2013 RPS Legislation: Gauging the

Despite challenges in many states, 2013 has been a year of progress for renewable portfolio standards.

Renewable portfolio standards (RPSs) have long served as a key driver of state-level renewables markets. Lawrence Berkeley National Lab has projected that if full RPS policy compliance is achieved in all states with such policies currently on the books, 93,000 megawatts (MW) of new renewables will be added to U.S. grid by 2035.[1]

For several months in 2013, efforts to scrap or diminish RPS policies held the national spotlight, with numerous media forecasting a grim outlook for these policies. However, as of September, only seven states had enacted legislation to amend their RPS policies, and in our judgment, 2013 is yet another year of overall RPS policy advancement. For descriptions of RPS legislation introduced in 2013, see our April 2013 report.[2]

Our assertion requires some justification. This article profiles 11 bills enacted in seven states in 2013, with an emphasis on quantifying the changes made, including the amount of additional new renewables required and the amount of existing resources newly qualified for the standard. Because RPS policy implementation is rooted in supply and demand, we've grouped these bills into two general categories: those that primarily affect demand for renewables (e.g.,

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Impacts

SWEDISH WIND FARM BY TOMASZ SIENICKI

By **JUSTIN BARNES** and **CHELSEA BARNES**

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Maryland's H.B. 226, with a carve-out for offshore wind power, could support up to 1.6 million megawatt-hours (MWh) of new wind generation in 2017 and beyond, equivalent to 450 to 500 MW. However, PSC analysis of cost limitations suggests a likely maximum of 725,000 MWh, equivalent to roughly 210 MW of new offshore wind.

establishment of new targets, reductions in targets), and those that primarily affect supply (e.g., resource or renewable energy credit eligibility).

Demand-Side Changes

The most significant impacts of demand-side legislative changes in 2013 involve new requirements in Colorado, Maryland and Minnesota, as indicated in table 1 on page 18. The collective new benchmarks appear likely to eventually support more than 1,000 MW of additional renewables, including more than 500 MW of additional solar. The actual figures will depend on several factors, such as load growth, resource mix (as it influences capacity estimates), the use of compliance multipliers and the triggering of cost caps. Moreover, these impacts will not be wholly state-specific. For instance, the impact of Maryland's offshore wind carve-out

1 http://www.cleanenergystates.org/assets/2012-Files/RPS/RPS-SummitDec2012Barbose.pdf

2 http://www.kfwlaw.com/wp-content/uploads/2013/09/RPS_Legislation_KFW_Apr2013_sm.pdf

ALEC's efforts to repeal state RPS laws flopped in 2013. It's now drafting two new model bills for the 2014 legislative session that aim to diminish RPS policies.

TABLE 1 **Demand-Side Changes to State RPS Policies in 2013**

Bill	Changes to Law	Potential Impacts
CO S.B. 252	• Effectively raises the RPS for co-ops from 10% to 20% by 2020. • Establishes a distributed generation (DG) carve-out of 1% for co-ops with 10,000 or more customers and 0.75% for smaller co-ops; 50% of the carve-out must come from customer-sited systems. • Allows coal-mine methane and certain municipal solid waste (MSW) pyrolysis to qualify for the RPS. • Expands cost cap from 1% to 2% for co-ops. • Eliminates in-state resource preferences. • A separate executive order establishes an advisory committee that will evaluate the effectiveness and feasibility of the new law.	**Overall RPS**: 1.3 million MWh of additional renewables generation required by 2020 (i.e., approximately 430 MW, assuming an average capacity factor of 35% for wind). Impact of coal-mine methane and MSW pyrolysis uncertain. **DG**: 150,000 MWh of DG generation required by 2020, including 75,000 MWh from customer-sited systems (i.e., approximately 120 MW for larger co-ops and approximately 60 MW for larger co-ops, assuming an average capacity factor of 15% for solar).
MD H.B. 226	• Creates an offshore wind carve-out of up to 2.5% by 2017, reducing the requirement for other Tier 1 resources by an equivalent amount. • Establishes various cost-containment measures and protocols for approval of qualified resources.	**Offshore Wind**: Could support up to 1.6 million MWh of new offshore wind generation in 2017 and beyond, equivalent to 450-500 MW. However, PSC analysis of cost limitations suggests a likely maximum of 725,000 MWh, equivalent to roughly 210 MW of new offshore wind. **Other Tier I Resources**: Reduction in MWh requirement equivalent to any offshore wind contribution.
MN H.B. 729; S.B. 1057	• Establishes PV carve-out of 1.5% by 2020 for IOUs, of which 10% is required from customer-sited systems up to 20 kW. • Establishes related PV incentives, including a general statewide performance-based incentive (PBI) for systems up to 20 kW; a separate rebate for systems using Minnesota-made components for systems up to 40 kW; and a Value-of-Solar Tariff (VOST). • Explicitly assigns REC ownership to the utility for the Minnesota-Made incentive and the VOST, but not for net metering or the statewide PBI.	**PV**: 450 MW of new PV generation, of which 45 MW would be required from systems up to 20 kW.
MT S.B. 164	• Exempts from the RPS utilities serving 50 or fewer customers.	**Overall RPS**: Exempts Avista and Black Hills Power from the RPS, reducing the amount of renewable generation needed under the standard by 0.7% (approximately 5,100 MWh out of a total requirement of approximately 714,000 MWh in 2012).
MT S.B. 327	• Exempts from the RPS competitive suppliers serving four or fewer customers.	**Overall RPS**: Exempts Conoco-Philips from the standard, reducing the amount of renewable generation needed under the standard by 1.7% (roughly 12,350 MWh out of a total requirement of 714,000 MWh in 2012).
WA H.B. 1222; S.B. 5297	• Creates an additional alternative compliance method for utilities that have purchased only coal transition power since Dec. 7, 2006.	**Overall RPS**: Potentially reduces the amount of renewables generation required by giving Puget Sound Energy and any new purchasers of Centralia Coal energy an alternative compliance method that does not involve additional purchases of renewables. The ultimate impact is uncertain.

will depend on what can be achieved within the associated ratepayer impact limitations, and whatever is achieved will reduce demand for other Tier I resources in the state, which affects available supply on a regional level. Minnesota's new solar carve-out is unclear on whether existing and out-of-state resources qualify and how some other programs authorized in the legislation will operate within the context of RPS (i.e., renewable energy credit, REC, ownership). The outcomes, when determined, could have both state and regional implications for solar development. Legislation enacted that had the effect of reducing existing RPS policies was generally minimal in impact (e.g., in Montana), although the impact of Washington's legislation is difficult to predict.

Supply-Side Changes

Like demand-side RPS changes, supply-side RPS changes often have regional rather than state-specific impacts and in some cases involve an amount of uncertainty. Connecticut's RPS bill is probably the best example of both interstate connectedness and uncertainty; each individual provision has implications for regional supply and demand, and some important details (e.g., the strategy for a migration away from existing biomass and landfill gas dependence) are undetermined. The same could be said for RPS amendments enacted in Nevada, where it is uncertain whether utilities will be able to sell excess credits, and in Montana, where it is unknown to what extent the RPS amendments will stimulate hydropower expansions. Table 2 (facing page) outlines the changes and impacts of supply-side legislation enacted in 2013.

None of the enacted supply-side bills seems destined to have an immediate, significant or detrimental impact on renewables as a whole. On the contrary, the potential negative impacts likely will be small (e.g., the qualification of treated wood as biomass in Montana), while other changes have either generally positive implications, or represent accommodations that are not necessarily unreasonable or detrimental in the context of furthering renewables development. For solar specifically, we believe that the impacts are almost entirely positive, providing potential financing support for grid-supply projects in

New England, and at least slightly better opportunities for solar growth in Nevada.

2013-2014 Legislative Outlook for RPS Policies

Although most state legislatures have closed up shop for 2013, a few RPS bills could see action in the 10 state legislatures still in session. A total of six "weakening" bills are still in play in Ohio, Wisconsin, Pennsylvania and California; we consider Ohio's RPS repeal bill (S.B. 58) the most likely to see any real action. Ten "strengthening" bills remain in committee in Pennsylvania, New York, New Jersey, Michigan, Massachusetts and the District of Columbia (D.C.); the D.C. bill (B20-0418) to eliminate black liquor and other forms of biomass as eligible resources is the only such bill under active consideration.

Looking forward to 2014, it is almost certain that legislators will continue to debate and tinker with RPS policies. However, activity might be muted because in many states, even-year legislative sessions are less active than odd-year sessions, and some states (such as Montana and Texas) are not scheduled to convene at all in 2014. In addition, it is expected that many of the unresolved issues in 2013 will be carried forward for discussion in 2014, especially in the 25 states (and D.C.) that carry over legislation from odd-year sessions to even-year sessions.

The American Legislative Exchange Council (ALEC), which has been credited with (and discredited for) stirring up several RPS repeal efforts in 2013, has been busy drafting two new model bills for the 2014 legislative session that aim to diminish state RPS policies. Although ALEC's efforts to repeal state RPS laws flopped in 2013, it appears that the organization is converting its strategy for 2014 to an approach that sounds (at least superficially) less "anti-renewables." Together, the two new model bills — the Market-Power Renewables Act and Renewable Energy Credit Act — would phase out RPS requirements, replace them with voluntary markets, expand the types of energy that would qualify as renewable, remove caps on the amount of RECs that may be used for compliance, and allow bulk purchases of RECs to be used for compliance in advance of future requirements. Thus, the new model bills amount to a change in branding and design, but with the same underlying intent.

