commission is to review whether this provision unduly constrains renewable development no later than 6/30/2011 "… do not exceed benchmarks based on market prices for renewable energy resources in the region…." as tracked by the IPA and approved by the Illinois Commerce Commission. Pass through authorization	20 ILCS 3855 Sec. 1-75(c)(2) 20 ILCS 3855 Sec. 1-75(c)(1) 220 ILCS 5/16-111.5(k)(1)
Indiana	--	--
Massachusetts		
Michigan	Need to take life cycle costs into account for regulated utilities MI Pub Serv Comm to determine cost recovery on "reasonable and prudent" standard for its regulated utilities	Sec. 21(6)b and Sec. 37(b) Sec. 37 and Sec. 45(1)

	Subject to rate impact cap per customer class: o $3/month residential o $16.58/month commercial 2ndary o $187.50/month commercial primary or industrial Annual rate recovery proceeding	Sec. 45(2) Section 49
Missouri	MPSC to allow for recovery up to 1% increase in maximum average retail price	393.1030.2(a) and (d)
New Jersey	BPU to determine rate recovery	48:3-87(d) and several BPU dockets determining rates
New York	"The revenue necessary to support this program, including an appropriate administrative fee, will be raised through a non-bypassable volumetric charge on the delivery customers of each of the State's IOUs.	p. 65, 83 (Commission orders #3, 4, 7, 8 and 9)
North Carolina	Cost recovery for "incremental costs" that are reasonable and prudent through an annual rider with caps for residential, commercial and industrial customer accounts Allowed to pass through costs Burden of proof as to whether costs were reasonable prudent on electric public utility	NC Gen. Stat. §62-133.8(h) & NCAC R8-67(c)(9) NCAC R8-67(e) NCAC R8-67(e)(16)
Ohio	Cost cap at 3 cents above conventional (if above utility does not have to comply with goal) (E) All costs incurred by an electric distribution utility in complying with the requirements of this section shall be bypassable by any consumer that has exercised choice of supplier under section 4928.03 of the Revised Code An electric utility or electric service provider may request a determination if the cost of compliance exceeds 3% or more	ORC Ann. 4928.64(C)(3) ORC Ann. 4928.64(E) Rule 4901:1-40-07
Pennsylvania	A default service provider may recover "reasonable and prudent" costs Recovered thru automatic adjustment clause	PAC §75.67(a) PAC §75.67(c)
Texas	Commission to adopt rules to administer and enforce	Tex. Utilities Code §30.904(c)
Virginia	Participating utility may recover all incremental costs through rate adjustment clauses	VA Code §56-585.2.E
Washington	A qualifying utility is considered to be in compliance if it invested 4% of its total annual retail revenue requirement on the incremental costs of renewable resources and/or RECs An IOU is entitled to recover all prudently incurred costs associated with compliance	Rev. Code Wash. §19.285.050(1) Rev. Code Wash. §19.285.050(2)

	Each qualifying utility must submit an annual report to the Dept. (with IOUs also submitting to the Commission)	Rev. Code Wash. §19.285.070 WAC 480-109-040
	Alternatives to RPS compliance—(1) invest 4% of total annual retail revenue requirements on the incremental costs of of eligible renewable resources and/or REC; (2) claim force majeure (3) claim that (a) weather adjusted load did not increase (b) have acquired RECs for non-renewable purchases other than spot AND (c) invested at least 1% of the total annual retail revenue on renewable resources and/or RECs	WAC 480-109-030

Appendix 2. Summary of Generation & Transmission Siting Highlights by State

Arizona	• Power plant and transmission siting committee of the Arizona Corporation Commission[1]
	• Plant: "thermal electric, nuclear or hydroelectric generating unit with nameplate rating of 100 MW or more[2]
	• Transmission line: 115kV or more[3]
	• Transmission lines must be submitted as part of a 10 year plan[4]
	• Plant and transmission lines require a "certificate of environmental compatibility"[5]
	• Is not specific to renewable. Only covers renewables that have a thermal component.
	• Hearing required[6]
	• Parties required:[7]
	  o The applicant
	  o Each county and municipal government and state agency interested in the proposed site
	  o Any domestic nonprofit corporation formed in whole or in part to:
	    ▪ Promote conservation
	    ▪ Promote natural beauty
	    ▪ Protect personal health
	    ▪ Protect other biological values
	    ▪ Preserve historical sites
	    ▪ Promote consumer interests
	    ▪ Represent commercial and industrial groups
	    ▪ Promote orderly development of an area
	    ▪ Any others that have request (10 days prior) to be included
	  o Any other person deemed appropriate at any time by the committee or hearing officer
	• Cannot construct until certificate of environmental compatibility is issued[8]
	• Certificate is transferrable unless restricted in the certificate[9]
	• Court jurisdiction limited only to compliance enforcement[10]

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1 AZ. REV. STAT. §40-360 et. seq.
2 AZ. REV. STAT. §40-360.9
3 AZ. REV. STAT. §40-360.10
4 AZ. REV. STAT. §40-360.02
5 AZ. REV. STAT. §40-360.03
6 AZ. REV. STAT. 40-360.04
7 AZ. REV. STAT. 40-360.05
8 AZ. REV. STAT. 40-360.07
9 AZ. REV. STAT. 40-360.08
10 AZ. REV. STAT. 40-360.11

	• Arizona Corporation Commission jurisdiction under this act is limited only to those regulated by the Commission[11]
	• Interview:[12]
	  o Verified that all siting must go through committee
	  o Need is definitely a factor
	  o Still included in rate base if the utility is regulated, but many entities are not regulated by the APSC such as munis and irrigation districts.

California	• CA Energy Commission has exclusive statutory responsibility for licensing thermal power plants[13]
	• 50 MW and larger and related facilities[14]
	• One stop permitting process[15]
	• Applies to electric transmission lines associated with thermal plants[16]
	• Must consider environmental impact and need[17]
	• Permitting for geothermal generation facilities is delegated to local governments.[18]
	• Interview:[19]
	  o Confirmed siting with Energy Commission for 50 MW or greater plants
	  o All plants need a certificate of need
	  o Mix on whether included in rate base or not (although utilities rarely build)
	  o IPPs are subject only to local and environmental permitting

Florida	• Statute separates power plant[20] and transmission lines [21] into two different code sections • Both are administered mainly by the Fla. Dept of Environmental Protection • Power plant defined as "any steam or solar electrical generating facility" less than 75 MW—smaller does have the option to use the process—does not involve wind [22] • 75 MW threshold with election to use the process for smaller thermal projects[23]

11 AZ. REV. STAT. 40-360.12

12 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

13 Cal. Pub. Res. Code §25550.

14 Cal. Pub. Res. Code §25120.

15 20 Cal. Code of Reg. §1721.

16 Cal. Pub. Res. Code §21507; 20 Cal. Code of Reg. §1702(m).

17 20 Cal. Code of Reg. §1726.

18 20 Cal Code of Reg. §1860.

19 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

20 Fla. Stat. §403.501 to §403.518.

21 Fla. Stat. § 403.52 to §403.5365.

22 Fla. Stat. §403.503(14).

23 Fla. Stat. §403.506.

	• Requirement that certain state agencies will submit a report within 100 days of the application:[24]
	  o Dept of Community Affairs
	  o Water management district
	  o Local governments where plant is to be located
	  o Fish & Wildlife Conservation Commission
	  o Each regional planning council
	  o Dept of Transportation
	  o Any other agency requested
	• Act supersedes all other laws and regulations[25]
	• Certification under the act constitutes the sole required license of the state (one stop shop)[26]
	  o Certification includes "associated facilities"[27]
	  o Covers transmission as an "associated linear facility"[28]
	• Certification under this act does not affect the rate making powers of the Fla. PSC[29]
	• May use certification process for existing plants to allow for one-stop licensing process and not subject to the PSC[30]
	• Certification serves as exclusive forum for determination of need done by the commission.[31]
	  o To take into account "the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, the need for fuel diversity and supply reliability, whether the proposed plant is the most cost-effective available, and whether renewable energy sources and technologies, as well as conservation measures, are utilized to the full extent reasonably available."[32]
	
	Fla. Transmission
	• Leg. Intent= centralized and coordinated licensing process for the location of electric transmission line corridors[33]
	• Available only to "electric utilties"—see definition of "Applicant"[34]
	• "Electric utilities" includes cities and towns, counties, public utility districts, electric cooperatives, RTOs, operators independent transmission systems, or

24 Fla. Stat. §403.507.

25 Fla. Stat. §403.510.

26 Fla. Stat. §403.511.

27 Fla. Stat. §403.511(1).

28 Fla. Stat. §403.5112(1).

29 Fla. Stat. §403.11(4).

30 Fla. Stat. §403.5175.

31 Fla. Stat. §403.519.

32 Fla. Stat. §403.519(3).

33 Fla. Stat. 403.521.

34 Fla. Stat. §403.522(4).

	other transmission organizations approved by FERC[35]
	• Transmission line is defined as greater than or equal to 230kV line[36]
	
	• Not applicable to:
	  o Transmission lines certified under the Plant Siting Act (403.524(1))
	  o Transmission lines approved under chapter 380 (403.524(2)(a)
	  o Transmission lines where construction is limited to established rights-of-way (403.524(2)(c))
	  o Transmission lines that are less than 15 miles in length or located in a single county (403.524(d))
	  o If not included under this act, then other applicable state and local laws apply (403.524(3))
	• Parties must include: (403.527(2))
	  o The Dept
	  o The commission
	  o Dept of Community Affairs
	  o Fish and Wildlife conservation
	  o Dept of Transporation
	  o Affected Water Management Districts
	  o Affected Local Gov
	  o Regional Planning Council
	  o Any other agency
	  o Any domestic nonprofit corporation formed in whole or in part to: (430.527(2)(c)
	    • Promote conservation
	    • Promote natural beauty
	    • Protect personal health
	    • Protect other biological values
	    • Preserve historical sites
	    • Promote consumer interests
	    • Represent commercial and industrial groups
	    • Promote orderly development of an area
	    • Any others that have request (10 days prior) to be included
	  o Certification constitutes the sole license to transmission lines (one stop shopping) (403.531)
	  o Certification supersedes all laws and regs (403.536)
	  o FPSC to provide a determination of need for transmission line (403.537)
	  o Interview:[37]
	    ▪ Need determination of need
	    ▪ 7 plants in various states of building (4 nuclear/ 3 IGCC)
	    ▪ File for determination of need with the PSC, then file with

35 Fla. Stat. §403.522(12).

36 Fla. Stat. §403.522(22).

37 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

	state EPA which sends to siting board ▪ Rate basing new plants is up for discussion
Georgia	• No plant built or long-term PPA with a certificate of public convenience and necessity from the Commission[38] • Certificate will be based on need[39] • All electric member corporations and municipalities are subject the Georgia Commission with the exception of rate setting.[40] • Person operating or constructing a plant for generating electricity has condemnation authority[41] • The Georgia Dept of Environmental Quality includes generation plants in the Standard Classification and the site must be classified consistent with generation plants.[42] • Interview:[43] o 2 nukes in early stages of development and 2 modifications to existing plants (one being converted to biomass) o Need assessment is required even for IPPs o Nukes would be rate based (and use CWIP)
Illinois	• No public utility can begin construction of any new plant, equipment or facility without a certificate of public convenience and necessity.[44] • Interview:[45] o Utilities no longer owned power plants since 1988. No new power plants in 20 years. o Generation is regulated by FERC not by the state. Any built must go through FERC. o State buys power on the open market o Siting transmission lines still fall within the jurisdiction of the ICC
Indiana	• A public utility may not begin construction of, purchase or lease a generation facility without a certificate of public convenience and necessity from the Commission.[46] • Utility allowed recovery in rates if certificate of public convenience and necessity is issued by commission.[47] • Alternative Energy that is exempt from utility purchase requirements:[48]

38 GA. CODE ANN. §46-3A-3.

39 GA. CODE ANN. §46-3A-4(a).

40 GA. CODE ANN. §46-3-12.

41 GA. CODE ANN. §22-3-20.

42 Ga. COMP. R. & REGS. R 110-3-2-.04(e)3(v).

43 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

44 ILL. STAT. §8-406.

45 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

46 INDIANA CODE §8-1-8.5-2.

47 Id. §8-1-8.5-6.5.

48 Id. §8-1-2.4-5.

	o Not more than 80 MW. o For industrial, commercial or residential purposes. o Is owned or operated by and entity that: ▪ Is NOT primarily engaged in the business of producing or selling electricity. ▪ Does NOT sell electricity to residential users other than the tenants or the owner or operator of the facility. • Policy of state to encourage the development of alternative energy production facilities.[49] • Alternative energy includes solar, wind, waste management, resource recovery, refuse-derived fuel, or wood burning facility.[50] • Includes site[51] and transmission and distribution facilities[52] used to conduct electricity at or near the project site • Utilities encouraged to use alt. energy facilities on an avoided cost basis[53] • Interview:[54] o Turned over most responsibility for transmission to FERC o 630 MW gas-fired generation underway (rate based) o Several wind farms underway (not rate based) o Utility is defined broadly by statute so nearly everyone must get approval o Commission can waive however under 8.1-2-2.5
Mass.	• Statute established an Energy Facilities Siting Council within the Department of Telecommunications and Energy[55] • Applies to electric companies, other corporations empowered to "generate, transmit, distribute or sell electricity for ultimate use by 50 or more persons."[56] • Regs requires a 10 year forecast with facilities included[57] • Council approves the forecast[58] • Electric facilities must be consistent with long-range forecasts and must approved by the Council.[59] • Specifically, generation facilities must be approved by the board.[60]

49 Id. §8-1-2.4-1.

50 Id. §8-1-2.4-2(b)(1).

51 Id. §8-1-2.4-2(b)(2).

52 Id. §8-1-2.4(b)(3).

53 Id. §8-1-2.4-4.

54 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson on, October 1, 2009.

55 MASS. ANN. LAWS §69H.

56 MASS. ANN. LAWS §69G "Electric company".

57 MASS. ANN. LAWS §69I; 980 CMR 7.04.

58 980 CMR 7.02(9)(b.)

59 MASS. ANN. LAWS §69J.

60 MASS. ANN. LAWS §69J1/4.

	• "Generation facilities" means a generating unit of 100 MW or greater.[61]
	• The siting board to review and set standards for the state of the art environmental performance characteristics.[62]
	• Plant and transmission must seek a "certificate of environmental impact and public interest with respect to such facility."[63]
	• EFSC supercedes all over state agency or local governmental decisions.[64]
	• Transmission provider can seek a jurisdictional ruling from EFSC[65]
	• Interview:[66]
	    o Power plants are not integrated but state has authority over sites
	    o ISO New England does all planning for transmission
	    o Requires a need determination for plants and transmission

Michigan	• Commission requires public convenience and necessity required for a "major transmission line" or for "constructing, repairing, replacing or improving an existing transmission line, include the addition of circuits to an existing transmission line.[67]
	• g) "Major transmission line" means a transmission line of 5 miles or more in length wholly or partially owned by an electric utility , affiliated transmission company, or independent transmission company through which electricity is transferred at system bulk supply voltage of 345 kilovolts or more.[68]
	• The act supersedes all other state laws.[69]
	Plants
	    o No centralized authority for power plants
	    o Go to environmental and zoning authorities.
	    o Interview:[70]
	        o 3 coal facilities in permitting phase at DEQ (mix of whether rate based or not)
	        o 1 nuclear facility at NRC
	        o Whether a certificate of need is required is dependent on the proposer's size and legal statues (e.g. IOU vs. cooperative)
	        o Independent Power Producers do not need a certificate of need
	        o Transmission must get a certificate of need

Missouri	• No centralized siting for either plants or transmission • Public Service Commission has authority over manufacture, sale and distribution of electricity.[71]

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61 Mass. Code §69G.

62 Mass. Ann. Laws §69J1/4.

63 Mass. Ann. Laws §69K.

64 Mass. Ann. Laws §69K1/2.

65 980 Mass. Code Regs. 7.02(10).

66 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

67 Mich. Comp. Laws Serv. §460.565.

68 Mich. Comp. Laws Serv. §460.562(g).

69 Mich. Comp. Laws Serv. §460.563 and Mich. Comp. Laws Serv. §460.570.

70 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

	• Interview[72]: o one new coal plant being developed for inclusion in rate base o some transmission but the utilities do not need permission since it is within their territory o No state regulation for IPPs but on built in Missouri yet.
New Jersey	• Public utility definition only extends as far as distribution[73] • Interview:[74] o NJBPU no longer has jurisdiction over power plants o Still involved in transmission o Can get one-stop treatment for transmission at BPU (optional—could go to each local authority)
New York	• Article X expired at the end of 2002 and has not been replaced with respect to siting plants.[75] The New York legislature has not passed a replacement.[76] • Transmission lines o One stop shop[77] o Electric Transmission means[78]: ▪ Greater than or equal to 125 kV and a distance of one mile or more ▪ Greater than or equal to 100 kV but less than 125kV and 10 miles or more o Certificate requires environmental compatibility and public need.[79] o Public need is a component of the application[80] o Notice[81] ▪ Commissioner Environmental Conservation ▪ Commissioner Economic Markets ▪ Commissioner Agriculture and Markets ▪ Secretary of State ▪ Each affected state legislator ▪ Commissioner of Parks, Recreation and Historic Preservation ▪ Other special districts o Parties to include:[82] ▪ Dept of Environmental Conservation

71 Mo. Rev. Stat. §386.250(2).

72 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

73 N.J. Stat. Ann. §48:2-13(a).

74 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

75 http://www.dps.state.ny.us/articlex.htm (Sept. 27, 2009).

76 http://albany.bizjournals.com/albany/stories/2009/03/dail.

77 http://www.dps.state.ny.us/Article_VII_Process_Guide.pdf, p. 3.

78 N.Y. Pub. Service Law §85-2.1(e)(1).

79 N.Y. Pub. Service Law §85-2.1(d).

80 N.Y. Pub. Service Law §85-2.8(d).

81 N.Y. Pub. Service Law §85-2.10.

82 N.Y. Pub. Service Law §85-2.11(a).

	▪ Dept of Economic Development ▪ Dept of State ▪ Dept of Agriculture and Markets ▪ Office of Parks, Recreation and Historic Preservation ▪ Dept of Transportation ▪ Affected municipalities ▪ Individual residents ▪ Any domestic nonprofit corporation or association, formed in whole or in part, (i) to promote conservation or natural beauty, (ii) to protect the environment, personal health or other biological values; (iii) to preserve historic sites; (iv) to promote consumer interests; (v) to represent the interests of commercial and industrial groups; or (vi) to promote the orderly development of the areas in which the facility is proposed to be located. o NY has issued the "Siting New Energy Infrastructure, New York State Energy Plan 2009 ▪ Discusses interstate, FERC and state compacting issues. • Interview[83]: o Article 10 expired about 4 years ago. Have SEQRA (State Environmental Quality Review) for anything with an environmental impact. The local authority becomes the lead for SEQRA. o Market state. All generation development done by independents. Still have some legacy plants but utilities are discouraged from building anything new. Nothing is rate based. o Transmission authority comes under article 7
North Carolina	o Power Plant o Certificate of public convenience and necessity require; very broad coverage—"no public utility or other person shall begin the construction of any steam, water, or other facility for the generation of electricity to be directly or indirectly used for the furnishing of a public utility service…"[84] o Includes electric membership coporations[85] o Commission may revoke or modify certificate at is own motion[86] o Provides for rate recovery through a general rate case of the actual costs incurred in constructing a generating facility[87] o Transmission o Public utility means a person… egaged in producing, generating, transmitting, delivering or furnishing electricity for private or public use, including counties, municipalities, joint municipal power

83 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

84 N.C. GEN. STAT. 62-110.1(a).

85 N.C. GEN. STAT. 62-110.1(b).

86 N.C. GEN. STAT. 62-110.1(e1).

87 N.C. GEN. STAT. 62-110.1(f1).

	agencies, electric membership corporations, and public and private corporations"[88] o No public utility or any other person may begin to construct a new transmission line without first obtaining from the Commission a certificate of environmental compatibility and public convenience and necessity.[89] (c) A certificate is not required for construction of the following lines:[90] (1) A line designed to carry less than 161 kilovolts; (2) The replacement or expansion of an existing line with a similar line in substantially the same location, or the rebuilding, upgrading, modifying, modernizing, or reconstructing of an existing line for the purpose of increasing capacity or widening an existing right-of-way; (3) A transmission line over which the Federal Energy Regulatory Commission has licensing jurisdiction, if the Commission determines that agency has conducted a proceeding substantially equivalent to the proceeding required by this Article; (4) Any transmission line for which, before March 6, 1989, a public utility or other person has surveyed a proposed route and, based on that route, has acquired rights-of-way for it by voluntary conveyances or has filed condemnation proceedings for acquiring those rights-of-way which, together, involve twenty-five percent (25%) or more of the total length of the proposed route; (5) An electric membership corporation owned transmission line for which the construction or upgrading has had a proceeding conducted which the Commission determines is substantially equivalent to the proceeding required by this Article; (6) Any line owned by a municipality to be constructed wholly within the corporate limits of that municipality. o o Interview:[91] ▪ 4 plants about to start construction (3 gas, one coal) all of which are being rate based ▪ All need a certificate of public convenience and necessity ▪ IPP would still need to file for a certificate of public convenience and necessity
Ohio	o Transmission o Statement of need required[92]

88 N.C. GEN. STAT. 62-100(6).

89 N.C. GEN. STAT. 62-101(a).

90 N.C. GEN. STAT. 62-101(c).

91 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

92 OHIO ADMIN. CODE §4906-15-02.

	o Power Plants
	  o No determination of need
	  o Sets forth the technical requirements for siting[93]

Penn.	Siting law for transmission only contemplates build by a public utility and follows traditional methodology[94]

Texas	o Commission directed to "encourage development, construction and operation of new renewable energy projects…."[95]
	o Commission is to consider the financial commitment by generators in determining a Competitive Renewable Energy Zone.[96]
	o "The commission, after consultation with each appropriate independent organization, electric reliability council, or regional transmission organization:[97]
	
	(1) shall designate competitive renewable energy zones throughout this state in areas in which renewable energy resources and suitable land areas are sufficient to develop generating capacity from renewable energy technologies;
	
	(2) shall develop a plan to construct transmission capacity necessary to deliver to electric customers, in a manner that is most beneficial and cost-effective to the customers, the electric output from renewable energy technologies in the competitive renewable energy zones; and
	
	(3) shall consider the level of financial commitment by generators for each competitive renewable energy zone in determining whether to designate an area as a competitive renewable energy zone and whether to grant a certificate of convenience and necessity.
	
