Chapter 9

Retail Electricity Tariff and Mechanism Design to Incentivise Distributed Generation

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Chapter 9

Retail Electricity Tariff and Mechanism Design to Incentivise Distributed Generation[34]

Ramteen Sioshansi

Abstract

*This chapter examines the question of how to incentivise the adoption and use of renewable energy resources, with particular attention given to distributed renewable energy. Prior experience suggests that price and quantity-based programmes such as feed-in tariffs provide more efficient renewable adoption and use and lower costs than programmes that set quantity targets only. Some cost-allocation issues raised by the use of distributed renewable energy systems and fixed time-invariant retail pricing are also examined. This combination can result in customers with distributed renewable energy systems paying a disproportionately small portion of system capacity costs. This chapter suggests two retail-pricing schemes – i.e., real-time pricing and a two-part t*ariff with demand charges – to address these issues.

Keywords: Distributed generation, retail electricity pricing, incentive mechanisms

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All the opinions expressed here are solely those of the author and do not necessarily represent those of any other individual or organisation, including ERIA.

1. Introduction

The recent years have seen more 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 and favourable regulations.

According to Sawin et al. (2014), at least 144 countries had some type of renewable energy target or incentive programme in place as of early 2014. These incentive mechanisms aim 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 the use of these technologies, the lower the expected costs because of economies of scale in manufacturing and installation and `learning-by-doing' effects. These technologies thus become more competitive compared with alternatives. If taken to fruition, the incentive programmes can drive DRE technologies to a point of maturity such that they will be able to compete with alternatives even without any incentive mechanisms at all.

Different jurisdictions have used various combinations of incentive mechanisms to spur DRE adoption. These mechanisms can be in terms of either (a) direct financial subsidy for DRE adoption or use or (b) provision of a guaranteed market for DRE energy. Experience to date has shown that these mechanisms have different levels of success in encouraging DRE adoption.

Moreover, there are key implementation nuances that can help or hinder the performance of incentive mechanisms. Some incentive mechanisms have 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 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 programmes to mitigate these issues.

This chapter studies the problems in incentive and retail tariff programmes that are designed to efficiently encourage DRE adoption and use. It also identifies lessons from previous attempts and failures. It presents its recommendations on how to mitigate the unintended cost-allocation consequences of DRE-related incentive schemes through better tariff design.

The remainder of this chapter is organised as follows: Section 2 summarises the types of incentive programmes used to date. It also provides a comparative assessment of how well different programmes faired and discusses the philosophical reasons certain mechanisms are sometimes favoured over others. Section 3 introduces the negative cost-allocation consequences of these programmes. Section 4 discusses a proposal for retail tariff design that can address some of the cost-allocation issues discussed in Section 3. Section 5 presents the conclusions.

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.[35] Distributed renewable energy historically has two competitive disadvantages relative to other 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, thus increasing the financing costs of DRE technologies. Second, DRE technologies may have higher upfront costs due to their relative immaturity compared to conventional alternatives, further complicating financing.

Incentive mechanisms aim 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 drive this cost and risk reduction. The four major incentive mechanisms commonly used are the (a) feed-in tariff (FIT), (b) quota-obligation, (c) tendering, and (d) net-metering systems. This study also discusses other financial subsidy systems that have been used and important technical considerations when integrating DRE into electric power systems.

2.1. Feed-In tariffs

Feed-in Tariffs (FITs) are currently the most widely used DRE-related incentive

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

mechanism. Umamaheswaran and Seth (2015) defined the fundamental features of FITs as a guaranteed price for and guaranteed purchase of energy produced by a DRE system. That is to say, a FIT programme provides a guaranteed payment for each kWh of energy produced by a qualifying DRE installation. Most FIT programmes also require the local utility or system operator to accept any DRE provided by the end customer, except when this is infeasible for technical reasons. These design features reduce the risk associated with a DRE investment by providing a guaranteed market for energy produced.

