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Abstract

To better reflect local grid conditions to consumers, many regulators are reforming their distribution network tariffs. In this literature review, we start by discussing the difference between short-run and long-run marginal pricing for distribution grids. Short-run marginal pricing is first-best but hard to implement in practice. Several authors therefore argue to that it makes sense to signal long-run marginal costs through a forward-looking charge based on a forward looking cost model. After, we compare four implementations of forward looking cost models that are currently being used in Great-Britain. Finally, we discuss the link between cost models and charge design. We formulate two conclusions. First, forward looking cost models are complex both for the regulator and the grid users. Designing cost-reflective distribution tariffs can help, but tariffs are regulatory tools with limitations. Second, we identify a gap in the literature. There is more academic work on charge design than on forward looking cost models.

Keywords

Distribution network tariffs; distributed energy resources; network modelling; electrification.

1. Why most regulators are reforming their distribution tariffs*

Historically, distribution network tariffs were simple rather than cost reflective. At lower voltage levels, households and businesses were mainly charged based on their annual consumption in euro/kWh. At higher voltage levels, it was more common to also use capacity in euro/kW and time-of-use elements in the charges. In contrast with generation plants and industrial load, households and businesses were passive grid users with very limited possibilities to consider adjusting network usage according to network charges. Investments in distribution networks were limited so the main job of tariffs was to recover sunk costs. Volumetric charges were also considered fair because wealthier households and businesses consumed more volume than the less privileged.

The situation changed with the large-scale introduction of rooftop PV, which created two issues. First issue is that the welfare transfer reversed. Wealthier households and businesses can more easily invest in rooftop PV. In some hours of the day, these prosumers inject the output of their PV panels into the network, and in other hours they withdraw that energy back from the network. If we only measure and charge the net effect, they no longer pay for the network they continue to use at the expense of other users who cannot afford PV panels. Second issue is the risk of overinvestment in the distribution network. Large-scale PV and wind generation in distribution grids can create new peaks that trigger network investments. The job of tariffs is then to signal the costs of network reinforcements in addition to recovering sunk costs.

Distribution tariffs can also have an impact on the decarbonization of the transport and building sector with the integration of electric vehicle charging infrastructure, and heat pumps into distribution grids. Distribution tariffs can guide the investment siting and sizing decisions for assets, such as wind, PV and electric vehicle charging infrastructure. They can also guide behaviour of grid users after the decision to connect in a certain location with smart charging of electric vehicles, smart heating, and the use of other appliances.

2. Why cost-reflective distribution tariffs include charges based on forward looking cost models

Marginal pricing is the first-best solution, but there are many challenges with marginal pricing in distribution grids.

First challenge is that marginal pricing in distribution grids would require a big change to electricity markets. They currently do not take into account distribution or transmission constraints. Electricity markets with integrated transmission and distribution constraints would produce market prices for each transmission and distribution location or node in each market period. If there is no congestion in the network, market prices would converge and the marginal price of the network would be zero (disregarding losses). If there is congestion, the market prices would diverge and the marginal price of the network would be positive. Each congested network component would have a price, which would help recover the network investment costs, and also signal where grid expansion is needed. This is referred to as locational marginal pricing. The literature originally focused on transmission, and more recently extended the concepts towards distribution locational marginal pricing.[1]

* This policy paper was commissioned by Ofgem, the GB regulator, in May 2020. Leonardo Meeus is member of the Academic Panel at Ofgem.

1 The book 'Spot Pricing of Electricity' by Schweppe et al. (1988) and the paper 'Contracts networks for electric power transmission' by Hogan (1992) were seminal works that laid the foundations for the implementation of location marginal pricing (LMP) for transmission networks (nodal pricing) in the US. Caramanis et al. (2016) and Papavasiliou (2018) extended these concepts to Distribution Locational Marginal Pricing (DLMP).

