Retail Electricity Tariff and Mechanism Design to Incentivize Distributed Renewable Generation

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Abstract

This paper examines the question of how to incentivize the adoption and use of renewable energy resources, with particular attention on distributed renewable energy (DRE). Prior experience suggests that price and quantity-based programs, such as feed-in tariffs, provide more efficient renewable adoption and use and lower program costs than programs that set quantity targets only. We also examine some cost-allocation issues raised by the use of DRE systems and fixed time-invariant retail pricing. This combination can result in customers with DRE systems paying a disproportionately small portion of system capacity costs. We suggest two retail-pricing schemes, real-time pricing and a two-part tariff with demand charges, to address these issues.

Keywords: Distributed generation, retail electricity pricing, incentive mechanisms

1. Introduction

Recent years have seen increasing installation and use of distributed renewable energy (DRE), especially photovoltaic (PV) solar, in many parts of the world. This has been spurred, in part, by subsidies for and favorable regulatory treatment of these technologies. According to Sawin et al. (2014), at least 144 countries had some type of renewable energy target or incentive program in place as of early 2014. The aim of these incentive mechanisms has been to reduce the privately incurred cost and risk of installing these technologies, spurring greater use in the short-run. In the long-run, the greater use of these technologies is intended to lead to cost reductions through economies of scale in manufacturing and installation and 'learning-by-doing' effects. This increases the competitiveness of these technologies compared to alternatives, decreasing the cost of financing and deploying DRE systems. If taken to fruition, these programs are meant to lead DRE technologies to a point of maturity that they can compete with alternatives without any incentive mechanisms.

Different jurisdictions have used various combinations of incentive mechanisms to spur DRE adoption. These mechanisms can be differentiated based on the extent to which they provide a direct financial subsidy for either DRE adoption or use as opposed to providing a guaranteed market for DRE energy. Experience to date shows that these mechanisms have different levels of success in encouraging DRE adoption. Moreover, there are very important and nuanced implementation details that can help or hinder the performance of incentive mechanisms. Some of these incentive mechanisms have also created unintended negative cost-allocation issues. These cost-allocation issues are mostly related to the fact that retail electricity pricing lumps the variable cost of energy generation with the fixed cost of investing in generation, transmission, and distribution capacity. These two types of costs are remunerated using a volumetric charge on energy consumption to retail customers. Some price-based incentive mechanisms for DRE result in capacity-related

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costs being increasingly borne by customers who do not have access to DRE, creating undesirable cross-subsidies. As such, some jurisdictions have, *ex post*, limited or rescinded incentive programs to mitigate these issues.

This paper studies these problems in incentive and retail tariff design to efficiently encourage DRE adoption and use. It also provides lessons learned from previous attempts and failures. It further makes some recommendations on how to mitigate the unintended cost-allocation consequences of DRE-related incentive schemes through better tariff design. The remainder of this paper is organized as follows. Section 2 summarizes the types of incentive programs used to date. It provides a comparative assessment of how well different programs work in incentivizing DRE adoption and reducing financing risks and costs. This section also discusses some of the philosophical reasons that certain mechanisms are sometimes favored over others. Section 3 introduces the negative cost-allocation consequences of these programs. Section 4 discusses two proposals for retail tariff design—real-time pricing and two-part tariffs with demand charges—that can address some of the cost-allocation issues discussed in Section 3. It should be noted that the pricing schemes proposed are not novel. Sakhrani and Parsons (2010) discuss the historical use of demand charges and time-variant energy charges for small residential customers in some jurisdictions. Rather, our contribution in Section 4 is to model and study the benefits of using such pricing schemes for cost recovery in the context DRE. Section 5 concludes.

2. Distributed Renewable Generation Incentive Policies

This section provides an overview of the different types of incentive mechanisms commonly used in different jurisdictions to encourage the adoption and use of DRE.[1] DRE historically has two competitive disadvantages relative to alternatives. The first is that DRE can be seen as a risky investment compared to better understood conventional alternatives. *Ceteris paribus*, investors may prefer conventional alternatives to DRE, increasing DRE financing costs. Secondly, DRE technologies may have higher upfront costs due to their relative immaturity compared to conventional alternatives.

The goal of incentive mechanisms is to reduce the privately incurred cost and risk of adopting and using DRE technologies. The incentive mechanisms that have been historically used can be differentiated by how they achieve this cost and risk reduction. We now summarize the key features of four major incentive mechanisms seen in use: the (i) feed-in tariff (FiT), (ii) quota-obligation, (iii) tendering, and (iv) net-metering systems. We also discuss other financial subsidy systems that have been used and some other important technical considerations relating to integrating renewables and DRE into electric power systems.

2.1. Feed-In Tariff

FiTs are currently the most widely used DRE-related incentive mechanism. While the designs vary between jurisdictions, Umamaheswaran and Seth (2015) define the fundamental features of an FiT as a guaranteed price for and guaranteed purchase of energy produced by a DRE system. That is to say an FiT program provides a guaranteed payment for each kWh of energy produced by a qualifying DRE installation. Most FiT programs also require the local utility or system operator to accept any DRE energy provided by the end customer, except when doing so is technically infeasible. These design features reduce the risk of investing in a DRE system by providing a guaranteed market for energy produced.

The primary advantage of an FiT program is that it effectively manages revenue risk for a DRE system by guaranteeing the quantity of energy sold and the price at which it is sold. According to Lipp (2007) these price and quantity guarantees are often provided for eight to 30 years. Fouquet and Johansson (2008) and Umamaheswaran and Seth (2015) note that this reduced risk allows DRE developers to more effectively leverage debt to bring down financing costs. Lipp (2007) also notes that an FiT program can be tailored to different DRE technologies. For instance, the guaranteed price for a kWh provided by a distributed solar plant can be set differently from that for a distributed wind plant. This allows the FiT program to

[1] The incentive mechanisms discussed here have typically been applied to all sources of renewable energy, including DRE and utility-scale systems.

accommodate the relative maturity of different technologies. van der Linden et al. (2005) and Lipp (2007) note that the price guarantees in an FiT program can also decline over time. This allows the program to adapt to changing technology maturity levels over time and can also provide strong incentives for technology cost reductions.

van der Linden et al. (2005) note that the main criticism of the FiT system is that its efficiency depends on the price guarantee being set correctly. If the price is too high the system could result in excessive windfall profits to generators at the expense of consumers or taxpayers. If it is set too low, the program may be ineffective in spurring any DRE development. The information needed to correctly set FiT price guarantees largely comes from DRE owners or developers, who may not have any incentive to reveal their true costs. Indeed, these agents may have strong incentives to overstate costs. FiT design is in fact even more complex than this information asymmetry suggests. The mix of generation technologies that is ultimately deployed depends on the relative price guarantees set for them. This becomes an even more formidable task for a regulator, as it must know the costs of technologies and what an 'optimal' technology mix is, taking into account relative technology maturity and performance. Another criticism of FiTs that Lipp (2007) mentions is that the guaranteed prices for different DRE technologies do not encourage competition between technologies. As such, the mix of DRE technologies deployed may not be least-cost.