The primary advantage of a FIT programme is that it manages the revenue risk in a DRE system by guaranteeing the quantity of energy sold and the price at which it is sold. This lowered risk tends to effectively ease project financing. According to Lipp (2007), these price and quantity guarantees are often provided for 8 to 15 years, but sometimes for as long as 30 years. Fouquet and Johansson (2008) and Umamaheswaran and Seth (2015) noted that the reduced risk allows DRE developers to more effectively leverage debt and to bring down financing costs.

Lipp (2007) also highlighted that a FIT programme can be tailored to different DRE technologies. For instance, the guaranteed price per kWh provided by a distributed solar plant can be set differently from that for a distributed wind plant. This allows the FIT programme to accommodate the relative maturity of different technologies. Van der Linden et al. (2005) and Lipp (2007) observed that the price guarantees in a FIT programme can also decline over time.

Van der Linden et al. (2005) noted that the main criticism of the FIT system is that its efficiency depends on how accurate the price guarantee has been set. 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 programme may be ineffective in spurring any DRE development.

The information needed to correctly set FIT price guarantees largely comes from DRE owners or developers, although these may not have any incentive to reveal their true costs. In fact, these agents may have strong incentives to overstate their costs.

The FIT design is 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, according to Lipp (2007), 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 the least cost.

Feed-in tariffs have been implemented in a number of jurisdictions successfully; that is, in the sense that they have spurred DRE adoption. One of the first examples, the Public Utility Regulatory Policy Act (PURPA) of 1978 in the United States, guaranteed payments for qualifying energy-producing facilities. Payments were based on assumed future fossil fuel costs, which were estimated at $100 per barrel of oil by 1998. However, the high price guarantees of PURPA did not prevail and the programmes 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 was implemented in Germany and Denmark in the 1990s. Programmes required utilities to purchase energy from qualifying renewable energy installations at prices that were established by the government. The price premia aimed to compensate renewable energy facilities for the unpriced environmental benefits of their renewable energy generation. Denmark introduced its FIT programme in 1993 with a fixed price paid to qualifying facilities. This was modified towards a more market-based design in 2001. Under the new design, qualifying facilities are paid the price established by NordPool[36] plus an environmental premium. According to Mitchell et al. (2006), this created a 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 programmes in the 1970s. As with PURPA, these programmes were spurred by high fossil fuel prices. The first German programme had a similar design as PURPA, but provided much lower price guarantees. Thus, it had very limited success in spurring technology deployment. A FIT bill, which required utilities to connect DRE generators to the grid and purchase their produced electricity at a price that is 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 in the system

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

within five years.

The FIT law was 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 action acknowledged the 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, costs were borne by customers of each local utility. The new programme, on the other hand, spreads these costs nationwide. This way, it avoids the scenario where costs are 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 cluster). The new FIT law fixed payments to qualifying facilities for 20 years but also included explicit provisions to reduce rates paid to new deployments over time to reflect the maturing of technologies.

Parts of the FIT concept here have been employed in other parts of the world as well. As an example, Liu and Kokko (2010) discussed the `Opinion on Wind Power Farm Construction and Management' of the Chinese Ministry of Power in 1994. This policy statement required power grids to purchase all electricity generated by wind plants and made sure that the price paid was set high enough to cover costs. It provided 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. The 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

Compared to the FIT, the quota-obligation system takes a fundamentally different approach to incentivising DRE. Under this 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). The RPS, widely used in the United States and in other countries, typically covers all renewable energy sources, including DRE, in its mandate.

Renewable portfolio standards can vary considerably in their implementation details. One question on the design of RPS is: To whom should the obligation be placed? Often, the obligation is placed on the retail energy supplier. However, it could presumably be placed on generators or end customers. In the latter's case, the retail energy supplier would procure qualifying energy resources on behalf of most customers. This is tantamount to the RPS placing the obligation on the retail supplier. However, placing the obligation on the customer may give large commercial and industrial customers added flexibility 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 should specify either the amount of renewable energy or the renewable capacity that must be procured. Of the two, the former is more typically used as it provides a strong incentive to build plants in locations that have available renewable resource and to drive plants to operate efficiently. These outcomes, in contrast, cannot be attained if generating facilities' obligation is capacity-based.