	(h) In considering an application for a certificate of public convenience and necessity for a transmission project intended to serve a competitive renewable energy zone, the commission is not required to consider the factors provided by Sections 37.056(c)(1) and (2)."
	o Public Utility Commission established regulatory process for establishing Competitive Renewable Zones[98]
	  o Includes determining the maximum MW for the zone and the transmission improvements required
	  o Once a CREZ is created by Commission Order, entities interested in constructing the transmission improvements required are required to submit expression of interest to the Commission.[99]
	o The Commission can require utilities to expand transmission facilities[100]

93 OHIO ADMIN. CODE §4906-13-01 et. seq.

94 PA. CODE §57.71 et. seq. 57.91 et. seq.

95 TEX. UTIL. CODE §39.904(c)(2)(B).

96 TEX. UTIL. CODE §39.904(g)(3).

97 TEX. UTIL. CODE §39.904.

98 16 TEX. ADMIN. CODE §25.174.

99 16 TEX. UTIL. CODE §25.714(c).

Virginia	o Traditional for transmission except for special provisions for renewables below[101]
	o In a utility's Integrated Resource Plan, the utility must evaluate and propose contract for and/or building new generation.[102]
	o Law addressing the public rights of way as pertains to renewables[103]
	o Renewable co-location of distribution facilities sets out the process for the distribution facilities associated with renewable energy projects[104]
	o Legislation from 2008 requires the Commission to review the rates for the provision of generation, distribution and transmission of each investor-owned recumbent utility in the first six months of 2009.[105] After the initial review, the utilities must submit a biennial filing.[106]
	o Transmission costs provided by the RTO as approved by FERC are deemed reasonable and prudent.[107]
	o Interview:[108]
	    o Two facilities underway: one combined cycle gas and one coal gasification
	    o Coal gasification had a legislative need proceeding[109] rather than a regular need proceeding at the commission.
	    o Both facilities are being rate based
	    o Commission approves transmission: one major 500 kV line underway; one other approved by not under construction

Washington	o EFSC established and charged to regulate siting of energy facilities.[110] o Energy facility means "an energy plant or transmission facilities"[111] o Energy plant o Stationary thermal power plant of 350 MW or greater or floating thermal power plants (suspended on surface of water, e.g. barge) of 100 MW or greater [112] o Applies to new construction of energy facilities and reconstruction or enlargement of existing facilities[113]

100 16 TEX. UTIL. CODE §25.199.

101 VA. CODE ANN. §56-49 et. seq.

102 VA. CODE ANN §56-599.

103 VA. CODE ANN. § 67-1102.

104 VA. CODE §67-1100 et. seq.

105 VA. CODE ANN. §56-585.1.A (as amended March 8, 2008).

106 VA. CODE ANN. §56.585.1.A.3.

107 VA. CODE ANN. §56.585.1.A.4.

108 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

109 VA. CODE ANN. §56.585.1.

110 WASH. REV. CODE §80.50.040.

111 WASH. REV. CODE §80.50.020(10).

112 WASH. REV. CODE §80.50.020(14)(a).

113 WASH. REV. CODE §80.50.060.

	o Option for choose to use EFSC for new construction, reconstruction or enlargement of alternative energy resources[114]
	o State Attorney General directed to appoint an assistant attorney general as counsel for the environment.[115]
	o Governors office for approval—rejection by governor is final[116]
	o Chapter supersedes all other state or local laws or regulations[117]
	o Interview:[118]
	    o State siting council responsible for large thermal plants
	    o Alternative energy and transmission lines 115 kV and over can opt into council or go through local processes
	    o Currently no transmission but over 115kV can opt into council
	    o Permitting two wind farms through council
	    o State administration has proposed 3 large transmission projects
	    o No requirement of need—law assumed demand is increasing in WA
	    o Siting is siting only—if a utility wants to rate base they would need to take the UTC

114 WASH. REV. CODE §80.50.060(2).

115 WASH. REV. CODE §80.50.080.

116 WASH. REV. CODE §80.50.090.

117 WASH. REV. CODE §80.50.110 and §80.50.130.

118 Interview with Commission Staff conducted by Nathan Taylor, Holly Hammons and Joshua Carson, October 1, 2009.

Appendix 3. State Net Metering Laws and Regulations

Arizona

Legal Sources

In the Matter of Proposed Rulemaking Regarding Net Metering, Docket No. RE-00000A-07-0608, Decision No. 70567 (June 5, 2008) Appendix A

Ariz. Admin. Code (AAC) R14-2-2301 – R14-2-2308 (note, these rules have not yet appeared in the Code as of July 18, 2009)

Covered Utilities

AAC R14-2-2302(7): Electric Distribution companies subject to Arizona Corporation Commission jurisdiction

Covered Customers

AAC R14-2-2303(11), (12): Any electric power customer who generates electricity, or has electricity generated for him/her/it, from a qualifying facility to be used to offset electric energy provided by the electric utility that normal provides him/her/it with electric power service.

Qualifying Technologies:

AAC R14-2-2302(13)(c): generates electricity from
Renewable Resources
A Fuel Cell
Combined Heat & Power (CHP)

Renewable Resources are : AAC R14-2-2302(14): :

- AAC R14-2-2302(14)(a) **Biogas**, which is defined by AAC R14-2-2302(3) as gases derived from:
    - AAC R14-2-2302(3)(a): Plant derived matter
    - AAC R14-2-2302(3)(b): Agricultural food and feed matter
    - AAC R14-2-2302(3)(c): Wood wastes
    - AAC R14-2-2302(3)(d): Aquatic plants
    - AAC R14-2-2302(3)(e): Animal wastes
    - AAC R14-2-2302(3)(f): Vegetative wastes

- AAC R14-2-2302(3)(g): Waste water treatment facilities using anaerobic digestion
- AAC R14-2-2302(3)(h): Municipal solid waste through
  - AAC R14-2-2302(3)(h)(i): A digester process
  - AAC R14-2-2302(3)(h)(ii): An oxidation process
  - AAC R14-2-2302(3)(h)(iii): Other gasification process

- AAC R14-2-2302(14)(b) **Biomass**, which is defined by AAC R14-2-2302(2) as any raw or processed plant-derived organic matter available on a renewable basis, including:
  - AAC R14-2-2302(2)(a): dedicated energy crops & trees
  - AAC R14-2-2302(2)(b): Agricultural food and feed crops
  - AAC R14-2-2302(2)(c): Agricultural crops and residues
  - AAC R14-2-2302(2)(d): Wood wastes and residues, including
    - AAC R14-2-2302(2)(d)(i): Landscape waste
    - AAC R14-2-2302(2)(d)(ii): Right-of-way tree trimming
    - AAC R14-2-2302(2)(d)(iii): forest thinnings $\leq$ 12 inch dia.
  - AAC R14-2-2302(2)(e): Dead and downed forest products
  - AAC R14-2-2302(2)(f): Aquatic plants
  - AAC R14-2-2302(2)(g): Animal wastes
  - AAC R14-2-2302(2)(h): Other vegetative waste materials
  - AAC R14-2-2302(2)(i): Non-hazardous plant matter waste material that is segregated from other waste
  - AAC R14-2-2302(2)(j): Forest-related resources such as
    - AAC R14-2-2302(2)(j)(i): Harvesting & mill waste
    - AAC R14-2-2302(2)(j)(ii): Pre-commercial thinnings
    - AAC R14-2-2302(2)(j)(iii): Slash
    - AAC R14-2-2302(2)(j)(iv): Brush
  - AAC R14-2-2302(2)(k)
    - AAC R14-2-2302(2)(k)(i) Waste pallets

        - AAC R14-2-2302(2)(k)(ii) Crates
        - AAC R14-2-2302(2)(k)(iii) Brush
    - AAC R14-2-2302(2)(l): Recycled paper fibers that are no longer suitable for recycled paper production, but not the following:
        - AAC R14-2-2302(2)(l)(i): Painted, treated, or pressurized wood
        - AAC R14-2-2302(2)(l)(ii): Wood contaminated with plastics or metals
        - AAC R14-2-2302(2)(l)(iii): Tires
        - AAC R14-2-2302(2)(l)(iv): Recyclable post-consumer waste paper

- AAC R14-2-2302(14)(c) **Geothermal**, which is defined by AAC R14-2-2302(9) as heat from within the earth's surface
- AAC R14-2-2302(14)(d) **Hydroelectric**, which is defined by AAC R14-2-2302(10) as kinetic energy derived from moving water
- AAC R14-2-2302(14)(e) **Solar**, which is defined by AAC R14-2-2302(15) as radiation or heat from the Earth's sun that produces electricity from a device or system
- AAC R14-2-2302(14)(f) **Wind**, which is defined by AAC R14-2-2302(16) as energy derived from wind movement across the earth's surface that produces electricity from a device or system

AAC R14-2-2302(8): Fuel Cells are devices that convert a fuel's chemical energy into electricity without intermediate combustion or thermal cycles. Fuel cells must use a renewable fuel to be eligible for net metering

AAC R14-2-2302(4): Combined Heat & Power (CHP) [co-generation), generates electricity and useful thermal energy a single, integrated system capable of producing power and thermal energy so that its power output and ½ of its thermal output is $\geq$ 42.5% of fuel's energy input

<u>Capacity Limits-Individual Facility</u>

AAC R14-2-2302(13)(d) $\leq$ 125% of Net Metering Customer's (NMC)

- Total connected load (Note—find out what this means) or
- Electric service drop capacity (if total connected load cannot be calculated) (note—find out what service drop capacity means)

AAC R14-2-2303: However, it appears that with the consent of the utility, as registered in a special contract between it and a prospective customer-generator, a customer-generator's qualifying net metering generating facility may have a larger capacity than the stated limit.

Capacity Limits-Aggregate

ACC R14-2-2307(B): None, but utilities are entitled to impose them subject to Commission approval.

Time Limits

None

Billing Rules

General Rule: AAC R14-2-2305; R14-2-2306(A), (B)—billed for electricity received from the grid on non-discriminatory basis in accordance with how customers with same load characteristics or same rate class to which NMC would have been assigned absent participating in net metering program

Other Costs, Revenues: AAC R14-2-2305—NMCs can be assessed additional charges that are justified by cost of service and cost/benefit analyses.

Billing for Net Excess Consumption (NEC): AAC R14-2-2306(C)—NMCs are billed each billing period for net kwh supplied to them under the applicable standard rate schedule.

Billing for Net Excess Generation (NEG): AAC R14-2-2306—For each billing period the net excess generation will be calculated and
(D) Excess kwh, but not kw or kVA, will be credited to NMC's bill for next billing period.
(E)Under TOU rates, excess kwh, but not kw or kVA, will be credited in accordance to whether the excess occurred during on-peak or off-peak
(F)Annual Reconciliation: NMC's will receive check or billing credit in the amount of the utility's Avoided Cost

California

Legal Sources

California Public Utility Code (CPUC) §§ 2827, 2827.5, 2827.7-.10

Covered Utilities

Net Metering for Customers Generating Electricity with Solar, Wind or Hybrid Facilities

CPUC § 2827(b)(4): electricity distribution utilities & cooperatives

CPUC § 2827(b)(3): electricity distribution utility or cooperative means

- Electrical corporations
- Local publicly owned electric utility
- Electrical cooperative
- Other entities, except energy service providers, that provide electrical service

CPUC § 2827(b)(3): electric distribution utility or cooperative excludes Publicly owned utilities serving more than 750,000 customers that also provide water service (only Los Angeles Department of Water & Power meets this definition)

Electric corporation is defined more by what it isn't than what it is, as follows:

- CPUC § 218(a): generally, electric corporations are corporations or persons that own, control, operate or manage electric generation plants for compensation for purposes of selling or transmitting electricity to others
- CPUC § 218(b): Electric corporations are not involved with co-generation or non-conventional power sources of electricity for purposes of generating electricity solely for any or all of the following purposes
  - CPUC § 218(b)(1) Own use or use of tenants
  - CPUC § 218(b)(2) Use of or sale to 2 or less electric corporations solely for use on real property on which the electricity is generated or on real property immediately agent thereto; however this exception does not apply when a street separates the adjacent property from the generating property and any of the following conditions are present:
    - CPUC § 218(b)(2)(A) There is not real common ownership of the two properties

        - CPUC § 218(b)(2)(B) Useful thermal output from the co-generation plant is not used on the adjacent property for petroleum production or refining

        - CPUC § 218(b)(2)(C) Electricity furnished to adjacent property is not used by a subsidiary or affiliate of the corporation or person generating the electricity

    - CPUC § 218(b)(3) Sale or transmission to an electrical corporation, state agency or local agency but not for sale or transmission to others

- CPUC § 218(c): Electric corporations do not generate electricity with landfill gas for one or more of the following purposes

    - CPUC § 218(c)(1) its own use or use of 2 or less tenants located on property where the electricity is generated

    - CPUC § 218(c)(2) use or sale to not more than 2 other corporations solely for use property where the electricity is generated

    - CPUC § 218(c)(3) sale or transmission to an electric corporation, state agency or local agency

- CPUC § 218(d): Electric corporations do not generate electricity with digester gas technology for one or more of the following purposes

    - CPUC § 218(d)(1) its own use or use of 2 or less tenants located on property where the electricity is generated

    - CPUC § 218(d)(2) use or sale to not more than 2 other corporations solely for use property where the electricity is generated

    - CPUC § 218(d)(3) sale or transmission to an electric corporation, state agency or local agency if the sale or transmission of electricity service to a retail customer is provided through the transmission system of a local publicly owned electric utility or electrical corporation of that retail customer

- CPUC § 218(e) electric corporations are not independent solar energy producers

CPUC § 2776: Electrical cooperatives are private entities organized to transmit or distribute electricity exclusively to its stockholders or members at cost

Electric service providers

- CPUC § 218.3(a) offer electrical service to customers within the service territory of an electrical corporation and includes unregulated affiliates and subsidiaries of an electrical corporations

- CPUC § 218.3(b) do not

- o Offer electrical service solely to service customer load consistent with the conditions under which electric corporations are not cogenerators
- o Include an electrical corporation or public agency that offers electrical service
  - ▪ Within its jurisdiction or service territory of a local publicly owned electric utility
  - ▪ To residential and small commercial customers

- CPUC § 218.3(c) are not independent solar energy producers

CPUC § 331(h): small commercial customers are those with maximum peak demand < 20 kw

Net Metering for Customers Generating Electricity with Biogas Digesters

CPUC §§ 2827.9(b)(1), (c): Electrical Corporations

Net Metering for Customers Generating Electricity with Fuel Cells

CPUC §§ 2827.10(a)(1), (b): Electrical Corporations

Covered Customers

CPUC § 2827(c)(4): customers of covered utilities who generate electricity from qualifying solar, wind, hybrid facilities located on their premises primarily to offset their own electric power requirements, including the following types of customers:

- Residential
- Small commercial
- Commercial
- Industrial
- Agricultural

CPUC §§ 2827.9(b)(2)(A): customers of electrical corporations who

- Generate electricity from qualified biogas digester facility
- Receive government funding for, or self-finances, a pilot project for developing biogas electricity generation.

CPUC §§ 2827.10(a)(3)(A): customers of electrical corporations who

- Generate electricity from qualified fuel cell facility

- Receive government funding for, or self-finances, a pilot project for developing biogas electricity generation

CPUC §§ 2827(b)(1): co-energy metering customers, which are net metering customer generators of local publicly owned electric utility that applies a generation-to-generation energy and time-of-use credit formula

CPUC §§ 2827(b)(7): Wind energy co-metering customers, which are customer generators with wind projects > 50 kw and ≤ 1 MW

Qualifying Technologies:

CPUC §§ 2827(b)(4); 2827.9(a)(1), (b)(3); 2827.10(a)(2), (3)(C): facilities meeting capacity and time limits that generate electricity from

- Solar
- Wind
- Solar-Wind Hybrid
- Biogas
- Fuel Cells

CPUC §2827.9(b)(3): Qualifying biogas facilities generate electricity from biogas digesters using

- Manure methane
- Anaerobic digestion of
  - Biosolids
  - Animal wastes

CPUC §§ 353.2(a)(2); 2827.10(a)(2), (3)(C) Eligible Fuel Cell facilities

- Include
  - Integrated power plant systems containing a stack, tubular array, or other functionally similar configuration used to electrochemically convert fuel to electricity;
  - An inverter and fuel process system where necessary;
  - Other plant equipment, including heat recovery equipment, necessary to support the plant's operation or its energy conversion
- Produce zero emissions or emissions ≤ 2007 State Air Resources Board limits for distributed generation

Capacity Limits-Individual Facility

Solar, Wind, Solar-Wind Hybrid Facilities

CPUC § 2827(b)(4): ≤ 1 MW

Biogas Digester Facilities

CPUC §§2827.9(b)(2)(A)(i), (B)

- Normally ≤ 1 MW
- Large projects are eligible if they
  - Have no more than 3 biogas digesters
  - > 1 MW & ≤ 10 MWs

Fuel Cell Facilities

CPUC §2827.10(a)(3)(A) ≤ 1 MW

Capacity Limits-Aggregate

Solar, Wind, Solar-Wind Hybrid Facilities

CPUC §§ 2827(c)(1), (3): for each covered utility—2.5% of its aggregate peak demand

Biogas Digester Facilities

CPUC §2827.9(c): Within the service territories of the three largest covered electrical corporations—50 MW combined statewide cumulative rated generating capacity

Fuel Cell Facilities

CPUC §2827.10(b)

- Within each covered electrical corporation's service territory
  - 22.5 MW for electrical corporations with peak demand ≤ 10,000 MW
  - 45 MW for electrical corporations with peak demand > 10,000 MW
- Statewide—112.5 MW combined cumulative rated generation capacity among all covered electrical corporations

Time Limits

Solar, Wind, Solar-Wind Hybrid Facilities

CPUC § 2827(c)(4): net metering program sunsets Jan 1, 2010.

CPUC § 2827.7: Facilities grandfathered into program if
- Permitted for construction on or before Dec. 31, 2002
- Completely constructed on or before Sept. 30, 2003

Biogas Digester Facilities

CPUC §2827.9(f): must be put into operation by Dec. 31, 2009

Fuel Cell Facilities

CPUC §§ 353.2(a)(1); 2827.10(a)(3)(C), (f)
- As a required ultra-clean, low-emission facility, must initiate operation between
    - Jan. 1, 2003
    - Dec. 31, 2008
- As an eligible fuel cell facility, must initiate operation before Jan. 1, 2010

Billing Rules

General Rule:

Net metering customer generators are billed for electricity taken from the grid on non-discriminatory basis in accordance with how customers with same load characteristics or same rate class to which customer-generator would have been assigned absent participating in net metering program.
- CPUC § 2827(g) for most solar, wind, solar-wind hybrid customer-generators
- CPUC §§ 2827(b)(1), (i)(2) for co-energy solar, wind, solar-wind hybrid customer-generators [those with facilities having a generating capacity > 10 kw and ≤ 1 MW and receive electric service from a local publicly-owned utility that uses a co-energy metering program]
- CPUC §§ 2827(b)(7); 2827.8(d) for wind co-energy customer-generators [those with facilities having a generating capacity > 50 kw and ≤ 1 MW
- CPUC § 2827.9(d) for biogas digester customer-generators
- CPUC § 2827.10(d) for fuel cell customer-generators

***Other Costs, Revenues*:**

Metering Costs: customer-generators are charged for any costs of installing meters and other devices needed to record electricity flows to and from the grid

- CPUC § 2827(c)(1) for most solar, wind, solar-wind hybrid customer-generators
- CPUC §§ 2827(b)(1), (i)(1) for co-energy solar, wind, solar-wind hybrid customer-generators
- CPUC §§ 2827(b)(7); 2827.8(a) for wind co-energy customer-generators
- CPUC § 2827.9(b)(4) for biogas digester customer-generators
- CPUC §§ 2827.9(b)(4), 2827.10(d) for fuel cell customer-generators

CPUC § 2827(k): Costs/Revenue Obligations not recoverable from customer generators shall be borne by all customers, net metering and non net metering, within the customer generators' customer classes.