It is very likely that further legislative efforts to repeal, freeze or otherwise dismantle RPS policies will continue in 2014, and that at least some of these efforts will contain provisions inspired by ALEC's model bills. For instance, we consider it very likely that bills seeking to expand resource definitions to include large or existing hydropower will crop up in states such as Maine and others that saw similar efforts during 2013. However, while predictions of legislative outcomes are always speculative, we do not see any compelling reasons suggesting that 2014 outcomes will be much different than 2013 outcomes. We expect states to continue making measured revisions that generally portend positive impacts on renewables development. **ST**

TABLE 2 **Supply-Side Changes to State RPS Policies in 2013**

Bill	Changes to Law	Potential Impacts
CT S.B. 1138	• Increases size limit of small hydro from 5 MW to 30 MW for Class I resources and removes river-flow impact limitation. • Gradually reduces REC values for biomass and landfill gas. • Prohibits REC double-counting for out-of-state resources. • Sets conditions and limits for large hydro qualification as a Class I resource. • Establishes long-term contracting programs for new and existing Class I resources (up to 4% of retail load each).	**Small Hydropower**: Qualifies an estimated 70 MW of existing hydropower in New England as a Class I resource. **Out-of State Resources**: Disqualifies an estimated 21.6 MW of existing resources in NY and prevents qualification of more than 20 MW of resources in VT. **Biomass/Landfill Gas**: Reduction strategy hasn't been determined, but could affect approximately 350 MW of existing facilities currently qualified as Class I resources. **New Class I Contracting**: Per a July 2013 RFP, 174 MW (525 MW of wind capacity) under long-term electricity and/or REC contracts, limited to facilities 20 MW or larger in aggregate.
MT S.B. 325	• Revises the definition of eligible biomass to allow chemically-treated wood to qualify as a renewable resource.	**Non-Biomass Renewables**: Could experience reduced opportunities under the standard, but the actual impact is unknown. Currently, no utilities are using biomass to comply with the RPS, and no biomass facilities exist in MT.
MT S.B. 45	• Allows incremental generation from expansions of existing hydropower facilities that commence construction after Oct. 1, 2013, to qualify for the standard.	**Non-Hydro Resources**: Could experience reduced opportunities under the standard, but the impact is unknown. Montana has more than 2,700 MW of hydro capacity; a large base exists for potential expansions, although much of it is federally owned.
NV S.B. 252	• Eliminates the current 2.4-multiplier for PV for facilities constructed after 2015. • Limits energy efficiency to 25% of standard in 2013 and 2014; 20% for 2015-19; 10% for 2020-24; and none thereafter. • Establishes separate protocols for utilities to sell excess RECs where the surplus exceeds 10% and 25% of the subsequent year's compliance requirement.	**Energy-Efficiency Phase-Out:** Results in approximately 8 million to 9.5 million MWh of additional renewables generation required through 2025. Coupled with compliance requirement increases, could impact solar by forcing utilities to use solar credits to meet the general renewables requirement. **Excess Credit Sales:** If credit sales take place, they will likely be most impactful for the solar tier, which has a larger expected surplus in relation to compliance requirements than the general renewables tier. Sales are unlikely to impact utility use of efficiency for compliance because excess credits may be difficult to sell and utilities will unlikely need to utilize past surpluses under the reduced allowances for efficiency under the standard.
WA S.B. 5400	• Allows utilities that serve retail customers in other states to use owned or contracted generation from renewables facilities (except hydropower) in those states to meet the WA RPS.	**Overall RPS:** Effectively increases the renewables supply available to PacifiCorp. In practice, it will allow 1,133 MW of PacifiCorp's wind resources in eastern Wyoming to qualify for the RPS. Previously, these resources would have qualified only if the electricity was delivered into WA on a real-time basis.

Policy: Solar for Everyone?

By Kathie Zipp | April 5, 2012

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Solar for Everyone? *Not yet — but we just might be headed in the right direction.*

By: Justin Barnes, Senior Policy Analyst at the North Carolina Solar Center

Discussions of state solar policy frequently revolve around the costs and benefits associated with particular approaches and few would dispute that an analysis of these broad considerations is an essential step in the formulation of any public policy.

However, gross costs and benefits are not the entire picture. The distribution of costs and benefits is an equally important consideration, and finding the proper balance is intensely challenging for policymakers. “Solar for everyone” has a nice sound, but it is easier said than done.

To illustrate how the equity dilemma can play out in practice, let’s consider a hypothetical cash incentive program where funds are raised from electricity ratepayers. The ratepayers pay a surcharge of some type (e.g., a societal benefits charge, an RPS rider, etc.) on their bills, which is then used to pay the incentive.

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The presumption behind a blanket surcharge on all customers is that these same customers all stand to benefit from the resultant program in some way. However, the most tangible benefits accrue only to those who are able to participate in the program; for a variety of reasons, most customers are not able to do so.

Renters or lessees, for instance, are frequently not able to participate in solar incentive programs. Other customers who do own a residence or a building may not have an appropriate site for solar as a result of extensive shading, unfavorable roof orientation or restrictions on how structures may be modified (e.g., zoning rules, private covenants, and historic structure status). Still others may not be able to afford the cost of a solar installation even with an incentive. Similar criticisms exist for other support mechanisms, including tax incentives and net metering, ultimately giving rise to the accusation that solar benefits only a select few at the expense of the larger populace.

There are, of course, counterarguments to this assertion, as well as policy solutions that can help rectify inequities where they do exist. For instance, one can argue that the environmental benefits of solar accrue to society as a whole rather than any individual, and that economic development and job creation benefit a diverse group of individuals and businesses. On the policy side, solar access laws, low-income programs, community solar programs, and laws that allow third-party ownership structures can make solar a viable option for those that would not have otherwise had the opportunity.

Unfortunately, though, in reality there is no such thing as a perfect distribution of benefits and costs, and the scenario described earlier barely scratches the surface of important policy questions. For instance, should development be aligned with the location of ratepayer collections or focused on locations where benefits are the greatest (e.g., areas of grid congestion)? What is the proper balance of customer-sited vs. utility-scale generation? Should utilities be able to own solar assets on customer rooftops? If so, does this reduce customer-owned opportunities, and should non-utility solar service providers be extended this same opportunity?

The solar policy landscape is rife with such issues, and stakeholder consensus is hard to come by. On the other hand, the increasing diversity of the U.S. solar market suggests that a combination of policy evolution and private sector innovation is moving the industry towards more opportunities for more stakeholders. So solar for everyone? Not yet — but we just might be headed in the right direction. **SPW**

THE INTERSECTION OF NET METERING & RETAIL CHOICE

An Overview of Policy, Practice, and Issues

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Introduction

Net metering is one of the most important, least-cost policies by which owners of solar photovoltaic (PV) or other renewable systems may recoup their energy investment. This policy essentially allows a renewable energy system owner to bank excess kilowatt-hours (kWh) on the electric grid when the system is producing more energy than needed on-site and to use those kWh at a later time. In regulated markets, with only one utility interacting with one customer, this is a relatively straightforward process. In retail choice markets, however, the process can be slightly more complex because there are more parties that must communicate in order for a customer to be appropriately compensated for excess energy. As a result, net metering in restructured states has traditionally not been well understood. This paper is designed to delineate the policy structures and the communication paths necessitated by net metering in retail choice markets.

Each retail choice state operates differently in regard to net metering, but the key players in each state are generally the same: competitive suppliers that provide energy, distribution utilities that deliver the energy, and end-user customers, all operating in a functioning competitive energy market (the *Definitions* section, found at the end of this paper, provides some further descriptions of the roles of these players). To better understand the complexity of wholesale markets, it is important to bear in mind the relationships and paths of communication among these players. Most relationships center on the competitive supplier as it generally maintains communication with other players—in particular, the customers and the utilities—within the wholesale energy market.

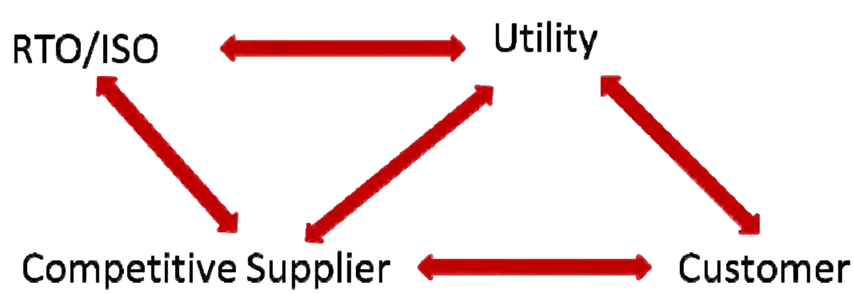

Figure 1: Simplified diagram of key stakeholders in restructured markets and the relationships among them.

Many restructured states have yet to see a significant number of retail choice customers with net metered systems, despite the fact that several of these states have some of the best net metering policies in the country.[1] This is likely due to a number of reasons, including the relative novelty of these policies and the large electric load of most retail choice customers, which is often greater than the allowable system size limits for net metering. States may need to clarify several provisions in their regulations in order to see a widespread adoption of net metering. For example, would a customer need to break an existing competitive supply contract in order to net meter and if so, are there fees associated with that? What does non-discrimination mean regarding competitive supplier obligations toward net metering? And how exactly should a state regulatory commission stipulate netting practices between a utility and competitive supplier? These and other questions illustrate the need for more information and clarity in state rulemaking procedures going forward.

By studying the different facets of crediting mechanisms, we were able to define five theoretical models describing different ways competitive suppliers and utilities provide net metering options for their customers. Following these models we provide case studies to illustrate the models, a brief discussion of unresolved policy concerns, and initial recommendations based on our research up to this point. The main purpose of this paper is to define the current methods of providing net metering in restructured states and to set the stage for further discussion that may later inform best practices around net metering in retail choice markets.

Electricity Competition

The electric industry is essentially a sum of its component pieces: production, transmission, distribution and customer service. Traditional, vertically integrated electric companies incorporate all four of these components. In the early 1900s, the U.S. Congress proclaimed that such electricity companies had a "natural monopoly" in any given geographic area and that these utilities were providing a public service. In return for their monopoly status, public utilities were, and continue to be, regulated by government entities.

However, in the wake of the energy price shocks of the 1970s and early 1980s, policymakers began to question the efficiency of such a highly regulated system. The federal Public Utility Regulatory Policies Act of 1978 (PURPA) marked the beginning of the deregulation movement in the United States. Deregulated or restructured markets generally require public utilities' traditional functions to be split among several companies or different arms of the same company. In particular, PURPA allowed non-utilities to construct, operate and own power plants, and it required utilities to purchase the energy generated by these facilities.

In the early 1990s some states started pushing electricity sales onto the open market by allowing competitive companies (suppliers) to provide electricity, and utilities to continue

[1] Freeing the Grid 2010: http://www.newenergychoices.org/uploads/FreeingTheGrid2010.pdf

providing billing and transmission or distribution services. One of the more comprehensive studies on this topic, *Alternating Currents: Electricity Markets and Public Policy*, succinctly describes the nature of such competitive markets:

> "…a broad consensus has emerged that a line should be drawn between the potentially competitive segments of the electricity industry and those that should remain regulated for the foreseeable future. To oversimplify a bit, that consensus would retain regulation of the 'wires' side of the business—local distribution and long-distance transmission—while extending competition to the 'energy' side of the business—the generation and marketing of electricity."[2]

While it seems like there may be an inherent conflict of interest between utilities and competitive suppliers in a restructured market, the federal government has set up a system to provide oversight and to ensure equal access to transmission services. In the mid-1990s, the Federal Energy Regulatory Commission (FERC) issued guidelines for the implementation of Independent System Operators (ISOs) that would oversee utility-owned transmission lines and prevent discrimination against competitive suppliers.[3] FERC then created Regional Transmission Organizations (RTOs), as an extension of ISOs, to monitor grid reliability, security, non-discrimination and other important aspects of an increasingly complex electric system.

State regulatory commissions do not directly regulate competitive suppliers. However, suppliers must be certified by the commission, and must comply with reporting and other obligations. If a competitive supplier fails to operate according to consumer protection and other laws, the state regulatory commission could revoke the supplier's certification, which would make the supplier ineligible to provide electric service to customers in that state. In this sense, state regulatory commissions have power over suppliers, but not in the same manner as regulated utilities in non-restructured states.

States with restructured electricity markets are predominant in the New England, Mid-Atlantic, and Midwest regions. This paper focuses on states in these regions as well as Texas, which is fully competitive, and California, which re-introduced competition (referred to in California as "direct access") in 2009. Due to wide variation in state policy, there is no standard approach to competitive electricity markets. For example, customer billing can be achieved through separate bills from the competitive supplier and utility, or through consolidated billing, where either entity can issue the bill. Moreover, variation in state net metering policies adds an additional layer of complexity. This paper describes as clearly as possible the different approaches to net metering adopted by the states we researched, and the implications of those approaches.

