International Review of Cost Recovery Issues

Office of Gas and electricity Markets

FINAL REPORT

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CONTENTS

1. INTRODUCTION

As part of Ofgem's July 2016 open letter on Charging Arrangements for Embedded Generators and the more recent joint call for evidence with the Department for Business, Energy & Industrial Strategy (BEIS) on a smart and flexible energy system, Ofgem has committed to a targeted review of certain issues related to electricity network charging.[1]

One of the two issues considered in the Targeted Charging Review will be the allocation of sunk/fixed costs within the network charging methodologies and their implications for storage and 'behind the meter' generation. An expected output is a set of principles for how cost-recovery charges should be structured, with the principles ideally compatible with future charging regimes that may emerge in Great Britain (GB).

1.1. Terms of reference

Ofgem has commissioned CEPA and TNEI to provide a review of how different approaches to addressing the issues of 'behind the meter' and cost recovery have manifested and been addressed in practice in different jurisdictions. The objective of the work is to highlight possible implications and lessons that could be learned for the GB market in taking forward its Targeted Charging Review on sunk/fixed cost allocation issues.

1.2. International case studies

Following a short-listing process, we undertook research into the following international case studies:

- United States of America (USA);
- Victoria, Australia;
- Netherlands;
- Spain; and
- Italy.

1.3. Document structure

The rest of this report is structured as follows:

- Section 2 provides a summary of findings from the international review and some of the possible implications for GB.
- Sections 3 – 7 present the detailed individual country case studies and the findings for each.

[1] Ofgem (2016): 'Update on charging arrangements for Embedded Generation'

2. SUMMARY OF FINDINGS

The international case studies that we have reviewed in the following report highlight the different approaches taken to try to deal with the network cost recovery issues that have been, or are being faced, in other jurisdictions. They suggest that there are a range of regulatory considerations and potential policy responses available.

The problem

Fundamentally, the problems in all the case studies have arisen from, or been exacerbated by, the significant investment that has been required in the electricity networks and the electricity system more generally, to deliver current service levels. This has meant that the sector is now characterised by high fixed/sunk costs that need to be recovered from existing users of the system. As final electricity consumption has historically tended to be relatively price insensitive, the network tariff structures that have been used to recover these fixed/sunk costs historically, such as volumetric kWh charges, have been largely suitable.

However, with these historical charging arrangements, new Distributed Energy Resource (DER) technologies – such as on-site distributed generation (DG) (e.g. solar photovoltaic (PV) facilities) and, in future, low cost storage – have the opportunity to reduce their users' contribution to fixed / sunk cost recovery and by doing so increase the cost burden on other customer groups.[2] In effect, behind the meter generation and other DER applications have offered the opportunity for network users to become more price sensitive to the recovery of fixed/sunk costs, as reducing *net* demand (e.g. through on-site generation) can allow the fixed / sunk costs invested in the system to be avoided.

Reforms to network charging

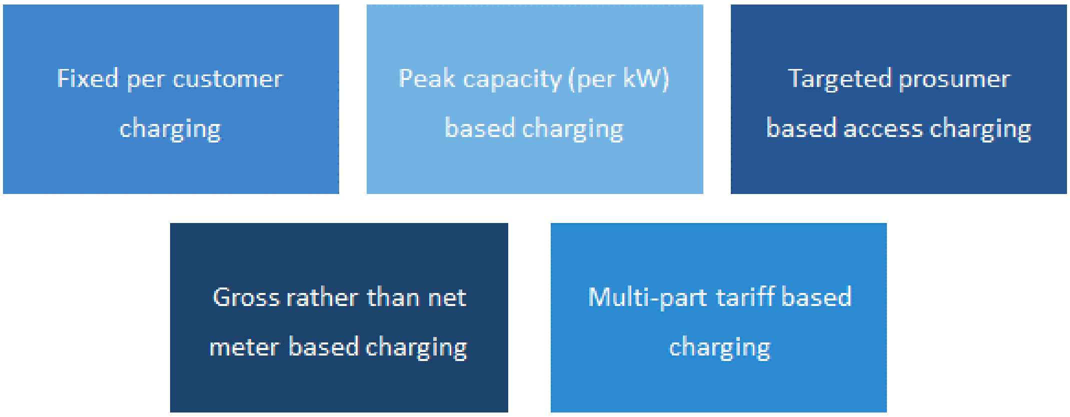
The case studies highlight a range of possible approaches for how changes to the charging basis can be used to address these problems (see Figure 2.1 below).

The European case studies (e.g. Netherlands and Spain) provide examples of shifting the charging basis away from volumetric charges and towards capacity (i.e. per kW charges). In the USA, some proposed solutions to the problems have included multi-part tariff structures (involving both fixed and variable components), or targeted electricity network access charges applied specifically to "prosumers". The shift in Spain to recover a share of network costs from "prosumers" based on both energy withdrawn from the grid but also energy self-

[2] Decker (2016) also highlights potential impacts on retail markets where "*if customer-generators with storage only maintain a connection to the grid as back-up, then a default supplier in an area is faced with a situation of being required to maintain a connection to many customers who consume very little grid-supplied electricity, and, consequently, contribute to only a proportion of fixed network cost recovery. This may be exacerbated by the fact that non-default suppliers may refuse to offer contracts to small users of grid-supplied electricity on the basis that they are not profitable.*" See Decker (2016): 'Regulatory networks in decline', Journal for Regulated Economics, 49, pp. 344-370

consumed, highlights the possibility of addressing cost recovery problems by shifting the charging basis to gross rather than net consumption.

Figure 2.1: Potential measures to reform the charging basis



Source: CEPA & TNEI

Note: these options are not necessarily mutually exclusive and could be used in combination

Common themes and challenges

While the different options presented above can have a clear supporting rationale in public / welfare economic theory and principles, they can in themselves also lead to major impacts on different stakeholder groups if their adoption requires a shift from the existing network charging basis (e.g. volumetric, kWh, charges). Reforms in some countries have been considered highly controversial by certain stakeholders, particularly those whose business models have faced potential negative effects.

The case-studies also illustrate how reducing the sunk/fixed cost avoidance benefits from the uptake of DERs is likely to create a starker focus on how the net-benefits that DERs can contribute to the system (from the perspective of *future* rather than sunk costs and investments) should be valued and reflected in the network tariff structure.[3] The USA and Australian (Victoria) case studies provide examples of this.

All the international case studies highlight the importance of the regulator carefully managing the trade-offs between more efficient pricing structures and their distributional impacts. Another clear theme is the importance of developing potentially challenging transition processes to reform the existing charging basis to minimise distortions or windfall effects. Some of the case studies presented below suggest some success in mitigating consumer harm or opposition to reform through carefully designed transitional arrangements, though not without some coordinated effort and cost (e.g. the Netherlands). Others have initially avoided transitional arrangements such as grandfathering, only to revise (or continue to be in the process of revising) arrangements at a later date.

[3] Of course, GB is already relatively advanced in this area compared to many other countries given that 'cost reflective' charging structures are a core part of the existing regulatory system.

Finally, distribution effects are almost inevitable with changes in the charging basis and care needs to be taken to ensure that any changes are not unduly discriminatory against particular customer groups. Some of the case studies demonstrate consideration of the impacts on vulnerable customers and how these can be mitigated, perhaps through revisions to wider regulation or policy.

Summary of changes to network charging arrangements and their impact by case study

Table 2.1 provides a summary of each of the case-studies, the general conclusions and key issues that have been observed in the charging reform programme in question. Subsequent sections of the report review each of the case studies in more detail.

Table 2.1: Summary of changes to network charging arrangements and their impacts

Country / Region	Original charging arrangements	Problem identified	Change introduced	Impacts	Conclusions
USA, Nevada	Net energy metering - customers can net off generation and demand, effectively being paid retail rate for energy generated.	Significant growth in distributed solar generation. Concerns of avoided costs from DG being transferred to consumers without DG.	12-year phase-in of new tariff arrangements with base rate service charge increasing by over 300% and rate paid for DG reducing to 25% of original value. No grandfathering of existing schemes under original arrangements. However, this ruling was subsequently reversed, providing 20-year application for existing relevant customers.	Significant stakeholder opposition. A number of solar companies ended operations in Nevada and claimed that network monopolies were being protected at customer expense. Also, suggestions that analysis did not account for avoided transmission and distribution capacity, ancillary services, interconnection, administration and environmental costs.	Impacts of rate changes should be carefully considered. May present an opportunity to introduce Time of Use (ToU) charges rather than simply expanding fixed charge elements. Grandfathering is also an important consideration. A robust, third party (i.e. non-utility) cost benefit analysis including long term benefits of DG is essential to evaluate options for change.