Billing for Net Excess Consumption (NEC):

Net excess consumption is totaled monthly in accordance with the customer-generator's applicable rate schedule

- CPUC § 2827(h)(2)(A)-(B) for most solar, wind, solar-wind hybrid residential and small commercial customer-generators
- CPUC § 2827(i)(2) for co-energy solar, wind, solar-wind hybrid customer-generators
- CPUC § 2827.8(b) for wind co-energy customer-generators
- CPUC § 2827.9(e)(2)(A) for biogas digester customer-generators
- CPUC §§ 2827.9(e)(2)(A); 2827.10(e) for fuel cell customer-generators

Payment for NEC is based on the rates contained in the applicable contract or tariff, and it is due at the

- End of 12 months following date of interconnection
    - CPUC § 2827(h)(2)(C) most solar, wind, solar-wind hybrid residential and small commercial customer-generators
    - CPUC §§ 2827(a)(7), (h)(2)(C) wind co-energy residential and small commercial customer-generators
    - CPUC § 2827.9(e)(2) biogas digester customer-generators

  - CPUC §§ 2827.9(e)(2)(A); 2827.10(e) for fuel cell customer-generators

- End of each monthly billing period

  - CPUC § 2827(h)(2)(C) most solar, wind, solar-wind hybrid commercial, industrial and agricultural customer-generators

  - CPUC §§ 2827(a)(7), (h)(2)(C) wind co-energy commercial, industrial and agricultural customer-generators

  - CPUC § 2827(i)(3) for co-energy solar, wind, solar-wind hybrid customer-generators

Billing for Net Excess Generation (NEG):

Net excess generation is determined differently for co-metering customer generator than for other customer generators, as follows:

- CPUC § 2827(i)(2), (3): For co-metering customer generators, it is the positive monetary difference between

  - electricity provided by the customer generator to the utility valued at the generation component of the applicable standard kwh rate and

  - the electricity supplied by the utility to the customer generator valued at the full applicable standard kwh rate

- For other customer generators, there is a discrepancy with the calculation being the degree to which the electricity supplied by the utility is exceeded by either

  - CPUC §§ 2827(a)(7),(h), 2827.9(e) The total electricity generated by the customer generator, or

  - CPUC §§ 2827(h)(2), (3), 2827.9(e)(2), (3): The electricity generated and fed back to the utility by the customer generator

Net monthly credits are valued differently for various types of customer generators, as follows:

- CPUC § 2827(h)(2)(A)-(C) for most solar, wind, solar-wind hybrid customer-*generators*, they are valued at the full sales rate per kwh in the applicable contract or tariff

- CPUC § 2827(i)(2) for co-energy customer generators, they are valued by the generation component of the applicable rate structure

- CPUC §§ 2827(a)(7), 2827.8(b) for wind co-energy customer-generators, they are valued by the generation component, exclusive of certain surcharges, of the applicable rate structure

- CPUC §§ 2827.9(e)(2)(A); 2827.10(e)for biogas digester and fuel cell customer-generators, they are valued the price per kwh for retail sales of generation, exclusive of surcharges, in the applicable rate structure

Net monthly credits are

- CPUC §§ 2827(a)(7), 2827(h)(2)(C), monetized and carried over to next billing for most solar, wind, & solar-wind hybrid customer generators
- CPUC § 2827(i)(3) are computed for each monthly billing period for co-energy solar, wind, solar-wind hybrid customer-generators, credits and either
    - Monetized and then either
        - Paid to the customer generator, or
        - Carried forward as a monetary credit, or
    - Carried forward as a kwh credit
- CPUC §§ 2827.9(e)(2)(A), (B), 2827.10(e) monetized and paid biogas digester and fuel cell customer generators

At the end of the 12 month period, any NEGs are zeroed out

- CPUC § 2827(h)(3) for most solar, wind, solar-wind hybrid customer-generators
- CPUC § 2827(i)(3) for co-energy solar, wind, solar-wind hybrid customer-generators
- CPUC §§ 2827(a)(7), (h)(3) for wind co-energy customer-generators
- CPUC § 2827.9(e)(3) for biogas digester customer-generators
- CPUC §§ 2827.9(e)(3); 2827.10(e) for fuel cell customer-generators

Florida

Legal Sources

Fla. Stat. (FS) §§ 366.051, 366.91, 377.803(4)-(8)
Fla. Administrative Code, Rule 25-6.065

Covered Utilities

FS §366.91(5) public utilities, which are defined as:

- FS §366.02(1): entities supplying electricity to or for the public but not
  - A cooperative, or
  - A municipality or any agency thereof
- FS §366.02(2): electric utility
  - is
    - A municipality
    - A Cooperative
    - An Investor-owned entity
  - That owns, maintains or operates an electric
    - Generation system and/or
    - Transmission system and/or
    - Distribution system

FS § 366.91(6) municipal electric utilities, rural electric cooperatives

Fla. Administrative Code (FAC), Rule 25-6.065(1) investor-owned utilities

Covered Customers

FS §366.91(2)(b), (c); FAC, Rule 25-6.065(2)(a), (2)(c): customers who

- Generate electricity
- From qualifying net metering generating facilities located on their premises
- To offset electric energy normally provided by an electric utility

Qualifying Technologies:

FS §§366.91(2)(b), (d); 377.803(4); FAC, Rule 25-6.065(2)(d): facilities that generate electricity from one or more of the following renewable energy sources

- Hydrogen produced from sources other than fossil fuels
- Biomass which is defined at FS §366.91(2)(a) as a power source comprised of, but not limited to:
    - Combustible residues or gases from forest products manufacturing
    - Waste, byproducts, or products from agricultural and orchard crops
    - Waste or co-products from livestock and poultry operations
    - Waste or byproducts from processing
    - Urban wood waste
    - Municipal solid waste
    - Municipal liquid waste treatment operations
    - Landfill gas
- Solar energy
- Geothermal energy
- Wind energy
- Ocean energy
- Hydroelectric power
- Waste heat from sulfuric acid manufacturing operations

Capacity Limits-Individual Facility

FAC, Rule 25-6.065(3): $\leq$ 2 MW

Capacity Limits-Aggregate

None

Time Limits

None

Billing Rules

General Rule: billed for electricity received from the grid on non-discriminatory basis according to

- FAC, Rule 25-6.065(8)(d), (h) normal billing practices and applicable rate schedules, or

- FAC, Rule 25-6.065(8)(h) at customer-generator's choice, any applicable and available standby or supplemental service rate schedule

Other Costs, Revenues:

- FAC, Rule 25-6.065(4)(b)-(d), (g); (5)(a)-(c): customer-generators bear the cost of making sure that their net metering generating system meets all applicable interconnection safety and performance standards

- FAC, Rule 25-6.065(4)(a)(2),(e), (f): Applications fees

  - FAC, Rule 25-6.065(a)(2),(e): shall not be imposed on customer-generators whose qualifying net metering generating systems have capacities of ≤ 10 kw

  - FAC, Rule 25-6.065(a)(2),(f): may be imposed on customer-generators whose qualifying net metering generating systems have capacities of > 10 kw and ≤ 2 MW

- FAC, Rule 25-6.065(4)(f): utilities may impose, with commission approval, an Interconnection Study charge on customer-generators whose qualifying net metering generating systems have capacities of > 100 kw and ≤ 2 MW

- FAC, Rule 25-6.065(5)(d): indemnity for losses to third parties due to operation of customer-generator's qualifying net metering generating system—each party—customer-generator/utility—must indemnify the other when the losses were due to their negligence

- FAC, Rule 25-6.065(5)(e): Insurance coverage—the customer generator must pay for insurance coverage as follows:

  - No obligation for customer generators whose qualifying net metering generating systems have capacities of ≤ 10 kw

  - Up to $1,000,000 for customer-generators whose qualifying net metering generating systems have capacities of > 10 kw and ≤ 100 kw

  - Up to $2,000,000 for customer-generators whose qualifying net metering generating systems have capacities of > 100 kw and ≤ 2 MW

- FAC, Rule 25-6.065(8)(b)—Meter Costs: the investor-owned utility bears the cost of installing meters necessary for determining the net difference between electricity supplied by the utility to the customer-generator and the electricity supplied to the grid by the customer-generator

- FAC, Rule 25-6.065(8)(h)—customer-generator must pay customer charges and demand charges under applicable rate schedule even during months when he/she/it provides the grid with excess generation

- FAC, Rule 25-6.065(9)—renewable energy certificates

    - Are retained by customer generators

    - Costs of additional meters needed to measure renewable electricity for purposes of receiving renewable energy certificates are

        - Normally paid by the customer generator

        - But may be paid by the utility as a result of it purchasing the renewable energy certificates from the customer generator

Billing for Net Excess Consumption (NEC): FAC, Rule 25-6.065(8)(b)—customer-generators are billed each month for net kwh supplied to them by the utility under the applicable standard rate schedule.

Billing for Net Excess Generation (NEG): FAC, Rule 25-6.065(8)(e), (f)—each month, the net excess generation will be calculated and

- Excess kwh will be credited to the customer-generator's energy consumption for the next monthly billing period.

- Annual Reconciliation: at the end o f a calendar year, the customer-generator will be paid for his/her its unused kwh at an average annual rate based on the utility's COG-1 as-available energy tariff

Georgia

Legal Sources

Ga. Code Ann. (GCA) §§ 46-3-50, -52 through -56 (Note: Georgia does not mandate net metering per se, but instead sets out a mandate to accommodate distributed generation with some distributed generators fitting the definition of customer generators engaged in net metering)

Covered Utilities

Georgia's distributed generation statutes are somewhat unclear about what entities are subject to the distributed generation mandates:

- GCA § 46-3-52(7) defines the term electric service provider as entities which distribute electricity to retail electric customers, including:
    - electric utilities, which is defined by GCA § 46-3-52(9) as any retail supplier of electricity whose rates are regulated by the Florida Public Service Commission
    - electric membership corporation
    - municipal electric utilities, which are defined by GCA § 46-3-52(10) as electric utilities owned or operated by a city or town
- A variety of distributed generation mandates are imposes specifically on electric service providers, including:
    - GCA § 46-3-52(5)(D), (E), which help define the characteristics of distributed generation facilities by requiring that they
        - Operate in parallel with an electric service provider's distribution facilities
        - Connect to the distribution system of an electric service provider
    - GCA § 46-3-54, which imposes mandates on electric service providers to supply certain types and provide metering services under specific mandates enforced by some regulatory body
    - GCA § 46-3-55, which specifies terms under which electric service providers are to charge for electricity they supply customer generators and to pay for electricity they receive from customer generators' distributed generation facilities

- GCA § 46-3-56, which imposes mandates on electric service providers to purchase energy from customer generators and provide for the establishment and enforcement of safety standards and regulations

- GCA § 46-3-52(8) defines the term electric supplier, which includes
  - Electric utilities
  - The Tennessee Valley Authority
  - Electric membership corporations that provide wholesale service
  - Entities that provide wholesale service to municipalities, including
    - Municipal electric utilities
    - Any other person

- Several provisions seem to impose distributed generation mandates on entities known as electric suppliers:
  - GCA § 46-3-54(2)-(4), metering mandates
  - GCA § 46-3-55(b): terms of voluntary purchases of energy from customer generators
  - GCA § 46-3-55(d): opportunity for a relevant governing body to impose additional safety, power quality and interconnection requirements on customer generators of electric suppliers
  - GCA § 46-3-55(f): exemption from liability for losses, injuries or deaths resulting from a cogenerator or a distributed generation facility being interconnected to an electric supplier's electrical system

Covered Customers

GCA § 46-3-52(4), (5) customer generators, defined as owners and operators of qualified distributed generation facilities that are:

- located and operated on the customer generators' premises
- Operated primarily to meet all or part of customer generators' electricity requirements
- connected to a distribution system on either side of an electric service provider's meter

GCA § 46-3-52(5)(B) appears to limit customer generators to residential and commercial entities because it sets capacity limits on distributed generation facilities only on those owned and operated by residential and commercial customer generators

Qualifying Technologies:

GCA § 46-3-52(5)(A) solar photovoltaic systems, fuel cells, wind turbines

Capacity Limits-Individual Facility

GCA § 46-3-52(5)(B) peak generating capacity of not more than

- 10 kw for residential applications
- 100 kw for commercial applications
- Note, if other customer classes can be customer generators (ie., industrial), then apparently the capacities of their distributed generation facilities are not limited

Capacity Limits-Aggregate

GCA § 46-3-56(a) sets an aggregate limit of 0.2% of electric service provider's previous year's annual peak demand, but it is based on subscriptions to renewable energy sources from all renewable energy programs, not just the capacity of eligible customer generators' distributed generation facilities.

Time Limits

None

Billing Rules

General Rule:

GCA § 46-3-55(1)(B) billed for electricity received from the grid according to tariffs filed with the regulating entity

Other Costs, Revenues:

- GCA §§ 46-3-54, 46-3-55(2)(B)—Meter Costs: the customer generator bears the cost of installing and operating the necessary meters
- Metering Service Costs/Fees
  - GCA § 46-3-54(2) Shall be set by agreement between customer generator and electric service provider under rates set by appropriate governing body
  - GCA § 46-3-54(3) Shall
    - Include direct costs of interconnecting or administering metering services or distribute generation facilities

    - Such costs cannot be allocated among the utility's entire customer base

  - GCA § 46-3-54(4) may include a monthly service charge but may not include, unless agreed to by customer generator or approved by the commission,

    - Standby charge
    - Capacity charge
    - Interconnection charge
    - Other fee or charge

- GCA § 46-3-55(1)(C)(i), (2)(C)—Customer charges: customer generators pay appropriate customer charges even if they produce net excess generation

- GCA § 46-3-56(c), (d) customer-generator must pay all the costs required to connect his/her/its distributed generation facility to the grid

- GCA § 46-3-56(f) customer generators are responsible for damages, injuries or deaths arising from the interconnection of their qualifying net metering generating systems to the grid

Billing for Net Excess Consumption (NEC): GCA § 46-3-55(1)(B) customer generators are billed each month for net kwh supplied to them by the utility under the applicable standard rate schedule.

Billing for Net Excess Generation (NEG) & Distributed Generation (DG):

- GCA § 46-3-55(1)(C) net excess generation is electricity generated by the customer generator's distributed generation system less the electricity supplied by the electric service provider (Note—this seems high because it does not limit the customer generation to be that provided to the grid)

- GCA §§ 46-3-55(1)(C)(ii), -56(a) net excess generation will be credited on the bill for the billing period during which it was generated at an agreed to rate filed with the commission, but such rate shall not exceed the utility's avoided energy cost unless the amount of energy involved has been subscribed to under any renewable energy program

- GCA § 46-3-56(b)—Once the electric service provider has purchased renewable energy equal to 0.2% of its annual peak demand, it may, but need not, purchase the NEG. If it does, it will credit the customer's bill at a cost of energy defined by the commission.

Illinois

Legal Sources

220 Ill. Comp. Stat. (ICS) 5/3-105, 5/16-102, 5/16-107.5;

Ill. Admin. Code (IAC) tit. 83, §§ 465.5, .10, .20, .30, .35, .40, .50, .80; 466.50

Covered Utilities

220 ICS 5/16-107.5(b)(ii); IAC tit. 83, § 465.5: Electric utilities furnishing or selling electricity to retail customers and alternative retail electric suppliers

220 ICS 5/16-102(definition of electric utility); IAC tit. 83, § 465.5(definition electric utility)—electric utilities are public utilities that are authorized to furnish or sell electricity or light to retail customers within a service area.

- 220 ICS 5/3-105(a) defines public utility as individuals and various kinds of organizations that produce, store, transmit, sell, deliver or furnish electricity that is not solely used for communications purposes by
    - owning, controlling, operating, or managing equipment, plant, property for that purpose, or
    - owning or controlling any franchise, license, permit or right for that purpose
- 220 ICS 5/3-105(b) excludes from the definition of public utility
    - 220 ICS 5/3-105(b)(1) Public utilities owned and operated by various public bodies or owned by various public bodies and operated by their lessees or agents
    - 220 ICS 5/3-105(b)(3) electric cooperatives
    - 220 ICS 5/3-105(b)(7) cogeneration, small power production, and other qualifying facilities defined by and regulated under PURPA and not subject to any state regulatory jurisdiction
    - 220 ICS 5/3-105(b)(9) alternative retail suppliers
    - 220 ICS 5/3-105(b)(10) The Illinois Power Agency
- 220 ICS 5/16-102(definition of Retail customer): Retail customer is a single entity using electric power or energy at a single premises that
    - either
        - Is served or eligible to be served by an electric utility, or

    - Is serviced by a municipal or cooperative within areas they were entitled to serve prior to restructuring

  - Or on date restructuring act was passed was receiving electric service from a public utility and

    - resold or redistributed electricity within a building prior to Jan. 2, 1957(?), or

    - provided lighting services to tenants in a multi-occupancy building under the authority of an electric utility's tariff on file with the Commission

- 220 ICS 5/16-102(definition of Service Area): Service area means the geographic area an electric utility was entitled to serve prior to restructuring and was during that time actually serving a retail customer located within such area

220 ICS 5/16-102(definition of alternative retail electric supplier)—Alternative retail electric suppliers

- are persons and several types of public or private organizations/entities—including resellers, aggregators, and power marketers—that sell, lease, exchange for value, deliver, or furnish electric power or energy to retail customers

- Are not

  - Electric utilities

  - Electric cooperatives and municipal systems serving retail customers with territories they were allowed to serve prior to restructuring

  - Public utility owned by a public institution of higher education and operated by such institution or its agents in an area where it would have been entitled to operate prior to restructuring

  - Retail customers acquiring all their electric power and energy from their own cogeneration or self-generation facilities

  - Third parties that own, sell, operate, or arrange for the installation of a customer's own cogeneration or self-generation facility

  - Industrial or manufacturing customer that own distribution facilities and used them to provide electricity to third-party contractors located on its premises and integrally / predominantly engaged in the customer's industrial or manufacturing processes

Covered Customers

220 ICS 5/16-107.5(b)(i); IAC tit. 83, § 465.5: retail electric power customers operating qualified facilities on their own premises primarily to offset their electrical requirements.

Qualifying Technologies:

220 ICS 5/16-107.5(b)(i), (iii); IAC tit. 83, § 465.5(definition of eligible renewable electrical generating facilty: electric power generators powered by renewable sources, including

- Solar
- Wind
- Dedicated crops
- Anaerobic digestion of livestock or food processing waste
- Fuel cells powered by renewable fuels
- Microturbines powered by renewable fuels
- Hydroelectric

Capacity Limits-Individual Facility

220 ICS 5/16-107.5(b)(i); IAC tit. 83, § 465.5: $\leq$ 2 MW

Capacity Limits-Aggregate

220 ICS 5/16-107.5(j); IAC tit. 83, § 465.35(b):

- 1% of the purchasing utility's peak demand, unless the utility chooses to go beyond the limitation
- Until March 9, 2009, certain utilities (Ameren, Companies, ComEd, MidAmerican) were limited to opening no more than 200 net metering accounts for customer generators with facilities $\leq$ 40 kw

Time Limits

IAC tit. 83, § 465.35(h): None

Billing Rules

General Rule: billed for electricity received from the grid on non-discriminatory basis in accordance with how customers with same load characteristics or same rate class to which the customer generator would have been assigned absent participating in net metering program.

Alternatively, electricity provider and customer generator can enter into arms length agreement about terms of net metering service

- 220 ICS 5/16-107.5(e); IAC tit. 83, § 465.50(a)(1)(B), (2)(A)—all residential customer generators and non-residential customer generators operating facilities with capacities ≤ 40 kw

- 220 ICS 5/16-107.5(f)(3); IAC tit. 83, § 465.50(b)(1)(A), (2)(A) —non residential customer generators operating facilities with capacities > 40 kw and ≤ 2 MW.