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[2] Brennan, et al., pg 62.

[3] 1996 FERC Order 888, available at http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp

Structure of research

For this paper, we reviewed 15 states and the District of Columbia.[4] Oregon and Virginia previously allowed retail choice but restructuring has since been suspended so we chose not to include those in the study. For this research we began with a review of state rule definitions regarding net metering applicability. Specifically, our research encompassed the following issues:

1. Definition of utility;
2. Definition of customers who are eligible to net meter;
3. Whether or not suppliers are required to offer net metering;
4. Whether distribution charges are netted for retail choice customers;
5. Whether there is a separate rate option for competitive suppliers;
6. Safe harbor or non-discrimination clauses for net metering customers;
7. Allowed meter configuration for customers (bi-directional, dual, etc.);
8. Billing arrangements by competitive suppliers;
9. How monthly rollover is conducted;
10. Monthly and annual rollover rate; and
11. Any charges that net metering customers might face.

We followed this review with discussions with legal experts, competitive suppliers and regulatory commission staff in these states to answer additional questions. We then grouped states into categories and determined what general types of net metering configurations are possible, given states' experience thus far. We present these configurations as possible scenarios which we call 1) Utility-Side Netting, 2) Dual-Bank Netting, 3) Partial Netting Arrangement, 4) Hybrid Netting, and 5) No-Netting. Each scenario presents a different paradigm of how net metering works by showing how a customer is compensated, and how utilities and competitive suppliers communicate under that scenario. Following this discussion, we provide examples from state policies that illustrate these scenarios. By examining the different types of compensation mechanisms and how they operate, we can gauge the extent to which stakeholders might embrace net metering and the alterations that might be considered to improve the playing field for distributed generation.

Based on initial research, Table 1 presents an abbreviated view of net metering in each state.

[4] California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas and Washington D.C.

State	System Size Cap	Supplier Required to Offer NM?	Applicable Scenario	Monthly Carryover Rate
California	1 MW (10 MW for 3 biodigesters)	No	Dual-Bank, if supplier offers net metering[5]; likely Partial Netting otherwise	Monetized credit based on full retail rate
Connecticut	2 MW	Yes	Utility-Side Netting	1:1 kWh credit
D.C.	1 MW	No	Dual-Bank Netting	Retail for 100 kW or less, generation rate for 100 kW - 1 MW.
Delaware	2 MW	Yes	Utility-Side Netting	1:1 kWh credit
Illinois	40 kW	Yes	Dual-Bank or Utility-Side Netting	1:1 kWh credit
Maine	660 kW	No	Utility-Side Netting[6]	1:1 kWh credit
Maryland	2 MW	Not Addressed	Currently Utility-Side Netting[7]	1:1 kWh credit
Massachusetts	10 MW for Government, 2MW for others	Not Addressed	Hybrid	Monetized credit, based on calculation (~ retail rate)
Michigan	150 kW	Yes	Utility-Side up to 20 kW	1:1 kWh credit
New Hampshire	100 kW	No	Unclear,	1:1 kWh credit

[5] If a competitive supplier does not offer net metering, net metering treatment many vary by utility. San Diego Gas & Electric indicates that it will offer Partial Netting but the authors were unable to obtain definitive responses from the other investor-owned utilities in California.

[6] In Maine, state law requires customers to receive a full kWh credit. The law is less clear regarding the obligation on the competitive supplier, stating that "customers that elect net energy billing may obtain generation service from any competitive electricity provider *that agrees* to provide service on a net energy basis." However, based on communication with a Central Maine Power (CMP) representative the utility practice is to provide suppliers with net energy information for billing purposes, which implies Utility-Side Netting and CMP's supplier contract (available at http://www.cmpco.com/MediaLibrary/3/6/Content%20Management/Suppliers%20And%20Partners/PDFs%20and%20Doc/ExhibitA012505.doc) also confirms this. CMP provides distribution for roughly 75% of retail sales in ME.

[7] A rulemaking underway in Maryland could potentially change this scenario.

			probably Partial Netting[8]	
New Jersey	Customer's average annual load	Yes	Utility-Side Netting	1:1 kWh credit
New York	2 MW	Not Addressed in rules	Utility-Side Netting	1:1 kWh credit
Ohio[9]	No specific limit	No	Hybrid or Partial (U)	unbundled generation rate
Pennsylvania	3 MW for commercial systems	No	Unclear, probably Partial Netting[10]	1:1 kWh credit
Rhode Island	3.5 MW	Not Addressed	Unclear, possibly Hybrid[11]	Monetized credit, based on calculation (~ retail rate)
Texas	Not allowed	No	No Netting	N/A

Table 1: Overview of net metering scenarios in retail choice states

Net Metering Methodology

It is potentially more complicated to provide net metering to a competitive supplier's customer than to a default or standard-offer service (SOS) customer. This is largely due to the difference in some cases between the competitive supplier's net metering obligation and those of the utility. The following section lays out a series of possible scenarios which describe how net metering might operate under different regulatory regimes. Several factors determine the applicability of a given arrangement to a competitive supplier's customer:

- The metering arrangement that provides customer usage data, upon which all transactions are based;

[8] New Hampshire state law previously required competitive suppliers to offer net metering. A recently enacted law in June 2010 (H.B. 1353), appears to reverse this provision and allow competitive suppliers to offer net metering at their discretion.

[9] Competitive suppliers in Ohio were previously required to offer net metering but legislation enacted in May 2008 (S.B. 221) removed the net metering obligation for suppliers.

[10] Pennsylvania state law requires customers to receive a full kWh credit. This potentially conflicts with the fact that Pennsylvania's net metering law clearly does not require competitive suppliers to net their charges. Based on conversations with utility personnel, there is not currently a single standard approach in use for addressing net metering for customers that choose a competitive supplier.

[11] Based on similarities between Massachusetts and Rhode Island statutes, a hybrid approach seems likely although this could not be definitively confirmed by the authors.

- The respective obligations of the competitive supplier and the utility to offer service on a net energy basis; and
- Whether net excess generation (NEG) in a billing period takes the form of a kWh credit or a monetary credit.

In some regimes multiple arrangements may be possible but not necessarily put into practice. For sake of clarity, we use the terms "Full Netting," "Utility-Side Netting," "Dual-Bank Netting," "Partial Netting" and "Hybrid Approach." To our knowledge these terms are not commonly used in the industry. It is also important to bear in mind that these scenarios are abstract in nature and only attempt to capture the general nature of the different crediting methods.

1. Full Netting Arrangements

Full Netting arrangements are circumstances in which competitive suppliers are either obligated to offer net metering or choose to do so voluntarily. We use the term Full Netting to describe situations in which the customer is charged only on net usage throughout a billing period and NEG compensation is provided in some form by both the supplier and the utility.

1.1 Utility-Side Netting

The Utility-Side Netting arrangement is appropriate if NEG for a billing period is carried forward as a kWh credit. Under this arrangement, net metering can be accomplished through the use of a single, bi-directional meter that records only net usage. Customers could also use a dual-register (or dual-meter) arrangement where values are separately obtained for gross imports from the grid and gross exports to the grid, but such an arrangement is not necessary. In the Utility-Side Netting arrangement, the utility can be seen as operating a "credit bank," and all netting of customer generation and consumption takes place before the competitive supplier receives any billing information from the utility.[12] Below we present four possible Utility-Side Netting situations:

> **Possibility I**: The customer enters a billing period with a zero balance on his electricity account. During the billing period, the customer imports a total of 1,000 kWh from the grid and exports a total of 900 kWh to the grid. The customer's net usage during the billing period is therefore 100 kWh. The utility would bill the customer for 100 kWh of distribution charges. The supplier would then charge the customer for 100 kWh of energy supply charges based on net usage information that the utility provided to the supplier.
>
> **Possibility II**: The customer enters a billing period with an electricity account balance of zero. During the billing period, the customer imports a total of 900 kWh from the grid and exports a total of 1,000 kWh to the grid. The customer therefore has NEG of 100 kWh for the billing period. The utility would not bill the customer for distribution

[12] Unless otherwise indicated, we assume that the customer receives separate bills from the utility for distribution charges and from the competitive supplier for energy supply charges. In most cases, there is no reason that a consolidated billing arrangement could not work in same fashion.

service. The supplier would then likely receive billing information from the utility indicating that the customer had zero net usage for the billing period; therefore, like the utility, the supplier would not bill the customer for energy supply charges. The utility would then deposit a 100 kWh credit into the customer's credit bank for use during future billing periods.

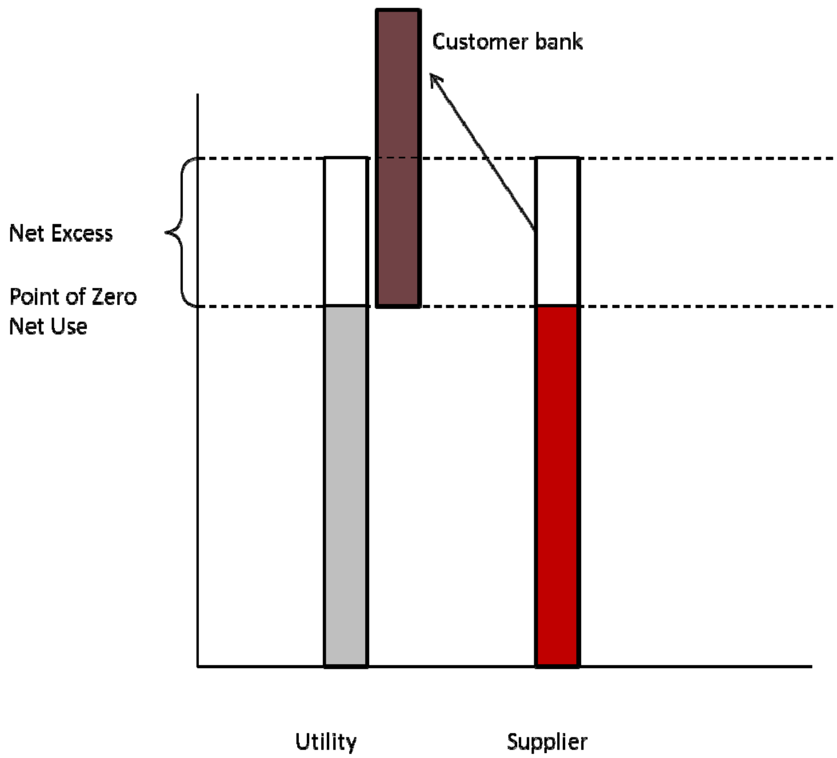

Figure 2: Full Netting, Utility-Side. Supplier and Utility both issue credits that go into a customer bank, operated by the utility

Possibility III: Following Possibility II above, the customer begins the billing period with an account credit of 100 kWh, and has net usage of 50 kWh over the course of the billing period. The utility applies the 100 kWh credit to the 50 kWh in net usage for the billing period, leaving 50 kWh remaining in the credit bank as NEG. The utility would not bill the customer for distribution charges for the billing period. Likewise, the supplier would not bill the customer for supply charges, after receiving billing information from the utility indicating that the customer had zero net usage for the billing period.