FiTs have been implemented in a number of jurisdictions successfully, in the sense that they have spurred DRE adoption. Lipp (2007) provides a succinct history of FiT programs. One of the first examples was the Public Utility Regulatory Policy Act (PURPA) of 1978 in the United States. PURPA guaranteed payments for qualifying energy-producing facilities. The payments were based on assumed future fossil fuel costs, which were estimated at $100 per barrel of oil by 1998, and the estimated avoided cost of conventional generation. The high price guarantees of PURPA did not prevail, however, and the programs were ended as a result of falling fossil fuel prices and the introduction of restructured wholesale electricity markets in the late 1990s and early 2000s.

The second wave of FiTs were implemented in Germany and Denmark in the 1990s. These programs required utilities to purchase energy from qualifying renewable-energy installations at prices that were established by the government. The rationale behind these price premia was to compensate renewable-energy facilities for the unpriced environmental and other benefits of their generation. Denmark introduced its FiT program in 1993 with a fixed price paid to qualifying facilities. This was modified in 2001 to have a more market-based design. Under the new design, qualifying facilities are paid the price established by NordPool[2] plus an environmental premium. According to Mitchell et al. (2006) this does create some added price risk for a DRE deployment, because part of the guaranteed payment is tied to a volatile wholesale electricity market price. However, a portion of the price guarantee (*i.e.*, the environmental premium) is fixed through legislation.

Germany began DRE-related incentive programs in the 1970s. As with PURPA, these programs were spurred by high fossil fuel prices. The first German program had a similar design to PURPA, but provided much lower price guarantees. Thus, it had very limited success in spurring technology deployment. An FiT bill, which required utilities to connect DRE generators to the grid and purchase their produced electricity at a price of 65% to 90% of the average tariff for retail customers, was later passed in 1990 (Mitchell et al., 2006). This bill helped spur close to 1 GW of renewable energy capacity entering the system within five years. The FiT law was later revised in the 2000s in several important ways (Mitchell et al., 2006). One was to move away from fixing the price supports based on retail prices. Instead, the price supports were set based on technology and location within the country. According to Lipp (2007) and Fouquet and Johansson (2008) this reflected differences in technology maturity and renewable resource availability in different parts of the country. The method of allocating FiT costs across ratepayers within Germany was also modified, to better distribute costs. Under the original FiT law these costs were borne by the customers of each local utility. The new program spreads these costs nationwide, instead. This prevents the costs being borne disproportionately by customers residing in areas of the country with relatively good renewable resources (which is where qualifying facilities are more likely to be clustered). The new FiT law fixed payments to

[2]NordPool is the wholesale electricity market operator in the Scandinavian countries.

qualifying facilities for 20 years but also included explicit provisions to reduce rates paid to new deployments over time to reflect technologies maturing. Liou (2015) summarizes further reforms to the German FiT program in 2012. These reforms were mainly undertaken to reflect the rapidly decreasing costs of DREs, especially solar PV. These FiT reforms included a further reduction in all FiT payments, a cap specifying that 10% of electricity produced by commercial-scale PV (larger than 10 kW) would not be eligible for FiT payments, and an overall cap that fully eliminates FiT payments once 52 GW of eligible PV is installed.

Parts of the FiT concept have been employed in other parts of the world as well. As an example, Liu and Kokko (2010) discuss the 'Opinion on Wind Power Farm Construction and Management,' issued by the Chinese Ministry of Power in 1994. This policy statement requires power grids to purchase all electricity generated by wind plants and that the price paid should be set high enough to cover costs. This policy provides the guaranteed purchase requirement of a FiT and suggested a remuneration scheme for cost recovery. This was followed up by a policy outlining the 'Approach of Grid Enterprises Purchasing Renewable Energy Electricity' in 2007. This policy states that renewable facilities have priority access to the electric power grid and that grid enterprises are required to purchase renewable energy at a regionally defined benchmark price.

2.2. Quota-Obligation System

The quota-obligation system takes a fundamentally different approach to incentivizing DRE compared to an FiT. Under a quota-obligation system, there is a legal obligation to procure a certain amount of energy from qualifying resources. Most quota-obligation systems take the form of a renewable portfolio standard (RPS). RPSs are very widely used in the United States and in some other countries. RPSs typically count all renewable energy sources, including DRE, toward meeting the mandate.

RPSs can vary considerably in their implementation details. One question is whom the obligation is placed on. Most often the obligation is placed on the retail energy supplier, however it could presumably be placed on generators or end customers. In the latter case, the retail energy supply would likely procure qualifying energy resources on behalf of most customers. In this case the RPS would effectively be akin to placing the obligation on the retail supplier. However, placing the obligation on the customer may provide some added flexibility to large commercial and industrial customers to procure qualifying energy resources on their own through competitive tenders. Quota-obligation systems typically provide strong financial penalties for unmet obligations.

Another design question is whether the RPS specifies the amount of renewable energy or renewable capacity that must be procured. The former is more typically used. This is done to provide a strong incentive to build plants in locations that have good renewable-resource availability and to operate the plants efficiently. Otherwise, if the obligation is capacity-based, generating facilities may not be built or operated efficiently.

Energy-based RPS programs typically create a new set of tradeable instruments, known as renewable energy certificates (RECs). RECs are 'created' whenever a qualifying renewable facility produces energy. These can be traded or sold to entities that then use them to meet their RPS obligations. RECs do not typically have to be sold to the party buying the energy produced by the renewable facility. In fact, the separation of the REC from the underlying energy can help to facilitate renewable delivery. For instance, a small retail supplier with an RPS obligation may have difficulty balancing variable generation from a renewable generator with its customers' demands and its other energy supply sources. In such a case, the retail supplier can purchase RECs from a qualifying renewable facility to meet its RPS. The retail supplier can then use dispatchable generation to serve its customers' demands. The renewable facility can sell its energy in an organized wholesale market or through bilateral contracts to a third party that does not purchase the associated RECs. Quota obligation systems also vary in terms of how much RECs can be exchanged intertemporally, *i.e.*, whether excess RECs can be 'banked' for future use or to satisfy previous unmet obligations.

The primary benefit of a quota-obligation system is that it theoretically achieves the target DRE level at minimal cost (van der Linden et al., 2005). This is because the design explicitly incentivizes the obligation to be met using the lowest-cost technology available. The design also provides strong incentives to reduce technology costs. Mitchell et al. (2006) and Lipp (2007) raise something of a philosophical advantage to quota-obligation systems, in that technology choice and prices are not set by legislative or regulatory fiat. Instead, by setting an obligation and allowing entities to use any combination of qualifying technologies to meet it, the market is able to determine what combination of technologies to use. Mitchell et al. (2006) further note that because the quota-obligation system does not set specific prices for different technologies, the government is not in a position of picking 'winners' and 'losers.'