Other Costs, Revenues:

Metering Costs

- 220 ICS 5/16-107.5(c)—electricity provider covers the costs for residential customer generators and non-residential customer generators operating facilities with capacities ≤ 40 kw

- 220 ICS 5/16-107.5(c)—dual metering is used for non-residential customer generators, and the metering cost is borne by such customer generators if they operate facilities with capacities > 40 kw and ≤ 2 MW

Taxes, fees, utility deliver charges

- 220 ICS 5/16-107.5(e); IAC tit. 83, § 465.50(a)(1)(B), (a)(2)(B)—residential customer generators and non-residential customer generators operating facilities with capacities ≤ 40 kw are responsible for taxes, fees, and utility delivery charges applicable to the ***net amount*** of electricity they receive from the electricity provider

- 220 ICS 5/16-107.5(f)(1); IAC tit. 83, § 465.50(b)(1)(B), (2)(B)—non-residential customer generators operating facilities with capacities > 40 kw and ≤ 2 MW are responsible for taxes, fees, and utility delivery charges applicable to the ***gross amount*** of electricity they receive from the electricity provider

220 ICS 5/16-107.5(e)—customer generators are responsible for the costs of complying with Interconnection safety and performance standards, including fees, equipment and insurance required by Illinois' interconnection standards

220 ICS 5/16-107.5(g); IAC tit. 83, § 465.80(a)—customer generators own all renewable energy and greenhouse gas credits attributable to the operation of their qualifying net metering generating facilities, but they and their electricity provider may enter into arms length agreements regarding ultimate ownership of these credits

Billing for Net Excess Consumption (NEC): Billed for net consumption under the applicable tariff or contract

- 220 ICS 5/16-107.5(e), (f)(3); IAC tit. 83, § 465.50(a)(1)(B), (2)(A)—residential customer generators and non-residential customer generators operating facilities with capacities $\leq$ 40 kw

- 220 ICS 5/16-107.5(e), (f)(3); IAC tit. 83, § 465.50(b)(1)(A), (2)(A) —non residential customer generators operating facilities with capacities > 40 kw and $\leq$ 2 MW.

Billing for Net Excess Generation (NEG): There seems to be a discrepancy between what is called for by the net metering statute and what is called for by the net metering regulations.

- The statutory rules are as follows:
    - 220 ICS 5/16-107.5(d)(2) provides the general rules for handling net excess generation, which are as follows:
        - Net excess generation occurs when the amount of electricity produced by the customer generator exceeds the amount of electricity consumed from all sources by the customer generator—it is assumed that the difference is the amount of electricity the customer generator supplied the electricity provider
        - The net excess generation credit is expressed in kwh
        - The kwh credit is applied to the next billing period, and such credits are carried over from billing period to billing period
    - 220 ICS 5/16-107.5(f)(2) specifies that for non-residential customer generators operating qualifying net metering generating facilities with capacities > 40 kw and $\leq$ 2 MW, the net excess generation credit is monetized at a price =
        - The electricity suppliers avoided cost of electricity supply over the monthly period, or
        - Terms of a power-purchase agreement between the customer generator and the electricity provider
    - 220 ICS 5/16-107.5(f)(3) specifies a different means of handling net excess generation credits for customer on time of use rates (Note, this provision is under a section that seems applicable only to non-residential customer generators with large qualifying net metering generating facilities but by logic it seems to apply to any type of customer who is served under time of use rates)
        - Net excess generation is determined by discrete time of use periods

        - The net excess credit is monetized at the electric service provider's retail price per kwh for each discrete time of use period

    - 220 ICS 5/16-107.5(d)(3) at the end of each annualized net metering period, or whenever a retail customer terminates service with an electricity provider, any outstanding net excess generating credits expire (note, this seems to apply to all customer generators)

- The regulations governing the handling of net excess generation credits are:

    - IAC tit. 83, § 465.50(a)(1)(C)For residential customers and non-residential customer operating qualifying net metering facilities with capacities $\leq$ 40 kw who are not on time of use rates:

        - Credits are expressed as the net kwh supplied by the customer generator during the billing period

        - If the electric utility is not the electricity provider, the electric utility shall provide a credit for delivery service = to the kwh delivered by the customer generator to the electric utility's distribution system

        - These kwh credits are carried forward billing period to billing period

        - Outstanding net excess generation credits expire at the end of the annualized net metering period or when the customer generator terminates service with the electricity provider

    - For residential customers and non-residential customer operating qualifying net metering facilities with capacities $\leq$ 40 kw who are on time of use rates:

        - IAC tit. 83, § 465.50(a)(2)(C) (a)(2)(A)Net excess generation or consumption is determined for each discrete time period and monetized at tariff or contract rate

        - IAC tit. 83, § 465.50(a)(2)(A) The charges and credits for these times period are summed to determine if there is a net excess charge or credit for the billing period

        - IAC tit. 83, § 465.50(a)(2)(C) The total monetized credits will be the sum of the energy credit (presumably as calculated under § 465.50(a)(2)(A)) and total net excess kwh x either the utility's kwh delivery rate or a bundled service rate if applicable (note, the monetary credit for delivery service is provided by the electric utility if it is not the electricity provider).

        - IAC tit. 83, § 465.50(a)(2)(C) Monetary credits are carried over from billing period to billing period and can be applied offset any charges assessed by the electricity provider

        - IAC tit. 83, § 465.50(a)(2)(C) Outstanding net excess generation monetary credits expire at the end of the annualized net metering period or when the customer generator terminates service from the electricity provider

    - IAC tit. 83, § 465.50(a)(2)(A) For non-residential customers operating qualifying net metering facilities with capacities > 40 kw and $\leq$ 2 MW who are not on time of use rates:

        - the net excess generation credit shall be monetized at the electricity provider's avoided cost of electricity supply

        - it appears that this credit shall not be applied to future billing periods for the statute says the customer generator shall be compensated with the credit

        - The credit can be used to offset any charge assessed by the electricity provider

    - For non-residential customers operating qualifying net metering facilities with capacities > 40 kw and $\leq$ 2 MW who are on time of use rates:

        - IAC tit. 83, § 465.50(b)(2)(A) Net excess generation or consumption is determined for each discrete time period and monetized at tariff or contract rate

        - IAC tit. 83, § 465.50(b)(2)(A) The charges and credits for these times period are summed to determine if there is a net excess charge or credit for the billing period

        - IAC tit. 83, § 465.50(b)(2)(B) The credit can be used to offset any charge assessed by the electricity provider

        - IAC tit. 83, § 465.50(b)(2)(B) it appears that this credit shall not be applied to future billing periods for the statute speaks of any compensation to the customer generator

Indiana

Legal Sources

170 Ind. Admin. Code (IAC) 4-4.2-1 through 4.4.2-10

Covered Utilities

170 IAC 4-4.2-2: investor owned utilities . . . engaged in production, transmission, sale, or distribution electric service.

Covered Customers

170 IAC 4-4.2-1(d)(2), (3): retail electric power customers operating qualified facilities on their own premises primarily to offset their electrical requirements.

- 170 IAC 4-4.2-4: net metering must be offered to residential customers and K-12 schools
- 170 IAC 4-4.2-4: net metering may be offered, at utility's discretion, to other customers

Qualifying Technologies:

170 IAC 4-4.2-1(d), (j): generation facilities producing electricity from the following energy sources

- Solar photovoltaic
- wind and
- hydroelectric

Capacity Limits-Individual Facility

170 IAC 4-4.2-1(d)(1): $\leq$ 10 kw

Capacity Limits-Aggregate

170 IAC 4-4.2-4: Utilities **may** impose an aggregate capacity limit of 0.1% of their most recent summer peak demands

Time Limits

None

Billing Rules

General Rules:

- 170 IAC 4-4.2-3: Net metering generating facilities are exempt from revenue requirement and associated regulation

- 170 IAC 4-4.2-7(1): customer generator subject to charges, credits, rates in tariffs and administrative rules that would have applied if he/she/it were not participating in net metering.

Other Costs, Revenues:

Metering costs:

- Metering alternatives
  - 170 IAC 4-4.2-6(a)(1): a single meter capable of measuring net kwh
  - 170 IAC 4-4.2-6(a)(2): 2 meters—1 measuring kwh from the utility to the customer generator and the other measuring kwh from customer generator to the utility

- In conjunction with metering, customer generators need not pay costs and fees for
  - 170 IAC 4-4.2-6(b)(1): Additional metering for single phase configurations
  - 170 IAC 4-4.2-6(b)(2): Requests to participate in net metering
  - 170 IAC 4-4.2-6(b)(3): Initial net metering facility inspection

170IAC 404.2-5 Interconnection Requirements: customer generator must bear the costs of complying with all safety and performance interconnection standards

170IAC 4-4.2-8(a): Insurance Costs—customer generators required to obtain insurance covering losses up to $100,000 that could occur from the operation of the net metering generation facility

170 IAC 4-4.2-8(b): Indemnity Obligation—customer generators and participating utilities must indemnify and hold harmless the other party for claims, liabilities, damages and expenses occurring as result of act or omission by such other party (and those associated with him/her/it) in the construction, ownership, operation, or maintenance of such other party's facilities used in net metering

Billing for Net Excess Consumption (NEC):

170 IAC 4-4.2-7(2): Customer generator is billed for the net kwh consumed, meaning the positive difference between the electricity delivered by the utility to the customer generator and the electricity delivered by the customer generator to the utility, at the rate contained in the tariff that would have applied if he/she/it did not participate in net metering

Billing for Net Excess Generation (NEG)

- 170 IAC 4-4.2-7(2): Customer generator is credited in the next billing period for the net kwh generated by his/her/its net metering facility, meaning the positive difference between the electricity delivered by the customer generator to the utility and the electricity delivered by the utility to the customer generator

- 170 IAC 4-4.2-7(3): If customer generator discontinues net metering, any unused kwh credit reverts to the utility

Massachusetts

Legal Sources

Mass. Gen. Laws (MGL) ch. 164, §§ 138-140

220 Mass. Code Regs. (MCR) 18.01-.09 (Proposed)

Covered Utilities

MGL ch. 164, §§ 1(definition of distribution company), 138(definition of Net Metering); 220 MCR 18.01, .02(definition of Distribution Company), .03—electric distribution companies, which are

- Companies engaged in distribution of electricity or owning, operating or controlling distribution facilities
- Not entities or their affiliates that produce electricity, steam and chilled water and
    - Electricity produced is primarily for the benefit of
        - Hospital
        - Non-profit educational institution
    - Plant and equipment used was in operation prior to Jan. 1, 1986

Covered Customers

MGL ch. 164, § 139(a), (b), (e); 220 MCR 18.02(definitions of Customer, Host Customer), 18.03, 18.06: distribution company customers using electricity generated by qualifying generating facilities but not including:

- Electric utilities
- Generation companies
- Aggregators
- Suppliers
- Energy marketer
- Energy broker

MGL ch. 164, §§ 138 (definitions of Neighborhood, Neighborhood net metering facility), 140; 220 MCR 18.02(definitions of Neighborhood, Neighborhood net metering facility): a group $\geq$ 10 residential customers within a single neighborhood (a geographic area encompassing a unique community of interests) , that owns or is served by a qualifying generating facility located within the neighborhood, and is served by a single distribution company.

MGL ch 164, § 139(a)(1); 220 MCR 18.05(1): distribution company customers living within the same ISO-NE load zone as owners/operators of qualifying wind or solar generating facilities with capacities $\leq$ 1 MW who are designated by said owers/operators to receive net metering credits earned by said generating facilities

MGL ch 164, § 139(b)(1); 220 MCR 18.05(4): distribution company customers living within the same ISO-NE load zone as owners/operators of qualifying agricultural, wind or solar generating facilities with capacities > 1 MW and $\leq$ 2 MW who, with the assent of the distribution company, are designated by said owers/operators to receive net metering credits earned by said generating facilities

Qualifying Technologies:

MGL ch 164, § 138; Qualifying technologies vary depending on whether are the power source of facilities operated as part of an agricultural business, as follows:

- MGL ch 164, § 138(definitions Class II, & Class III metering facilities); 220 MCR 18.02(definitions Class II, & Class III metering facilities)—generating facilities not operated as a part of an agricultural business that generate electricity from the following technologies:
    - Solar
    - Wind
- MGL ch. 25A, § 11F(c), (d), ch 164, § 138(definitions of Agricultural net metering facility and Renewable energy); 220 MCR 18.02(definitions of Agricultural net metering facility and Renewable energy)—generating facilities operated as a part of an agricultural business and powered by renewable sources including:
    - Solar photovoltaic
    - Solar thermal
    - Wind
    - Ocean thermal
    - Wave
    - Tidal
    - Fuel cells using renewable fuels
    - Landfill gas
    - Certain hydroelectric facilities

- o Low emission advanced biomass using certain fuels such as
    - ▪ Wood
    - ▪ By-products or waste from
        - •Agricultural crops
        - •Food, or
        - •Animals
    - ▪ Energy crops
    - ▪ Biogas
    - ▪ Liquid biofuel, including but not limited to
        - •Biodiesel
        - •Organic refuse derived fuel
        - •algae
- o Marine
- o Hydrokinetic
- o geothermal

- MGL ch 164, § 138(definition of Class I net metering facility)—small capacity non-transmission facilities that generate electricity regardless of the facilities primary energy source

Capacity Limits-Individual Facility

Class I net metering facility, as defined by MGL ch 164, § 138; MCR 18.02: $\leq$ 60 kw

Class II net metering facility, as defined by MGL ch 164, § 138; MCR 18.02, which encompasses agricultural net metering facilities: > 60 kw and $\leq$ 1 MW

- o The limit is per facility for customers who are not municipalities or other government entities
- o The limit is per generating unit for municipalities and other governmental entities

Class III net metering facility, as defined by MGL ch 164, § 138; MCR 18.02, which encompasses agricultural net metering facilities: > 1 MW and $\leq$ 2 MW

- The limit is per facility for customers who are not munipalities or other government entities
- The limit is per generating unit for municipalities and other governmental entities

Capacity Limits-Aggregate

MGL ch 164, § 139(f); MCR 18.07: $\leq$ 1% of distribution company's peak load

Time Limits

None

Billing Rules

General Rule:

MGL ch 164, §§ 138 (definitions of Class I, Class II, Class III net metering credits), 139(a)(2), (b)(2); 220 MCR 18.03(1): No reference is made to customer generators being subject to rates applicable to the rate classes to which they would belong absent participating in net metering. Instead, reference is made to applicable rates for Net Excess consumption and a particular credit formula for Net Excess Generation.

Other Costs, Revenues:

MGL ch 164, § 139(c); 220 MCR 18.09(4): all distribution company customers shall be billed annually uniform surcharges covering

- Distribution portion of net metering credits
- Distribution delivery charges displaced by the operation of qualifying generating facilities

MGL ch 164, § 139(d); 220 MCR 18.03(2), 18.09(2), (3): customer generators are responsible for the costs of meeting interconnection, reasonable liability insurance and meter installation

MGL ch 164, § 139(d); 220 MCR 18.03(2): customer generators with net metering facilities having capacities $\leq$ 60 kwh who are in compliance with interconnection and installation requirements may not be charged special fees such as

- Backup charges
- Demand charges
- Additional controls
- Liability insurance

MGL ch 164, § 141: where scale the of on-site generation would decrease the affordability of electricity service for low income customers, a fully compensating adjustment shall be made to the low income rate discount

220 MCR 18.09(1): Host customer generators own renewable energy certificates created by renewable qualifying net metering generating facilities

MGL ch 164, § 139(d); 220 MCR 18.03(2), 18.09(2), (3): Distribution companies must file tariffs that:

- Require owners/operators of qualifying facilities to maintain adequate insurance
- Deal with the costs of Metering installation and the distribution upgrades needed to accommodate metering installations

Billing for Net Excess Consumption (NEC):

MGL ch 164, §§ 139(a)(2), (b)(2); 220 MCR 18.03(4): customer generators are billed for the net kwh consumed at the applicable per kwh rate

Billing for Net Excess Generation (NEG)

MGL ch 164, § 138 (definition of Class I net metering credit & net metering facility); 220 MCR 18.04(2):

- for qualifying facilities that
    - Have capacities $\leq$ 60 kw
    - Do not use solar or wind for their energy sources
- credit =
    - excess kwh generated x
    - average monthly clearing price at the ISO-NE

MGL ch 164, § 138 (definitions of Class I, Class II, and Class III net metering credits & net metering faciilities); 220 MCR 18.04(1):

- for qualifying facilities that
    - Have capacities $\leq$ 60 kwh and uses solar or wind for their energy sources
    - Have capacities > 60 kwh and $\leq$ 1 MW
    - Are operated by municipalities or other government entities and have capacities > 1 MW and $\leq$ 2 MW
- credit =

- excess kwh generated x
- sum of
  - applicable ISO-NE default service kwh charge
  - distribution kwh charge
  - transmission kwh charge
  - transition kwh charge

MGL ch 164, § 138 (definition of Class III net metering credit and net metering facilities); 220 MCR 18.04(3):

- for owners/operators
  - of qualifying facilities with capacities > 1 MW and $\leq$ 2 MW
  - who are not municipalities or other government entities
- the credit =
  - excess kwh generated x
  - sum of
    - applicable ISO-NE default service kwh charge
    - transmission kwh charge
    - transition kwh charge

MGL ch 164, § 138 (definitions of Class I, Class II, and Class III net metering credits & net metering facilities); 220 MCR 18.04(5): net metering credits shall not include

- demand side management kwh charges
- renewable energy kwh charges

MGL ch 164, §§ 139(a)(1), (b)(1); 140(a); 220 MCR 18.04(5), 18.05(3): net metering credits

- are applied to the accounts of owner/operators of qualifying generating facilities or the qualifying designees of said owner /operators, and
- may be carried forward from month to month

Michigan

Legal Sources

Mich. Comp. Laws (MCL) §§ 460.6j; .6k; .10g(1)(a); .111(c); .562(e); .1003(f), (i); 1007(j); .1011(i)-(k); .1113(c); .1173; .1175; .1177; .1179

Mich. Admin. Code (MAC) r.460.601a; .601b; .604; .640; .642; .644; .646; .648; .650; .652; .654

Covered Utilities

MCL §§ 460.10g, 460.111, 460.562(e), 460.1171, 460.1173(1); MAC r.460.601a(r), r.460.640(1): entities obligated to offer net metering include:

- electric utilities, which are persons selling electricity to retail customers under rates regulated by the Michigan Public Service Commission)
- Electric Provider, which are persons or entities whose sell electricity to retail customers under rates regulated by the commission, and
- alternative electric suppliers, which are persons selling electric generation service to retail customers
    - but do not physically deliver electricity directly to retail customers and are
    - not public utilities, which for net metering purposes are electric and power companies regulated by the commission that are
        - private
        - cooperative
        - corporate
        - not municipally owned

Covered Customers

MCL § 460.1173(1); MAC r.460.601a(t), r.460.640(7): retail customers of any class that operate qualified electric generators sized/designed to meet only their electricity needs

Qualifying Technologies:

MCL §§ 460.1005(b); MAC r.460.601a(t) methane digesters and renewable electric generators

- MAC r.460.601b(d): methane digesters are renewable energy sytems that use animal or agricultural waste to produce fuel gas capable of being burned for the generation of electricity

- MCL § 460.1011(i), (k): renewable electric generators are those that use one or more of the following renewable energy resources to generate electricity
    - Biomass, which is defined by MCL § 460.1003(f) as organic matter that is not derived from fossil fuels, can be converted to use as fuel for the production of energy, replenishes over a human time frame, and includes, is not limited to:
        - Agricultural crops & wastes
        - Short-rotation energy crops
        - Herbaceous plants
        - Trees and wood derived from sustainably managed forests or procurement systems
        - Paper and pulp products
        - Precommercial wood thinning waste, brush, yard waste
        - Wood wastes and residues from the processing of wood products or paper
        - Animal wastes
        - Wastewater sludge or sewage
        - Aquatic plants
        - Food production and processing waste
    - Solar and solar thermal energy
    - Wind energy
    - Kinetic energy of moving water, including
        - Waves, tides, currents
        - Water released through a dam
    - Geothermal energy
    - Municipal solid waste
    - Landfill gas produced by municipal solid waste

Qualifying technologies do not include:

- MCL § 460.1011(k)(i): hydroelectric pumped storage facilities
- MCL § 460.1011(k)(ii): hydroelectric facilities using dams constructed after effective date of Michigan's net metering statutes unless they are:

  - Repairs of or replacement for prior existing dams
  - Upgrades that improve the energy efficiency of prior existing dams

- MCL § 460.1011(k)(iii): incinerators that are not municipal solid waste generators and municipal incinerators that were not brought on line before the effective date of Michigan's net metering statutes

Capacity Limits-Individual Facility

The aggregate capacity limits on qualifying generators at a single site are:

- MCL § 460.1005(b)(i); MAC r.460.601a(t)(i): 150 kw for qualifying renewable generators
- MCL § 460.1005(b)(ii); MAC r.460.601a(t)(ii): 550 kw for methane digesters

Capacity Limits-Aggregate

Each covered public utility and alternative electric supplier may limit the aggregate capacity of electric generation systems covered by net metering as follows:

- MCL § 460.1173(2): overall aggregate limit = 1% of previous year's peak load
- The public utility/alternative electric supplier, shall allocate its available net metering capacity as follows:
  - MCL § 460.1173(2)(a): 0.5% peak load capacity for qualifying generators with capacities $\leq$ 20 kw
  - MCL § 460.1173(2)(b): 0.25% peak load capacity for qualifying generators with capacities > 20 kw and $\leq$ 150 kw
  - MCL § 460.1173(2)(c): 0.25% peak load capacity for qualifying generators with capacities > 150 kw

Time Limits

MCL § 460.1173(1): The net metering programs of each covered utility and alternative electric supplier shall be for a period $\geq$ 10 years

Billing Rules

General Rule:

MAC r.460.604(2): net metering customers shall be provided electric service at nondiscriminatory rates identical with respect to rate structure, retail rate components, and any monthly charges, to those that would have applied if net metering was not involved.