Possibility IV: Along these lines, if the same customer instead had net usage of 150 kWh for the billing period, the customer would be left with a balance of zero in the credit bank and with energy supply and distribution charges that apply to 50 kWh for the billing period.

The Utility-Side netting system functions regardless of how annual reconciliation of customer accounts takes place. If carryover is indefinite, then the banking process simply continues month-to-month, as described above. If annual NEG is forfeited, however, the customer simply enters the following year with an account balance of zero. Additional complications arise if annual NEG is compensated as something other than a kWh credit (e.g., a monetary credit at the energy supply or avoided cost rate), because the annual compensation then represents a partial rather than a full kWh credit, monetary or otherwise. This is problematic because it potentially allows the customer to accumulate two different types of credits on their account, one set for monthly kWh credits and another set for annual compensation.

One solution to this issue is to make the annual compensation a payment to the customer rather than a bill credit. Depending on state law, either the utility or the competitive supplier could provide this compensation. It may make more sense to place this responsibility on the competitive supplier, since these annual compensation rates typically reflect energy supply rates rather than distribution rates. However, the utility could just as easily undertake the annual compensation obligation, regardless of the compensation rate. One advantage to placing the obligation on the utility is that the utility may be better positioned to recover costs associated with any such payment (depending on state law). A final option is to allow compensation as a monetary account credit, but to allow the customer to use the credit to offset non-volumetric charges on the customer’s bill that may not be offset by kWh credits.

1.2 Dual-Bank Netting

The Dual-Bank Netting arrangement is similar to the Utility-Side Netting Arrangement in that both energy supply and distribution charges are based on net usage by the customer. In effect, both the utility and the supplier are netting their respective charges. The difference between this arrangement and the Utility-Side Netting arrangement is that the Dual-Bank arrangement relies on separate NEG banks for energy supply and distribution charges. Dual-Bank Netting can be accomplished using a single bi-directional meter as long as the utility can provide negative usage data and the supplier can accept such data. If not, then a dual-register metering system would be necessary.

This approach provides increased flexibility in net metering operation. By separating utility obligations from supplier obligations, competitive suppliers that offer net metering on their own terms (rather than those dictated by state law) have more flexibility to offer customized net metering contracts. Charges or credits that accrue on the distribution side, which are typically strictly determined by state law, can be addressed under separate terms. This separation also removes the potential that either the utility or the supplier benefits at the expense of the other due to the crediting procedures that exist. The customer meanwhile continues to receive the full benefits provided by net metering.

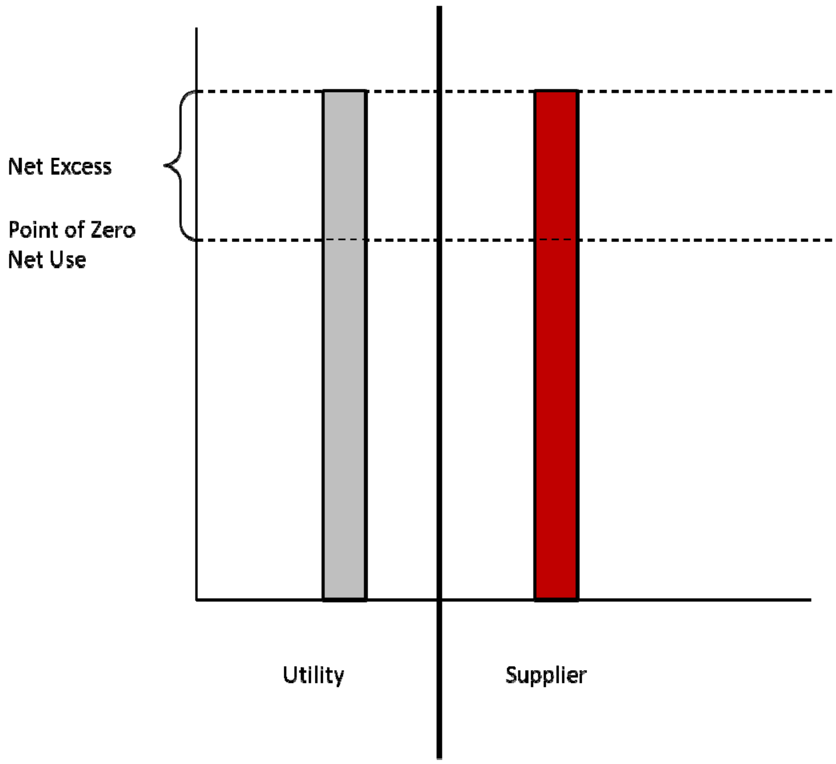

Figure 3: Full Netting – Dual Bank. Under this approach, both the supplier and the utility separately net their respective charges to the customer.

Due to variations in customized supplier contracts, we will not attempt to describe all of the potential outcomes of this arrangement. However, several key points about Dual-Bank Netting warrant discussion:

- Dual-Bank Netting may not be well-suited for consolidated billing arrangements where a utility bills for both energy supply and distribution charges and remits payments for energy supply to the supplier. If supplier net metering contracts necessitate complex calculations in order to arrive at the value of a NEG credit, it stands to reason that these calculations should be performed by the supplier rather than the utility.
- In contrast to the Utility-Side Netting arrangement described above, in order for Dual-Bank Netting to operate, NEG over the course of a billing period must be reported to the supplier as such. It cannot be reported as zero net usage because this would deprive the supplier of the information it needs to calculate a credit. If data from a dual-register meter is reported, the values for gross imports from the grid and gross exports to the grid must be clearly differentiated.
- Since the intermingling of distribution and energy supply charges is not permitted, NEG credits for distribution service should be determined as kWh distribution credits or as monetary credits at the actual distribution rate. This ensures that a customer of a competitive supplier is essentially on the same footing in terms of distribution netting as

a default or SOS customer who receives a retail kWh credit for NEG. Energy supply credits could be determined as kWh credits, but in that case, the simpler Utility-Side Netting system would achieve the same result as Dual-Bank Netting (i.e., combined kWh netting).

- Even states whose laws require competitive suppliers to offer net metering under specific terms could use Dual-Bank Netting. For instance, in some states net metering may act as a "rider" on any contract offered by competitive suppliers. In such states, simply netting out a kWh credit from a prior billing period for usage during a future billing period (as would happen in Utility-Side Netting) may not accurately reflect the terms of the contract. To put it another way, one kWh of export is not necessarily equivalent to one kWh of use at another time, depending on how the supply contract is structured. Rather than have a utility attempt to sort this out, it may make more sense to allow the supplier to operate the supply credit bank in a Dual-Bank Netting arrangement.
- The downside of Dual-Bank Netting is that it is more complicated than Utility-Side Netting. We are not aware of any specific technical barriers that would inhibit the function of this arrangement, but it is possible that the utility's or supplier's software is unable to process negative usage data. The advantages of a simpler, less flexible process might outweigh the added value of a more elaborate mechanism. It is also worth noting that Dual-Bank Netting could place competitive suppliers in a more active role as net metering program administrators.

2. Partial Netting Arrangements

Partial Netting arrangements refer to a situation in which a customer is supposedly permitted to net meter but is unable to obtain the full value of net metering because some charges are not based on net usage. A Partial Netting arrangement, as the name implies, is not net metering as the term is generally understood because it does not require the netting of both energy supply and distribution charges over the course of a billing period. This type of arrangement necessitates a metering system that tracks electricity pulled from the grid and electricity exported to the grid separately, as opposed to a single bi-directional meter that records only one value for net usage.

2.1 Partial Netting Arrangement: No Supplier Obligation

Under this scenario the utility is required to net distribution charges, but energy supply charges are not netted. Thus, in contrast to the Full Netting arrangements described above, the kWh values used for distribution billing are different than those used for energy supply billing.[13]

[13] This assumes that at some point during the billing period the customer is producing more energy than the customer is using on-site, resulting in an export of electricity to the grid.

Possibility I: The customer begins a billing period with an electricity account balance of zero and has a net usage of 100 kWh (e.g., exports 900 kWh and imports 1,000 kWh) over the course of the billing period. The utility bills the customer for distribution charges on 100 kWh. The utility reports the customer's gross usage of 1,000 kWh to the competitive supplier, which then bills the customer for 1,000 kWh in energy supply charges.

Possibility II: The customer begins a billing period with an electricity account balance of zero and has NEG of 100 kWh over the course of the billing period (e.g., exports 1,000 kWh and imports 900 kWh). The utility reports a gross usage of 900 kWh to the competitive supplier, which then bills the customer for 900 kWh in energy supply charges. The customer receives a zero bill for distribution charges from the utility and has his account credited for 100 kWh in NEG. Depending on state law, this credit could be carried forward as a kWh credit against distribution charges, or as a monetary credit.

Interestingly, in this situation, the monetary credit could in fact be determined at a rate other than the normal volumetric rate for distribution charges. In practice, one kWh of NEG during a billing period does not necessarily offset one kWh of net usage during a future billing period. This could benefit the generator if the compensation rate is higher than the distribution rate; however, because the supplier is not obligated to net its charges, the credit could only be used against future distribution charges.

Possibility III: Following Possibility II above, the customer enters a billing period with a monetary or kWh credit on their account equivalent to 100 kWh. During the billing period the customer imports 1,000 kWh from the grid and exports 950 kWh to the grid. The customer therefore has net usage of 50 kWh for the billing period. The utility reports gross usage of 1,000 kWh to the competitive supplier, which bills the customer for 1,000 kWh in energy supply charges. On the distribution side, the customer's bill would depend on the compensation rate used for NEG. If NEG is carried over as a distribution-kWh or equivalent monetary credit, then the customer would receive a zero bill for distribution charges and have a credit for 50 kWh (or the monetary equivalent) remaining in the account bank.

Possibility IV: Following Possibility III, in a situation where the customer has 150 kWh of net usage, the full 100 kWh credit would be eliminated and the customer would be billed for 50 kWh in distribution charges. If the compensation rate differs from the actual distribution rate, the customer would see a different result.