Country / Region	Original charging arrangements	Problem identified	Change introduced	Impacts	Conclusions
USA, California	Net energy metering - customers can net off generation and demand effectively being paid retail rate for energy generated. Tiered volumetric tariffs so consumers of more net energy pay higher $/kWh.	Estimates of significantly higher gains to solar companies than utilities' avoided costs. Predictions of significant shift of charges from DG to non-DG customers by 2020.	The regulator's reforms included: • gradual move to two-tier rather than four-tier system; • move towards mandatory ToU tariffs for DG by 2019; • minimum $10 monthly charge, even without consumption; • "non-bypassable" charges, such as for nuclear decommissioning, which were previously charged on net consumption, will be charged on total electricity delivered from the grid; and • utilities can charge a one-off connection fee, estimated between $75 and $150. Additional schemes are in place for low income customers. Changes were grandfathered for existing solar arrays.	Like elsewhere in the USA, the changes have proved controversial but are considered a better balance between the interests of solar companies and utilities than similar reforms introduced in other States. The old tiered system was seen as "fairer" and more environmentally-friendly because it incentivised lower electricity use. The solar industry suggests that the additional complexity of the new tariffs will result in higher financing costs. Changes to the ToU component are proving challenging. Historically, peak demand was during summer afternoons, but now a "duck curve" effect is starting to occur.	Consumer acceptance of tariffs depends on perception of fairness between energy users. Important to strike balance between reflective charging and simplicity. ToU tariffs must be flexible enough to adapt to changing trends in demand and generation.

Country / Region	Original charging arrangements	Problem identified	Change introduced	Impacts	Conclusions
Australia, Victoria	Charges were set by individual Distribution Network Service Providers (DNSPs) according to a series of "pricing principles". Included a requirement to 'take into account' Long Run Marginal Costs (LRMCs), and to 'adjust prices in a way that minimises distortion' where prices do not recover all revenues. Moratorium on changes to charging arrangements until 2013 prevented introduction of ToU tariffs.	Significant PV deployment coupled with roll-out of smart meters has drastically changed the way that customers use the electricity network in recent years.	The Australian Energy Market Commission (AEMC) (the rule maker for Australian electricity and gas markets) introduced new charging rules. In practice these are being adopted in the following ways: • DNSPs are using forward looking principles to determine LRMC which is being recovered based on peak instantaneous demand; •minimised distortions for residual costs; •transitional arrangements are being used to protect consumers; and • no locational signals are being provided to minimise complexity.	ToU pricing has now been introduced on an opt-in basis. It is too early to draw robust conclusions. The new charging rules have received a mixed response from stakeholders. One consumer advocacy group has suggested that the new demand (kW or kVA) tariffs should become mandatory rather than opt-in. Further changes have been proposed including higher connection fees and 'exit fees' but these proposals have been criticised with suggestions that they increase the incentive for disconnection from the network.	Victoria provides an interesting case given that the approach to charging reform – with a distinction between cost-reflective and residual charges – aligns closely with the way these issues are being considered in GB. The explicit importance placed on considering consumer and distributional impacts has led transitional arrangements to be considered. However, the opt-in nature of the reforms at this stage may dilute their impact.

Country / Region	Original charging arrangements	Problem identified	Change introduced	Impacts	Conclusions
The Netherlands	Distribution and transmission tariffs were partly volumetric and partly capacity based. Charges were only applied to demand. Consumers received separate bills from the supplier and from their distribution company.	The Dutch government reviewed the charging arrangements in 2008 mainly to simplify them and introduce a retail-centred supply model. Making distribution charging more consistent with drivers of distribution network costs was a secondary policy driver.	Following the review, in 2009, a flat capacity charge was introduced for household and small industrial consumers. The charge was based on either the capacity of connection or the maximum power admissible by their connection, with fuse size used as a proxy where needed. The Dutch government introduced transitional arrangements to minimise windfall distributional effects from the change to the charging structure and to encourage consumers to reduce the size of their connections. Transmission charging changes followed in 2015 to base them on contracted peak capacity and monthly measured peak demand.	While transitional arrangements could not completely prevent negative impacts on certain consumer types, the transitional arrangements seem to have minimised negative consumer impact and the simplification of tariffs has been welcomed. The European Distribution System Operators for Smart Grids (EDSOSG) are advocates of the Dutch arrangements which they suggest have reduced revenue uncertainty for Distribution System Operators (DSOs).	The Netherlands case study seems to suggest that capacity based network charging can work as a stable mechanism for network cost recovery. The transitional arrangements and efforts of Government and utilities to publicise the arrangements and work with consumers to prevent negative effects, seems to have been important in enhancing acceptance of new arrangements.

Country / Region	Original charging arrangements	Problem identified	Change introduced	Impacts	Conclusions
Spain	The charging structure until early 2013 involved a contracted capacity component and a dominant volumetric energy component.	For some years, Spain had experienced a tariff deficit with revenues for DSOs not being sufficient to cover regulated allowed revenues. This revenue under-recovery has led to steadily increasing tariffs. Cost recovery problems have been exacerbated by the rapid take-up of DERs, in particular from on-site generation with solar PV.	The Spanish regulator has shifted revenue recovery from volumetric based charges onto capacity. Provisions were also introduced which require consumers (larger than 10 kW) to pay charges on the electricity produced on their premises alongside the electricity they source from the grid (the so-called 'sun-tax').	While it is too early to draw conclusions, capacity based charging seems to have reduced contracted capacity requirements at low voltage levels. The 'sun tax' has been highly contentious with significant opposition from the solar PV industry. Spanish MPs have recently indicated that the 'sun tax' arrangements may be reviewed.	Spain provides another European example in which the network charging basis has shifted more to connection capacity. However, the 'sun tax' reforms have been highly contentious and continue to be under review. This highlights the opposition that may occur where significant changes are introduced to the contribution self-generating facilities are expected to make to recovery of fixed / sunk network and other system costs.

Country / Region	Original charging arrangements	Problem identified	Change introduced	Impacts	Conclusions
Italy	All households faced: • capacity based charging elements, set through their smart meters (roll-out complete); • a flat component; and • a progressive volumetric component.	While less of an issue than in Spain, Italy has also faced a tariff revenue deficit. This has been resolved by passing any under-recovery through to allowances in subsequent years.	The Italian regulator is gradually eliminating the progressive structure of the distribution network tariffs. By 2018, the network and system charge tariffs will be the same for all consumption levels. Capacity components have also recently been introduced into transmission tariffs for HV and EHV customers but not for MV and LV customers. Self-generation projects are gradually being required to contribute to the grid costs, depending on their capacity.	The changes are currently in progress or yet to be introduced. Hence it is too early to evaluate impacts.	As the reduction of importance of the progressive volumetric element is likely to result in regressive distributional impacts, the re-distribution of charges may become a contentious issue. The reforms will also lower incentives to reduce consumption from the grid.

Source: CEPA and TNEI

3. UNITED STATES OF AMERICA

Distribution charge as percentage of retail bill: 28% in 2016[4]

Mature retail competition in place? No

3.1. The problem

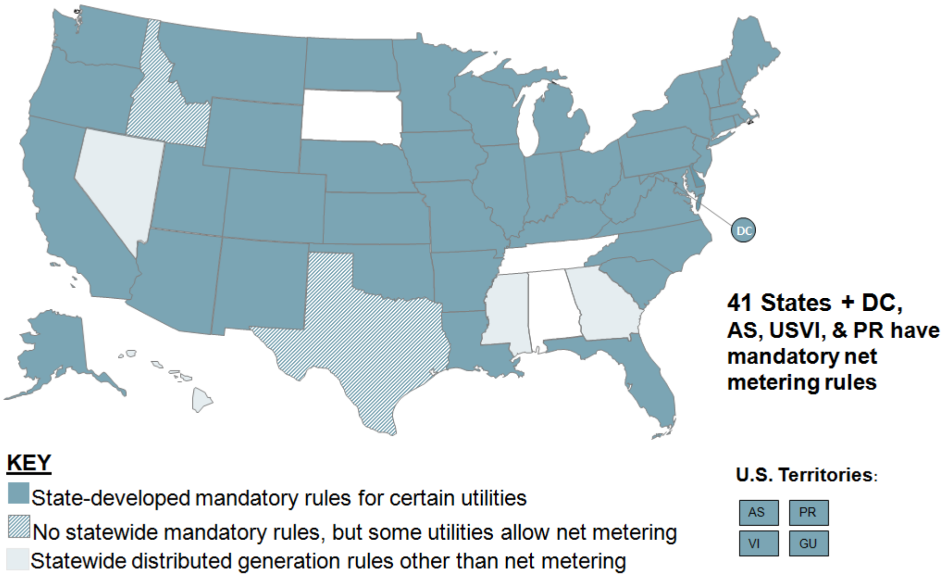
In the USA, the majority of states have vertically integrated utilities, operating as regulated monopolies. Typically, customers experience bundled tariffs, based on the average costs of serving customer classes.

Net Energy Metering

Most US States have Net Energy Metering (NEM) policies (see Figure 3.1). Domestic customers can net off their export against their import, effectively being paid the retail rate - which includes transmission and distribution costs - for their generated electricity. Opponents argue that the fixed costs of the distribution and transmission networks are increasingly borne by the remaining customers who do not have PV. Solar advocates argue that these calculations do not capture the full longer term benefits of distributed solar power.

The NEM tariffs have the benefit of simplicity, giving a clear signal to households, but they are unable to accurately reflect the costs and benefits of PV to the distribution network, or provide signals for customers and utilities to reduce longer term whole-system costs.