Other Costs, Revenues:

MCL § 460.1175(1); MAC r.460.642(6): application costs—prospective net metering customer generators shall pay no more than

- $25 for application fees
- $100 in the aggregate for application and interconnection review fees

MCL § 460.1175(1): interconnection costs—paid by customer generators operating qualifying generators with capacities > 20kw

MCL §§ 460.1007(j), 460.1175(1); MAC r.460.652(1): standby charges—shall be paid by customer generators operating qualifying generators with capacities > 150 kw

- MCL § 460.1007(j); MAC r.460.652(1): Standby charges = retail distribution charge per kwh x imputed customer usage during billing period
- MCL § 460.1007(j); MAC r.460.652(1): Imputed customer usage is the ∑ metered onsite generation and net of the bidirectional flow of power

MCL §§ 460.1177(1)-(3); MCA r.460.648(1)-(3): Costs of the meters needed for measuring bi-directional energy flows vary depending upon the capacity of the customer generator's qualifying generating facility and the number of customers served by the implementing public utility:

- MCL §§ 460.1177(1)-(3); MCA r.460.648(1)-(2): Costs of such meters needed by Customer generators operating qualifying generating facilities with capacities ≤ 150 kw:
    - Shall be covered by electric providers with over 1,000,000 customers
    - Shall be covered by the consumer generator served by electric providers with < 1,000,000 customers, but said costs are limited to the incremental cost above that of conventional meters
- MCL §§ 460.1177(1)-(3); MCA r.460.648(3): Costs of such meters needed by customer generators operating qualifying generating facilities with capacities > 150 kw shall be paid by the customer generator.

MAC r.460.648(1)(c): costs of generator meter at qualifying facilities ≤ 20kw shall = the electric provider's costs and are to be paid by the consumer generators requesting them

MCL § 460.1175(2), MAC r.460.646(1): Costs of testing and inspecting for purposes of insuring safe, effective and efficient interconnection between a consumer generator's qualifying generating facility and the grid will be covered by public utilities and alternative electric suppliers.

MCL § 460.1179; MAC r.460.654: customer generators own renewable energy credits associated with electricity generated under the net metering program but they can be purchased or traded for by an electric provider

MCL §§ 460.6j, 460.6k, 1175(1): Reasonable costs of operating net metering program of public utilities and alternative electric suppliers are to be recognized and recovered as follows:

- For electric utilities with 1,000,000 or more customers:
    - Non-energy costs will be billed to all customers through non-fuel base rates
    - Energy costs will be billed to all customers through the power supply cost recovery mechanism
- For electric utilities with < 1,000,000 customers:
    - Energy costs will be billed to all customers through the power supply cost recovery mechanism
    - Non-energy costs will be billed to all customers through a cost recovery mechanism developed especially for the purpose by the Commission
- Costs specifically recognized by statute and regulation as reasonable costs of net metering include:
    - MCL § 460.1175(2): costs of interconnection tests and inspections
    - MAC r.640.648(1)(a): costs of electric providers with 1,000,000 or more customers for providing bi-directional metering to customer generators operating qualifying facilities with capacities ≤ 20 kw
    - MAC r.640.648(2)(a): costs of electric providers with 1,000,000 or more customers for providing bi-directional metering to customer generators operating qualifying facilities with capacities> 20 kw and ≤ 150 kw
    - MAC r.640.648(2)(c): costs of electric providers for providing generator meters to customer generators operating qualifying facilities with capacities> 20 kw and ≤ 150 kw

Billing for Net Excess Consumption (NEC):

MAC r.460.604(2): net metering customers shall be provided electric service at nondiscriminatory rates identical with respect to rate structure, retail rate components, and any monthly charges, to those that would have applied if net metering was not involved.

Billing for Net Excess Generation (NEG)

General rules for handling NEG are:

- MCL § 460.1177(4); MAC r.460.650(1), r. 460.652(1): customer generators are credited for their net generation by the suppliers of their electric generation service

- MCL § 460.1177(4); MAC r.460.650(2), r. 460.652(2): all credits are applied to the power supply charges in the bill for the next billing period, and any remaining excess is carried over to subsequent billing periods

- MAC r.460.650(3), r.460.652(4): consumer generators who leave the electric provider's system, or have their services terminated, will receive a refund of any outstanding net metering credits.

Net billing credits will be calculated as follows:

- MCL §§ 460.1013(c), 460.1173(5)(d); MAC r.460.601a(v), r.460.650(1): For customer generators operating a qualifying generator with a capacity $\leq$ 20 Kw: credit =
    - net kwh generated x
    - full retail rate, which includes
        - power supply component
        - distribution component

- MCL §§ 460.1007(j), 460.1173(5)(e); MAC r.460.652(5): For customer generators operating a qualifying generator with a capacity> 20 kw
    - credit = net kwh generated x power supply component of full retail rate
    - the power supply component of the full retail rate is one of the following
        - monthly avg. real-time locational marginal price for energy at the commercial pricing node within electric provider's distribution territory during billing period or time of use pricing period
        - power supply component of full retail rate during billing period or time of use pricing period

Missouri

Legal Sources

Mo. Rev. Stat. (MSR) §§ 386.20(7), (15), (43); .890; 394..010 et seq.

Mo. Code Reg. (MCR) tit. 4, § 240-20.065

Covered Utilities

MRS § 386.890 2.(7); MCR tit. 4, § 240-20.065(1)(E): municipal utilities, electrical corporations regulated by Missouri's Public Service Commission, and rural electric cooperatives organized under Missouri's Rural Electric Cooperatives statutes.

MSR) § 386.20(15): Electrical Corporation is an entity that owns, operates, controls or manages any electric plant

- excludes railroads, light rail, street railroad corporations that generate electricity
    - solely for railroad, light rail, street railroad purposes, or
    - use of tenants
    - and not for sale to others
- also excluded non-railroad related customer generators when they produce electricity
    - solely on or through private property
    - for
        - railroad, light rail, or street railroad purposes
        - own use
        - use of its tenants
        - and not for sale to others

Covered Customers

MRS § 386.890 3.; MCR tit. 4, § 240-20.065(1)(C): owners or operators with qualifying generating facilities that are

- located on premises they own, operate, lease or otherwise control
- primarily to meet part or all of their electrical energy requirements.

Qualifying Technologies:

MRS §§ 386.890 2.(3)(a), 2.(6); MCR tit. 4, § 240-20.065(1)(G): electric energy generators powered by a renewable energy resource, including:

- wind
- solar thermal sources
- hydroelectric sources
- photovoltaic cells and panels
- fuel cells using hydrogen produced one of the following energy sources:
    - wind
    - solar thermal
    - hydroelectric
    - photovoltaic cells and panels
- Other energy sources that become available and are certified as renewable by the Missouri Department of Natural Resources after August 28, 2007.

Capacity Limits-Individual Facility

MRS § 386.890 2.(3)(b); MCR tit. 4, § 240-20.065(1)(C)(2): $\leq$ 100 kw

Capacity Limits-Aggregate

MRS § 386.890 3.(1); MCR tit. 4, § 240-20.065(3)(A):

- Overall: 5% of electric supplier's single hour peak load for previous year unless extended by Commission or other governing body increases it;
- Annual Limit: 1% of electric supplier's single hour peak load for previous year

Time Limits

None

Billing Rules

General Rule:

Customer generators are to be treated the same way they would be treated under tariffs applicable to customers not participating in net metering:

- MRS § 386.890 3.(2); MCR tit. 4, § 240-20.065(3)(B): must be offered tariffs or contracts equivalent to other customers
- MRS § 386.890 3.(2); MCR tit. 4, § 240-20.065(3)(B): may not be billed for any additional standby, capacity, interconnection, or other fee or charge that would not applicable if they were not customer generators
- MRS § 386.890 6.(1); MCR tit. 4, § 240-20.065(3)(F): may not be billed for fees and charges associated with meeting applicable safety, performance, interconnection, and reliability standards unless they apply to similarly situated customers who are not customer generators
- MRS § 386.890 5.(1); MCR tit. 4, § 240-20.065(6)(A): net electrical energy must be measured according to the normal metering practices for all customers within a customer generator's rate class

Other Costs, Revenues:

MRS § 386.890 4.; MCR tit. 4, § 240-20.065(5)(D): Costs of new meters, meter installation, upgraded or new distribution facilities needed to support interconnecting customer generators with the grid:

- shall be responsibility of customer generators
- retail electric suppliers shall, at, customer generators request:
    - pay these costs up front
    - bill customer generators for them + reasonable interest rate over 12 billing cycles

MRS § 386.890 4.; MCR tit. 4, § 240-20.065(5)(D): Costs of testing, maintaining, or changing metering equipment: shall be the responsibility of customer generators

MRS § 386.890 2.(3)(f), (g); MCR tit. 4, § 240-20.065(1)(C)(6), (7): customer generators must bear the costs of complying with all interconnection safety and performance standards

Liability for damages to property or person caused by customer generators' generation units:

- MRS § 386.890 11.; MCR tit. 4, § 240-20.065(3)(D): Fall exclusively on customer generators
- Exceptions

- MRS § 386.890 11.; MCR tit. 4, § 240-20.065(3)(D): Retail supplier liable when its fault is established by clear and convincing evidence, or

- MRS § 386.890 16.: Manufacturer is liable when damage is caused by a defect in customer generator's generation unit

Responsibility for Carrying Liability Insurance:

- MRS § 386.890 6.(1), (2), (3)(b): The Public Service Commission may establish insurance requirements in conjunction with establishing safety, performance, interconnection, and reliability standards

- The Public Service Commission has recently modified the insurance requirements as follows:

    - MCR tit. 4, § 240-20.065(4)(A): $\geq$ \$100,000 for customer generators with generation facilities having capacities > 10 kw

    - MCR tit. 4, § 240-20.065(4)(B): none for customer generators with generation facilities having capacities $\leq$ 10 kw

MRS § 386.890 14.; MCR tit. 4, § 240-20.065(3)(E): Costs of providing net metering: Retail Electric Suppliers may recover them through their rate structures

Billing for Net Excess Consumption (NEC):

MRS § 386.890 5.(2); MCR tit. 4, § 240-20.065(6)(B): net excess energy consumed by consumer generator shall be billed in accordance with rates applicable to customers within the same rate class.

Billing for Net Excess Generation (NEG)

MRS § 386.890 2.(1), 5(3)-(5); MRC tit. 4, §§ 240-20.065(1)(A), (6)(C), (6)(D): For any billing period when the customer generator achieves net excess generation, customer generators shall be:

- billed for the customer charge normally assessed on customers within their rate classes

- credited for net excess generation as follows

    - credit = net excess kwh x amount $\geq$ the annual average cost per kwh of fuel for the participating electric utility;

    - credit will be applied to the next billing period

    - credit will expire without further compensation to customer generator

        - at the end of 12 billing cycles

        - customer generator discontinues service
        - customer generator discontinues net metering relationship
    - credit may be provided by wholesale generator serving retail electric suppliers who are rural electric cooperatives and municipal utilities upon an agreement between such retail suppliers and their wholesale generators and the exercise of an option by the retail suppliers

MRS § 386.890 5(3); MRC tit. 4, § 240-20.065(6)(D): Net Excess Generation is defined as the positive difference between

- total amount of electricity generated by the customer generator and
- total electricity supplied to the customer generator by the utility

New Jersey

Legal Sources

N.J. Stat. (NJS) §§ 48:3-51, 48:3-57(a)(1); 48:3-87e.(1)

N.J. Admin. Code (NJAC) §§ 14:4-1.2 (definitions of Basic Generation service, Electric Distribution company, Electric distribution system, Electric generation service, Electric power supplier, Electric public utility), 14:8-1.2 (definitions of Class I renewable energy, Net metering, Societal benefits charge, Solar electric generation, Supplier/provider), 14:8-2.2, 14:8-2.5, 14:8-4.1 through 14:8-4.4

Covered Utilities

NJS §§ 48:3-51 (definitions of Basic Generation service, Electric power supplier), 48:3-57(a)(1), 48:3-87e(1); NJAC §§ 14:8-1.2 (definitions of Basic Generation service, Electric Distribution company, Electric distribution system, Electric generation service, Electric power supplier, Electric public utility), 14:8-4.1(a): entities required to offer net metering include:

- basic generation service providers, which are public utilities offering non-competitive generation services regulated by the New Jersey Board of Public Utilities
- electric distribution companies, which are public utilities that distribute electricity to end-users but are not electric power suppliers unless they also furnish basic generation service;
- electric power suppliers, other than basic generation service providers, which are persons and entities licensed to offer and to assume contractual and legal responsibility for providing electric generation services to retail customers
    - including
        - load serving entities
        - marketers
        - brokers
    - excluding electric public utilities providing electric generation only as a basic generation service

Covered Customers

There is an ambiguity between the statutory listing of persons eligible to net-metering customers and the regulatory definition of net-metering customer-generators, as follows:

- NJS § 48:3-87e.(1): industrial, large commercial, residential and small commercial customers that generate electricity with qualifying generation systems on the customer's side of the meter;

- NJAC §§ 14:8-4.2 (definition of customer-generator), 14:8-4.3(a): residential or small commercial customers that generate electricity on the customer's side of the meter

<u>Qualifying Technologies:</u>

NJS §§ 48:3-51(definition of Class I renewable energy), 48:3-87e.(1); NJAC§§ 14:8-1.2 (definition of Class I renewable energy)14:8-2.2, 14:8-2.5, 14:8:14-4.1(a), 14:8:14-4.3(a): generating facilities qualified for net metering include those generating electricity from:

- Solar technologies in the form of Solar RECs
- Photovoltaic technologies in the form of Solar RECs
- Wind energy
- Fuel cells powered by
  - Methanol
  - Ethanol
  - Landfill gas
  - Digestor gas
  - Biogas
  - Other fuels (exclusive of fossil fuels, wastes from fossil fuels, waste from an inorganic source) regenerated over a short time frame and derived from:
    - Solar technologies (thermal, photochemical, photovoltaic) or
    - Photosynthetic energy stored in biomass
    - Other natural sources (wind, hydropower, geothermal, tidal)
- Geothermal energy generated by a steam turbine driven by hot water or steam extracted from geothermal reservoirs in the earth's crust
- Wave or tidal action
- Methane gas from landfills
- a biomass facility, including

- combustion of gas from the anaerobic digestion of food waste and sewage sludge
- combustion of the following types of biomass, provided they are determined to have been cultivated and harvested in a sustainable manner
  - bioenergy crops (plants grown and harvested specifically to be used as a fuel for generating electricity, including wood produced at a bioenergy plantation)
  - wood from tree thinning or trimming that is neither old-growth timber or adulterated by non-cellulose substances or material
  - gas generated by anaerobic digestion of biomass fuels other that food waste and sewage sludge
  - ground or shredded pallets or scrap wood produced at qualifying recycling facilities that is not adulterated by non-cellulose substances or material
  - wood shavings or scrap from lumberyards and paper mills (excluding black liquor) that is not adulterated by non-cellulose substances or material

Capacity Limits-Individual Facility

NJAC § 14:8-4.3(a): capacity limits on each customer-generator's qualifying facility are:

- 2 MW
- ≤ amount of electricity supplied to the customer-generator from the grid over an annualized period (?)

Capacity Limits-Aggregate

NJS § 48:3-87e.(1): There is no hard aggregate capacity limit. Instead, the New Jersey Utility Board

- May authorize an electric power supplier or a basic generation service provider to discontinue offering net metering
- When to total statewide generating capacity owned and operated by net metering customers equals 2.5% of the State's peak electricity demand.

Time Limits

None

Billing Rules

General Rule:

NJS § 48:3-87e.(1): Net metering service must be offered at non-discriminatory rates.

NJAC § 14:8-4.3(n): non-discriminatory rates are those that are that would be charged if the customer-generator was not receiving net metering service. Specifically, the rates

- Must be identical to the otherwise prevailing rates as to
  - Rate structure
  - Retail rate components
  - Any monthly charge
- However, suppliers/providers/distribution companies may, with approval of the board, use customer-generators' special load profiles that incorporate the customer-generators' real-time generation

Other Costs, Revenues:

NJAC § 14:8-4.3(o): Customer-generators may not be billed for any fee or charge or be required to have additional equipment, insurance or things unless

- The fee, charge, or requirement is authorized by the net metering, interconnection rules, or
- The fee, charge or requirement applies to customers not receiving net metering service

NJAC § 14:8-4.4(c): Metering costs

- Electric distributions companies shall supply customer-generators with a revenue meter capable of measuring bi-directional flows of electricity if the customer-generator does not have such a meter
- Any subsequent revenue meter change shall be paid by the customer-generator
- Costs of any additional meters shall be paid by
  - electric distribution companies, if they install such meters on their own initiative after receiving permission from customer-generator
  - customer-generators, if such meters are installed at their request, and the charge shall be the actual cost of the meter and its installation

NJAC § 14:8-4.3(l), (m): customer generators control the destiny of any solar renewable energy credits and renewable energy credits they may receive as a result of operating their qualifying net metering generating facilities.

Billing for Net Excess Consumption (NEC):

NJS § 48:3-87e.(1); NJAC § 14:8-4.3(n): If customer-generator receives more electricity from the grid than it contributes, then he/she/it shall be billed for the net excess consumption in accordance with the applicable non-discriminatory rates (Note, this is implied because there is no express provision concerning net excess consumption

Billing for Net Excess Generation (NEG)

The statutes and regulations seem to define net excess generation differently, as follows:

- NJS § 48:3-87e.(1) appears to define excess as the difference between
  - Total kwh generated by customer generator
  - Total kwh supplied to customer generator by distribution company
- NJAC § 14:8-4.3(c) defines excess that the difference between
  - Total kwh generated by the customer generator that is supplied to the electric distribution company
  - Total kwh supplied to customer generator by distribution company

The statutes and regulations seem to differ on how net excess credits are to be handled

- NJS § 48:3-87e.(1) offers three methods
  - Kwh credit method
    - the net excess generation credit is expressed in kwh
    - the exces kwh is applied customer-generator's bill during the next billing period
    - such excess kwh credits shall be carried over month to month throughout an annualized period
    - at the end of the annualize period, the customer-generator is compensated for remaining net excess generation at an unspecified rate or value
  - real time monetized credit basis, which seems to permit the customer generator to choose to be compensated for net excess generation during each billing period in which it occurs in accordance with one of the following rates or values
    - the net excess kwh x applicable average marginal locational price of energy, or

        - the PJM real-time locational marginal pricing rate adjusted for losses

    - A negotiated purchase of net excess generation: the customer-generator and the electric power supplier/basic generation service provider, may enter into a bilateral agreement detailing how the customer-generator will receive credit/compensation for its net excess generation

- NJAC § 14:8-4.3(c)-(e) offers only an annualized net excess generation credit process, as follows:

    - The net excess generation credit from one billing period is used to reduce the bill for the next billing period, but it is not specified whether this is done through a kwh credit or a monetized credit

    - Net excess credits accumulate month to month to end of annualized period

    - Customer generator then compensated at value = remaining kwh x avg. locational marginal price of energy in applicable transmission zone

New York

Legal Sources

N.Y. Pub. Serv. Law (NYPSL) §§ 2, 66-j, 66-l

Order Modifying and Authorizing Net Metering Tariffs [NMO] (N.Y. Pub. Serv. Comm'n February 13, 2009).

Covered Utilities

NYPSL §§ 2(13), 66-j(3)(a)(i), 66-l(3)(a)(i): Electric corporations, which are essentially investor-owned utilities that own, operate or manage any electric plant for purposes other than operating railroads/street railroads, their own use, the use of their tenants, or for users close to a co-generation, small hydro or alternative electric production electric plant.

NMO 3 & n.1: In its latest net metering order, the N.Y. Publ. Serv. Comm'n stated that the electric corporations covered by the net metering laws are major electric utilities, which it identified as:

- Central Hudson Gas & Electric Co.
- Consolidated Edison Co. of New York, Inc.
- Niagara Mohawk Power Corporation d/b/a National Grid
- Orange & Rockland Utilities, Inc.
- Rochester Gas & Electric Corp.