Second challenge is short versus long-run marginal pricing in distribution grids. Some have strongly argued against long-run marginal pricing because marginal pricing is short-run pricing by definition[2]; and long-run marginal pricing implies that you put a price on capacity when there is spare capacity, which is inefficient because it can distort the behaviour of grid users that react to that price signal. Others have argued that short-run marginal prices are not always available (see first challenge with marginal pricing in distribution grids), and even if they would be available, the signal would be too weak or uncertain to guide the siting and sizing decision for new grid connections. They therefore advocate for long-run marginal pricing via grid tariffs as an alternative or complement for locational marginal pricing via electricity markets.[3]

Third challenge is cost recovery. The congestion revenues collected with locational marginal pricing are known to recover only a fraction of the total costs in transmission grids.[4] The reason is that grids are typically overdesigned. We overdesign grids because we want to keep a reliability margin, and when we reach the limits of the grid, we invest more than what we need because the investments are lumpy and have strong economies of scale. Distribution tariffs that are set following a long-run marginal pricing approach typically cover more of the total investment costs. Under such an approach, a cost model is used to simulate the grid investments that are needed to handle future demand and generation and allocates these costs to grid users. These simulated costs do not take into account the historical or sunk costs that still need to be recovered.

To achieve cost recovery, we therefore need an additional charge. Following the principles of Ramsey-Boiteux pricing, this charge should achieve cost recovery with minimal distortions. This can be achieved with fixed charges.[5] The only way to avoid fixed charges is to disconnect from the grid, so the only possible distortion is consumers going off-grid, which is currently not economical in most places. The simplest version of fixed charges is that all grid users pay the same annual fee to remain connected to the grid. This can be considered unfair for smaller users as opposed to larger users, and it is not always easy to find a good metric to differentiate small from lager users. The trick can be to look at historical consumption and/or voltage levels, or even at income levels or property value.[6]

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2 Giving additional signals beyond (short-run) marginal pricing remains controversial, as for example discussed in Borenstein (2016). Léautier (2019) discusses that LMP lead to optimal generation incentives while LRIC transmission charges will not, except if the network is optimally designed, which is unlikely in practice.

3 MIT Energy Initiative (2016), p. 110: "We maintain that adding an economic signal on top of LMPs (if employed) makes economic sense if the signal is sent to agents connected to a node where the withdrawal or injection of power at a given moment in time indicates the need for new network investment. …. LMPs alone fail to fully capture the long-term marginal or incremental costs of network expansion.''

4 Pérez-Arriaga et al. (1995) show that revenues from efficient nodal prices recover only up to approximately 30% of the total costs of an actual transmission grid. Main identified reasons are discrepancies between static and dynamic optimal expansion plans, planning deviations and errors, the strongly discrete nature of investments, economies of scale, reliability constraints and other constraints on network investments.

5 Newbery (2011) discusses fixed charges as one of the possible implementations of the Ramsey principles. Borenstein (2016) notes that raising the volumetric price above its full social marginal cost to make up for this revenue shortfall has been the most common policy choice for many decades, especially at lower voltage levels. He emphasizes that it is particularly important now to consider alternatives. The leading alternative is higher fixed charges, but they can lead to significant equity concerns.

6 Burger et al. (2020) test the calculation of differentiated fixed charges based on historical consumption patterns (10-year window), geography or customer income. The authors argue that differentiated fixed charges based on historical consumption, geography, or income, are better than low-income programs because such programs historically have very low opt-in rates. Batlle, Mastropietro, and Rodilla (2020) advocate moving residual costs in the bill to a differentiated fixed charge that is based on the historical consumption of each customer. Pollitt (2018) states that sunk grid costs can be recovered through charges by income, property value, kW connection capacity or another indicator of income (or ability to pay). Schittekatte et al. (2018) discuss the impact in terms of cost-effiency and equity when sunk costs are recuperated by other types of charges than fixed charges.

In conclusion, cost-reflective distribution tariffs are two-part tariffs: they combine a forward-looking charge based on a forward-looking cost model, in combination with a fixed charge to recover the residual costs. In what follows, we discuss the detailed design choices related to forward-looking costs models and charges.