However, these features of the quota-obligation system can be weaknesses. If a goal of DRE incentive programs is to drive down costs in the long-run, a quota-obligation system may only do this for technologies that are already mature (van der Linden et al., 2005; Lipp, 2007). This is because less mature technologies that are more costly will not be deployed until the marginal cost of the mature technology is equalized with the less mature one. This 'myopic' design of a quota-obligation system can retard the development of a nascent technology that may be beneficial to develop from a long-run perspective. Nascent technologies may be more difficult to finance under a quota-obligation system because they would appear risky relative to more mature technologies. One way to overcome this problem would be to set technology-specific obligations or technology-specific 'REC production rates'. For example, one could design a program in which wind generators produce one REC per MWh whereas tidal generators produce three RECs per MWh. This distinguishes between technologies at different maturity levels. However, the same issues related to setting the proper price in an FiT are now raised if this conversion-rate approach is used in a quota-obligation system. The United Kingdom implemented such a technology-specific conversion rate in its quota-obligation system (Fouquet and Johansson, 2008).

Another major weakness of the quota-obligation system is that it can introduce more price uncertainty compared to an FiT. This is largely because the REC price is set in the market, and market dynamics can vary over the life of a DRE or other renewable deployment. Moreover, economic theory holds that RECs in a quota-obligation system only have value if the obligation is not met. Otherwise, there would be excess RECs and the price should presumably fall to a level that drives excess renewable projects (and their RECs) out of the market. In some cases these design features have led to the obligation being persistently unmet. In these cases the underlying goal of the program is not achieved, unless the obligations are intentionally set at higher-than-desired levels. In other instances, the price risk and uncertainty have made financing renewable and DRE projects more difficult. One approach to deal with this price risk and the associated financing difficulties is for retail suppliers to develop their own renewable projects and self-supply their obligations. These integrated firms tend to be larger and have greater access to capital and financing. Moreover, a retail supplier has a guaranteed 'market' for its RECs, reducing the volume risk that an independent renewable generator faces. For these reasons, quota-obligation systems are often observed to favor large producers (Mitchell et al., 2006; Lipp, 2007), making them a less desirable mechanism to incentivize DRE. This is for the simple reason that most DRE projects tend to be owned and operated by small producers. The self-supply of obligations by large retail suppliers also reduces the liquidity of the REC market, which can hinder price formation.

The quota-obligation system implemented in the United Kingdom has an additional provision that further exacerbated REC price uncertainty. In the United Kingdom's program, penalties that are assessed for non-compliance with the mandate are 'recycled' back to compliant entities. These recycled payments are made in proportion to the number of RECs that an entity submits. Thus, these recycled payments, which can be difficult to predict from year to year, effectively increase the value of each REC (Mitchell et al., 2006).

Another weakness of the quota-obligation system is that its cost is difficult to predict *a priori*. This depends on how aggressively the obligation is set and the level of the penalty for non-compliance. These and other factors determine the market price of RECs. It is also important to stress that if these values are set too aggressively, this can result in excessively high REC prices and windfall profits to qualifying renewable and DER suppliers.

The first application of quota-obligation systems, in the form of RPSs, appeared in the United States (van der Linden et al., 2005). The experience in the United States has been quite mixed. On one hand, Texas has had a very successful program that seems to have overcome many of the volume and price risks that a quota-obligation system can carry. Langniss and Wiser (2003) note that under the RPS in Texas, electricity suppliers have been willing to sign 10- to 25-year contracts with renewable suppliers for RECs and the associated energy. These long-term contracts provide the type of revenue guarantee that an FiT does, allowing for lower-cost financing of a renewable project. As an opposite example, van der Linden et al. (2005) note the case of utilities in the state of Nevada, which signed contracts with renewable developers that failed to bring their projects on-line. This resulted in substantial under-compliance with the quota-obligation in the state. The state regulator further declined to penalize the utilities for this lack of compliance. This regulatory uncertainty and apparent willingness by the regulator to rescind penalties can significantly undermine future attempts at implementing a RPS in the state.

Sweden implemented a quota-obligation system beginning in 2003, which has seen disappointing results (van der Linden et al., 2005). In the first year of the program the compliance level was about 77.1% of the quota, despite an excess of about 2 million RECs being banked for future use. The explanation for this behavior is that market participants expected the price of RECs to rise in subsequent years. One issue with the Swedish system has been regulatory uncertainty. The program was initially slated to run until 2010, without any clear indication of whether it would continue past that point. Thus, a potential renewable or DRE project could only rely on a seven-year REC market. This design feature significantly limited the extent to which the program provided revenue certainty to a potential DRE or renewable developer. Moreover, the program underwent several modifications during this seven-year period and other future changes had been proposed. This included changes to the future quota level and potential harmonization of the program with Norway.

van der Linden et al. (2005) note one major lesson of the experience with quota-obligation systems, which applies just as well to any other type of incentive program, is that there must be clear political commitment to the program. Any risk (or even a perceived risk) that a program will be substantively modified or abandoned could significantly halt project development. Some DRE and renewable incentive programs have included explicit provisions for the government to conduct subsequent studies of the effectiveness of the program. One such example is the quota-obligation system implemented in the United Kingdom (van der Linden et al., 2005). These types of provisions can be interpreted by the market as an indication that political support for an incentive program may waver in the future, even if the government insists that the reviews are limited in scope.

These and other issues with quota-obligation system have kept some of them from delivering their theoretical promise of meeting renewable targets at minimum cost. Fouquet and Johansson (2008) estimate that in 2003 wind generated in the United Kingdom, which operates a quota-obligation system, cost €0.096/kWh as opposed to costing between €0.066/kWh and €0.088/kWh in Germany, which operates an FiT. This is despite wind speeds in the United Kingdom being much more favorable to wind development there compared to Germany. Lipp (2007) finds similar disappointing cost results for the quota-obligation system in the United Kingdom. She reports that the incentive scheme in the United Kingdom delivers wind at an average cost of €110/MWh as opposed to average costs of €80/MWh and €57/MWh in Germany and Denmark, respectively. She explains the excellent performance of the Danish FiT system as motivating producers to reduce wind turbine costs, as this allows them to sell more turbines within the country.

2.3. Tendering System

Tendering systems are very similar to quota-obligations in their approach to incentivizing renewable and DRE development. Like a quota-obligation, a tendering system is a purely quantity-based approach, without any guaranteed price levels. The main difference between the two types of programs is that a tendering system relies on a centralized auction-like mechanism, which is often administered by the government, to award renewable energy power purchase agreements (PPAs). As with a quota-obligation system, a tendering scheme could set different targets for different renewable and DRE technologies. Most, however, do not differentiate between technologies. This design choice is made for the same reason as with a quota-obligation system. By fixing the total quantity of renewable resources desired, the market determines what is a least-cost combination of technologies to deploy.