Figure 3.1: States with NEM policies



Source: DSIRE, July 2016, dsireusa.org/resources/detailed-summary-maps)

[4] EIA Annual Energy Outlook 2016, Table 8

3.2. Changes introduced

Proposed changes

Many states and utilities are exploring potential changes. In the year July 2014-15[5]:

- 48 utilities across 24 states proposed significantly increased fixed charges for residential customers.
- 17 utilities across 12 states proposed extra monthly charges for customers with residential PV.
- Many states are also considering charges on instantaneous peak demand.
- Many utilities and states are reconsidering the details of net metering, such as system size limits, compensation for excess generation, and aggregate caps.

Utilities' proposals have received mixed responses from regulators.

Value of solar

There have been attempts by utilities and regulators to design "Value of Solar" (VOS) tariffs. Under VOS tariff designs, customers purchase electricity at the standard retail rate, but sell generated electricity back to the grid at a VOS rate, calculated based on studies estimating the benefit/cost to the network. However, these have not been widely adopted by utilities.

3.3. The impact

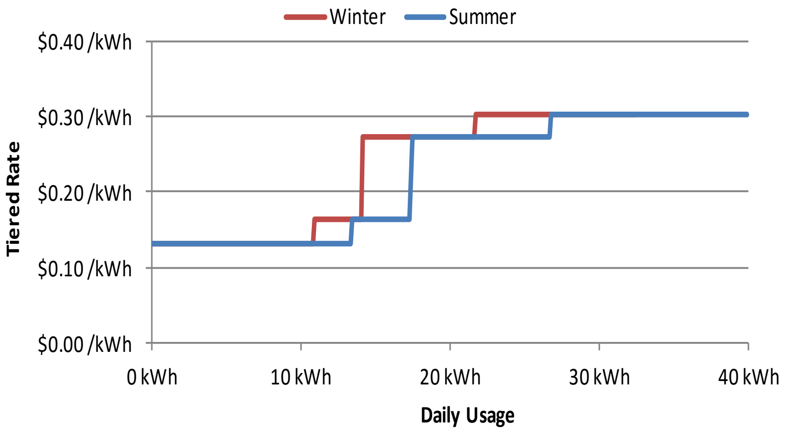
Proposed changes have often proved very controversial. Tariff changes have in many cases had a significant impact on the solar industry and on vulnerable consumers, whereas it has been suggested rates appear less likely to impact investment decisions on commercial and domestic developments.

3.4. Two specific USA State case-studies

Two states where changes to NEM have already been introduced, Nevada and California, are compared in the table below. In both states the changes have proved very controversial. Although it is too early to see the long-term impacts, California appears to have been broadly more successful than Nevada in achieving a change that is accepted by stakeholders.

[5] https://nccleantech.ncsu.edu/wp-content/uploads/Q32016_FinalExecSummary.pdf

Table 3.1: Case studies of Nevada and California

	Nevada	California
Regulator	Public Utilities Commission of Nevada (PUCN)	California Public Utility Commission (CPUC)
Main Utilities	NV Energy – with subsidiaries Nevada Power Company (NVE South) and Sierra Pacific Power Company (NVE North)	Southern California Edison, Pacific Gas & Electric Company, San Diego Gas and Electric
Tariff rules prior to changes	NEM available to domestic and commercial customers since 1997, for generation <1MW and <100% of the customer's annual electricity demand. Excess generation can be carried forward between months.[6] Large commercial customers also face a demand charge, based on peak demand during the billing period. Before the changes, the main elements of the bill for a single family residential household were a basic service charge of $12.75/month and a volumetric charge of $0.11/kWh.	NEM available since 1996 to systems <1MW. Excess generation credited to customer's bill at retail rate.[7] Tiered volumetric tariffs, so consumers of more net energy pay more per kWh. E.g. Residential tariff, Southern California Edison Residential – see figure below, 2014 (source: Edison Foundation)  *No peak time tariff, very small fixed tariff ($11/year)

[6] DSIRE http://programs.dsireusa.org/system/program/detail/372
[7] DSIRE http://programs.dsireusa.org/system/program/detail/276

<table>
<tr><th></th><th>Nevada</th><th>California</th></tr>
<tr><td>The problem</td><td>Solar grew by >80% in 2014 to 2016, due to incentives and good solar resource. NEM generation in 2016 was forecast as 234MW, i.e. 1% of total energy generation in Nevada. Installed capacity was forecast at approx. 3% of peak demand.[8]

There were concerns from the regulator and utility that DG-customers were avoiding utility costs and shifting cost onto non DG-customers. The PUCN found that the disparity constituted a monthly subsidy of $9 to $114 to DG customers. [9]</td><td>It was estimated that a 4kW solar project gains Net Present Value (NPV) of $20k from NEM. It is argued that this is far higher than the utility's avoided costs. Tiered tariffs mean higher energy consumers particularly stand to gain from PV. 75% of rooftop solar is leased, and most of the benefit goes to the leasing company rather than the householder.[10]

It was predicted that by 2020, approximately $1.1billion/year would be shifted from DG to non-DG customers. This equates to 3% of the utility's revenue requirement.[11]</td></tr>
<tr><td>Changes introduced</td><td>A tariff change was agreed with a 12-year phase-in. The rates for a single residential household are shown below[12]. The basic service charge will increase by over 300%, and the rate paid for generated electricity will decrease to <25% of its current value.

<table>
<tr><th></th><th>Basic Service Charge (monthly)</th><th>Volumetric Charge (per kWh)</th><th>Credit for generated energy (per kWh)</th></tr>
<tr><td>Prior Rate</td><td>$12.75</td><td>$0.11289</td><td>effectively $0.11289</td></tr>
<tr><td>2016</td><td>$17.90</td><td>$0.11067</td><td>$0.09199</td></tr>
<tr><td>2019</td><td>$23.05</td><td>$0.10845</td><td>$0.07429</td></tr>
<tr><td>2022</td><td>$28.21</td><td>$0.10623</td><td>$0.05747</td></tr>
</table></td><td>Legislation was passed in October 2013, directing the CPUC to reform residential tariffs by Dec 2015.
In Jan 2016, the CPUC voted the following changes:

gradual move to two-tier rather than four-tier system;
add a super-user surcharge (affects <10% of customers);
move towards mandatory ToU tariffs for DG by 2019;
minimum charge of $10 monthly, even if net consumption is zero;
"non-bypassable" charges, such as for nuclear decommissioning, which were previously charged on net consumption, will be charged on total electricity delivered from the grid; and
utilities can charge a one-off connection fee, estimated between $75 and $150.

However, the CPUC rejected calls for fixed charges, access charges, installed capacity fees etc, stating that further work and discussion is needed.</td></tr>
</table>

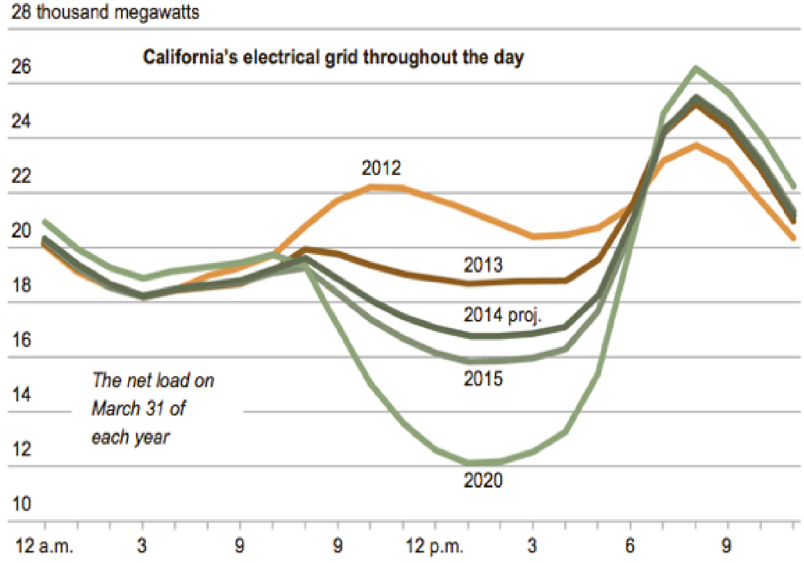
[8] Nevada Net Energy Metering Impacts Evaluation, Energy+Environmental Economics, July 2014
[9] R Street Policy Study No.59, March 2016, Rash Ratemaking: Lessons from Nevada's NEM Reforms, Devin Hartman
[10] Net Energy Metering: Subsidy Issues and Regulatory Solutions. Issue Brief September 2014, The Edison Foundation
[11] Energy+Environmental Economics, Inc, California Net Metering Ratepayer Impacts Evaluation, October 28,2013, p.6
[12] NV Energy, Net Metering https://www.nvenergy.com/renewablesenvironment/renewablegenerations/NetMetering.cfm

<table>
<tr><th></th><th>Nevada</th><th>California</th></tr>
<tr><td></td><td><table><tr><td>2025</td><td>$33.36</td><td>$0.10418</td><td>$0.04157</td></tr><tr><td>2028</td><td>$38.51</td><td>$0.10179</td><td>$0.02649</td></tr></table>There was no grandfathering of existing schemes to avoid the rate increase.</td><td>There are additionally schemes in place to help low income customers. Existing solar arrays were grandfathered.</td></tr>
<tr><td>Impact assessment</td><td>17,000 householders who had already invested in solar lost out through the ruling. Solar companies including Vivint Solar, SunRun and SolarCity have ended their operations in the state. SunRun criticised the retrospective application of the new tariffs for undermining investor confidence in the Nevada government. SolarCity claimed the PUCN had protected the utilities' monopoly, at the cost of Nevada customers.