3. Experience with forward-looking cost models

A forward-looking cost model simulates the grid investments that are needed to handle future demand and generation and allocates these costs to grid users.

In what follows we discuss the main differences of the cost models that are currently being used in GB. The Investment Cost Related Pricing (ICRP) is currently used at transmission level, the Long-Run Incremental Cost (LRIC) and Forward Cost Pricing (FCP) models are used at distribution level at higher voltage levels and the Distribution Reinforcement Model (DRM) is used at the lower voltage levels. We compare these cost models along four dimensions: the modelling horizon, the considered cost drivers, the modelling of grid investments and the calculation of charges. Finally, a summarising table is provided.

3.1 How forward looking are the cost models?

The most forward-looking model is the Long-Run Incremental Cost (LRIC) model that looks 40 years into the future. The Forward Cost Pricing (FCP) looks 10 years into the future. The Investment Cost Related Pricing (ICRP) looks at the year being modelled (which could be the upcoming charging year or some point in the future) but does not signal future investment.

The Distribution Reinforcement Model (DRM) looks at the costs caused by a fixed demand growth of 500 MW at each voltage level in an unspecified future.

Note that models that are more forward looking will of course produce more forward-looking signals, but they will also be more prone to forecast errors. A possible solution is to work with scenarios or stochastic methods to overcome this.[7]

3.2 Which cost drivers are considered by the cost models?

ICRP and DRM focus on the peak demand period. ICRP checks if generation causes critical transmission flows in the peak demand period. DRM checks if peak demand causes critical flows from the transmission grid into the distribution grid. LRIC and FCP consider the condition of the network under two critical periods. In addition to the peak demand period, they also consider an off-peak demand period to check if the infeed of generation in distribution grids can cause critical flows in certain branches when demand is low.

DRM does not consider generation, and only looks at flows caused by peak demand in a distribution grid. The model checks if that peak demand can be imported from the transmission grid into the distribution grid.

LRIC, FCP, and ICRP do consider generation. These models make assumptions about generation infeeds during critical periods. LRIC and FCP consider that some of that generation is connected to distribution grids, and they also scale it into the future so that part of the demand growth is covered by

[7] Ault, Elders, and Green (2007) apply the ICRP methodology to calculate transmission charges in Great Britain. The authors highlight the sensitivity of the transmission charges produced by this methodology to changes in demand and generation scenarios, and network topology. Bell et al. (2011) argue that LRIC is very sensitive to assumptions made about not only demand growth, but also the availability and dispatch of generators in the future. Gu and Li (2011) note the sensitivity of FCP to assumptions on the size of test generators used to calculate generation charges.

additional distributed generation. A so-called F-factor is used to account for the contribution of distributed generation in covering peak demand. In the ICRP model, generation capacity follows the estimated peak load growth, and generation is dispatched in proportion to generation capacity to simulate flows in the transmission network.

Note that the reality is that peak load is not the only critical situation in grids at transmission and distribution level. Modelling the interaction between generation and load is increasingly important for cost models. However, this implies additional assumptions that will drive the results of the models. A possible solution can be to work with scenarios, and contingencies.

3.3 How are grid investments modelled?

ICRP is single-stage greenfield model that builds up the grid from scratch to handle the peak demand period. It is referred to as an ultra-long run model because it simulates the investments needed to replace the current grid and expand it to the level required by the forecasted peak load and the generation to cover that load. ICRP invests in the grid following a relatively simple cost function that represents the unit-cost of expanding the existing grid. It assumes that the grid can be expanded linearly.

LRIC and FCP are multi-stage brownfield models that only invest to reinforce the grid, assuming that the current grid does not yet have to be replaced. They are referred to as incremental models. They invest by scaling up the existing grid in lumpy steps with standardized costs for the existing components.

DRM is a single-stage and greenfield model, like ICRP. DRM includes a sophisticated investment model, like LRIC and FCP. DRM is the only GB model that works with a reference grid instead of actual grids. ICRP replaces the existing grid, but keeps its topology. LRIC and FCP incrementally build on (simplified) models of the the existing grids. DRM assumes that there is a reference grid that is a good enough approximation for the existing grids.