In theory, tendering systems are functionally equivalent to quota-obligations and should give the same results. This includes developing a least-cost combination of renewable technologies. Moreover, a secured PPA should provide a potential renewable developer with price and quantity stability. If the PPA includes a price guarantee, this has the potential to provide greater risk and financing-cost reductions than a quota-obligation system. In practice, however, most tendering schemes have not worked as well as FiT or quota-obligation programs. One program that provides some very valuable lessons on tendering-system design is the one implemented in China. Liu and Kokko (2010) note that the cost-minimizing design of the tendering system resulted in bids that were so low that it was unlikely that the winning bidder would be able to recover its costs. This resulted in several of the contracted projects being severely delayed or never built. Similar results were seen with tendering systems used in England and Wales and California (Langniss and Wiser, 2003; van der Linden et al., 2005; Lipp, 2007; Fouquet and Johansson, 2008; Umamaheswaran and Seth, 2015). These programs have since been replaced with quota-obligation systems.

2.4. Net-Metering System

Unlike the three other types of incentive systems discussed thus far, net-metering schemes are specifically geared toward incentivizing DRE investment. A net-metering system requires a customer's local utility to purchase energy produced by a customer-sited DRE system at the same retail price charged to the customer for energy consumption. If the DRE system produces less than the customer's energy consumption, this DRE production offsets the amount of energy drawn from the utility system. Thus, the utility sells less energy to the customer. Otherwise, if the DRE system produces more than the customer's energy consumption, the excess energy is fed back into the utility system. In this case the customer's meter runs backward to reflect the energy being sold to the utility. Thus, the utility only charges the customer for *net* energy sales.

A net-metering system is similar to a FiT in many ways. This is because a DRE system has a guaranteed 'market' for energy sales, insomuch as the utility is required to accept excess energy produced by the system. Moreover, the DRE system also has a guaranteed price, which is the retail price of electricity. Indeed, many FiT programs are applied to both utility-scale renewable plants and DRE systems. In such a case, the FiT is functionally similar to a net-metering scheme, except that the price paid to the DRE system may be higher than with a pure net-metering scheme. This depends on whether the DRE earns the guaranteed payments specified in the FiT program (in addition to offsetting consumption in computing customer retail supply charges). Net-metering schemes can also be combined with quantity-based schemes, such as a quota-obligation system. For instance, many RPS programs in the United States allow a utility to use RECs created by DRE resources in its service territory to meet its quota.

Net-metering schemes have been fairly successful, where conditions are appropriate. In the United States, they have been very successful in the southwestern states, especially in California. This region of the United States has excellent solar resource, and rooftop PV solar is the most practical DRE technology available today. Moreover, retail electricity rates in California have historically been high, making the economics of such installations cost-effective. Kavalec et al. (2013) report that so-called self-generated solar PV in the state of California in 2012 (which would have been eligible for net metering) contributed 668.2 MW toward the peak demand.

2.5. Other Financial Subsidies

In addition to the four programs already discussed, some jurisdictions have pursued other more direct financial subsidies. One approach, which addresses the high capital cost of many DRE and renewable technologies, is to provide direct capital subsidies. These could take the form of project-specific grants. In the United States, these often take the form of investment tax credits, which provide tax relief based on the capital cost of a project. Lo (2014) discusses two direct subsidy programs offered by the Chinese government beginning in 2009 to incentivize PV adoption. The first is the Solar Roofs program, which provides a subsidy amounting to 50% of the bidding price for the supply of critical components of building-integrated and rooftop solar PV systems. China also implemented the Golden Sun Demonstration project, which subsidizes the types of systems covered by the Solar Roofs program, in addition to rural electrification and large-scale PV projects. The amount of the subsidy provided by both programs has declined over time, reflecting cost decreases.

Capital cost-based subsidies, such as those offered by the Chinese programs, are typically seen as sub-optimal, because the incentives are not performance-based (van der Linden et al., 2005). Thus, a DRE or renewable developer may not operate or maintain the facility efficiently. Similarly, the incentive to locate a project where renewable resources are ideal is muted and a developer may instead opt for a location that minimizes investment cost. For these reasons, production- or performance-based subsidies are strongly preferred. The four mechanisms discussed before all have this feature (in the case of a tendering or quota-obligation system, it has this feature if the obligation is energy- as opposed to capacity-based).

Tax-based incentives (either production- or investment cost-based) are often preferred to more direct financial subsidies or grants. This is because the cost of a tax-based incentive is typically more opaque, reducing potential political opposition to a program.

2.6. Renewable Integration

Integrating renewable and DRE resources into an electric power system can entail ancillary costs, in addition to the capital cost of the plant itself. One of these is the cost of transmission and distribution infrastructure to interconnect a plant with the system. Transmission infrastructure would apply more to utility-scale renewables whereas distribution infrastructure to DRE. Texas and China present two interesting case studies of possible means of addressing these additional investment costs. In the case of Texas, the state has proactively made transmission investments in anticipation of where it expects future renewable resources to be deployed (Langniss and Wiser, 2003). These costs are then socialized to customers on a *pro rata* basis. In the case of China, Liu and Kokko (2010) note that State Grid (one of the two transmission system operators in the country) invested in a wind power project. The investment provided State Grid with a strong incentive to make transmission investments. By doing so, it was able to maximize the value of its wind-plant investment. It should be noted, however, that State Grid's investment in the wind plant contradicts China's policy decision to separate power generation from transmission operation.

These two cases suggest policy steps that could be taken to incentivize transmission and distribution investments. Proactively making transmission and distribution investments in anticipation of renewable and DRE installations could reduce risks (and associated financing costs) of plants not being able to deliver their product to the market. Although cost socialization is typically suboptimal, it is an easy means of allocating these costs. Vertically integrating transmission and generation runs counter to most electricity market restructuring efforts. For this reason, we do not necessarily recommend the Chinese approach for transmission investment. However, this type of an arrangement could be implemented for distribution infrastructure investments needed for DRE integration. One approach would be to have distribution utilities directly contract with DRE owners to purchase their energy and, if operating with a quota-obligation system, RECs. Doing so would provide the utility with strong incentives to ensure that there is sufficient distribution capacity available to efficiently use available DRE resources.

3. Cost-Allocation with Distributed Renewable Energy

DREs and many of the programs used to incentivize their adoption and use raise some unique retail pricing challenges that have not been encountered in the past. This is because electricity service involves the provision of capacity and energy. Sufficient generation, transmission, and distribution capacity must be built and maintained to serve the anticipated system peak. At the same time, these assets are operated to provide energy to end customers.

Historically, the cost of providing energy and capacity services has been recovered from customers through volumetric charges on energy consumption (Sakhrani and Parsons, 2010). This type of volumetric pricing is especially prevalent for residential customers.[3] Some large commercial and industrial customers may, conversely, be subjected to more exotic pricing mechanisms. The use of energy-based volumetric pricing follows from the assumption that the costs of providing customers' capacity and energy needs are roughly proportional to one another. In other words, a customer with twice as much energy consumption as another would impose roughly double the capacity-related costs on the system. Moreover, the cost of implementing

[3] We noted in Section 1 that some jurisdictions employ more sophisticated retail pricing schemes, such as demand charges, for small residential customers today.

volumetric pricing is low. Volumetric pricing requires a simple electromechanical induction meter to be read periodically to determine aggregate electricity consumption. More exotic retail pricing schemes may require advanced metering infrastructures, which have historically been relatively expensive.