Some experts argue that the analysis behind the changes did not adequately consider avoided transmission and distribution capacity, the cost of ancillary services, interconnection, administration and environmental costs. [13]
In September 2016, the ruling regarding grandfathering was reversed, such that the original scheme will now apply for 20 years for customers already approved under NEM or with already submitted applications. This is estimated to affect 32,000 businesses and householders.</td><td>The decision was seen as striking a balance between utilities and solar companies, with a much better deal for solar companies than other states such as Nevada or Hawaii.

It is too soon to see the full impact. As elsewhere in the US, the attempted changes proved controversial - in 2015, solar advocates delivered wheelbarrows of petitions from over 130,000 electricity users to CPUC.</td></tr>
<tr><td>Lessons learnt</td><td>A robust third party analysis of costs and benefits should be undertaken. This must consider the long-term benefits of DG, including how this can interact with network planning to reduce long-term costs. Where the utility is a competitor to DG this is problematic to achieve, as the utility holds the necessary data for quantification of these benefits, but may have a financial incentive not to release them.[14]
A cost-shift towards non-PV customers is not sufficient evidence that PV is being under-charged, if the methodology was not cost-reflective to begin with.</td><td>The old tiered system was seen as "fairer" and more environmentally-friendly because it incentivised lower electricity use. Consumer acceptance of tariffs depends on perception of fairness between energy users.
ToU tariffs are challenging to implement well, since historically peak demand was during summer afternoons, but now a "duck curve" effect is starting to occur (see figure below). ToU tariffs must be flexible enough to adapt to changing trends in demand and generation.</td></tr>
</table>

[13] R Street Policy Study No.59, March 2016, Rash Ratemaking: Lessons from Nevada's NEM Reforms, Devin Hartman
[14] R Street Policy Study No.59, March 2016, Rash Ratemaking: Lessons from Nevada's NEM Reforms, Devin Hartman

	Nevada	California
	• Applying the traditional rate design methodology of averaging costs and benefits over a whole consumer class means that the tariff cannot take into account the local costs and benefits of solar. • Demand charges (i.e. based on peak kW usage) should be considered, rather than expanding fixed charges, as they may be able to lead to more efficient longer term results. This is because demand charges will encourage users to reduce peak time usage (and therefore decrease network costs), rather than fixed charges, which have been perceived as simply a way of preventing a shift of cost towards non-DG customers. • Every rate change undermines stability and increases risk. In particular, rate changes tend to have a very large impact on investment decisions in co-located DG, compared to a relatively minimal impact on residential and commercial demand investment decision. Changes should be made in the context of long term, predictable rate design, and should consider investor confidence. • In a vertically integrated system, tariffs have complex interactions with other incentives (e.g. Nevada's renewable procurement standard)	 *Source: CalISO* • The solar industry has argued the changes will add complexity and uncertainty, and so will increase the cost of financing of solar projects.

3.5. Lessons for GB

Energy rates changes and NEM issues have become a controversial topic in the USA. As most states have vertical integration between distribution and supply, this includes network charges. Changes to energy rates have a particularly pronounced impact on vulnerable consumers and on the domestic solar industry – for example, in Nevada many domestic solar companies have ceased trading in the state due to rates changes.

In the US, there has been a tension between the avoidance of "rate shock" – rapid changes in tariffs for individual customer groups – and the development of cost reflective tariffs. Although in GB, network charges are more cost-reflective than in the US, changes to cost recovery could still have a significant impact on the overall charge seen by customers.

US precedent would also suggest that reforms to the network charging basis are more likely to be accepted by the DG industry if they are based on a robust and impartial assessment of the costs and benefits of DG, and have long term validity. Grandfathering should also be considered carefully, to balance the aim of overall reduced cost to the consumer against the risk of a large impact on individual households.[15]

The controversy in Nevada, where critics argued that the rates changes did not take into account the long-term benefits of solar PV highlights the importance of basing changes on a robust and independent analysis that includes the long-term network benefits of DG. Due to the vertically integrated nature of the US market, there are particular issues with accusations of bias, as networks are seen as competitors to DG. In GB, the electricity network companies do not directly compete with DG in energy generation. However, flexibility providers and DG have the potential to defer or reduce network reinforcement, therefore, reducing the potential asset base of the network owner. Therefore, the US example suggests that forward-looking, LRMC based assessments, of the impacts of DG on network costs are appropriate, but that any proposals made by the utilities themselves, need to be independently scrutinised by Ofgem and other interested stakeholders.

The US reform process also shows that the benefits of simplicity in fixed and volumetric charges need to be weighed up against the benefits of sending an efficient signal to consumers, via demand charges (i.e. based on peak kW usage) or ToU charges (based on energy usage in specified periods). In:

- Nevada, the change to a large fixed charge and a reduced credit for generated energy does not give any scope for realising the potential benefits of PV to the network; whereas
- California, ToU tariffs have the potential to encourage efficient investment that reduces network costs.

[15] In Nevada, the decision not to grandfather existing tariffs to households who had invested in PV was particularly controversial and was eventually reversed.

Demand and ToU charges are more likely to be accepted by the DG industry. However, they are more difficult to implement technically, and ToU charges must be flexible enough to adapt to changing system usage and generation patterns. In California, the opportunity has been taken to simplify other parts of the charging system (the tiered charging structures) somewhat balancing out the increased complexity of the ToU charging.

In the US, at domestic and small-scale commercial level, rates are usually set to be cost-reflective for the 'average' customer for large classes of customers; similar to GB's CDCM[16]. Critics have argued that this severely limits the ability to send efficient signals to customers, as it is difficult to send a useful signal to specific customers even if the methodology captures the average benefit of solar. In reality the LRMC of each customer's actions may vary significantly, but these effects tend to be averaged out in the CDCM. Whilst it may be impractical to have a higher granularity of analysis for small scale customers, it is important to consider whether the customer classes in the CDCM (a group of customers who had a similar network impact prior to the growth of flexibility and DERs) are still appropriate. For example, will sending the same ToU signal to all customers in a given class have the desired impact? Again, a balance must be struck between efficient signals and simplicity.

[16] The Common Distribution Charging Methodology (CDCM) is the methodology, principles and assumptions that underpin the calculation of electricity distribution use of system charges for HV and LV networks in GB.

4. VICTORIA - AUSTRALIA

Distribution charge as percentage of retail bill: approximately 20% in 2013[17]

Mature retail competition in place? Yes[18]

4.1. The problem

The way that customers use the electrical networks in Australia has changed significantly in recent years. We have looked at the state of Victoria as an example, although similar case studies can be found in other states in Australia (see references below).

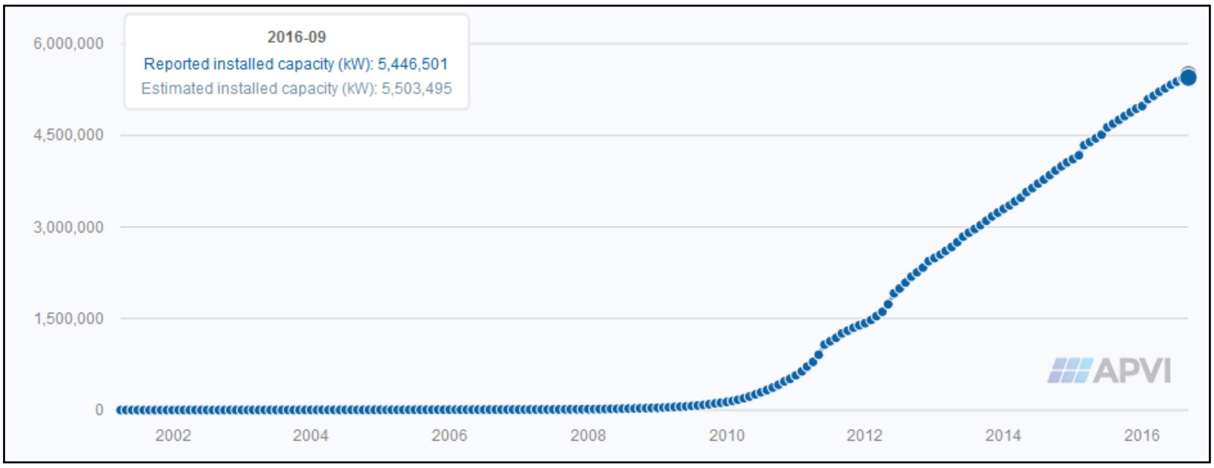
Smart Meters

In Victoria, the smart meter roll-out is essentially complete[19] – 2.8m smart meters have been deployed by Victoria's five electricity DNSPs – CitiPower, Jemena, Powercor, SP AusNet and United Energy. This allows for both the utilities and their consumers to obtain better information about their electricity consumption.

PV Deployment

There has been a significant deployment of solar PV across the whole country, as demonstrated in Figure 4.1, which shows that since 2010 the cumulative capacity of installed PV has risen from 133 MW in 2010 to an estimated 5.5 GW in late 2015.