Energy-based RPS programmes typically create a new set of tradable instruments known as renewable energy certificates (RECs) whenever a qualifying renewable facility produces energy. These can be traded or sold to entities that then use them to meet their RPS obligations. Renewable energy certificates do not typically have to be sold to the buyer of the energy from 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, and 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. It can then use dispatchable generation to serve its customers' demands.

The renewable facility can sell its energy in an organised wholesale market or through bilateral contracts with 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 incentivises parties to met their obligations using the lowest-cost technology available. Relatedly, the design provides strong incentives to reduce technology costs. Mitchell et al. (2006) and Lipp (2007) saw a philosophical advantage to quota-obligation systems, in that the 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 quota-obligation systems allow the market to determine what combination of technologies to use. Mitchell et al. (2006) further noted that because the quota-obligation system does not set specific prices for different technologies, the government is not in a position to pick 'winners' and 'losers.'

However, these features of the quota-obligation system can be weaknesses as well. If a goal of DRE incentive programmes is to drive down costs in the long run, a quota-obligation system may only achieve this for mature technologies (van der Linden et al., 2005; Lipp, 2007). The less mature technologies that are costlier will not be deployed until the marginal cost of the mature technology is equalised with the less mature one.

This 'myopic' design of a quota-obligation system can retard the development of a nascent technology that shows some promise from a long-run perspective. To overcome this problem, one can set technology-specific obligations or technology-specific `REC production rates'. For example, one can design a programme wherein wind generators produce one REC per megawatt hour (MWh) whereas tidal generators produce three RECs per MWh. This way, a distinction is set among technologies at different maturity levels. The United Kingdom implemented such a technology-specific conversion rate in its quota-obligation system (Fouquet and Johansson, 2008).

However, the same issues related to setting the proper price in a FIT will now be faced if this conversion rate approach is used in a quota-obligation system.

Another major weakness of the quota-obligation system is that it can introduce more price uncertainty than the 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 renewables 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. The underlying goal of the programme is therefore not achieved, unless the quota-obligations are intentionally set at higher-than-desired levels.

In other instances, the price risk and uncertainty have made financing DRE and renewable projects more difficult. A way 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. By integrating, these firms now become larger and thus have greater access to the capital and financing they need. Moreover, each retail supplier has a guaranteed 'market' for its RECs, reducing the volume risk that an independent renewable generator faces. Thus, quota-obligation systems as a mechanism are less likely to incentivise DRE projects. That is, while DRE projects tend to be owned and operated by small producers, quota-obligation systems are often observed to favour large producers instead (Mitchell et al., 2006; Lipp, 2007). 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 RECs' price uncertainty. In the United Kingdom's programme, 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*. The market price of RECs is determined by how aggressively the obligation is set, the level of the penalty for non-compliance and other factors. It is also important to stress that if values are set too aggressively, this can result in excessively high REC prices and windfall profits to qualifying renewable and DRE suppliers.

The first application of quota-obligation systems, which was in the form of RPSs, appeared in the United States (van der Linden et al., 2005). Through the years, the US experience has been quite mixed. On one hand, Texas has had a very successful programme that seems to have overcome many of the volume and price risks that a quota-obligation system can carry. Langniss and Wiser (2003) noted 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 a FIT does, allowing for lower-cost financing of a renewable project.

On the other hand, van der Linden et al. (2005) cited the case of utilities in the state of Nevada. Here, the utilities had signed contracts with renewable developers that failed to bring their projects on-line, resulting in substantial under-compliance with the state's quota-obligation. The state regulator further declined to penalise 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 an RPS in the state.

Similarly, Sweden implemented a quota-obligation system beginning in 2003 that has seen disappointing results (van der Linden et al., 2005). In the first year of the programme, the compliance level was about 77.1% of the quota, despite an excess of about 2 million RECs being banked for future use. The outcome was due to market participants' expectation that the price of RECs will rise in subsequent years.