Covered Customers

Customer-generators covered by New York's net metering laws are:

- NYPSL §§ 66-j(1)(a)(i); 66-l(1)(a), (b); NMO 2-3: residential customers who own or operate qualifying electric generating equipment that is located or used and his/her primary residence
- NYPSL §§ 66-j(1)(a)(ii); 66-l(1)(a), (c); NMO 2-3: farm service customers who own or operate qualifying electric generating equipment located and used on land that is
    - Used for agricultural purposes, and
    - the location of the customer-generator's primary residence if he/she/it is generating electricity with wind energy

- NYPSL §§ 66-j(1)(a)(iii); 66-l(1)(a), (c-1); NMO 3: non-residential customers who own or operate qualifying electric generating equipment that is located or used and his/her/its premises

Qualifying Technologies:

Electric generating equipment qualifying for net metering service includes:

- NYPSL § 66-j(1)(a)(i), (iii); (d); NMO 2: photovoltaic solar systems owned &/or operated by residential and non-residential customer-generators

- NYPSL § 66-j(1)(a)(ii), (e); NMO 2: equipment owned/operated by person engaged in farming operations that generates electricity using fuel that is at least 90% biogas produced by the anaerobic digestion of agricultural waste (ie., livestock manure, farming wastes, food processing wastes) of which at least 50% by weight of the biogas feedstock is livestock manure materials

- NYPSL § 66-l(1)(a)-(c-1), (f); NMO 3: wind electric generators

Capacity Limits-Individual Facility

Capacity limits on individual qualifying electric generating equipment are:

- NYPSL §§ 66-j(1)(d)(i)(A); 66-l(1)(b), (f); NMO 4: ≤ 25 kw if owned/operated by a residential customer-generator

- NYPSL §§ 66-j(1)(e); 66-l(1)(c-1), (f); NMO 4, 5: ≤ 500 kw if owned/operated by a farm service customer-generator

- NYPSL §§ 66-j(1)(d)(i)(B); 66-l(1)(c), (f); NMO 4, 5: ≤ the lesser of 2 MW or the customer's peak load for the prior twelve months if owned/operated by a non-residential customer-generator

Capacity Limits-Aggregate

Aggregate Capacity Limits are a follows:

- NYPSL § 66-j(3)(a)(iii); NMO 4: aggregate combined rated capacity limit for solar and farm waste generating equipment—1 % of each covered utility's peak demand for 2005

- NYPSL § 66-l(3)(a)(iii); NMO 5: aggregate rated capacity limit for wind generating equipment—0.3% of each covered utility's peak demand for 2005

- NYPSL §§ 66-j(3)(b); 66-l(3)(b): each utility may choose to add more net metering customer generators after reaching the aggregate capacity limit for each qualifying electric generating equipment type

Time Limits

NYPSL §§ 66-j(3)(b); 66-l(3)(b): post January 1, 2012—the NY Pub. Serv. Comm'n may increase the aggregate capacity limits for any of the qualifying electric generating types if it finds that doing so is in the public interest

Billing Rules

General Rules:

NYPSL §§ 66-j(3)(a)(i), 66-l(3)(a)(i): electric corporations required to develop and make available model net metering contracts and schedules establishing "consistent and reasonable rates, terms and conditions" for net metering service

NYPSL §§ 66-j(4)(a), (b), (d); 66-l(4)(a), (b), (d): net metering customers are to be treated the same way as to rates as are customers within their same service class who do not generate electricity onsite

Other Costs, Revenues:

Customer-generators may be subject to the following types of costs other than rates applicable to customers within their service classes that do not have self-generating facilities:

- Equipment necessary to insure safety and reliability of service (including dedicated transformers): Customer-generators bear this cost up to the following limits:
    - NYPSL § 66-j(3)(c)(i): $350 for residential customer-generators operating qualifying solar generating facilities
    - NYPSL § 66-j(3)(c)(ii): $5,000 per farm operation for customer-generators operating qualifying farm waste generating facilities
    - NYPSL §§ 66-j(3)(c)(ii), 66-l(3)(c)(iii): Limit to be established by N.Y. Pub. Serv. Comm'n for non-residential customer-generators operating qualifying solar or wind generating facilities
    - NYPSL § 66-l(3)(c)(i): $750 for customer-generators operating qualifying wind generating facilities with capacities $\leq$ 25 kw
    - NYPSL § 66-l(3)(c)(ii): $5,000 for customer-generators operating qualifying wind generating facilities with capacities > 25 kw and $\leq$ 500 kw
- NYPSL §§ 66-j(4)(d), 66-l(4)(d): Demand Charges: Customer-generators may be charged kw demand charges under the following circumstances:
    - kw demand charges are imposed on customers within the customer-generators' service class who do not self-generate

  - the kw demand charge assessed to customer-generators is
    - calculated at the same kw rate applicable to customers within the customer-generators' service class who do not self-generate
    - determined by the maximum measured kw demand actually placed on the grid by the customer-generator during the billing period

- Costs of compliance with safety standards
  - NYPSL §§ 66-j(5)(a), (b); 66-j(5-a)(a)-(d); 66-l(a)-(c): Imply that Customer-generators bear the costs of complying with safety, performance, testing and insurance requirements, for customer-generators may not be assessed more than the costs of complying with safety, performance, testing and insurance requirements
  - However, additional safety, performance, testing and insurance requirements may be charged to customer-generators
    - NYPSL §§ 66-j(5)(b)(ii); 66-j(5-a)(a), (b); 66-l(5)(c): Who operate qualifying farm waste or wind generating facilities or are non-residential customer generators operating qualifying solar generating facilities
    - NYPSL §§ 66-j(5)(b)(iii); 66-j(5-a)(b); 66-l(5)(c): With capacities > 20% of the rated capacity of the local feeder line through which they supply electricity to the grid

- Metering Costs: There is statutory ambiguity with respect to net metering costs that may have been resolved by the NYPSC:
  - NYPSL §§ 66-j(2), 66-l(2): State that
    - Electric Corporations are to provide for interconnection and net metering of solar, farm waste and wind electric generating equipment
    - There is no indication as to whether provide means at the expense of the Electric corporations
    - However, § 66-l(2) apportions 50% of the costs of interconnection on customer generators using wind electric generators with capacities > 25 kw, which at least implies that the Electric Corporations are to bear the costs of interconnection and the meters needed for net metering for all other customer generators
  - NMO 11-12: Metering Installation Costs—the N.Y. Pub. Serv. Comm'n interprets NYPSL §§ 66-j, 66-l as requiring electric corporations to

bear the costs of installing any additional metering required to enable the measurement of bi-directional flows of electricity between the grid and customer-generators

NMO 10: Ownership of Environmental Attributes: The net metering statutes are silent as to who owns the environmental attributes of electricity produced by qualifying net metering generating facilities. The NYPSC declined to specify who owns these attributes, thereby refusing to rule that they belong to customer generators

Billing for Net Excess Consumption (NEC):

NYPSL §§ 66-j(4)(a), 66-l(4)(a): customer-generators are charged each billing period for their net excess consumption at the same per kwh rate charged to other customers within their same service class who do not generate electricity on site.

Billing for Net Excess Generation (NEG):

NYPSL §§ 66-j(4)(a), 66-l(4)(a): Definition of net excess generation is ambiguous. Excess occurs when customer generator generates more electricity than he/she/it is provided by the Electric Corporation, but the credit is based on the net excess he/she/it provides (presumably to the Electric Corporation).

There is inconsistency in the statutory mandates and the regulatory implementation thereof:

- NYPSL §§ 66-j(4)(b), 66-l(4)(b): Statutory mandates state that customer-generators are to receive during the next billing period a dollar credit for their net excess generation achieved in the current billing period valued at the same rate per kwh rate charged to other customers within their same service class who do not generate electricity on site.

- NMO 6: In implementing the statutory mandates, the N.Y. Pub. Serv. Comm'n handles credits for next excess generation as follows:

    - Customer-generators who are not demand metered receive kwh credits for their net excess generation which are applied to the next billing period

    - Demand metered customer generators

        - Receive a dollar credit based on kwh x applicable rate in the current billing period

        - But, if dollar credit exceeds the customer-generators bill, the dollar credit is converted into a kwh credit and carried over to the next billing period

Annualized reconciliation:

- NYPSL §§ 66-j(1)(a)(i), (ii); 66-j(4)(c); 66-l(4)(c): At the end of each annualized period of service, all customer-generators except those who are non-residential shall receive a payment for any remaining net excess generation valued per kwh at the electric corporation's avoided cost

- NYPSL §§ 66-j(1)(a)(i), (ii); 66-j(4)(c); 66-l(4)(c); NMO 7-8: At the end of each annualized period of service, non-residential customer-generators will have any remaining net excess generation will be carried over to the next annualized service period.

North Carolina

Legal Sources

N.C. Gen. Stat. (NCGS) § 62.133.8(a)(3),(6)-(8); ((i)(6):

- provides key definitions referred to by the North Carolina Public Utility Commission in its 2009 Net Metering Order (see below)

- mandates that the North Carolina Public Utility Commission consider whether "it is the public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a generation capacity of one megawatt or less."

Various Net Metering orders issued by the North Carolina Public Utility Commission but not published in the North Carolina Register in which net metering policies were established but not codified in North Carolina's Administrative Code:

- Order Adopting Net Metering, N.C. Pub. Util. Comm'n (Docket No. E-100, Sub 83, Oct. 20, 2005) [hereinafter cited as OANM];

- Order Modifying Net Metering Tariffs & Riders, N.C. Pub. Util. Comm'n (Docket No. E-100, Sub 83, July 6, 2006) [hereinafter cited as OMNM];

- Order Amending Net Metering Policy, N.C. Pub. Util. Comm'n (Docket No. E-100, Sub 83, March 31, 2009) [hereinafter cited as OANMP]

Covered Utilities

OANM 1, 4-5; OMNM 1, 8-9; OANMP 2, 16: Progress Energy Carolinas, Inc; Duke Power, Dominion North Carolina Power

Covered Customers

OANM 4, OANMP 15: Any retail customer of a covered utility that owns a qualified net metering generating facility installed to meet his/her/its own electricity needs.

Qualifying Technologies:

NCGS § 62.133.8(a)(7), (8); OANMP 14, 15: Qualifying net metering generating facilities are facilities other than hydroelectric power facilities with capacities > 10 MW that generate electricity power or useful combined heat and power from one of the following renewable resources:

- solar electric

- solar thermal

- wind
- hydropower
- geothermal
- ocean current
- wave energy
- biomass resource, including:
    - agricultural waste
    - animal waste
    - wood waste
    - spent pulping liquors
    - combustible residues
    - combustible liquids
    - combustible gases
    - energy crops
    - landfill methane
- waste heat that is
    - derived from a renewable resource
    - used to produce electricity
    - at customer-generator's facility
- hydrogen derived from a renewable resource

Capacity Limits-Individual Facility

OANMP 11, 12, 15: $\leq$ 1 MW

Capacity Limits-Aggregate

OANMP 11, 12: None

Time Limits

None

Billing Rules

General Rule:

OANMP 15: Customer-generators may choose to take retail electric service under any rate schedule applicable to their circumstances and must be treated the same way as non-net metering customers within those rate schedules with respect to standby, capacity, metering or other charges.

Other Costs, Revenues:

OANMP 15:

- Standby, capacity, metering and other charges may be imposed on customer-generators if they are imposed on non-net metering customers served under the same rate schedule.
- However, standby charges may not be imposed on:
  - Residential customer-generators operating qualifying electric generating facilities with capacities $\leq$ 20 kw
  - Non-residential customer-generators operating qualifying electric generating facilities with capacities $\leq$ 100 kw

OANMP 13, 14, 16: Renewable Energy Credits earned by customer-generators are allocated as follows:

- To customer-generators when they accept retail electric service under a TOU demand rate schedule;
- To public utilities when customer-generators accept retail electric service under rate schedules other than a TOU demand rate schedule

Billing for Net Excess Consumption (NEC):

OANMP 12, 13, 15: Customer-generators may choose to be subject to the rates applicable to rate schedule available to other customers within their rate classes

Billing for Net Excess Generation (NEG)

OANM 3: Net Excess Generation is expressed in kwh and occurs when

- Electricity delivered to the grid by the customer generator
- Exceeds the electricity supplied to the customer generator by the utility

Customer-generators may receive credit for their net excess generation as follows:

- OANMP 15 For all net-metering customers, credits are
    - Applied to the next billing period
    - Carried forward month to month
    - At beginning of the summer billing season, any remaining excess credit is given free of charge to the utility and the credit balance is zeroed out.
- OMNM5, 6, 8; OANMP 15, 16 For customer-generators on TOU rates: The credit is only the kwh portion of the TOU rates and is applied as follows:
    - Net excess generation during peak period shall
        - Offset on peak consumption
        - Remainder than shall be used to offset off-peak consumption
    - Net excess generation during off-peak period may offset only off-peak consumption

Ohio

<u>Legal Sources</u>

Ohio Rev. Code Ann. (ORCA) §§ 4905.03(A)(4); 4928.01(A)(11), (29)-(32), (34), (35); 4928.02(C), (D), (F), (K), (L); 4928.67

Ohio Admin. Code (OAC) 4901:1-10-01(C); 4901:1-10-28; 4901:1-21-01(A), (B), (D), (F), (J), (N), (P)-(R); 4901:1-21-13, as found in Re Administrative Code, Ohio Pub. Util. Comm. (OH-PUR, slip copy, Nov. 5, 2008), 2008 WL 4862505 *27, *74-77, *88, *89 [hereinafter OH-PUR]

FirstEnergy Corp. v. Pub. Util. Comm., 95 Ohio St. 3d 401, 768 N.E.2d 648(2002).

<u>Covered Utilities</u>

ORCA §§ 4928.01(A)(7), (9) (11), (30); 4905.03(A)(4); 4928.67(A)(1), (2): Ohio statutes designate the entities that are to provide net metering as follows:

- ORCA §4928.67(A)(1), (2): mandate that electric utilities offer net metering
- ORCA § 4928.01(A)(11): defines electric utility as an electric light company that
  - Has a certified territory
  - Provides on a for profit basis
    - A non-competitive retail electric service, or
    - Both a non-competitive and a competitive retail service
  - But is not
    - A municipal electric utility, or
    - A billing and collection agent
- ORCA §§ 4905.03(A)(4), 4928.01(A)(7): defines electric light company as an entities that supply electricity to consumers for light, heat and power on a for profit and not-for profit basis
  - Including
    - Companies supplying electric transmission services for delivering electricity to consumers
    - Electric Services Companies
  - Excluding

        - Self-generators that consume electricity they produce, sell electricity for resale, or obtains electricity from generating facility located on their premises
        - Regional transmission organizations approved by the FERC

- ORCA § 4928.01(A)(4), (9); (C): Electric Service Companies engage on a for-profit and not for profit basis in supplying a competitive retail electric service.
    - They include
        - Power marketers
        - Power brokers
        - Aggregators
        - Independent power producers
    - They do not include
        - Electric cooperatives
        - Municipal electric utilities
        - Government aggregators
        - Billing and collection agents

OAC 4901:1-10-01(C), (J)-(M) at OH-PUR *27, 28; 4901:1-10-28(A)(1), (B)(1) at OH-PUR *74, *76; 4901:1-21-01(F), (J), (N), (Q) (P), (R), (GG) at OH-PUR *88, *89; 4901:1-21-13 (A) at OH-PUR *112: The Ohio Public Utilities Commission (OPUC) has established net metering regulations that apply to the following entities:

- EDUs (electric distribution utilities), companies that use their own facilities to deliver physically electricity to retail electricity consumers, are required to offer net metering services under terms established in net metering tariffs
- Competitive Retail Electric Service Providers [retail electric generation providers, power marketers, power brokers, but not EDUs] certified by OPUC to provide electric power to retail customers through the facilities of an EDU or electric transmission entity are required to offer net metering services under terms established in standard net metering contracts.

<u>Covered Customers</u>

Customers eligible for net metering include:

- ORCA §§ 4928.01(A)(29),(30); 4928.67(A)(1); OAC 4901:1-10-28(A)(1) at OH-PUR *74; 4901:1-21-13(A)(1) at OH-PUR *112: Standard net metering customer-generators are persons who

  - operate qualifying renewable electric generating facilities
  - located on their own premises
  - in parallel with the participating EDUs' transmission and distribution facilities
  - primarily to meet all or part of his/her/its electricity requirements

- ORCA §§ 4928.01(A)(29),(30); 4928.67(A)(2)(a); OAC 4901:1-10-28(B)(1) at OH-PUR *76; 4901:1-21-13(A)(2) at OH-PUR *112: Hospital net metering customer generators are
  - The following types of health care facilities:
    - Public health care facilities
    - Hospitals (general, mental, chronic disease, etc)
    - Laboratories
    - Outpatient departments
    - Nurses' home facilities
    - Extended care facilities
    - Self-care facilities
    - Central services facilities
    - Education & training facilities
  - Which
    - Operate its own generating facilities, renewable or otherwise
    - On the health care facilities premises
    - In parallel with the electric utility's transmission & distribution facilities

<u>Qualifying Technologies:</u>

ORCA § 4928.01(A)(31)(a); OAC 4901:1-10-28(A)(1)(a)(i) at OH-PUR *74, 4901:1-21-13(A)(1)(a) at OH-PUR *112: qualifying renewable electric generating facilities are those that

- use as its fuel:
  - solar
  - wind
  - biomass

    - landfill gas, or
    - hydropower
- or use
    - a microturbine, or
    - a fuel cell

Capacity Limits-Individual Facility

ORCA § 4928.01(A)(31)(d); OAC 4901:1-10-28(A)(1)(a)(iv) at OH-PUR *74, 4901:1-21-13(A)(1)(d) at OH-PUR *112: standard net metering customer-generators' qualifying facilities are limited to a size of a facility intended primarily to meet only the customer-generator's electricity requirements.

ORCA §§ 4928.01(A)(31)(d), 4928.67(A)(2)(a); OAC 4901:1-10-28(B)(1)(b) at OH-PUR *76, 4901:1-21-13(A)(2) at OH-PUR *112: hospital customer-generators' generating facilities are not subject to any capacity limits

Capacity Limits-Aggregate

None

Time Limits

None

Billing Rules

General Rule:

ORCA § 4928.67(A)(1); OAC 4901:1-10-28(A)(2) at OH-PUR *75, 4901:1-21-13(B) at OH-PUR *112: Standard customer-generators are subject to the same rate structure, retail rate components, and monthly charges in the contract they would have been assigned if they were not customer-generators

ORCA § 4928.67(A)(2)(b); OAC 4901:1-10-28(B)(3), (6)(a) at OH-PUR *76, 4901:1-21-13(B) at OH-PUR *112: Hospital customer-generators are subject to

- same rate structure, retail rate components, and monthly charges in the contract they would have been assigned if they were not customer-generators
- the market value of the electricity they generate at the time it is generated, which means the locational marginal price of energy determined by an RTO's operational market at the time the hospital generates the electricity

Other Costs, Revenues

ORCA § 4928.67(B)(1); OAC 4901:1-10-28(A)(4), (B)(4) at OH-PUR *75-*76, 4901:1-21-13(D) at OH-PUR *112: Standard and hospital customer-generators are responsible for the costs of any meters that must be installed to measure the flows of electricity in manners conducive to net metering, which are:

- Bi-directional net flow meter for standard customer generators

- Meter or meters capable of measuring the flows of electricity supplied by the grid and electricity generated by the customer-generator's net metering generation facility for hospital customer-generators (which means that one meter or a register on a single meter must measure the real time generation of electricity by the customer generators net metering generating facility

ORCA § 4928.67(B)(2); OAC 4901:1-10-28(A)(5) at OH-PUR *75, 4901:1-21-13(D) at OH-PUR *112: the electric utility must pay to have additional meters capable of measuring the flow of electricity in two directions at the premises of standard customer-generators

ORCA § 4928.67(B)(4), (C); OAC 4901:1-10-28(A)(3)(a), (B)(7)(a) at OH-PUR *75, *76; 4901:1-21-13(C)(1) at OH-PUR *112: Standard and hospital customer-generators are responsible for the costs of complying with:

- Safety and performance standards established by the
    - National Electric Code
    - Institute of Electrical & Electronic engineers
    - Underwriters Laboratory

- Ohio Public Utilities Commission rules control and testing requirements that are necessary to protect
    - Public and worker safety
    - System reliability

Standard and hospital customer generators who have complied with all mandatory safety, performance and system reliability standards specified in the net metering statute and regulations may not be required to incur the costs of:

- ORCA § 4928.67(D)(1); OAC 4901:1-10-28(A)(3)(a), (B)(7)(a) at OH-PUR *75, *76; 4901:1-21-13(C)(1) at OH-PUR *112: meeting additional safety or performance standards

- ORCA § 4928.67(D)(2); OAC 4901:1-10-28(A)(3)(b), (B)(7)(b) at OH-PUR *75, *76; 4901:1-21-13(C)(2) at OH-PUR *112: additional tests

- ORCA § 4928.67(D)(3); OAC 4901:1-10-28(A)(3)(c), (B)(7)(c) at OH-PUR *75, *76; 4901:1-21-13(C)(3) at OH-PUR *112: additional liability insurance

OAC 4901:1-10-28(A)(7), (B)(8) at OH-PUR *76, *77: standard and hospital customer-generators may not have imposed on them "any charges that relate to the electricity the customer-generator feeds back to the system."