Note that each of the models that are currently used have simplifications that can be challenged if they lead to distortions. This is a difficult trade-off simplicity and accuracy.[8]

A more difficult choice is between ultra-long run and incremental cost models. Incremental models remain closer to marginal pricing than ultra-long run models (see previous section). Incremental models will produce signals that are closer to the reality in the grid, but that are also more volatile. They will be relatively low when there is spare capacity and increase sharply when we are approaching a lumpy investment. Ultra-long run models continue to signal replacement costs, even if there is spare capacity. Solutions have been proposed to make incremental models more stable.[9] Solutions have also been proposed to take into account spare capacity in ultra long run models.[10]

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[8] Turvey (2006) discusses several simplifications of the ICRP methodology. The most important simplification is the assumption that the grid can be linearly expanded. Another example is that substation assets, such as transformers and switchgear, are not considered while they do form an important part of the reinforcement costs. DRM has been criticised due its lack of granularity, as it produces a postage stamp charge for each voltage level (Li et al., 2009).

[9] Tooth (2014) discusses a simplified pricing rule that would lead more stable prices. By setting the LRMC to the annuitized cost of the next augmentation – without discounting – the reinforcement signal will be stronger further from the reinforcement time. This is an extreme averaging of the LRMC signal. Another option is to decrease the frequency of price changes (Strbac and Mutale, 2005).

[10] In predecessors of the current ICRP methodology, a spare capacity discount was applied to certain branches. Turvey (2006) defends the decision to drop this spare capacity indicator as it fails to account for future spare capacity, i.e., the fact that newly built capacity will not be fully utilized.

3.4 How are charges calculated?

LRIC and ICRP calculate nodal charges, while FCP calculates zonal charges by dividing the network in so-called 'Network Groups'. These models result in locational charges that can be positive or negative. The DRM model does not take into account locational differences in distribution grids, it is essentially a postage stamp method for each voltage level.

The charges that are designed based on these models are often simplified. They are typically merged into zones of nodes with similar characteristics, and demand and/or generation credits can be set to zero. They are typically also applied to more critical periods than the one or two periods that are modelled. Other issues to consider when translating the charges that come out of the model towards charges that can be used in practice are discussed in more detail in the next section.

Table 1: Summarising table of the forward-looking cost models that are currently used in GB

	Horizon	*Forward looking cost drivers*	*Grid investment modelling*	*Charge*
Investment Cost Related Pricing (ICRP)	One specific year, e.g. next charging year	Peak demand being serviced by different types of generation	Single stage greenfield model with simple cost function	Transmission: nodal demand and generation charge with demand credits set to zero
Distribution Reinforcement Model (DRM)	No specific horizon, instead impact of a 500MW demand increase	Peak demand impacting flows between transmission and distribution	Single stage greenfield model with lumpy grid expansion based on a new optimized asset mix	Distribution (lower voltages): Average demand charge, no cost for generation
Long-Run Incremental Cost (LRIC)	40-years	Forecasted peak demand (demand peak period) and peak generation (off-peak demand period) assuming a 1% load growth rate	Multi-stage brownfield model with grid expansion based on standardized lumpy costs	Distribution (higher voltages): Nodal demand and generation charge with generation credits for contribution to peak demand
Forward Cost Pricing (FCP)	10-years	Forecasted peak demand (demand peak period) and peak generation (off-peak demand period)	Multi-stage brownfield model with grid expansion based on standardized lumpy costs	Distribution (higher voltages): Nodal demand and generation charge with generation credits for contribution to peak demand

4. Insights into distribution charge design

Forward looking cost models will typically allocate the investment costs to the critical peaks that drive the grid expansion. Sophisticated models can also identify different peaks for different locations, but there are many good reasons why regulators might prefer simpler tariffs for some or all grid users. First, sophisticated cost models are complex to administer. Second, some grid users might not be able to handle the complexity. Third, sophisticated tariffs, require smart meters (to precisely measure grid usage), and smart grids (to measure which peaks are critical at different locations). Changing distribution tariffs also implies welfare transfers, which can be politically sensitive.