DRE, and indeed all forms of distributed energy, threatens the viability of this historic cost-recovery mechanism. This is because DRE can affect a customers' energy needs disproportionately to its capacity needs. To understand this effect more concretely, we use the concept of capacity value (Garver, 1966). A resource's capacity value measures its contribution to system reliability, which is the likelihood that the system will be able to serve customer demands in the face of supply and demand uncertainties. Supply uncertainties can include mechanical, maintenance, or fuel-related outages of conventional generators or the inherent variability of renewables. A commonly used capacity value metric, effective load carrying capability (ELCC), assesses how much system loads can increase when a given resource is added to the system without changing the system's overall reliability.

To see how DRE affects electricity system cost recovery, consider the case of a residential customer in the Los Angeles, CA area. According to Kavalec et al. (2013), the average residential customer in the Los Angeles area consumed 6625 kWh of energy in 2013 and had a peak coincident demand of 1.6 kW. This means that the average customer imposes variable costs associated with the 6625 kWh consumed and fixed costs associated with the 1.6 kW of generation, transmission, and distribution capacity that must be built and maintained for the customer.

Now consider a rooftop PV panel installed on the residential customer's home. Madaeni et al. (2013) simulate PV generation in the Los Angeles, CA area and estimate that a 1 kW panel produces an average of 1726 kWh annually. They also estimate the ELCC of such a solar panel to be 0.52 kW. Thus, installing a PV panel reduces the customer's energy consumption and associated variable cost incurred by the system by 26% (compared to the 6625 kWh of average annual consumption) per kW of PV. Moreover, the customer's utility can reduce the amount of generation, transmission, and distribution capacity built and maintained for the customer (thereby avoiding the associated fixed cost) by 0.52 kW per kW of PV installed. This is because the utility can rely on the PV panel to contribute to serving the customer's demand, allowing it to reduce the amount of capacity built and maintained for the customer by 32% (relative to the 1.6 kW peak customer demand).

If the residential customer pays a volumetric tariff that depends solely on energy consumption, the customer's annual retail costs are reduced by 26% for each kW of PV capacity installed if a net-metering or similar system is in place. This creates an inefficiency, because the customer is undercompensated for the capacity value of the PV installation. Other incentive mechanisms, for instance an FiT, will exacerbate this inefficiency, because most of these programs provide incentive payments based on energy generated by a DRE without consideration of its effect on capacity needs and cost.

Indeed, volumetric charges based on energy consumption only can result in 'arbitrary' cost allocation to a customer with DRE. This is because the capacity value of DRE resources is highly system-specific. Madaeni et al. (2013) estimate ELCCs for 1 kW PV panels in the western United States and find that they can range between 0.52 kW and 0.70 kW. It is also important to stress that the ELCC estimates that Madaeni et al. (2013) provide is for marginal PV capacity being added to a system. As the penetration of PV increases, the ELCC of additional PV panels will be lower. This is because the hours of the year during which the system has the greatest probability of experiencing a supply shortage shifts from sunny afternoons to other hours that may have less solar resource available. Mills and Wiser (2012) survey capacity value estimates of solar PV for a variety of systems at different penetration levels. In all of the cases, they find that capacity values drop quite rapidly as the PV penetration increases.

The implication of the diminishing capacity value of PV is that as the penetration of PV increases, customers who install PV bear less of the cost of the capacity that must be installed to serve them. As an extreme example of this, consider a customer who installs enough PV to consume zero net energy from the electric grid. If such a customer pays a volumetric charge, the payment to the utility would be zero. However, generation, transmission, and distribution capacity would have to be installed and maintained to reliably serve such a customer. In this extreme example, all of the costs of this capacity would be borne by other customers! Moreover, if the system's overall PV penetration is sufficiently high, the PV installed by the customer in the example has almost no benefit in reducing capacity needs and costs.

Overall, volumetric charges result in inefficient cost allocation with DRE. It should be stressed that this issue is not limited to PV, as it can apply just as well to other DRE resources (*e.g.*, distributed wind). Moreover, this cost allocation problem is not limited to high penetrations of DRE. However, high penetrations of DRE exacerbates the issue, because the capacity value of most DRE resources tends to decrease as the penetration rises. In many parts of the world, the combination of DRE and volumetric energy-based tariffs can also create undesirable cross subsidies. This cross subsidy is due to DRE tending to be installed by customers that are socioeconomically better off than average. As these customers install more DRE, they pay a disproportionately smaller portion of capacity costs. These capacity costs are instead borne by customers without DRE, who tend to be socioeconomically worse off than those who own DRE.

4. Proposed Tariff Design

In this section we propose two retail pricing structures—real-time pricing (RTP) and a two-part tariff with demand charges—to address the cost-allocation issue raised in Section 3. We use the stylized screening model introduced by Stoft (2002) to justify our proposed pricing schemes. We proceed by first introducing the simplified capacity investment model. We then present the two cost-recovery theorems, which explain what wholesale pricing structures could be used to recover fixed capacity-investment and variable operating costs. Finally, we use the results of the two cost-recovery theorems to justify our proposed retail pricing schemes and discuss the relative tradeoffs between the two. Some practical implementation details are also discussed.

4.1. Capacity Investment Model

Our capacity investment model assumes that a power system entails capacity investment and generator operation. Capacity planning includes investments in generation, transmission, and distribution. We assume that the system has N different generation technologies available and let F_n denote the per-MW fixed cost of installing and maintaining generation technology n. Our model is agnostic to whether F_n represents the total fixed cost of the generation asset over its lifetime or an amortized cost (*e.g.*, the sum of an annualized capital cost and annual fixed maintenance cost). For ease of exposition we assume that F_n is an annualized fixed cost. F_n includes the cost of generation capacity in addition to the incremental transmission and distribution capacity required to deliver energy to end customers during the coincident peak-load period of the planning horizon. We also let C_n denote the per-MWh cost of operating generation technology n to serve customer demands.

We assume that when capacity investments are made, the system can plan on load curtailment. We denote load curtailment as the 'zeroth' technology. We have $F_0 = 0$, because there is no fixed investment cost associated with planning on load curtailment. We let C_0 denote the value of lost load (VOLL), which is the 'operating cost' of load curtailment.

Without loss of generality, we assume that the technologies are rank-ordered so that:

$$F_0 < F_1 < F_2 < \cdots < F_N,$$

and:

$$C_0 > C_1 > C_2 > \cdots > C_N.$$

If this assumption does not hold, then at least one technology is dominated by another (*i.e.*, it has higher fixed and variable costs). Such a dominated technology would not be built or operated in an optimal technology mix and can be excluded from consideration. We also assume, without loss of generality, that VOLL is greater than the operating costs of all of the generating technologies. If this is not the case, then it would be suboptimal for the technology that has a higher operating cost than VOLL to be built or operated. Because it has the lowest fixed and highest variable cost, we hereafter refer to technology 1 as the 'peaking' generation technology.

An optimal generation mix has three important properties, which are listed below.