Figure 4.1: Australian PV installations since April 2001: total capacity (kW)

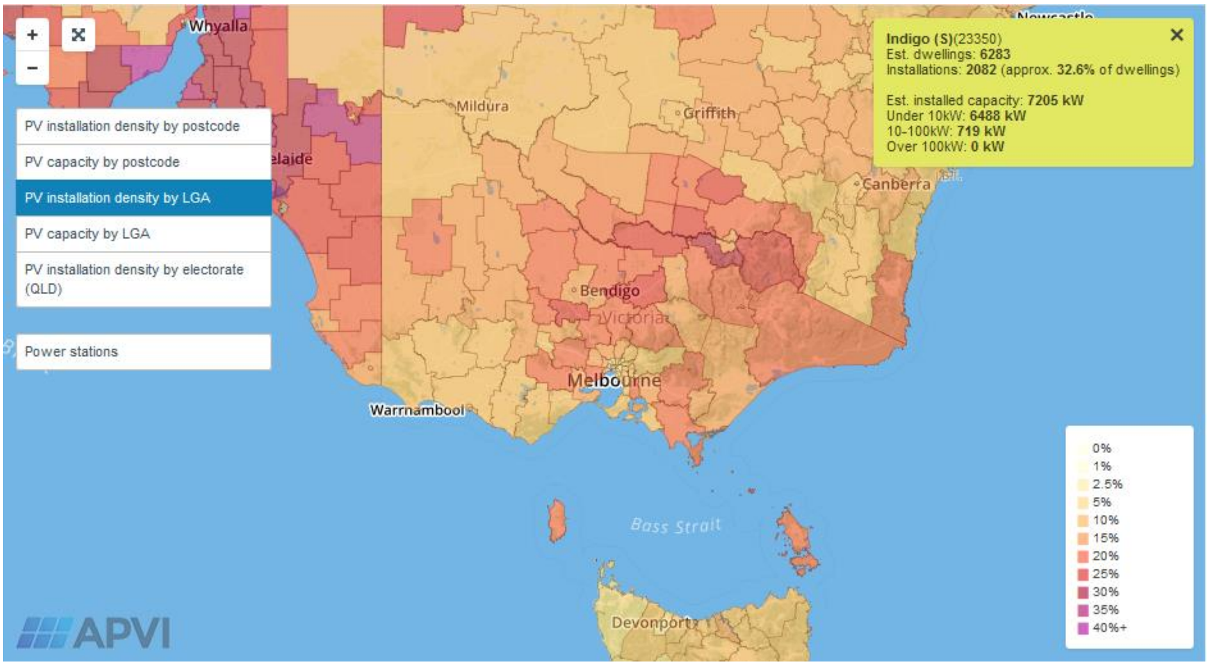


Source: APVI

Figure 4.1 shows the density of PV installations by Local Government Area in Victoria. Around 10-20% households have PV deployed, with some LGAs having a penetration of PV of >30%.

[17] http://talkingelectricity.com.au/wp/wp-content/uploads/2014/07/Topic-1_Bill-Breakdown.pdf
[18] http://www.aemc.gov.au/getattachment/6856bf1b-648a-432a-bf5f-54ea453a3d8a/Infographic.aspx
[19] http://www.smartmeters.vic.gov.au/about-smart-meters/end-of-rollout

Figure 4.1: Density of PV installations in Australia by LGA



Source: APVI

Charging Reforms

Significant PV deployment coupled with the roll-out of smart meters has drastically changed the way that customers have started to use the network in recent years.

In 2010, concerns about the impact on consumers of ToU tariffs following the smart-meter rollout led to a moratorium on tariff reform activities in Victoria[20]. This moratorium was in place from March 2010 to September 2013 and stopped the introduction of ToU tariffs until an assessment had been made. ToU pricing was eventually introduced on an opt-in basis.

In other states (such as Queensland), the rapid uptake of PV under the existing basis of network cost recovery has also been observed as having had major distributional impacts between different customer groups – see text box below.[21]

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[20] http://www.energynetworks.com.au/sites/default/files/position-paper_towards-a-national-approach-to-electricity-network-tariff-reform_december-2014_1.pdf

[21] This Queensland case study was prepared by Michael Pollitt as part of work undertaken by CEPA and TNEI on flexibility and network charging and is also included in the Cambridge Energy Policy Research Group (EPRG) working paper 'Electricity Network Charging for Flexibility'

Box 4-1 Net-Metering in South Queensland Case Study[22]

South Queensland in Australia has one of the highest penetration rates of domestic solar PV in the world. 22% of households had PV in 2014 (and 75% have air-conditioning). Distribution charges in South Queensland are charged based on 20% fixed cost and 80% per kWh. The massive increase in solar PV (from close to zero at the start of 2009) has resulted in a huge transfer of wealth and costs between customer groups. Solar PV consumers have lower metered consumption due to own production. This significantly reduces their share of the per kWh costs of the distribution system.

Meanwhile the revenue cap regulation of the distribution charges means that the same revenue has been recovered as the number of units has fallen, thus per unit charges have risen and the distribution of their payment between different types of households has dramatically changed.

Simshauser (2014)[23] analysed four types of household in this new situation in Queensland: households with no PV and no air-conditioning (this is the poorest group); households with air-conditioning and no PV; households with PV and no air-conditioning; and households with PV and air-conditioning. He looked at how the charging mechanism has shifted network charge payments between different customer groups and also considered a more cost reflective charging regime where each household pays a fixed charge, a per kW peak charge and a variable per kWh charge to better reflect underlying costs.

Simshauser's analysis found that households with PV and air-conditioning have only a fractionally lower peak per kW usage relative to those with no PV but air-conditioning. Meanwhile, households with air-conditioning and no PV currently pay less than they should towards distribution charges, given their relative cost of service.

This reveals that the starting point of charging is already unfairly subsidising peaky users with air-conditioning AND that the system has rapidly become much more unfair with the high take-up of PV (as described above, the installed PV reduces these customers net-metered consumption, which in turn reduces their contribution towards volumetric charges). When the more cost reflective three-part tariff scheme was considered by Simshauser (involving a fixed charge, a per kW charge and a variable per kWh charge), the result was customers with PV and air-conditioning paying 28 per cent more than currently, and those customer without PV and air-conditioning paying 15 per cent less (with the result that the poorer households pay around 180 AUD (£95) less).

Simshauser's analysis of the differences in network charges for residual customer groups under the existing charging mechanism in South Queensland, is shown in the table below.

[22] *Pollitt (2016): 'Electricity Network Charging for Flexibility'*
[23] Simshauser, P. (2014). Network tariffs: resolving rate instability and hidden subsidies, AGL Applied Economic and Policy Research Working Paper No.45 –

Box 4-1 Net-Metering in South Queensland Case Study[22]

Table 4-1: Differences in Network Charges for Residential Consumers in South Queensland

	House A	House B	House C	House D
Air-Con?	×	×	✓	✓
Solar PV	×	✓	×	✓
Maximum Demand (kW)	1.41	1.40	2.14	2.09
Metered Import (kWh)	6,253.4	3,820.1	7,560.6	4,707.1
Solar Export (kWh)		2,259.1		1,838.8
Gross Demand (kWh)	6,253.4	6,253.4	7,560.6	7,560.6
Number of customers	283,849	26,151	694,643	235,357
% of customers	23	2	57	19
Base network Tariff	$1,006.14	$698.57	$1,171.37	$810.69
Difference	$307.57		$360.68	

Source: Pollitt (2016): 'Electricity Network Charging for Flexibility'[24]

In 2014, the AEMC carried out a comprehensive review of network charging, with a view to introducing more cost reflective charges. External advice was sought from consultants and the AEMC looked in detail at several issues, including the recovery of residual costs.

Prior to the reform process, DNSPs had the freedom to choose how they set their charges, and would submit proposals to the Australian Energy Regulator (AER). The AEMC's initial Consultation Paper sets out the existing pricing principles which all DNSPs had to comply with. These included that:

- the revenue of each price class must be greater than the incremental cost and less than the standalone cost of the service;
- the DNSP 'take into account' the LRMC;
- DNSPs consider tariff transaction costs and responsiveness of retail customers; and

[24] http://www.eprg.group.cam.ac.uk/eprg-working-paper-1623/

- that prices are adjusted '*in a way that minimises distortion to efficient patterns of consumption*' if prices do not recover all revenues.

4.2. Changes introduced

New Rules from the AEMC

As a result of their 2014 review, the AEMC introduced new rules for network charges. These are detailed in the final determination[25], and summarised as follows:

- '*Each network tariff must be based on the long run marginal cost of providing the service*.'
- '*... the total revenue determined by the AER in the business' distribution determination must be recovered in a way that minimises distortions to price signals*...'
- '*Distribution businesses must also give effect to a consumer impact principle when developing their tariffs.*' This consumer impact principle has two parts.
    - '*The first part requires distribution businesses to consider the impact on consumers of changes in network prices.*'
    - '*The second part of this principle requires network prices to be reasonably capable of being understood by consumers.*'

The first and second of these rules are comparable with the issues under consideration by Ofgem relating to network charges – that is, the distinction between cost-reflectivity (currently achieved based on LRMC type principles) and cost-recovery (where Ofgem have identified some potential existing market distortions e.g. relating to embedded benefits).