There are many academic papers that compare the performance of different implementations and combinations of critical peak, volumetric, capacity, and fixed charges. The papers often also focus on certain challenges, such as PV, or batteries, or electric vehicles and heat pumps. For example, Schittekatte and Meeus (2020) focused on the issues related to households with PV-rooftops and batteries, and the associated welfare transfers between passive and active consumers. Küfeoğlu and Pollitt (2019) and Hoarau and Perez (2019) focused on the issues related to electric vehicles and PV. Protopapadaki and Saelens (2017) discuss the issues related to heat pump penetration. In what follows, we highlight the main insights.

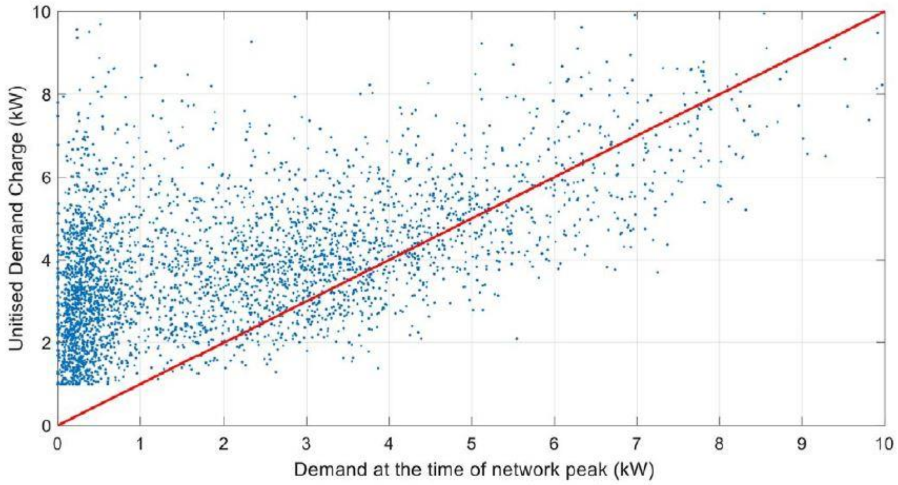
First, we can simplify tariffs by sacrificing their location granularity, while keeping the temporal granularity. This implies that charges can be based on the grid users' contribution to the system peaks. This simplified signal can be too strong for locations that have spare capacity, and not strong enough for locations that have critical situations in different periods than the system peaks. For example, tariffs could target the evening demand peaks when people come home and charge their electric vehicles. However, this system peak is not necessarily a critical peak at each location in the distribution grid; and some locations might experience critical peaks at other moments, for example, due to the infeed of solar and wind that is not evenly spread across locations in distribution grids.

Second, we can simplify tariffs by pricing critical periods rather than peaks. It might be difficult to hit a peak with precision, and by pricing a peak we might shift it to create a new critical peak. We can therefore charge based on the volume consumed or supplied during a certain period (i.e. time-of-use volumetric charges). The risk is that the signal to reduce critical peaks becomes weaker. And, if the periods in which we measure the volume are long, we also reintroduce the distortions caused by volumetric tariffs. Volumetric tariffs are known to distort the participation of decentralized energy resources in electricity markets. They indeed increase the transactions costs to trade via distribution grids.

Third, we can simplify tariffs by sacrificing their location and temporal granularity. This implies that charges are based on the grid users' individual peak or potential peak (i.e. connection capacity). This simplified signal can be too strong for individual peaks that do not coincide with critical peaks. For example, you might create an individual peak by charging your electric vehicle on a sunny Sunday. If you are in a neighbourhood with a lot of PV panels, your individual peak is not contributing to a critical peak, you might even be helping to avoid one. The signal can also be too weak for individual peaks that contribute to the critical peaks. For example, you might have a high peak one evening when you really need your electric vehicle to be charged. If this peak sets the charge, the incentive to do smart charging the following evenings is gone.