Property 1. *Once the generation mix is determined, the installed generators are operated based solely on the merit order of their variable costs. That is to say, generation decisions are determined solely based on the values of C_n and the capacity of each technology installed.*

An important assumption underlying Property 1 is that we do not consider technical restrictions, *e.g.*, ramping or unit commitment constraints, on generator operations. We also, hereafter, refer to the generating technology with the highest variable cost that is operating in a given hour as the 'marginal' generating technology.

Property 2. *Each technology should be marginal for the hours of the year during which it is the lowest-total-cost (inclusive of fixed and variable costs) alternative.*

Property 3. *Total system capacity should be built to equate the marginal cost of curtailing an incremental MW of load with the marginal cost of reducing an incremental MW of load curtailment with an additional increment of peaking capacity.*

Property 3 can be expressed mathematically by defining T_0 as the number of hours of the year during which load is curtailed. The marginal cost of an incremental MW load curtailment is defined as:

$$C_0 \cdot T_0,$$

or as the product of VOLL and the number of hours that load is curtailed. The marginal cost of reducing an incremental MW of load curtailment is:

$$F_1 + C_1 \cdot T_0,$$

or as the sum of the cost of building an additional increment of peaking capacity (*i.e.*, F_1) and the cost of operating the incremental peaking technology T_0 hours (*i.e.*, $C_1 \cdot T_0$). Thus, Property 3 requires that:

$$C_0 \cdot T_0 = F_1 + C_1 \cdot T_0.$$

Figure 1 illustrates Properties 1 through 3 and how they can be used with a load-duration curve (LDC) to determine an optimal generation mix for a three-technology example. Cases with greater or fewer technologies are analyzed analogously. The bottom pane of Figure 1 shows the total cost per MW-year of installing and operating each of the three generation technologies available, as well as Technology 0 (*i.e.*, load curtailment). The vertical intercepts of the cost curves are the fixed per-MW costs, *i.e.*, the F_n's, and the slopes are the variable per-MWh costs, *i.e.*, the C_n's.

The three properties of an optimal generation mix imply that the system should be built in such a way that it is operated along the lower envelope of the technology cost curves. This lower envelope is indicated by the bold red piecewise-linear curve in the lower pane of Figure 1. The kink points of the piecewise linear curve are used to determine the number of hours that each of the three technologies and load curtailment are marginal. T_0 represents the number of hours that load is curtailed and T_1 through T_3 the number of hours that each of technologies one through three is marginal. An optimal generation mix is found by projecting the kink points of the piecewise-linear curve up onto the LDC, which is in the upper pane of Figure 1, and then projecting the intersection points with the LDC onto the vertical axis. K_1 through K_3 indicate how many MW of each of the three technologies should be optimally built. The difference between the vertical intercept of the LDC and the sum of K_1 through K_3 indicates the maximum amount of load that is curtailed given this optimal generation mix. Moreover, the triangle at the top of the LDC indicates how many MWh of load is curtailed with the optimal generation mix.

4.2. Cost-Recovery Theorems

We now present the two cost-recovery theorems, which are then used to justify our proposed retail pricing mechanisms.

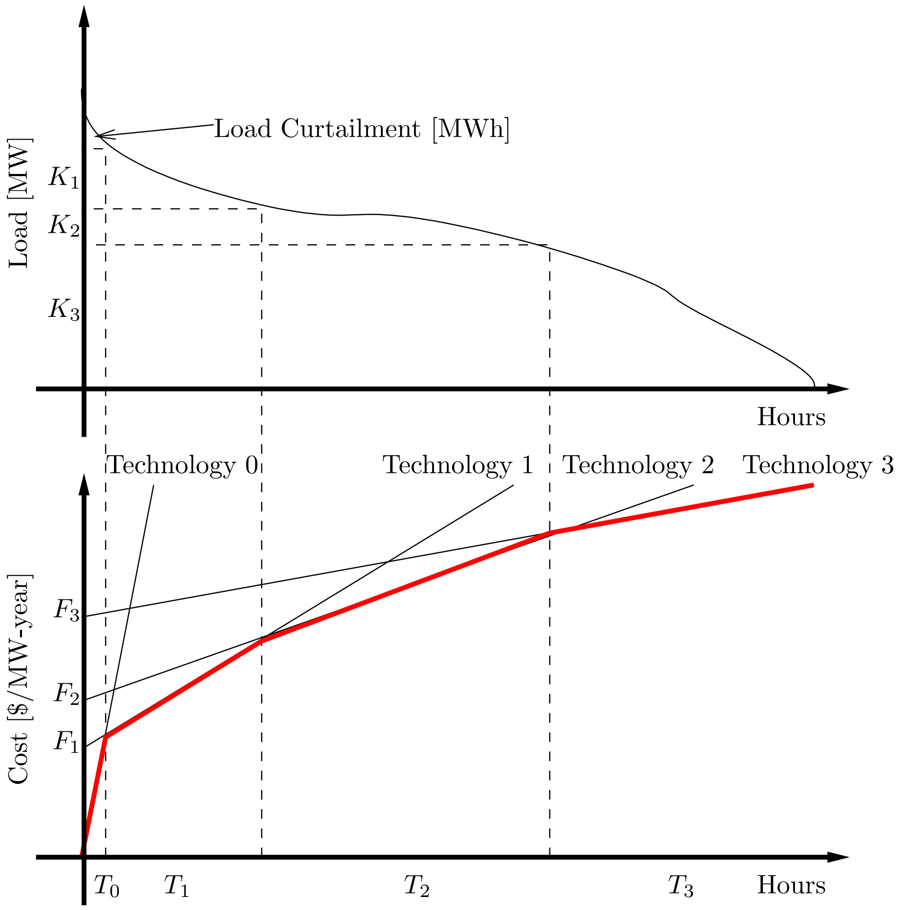

Figure 1: Determination of an optimal generation mix by combining load-duration and cost curves.

Theorem 1. *If the generation capacity mix is optimal (*i.e., *it satisfies Properties 2 and 3) and generators are dispatched in merit order based solely on C_n (*i.e., *Property 1 is satisfied), then the following remuneration scheme ensures full fixed- and variable-cost recovery:*

1. *whenever load is curtailed, the system marginal cost is set equal to VOLL (*i.e., *C_0); and*
2. *each MWh produced is paid the system marginal cost.*

Proof. We prove this result by referring to Figure 2. Consider the increment of capacity of technology n that operates:

$$\sum_{i=0}^{n-1} T_i + \hat{T}_n,$$

hours. The total fixed and variable per-MW cost of this capacity increment is given by:

$$F_n + C_n \cdot \left(\sum_{i=0}^{n-1} T_i + \hat{T}_n \right),$$

which is indicated by the dot in Figure 2.

Now, consider the per-MW revenue earned by this capacity increment through the remuneration scheme proposed. During the T_0 hours of the year that load is curtailed it is paid C_0 per MWh. During the T_1

hours of the year that Technology 1 is marginal it is paid C_1 per MWh. Repeating this argument we find that its total revenue is given by:

$$\sum_{i=0}^{n-1} C_i \cdot T_i + C_n \cdot \hat{T}_n. \tag{1}$$

Adding each of the revenue terms (corresponding to the hours of the year during which the different technologies are marginal) in Equation (1) traces the lower envelope of the cost curves and gives the same dot in Figure 2 corresponding to the per-MW cost of the capacity increment.