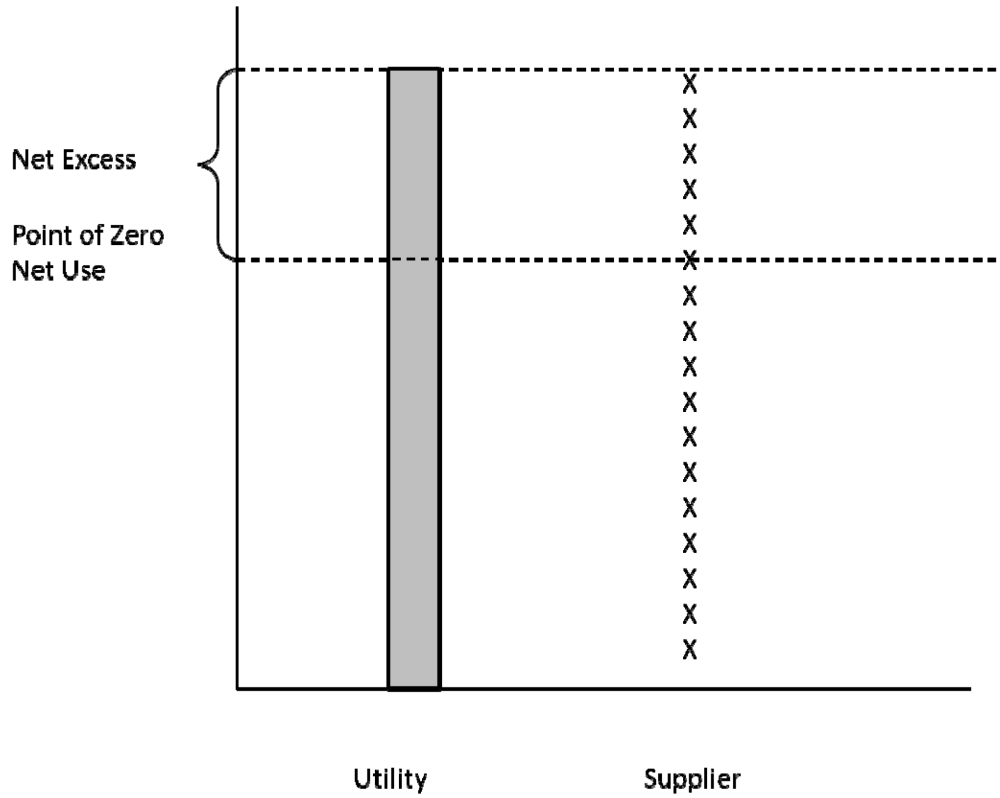

Figure 4: Partial Netting – No Supplier Obligation. In this arrangement, the utility nets all distribution charges but the supplier does not net any charges.

Logically, any annual reconciliation system under this Partial Netting arrangement would involve only the utility, since the competitive supplier does not have a netting or payment obligation. As noted above, if the monthly compensation rate and the distribution rate are different, the customer either over- or under-recovers distribution charges. In the under-recovery scenario (i.e., the compensation rate is less than the distribution rate) the customer is somewhat less likely to have a monetary credit left over at the end of an annual period. This would be particularly likely if a state's net metering law limits system size such that the system must be designed to serve expected annual on-site consumption (e.g., 110% of the previous year's kWh consumption). Most state net metering laws include some form of language to this effect so annual compensation practices are likely to be a non-issue for customers in this situation.

In the case of carryover at a distribution equivalent rate, or a rate that exceeds the distribution rate, annual reconciliation practices are more important to the customer. If excess credits are forfeited on an annual basis, the customer could be left with "stranded" or unusable credits, particularly in the over-recovery scenario. The same could be true if a state requires an indefinite rollover system. In either the forfeiture or the indefinite rollover scenario, the customer's ability to accumulate credits is greater than the customer's ability to use the credits against volumetric distribution charges. A customer could conceivably be a net electricity consumer over an annual period and still have excess credits that cannot be claimed. This is perhaps a reasonable outcome under the rationale that a customer who is a net energy consumer should not be entitled to compensation. However, if it is a goal of public policy to support distributed generation, it makes less sense to deprive a customer of this benefit, especially in light of the fact that the customer is not permitted to net energy supply charges under this arrangement. It is also somewhat contradictory to design a system that allows credits to accumulate, but that does not provide a mechanism for the customer to fully use them.

One potential solution to this problem would be to allow customers to use monetary credits to offset charges on any portion of the distribution bill, not just volumetric charges. Another solution would be to employ a mechanism for transferring unusable or unused credits onto another electricity account (i.e., “virtual net metering”).

2.2 Partial Netting Arrangement: No Utility Obligation

This arrangement is limited to circumstances in which the distribution utility is not required to net its charges, thereby placing any netting obligation on competitive suppliers. As with the Partial Netting, this arrangement does not qualify as a net metering policy because it does not require the netting of both distribution and energy supply charges over the course of a billing period. The outcomes of this arrangement from the perspective of the customer are structurally similar to those for the first Partial Netting arrangement so we will not repeat the possibilities here.

However, it is important to note that net metering has traditionally been an obligation placed on utilities rather than energy suppliers. We are not aware of any state that requires competitive suppliers to net their charges but does not require the utility to net its distribution charges. Thus, while it is possible to have a Partial Netting arrangement without a utility netting obligation, such a practice is not currently in use.

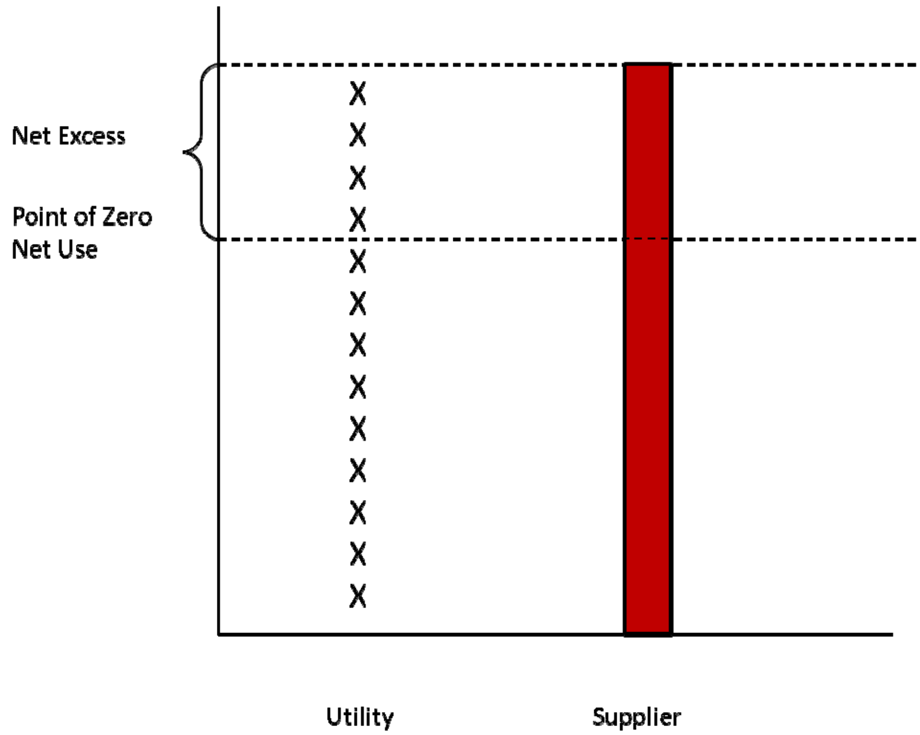

Figure 5: Partial netting, No Utility Obligation. Under this arrangement, the supplier nets supply charges but the utility does not net any distribution charges.

3. Hybrid Arrangement

The Hybrid arrangement combines aspects of the Full Netting arrangements and Partial Netting arrangements. As in the Partial Netting arrangements, either the supplier or the utility is not obligated to net its charges, but in the Hybrid arrangement the customer remains eligible for net metering. We assume the utility is obligated to offer net metering, as is true in most states. Hence the responsibility falls on the utility rather than the supplier in this arrangement. As described in the Full Netting arrangements, however, the Hybrid arrangement also uses a single bi-directional meter that only records net usage. This use of a single net meter is perhaps contrary to the premise that the supplier is not required to net its charges because it effectively mandates that the supplier's charges be netted up to the point of zero use over a billing period.[14] The Hybrid arrangement differs from the Full Netting arrangements in that the customer is compensated for NEG by the utility without any contribution from the supplier.

[14] A dual-register meter could also be used to arrive at net usage values in this arrangement. However, the distinguishing characteristic of this arrangement is that energy supply charges are netted up to the point of zero net usage. This is the only option using a single bi-directional meter arrangement. If a dual-register system is used

In the scenarios described below, compensation for NEG is determined as a monetary credit at a rate close to the full retail rate that the customer pays for electricity. The compensation level and type are actually mostly irrelevant to the function of the crediting system. The credit could be set as a kWh credit which only offsets distribution charges, or as a monetary credit at a lower rate. The only option *not* available is to award customers with a full kWh credit since the supplier does not provide any compensation for NEG. However, the use of a monetary credit for NEG is important in these Hybrid arrangements because it creates a situation where the choice of billing arrangement may influence the financial outcome.

> **Possibility I**: The customer enters a billing period with a zero balance on his electricity account and a net usage of 100 kWh over the course of the billing period. For the purposes of this scenario, we will assume that the combined energy supply rate is \$0.10/kWh and the distribution rate is \$0.075/kWh, amounting to a combined rate of \$0.175/kWh. For this billing period, the customer owes a total of \$17.50. If the competitive supplier bills separately for energy charges, the utility would provide net usage information (100 kWh) to the supplier, which would then bill the customer for \$10.00. The utility would likewise separately bill the customer for \$7.50 in distribution charges. If the utility uses consolidated billing, the utility would then bill the customer for 100 kWh of distribution charges and 100 kWh in energy supply charges, and would collect a total of \$17.50 from the customer. The utility would remit \$10.00 to the supplier on behalf of the customer for the energy supply charges.
>
> **Possibility II**: The customer enters a billing period with a zero balance on his electricity account and NEG of 100 kWh over the course of the billing period. If the supplier bills separately for energy charges, then the utility would provide billing information indicating zero net usage by the customer to the supplier. The supplier would then issue a zero bill for energy charges. If the utility uses consolidated billing, the customer would receive a zero bill for both energy supply and distribution charges from the utility. The supplier would receive a payment of zero from the utility, reflecting zero net usage by the customer. The customer's account would receive a monetary credit calculated by multiplying the customer's NEG (100 kWh) by the chosen credit rate. For this scenario, we assume the credit rate is \$0.15/kWh, so the customer receives a monetary credit of \$15.00.
>
> **Possibility III**: Following Possibility II above, the customer enters the next month with a monetary credit on his account equivalent to 100 kWh and has net usage of 150 kWh over the course of the billing period. If the competitive supplier issues a separate bill for energy supply, the utility would transmit billing data indicating 150 kWh in net usage by the customer over the billing period, and the supplier would bill the customer for 150 kWh in energy supply. While the customer still retains a credit of \$15.00 from the prior

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and no energy supply charges are netted, then the arrangement corresponds to that described in *Section 2.1 Partial Netting Arrangement: No Supplier Obligation*.

month, this credit cannot be used against generation charges levied under a separate supplier billing arrangement. The customer then pays the supplier $15.00 for energy supply charges accrued during the billing period. The utility, which does have an obligation to compensate for NEG, allows the customer to apply the $15.00 credit to the utility's distribution charges totaling $11.25 for the billing period. Thus the customer receives a zero bill for distribution charges and retains a monetary credit of $3.75 on his utility account.

In the case of consolidated billing by the utility, the outcome for the customer would differ. As above, the combined supplier and distribution rate is $0.175/kWh, thus the customer would owe $26.25 for the billing period. Because the customer has a $15.00 account credit from the prior billing period, the customer would be charged $11.25 for the combined distribution and energy supply charges for the billing period. The utility, although it has not collected any money from the customer, would still pay the supplier for $15.00 in energy supply charges as determined by the customer's net usage (150 kWh) during the billing period.