Note that charges based on individual peaks or connection capacities can be made time-granular (e.g. seasonal), which can strongly reduce the distortions. This is nicely illustrated in the study by Passey et al. (2017) using data from Ausgrid. As illustrated in Figure 1 there is a limited correlation to what a grid user pays under an individual peak charge and the contribution of the grid user to the system peak in Ausgrid. The same study shows how this distortion can be strongly reduced by introducing capacity charges that are differentiated per season. The study does not look at the importance of granularity across locations.

Figure 1: Individual-peak based network (vertical) charges paid versus contribution to the system peak (horizontal). Source: Passey et al. (2017)



5. Conclusions

A continuation of the fit and forget approach to distribution grid planning would be too expensive. We need to trade-off distribution grid expansion with the use of flexibility connected to the distribution grids. Flexibility can come from distributed generators as well as demand, and storage.

Designing cost-reflective distribution tariffs can help, but tariffs are regulatory tools with limitations. We can also improve distribution grid planning procedures, we can use flexibility markets, smarter connection agreements, and ultimately distribution locational marginal pricing. Clearly, a combination of these regulatory tools will be needed.

Another conclusion of this literature review is that there is more academic work on charge design than on forward-looking cost models. A gap in the literature that can hopefully inspire future research because there are many open questions regarding the detailed implementation of these cost models.

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7. Annex response to Ofgem's questions

1. Do you consider that the issues we have identified with an incremental cost model (e.g. the small size of the increment) could be mitigated and, if so, how? How much would this dilute the signals that an incremental model is designed to send?

Ofgem identified three issues with incremental cost models. In what follows, we confirm that these are also the issues discussed in the literature on the topic, and we illustrate the solutions that have been suggested.

First issue is *"Size of the increment – the DNOs have modelled the incremental model choices and it shows that charges would be very low and are unlikely to be strong enough to incentivise users to change their behaviour. This reflects that reinforcement is currently only 5 percent of DNOs' total costs."*

Reinforcements are currently a relatively small percentage of the DNO cost, but this might change soon with the integration of electric vehicles and heat pumps. Still, it is true that there is a big difference between the ultra-long run cost models that also account for replacement costs and the incremental cost models that do not account for replacement costs. The models that are used today in GB either take replacement costs fully into account (i.e. ICRP), or not at all (i.e. LRIC and FCP). An intermediate solution could be to have a cost model that is in between and considers a gradual need for replacement.

Second issue is: *"Volatility – some EHV connected customers have indicated that the EDCM charges are too volatile for them to respond to or take into account when making investment decisions. This is because the DNOs update their forecasts annually and changes could be driven by what other customers do, updated network cost estimates or an increase or reduction in expected load growth."*

This volatility is inherent to the way incremental models are build up as they take spare capacity into account. If reinforcements are far into the future, the present value of these reinforcement is low, and the charge will be low. If a certain location is approaching a lumpy reinforcement, prices can increase sharply, and then drop again after the reinforcement takes place. Even though this is actually a strength of the model, it might be opportune to reduce the volatility to create stability. Several solutions have been suggested in the literature to reduce the volatility.

Tooth (2014) introduces two possible solutions. One is to replace the present value of the reinforcement cost by an annualized average cost spread equally over time. Another less extreme solution is to introduce a cap and a floor for the charges. Strbac and Mutale (2005) argue that the frequency of changes to the tariffs could simply be reduced to reduce the volatility. Turvey (1976) states that a forward-looking analysis of long-term marginal costs per year does not necessarily mean that the charges have to vary every year.

There is also a difference between volatility and uncertainty of tariffs. Strbac and Mutale (2005) argued that grid users should get information about the utilization of distribution grids, the presence of spare capacity, and where additional distributed generation can still be hosted. This will help them anticipate when tariffs will change and adapt their behaviour accordingly.