Billing for Net Excess Consumption (NEC):

ORCA §§ 4928.01(A)(30), 4928.67(A)(1), (B)(3)(b); OAC 4901:1-10-28(A)(2),(6)(b) at OH-PUR *75, 4901:1-21-13(B), (E)(2) at OH-PUR *112, *113: For Standard Net Metering customer generators:

- Net Excess Consumption is measured in kwh and equals the positive difference between
  - The electricity supplied to the customer generator by the electric utility or competitive retail electric service provider, and
  - The electricity generated by the customer generator that is fed back to the electric utility or competitive retail electric service provider.
- Customer generators shall be billed for their net excess consumption
  - In accordance with normal billing practices
  - Presumably under the applicable non-discriminatory contract or tariff to which the customer generator was assigned as if he/she/it were not participating in net metering (Note, the statute and regulations imply this, but do not directly say it)

ORCA §§ 4928.01(A)(30), 4928.67(A)(2)(b), (B)(3)(b); OAC 4901:1-10-28(B)(3),(6)(a)-(c) at OH-PUR *76-77, 4901:1-21-13(B), (E)(2) at OH-PUR *112, *113: for Hospital Net Metering customer generators:

- Net Excess Consumption is measured in $ value and equals the positive difference between
  - The $ value of the electricity supplied to the hospital customer generator by the utility (and presumably a competitive retail electric service provider if one supplies generating services to a hospital, although the regulations governing net metering provided by competitive retail electric service providers do not state separate rules for billing hospital customer generators), and
  - The $ value of the total electricity generated by the customer generator, including the electricity that it consumes and the electricity it feeds back to the electric utility's (or competitive retail electric service provider's) system
- The $ value of electricity supplied to the hospital customer generator is the market value, which is the locational marginal price of energy as determined

by a regional transmission organization's operational market at the time the electricity is generated.

Billing for Net Excess Generation (NEG)

ORCA §§ 4928.01(A)(30), 4928.67(A)(1), (B)(3)(b); OAC 4901:1-10-28(A)(2),(6)(c) at OH-PUR *75, 4901:1-21-13(B), (E)(3) at OH-PUR *112, *113: For Standard Net Metering customer generators:

- Net excess generation is the positive difference between
  - The electricity generated by the customer generator that is fed back to the electric utility or competitive retail electric service provider, and
  - The electricity supplied to the customer generator by the electric utility or competitive retail electric service provider
- The Net Excess Generation Credit
  - Is the excess generation component expressed in kwh
  - Allowed to accumulate from billing period to billing period until
    - Its netted against the customer generator's bill, or
    - Customer generator requests in writing a refund $\leq$ the annual true-up of accumulated credits over a 12 month period
- Note, the Net Excess Generation provisions are ambiguous as to whether the credits
  - continue only until the end of the 12 month net metering period at which time the credits zero out, or the customer generator receives a refund upon his/her/its request, or
  - In absence of a request for a refund, continue on into another 12 month net metering period
- Note further, the Net Excess Generation provisions are also ambiguous as to
  - whether the excess generation component is a specific billing component through which only the costs of generating or purchasing power are recovered?
  - But see FirstEnergy Corp. v. Pub. Util. Comm., 95 Ohio St. 3d 401, 404-407, 768 N.E.2d 648, 651-653 (2002), that appears to mandate that only the energy portion of the customer generator's kwh part of the bill may be subject to the kwh net metering generation credit.

ORCA §§ 4928.01(A)(30), 4928.67(A)(2)(b), (B)(3)(b); OAC 4901:1-10-28(B)(3),(6)(a)-(c) at OH-PUR *76-77, 4901:1-21-13(B), (E)(3) at OH-PUR *112, *113:

- Net excess generation is

- measured in $ value and equals the positive difference between
  - The $ value of the total electricity generated by the customer generator, including the electricity that it consumes and the electricity it feeds back to the electric utility's (or competitive retail electric service provider's) system, and
  - The $ value of the electricity supplied to the hospital customer generator by the utility (and presumably a competitive retail electric service provider if one supplies generating services to a hospital, although the regulations governing net metering provided by competitive retail electric service providers do not state separate rules for billing hospital customer generators)
- The $ valued credit is
  - Netted against the hospital generator's bill
  - Until the hospital requests in writing a refund ≤ the annual true-up of accumulated credits over a twelve month period

- Note, the Net Excess Generation provisions are ambiguous as to whether the credits
  - continue only until the end of the 12 month net metering period at which time the credits zero out, or the customer generator receives a refund upon his/her/its request, or
  - In absence of a request for a refund, continue on into another 12 month net metering period

Pennsylvania

Legal Sources

73 Pa. Stat. (PS) §1648.2, .5; 66 Pa. Cons. Stat. (PCS) § 2803

52 Pa. Code (PC) §§ 75.11-75.15; 75.63(f), (g)

Covered Utilities

73 PS §1648.2 (definitions of Electric Distribution Company, Electric Generation Supplier, Net Metering); 66 PCS § 2803 (definitions of Electric Distribution Company, Electric Generation Supplier); 52 PC §§ 75.11, 75.12 (definition of net metering: There is somewhat of a discrepancy with respect to what entities are governed by Pennsylvania's net metering mandates and authorities:

- Definitions of net metering refer to entities called public utilities and do not mention electric distribution companies

- The regulatory provision establishing the scope of net metering regulations state that the rules apply to

    - Electric Distribution Companies (EDC): Public utilities that provide jurisdictional electricity transmission and distribution services to retail customers. They are required to offer net metering to qualified customer-generators

    - Electric Generation Suppliers (EGS): persons or corporations that sell electricity or related services—or purchase, broker, arrange or market electricity or related services for sale—to end users by utilizing jurisdictional transmission or distribution facilities of an EDC. They may, but need not, offer net metering to their customer-generators.

Covered Customers

73 PS §1648.2 (definitions of Distributed generation system, Customer-Generator and Net Metering), 1648.5; 52 PC §§ 75.11, 75.12 (definitions of net metering), 75.13(a): Net Metering is offered to non-utility owners or operators of distributed generation systems (defined as small-scale power generation of electricity and useful thermal energy

- Meet net metering technology qualifications

- Are within net metering capacity limits

- Generate electricity that in part is used to offset some the owner/operators electricity requirements

Qualifying Technologies:

73 PS §§ 1648.2(definitions of Customer-Generator, distributed generation system, net metering), 1648.5; 66 PCS § 2803 (definition of Renewable Resource); 52 PC §§ 75.12 (definition of net metering), 75.13(a): There is an apparent discrepancy in the statutes and regulations in specifying what net metering electric power technologies qualify for net metering

- 73 PS § 1648.2(definitions of Customer-Generator and distributed generation system) appear to require customer generators to own and operate cogeneration facilities to qualify for net metering, because
  - Customer-Generator is defined as an owner or operator of a net metered distributed generation system, and
  - Distributed generation system is defined as the small scale generation of
    - Electricity and
    - Useful thermal energy
- 73 PS § 1648.5 requires the electricity generation technology used for net metering to be renewable onsite generators
- 73 PS §§ 1648.2(definition of net metering), 52 PC § 75.12(definition of net metering) specifies a requirement applicable to net metering offered by EDCs and EGSs that the electricity generated by the customer-generator to offset some of his/her/its electricity requirements must be generated by an alternative energy generating system, which is a system that generates electricity using an alternative energy source, not all of which are renewable.
- 52 PC § 75.13(a)
  - specifies fuel source requirements for customer-generators of EDCs—they must generate electricity using either a Tier I or Tier II energy source, not all of which are renewable
  - but does not specify a fuel source requirement for customer-generators of EGSs

66 PCS § 2803 (definition of Renewable Resource): Renewable resource is includes, some, but not all technologies defined by statute as Alternative Energy Sources. They include:

- Solar voltaic energy
- Solar thermal energy
- Wind power
- Low-head hydropower

  - Geothermal energy
  - Landfill and mine-based methane gas
  - Energy from waste and sustainable biomass energy

73 PS § 1648.2 (definitions of Alternative Energy Sources, Tier I Alternative Energy Source): Tier I Alternative Energy Sources are defined as energy derived from

- Solar photovoltaic and solar thermal energy
- Wind power
- Low-impact hydropower, meaning hydropower technology that
  - Does not adversely change existing impacts to aquatic systems
  - Meets certification standards established the Low Impact Hydropower Institute and American Rivers, Inc., or their successors;
  - Provides an adequate water flow for protection of aquatic life and for safe and effective fish passage
  - Protects against erosion
  - Protects cultural and historic resources
- Geothermal energy, which entails producing electricity by extracting hot water or steam from geothermal reserve in the earth's crust and supplied to steam turbines that drive electric generators.
- Fuel cells, which are electro-chemical devices that convert chemical energy in a hydrogen rich fuel directly into electricity without combustion
- Biomass energy, which is technology that generates electricity using
  - Organic material from a plant that is
    - Grown to be used for producing electricity
    - Protected by being grown on land set aside under the Federal Conservation Reserve Program and can be produced without preventing the achievement of the FCRP goals of water quality protection, soil erosion prevention, and wildlife enhancement
  - Any solid nonhazardous, cellulosic waste material that is segregated from other waste materials, including
    - Waste pallets
    - Crates

        - Landscape or right-of-way tree trimmings
        - Agricultural sources (orchard tree crops, vineyards, grain, legumes, sugar, other crop byproducts or residues)

- Coal mine methane, which is methane gas emitted from abandoned or working coal mines

73 PS § 1648.2 (definitions of Alternative Energy Sources, Municipal Solid Waste, Tier II Alternative Energy Source): Tier II Alternative Energy Sources are defined as energy derived from:

- Waste coal, includes the combustion of waste coal
    - In facilities in which waste coal was
        - Disposed or abandoned prior to July 31, 1982
        - Disposed of thereafter in a permitted coal refuse disposal site
    - Used to generate electricity
    - In a process that
        - Uses a combined fluidized bed boiler
        - Is outfitted with a lime injection system
        - Is outfitted with a fabric filter particulate removal system
- Distributed generation systems, which involves small scale power generation of electricity and useful thermal energy
- Demand-side management, which involves managing customers consumption of and/or demand for electricity—this is listed as an energy source but really cannot be a qualifying net metering technology because it does not involve anything that generates electricity
- Large-scale hydropower, which means hydropower technology, including pumped storage, that does not qualify as low-impact hydropower
- Municipal solid waste, which includes energy from existing waste to energy facilities that are in compliance with all current environmental standards, especially those of the Clean Air Act and the Solid Waste Management Act.

Capacity Limits-Individual Facility

73 PS § 1648.2 (definition of Customer-Generator): The definition of customer-generator imposes capacity limits as follows:

- Net metering generators serving Residential customers: $\leq$ 50 kw
- Net metering generators located in non-residential locations: $\leq$ 3 MW

- Net metering generators located in non residential locations which serve special needs as set forth below: > 3 MW and ≤ 5 MW
  - o Are available to the grid during emergencies defined by the relevant regional transmission organization
  - o Are connected to or serve a microgrid that exists to serve the primary or secondary purpose maintaining critical infrastructure such as
    - Homeland security assignments
    - Emergency services facilities
    - Hospitals
    - Traffic signals
    - Waste water treatment plants
    - Telecommunications facilities

<u>Capacity Limits-Aggregate</u>

None

<u>Time Limits</u>

None

<u>Billing Rules</u>

General Rule:

EDCs are to charge their customer-generators

- 52 PC § 75.13(i):
  - o non-discriminatory rates identical with respect to rate structure, retail rate components and any monthly charges to the rates that are charged to other customers who are not customer-generators, or
  - o rates specified in a special use profile approved by the commission that incorporates the customer-generator's real time generation
- 52 PC § 75.13(j): only those fees or other type of charge that applies to other customers who are not customer-generators

Other Costs, Revenues:

52 PC § 75.13(h): Customer-generators own all alternative energy credits associated with their qualifying net metering generation systems unless they convey ownership to others or refuse to comply with the alternative energy credits metering requirements

52 PC § 75.13(j): EDCs may not charge customer-generators for additional equipment, insurance or other requirements that are not authorized by net metering regulations or the Commission

52 PC § 75.14(a), (b): EDCs shall cover the expense of installing bidirectional or dual metering needed to implement net metering if their customer-generators lack the proper net metering meters

With respect to the expense of additional metering needed to qualify for alternative energy credits:

- 52 PC § 75.14(c): Customer-generators pay for the additional metering if they intend to take or transfer title to alternative energy credits produced by their qualifying net metering generation systems

- 52 PC § 75.14(d): If customer-generators do not pay for the metering necessary to qualify for alternative energy credits, the EDCs serving them can obtain title to the alternative energy credits generated by their customer-generators' qualifying net metering generation systems by paying the costs of the alternative energy credit meters

- 52 PC § 75.63(g): Customer-generators with solar voltaic energy systems having capacities $\leq$ 15 kw may not have to install additional metering to qualify for alternative energy credits

52 PC § 75.14(e): Customer-generators pay the EDCs' costs of providing virtual and physical meter aggregation

52 PC §§ 75.12 (definition of base year), 75.15: With respect to Stranded Costs

- small commercial, commercial, and industrial customer-generators must pay their shares of stranded costs when their self-generation causes a reduction $\geq$ 10% in their electricity purchases through an EDCs transmission and distribution net work from one annualized period to another

- stranded cost obligations are calculated based on the applicable base year, which is

    - immediate prior calendar year if self-generation commenced on or after Jan. 1, 1999

    - 1996 if self-generation commenced before Jan. 1, 1999

Billing for Net Excess Consumption (NEC):

There is a lack of clarity about what constitutes net excess consumption, as follows:

- Neither the statutes nor the regulations expressly define net excess consumption, so what it means must be implied from definitions of net metering and provisions specifying how to credit or compensate customer generators for their net excess generation, which among them contain ambiguities
    - 73 PS § 1648.2(definition of net metering); 52 PC § 75.12(definition of net metering): net metering is defined to mean the difference between
        - The electricity supplied to a customer generator by an EDC or an EGS and
        - The electricity generated by a customer generator
    - 52 PC § 75.13(c) states customer generators are to be credited in each billing period for the total kwh of electricity they generate up to the total kwh of electricity they use (which includes electricity the customer generator generated and used him/her/itself and the electricity supplied to the customer generator by an EDC or an EGS), and then describes any possible net excess generation as the positive difference between
        - the amount of electricity the customer generator supplies the electric distribution system, and
        - the amount of electricity the EDC supplies the customer generator
    - 52 PC § 75.13(d): states that at the end of each year the customer generator is to be compensated for the positive difference between
        - The amount of excess kwh generated by the customer generator and
        - The amount of kwh delivered to the customer generator by the EDC
- From the foregoing provisions, it can be implied that net excess consumption is one of the two following alternatives:
    - Alternative 1: it is the positive difference between
        - the amount of electricity the EDC supplies the customer generator and

        - the amount of electricity the customer generator supplies the electric distribution system

    - Alternative 2: it is the positive difference between

        - the amount of electricity the EDC supplies the customer generator

        - the total amount of electricity generated by the customer generator

The rate at which customer generators are to be charged for their net excess consumption is not specified by the net metering statutes and regulations, so it must be implied

- 52 PC § 75.13(i) is the regulatory provision from which the rate is to be implied, and it states that

    - customer generators are to be provided with net metering services at nondiscriminatory rates identical with respect to rate structure, retail rate components, and any monthly charges to rates charged to customers that are not participating in net metering, unless

    - the EDC gets approval from the commission to use a special load profile based on the customer generators real time generation

- From this, it can be implied that customer generators are to be charged for their net excess consumption at the rates

    - specified in their applicable rate class, or

    - approved by the commission in accordance with their special load profiles

Billing for Net Excess Generation (NEG)

Net Excess Generation is not defined with clarity because of seemingly ambiguous and/or contradictory language in net metering statutes and regulations

- The ambiguous/contradictory statutes and regulations are as follows:

    - 73 PS § 1648.2(definition of net metering); 52 PC § 75.12(definition of net metering): net metering is defined to mean the difference between

        - The electricity supplied to a customer generator by an EDC or an EGS and

        - The electricity generated by a customer generator

    - 73 PS § 1648.5 specifies that customer-generators are to receive from EDCs on an annual basis full retail value for any excess electricity generated by their qualifying net metering generation system

- 52 PC § 75.13(c) states customer generators are to be credited in each billing period for the total kwh of electricity they generate up to the total kwh of electricity they use (which includes electricity the customer generator generated and used him/her/itself and the electricity supplied to the customer generator by an EDC or an EGS), and then describes any possible net excess generation as the positive difference between
    - the amount of electricity the customer generator supplies the electric distribution system, and
    - the amount of electricity the EDC supplies the customer generator
- 52 PC § 75.13(d): states that at the end of each year the customer generator is to be compensated for the positive difference between
    - The amount of excess kwh generated by the customer generator and
    - The amount of kwh delivered to the customer generator by the EDC

- From the foregoing, there are two possible definitions of net excess generation:
    - Alternative 1: it is the positive difference between
        - the amount of electricity the customer generator supplies the electric distribution system, and
        - the amount of electricity the EDC supplies the customer generator and
    - Alternative 2: it is the positive difference between
        - the total amount of electricity generated by the customer generator, and
        - the amount of electricity the EDC supplies the customer generator

Customer generators are to be credited / compensated for for their net excess generation as follows:

- 52 PC § 75.13(c) During each billing period
    - EDCs are to credit at full retail value
        - The total kwh produced by the customer generator
        - up to the total amount of electricity used by the customer generator (which includes the electricity supplied by the EDC to

the customer generator and the electricity generated and used by the customer generator)

- The full retail rate includes the following charges
    - Generation
    - Transmission
    - Distribution
- Customer-generators involved in virtual meter aggregation programs will have their credits
    - Applied first to the meter through which the customer-generator's qualifying net metering generation system supplies electricity to the EDC
    - Then through the remaining meters equally at each meter's designated rate

- 52 PC § 75.13(c) excess kwh from one billing period are to be carried over to the next billing period, with the excess defined as the positive difference between
    - The electricity supplied by the customer generator to the electric distribution system and
    - The electricity supplied by the EDC to the customer generator
- 52 PC § 75.13(c) excess kwh as defined above are to be carried from one billing period to the next and accumulated until the end of the year
- 52 PC §§ 54.182(definition of price to compare), 75.13(d), (f): At year end, or when service terminates, EDCs compensate customer generators for any remaining excess kwh at their price to compare, which include the following charges:
    - An annualized weighted average of retail generation charges
    - An annualized weighted average of retail transmission charges

52 PC § 75.13(e): EGSs shall credit or compensate their customer-generators for their net excess generation in accordance with terms stated in the service agreements between them.

Virginia

Legal Sources

Va. Code Ann. (VCA) §§ 56-576, 56-585, 56-594

20 Va. Admin. Code (VAC) §§ 5-315-10 through 5-315-70

Covered Utilities

The net metering statute and other relevant statutes seem to impose, or allow to be imposed, net metering requirements on a variety of entities

- VCA §56-594(A) authorizes, but does not require, the Virginia State Corporation Commission to promulgate net metering regulations that cover
  - Retail sellers
  - Owners/operators of
    - Distribution facilities
    - Transmission facilities
  - Providers of default service
- VCA §56-594(B)(definition of Eligible customer-generator) refers to the entity or entities with whom eligible customer-generators interact to obtain net metering in various ways, as follows:
  - a utility can agree to higher capacity limits
  - customer-generators' qualifying net metering generating facilities are
    - interconnected to a distributor
    - interconnected and operated in parallel to an electric company's transmission and distribution facilities
- VCA §56-594(B)(definition of net metering period) refers to a final interconnection with an electric service provider
- VCA §56-594(E): refers to the following entities that interact with customer-generators concerning renewable energy credits
  - Entity contracting to receive electricity
  - supplier

- VCA §56-580(F): exempts from State Corporation Commissions regulation under Virginia's Electric Utility Act transmission and distribution facilities that were owned/operated by a municipality as of July 1, 1999, unless the
    - municipality has agreed to regulated under the Act
    - municipality sells, offers to sell, or seeks to sell electric energy to eligible retail customers located in an area outside of its July 1, 1999 territory that does not have the following history;
        - it was served on July 1, 1999 by an incumbent utility but thereafter was served by a municipal utility under agreement with the incumbent utility, or
        - it is a part of municipal utility's current service area due to territorial changes agreed to by an incumbent utility
- VCA §56-576 provides definitions of some of the entities referred to in §56-594:
    - Supplier means various entities licensed by the Commission that offer to sell or sell electric energy to retail customers, including
        - Generators
        - Distributors
        - Aggregators
        - Brokers
        - Marketers
        - Other persons
    - Generators produce electric energy for sale
    - Distributors own, control, or operate a retail distribution system to provide electric energy directly to retail customers
    - Aggregators are agents or intermediaries that
        - Offer to purchase or purchases electric energy
        - Offer to arrange or arrange for the purchase of electric energy for the sale to or on behalf of two or more retail customers not controlled by or under control with the aggregator
    - Electric utilities are persons that generate, transmit, distribute electric energy for use by retail customers and are owned/operated by
        - Investors

- A cooperative
- A municipality

- VCA §56-585(A), (B), (D)—Default service providers are
  - distributors or distribution electric cooperatives
  - with the obligation/right to offer a commission defined service package
  - to retail customers located within their service areas
  - who have not contracted with any specific electric service supplier.