One interesting implication of the Hybrid arrangement is that if compensation for NEG is set sufficiently high and the competitive supplier uses a separate billing system, the customer can accrue credits at a greater rate than they can use those credits to offset distribution charges (This is similar to the situation discussed in Section 2.1, Partial Netting Arrangements). The effect decreases as the compensation rate approaches the actual distribution rate (or is set as a kWh credit against distribution charges), and as customer generation approaches or dips below annual on-site electricity needs. The effect also disappears if annual reconciliation practices provide for a payment to the customer because the customer is eventually able to claim the credits in cash. However, if the compensation rate is set at a high level and credits carry forward indefinitely, the customer may be left with stranded credits that cannot be used. Again, this could be avoided if a customer can transfer credits to another electricity account or if the customer can use monetary credits to offset other non-volumetric distribution charges on a bill.

Finally, as noted earlier, although the detailed scenario above assumes that the utility is required to compensate the customer for NEG, the arrangement could function in a similar fashion if the reverse were true (i.e., the supplier is the obligated party). Under such circumstances the supplier would likely provide compensation for NEG as a monetary credit (perhaps determined by a wholesale locational-marginal price) or as a generation kWh credit.

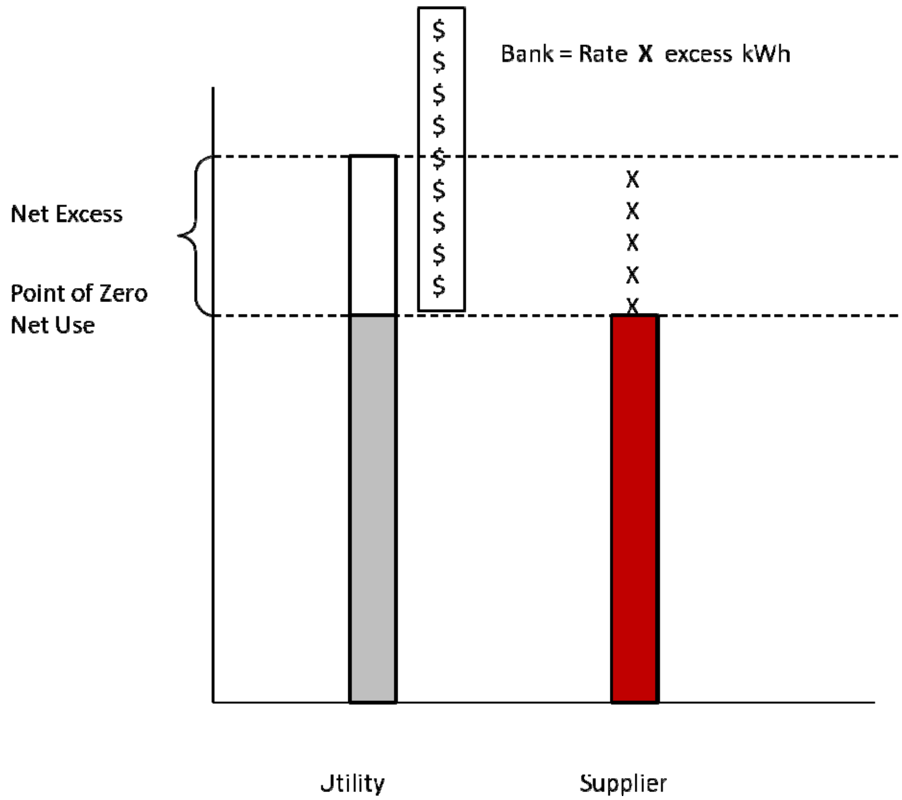

Figure 6: Hybrid. This approach combines aspects of other arrangements in that the monetized "credit bank" is operated by the utility, which receives no compensation from the supplier for excess supply charges.

4. Voluntary Supplier Arrangement

In states that have no net metering obligation, competitive suppliers remain free to contract with customers for the purchase of electricity exports at an agreed-upon rate. Should the contract purchase rate approximate the retail rate that the customer pays for electricity, the customer is effectively net metering. If the supplier agrees to a purchase rate that is less than the retail rate, the arrangement is the energy supply corollary of the Partial Netting arrangement described earlier. If the supplier does not agree to purchase electricity exports at any rate, then the practice ceases to resemble net metering in any form. In this situation, the customer would be charged for gross electricity imports from the grid for both distribution and energy supply, and receive no compensation for gross electricity exports. This approach is far outside the trending direction for state policies.

State Case Studies

Connecticut

Type: Previously Partial Netting, currently Utility-Side Netting

Meter Configuration: Not addressed in the rules, but the United Illuminating net metering tariff allows a single meter for non-demand customers.[15]

Billing Configuration: Utility provides a consolidated bill to customers. Competitive supplier sends the utility the energy supply price, utility arranges payment to the supplier.

Monthly Rollover: Supplier credits the customer-generator for NEG by reducing the customer-generator's bill for the next monthly billing period on a 1:1 kWh basis.

Annual Reconciliation: At the end of each annualized period the supplier compensates the customer-generator for any excess kWh generated, at the avoided cost of wholesale power.

Background: Connecticut is unique in that, prior to 2007, it provided a good example of a Partial Netting arrangement where no energy supply charges were netted. At the time, Connecticut law required that net metering customers be credited at an avoided cost of generation rate, but a monetized credit was applied against the distribution portion of the bill. The customer would still pay the full gross supply charges and the supplier would be paid an equivalent amount by the utility. For example, if a customer had 900 kWh of gross exports to the grid in a month and 1000 kWh in gross imports from the grid during a month, the bill would include 100 kWh in distribution charges and 1000 kWh in supply charges. If that same customer had gross exports of 1,100, the bill would show zero delivery charges, credited with 100 kWh at an avoided generation rate (to be used against delivery the next month), and billed for 1,000 kWh on the supply side. An equivalent 1,000 kWh payment would be provided to the supplier. This was only possible because (1) net metering was being accomplished through the use of two meters (or at least 2 separate registers for gross energy flows), and (2) competitive suppliers were not obligated to net their charges.

The law has and regulations since changed to require net metering on the part of competitive suppliers[16] so Connecticut's investor owned utilities (Connecticut Light and Power and United Illuminating) have changed their billing practice accordingly. The state now falls in the Utility-Side Netting category.

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[15] See United Illuminating Net Energy Rider
[16] See DPUC Docket No. 05-06-04RE04, available at: http://www.dpuc.state.ct.us/FINALDEC.NSF/2b40c6ef76b67c438525644800692943/aceab59ab86fb53a852574d400590509/$FILE/050604RE04-092908.doc

Delaware

Type: Utility-Side Netting

Meter Configuration: Single bi-directional meter required, or if multiple meters used, result must be the same as if a single meter was used.[17]

Billing Configuration: Customer may request consolidated billing from Delmarva Power & Light Company, the state's only investor-owned utility, or the competitive supplier. Customer may also request separate billing for distribution charges from Delmarva Power and energy supply charges from the supplier. For Delaware Electric Cooperative (DEC) customers, DEC has consolidated bills for all charges.[18]

Monthly Rollover: kWh credit, valued at the sum of delivery service charges and supply service charges for residential customers and the sum of the volumetric energy (kWh) components of the delivery service charges and supply service charges for nonresidential customers.

Annual Reconciliation: Customers may opt for indefinite rollover of credits or to receive a payment for excess at the energy supply rate.

Background: Delaware presents a clear example of the Utility-Side Netting arrangement. Here, customers have retail choice in the territory of DEC and Delmarva, the state's only investor-owned utility. As is the case in all competitive states, the distribution utility (or incumbent utility) is required to serve customers who do not choose a competitive supplier (i.e. SOS customers). When NEG occurs, the utility rolls over kWh charges from month to month at the retail rate. The supplier is then sent billing information *after* netting is applied, so that the supplier's charges are effectively being netted from month to month as well as within the billing period.

In Delaware the customer has the option to allow NEG to rollover indefinitely or request a payment from the electric supplier at the supply service rate. If the resulting compensation amounts to less than $25, the credit for annual reconciliation may be applied to the customer's electric account (as opposed issuing a check for payment). While Delaware's net metering law states that kWh credits may not be used to offset fixed monthly charges from the electric supplier, it does not appear to place any such limitation on any monetary credits stemming from annual reconciliation. Moreover the fact that payments are issued for balances in excess

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[17] See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DE02R&re=1&ee=1

[18] See CDR § 26-3000-3001 http://regulations.delaware.gov/AdminCode/title26/3000/3001.shtml#TopOfPage

of $25 indicates that the credit should be treated the same as cash, thus they should be able to offset any and all charges that require payment from the customer.[19]

The Delaware Public Service Commission website shows that there are 42 competitive suppliers licensed to operate in the state.[20] The rates of competitive suppliers who serve residential and small customer customers have to be contained in a standard contract, which are expressed in cents/kWh. For larger commercial and industrial customers, those rates are usually confidential unless advertised.

District of Columbia

Type: Dual-Bank Netting if supplier voluntarily offers net metering; Partial Netting if supplier does not offer net energy service

Meter Configuration: Metering equipment installed for net metering must be capable of measuring the flow of electricity in both directions. However, utilities may install additional meters capable of separate import/export measurements at their own expense.[21]

Billing Configuration: Generally appears to be supplier choice.

Monthly Rollover: Supply and distribution credits are compensated fully and separately by the supplier and utility for systems up to 100 kW. For systems between 100 kW and 1 MW, NEG is only credited at avoided cost.

Annual Reconciliation: Credits may be carried forward to the next month indefinitely.

Background: Competitive suppliers are not required to offer net metering in the District of Columbia but if a supplier chooses to offer net metering it would happen under a Dual-Bank mechanism.

Separate sections of the administrative code address kWh crediting based charges for energy supply and distribution service:

> **Distribution**: "if the electricity generated during the billing period by the customer-generator's facility exceeds the customer-generator's kWh usage during the billing period (excess generation), the customer-generator's next bill will be credited by the Electric Company for the excess generation at the full retail distribution rate. The credit for excess generation shall be expressed as a dollar value on the customer-generator's bill."

[19] Communication with Brian Gallagher.
[20] See http://www.depsc.delaware.gov/electric/elecsupplierinfo.pdf
[21] See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DC01R&re=1&ee=1

> **Energy**: "the net inflow or outflow of electricity supplied to or by the customer-generator will be billed or credited at the Competitive Electricity Supplier's energy rate specified in the agreement between the customer-generator and the Competitive Electricity Supplier. The Competitive Electricity Supplier shall be responsible for calculating the net energy bill (or credit) amount for each billing period."[22]

Netting can only be used to offset kWh-based charges. It seems a Dual-Bank Netting arrangement is necessary since the competitive supplier is responsible for calculating a customer's net energy supply bill but the utility is responsible for separately crediting distribution credits for NEG. If the supplier does not offer net energy services, the transaction would fall under a Partial Netting arrangement where only distribution charges are netted. This would require a dual-register or dual-meter arrangement, which is permitted under the administrative rules.