There too was the issue with regulatory uncertainty in the Swedish system. The programme was initially slated to run from 2003 to 2010 – a total of 7 years – without any clear indication of whether it would continue past that point. Thus, a potential renewable/DRE project could only rely on a seven-year REC market. This design feature significantly limited the extent to which the programme provided revenue certainty to a potential DRE or renewable developer. Moreover, the programme underwent several modifications during this 7-year period and beyond. This included changes to the future quota level and potential harmonisation of the programme with Norway. All these uncertainties increased financing challenges on potential renewable energy projects.

One major lesson from the experience with quota-obligation systems – which applies just as well to any other type of incentive programme – is that there must be clear political commitment to the programme. Any risk (or even a perceived risk) that a programme will be substantively modified or abandoned could significantly halt a project's development.

Some DRE and renewable incentive programmes include explicit provisions for the government to conduct subsequent studies of the effectiveness of the programme. 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 programme may waver in the future, even if the government insists that the reviews are limited in scope.

These and other issues have kept some quota-obligation systems from delivering their theoretical promise of meeting renewables targets at minimum cost. Fouquet and Johansson (2008) estimated that in 2003 wind generation in the United Kingdom, which operates a quota-obligation system, cost €0.096/ kilowatt hour (kWh) as opposed to the FIT cost of between €0.066/kWh and €0.088/kWh in Germany. This is despite wind speeds being much more favourable to wind energy development in the United Kingdom than in Germany.

Lipp (2007) found similar disappointing cost results for the quota-obligation system in the United Kingdom. That is, the incentive scheme in the United Kingdom delivers wind energy at an average cost of €110/MWh as opposed to the average costs of €80/MWh and €57/MWh in Germany and Denmark, respectively. According to Lipp, the excellent performance of the Danish FIT system has motivated its producers to reduce wind turbine costs, as this allows them to sell more turbines within the country.

Meanwhile, India uses state-level RPS-type mandates that are supplemented with tariffs and other provisions to subsidise renewable costs (Umamaheswaran and Seth, 2015). The national-level legislation further mandates that the state-level programmes introduce technology tiers – for instance, specifying targets for solar. An issue that has hampered the success of these efforts is that states have been focused on minimising policy costs. For instance, the tariff supports provided by many states for wind have been too low to encourage more investment and development.

2.3. Tendering system

Tendering systems are very similar to quota-obligations in their approach to incentivising 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 programmes is that a tendering system relies on a centralised 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 may set different targets for different renewable and DRE technologies.

Most tendering systems, 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 the 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 renewables developer with price and quantity stability. A price guarantee in the PPA should provide greater risk reduction than a quota-obligation system. In practice, however, most tendering schemes have not worked as well as FIT or quota-obligation programmes.

The tendering system implemented in China provides valuable lessons for other countries. Liu and Kokko (2010) noted that China’s aim to get the most minimal cost for its tendering system resulted in bids that were too low such that it was unlikely for the winning bidder to recover its costs. This resulted in several of the contracted projects being severely delayed or never built. Similar results were seen in tendering systems used in England, Wales, and California (Langniss and Wiser, 2003; van der Linden et al., 2005; Lipp, 2007; Fouquet and Johansson, 2008; Umamaheswaran and Seth, 2015). These programmes 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 towards incentivising investment in DRE. A net-metering system requires a local utility to purchase energy produced by its customer from the latter’s onsite facility at the same retail price charged to the customer for energy consumption. If the customer’s onsite renewable energy facility produces less than his/her energy consumption, this DRE production offsets the amount of energy drawn from the utility’s system. Thus, the utility sells less energy to the customer.

On the other hand, if the customer’s onsite renewable energy facility produces more than his or her energy consumption, the excess energy is fed back into the local utility system. In this case, the customer's meter runs backwards to reflect the energy being sold to the local utility. In other words, 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 its whole DRE system has a guaranteed 'market' for energy sales, insomuch as the utility company 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 programmes 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 in a pure net-metering scheme. This depends on whether the DRE earns the guaranteed payments specified in the FIT programme (in addition to offsetting consumption when 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 programmes 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 in areas where conditions are appropriate. In the United States, the schemes have been very successful in the southwestern states, especially in California. This region 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) reported 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 during peak demand.