Third issue is: *"Accuracy of forecasts – as noted previously, an incremental model relies on detailed network data and monitoring and forecasts about future load growth. We note that historically these forecasts have not been very accurate – e.g. high demand growth forecast in the long term develop statements, which has not materialised over time. In addition, DNOs have emphasised that, even with network data and power flow modelling, they still need to apply a number of assumptions and undertake a significant amount of work to calculate charges, which means the incremental signal may still be misaligned with actual network usage."*

The incremental cost models that are used in GB (i.e. LRIC and FCP) look further into the future than the ultra-long run model that is used (i.e. ICRP). The more forward looking they are, the more they are exposed to issues with forecast accuracy.

Some solutions imply more complex cost models. The models could evolve from deterministic to stochastic models, or work with more scenarios and sensitivities. Tooth (2014) suggests using different scenarios, e.g., a low-price and a high-price scenario. Similarly, Marangon Lima et al. (2002) talks about using the scenario technique to capture pessimistic, medium and optimistic figures for load growth rates, in combination with different assumptions for technological change. De Leao & Saraiva (2003) propose fuzzy power flow analysis to take into account load uncertainty with a stochastic model.

Other solutions imply simpler cost models. Strbac and Mutale (2005) argued that especially for LV distribution grids, it is maybe too complicated to model the actual grids with all their uncertainties. They illustrated that feeders could be classified into rural and urban; and into demand dominated, generator dominated (GD) or balanced (B). Charges could then be calculated for these reference grids.

Another difficulty is that tariff design can impact the forecasted scenarios. How to close the loop between expected load and generation scenarios and network tariff design based on forward-looking cost models has been discussed in Govaerts et al. (2020).

2. Are you aware of any academic literature on different cost model options, which could help guide our choice of incremental model (subject to our decision on whether to apply an incremental model) or ultra long-run model?

Ofgem identified pros and cons for the incremental cost model and the ultra-long run cost model. They are inline with the academic literature. However, there are many ways to implement the incremental and long run cost models, and implementation has a big impact on how outspoken the pro and cons are.

The above response to the first question already illustrates that the main disadvantages of incremental cost models (i.e. complex data requirements, difficulty of forecasting, volatility of the charges, and limited signal) depend on implementation. Many solutions have been proposed in the literature to reduce these cons.

The main disadvantage of ultra-long run models is that they do not signal spare capacity. We do not want grid users to avoid using the grid when there is spare capacity. Consumers will avoid using the network more at times when their usage has no impact on network costs. This is costly behaviour that is unnecessary (see more detailed discussion in the paper). In what follows, we discuss two modifications that have been made to ultra-long run models to reduce this con.

ICRP in GB has been modified to include spare capacity. The trick has been to reduce the length of lines with spare capacity so that they become cheaper in the model. Turvey (2006) argues that this failed to recognise the cost of the corresponding spare capacity, and the approach was also stopped.

Marangon Lima & Marangon Lima (2007) discuss the version of the ICRP method that has been implemented in Brazil for transmission. In the first implementation, the Brazilian regulator added a weighing factor to lower the cost of a branch with low utilization (i.e. spare capacity). The authors show that this weighing factor decreased the spatial signal of the tariff. We do not know if this weighing factor is still in place.

In other words, the volatility of the charges coming out of incremental cost models is valuable (it signals spare capacity) and costly (it provides uncertainty for siting decisions). It is not possible to have the best of both. It is possible to have a bit of both by picking a model that is in between the extremes of ultra-long run and incremental models.

3. What are your views on the use of a spare capacity indicator? Do you agree that it could help to mitigate the issues with an ultra long-run model and be a good compromise that effectively addresses the potential disadvantages with both cost model options?

As discussed under the previous question, we cannot get the best of both incremental cost models and ultra-long run models. We can be somewhere in between.

Solutions to make incremental models look more like ultra-long run models have been discussed under question one.

Solutions to make ultra-long run models look more like incremental models have been discussed under question two. They indeed involve the use of a spare capacity indicator.