According to the Public Service Commission website, as of February 2010, six suppliers were serving 3.3 percent of residential customers in D.C. and 16 were serving 27.8 percent of non-residential customers.[23]

Illinois

Type: Dual-Bank Netting or Utility-Side Netting

Meter Configuration: Metering equipment must be able to measure the flow of electricity in both directions at the same rate. For residential customers, this may be accomplished through use of a single bi-directional meter.[24]

Billing Configuration: Supplier choice of separate or consolidated billing.

Monthly Rollover: kWh rollover to the next month. If the utility is not the customer's electricity provider, the customer will receive a kWh credit for delivery service from the utility.

Annual Reconciliation: Any NEG remaining at the end of the annual period is granted to the utility.

Background: Illinois provides an interesting example of a state that could potentially fall into two different categories, Dual-Bank or Utility-Side Netting. Illinois' net metering law clearly requires both suppliers and utilities to provide net energy service and compensation for NEG for systems up to 40 kW. This means that only the Full Netting arrangements could apply. The administrative rules do not clearly address how net metering for competitive supply customers

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[22] DCMR 15-902.1, 902.3: http://www.dcregs.dc.gov/Notice/DownLoad.aspx?VersionID=3604634
[23] See http://www.dcpsc.org/customerchoice/whatis/electric/elec_restruc.shtm#Link4
[24] See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=IL13R&re=1&ee=1

should take place. The advantage of this is that it appears that crediting for NEG could be accounted for by either a Utility-Side Netting process or a Dual-Bank arrangement where generation credits are separated from distribution credits.

Since suppliers are allowed to contract with customers in any manner they choose, including refusing to serve a customer for any reason, the obligation to provide net metering essentially rests with utilities.

This fact is proven by the reporting numbers: there are roughly 300 net metering customers in the state, only two of whom are served by competitive suppliers.[25] The Illinois Competitive Energy association reports that over 57,000 electric customers have left their utility and chosen to contract with a competitive supplier, equating to about half of all kWh being provided by suppliers.[26] There are around 30 suppliers operating in the state.[27]

Massachusetts

Type: Hybrid

Meter Configuration: Not specifically addressed by rules, but current practice is to use a single net meter. Systems over 60 kW must also have a generation meter.[28]

Billing Configuration: Supplier choice, but there appears to be no option for a consolidated bill from the supplier.

Monthly Rollover: Utilities calculate net metering credits for each billing period, equal to the product of the: (a) excess kWh, by time-of-use rate, if applicable; and (b) sum of utility charges applicable to the customer's rate class. This generally ends up being a value slightly less than the customer's full retail rate.[29]

Annual Reconciliation: Credits may be carried forward to the next month indefinitely.

Background: Massachusetts provides a good example of a Hybrid arrangement that can be a bit complex. The state's net metering policy defines eligible net metering customers as any person or entity that takes electric service from a utility. Since all retail choice customers are also customers of utilities, the state's net metering law applies to all electric customers. However, the state's net metering law only requires utilities to provide net metering, not competitive suppliers.

[25] Communication with Illinois Commerce Commission (ICC) staff.
[26] See http://www.illinoiscompetitiveenergy.com/
[27] Communication with ICC staff
[28] Communication with MA Department of Public Utilities (DPU) staff
[29] See http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MA01R&re=1&ee=1

The use of a single net meter forces all charges to be netted up to the point of zero net use on the part of the customer. Beyond this point, the supplier has no obligation, but state regulations still require NEG to be carried forward as a monetary credit which includes both an energy supply and a distribution component. The utility performs this carry-forward and the customer receives the full monetary value of the credit. However, as described earlier in the Hybrid arrangement section, the choice of billing system can limit the extent to which the customer can use accrued credits. The utility bears the heaviest obligation under this arrangement, since it may have to pay the supplier for energy supply charges that were not collected from the customer. In Massachusetts, however, credits may be allocated to other customers under some circumstances. This mitigates the problem of the customer accruing unusable net excess credits in situations where the supplier issues a separate bill.

Around 95 percent of retail choice customers are large energy users, mostly comprised of big box retail stores and a few small industrial customers. Big industrial customers are not as prevalent in New England as elsewhere but there are a fair number of big box retailers engaging in net metering. Only a very small portion of retail choice customers are residential.[30]

Texas (and Green Mountain Energy)

Type: No Netting

Meter Configuration: Dual register. This could mean a single meter but it must register electricity imports and exports separately.

Billing Configuration: Retail provider bills for everything.

Monthly Rollover: None statewide. Green Mountain Energy (GME) allows simulated rollover within parameters.

Annual Reconciliation: None statewide, indefinite rollover for GME.

Background: Texas provides the sole example of a retail choice state that has essentially disallowed net metering. In Texas, utilities are not required to net their distribution charges and retail providers are permitted, but not required, to compensate customers for electricity exported to the grid by distributed generation systems. Retail providers in Texas are responsible for billing customers for both energy supply and distribution charges. The retail provider then pays the utility for distribution charges associated with the gross amount of electricity that their customer imports during a billing period. This creates a situation where

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[30] Personal communication with MA DPU representatives.

the retail provider can offer a program resembling net metering to its customers. However, the retail provider remains responsible for paying the utility for customer distribution charges.

Under GME's Renewable Rewards program, systems are installed on the customer's side of the meter and may serve a customer's on-site electricity demand.[31] Any NEG produced by the customer's system is metered separately and the customer's account is credited (the following month) for the exported energy up to 500 kWh per month at the retail rate. Energy exports in excess of 500 kWh per month are then credited at half of the retail rate. Within a billing period, the customer continues to pay both energy supply and distribution charges on the gross amount of energy consumed from the grid. By offering a retail credit for up to 500 kWh of gross electricity exports, the GME program mimics net metering up to a point. GME effectively pays for the customer's distribution charges up to 500 kWh a month since the credit reduces the amount of money collected from the customer.

Green Mountain Energy is foremost a renewable energy company so part of its mission is to chart a path that includes whatever support for renewable energy that it can offer. It declined to say what its net metering numbers are, although representatives maintained that they would sign up every distributed generation customer in the state if they could.

Discussion

In many of the states examined, net metering has not yet seen much growth among retail choice customers. Perhaps this is because most customers who engage in competitive choice contracts have such a large electricity demand it would be only on rare occasions they would feed any on-site energy production back to the grid. Therefore, large customers might prefer a buy-all, sell-all option or a behind-the-meter agreement that any on-site distributed generation would only reduce demand, with no chance of export (by using a minimum import relay). However, some states that have a more mature retail choice market and/or renewable energy incentive structure have seen considerable interest in net metering among retail choice customers.

During the course of the interviews, we noted a number of issues that can affect the availability and feasibility of net metering. Accompanying these issues are several questions that a regulatory commission can address to cover stakeholders' interests. In many cases, these issues were either not predicted or not discussed at state regulatory rulemakings. The following is a summary of the issues and lingering questions we discovered in our interviews.

[31] http://www.greenmountainenergy.com/index.php?option=com_content&view=article&id=162&Itemid=167/

Netting Distribution Charges

It is important to determine whether or not the distribution utility is required to net distribution charges when a customer is served by a competitive supplier. Generally the obligation to net distribution charges is placed on the distribution utility, even if the competitive supplier does not have a clear obligation to net energy supply charges. States employ various methods to assert this obligation but, on occasion, the issue remains unclear. The clearest examples (e.g., IL, MI, D.C., and MA) have rules that specifically define netting distribution charges as a distribution utility obligation. In other cases (e.g., DE), utility tariffs clarify this obligation.

Texas is the only state in our study where the distribution utility is clearly not required to net distribution charges and in fact is the only state where net metering is not generally available. If a competitive supplier wishes to offer something that resembles net metering to customers, they must still pay the distribution utility for gross (not net) electricity supplied to the customer. This creates a clear disincentive on the part of the competitive supplier to offer any payment for NEG that approaches the retail rate, unless the value from NEG is greater than the cost of gross distribution charges to the customer.

The language defining how crediting or rollover takes place may be important in a discussion of this issue. If the credit for NEG takes place at avoided cost or some other variation on the energy supply rate, the argument that a utility remains obligated to net distribution charges is less compelling. Stated another way, if other portions of the net metering law do not specifically address the netting of distribution charges for customers of competitive suppliers, it could be inferred that the netting obligation refers only to supply charges because NEG is referred to as an energy supply credit. This is not to suggest that a full analysis of a state's net metering law would arrive at this confusion, since net metering laws in general typically place the clearest net metering obligation on utilities. It does however hold the potential to create confusion and debate over where the net metering obligation lies and what exactly that obligation entails.

Value of Excess Energy

A second issue we would like to note focuses on the value of exported energy from a net metered system to the competitive supplier, and how this compares to the value defined by whatever rules may be in place for customer compensation.

The value of NEG is a multifaceted issue because it hinges on the wholesale market settlement process and how individual customer loads are addressed, as well as the nature of the contract that a customer signs with a competitive supplier. Contracts may contain a fixed price, vary based on an index, use hybrid fixed/index approach, or rely on other complex pricing methods. However, administrative price-fixing solutions do not always correspond to the real value of NEG. For example, if a customer purchases a fixed-price product and monthly compensation is determined as the monthly average locational-marginal price (LMP), it is likely that the value of compensation will differ from the fixed price that a customer pays. Furthermore it will also likely differ from the actual value of the energy supplied as determined on a real-time basis under the real-time LMP.

Compensation Methodology

Following closely the value of NEG issue, another important discussion topic relates to the appropriate compensation methodology for net metering credits. In principal, it seems that the real-time LMP is probably the most accurate measure of how much the energy component of a kWh is worth. But does this constitute fairness from the customer-generator's perspective? In other words, if the customer pays a fixed price for energy, shouldn't compensation also take place at that same fixed price?

The symmetry of fixed rates may be appealing in the sense that it equates renewable energy production (and value) with energy consumption (or lack thereof). A customer might choose a fixed price plan in order to reduce electricity cost exposure to price volatility (i.e., high prices). However, it may not be optimal from an economic perspective of electricity generation and consumption, which vary on both the temporal and spatial scales. At the same time, requiring compensation at a specific rate that departs from the value of the energy that it actually receives (essentially the LMP), without also requiring the supplier to offer net metering service, would likely cause the supplier to choose not to offer net metering services. For example, Ohio law requires NEG to be compensated at the avoided cost rate but competitive suppliers are not required to offer net metering. Since avoided cost almost certainly differs from the LMP rate, competitive suppliers may incur more risk by offering net metering voluntarily. The risk in this case is that the level of compensation exceeds the value of the exported energy.

However, compensating the customer at the LMP rather than the LMP plus distribution charges essentially assumes that NEG holds no benefits for the distribution grid. Being compensated at an hourly LMP exposes the customer to the opposite risk in the sense that NEG compensation could be much lower than the price the customer pays. In this case, the customer would have an incentive to use more energy during peak energy production periods of on-site generation, assuming this is possible, so as not to export energy to the grid if it would generates a lower value under real-time LMP pricing.