2.5. Other financial subsidies

In addition to the four programmes already discussed, some jurisdictions have pursued more direct financial subsidies. One approach, which addresses the high capital cost of many DRE and renewable technologies, is direct capital subsidies.

Direct capital subsidies can take the form of project-specific grants. In the United States, these are in the form of investment tax credits, which provide tax relief based on the capital cost of a project. However, capital cost-based subsidies are typically seen as suboptimal, 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 minimises investment cost.

For these reasons, production- or performance-based subsidies are strongly preferred. The four mechanisms discussed earlier all have this feature (Note that in the case of a tendering or quota-obligation system, it has this feature if the obligation is energy-based as opposed to capacity-based.).

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

2.6. Renewables Integration

Integrating renewables and DRE resources into an electric power system can entail ancillary costs, in addition to the capital cost of the plant itself. One is the cost of transmission and distribution infrastructure that can interconnect a plant with the DRE system. Transmission infrastructure would apply more to utility-scale renewables whereas distribution infrastructure is to DREs. Texas and China present two interesting case studies on how to address 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 will be deployed (Langniss and Wiser, 2003). These costs are then socialised to customers on a pro-rata basis. In the case of China, Liu and Kokko (2010) noted that the State Grid (one of the two transmission system operators in the country) invested in a wind power project. The investment provided the State Grid with a strong incentive to make transmission investments. By doing so, it was able to maximise the value of its wind plant investment. It should be noted, however, that the 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 may be taken to incentivise transmission and distribution investments. Proactively making transmission and distribution investments in anticipation of renewable and DRE installations reduces risks associated with plants' inability to deliver their product to the market. Although cost socialisation is typically suboptimal, it is an easy means of allocating costs.

Vertically integrating transmission and generation runs counter to most electricity market restructuring efforts. For this reason, this paper does not necessarily recommend the Chinese approach of transmission investment. However, this type of an arrangement could be implemented for distribution infrastructure investments needed for DRE integration. One approach is 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 proper incentives to ensure that there is sufficient capacity to distribute available DRE resources.

3. Cost-allocation issues with distributed renewable energy

Distributed renewable energy programmes and others that incentivise renewable energy adoption and use have 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. This type of volumetric pricing is especially applied for residential customers. Some large commercial and industrial customers may, conversely, be subjected to more exotic pricing mechanisms. The use of energy-based volumetric pricing emanates from the assumption that the costs of providing customers' capacity and energy needs are roughly proportional to their energy use. In other words, a customer with twice as much energy consumption as another would impose roughly double the capacity-related costs on the system.

The cost of implementing 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 an advance metering infrastructure that has historically been relatively expensive.

Distributed renewable energy (and indeed, all forms of distributed energy) threatens the viability of this historic cost recovery mechanism. This is because DRE can affect a customer’s energy needs disproportionately to their capacity needs. To understand this effect more concretely, the concept of capacity value is used (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. As a commonly used capacity value metric, the 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 understand how DRE affects electricity system cost recovery, consider the case of a residential customer in the Los Angeles 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) simulated PV generation in the Los Angeles area and estimated 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 and 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 programmes provide incentive payments based on energy generated by a DRE without consideration of its effect on capacity needs and cost.

Volumetric charges based on energy consumption only can result in `arbitrary' cost allocation to a customer with DRE because the capacity value of DRE resources is highly system-specific. Madaeni et al. (2013) estimated ELCCs for 1 kW PV panels in the western United States and found that they can range between 0.52 kW and 0.70 kW. It is also important to stress that the ELCC estimates from Madaeni et al. (2013) are 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 load shortage will shift from sunny afternoons to other hours that may have less solar resource available. This is supported by the survey done by Mills and Wiser (2012) on a variety of systems at different PV penetration levels: They found that capacity value estimates of solar PV drop quite rapidly as the penetration of PV increases.