A more detailed quantitative analysis of the alternatives is needed.

4. What are your views on how we might be able to reflect charges and credits under and ultra long-run model, where there is limited data on network connectivity and load flows? To what extent could this be mitigated by finding a balance between full granularity and fully averaged charges across a DNO region?

We find two views in the literature and in practice.

First view is that cost models can be nodal, but that does not mean that the charges have to be. ICRP for example clusters the nodal charges into zones.

Second view is that clustering can be done beforehand to simplify the model, and to overcome the data challenges. This is the approach with references models proposed by Strbac and Mutale (2005) that we referred to when answering the first question. Another example of this approach is presented by Rodriguez Ortega et al. (2008) who propose a supervised learning technique for clustering.

5. To what extend do you think the cost model itself matters when compared to the importance of the signal sent by the charge design? What are your thoughts on our initial views regarding the application of volumetric ToU and capacity-based charges and their relationship with the incremental and ultra long-run cost models?

A simplified cost model can limit the charge design, but sophisticated models do not imply that the charge design has to be equally sophisticated. In what follows, we discuss the issues to consider for the location and time granularity of charges.

First, locational granularity of charges. DRM starts from a generic grid situation so it does not enable a charge design with location granularity. The other models do enable locational granularity, but it does not mean that it has to be used. For example, the ICRP calculates nodal charges, but the charge design clusters them into zones.

Second, time granularity of charges. The models typically focus on a few critical periods so they enable critical peak pricing. But, this does not mean that charges cannot be simplified into volumetric ToU or capacity charges, which can be considered as approximations of critical peak pricing. We discussed this in detail in the above paper under the section of forward-looking charge design.

In other words, both are important.

6. You mentioned the last time we spoke that evidence in Europe has suggested that, while an incremental model is preferred in theory, in practice regulators are finding that a ultra long run model or historical allocative model that sends an investment signal can drive a more effective customer response. Are there any further insights you can provide regarding this issue and other developments in Europe?

If we measure the success or effectiveness of a distribution tariff by the distribution grid investments that have been avoided or delayed, giving stronger signals via an historical allocative and/or ultra long-run approach can be appealing.

However, it is not necessarily bad that grid users do not change behaviour in response to a signal, it may simply be the cheapest option. If today reinforcement costs are a small part of the total costs, it is an indication that there is a lot of spare capacity in distribution grids. Signalling users not to use this spare capacity, is also a costly distortion.

What kind of signal we want to give depends on our assessment of the future? If we have to choose between a too strong signal or a too weak signal, which one do we prefer? Both will create distortions, but which of the two will be most costly or problematic?

7. We were recently involved in a CEER working group that prepared guidance on distribution tariffs. The discussion during the drafting phase and the ultimate recommendations suggest that a number of European countries are a long way from introducing significant granularity or dynamism in their charges. However, there was very limited discussion about the cost models that underpin the design of the charges themselves. How do our proposed cost models compare with what is done in other European countries, and to what extent are they evolving over time?

Most regulators in Europe are focusing on the charge design. Locational granularity in the charges seems to be more controversial than time granularity. Many regulators are considering using a hybrid tariff combining a time of use volumetric and/or seasonal capacity signal with a fixed component. A part of the historical costs can then be allocated via the volumetric and/or capacity signal, and another part via a fixed component.

Distribution cost models might be used to decide which share of the historical costs to recover via which tariff component. We are not aware of publicly documented forward looking cost models used by other regulators. There are also very few academic papers that refer to the use of cost models by other regulators. In Sweden, the industry uses cost models, which have been approved by the regulator.

A conclusion of this literature review is that there is more academic work on charge design than on forward-looking cost models. A gap in the literature that can hopefully inspire future research because there are many open questions regarding the detailed implementation of these cost models.

Regulators are increasingly looking at how to smartly combine the regulatory tools that can help to reduce the need for investments in distribution grids: distribution tariffs, flexibility markets, smart connection agreements, and ultimately distribution locational marginal pricing.

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