The third rule highlights another important facet of tariff reform (which was also highlighted by the initial moratorium) – that ultimately, tariff reform has the potential to affect end consumers of electricity and distributional impacts should be considered.

Stakeholder Views[26]

The Australian Energy Networks Association (ENA) broadly welcomed the intent of the proposals. They identified with the issues being considered by the AEMC and agreed with the proposals for greater engagement with stakeholders on the structure of tariffs and on improving the transparency of arrangements.

[25] http://www.aemc.gov.au/getattachment/de5cc69f-e850-48e0-9277-b3db79dd25c8/Final-determination.aspx

[26] Not unexpectedly, the AEMC's proposals received significant interest throughout their development. Below we have summarised the views of three stakeholder groups of particular interest. Further insight into how proposals were received can be found at the following link: http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements

However, they had concerns with the reduction of flexibility for distribution networks to introduce cost reflective tariffs within their own jurisdictions. They also asked the AEMC to recognise the importance that the ENA placed on the continued role of fixed charge tariff components for those customers without smart meters. They suggested that fixed charge components may need to increase to ensure cost recovery as volumetric elements were reduced. They noted the distributional impact that this could have on vulnerable customers requesting that the government review customer hardship programmes.

Consumer groups similarly welcomed the introduction of changes to tariff arrangements. They identified benefits in terms of enhanced efficiency and avoided investment potential. However, they also identified the potential for increased complexity of tariff structures and for consumer disengagement which they believed could undermine the benefits case of reform. In their consultation response to the draft proposals, consumer bodies advocated clear communication of reforms and for retailers to reflect tariff changes in their consumer offerings. They proposed that the AEMC include a consumer impact and understanding principle to the rule changes being developed, which was included within the AEMC's final rule changes.

The Energy Retailers Association of Australia (ERAA) shared the consumer advocacy group's view regarding minimising complexity of tariffs and communicating reform effectively. They said that less complex tariff structures would make it easier for them to pass through reflective signals in retail offerings. They also emphasised the importance of a smooth transitioning process of the revised arrangements over one or two price control periods with improved affordability initiatives to soften any impacts on vulnerable consumers.

Implementation of the New Rules

The AER's Final Decision[27] on the tariff structures of the Victorian DNSPs from August 2016 shows how these rules have been implemented in practice. This decision highlights the following:

- **The DNSPs are using forward looking principles to calculate LRMC:** Average incremental costs (including capital and operational costs) associated with expected increase in demand are calculated over a period of 10 – 20 years (depending on the DNSP) and used to determine tariffs. The AER noted that replacement capex should be included in LRMC estimates.
- **Locational signals are not provided:** Cost reflective tariffs are calculated for each voltage level (LV residential, LV business, HV business, Sub-transmission) but not at individual locations. This does reduce the extent to which the tariffs are 'cost reflective'. However, this appears to have been in response to a stakeholder message that 'locational tariffs are complex for consumers to understand.'

[27] https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Victorian%20distribution%20businesses%20-%20Tariff%20Structure%20Statement%202017-20.pdf

- **LRMC tariffs are being recovered based on peak instantaneous demand:** All the DNSPs have linked the LRMC to proposed kW or kVA demand charges. For these, charging windows which target peak demand periods have been proposed. This aligns with the principle that peak demand is what drives network investment.
- **Residual costs are being recovered in a manner which minimises distortions:** All the Victorian DNSPs will recover residual costs either from fixed $ charges or from $/kWh energy charges, although the AER notes that all the DNSPs have proposed to reduce the kWh component and increase the fixed component in order to signal '*to customers the value of being connected to the network*'. This would preclude the possibility of 'embedded benefit' style distortions due to the triad arrangements. However, where charges are based on energy consumption (particularly net-metered energy consumption) there would still be potential for users with behind-the-meter generation to reduce their contribution to network cost-recovery.
- **Transitional arrangements are used to protect consumers:** Capacity based demand (i.e. kW or kVA) tariffs will be opt-in only for all customers with a demand of less than 40 MWh/annum, with a higher threshold of 60 MWh/annum for business customers proposed by some DNSPs. For all other consumers, demand tariffs will apply automatically but the magnitude of these tariffs will gradually increase over a transitional period between 2017 and 2020. In their decision, the AER noted that the transitional arrangements contribute '*to the achievement of compliance with the distribution pricing principles by enabling these customers to become aware of how the new charges will affect them.*' This may suggest that applying new tariffs on an opt-in or transitional basis has been part of the DNSPs' responses to the "consumer impact" rule.

4.3. The impact

These rules have been supported by some but others have opposed them. The Consumer Utilities Advocacy Centre, a consumer advocacy group, has suggested that the switch to demand tariffs should be mandatory, preceded by an 18 month period of communication in order to ensure that customers are informed.

They point out that if demand tariffs are rolled out on an opt-in basis, then consumers would only choose these if it would result in them paying less. Any users who would pay more with a demand charge will presumably not opt in. However, the DNSP still has a regulated revenue that they need to recover, and so their residual costs would increase accordingly. Therefore, the fixed/volumetric tariffs would increase for all other users.

The ENA published further proposals in 2015 for how tariff reform activities could continue, but these have been criticised by some stakeholders. The ENA discussed a range of options, including higher connection costs and even 'exit fees' for recovery of sunk costs when users disconnect.

As reforms are ongoing, it is too early to opine on exactly what the impact of the review and rule changes has been, although debate on the subject continues and it seems certain that any proposals will attract criticism from certain parties.

4.4. Lessons for GB

Well informed debate on charging reform is taking place in other countries, and the Victorian case study provides a particularly good example of a case with very good information. The review has been wide ranging, detailed and transparent with lots of published information and analysis available from a number of groups including third parties. The approach to charging reform – with a distinction between cost-reflective and residual charges – aligns closely with the way these issues are starting to be considered in GB.

The new rules have encouraged a move towards a charging structure which appears to more broadly align with the principles we would consider to be efficient – cost reflective elements are recovered based on peak kW demand and cost recovery elements are recovered through fixed charges (with some energy charges).

Consumer impacts have been considered throughout and change will be introduced incrementally. There is even a specific rule the DNSPs must follow which requires them to consider consumer impacts. However, the reforms may need to go further and make some changes (e.g. the introduction of peak demand charges) compulsory for all users to completely prevent adverse distributional impacts.

5. THE NETHERLANDS

Distribution charge as percentage of retail bill: approximately 21-23%[28]
Mature retail competition in place? Yes

5.1. The problem

The Dutch Government sets the principles of the tariff structure by law. The network operators then decide which structure to adopt, while the regulatory authority determines the authorised revenue. The Government launched a review of tariff structures in 2008. The primary reason for launching the review was not the cost recovery issue that is being considered in the UK. Rather, the Government wanted to reform the supply model to centre it around energy retailers. Prior to the review, consumers received separate bills from suppliers and from Dutch DSOs. Therefore, the primary aim of the review was to reform and simplify the billing process to allow improved consumer interfaces.

However, the Government had also identified that network costs were mainly capacity driven and determined by peak demand. As a secondary consideration within their review, they wanted to consider how distribution charging approaches could be made more consistent with the drivers of distribution network costs.

5.2. Changes introduced

Following the review, the Dutch Government revised the distribution tariff structure. While the previous charges had been based partly on volume and partly on capacity, this was replaced with a flat capacity charge for:

- household customers with a connection of less than 3x25A; and
- small industrial customers with a connection of less than 3x80A.

Charges continued to be applied to those with a demand connection only. The charge was based on either the capacity of connection or the maximum power admissible by their connection. Where necessary, fuse size is used as a proxy for this.

Transitional considerations

Within its review, the government had identified that this change to tariffs could cause bills of certain customers (i.e. those with relatively low energy usage and relatively high installed capacity) to increase significantly.

[28] ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2015 Retail Markets p. 12. http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016. NB: Breakdown by distribution and transmission charge not available.

To mitigate distributional effects and avoid a public backlash, the government coincided the changes to tariffs with reforms to a separate energy tax. This energy tax was introduced to stimulate energy efficiency and included a variable volumetric component. At the time of distribution tariff changes, the volumetric component was increased (to replace the energy efficiency incentive that had been in place through the demand tariff) and a fixed tax rebate introduced for the first two years in order to leave ‘standard connection’ customers with a relatively similar overall energy payment as they had had previously throughout a transitional period. See examples of charges pre and post reforms below.