This diminishing capacity value of PV has its implication. That is, 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, 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 this example has almost no benefit in reducing capacity needs and costs.

Overall, volumetric charges result in inefficient cost allocation in 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, a high penetration 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 because DRE tends to be installed by customers that are socio-economically 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 and who tend to be socio-economically worse off than those with DRE.

4. Proposed tariff design

In this section, two retail pricing structures are proposed – i.e., real-time pricing (RTP) and a two-part tariff with demand charges – to address the cost-allocation issue raised in Section 3. The stylised screening model introduced by Stoft (2002) is used here to justify the proposed pricing schemes.

This section first introduces the simplified capacity investment model. Then, it presents the two cost recovery theorems that explain what wholesale pricing structures could be used to recover fixed capacity investment and variable operating costs. Finally, results of the two cost recovery theorems are used to justify the proposed retail pricing schemes. This paper then discusses the relative trade-offs between the two. Some practical implementation details are also discussed.

4.1. Capacity investment model

The capacity investment model here assumes that a power system entails capacity investment and generator operation. Capacity planning includes investments in generation, transmission, and distribution. The system is assumed to have N different generation technologies available. Let F_n denote the per-MW fixed cost of installing and maintaining generation technology n. The model is indifferent as to whether F_n represents the total fixed cost of the generation asset over its lifetime or an amortised cost (e.g., the sum of an annualised capital cost and annual fixed maintenance cost). For ease of exposition, assume that F_n is an annualised fixed cost. Also, 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. Let C_n denote the per-MWh cost of operating generation technology n to serve customer demands.

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

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

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

and:

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

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. 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, technology *1* is hereafter refer to as the `peaking' generation technology.

An optimal generation mix has three important properties:

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 technical restrictions are not considered (e.g., ramp-constrained unit commitments) in generator operations. Hereafter, generating technology with the highest variable cost operating in a given hour is referred to here 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:

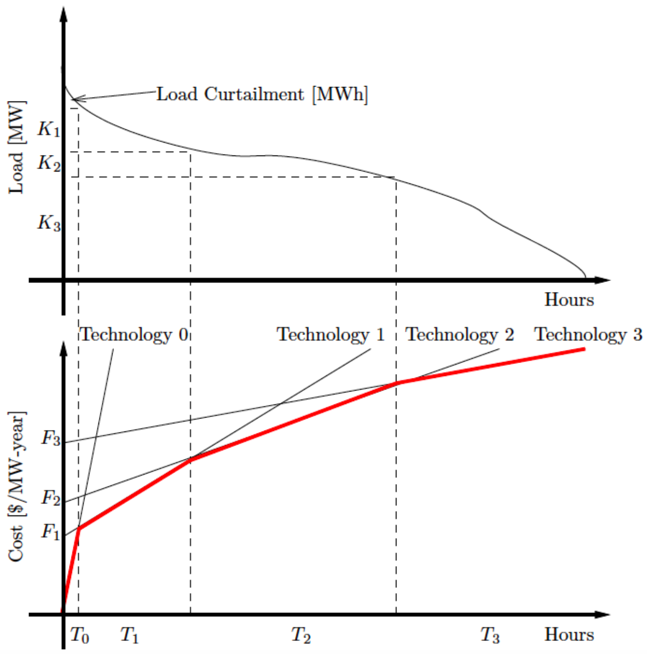
$$F_1 + C_1 \cdot T_0,$$

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 9.1 illustrates Properties 1 to 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 analysed analogously. The bottom pane of Figure 9.1 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, the C_n's.

Figure 9.1: Determination of an Optimal Generation Mix By Combining Load-duration and Cost Curves



Source: Prepared by the author.

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 9.1. 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. Meanwhile, T_0 represents the number of hours that load is curtailed and T_1 through T_3 are 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 9.1, and then projecting the intersection point with the LDC onto the vertical axis.