The Virginia State Corporation Commission has promulgated net metering regulations that obligate the following entities to provide net metering services:

- 20 VAC § 5-315-10—the net metering regulations cover the relationships between customer-generators and
  - Electric distribution companies
  - Energy service providers
- 20 VAC § 5-315-20 provides the following definitions
  - Electric Distribution Company—own/operate distribution facilities that deliver electric energy to customer-generators' premises
  - Electric Service Providers—are entities that provide customer-generators with electric energy under
    - Tariffed service
    - Competitive service or
    - Default service

Covered Customers

VCA §56-594(B)(definition of eligible customer-generator(iii-v)); 20 VAC § 5-315-20(definitions of net metering customer and renewable fuel generator)—persons or entities qualified to be net metering customer-generators own & operate, or contract with others to own & operate, a qualifying net metering generating facility that is

- Located on his/her/its premises
- Connected to the customer's wiring on the customer's side of its interconnection with the distributor
- Interconnected and operated in parallel with an electric company's transmission and distribution facilities

- Primarily intended to meet most of the customer-generator's own electricity requirements

Qualifying Technologies:

VCA §§ 56-576(definition of Renewable energy), 56-594(B)(definition of Eligible customer-generator(ii)); 20 VAC § 5-315-20(definitions of net metering customer and renewable fuel generator(2)): qualifying net metering generating facilities that rely exclusively on renewable energy sources,

- Which include
    - Sunlight
    - Wind
    - Falling water
    - Biomass, sustainable or otherwise and liberally defined
    - Waste
    - Municipal solid waste
    - Wave motion
    - Tides
    - Geothermal power
    - Thermal or electric energy resulting from co-firing of biomass
- And do not include
    - Coal
    - Oil
    - Natural gas
    - Nuclear power

Capacity Limits-Individual Facility

VCA §56-594(B)(definition of eligible customer-generator(i)); 20 VAC § 5-315-20(definition of renewable fuel generator(1))

- $\leq$ 10 kw for residential customers
- $\leq$ 500 kw for non-residential customers
- However, these capacity limits may be increased by the electric distribution company and/or the energy service provider

Capacity Limits-Aggregate

VCA §56-594(E); 20 VAC § 5-315-40(B): 1.0% of the previous year's peak load forecast for the service area of each electric distribution company operating in Virginia

Time Limits

20 VAC § 5-315-30 specifies certain notification/response/interconnection time limits, as follows:

- 20 VAC § 5-315-30(A): notice goes to affected
  - Distribution company, and
  - Energy service provider if different than distribution company
- 20 VAC § 5-315-30(A)(1): for customer-generators with qualifying net metering generating facilities with capacities ≤ 25 kw
  - Customer-generators must have all equipment necessary for grid interconnection in place prior to giving the requisite notice
  - Notice must be 30 days or more prior to date of desired interconnection
  - Electric distribution company has 30 days from date of notice to determine if all interconnection requirements have been met
- 20 VAC § 5-315-30(A)(2): for customer-generators with qualifying net metering generating facilities with capacities > 25 kw
  - Customer-generators
    - must have all equipment necessary for interconnection to the grid in place prior to giving the requisite notice
    - should contact affected distribution company before making financial commitments
  - Notice must be 60 days or more prior to date of desired interconnection
  - Electric distribution company has 60 days from date of notice to determine if all interconnection requirements have been met
- 20 VAC § 5-315-30(B): customer-generators may interconnect his/her/its qualifying net metering generating facility to the grid
  - 31 days after given requisite notice if the qualifying net metering generating facility has a capacity ≤ 25 kw
  - 61 days after given requisite notice if the qualifying net metering generating facility has a capacity > 25 kw

- The affected distribution company and/or energy service provider may request and receive a waiver of this interconnection requirement

Billing Rules

General Rules:

VCA §56-594(D): The State Corporation Commission is required to establish minimum requirements for net metering contracts and tariffs, and they shall

- Protect customer-generators from being discriminated against on account of their status as customer-generators
- Enable customers subject to time-of-use tariffs with electricity supply demand charges contained within the energy supply portion of time of use tariffs to become eligible net metering customers

20 VAC § 5-315-50: Contracts and tariffs governing the relationships among customer-generators, electric distribution companies and energy service providers shall be identical to contracts or tariffs to which the customer-generator would have be subject if he/she/it was not a customer-generator with respect to such components as

- Rate structure
- Retail rate components
- Monthly charges

20 VAC § 5-315-50: Conflicts with VCA §56-594(D) as to the eligibility of customers under time-of-use contracts/tariffs with electricity supply demand charges to be customer-generators, for it states an exception to its non-discrimination requirement that says "time of use metering is not permitted."

Other Costs, Revenues:

VCA §56-594(C): State Corporation Commission shall fairly apportion costs of installing net metering equipment and interconnecting customer-generators' qualifying net metering generating facilities to the grid

20 VAC § 5-315-50: with respect to altering metering equipment that requires meter reading to be done off-site so that net metering can occur

- The electric distribution company shall incur the costs of metering modifications and additions if the off-site reading meters were installed, or will be installed, for its convenience
- The customer-generator shall bear the costs of metering modifications and additions if the off-site reading meters were installed, or will be installed at

the request of the customer-generator and the electric distribution company otherwise would not have installed such meters

Customer-generators are responsible for costs of

- VCA §56-594(C); 20 VAC § 5-315-40(A)(2)-(4): assuring that their qualifying net metering generating facilities meet all applicable safety and performance standards

- any additional safety, performance measures deemed essential by the commission, such as:

    - VCA §56-594(C)(i) installing additional controls

    - VCA §56-594(C)(ii) performing, paying for additional tests

    - VCA §56-594(C)(iii); 20 VAC § 5-315-60: purchasing additional insurance covering

        - ≥ $100,000 of losses associated with the use of a qualifying net metering generating facility with a capacity ≤ 10 kw

        - ≥ $300,000 of losses associated with the use of a qualifying net metering generating facility with a capacity > 10 kw

    - Certain inspection fees

        - 20 VAC § 5-315-40(A)(5) ≤ $50 for inspecting inverter settings for static inverter-connected qualifying net metering generating facilities with capacities ≤ 10 kw

        - 20 VAC § 5-315-40(A)(6) ≤ $50 for inspecting all protective equipment settings for nonstatic inverter-connected qualifying net metering generating facilities that have been interconnected to the grid in accordance with the electric distribution company's interconnection guidelines

Certain customer-generators are subject to some specific additional costs

- VCA §56-594(D): customer-generators taking electric service under demand charge based time-of-use tariffs must pay the incremental costs required to provide them with net metering service

- Customer-generators owning/operating qualifying net metering facilities with capacities > 25 kw must pay the costs of

    - 20 VAC § 5-315-40(A)(7)(a): preventing

        - Damage to the electric distribution company's facilities

        - Voltage regulation or power quality problems at other customer revenue meters

- 20 VAC § 5-315-40(A)(7)(b): interconnecting qualifying net metering generating facilities with capacities > the capacity of the electric distribution company's secondary, service, and service entrance capable connected to the point of interconnection

- 20 VAC § 5-315-40(A)(7)(c): avoiding overloading the electric distribution company's transformer, or any transformer winding

- 20 VAC § 5-315-40(A)(7)(d): integrating properly with the electric distribution company's facilities grounding

- 20 VAC § 5-315-40(A)(7)(e): avoiding voltage imbalances > 3% when the electric distribution company's transformer, with the secondary connected to the point of interconnection, is a three-phase transformer

VCA §56-594(E): customer-generators have opportunity to derive revenues from renewable energy certificates associated with their qualifying net metering generating facilities, as follows:

- Customer-generators own the renewable energy certificates associated with their qualifying net metering facilities

- When customer-generator enters into a power purchase agreement with its supplier, he/she/it has a one-time option to sell the renewable energy certificates to the supplier at a price set by the Commission to reflect the value of renewable energy certificates

- Customer-generators and their suppliers may at anytime voluntarily enter into an agreement for the supplier to purchase the customer-generator's renewable energy certificates at a mutually agreed to price

VCA §56-594(E): Costs associated with net metering shall be recovered by the supplier as follows:

- These costs include
    - Rates paid to customer-generators for the purchase of excess electricity generated by their qualifying net metering generating facilities
    - Rates paid to customer-generators to purchase their renewable energy certificates
    - Administrative expenses associated with managing customer-generators' power purchase agreements

- These costs are recoverable
    - Through the supplier's Renewable Energy Portfolio Standard (RPS)rate adjustment clause if the supplier has a commission-approved RPS plan

- o Through the supplier's fuel adjustment clause if the supplier does not have a commission-approved RPS plan

Billing for Net Excess Consumption (NEC):

VCA §56-594(B)(definition of net energy metering); 20 VAC § 5-315-20(definition of net metering service): Net Excess Consumption is not explicitly defined, but in can be implied from the statutory and regulatory definitions of net metering that is the positive difference between:

- Electricity supplied to the customer generator from the electric grid, and
- The electricity generated and fed back to the grid by the customer generator

VCA §56-594(D); 20 VAC § 5-315-50: Billing rules for net excess consumption are not explicit except that the statutes and regulations provide that the terms of the requisite non-discriminatory tariff or contract control the electric energy consumed from the grid by customer generators.

Billing for Net Excess Generation (NEG)

VCA §56-594(B)(definitions of Net energy metering & Net metering period), (E); 20 VAC §§ 5-315-20(definitions of Billing period, Net metering service & Net metering period), 5-315-50: Virginia measures net excess generation as follows:

- The presence of net excess generation is determined at the end of each billing period (the time between the issuance of customers' monthly bills) and each net metering period (each successive 12-month period beginning with the first meter reading date following the date the facility was finally interconnected with the electric distribution company)
- Net Excess Generation seems to be defined in contradictory ways as follows:
    - o Under definitions of net energy metering and relevant Administrative Code provisions, it means the positive difference between
        - ▪ The electricity generated and fed back to the electric grid by the customer-generator, and
        - ▪ The electricity supplied to the customer-generator from the grid
    - o But, VCA §56-594(E) defines it as the net positive difference between
        - ▪ The total electricity generated by the customer-generator
        - ▪ The total electricity consumed by the customer-generator

The regulatory provisions governing how customer generators are to be credited for their net excess generation lack clarity as to whether the credits are monetized or in kwh and whether customer generators are to receive payments or billing credits for their year-end net excess generation

- VCA §56-594(B)(definition of net metering period); 20 VAC § 5-315-20(definition of net metering period): Both the statutes and the regulations define an annualized net metering period for purposes of compensating or crediting customer generators for their net excess generation, as follows—
  - Each successive 12 month period
  - Beginning with the 1st meter reading
  - Following the date of final interconnections
- VCA §56-594(E); 20 VAC § 5-315-50: both call for customer generators to be compensated at the end of each net metering period to the extent that they have achieved net excess generation over that period (the basis of this compensation is discussed in a subsequent paragraph)
- 20 VAC § 5-315-50: contains a phrase in the midst of provisions spelling out a complicated means of determining what customer generators should be paid for their net excess generation that gives customer generators the option of receiving account credit instead of a payment for their year-end net excess generation
- 20 VAC § 5-315-50: ends with language that seems to require that customer generators receive billing credits instead of payments for their net excess generation as follows:
  - Customer generators receive a credit at the end of each monthly billing period and at the end of the annual net metering period
  - The basis for theses credits, $ or kwh, is not specified
  - Monthly credits carry forward month to month
  - Net excess generation credit for the current net metering period is calculated as the positive difference between:
    - The accumulated net excess generation credit for the current net metering period
    - Any net excess generation credit carried over from the previous net metering period
  - The carry over net excess generation credit is then the lesser of
    - The current net metering period net excess generation credit and
    - The customer generators accumulated billed consumption for the current net metering period

VCA §56-594(D), (E); 20 VAC § 5-315-50: The general rules governing payments owed to customer generators for net excess generation at the end of the net metering period are that

- the compensation for the net excess generation shall be based on the price set out power purchase agreement between him/her/it and the supplier which must be equal to either
    - the rates established in the applicable non-discriminatory contract or tariff that the commission has approved for being consistent with the contract or tariff that would have applied in the absence of net metering, or
    - a higher rate agreed to by the parties
- the customer generator must pay the nonusage sensitive charges

20 VAC § 5-315-50: Special rules govern the compensation of customer generators for their net excess generation at the end of a net metering period when the distribution company involved is also the electric energy supplier

- Investor-owned electric distribution companies with retail service territories within a PJM Interconnection, L.L.C. (PJM)load zone shall pay a price equal to one of the following:
    - The zonal day-ahead annual simple average locational marginal price (LMP) for the most recent calendar year ending on or before the end of each net metering period
    - A mutually agreed to price higher than the applicable PJM load zone LMP
    - A price established by the commission after notice and hearing
- Investor-owned electric distribution companies with retail service areas outside of any PJM load zone shall pay a price equal to one of the following:
    - The system-wide PJM day-ahead annual simple average LMLP for the most recent calendar year ending on or before the end of each net metering period
    - A mutually agreed to price higher than the applicable PJM load zone LMP
    - A price established by the commission after notice and hearing
- Cooperative distribution companies shall pay a price equal to one of the following:
    - The simple average of the cooperative distribution company's hourly avoidable cost of energy, including fuel, based on the energy and energy-related charges of its primary wholesale power supplier for the net metering period

- A mutually agreed to price higher than the applicable PJM load zone LMP
- A price established by the commission after notice and hearing

Washington

Legal Sources

Wash. Rev. Code Ann. (WRCA) §§ 80.60.005, .010, .020, .030, .040;

Wash. Admin. Code (WAC) §§ 480-108-001, -010, -030(1), (4)(a), (b), -40(1), (2), (6), (7)(a), (b), (9)-(15), -055, -065, -080, -090(1), (2)(a)-(e), -100, -120

Covered Utilities

There is a difference between the net metering statutes and net metering regulations as to which entities are required to offer net metering services:

- WRCA §§ 80.60.010(3), (5), .60.20(1): require a variety of entities that are engaged in distributing electricity to retail electric customers to provide net metering services, including:
  - Investor owned electrical companies
  - Public utility districts
  - Irrigation districts
  - Port districts
  - Electric cooperatives
  - Municipal electric utilities
- WAC §§480-108-010(definition electrical company), -040(7) require investor owned electrical companies engaged in generation, distribution, sale or furnishing of electricity within the jurisdiction of the Washington Utilities and Transportation Commission to offer net metering services
- So, the difference is that
  - The statutes impose the net metering mandate only on entities that are engaged in generating and distributing electricity
  - The regulations seem to impose net metering mandates on entities that do not engage in both generation and distribution
- WRCA §§ 80.04.010(definition of Electric Company): electric companies are investor or municipally owned entities that own, operate or manage electric plants for hire and do not include the following:
  - railroad or street railroad companies that generate electricity

        - for own use
        - use of their tenants
        - but not for sale to others
    - companies or businesses that are not themselves electric companies that employ cogeneration facilities to generate electricity
        - for own use
        - use of their tenants
        - for sale to various entities (electric companies, state or local public agencies, municipal corporations, or quasi municipal corporations) that sell or distribute electrical energy
        - but not for sale to others

Covered Customers

WRCA §§ 80.60.010(2), (10)(b)-(d), .020(1)(a): users of qualifying net metering

- located on their premises
- operated in parallel with transmission and distribution facilities of electric utilities required to offer net metering service
- intended primarily to meet all or part of their electricity requirements

Qualifying Technologies:

WRCA § 80.60.010(10), (14): qualifying net metering systems produce electricity from

- fuel cells
- facilities that also produce used and useful thermal energy from a single source
- facilities that have renewable energy sources such as
    - water
    - wind
    - solar energy
    - biogas from animal waste

Capacity Limits-Individual Facility

WRCA § 80.60.010(10)(a); : $\leq$ 100 kw

Capacity Limits-Aggregate

WRCA § 80.60.020(1)(a); WAC § 480-108-040(11): aggregate capacity limits:

- total capacity for all types of qualifying net metering services
  - through 2013—0.25% of each electric utility's 1996 peak demand
  - 2014 and thereafter—0.5% of each electric utility's 1996 peak demand
- Renewable electric power quota—≥ 50% of the utility's total net metering capacity

WAC § 480-108-040(11): aggregate capacity limits imposed on customer-generators receiving net metering service from investor-owned electric companies to ensure safe and reliable operations

- For qualifying net metering systems connected to an individual distribution feeder—10% of the distribution feeder's peak capacity
- Additional capacity limits may be imposed on qualifying net metering systems when necessary to insure safe and reliable operations of any feeder, circuit, or network to which they are interconnected

Time Limits

None

Billing Rules

General Rule:

The general rule is not a clear; it appears that that customer-generators are to be treated the same way as non-net metering customers who are in their same rate class, but it is unclear how customer-generators are assigned to a rate class and whether the billing rates and structures of those rate classes govern how customer generators are billed for net excess consumption.

- WRCA § 80.60.020(1)(c) customer-generators are to be charged the minimum monthly fees that are charged other customers within their rate class
- WRCA § 80.60.030(2): specifies that when customer-generators consume more electricity received from the electric utility than they generate and feedback to the electric utility they are to be billed for net excess consumption in accordance with normal metering practices—presumably at a rate equal to the rate per kwh charged to other customers within the same rate class that do not net meter although the statute does not say this directly
- WRCA §§ 80.60.020(1)(c), .030(3)(a): specify that when customer-generators generate and feed more electricity to the electric utility than the electricity

they receive and consume from the utility, they shall pay customer charges equal to those applicable to other customers within their rate classes

Other Costs, Revenues:

WRCA § 80.60.020(1)(c)(i), (ii); WAC §§ 480-108-040(13), -065: net metering interconnection and administration costs may be imposed on customer generators if they are > benefits net metering provides the entire customer base

There is some ambiguity in the net metering statutes and regulations about other costs and revenues to be borne or received by customer generators, as follows:

- With respect to meters needed to facilitate net metering
    - WRCA § 80.60.020(1)(b): implies, but does not state, that electrical utilities bear the costs of a standard kwh meter capable of registering bi-directional electricity flows
    - WAC § 480-108-040(7)(a): states that regulated electrical companies bear the costs of kwh meters capable of registering bidirectional electricity flows
    - WRCA § 80.60.020(1)(b)(i), (ii): Allocation of the costs of other types of meters needed to facilitate net metering is left to further determination by the appropriate regulatory body
    - WRCA § 80.60.020(2); WAC § 480-108-040(7)(b): costs of production meters and other equipment needed to facilitate meter aggregation for net metering purposes are to be borne by the customer generator
- WRCA § 80.60.020(1)(c)customer-generators are
    - to be Charged a the same monthly fee charged to non-net metering customers within their rate classes
    - not to be charged any additional
        - standby charges/fees
        - capacity charges/fees
        - Interconnection charges/fees, or
        - other charges/fees
- However, with respect to the costs of meeting applicable safety, power quality, and interconnection requirements
    - WRCA § 80.60.40(1), (2): imposes these costs on customer generators

- WAC § 480-108-040(12): makes the customer generator responsible for protecting its net metering system and equipment and complying with all applicable standards, codes, statutes and authorities
- WAC § 480-108-040(13):
  - imposes on customer generators the reasonable costs of initial interconnections
  - but then states that these costs can be spread among other ratepayers if it can be shown that the requested interconnection service will produce quantifiable benefits to other customers
- WAC § 480-108-040(6): customer generators must bear the costs of installing dedicated distribution transformers if they are needed to insure reliable service to other customers unless the quantifiable benefits to others rule applies
- WAC § 480-108-030(4)(a), (b): imposes an interconnection application fee on customer generators in the amount of
  - $\leq$ $100 for facilities with capacities $\leq$ 25 kw
  - $\leq$ $500 for facilities with capacities $\geq$ 25 kw and $\leq$ 100 kw
- WAC § 480-108-040(10), (14): customer generators are to bear the costs of subsequent upgrades to generation and interconnection facilities necessitated by modification of the electrical companies' electric systems, government regulations, or industry standards
- WRCA § 80.60.40(3): exempts customer generators who meet all applicable safety, power quality and interconnection requirements from the costs of
  - complying with additional safety or performance standards
  - performing or paying for additional tests
  - purchasing additional insurance
- WAC § 480-108-040(9): reinforces the no additional insurance requirement

Billing for Net Excess Consumption (NEC):

WRCA § 80.60.030(2):

- Defines net excess consumption as the positive difference between
  - Electricity consumed by customer generators that they received from the electric utility, and

  - Electricity generated by the customer generator that they fed back to the electric utility

- specifies that customer-generators are to be billed for net excess consumption in accordance with normal metering practice

- but fails to specify the rates customer generators are to be charged (presumably they are governed by the tariffs or contracts applicable to other customers within the customer generators' rate class rate that do not engage in net metering)

Billing for Net Excess Generation (NEG)

WRCA § 80.60.030(3): defines net excess generation in an ambiguous way:

- Its language seems to say that net excess generation is the positive difference between
  - Electricity generated by the customer generator, and
  - Electricity supplied to the customer generator by the electric utility
- As a consequence, net excess generation is too large unless, despite the statutory language, it means the positive difference between
  - Electricity generated by the customer generator that is fed back to the electric utility, and
  - Electricity supplied to the customer generator by the electric utility

Customer generators receive credit for their net excess generation as follows:

- WRCA § 80.60.030(3)(b): customer generators receive a kwh credit for their net excess generation
- WRCA § 80.60.030(3)(b): the credit is applied to the following billing period
- It is not stated explicitly that the net excess generation credit is applied to successive billing periods, but this can be implied from the fact that there is a year-end reconciliation of all net excess billing credits, as follows:
- At the end of a fiscal year ending April 30, unused net excess generation kwh credits are awarded
  - To the electric utility
  - Without compensation to the customer generator