Figure 5.1: Example charges before and after distribution tariff reform

Volume 2.000 kWh

	2008	Tariff		volume	amount
Distribution	Connection	32,64	euro		32,64
	Fixed part	18,00	euro		18,00
	Variable costs (kWh)	0,0336	€/kWh	2.000	67,20
Supply	Tax reduction	-199,00	euro		-199,00
	0-10.000 kWh	0,0752	€/kWh		150,40
					69,24

	2009	Tariff		volume	amount
Distribution	Connection	16,44	euro		16,44
	Fixed part	18,00	euro		18,00
	Capacity charge (25A)	115,6000	euro		115,60
Supply	Tax reduction	-318,62	euro		-318,62
	0-10.000 kWh	0,1085	€/kWh	2.000	217,00
					48,42

Volume 3.500 kWh

	2008	Tariff		volume	amount
Distribution	Connection	16,32	euro		16,32
	Fixed part	18,00	euro		18,00
	Variable costs (kWh)	0,0336	€/kWh	3.500	117,60
Supply	Tax reduction	-199,00	euro		-199,00
	0-10.000 kWh	0,0752	€/kWh	3.500	263,20
					216,12

	2009	Tariff		volume	amount
Distribution	Connection	16,44	euro		16,44
	Fixed part	18,00	euro		18,00
	Capacity charge (25A)	115,6000	euro		115,60
Supply	Tax reduction	-318,62	euro		-318,62
	0-10.000 kWh	0,1085	€/kWh	3.500	379,75
					211,17

Volume 5.000 kWh

	2008	Tariff		volume	amount
Distribution	Connection	16,32	euro		16,32
	Fixed part	18,00	euro		18,00
	Variable costs (kWh)	0,0336	€/kWh	5.000	168,00
Supply	Tax reduction	-199,00	euro		-199,00
	0-10.000 kWh	0,0752	€/kWh	5.000	376,00
					379,32

	2009	Tariff		volume	amount
Distribution	Connection	16,44	euro		16,44
	Fixed part	18,00	euro		18,00
	Capacity charge (25A)	115,6000	euro		115,60
Supply	Tax reduction	-318,62	euro		-318,62
	0-10.000 kWh	0,1085	€/kWh	5.000	542,50
					373,92

Source: Liander

Alongside the change, they also put time and resources into a public awareness media campaign in the lead up to the date of reforms going live. This was designed to inform consumers of the nature and high level reasons for the changes and to encourage them to take time to consider the level of connection that they needed, informing them that they may be able to save money by switching to a lower connection.

DSOs also worked with consumers directly to encourage them to consider the size of their connection. In 2009 and 2010, they introduced a subsidised charge for reducing the connection capacity, e.g. by installing a smaller fuse or other form of connection capacity. In 2013, they agreed to compensate consumers who had not realised they were paying more than they needed to and changed their contracted capacity for free. The total capacity of connection to a DSO's network is part of a calculation to determine allowed revenues in the Netherlands. Thus, it seems that DSOs may have been offering services to reduce capacity in contrast to natural incentives to maintain high connection capacity on their distribution network. Government and regulatory pressure may have played an important part in achieving this.

Changes to transmission charging

Following the move to capacity charging at distribution level, similar reforms have been introduced at transmission level. In 2015, transmission charges were introduced based on:

- contracted peak capacity; and
- monthly measured peak demand.

Energy based drivers do remain in some areas of the transmission charging structure. For example, consumers that use the grid for loading in less than 600 hours of the year receive reduced tariff rates. Again, these changes were mainly driven by simplification considerations. The Dutch regulator (ACM) is considering additional changes to further simplify charging arrangements by removing the contracted peak capacity element of the transmission charge moving to measured peak demand charging only.

5.3. The impact

The ACM considers the changes to have been beneficial. While meeting the primary objective of simplification, the reforms introduced in the Netherlands also seem to have been able to avoid some of the issues that may have arisen in the presence of volume based charges.

While there has been some consideration of distributional effects with certain customer types (i.e. those with high capacity needs but low volume requirements (e.g. buildings with elevators)) losing out, customers seem to have benefited from the improved charging simplicity more generally. The changes have also removed DSOs' volume risk, allowing them to better forecast charges and recover costs.

The EDSOSG are an advocate of the changes introduced in the Netherlands[29]. They suggest that the reforms have brought several benefits including:

- transparency surrounding energy bills for consumers;
- a simplification of billing and tariff structures, substantially reducing administrative costs; and
- reduced revenue uncertainty for DSOs.

[29] http://www.edsoforsmartgrids.eu/wp-content/uploads/151014_Adapting-distribution-network-tariffs-to-a-decentralised-energy-future_final.pdf

However, even where they accept that the move to capacity based charging may have been a beneficial step in the right direction, others have questioned whether further reforms may be needed. For example, some have considered whether the smart meter rollout (due for completion in 2020) should be used to introduce dynamic pricing. They argue that the capacity based charge has reduced the energy efficiency incentives placed on consumers.

In 2012, a Dutch DSO, Enexis carried out three pilot dynamic pricing projects (see box below).

EDSOSG argue that there has been no measurable impact on energy efficiency as energy based incentives are retained under the energy tax and supplier charge components of a consumer's bill.

Your Energy Moment: dynamic pricing trials

300 homes took place in three pilot projects which ran from 2012-2015. The consumers were provided with smart meters, solar panels and smart utilities and faced dynamic price tariffs.

According to Enexis' analysis of results there was a significant impact on consumer behaviour, 90% of consumers changed their settings to activate their utilities at the cheapest time of day while 10% preferred to base demand on levels of renewable energy.

Enexis are following up with further studies including one which is studying the effects of storage behind the meter and another testing the impact of dynamic tariffs on electric vehicles.

5.4. Lessons for GB

The charging reform process followed in the Netherlands seems to suggest that capacity based charging can work as a means to simplify charging arrangements and to create a stable mechanism for network cost recovery.

While concerns were raised regarding the potential negative impact on energy efficiency, energy use since the change suggests that volume based incentives which exist in other areas of the consumer's bill have avoided this effect.

Commentators suggest that consumers (save for certain exceptions who have been more negatively impacted by the changes) have benefited from the improved simplicity of charges and billing. Dutch DSOs meanwhile seem to have avoided some of the cost recovery issues being faced in other jurisdictions and the European DSO community identifies the Netherlands as a case study of where capacity based tariffs have been effective.

Another interesting element of this case study is the hands on transitional approach adopted by the Dutch Government and DSOs, with close working between the Government and the regulator to mitigate windfall impacts on consumers resulting from the change. A publicity campaign of the reforms also helped, though some consumers had to be compensated, and changes to consumer capacities performed by the DSO for free, after it was established that some consumers had not fully understood the changes and what it meant for them.

6. SPAIN

Distribution charge as percentage of retail bill: 22% of bill[30]

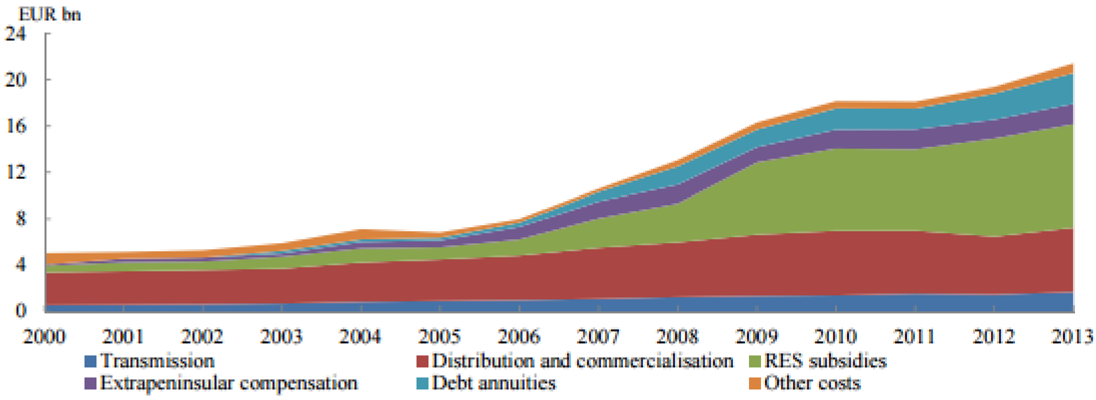
Mature retail competition in place? Yes

6.1. The problem

In 2013, Spain began an electricity market reform process, with the main aim of eliminating a persistent and significant 'tariff deficit' estimated at around €30bn in 2013.[31]

The 'tariff deficit' has accumulated over a 15-year period as tariff revenues for the network companies had not been enough to cover their regulated revenues which include renewable support mechanisms. The revenue under-recovery and the accrued interest has led to steady increases in tariff levels which presently account for about half the electricity cost paid by consumers. The figure below shows the evolution of regulated costs in the Spanish electricity system from 2000 to 2013. These costs have increased from around €5bn to over €20bn over the period. While there has been some increase in transmission and distribution costs, most of the increase has come from rising renewable support costs.

Figure 6.1: Evolution of regulated costs in the Spanish electricity system 2000-2013



Source: European Commission[32]

Spain has experienced significant uptake of DERs, particularly in the form of PV solar panels which has exacerbated the tariff deficit problem, due to the historic network tariff structure used to recover network and other system costs.