Thus, we have that:

$$F_n + C_n \cdot \left(\sum_{i=0}^{n-1} T_i + \hat{T}_n \right) = \sum_{i=0}^{n-1} C_i \cdot T_i + C_n \cdot \hat{T}_n,$$

meaning that this capacity increment exactly recovers all of its fixed and variable costs through the proposed remuneration scheme. □

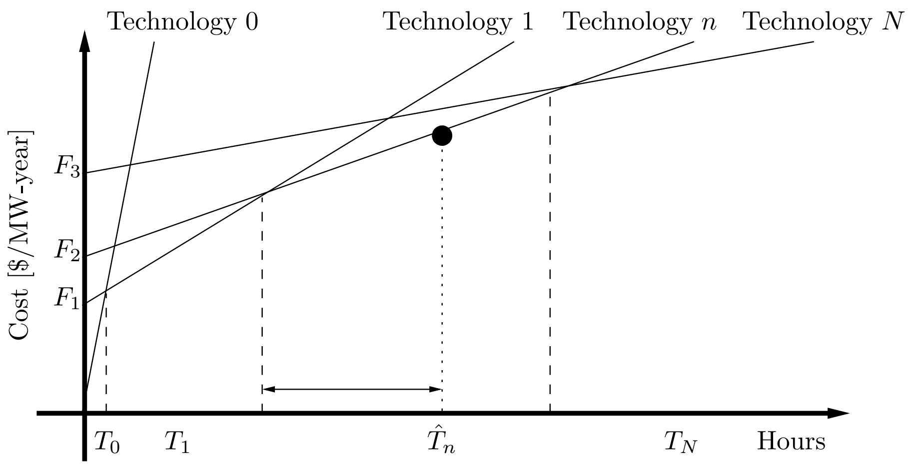

Figure 2: Illustration of proof of Theorem 1.

Theorem 2. *If the assumptions of Theorem 1 hold then the following remuneration scheme ensures full fixed- and variable-cost recovery:*

1. *whenever load is curtailed, the system marginal cost is set equal to the variable cost of the peaking technology (*i.e., C_1*);*
2. *each MWh produced is paid the system marginal cost; and*
3. *every generator is given a capacity payment equal to the capacity cost of the peaking technology (*i.e., F_1*).*

Proof. This result follows easily from Theorem 1. Under the remuneration scheme proposed here, the increment of generation capacity shown in Figure 2 earns:

$$C_1 \cdot T_0,$$

in per-MW revenues whenever load is curtailed. It also receives a per-MW capacity payment of F_1. Thus, its total per-MW revenue is defined as:

$$F_1 + C_1 \cdot T_0 + \sum_{i=1}^{n-1} C_i \cdot T_i + C_n \cdot \hat{T}_n.$$

However, Property 3 requires that:

$$C_0 \cdot T_0 = F_1 + C_1 \cdot T_0.$$

Thus, under the remuneration scheme proposed here the capacity increment shown in Figure 2 earns:

$$F_1 + C_1 \cdot T_0 + \sum_{i=1}^{n-1} C_i \cdot T_i + C_n \cdot \hat{T}_n = C_0 \cdot T_0 + \sum_{i=1}^{n-1} C_i \cdot T_i + C_n \cdot \hat{T}_n = \sum_{i=0}^{n-1} C_i \cdot T_i + C_n \cdot \hat{T}_n,$$

in per-MW revenues, which is exactly equal to the per-MW revenue earned under the remuneration scheme proposed in Theorem 1. □

4.3. Retail Pricing Proposals

Following from the two cost-recovery theorems, we propose two retail pricing structures that can alleviate the cost-recovery and potential cross-subsidy issue raised in Section 3. The first is retail-level RTP with a net-metering system and the second is a two-part tariff that includes a demand charge. As discussed in Section 1, these retail pricing schemes are not novel and are currently implemented in certain jurisdictions for small residential customers (Sakhrani and Parsons, 2010).

4.3.1. Real-Time Pricing

The motivation for RTP follows directly from Theorem 1. Theorem 1 shows that marginal pricing at the wholesale level ensures that the variable and fixed costs of all generation, transmission, and distribution assets are fully recovered. This is because inframarginal rents between the marginal price at any given time and a particular asset's variable cost contribute to recovering its fixed cost. Under this proposal, the time-variant wholesale marginal price is directly transferred to customers through time-variant real-time prices.

The primary advantage of RTP is that it efficiently prices the energy and capacity values of DRE resources. The ability of a DRE installation to reduce variable generation costs is captured by the time-varying retail price. If DRE produces energy when the retail price is high (meaning during times that the system is relying on high-variable-cost generation), the DRE is reducing this variable cost. The customer is given a direct financial incentive for providing this high-value energy, by having to purchase less energy from the system and relying on self-generated energy instead exactly when the retail price is high. Moreover, under RTP the retail price is at its highest when system capacity is limited and load is being served with high-variable-cost generation or curtailed. If a DRE resource provides energy when real-time prices are high, that means it is providing energy when system capacity is scarce. However, such a DRE resource is reducing the need for capacity to be built and maintained. Thus, the real-time prices properly value DRE in reducing system capacity needs. RTP also provides for efficient allocation of capacity cost among customers. This is because customers with DRE that reduces capacity needs purchase less energy from the system during periods of scarcity and contribute less inframarginal rent toward fixed-cost recovery.

Borenstein (2005) notes other advantages of RTP, which are independent of DRE, in providing for more efficient short-run consumption decisions and long-run investment than the alternative of time-invariant retail pricing. Borenstein (2002) also notes some benefits that RTP could provide in reducing the exercise of market power in liberalized wholesale electricity markets. RTP also has the potential to provide benefits in integrating large amounts of distributed and grid-scale renewable energy into power systems. This includes improved technical operations (Sioshansi and Short, 2009; Madaeni and Sioshansi, 2013a), long-term investment (De Jonghe et al., 2012), and short-run operations (Klobasa, 2010; Sioshansi, 2010; Dietrich et al., 2012; Madaeni and Sioshansi, 2013b).

The renewable-integration benefits of RTP stem from having customer demands follow the real-time availability of renewable energy. This is because real-time marginal prices reflect this availability. When the system has excess renewable energy available real-time prices drop whereas prices rise when the system is short on renewable supply. Having consumption patterns reshaped based on such price patterns mitigates the negative effects of renewable variability and uncertainty. These benefits of RTP would apply just as well to integrating DRE as they do to utility-scale renewable plants. Thus, RTP has an added benefit (beyond cost recovery) of easing technical challenges raised by integrating large amounts of DRE.