The potentially tricky part of this equation is that utility customers on a fixed-rate plan may in fact be compensated for NEG at a fixed energy supply rate, plus the distribution rate if retail compensation is required by law. This may create differential incentives when comparing the value of net metering under a competitive supply contract to that of a standard service offer from a distribution utility. From a customer's perspective, any decision would also need to be balanced against whatever cost advantages might be available for contracting for electricity supply from a competitive supplier as opposed to taking the SOS.

Market Settlement

A similar issue relates to whether wholesale energy markets compensate competitive energy suppliers for "negative loads" on the part of the customer (i.e., when the customer is exporting energy rather than consuming from the grid). In the PJM Interconnection region, for example, a customer load may be assigned a zero value, but cannot fall below zero, so the competitive supplier is not compensated for this excess. Some of our interview participants also mentioned that it may depend on how the utility reports market settlement information to the independent system operator (ISO), rather than the inability of market settlement software to incorporate negative loads. In other words, if a customer of a competitive supplier has a negative load for the billing period, the utility may only send the competitive supplier a zero load for the billing period so the grid gets "free" energy which would likely end up as energy that is unaccounted for in the settlement process.

Is the utility actually compensated by the ISO under some circumstances? It would seem so, because the supplier is given a zero load in settlement rather than a negative load. The utility could benefit if it reports a negative load for itself,[32] thereby effectively appropriating any negative load for both SOS customers and those of competitive suppliers. If the utility reports a zero load for market settlement and the energy goes on the grid but no one is compensated, the excess would end up as unaccounted-for energy. The utility experiences no difference monetarily unless it is required to monetize credits. Otherwise, it simply nets its own distribution charges and the supplier compensates the customer at the end of an annual period, if required. If compensation is not required (e.g., in MD), the utility also benefits because NEG is donated without compensation. The utility basically receives the generation benefits over the course of the year or else ends up at a zero balance if it was not compensated for negative loads during the course of wholesale settlement. It seems likely that, due to the scale of grid transactions, any additional unaccounted-for energy that results from zero-load reporting would be tiny.

A utility would typically be able to seek periodic cost recovery from all ratepayers for any real costs associated with operating a net metering program.[33] A competitive supplier, on the other hand, would have a much more difficult time recovering such costs. It would presumably not be able to recover costs through any existing customer contracts, and would therefore only be

[32] Theoretically, a utility would not necessarily need to report a negative load for market settlement (which may not be permitted anyway) in order to benefit from customer grid exports. If all positive and negative loads are aggregated together prior to being reported for market settlement, the negative portion would offset the positive portion without the need to report a negative number for settlement. The authors do not know whether current market settlement practices permit this, and indeed it seems more likely that the utility would simply report the same load information for both supplier billing and market settlement.

[33] Actual costs and benefits associated with distributed generation remain a hotly debated topic covered in several other studies (See, for example *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin*, available at: http://www.austinenergy.com/about%20us/newsroom/reports/PV-ValueReport.pdf). For this reason, we have chosen not to address the issue in this paper.

able to add revenue through new contracts to make up the shortfall. In turn, these contracts would need to be priced at a value which includes these costs, making the supplier less competitive with other suppliers who do not choose to offer net metering (if not required by state law).

Existing Contracts

Another important issue centers on how state rules treat existing contracts that do not address net metering and, which may in fact have prohibitions against customer generation. This is potentially a critical issue for competitive suppliers because they generally do not support any language that has the potential to alter an existing contract (refer to Constellation and Retail Energy Supply Association (RESA) comments in various net metering dockets).[34] Contracts could also address REC ownership which could potentially require a generator to hand over renewable energy credits.

The Michigan PSC, in its statewide net metering order, argued that statutory changes may impair contracts where there is a rightful public purpose. In Illinois' rulemaking, a question arose regarding whether termination fees are involved for breaking an existing contract to go on a contract that allows for net metering, and whether this gives the supplier unequal bargaining power with a net metering customer (i.e., if a customer wants net metering, he or she must pay a fee to terminate the existing contract). In Illinois, utilities are typically required to provide net metering service under a standard tariff with minimum terms, but a supplier may not be bound by the same terms (or their existing contracts could prevent a current customer from engaging in net metering).

Impartiality of Contracts

Lastly, we noted an unresolved issue regarding the effect that regulatory commission rules could have on contracts between competitive suppliers and their customers. Many states have non-discriminatory clauses in their statutes which require utilities and suppliers to treat net metering customers the same as non-net-metering (or typical) customers. Broadly interpreted, this type of clause could mean that a competitive supplier must allow net metering under the same terms they provide to typical customers.

In Delaware, for example, net metering is applicable to Delmarva Power and all electric suppliers, which are required to offer net metering at non-discriminatory rates. However, there is no rule or law that requires suppliers to serve customers that want to net meter (with the exception of the SOS provider because it has to service all customers who want service), so a supplier could simply decline to serve a new net metering customer On the other hand, the supplier cannot break its service contract because all suppliers are required to offer net

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[34] See, for example http://www.icc.illinois.gov/downloads/public/edocket/214195.pdf (page 2) and http://efile.mpsc.state.mi.us/efile/docs/15803/0014.pdf (page 9)

metering to their customers. If a competitive suppliers' business strategy is to make a profit solely on selling kWh, then there is little reason for a competitive supplier to retain a customer that reduces purchases of kWh through net metering.

Because competitive supply contracts are so diverse and customizable, it may not be possible to determine what a supplier would have offered to that same customer under a non-netting arrangement. Offerings could also vary geographically, creating further problems in proving that net metering is not being offered on fair terms. If compelled to net meter at terms outlined in other contracts in the state, a supplier could simply cease to offer certain contracts of that type to any customer. The only possible proof of "discrimination" would seem to arise in a situation where a customer decides to renew a contract and is not allowed to under the same terms, while other customers are allowed to take service under that standard contract, assuming that some sort of "standard" contract exists.

Initial Recommendations for Net Metering Policies

While competitive suppliers have generally had a limited experience so far with net metering, it will likely become an increasingly important issue for them in the future. States are trending toward removing net metering caps, allowing large energy consumers to meet larger percentages of their load through distributed renewable energy systems. We offer the following for net metering rule design that may promote the adoption of net metering among retail choice customers.

1. Administrative rules or utility tariffs should specifically address whether net metering is required and how it should operate for competitive supply customers. This may require clarifications to eligible customer definitions, crediting procedures, permitted meter arrangements, non-discrimination clauses, and other provisions in net metering regulations and tariffs.

2. Customers of competitive suppliers should have the opportunity to net meter on the same terms as default or SOS customers. Retail choice and net metering do not have to be mutually exclusive customer options, and there is no compelling reason that they should be. This is not to suggest that customers should be prevented from negotiating custom agreements with a supplier if they choose to do so. Rather, a standard, non-discriminatory, default option should be available but not compulsory

3. All parties (customer, utility, and competitive supplier) should be afforded the opportunity to be made "whole." As described above, competitive supply customers should be eligible for the same net metering benefits available to other customers. To the extent that offering net metering to competitive supply customers imposes *real* costs on either suppliers or utilities, every effort should be made to provide mechanisms for recovery of these costs.

Conclusion

The complex design of restructuring has led to an array of net metering options for customers of retail choice suppliers. For this paper we theorized different types of crediting scenarios through which utilities and suppliers could accomplish net metering. These scenarios are broken down into Full, Partial and No Netting Arrangements. There are essentially two ways for a customer to get a full retail kWh credit, arrangements we call Utility-Side and Dual-Bank Netting. Other less common approaches include Partial Netting, a Hybrid arrangement and No Netting. The following is a summary of how each of these works.

- In Utility-Side Netting, the competitive supplier nets supply charges and the utility nets distribution charges up to the point of net on-site consumption. The utility then nets all distribution and supply charges for NEG during a given billing period. The supplier implicitly credits for the excess the following month.
- In Dual-Bank Netting, the supplier and utility net each of their respective charges and credit NEG during a given billing period.
- In a Partial Netting arrangement, either the supplier or the utility (most likely the latter) net their respective charges during the billing period; both do not net their charges.
- In the Hybrid arrangement, both the supplier and utility net up to zero use but only one, either the supplier or utility, has an obligation to provide credits for NEG.
- In a No Netting scenario, neither the utility nor supplier is required to net charges, but the supplier may choose to offer net metering for other reasons.

Of these, Utility-Side Netting is administratively the most simple, if it is permitted by law. Dual-Bank Netting can be more complex than necessary but may provide for more flexibility in designing net metering contracts that more accurately reflect the value of distributed generation.

It is important to note that these scenarios are partially based on hypothetical questions we posed during the interview process. Due to states' relative lack of experience with net metering, some interview participants from regulatory commissions, utilities and competitive suppliers were only able to hypothesize about how crediting would theoretically work in their state. During the interview process we also unearthed some issues that are generally unresolved in many states. Most state rules are vague about the nature of credit valuation and compensation, leading some suppliers to avoid the issue of net metering entirely. State rules in most states also generally do not address the treatment of existing contracts between suppliers and customers, or the interpretation of non-discriminatory clauses that pertain to suppliers and utilities.

We hope this paper provides the basis for discussion going forward, in an aim to alleviate confusion and provide relevant policy examples and experiences from other states. As a result, policymakers and industry stakeholders will hopefully be better equipped to navigate a market-based approach to energy that more appropriately values the contributions that distributed generation systems make to the electric grid.

Definitions

Competitive Supplier (aka Supplier) – A company that provides generation supply to end users. The suppliers may or may not bill customers directly. Sometimes these companies also own generation assets but not always – they may purchase power on the market for their customers. It can also be called an Alternative Retail Electric Supplier or a Retail Choice Provider, depending on the state.

Distribution Utility (aka Utility) – A company that constructs and maintains the distribution wires connecting the transmission grid to the end-use customer. Most distribution utilities offer a Standard Offer Service (SOS). Utilities are sometimes referred to as Electric Distribution Companies (EDCs), or Transmission and Distribution Utilities (TDUs).

Independent System Operator (aka ISO) – In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system. An ISO usually operates within a single state, but sometimes encompasses multiple states.

Locational Marginal Price (LMP) – Electricity prices that vary by time and geographic location in wholesale electricity markets. At least two separate markets, day-ahead and real-time, exist for the daily buying and selling of electricity and operate on the basis of LMPs.[35]

Net Excess Generation (NEG) – The net amount of electricity a renewable energy system exports to the grid in a given billing period.

Regional Transmission Organization (RTO) – An entity that coordinates, controls and monitors an electricity transmission grid to provide power providers with non-discriminatory access to transmission services.

Standard Offer Service (aka Default Service) – Electricity service that is provided by a utility to customers who do not choose a competitive supplier.

Volumetric Energy Components – Any billing charge based on a kWh value, i.e., any charge that is not fixed.

Wholesale Energy Market – The forum through which electricity is bought and sold at the wholesale (defined by FERC as sale for resale) level. This may be managed by an ISO or Regional Transmission Organization (RTO).

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[35] http://www.esm.versar.com/pprp/factbook/glossary.htm

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