Then, 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

This section presents the two cost recovery theorems, which are then used to justify this study's proposed retail pricing mechanisms.

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. This result is proven by referring to Figure 9.2. 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 9.2.

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. By repeating this argument, its total revenue is given by:

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

Adding each of the revenue terms (corresponding to the hours of the year during which the different technologies are marginal) in the above equation traces the lower envelope of the cost curves and gives the same dot in Figure 9.2 corresponding to the per-MW cost of the capacity increment.

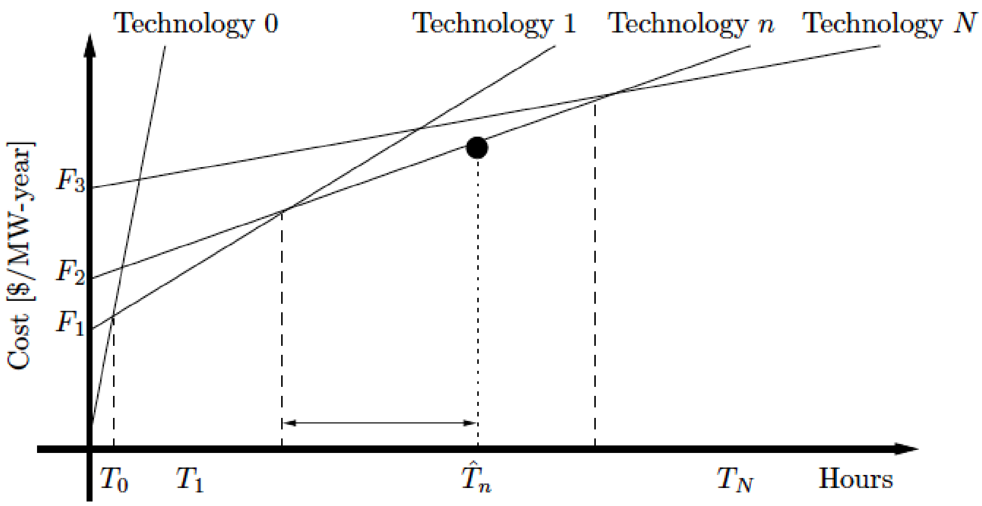
Thus,

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

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

■

Figure 9.2: Illustration of Proof of Theorem 1



Source: Prepared by the author.

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 9.2 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:

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

However, Property 3 requires that:

$$\mathrm{C_0 + T_0 = F_1 + C_1 \cdot T_0}$$

Thus, under the remuneration scheme proposed here, the capacity increment shown in Figure 9.2 earns:

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

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 the two cost recovery theorems, two retail pricing structures that can alleviate the cost recovery and potential cross-subsidy issue raised in Section 3 are now proposed. The first is the retail-level RTP with a net-metering system. The second is a two-part tariff that includes a demand charge.

4.3.1. Real-time pricing

The motivation for RTP comes 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 infra-marginal 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.

Under RTP, the retail price is at its highest when system capacity is limited and the load is either being served with high variable cost generation or curtailed. When a DRE resource provides energy when real-time prices are high, 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.

Real-time pricing also provides for efficient allocation of capacity cost among customers. Customers with DRE that reduces capacity needs will purchase less energy from the system during periods of scarcity and contribute less inframarginal rent towards fixed cost recovery.

Borenstein (2005) noted 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, i.e., the time-invariant retail pricing. Borenstein (2002) also noted some benefits that RTP could provide in reducing the exercise of market power in liberalised wholesale electricity markets. Real-time pricing also has the potential to provide benefits in integrating large amounts of distributed and grid-scale renewable energy into power systems. These benefits include 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 benefits of RTP in renewables integration 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. On the other hand, prices rise when the system is short on renewable supply. Having consumption patterns reshaped based on such price patterns mitigates the negative effects of renewables' variability and uncertainty.