The primary disadvantage of RTP is that it can introduce price and cost uncertainty to end customers. One way to overcome this is to use a hedging-type mechanism, such as that suggested by Borenstein (2007). Under such a scheme customers receive a certain allowance of energy at a locked-in time-invariant price. Customers then pay or are paid the real-time price for any deviation between the contracted quantity and their actual consumption. This type of an arrangement reduces bill volatility while still exposing customers to real-time prices for their 'marginal' energy consumption.

Another possibility is to introduce blocked time-of-use (TOU) or a similar pricing scheme. If such a pricing scheme is designed properly (*e.g.*, to reflect the average wholesale price of energy during different blocks of time), it should provide some of the DRE-related efficiency and cost-allocation benefits of RTP. Moreover, Borenstein and Holland (2005) show that such a retail pricing scheme can provide some of the general economic efficiency benefits of RTP. However, the renewable-integration benefits listed above would not be provided as these rely on customer demands responding to real-time renewable availability. Static blocked pricing, such as a TOU scheme, could not provide such demand response. Moreover, for such a TOU-type scheme to address the DRE cost-allocation issue, the price blocks would need to be updated as new renewable capacity is installed in the system. This is to ensure that the time blocks and the associated retail prices charged during each, reflect capacity scarcity given the *current* capacity mix. This price updating is, in essence, meant to correct for the declining capacity value of DRE resources as their penetration rises.

4.3.2. Demand Charges

The alternative of using demand charges follows from Theorem 2, which suggests the use of a capacity payment to supplement energy revenues for cost recovery. In theory, demand charges could be implemented with time-variant retail prices. Indeed, implementing such exactly mimics the remuneration scheme in Theorem 2. However, if time-variant pricing is to be used, RTP (in line with our first recommendation) would be preferred for the reasons discussed above. Thus, our alternative proposal is to price retail energy using a two-part tariff. The first part is a time-invariant energy charge, which is based on the average per-MWh variable cost of operating the system. The second is a capacity charge, which is based on the fixed cost of the peaking capacity in addition to capital and maintenance costs for transmission and distribution (*i.e.*, F_1).

As with the RTP proposal, this proposal would be based on *net* energy consumption by the end customer. The energy charge would be based on energy consumption net of energy produced by any DRE installation. The demand charge would be based on the peak net (of DRE production) customer demand. Setting the demand charge based on *net* peak demand is what ensures that the capacity value of DRE is properly remunerated. If a DRE resource contributes capacity value it reduces the amount of capacity that must be built and maintained to serve the customer. Thus, the DRE resource should reduce the demand charge, which is intended to pay for capacity costs.

Our proposal is agnostic as to whether the demand charge is determined based on an annual or sub-annual peak. For instance, a customer's monthly or seasonal peak could be used. An important implementation issue is whether the demand charge is based on each customer's individual peak consumption or consumption during the coincident-peak period. Setting the demand charge based on the coincident peak provides the correct economic signal. This is because a customer's consumption during the coincident-peak period determines how much capacity must be built and maintained to serve that customer. However, such a pricing scheme would introduce some uncertainty, as the customer would have to anticipate when the coincident-peak period is. This may have an advantage, however, in that the uncertainty may incentivize conservation during periods that the customer believes could be the peak-coincident period. An easier pricing scheme would set the demand charge based on each customer's individual peak consumption. While this may be simpler and carry less uncertainty to the end customer, it undervalues the capacity value of DRE resources. This is because a DRE resource may not reduce an individual customer's peak demand but may produce energy during the system's peak demand (thereby reducing capacity needs).

The primary disadvantage of using demand charges is that it does not carry all of the ancillary benefits that RTP does. This includes less efficient energy consumption decisions and loss of renewable-integration benefits. As noted above, an added benefit of RTP is that it can help mitigate the negative impacts of real-time DRE availability uncertainty and variability. Demand charges would have no benefit in this area.

5. Conclusion and Policy Implications

In this paper we examine the question of how to incentivize the adoption and use of renewable energy resources, with particular attention on DRE. Our survey of systems that have been used suggest that FiTs tend to work better than quantity-based systems. The tendering system has been the least successful of those implemented in the past. If well designed, a quota-obligation system can effectively encourage renewable adoption. However, even in the case of Texas, where an RPS has been largely successful, it is not clear if an FiT would not have delivered the same levels of renewable investment at lower cost (given the cost results observed in the United Kingdom). Comparing the experience in the United Kingdom, Germany, and Denmark suggests that FiTs can deliver renewables at lower total cost than quantity-only based mechanisms. This is a question requiring further research.

In the particular case of DRE a net-metering system, either on its own or in conjunction with an FiT or quantity-based incentive program, can effectively spur renewable investment. Its success largely depends on the quality of the renewable resource and the level of retail prices. The southwestern United States has seen great DRE deployment as a result of such programs. High penetrations of DRE introduce some major cost-allocation issues between customers with and without DRE systems. DRE with time-invariant volumetric charges results in an increasing share of capacity costs being borne by customers without DRE. This can create a vicious 'death spiral,' in which more and more customers adopt DRE systems due to increasingly rising retail prices. Eventually, capacity costs may be borne almost entirely by the socioeconomically disadvantaged, who do not have the means or financing to invest in DRE systems. To date, regulatory bodies in a number of regions that have acutely suffered from this issue have reacted by limiting, rescinding, or eliminating incentive programs for DRE. In other instances, explicit limits on how much DRE can be deployed have been enacted.

We propose two alternative retail pricing schemes—RTP and two-part tariffs with demand charges—to alleviate these cost-allocation and cross-subsidy issues. Moreover, RTP has some general economic efficiency and techno-economic renewable-integration benefits. This includes mitigating the negative impacts of real-time DRE availability variability and uncertainty. Demand charges, on the other hand, do not provide these ancillary benefits. These pricing schemes are not novel. Sakhrani and Parsons (2010) discuss the historical use of demand charges and time-varying energy charges for small residential customers. Our contribution here is to demonstrate the cost-allocation benefits of such pricing schemes in the face of DRE and other distributed generation technologies.

It is important to stress that the retail pricing structures that we suggest are directly amenable to and build off of the concept of a net-metering system. Moreover, other incentive programs, such as FiTs and quantity-based schemes, can be directly used in conjunction with these retail pricing schemes. One open question that this work raises is the long-term impact of the proposed retail pricing schemes on DRE financing and adoption. Time-invariant volumetric pricing of energy results in distortionary capacity pricing (either under- and over-valuing the capacity value of DRE, depending on the overall penetration level). What effect correcting this distortion would have on overall rates of DRE adoption is an open question that begs further research. Allocation of capacity costs to a DRE owner will have important implications on project financing.

Acknowledgments

The work reported in this paper was supported by the Economic Research Institute for ASEAN and East Asia (ERIA) through award number ERIA-RD/RE-001-001-411/04/FY14. The author would like to thank participants in the two 'Financing Renewable Energy Working Group Meetings' organized by ERIA for providing helpful comments and feedback. Armin Sorooshian, Yanfei Li, Ross Baldick, and three anonymous reviewers helped to this end as well. All of the opinions expressed here are solely those of the author and do not necessarily represent those of any other individual or organization, including ERIA.

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