These RTP benefits 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. They then pay or are paid the real-time price for any deviation between the contracted quantity and their actual consumption. This type of 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., reflects 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) showed that such a retail pricing scheme can provide some of RTP's general economic efficiency benefits. However, the renewables integration benefits listed above would not be provided as these rely on customer demands responding to real-time renewables' availability. Static blocked pricing such as a the 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 update is, in essence, meant to correct for the declining capacity value of DRE resources as their penetration rises.

4.3.2. Demand charges

The use of demand charges as an alternative stems 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 mimics the remuneration scheme in Theorem 2. However, if time-variant pricing is to be used, RTP (in line with the first recommendation) would be preferred for the reasons discussed earlier. The alternative proposal here 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 is to base the energy charge on the energy consumption of end consumers 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 ensures that the capacity value of DRE is properly remunerated. When a DRE resource contributes to the 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.

This proposal is indifferent as to whether the demand charge is determined based on an annual or sub-annual peak. That is, a customer's monthly or seasonal peak may be used. A more important implementation issue is whether the demand charge is based on each customer's individual peak consumption or on consumption during the coincident-peak period.

Setting the demand charge based on the coincident peak provides the correct economic signal. 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. On the other hand, such uncertainty may also come with an advantage in that it may incentivise conservation during periods that the customer believes to be the peak-coincident period.

The easier pricing option is to set the demand charge based on each customer's individual peak consumption. It may be simpler and carries less uncertainty to the end customer. However, it also undervalues the capacity value of DRE resources. That is, 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 in using demand charges is that it does not carry all the ancillary benefits that RTP has. As noted earlier, an added benefit of RTP is that it can help mitigate the negative impacts of uncertainty and variability in real-time DRE's availability. On the other hand, demand charges would have no benefit in this area. Demand changes allow less-efficient energy consumption decisions and loss of renewable integration benefits.

5. Discussion and conclusions

This chapter examined how the adoption and use of renewable energy resources, with particular attention on DRE, is incentivised. Incentive mechanisms have historically been used to reduce the privately incurred cost and risk of investing in renewable energy. In the short run, these mechanisms reduce project-financing costs and increase the deployment of renewables. In the long run, increased deployment of renewables reduces technology costs through economies of scale and learning by doing.

The tendering system has been the least successful of those mechanisms 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).

A comparison of the experiences of the United Kingdom, Germany, and Denmark suggests that FITs can deliver renewables at lower total cost than quantity only-based mechanisms. This study's survey of systems used thus suggests that FiTs tend to work better than quantity-based systems.

The particular case of a DRE net-metering system---either on its own or in conjunction with a FIT or quantity-based incentive programme---can effectively spur renewable investment. As seen in the southwestern United States' case, the programme's success largely depends on the quality of the renewable resource and the level of retail prices.

High penetrations of DRE come with some major cost-allocation issues between customers with DRE systems and those without DRE systems. Distributed renewable energy with time-invariant volumetric charges see an increasing share of capacity costs being borne by customers without DRE. This can create a vicious 'death spiral', where more and more customers adopt DRE systems due to rising retail prices. Eventually, capacity costs may be borne almost entirely by the socio-economically disadvantaged who do not have the means to invest in DRE systems.

To date, regulatory bodies in regions that have acutely suffered from cost-allocation issues have reacted by limiting, rescinding, or eliminating incentive programmes for DRE. In other instances, explicit limits on how much DRE can be deployed have been enacted. These types of reactions adversely affect DRE investment and risk by threatening the financing-cost reductions that the incentive programmes are meant to bring about.

Finally, this study proposes two alternative retail-pricing schemes – RTP and two-part tariffs with demand charges – to alleviate these cost-allocation and cross-subsidy issues. Real-time pricing has some general economic efficiency and techno-economic renewable integration benefits. For one, it can mitigate the negative impacts of real-time DRE availability variability and uncertainty. Demand charges, on the other hand, do not provide these ancillary benefits.

It is important to stress that these retail price structures are directly amenable to and built off the concept of a net-metering system. Moreover, other incentive programmes, such as FITs and quantity-based schemes, can be directly used along with these retail-pricing schemes.

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