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[30] ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2015 Retail Markets p. 12. http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016

[31] European Commission, *Electricity Tariff Deficit: Temporary or Permanent Problem in the EU?*, http://ec.europa.eu/economy_finance/publications/economic_paper/2014/pdf/ecp534_en.pdf

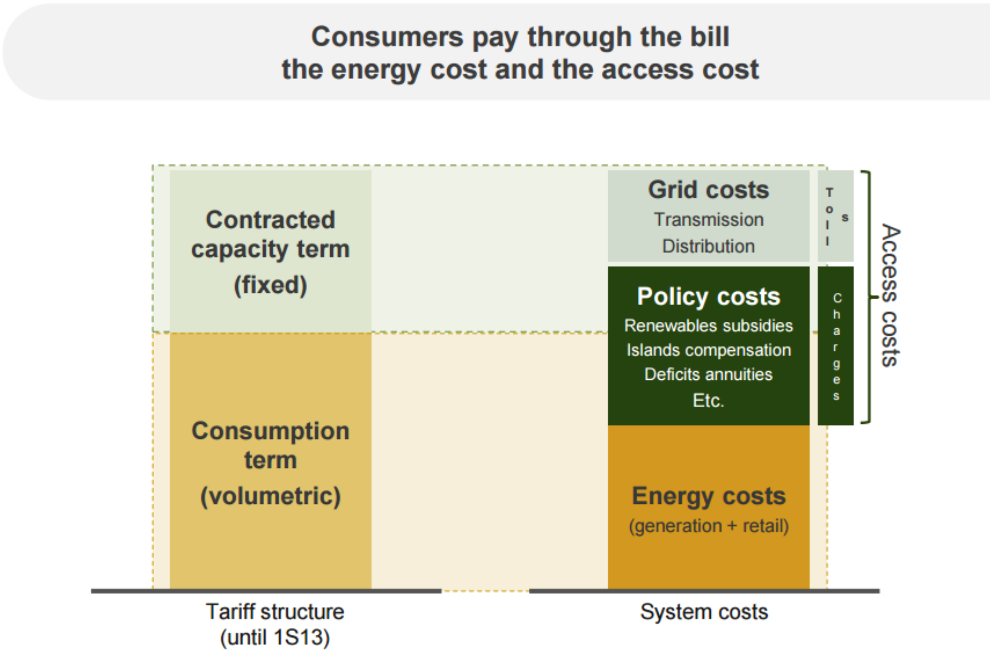
[32] European Commission, *Electricity Tariff Deficit: Temporary or Permanent Problem in the EU?*, http://ec.europa.eu/economy_finance/publications/economic_paper/2014/pdf/ecp534_en.pdf

Electricity users in Spain have historically been charged three types of costs through their electricity bill:

- grid costs for transmission and distribution networks;
- other system costs (non-Transmission System Operator (TSO) costs) – e.g. support mechanisms for renewable generation sources and non-peninsular generation systems; and
- energy costs including the cost of generation, losses, system reserves and back-up.

The charging structure faced by most consumer in Spain until early 2013 involved a contracted capacity component and a dominant volumetric energy component.[33] The charging structure meant that a portion of the fixed network and policy costs were covered by a volumetric consumption charge which could be reduced through on-site generation.

Figure 6.2: Tariff structure (until early 2013) and system costs covered by tariffs in Spain



Source: [*https://www.iea.org/media/workshops/2015/esapworkshopiv/Laveron.pdf*](https://www.iea.org/media/workshops/2015/esapworkshopiv/Laveron.pdf)

6.2. Changes introduced

The Spanish Parliament passed a new Electricity Law in December 2013, which was followed by a range of new secondary regulations in 2014.[34]

The new Electricity Law[35] sets out the requirement that self-consumption units should in general pay for the system costs in the same proportion as the rest of network users although

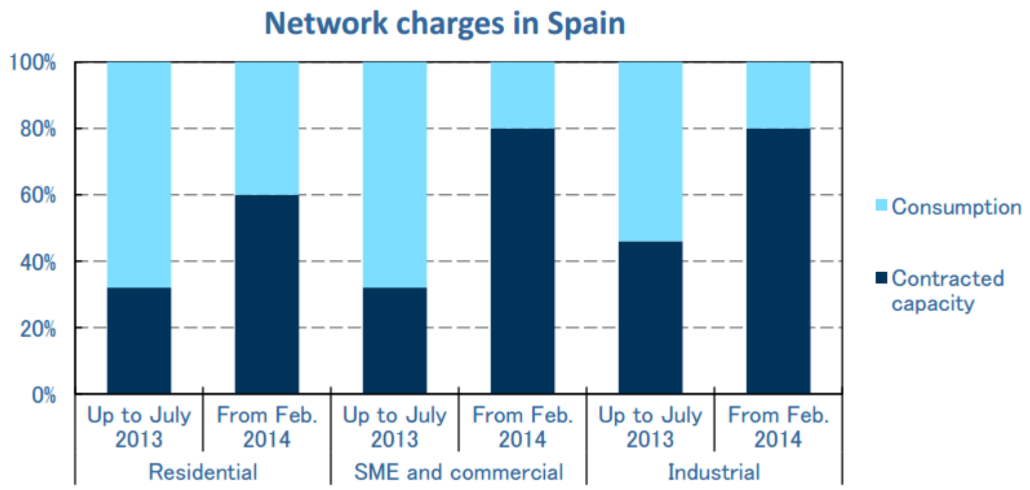
[33] There was also a separate tariff component which covers the use of metering devices. A single uniform tariff also applies to all of Spain so there are no locational signals given through transmission or distribution tariffs.
[34] https://ec.europa.eu/energy/sites/ener/files/documents/2014_countryreports_spain.pdf
[35] Electricity Sector Law 24/2013 (26 December)

there can be reductions where self-consumption brings reductions in system costs, and for consumers with capacity (consumption and self-generation) no greater than 10 kW.

The main reform introduced by the new rules in 2013/14 from a charging structure perspective has been shifting most of the revenue recovery from volumetric energy charges to capacity charges for all categories of consumers. As figure 6.3 shows, capacity tariffs now account for around 60% of network charges faced by residential consumers and around 80% of network charges faced by commercial and industrial consumers.

The new law also introduced the concept of 'access tolls' (*peajes*) which cover the cost of transmission and distribution networks and 'charges' (*cargos*) which recover separate non-network costs.

Figure 6.3: Proportion of capacity and consumption network charges in Spain before and after reforms



Source: IEA[36]

The charges for consumers vary by voltage level, power capacity contracted (household consumers usually have a tariff for contracted power lower than 10kW) and ToU (which encourages consumers to reduce grid use at peak times). For generators, an energy only tariff is applied, subject to the €0.5/MWh cap imposed by European regulations.[37]

The distribution network tariff methodology involves the following steps:

- calculate estimated revenue recovered from generation (based on €0.5/MWh tariff and expected production);
- break down the distribution cost by voltage level;
- break down the distribution cost of each voltage level between cost associated with power and cost associated with energy;

[36] http://www.emsc.meti.go.jp/activity/emsc_network/pdf/003_03_00.pdf
[37] Regulation (EU) No 838/2010 (Annex Part B)

- break down the distribution cost associated with power at each voltage level by time period; and
- break down the distribution cost associated with energy at each voltage level by time period.

The costs associated with each ToU period are allocated using a simplified network model.

In addition, Spain also introduced provisions targeted specifically at self-consumers. In October 2015, Spain adopted the so-called 'sun tax' which requires consumers to pay tolls/charges on the electricity produced on their premises alongside the electricity sourced from the grid.

The self-consumption regulation reflected the following principles:[38]

- those users that generate electricity for their own consumption without being connected to the grid should not have to pay any of the costs of the network system;
- in contrast, those users that are connected to the grid have a guarantee of supplies, including when self-generated electricity is not enough to cover consumption, thus benefiting from system reserves and capacity and should therefore contribute towards the costs of the system;
- a self-consumer connected to the system should contribute to the general costs of the system which do not depend on whether the electricity is self-consumed or not – such as: subsidies for renewable generation and electricity systems outside the peninsula (where generation is more expensive), historical debt, etc.;
- if self-consumers do not pay a share of these costs, this will result in higher bills for the other consumers which would be regressive given that vulnerable consumers are also less likely to be self-consumers; and
- a self-consumer connected to the system would still benefit by not paying for the electricity it produces including the taxes and losses that would be associated with it.

Thus, self-consumers are now being charged tariffs for the electricity produced on their premises to reflect:[39]

- the "charges associated with the electricity system cost" which includes costs associated with renewable and non-peninsular generation support schemes and historical tariff deficit – as it is considered that these costs should be paid by all grid connected electricity users irrespective of how the electricity is generated; as well as

[38] http://www.minetad.gob.es/en-US/GabinetePrensa/NotasPrensa/2015/Paginas/20151009-rd-autoconsumo.aspx

[39] To be able to measure the total electricity consumed, prosumers are required to install an additional meter that measures the amount of electricity self-generated.

- the ‘charge for other services of the system’ (i.e. back-up provided by the electrical system) – as it is considered that self-consumers benefit from system reserves even when self-consuming electricity.

The regulation also included two exceptions to the requirement to share network costs:

- island consumers where self-consumption reduces the cost of generation in those locations hence provides a saving for all consumers; and
- small consumers of up to 10 kW.

The regulation also distinguishes between two types of self-consumption modalities:

- Type 1: consumer with a contracted power of maximum 100 kW, owning at least one generation facility within its internal network, not registered as a production facility; and
- Type 2: ‘production with self-consumption’ – consumer associated to at least one generation facility connected within its network; the total power of the production facilities must be lower or equal to the consumer contracted power.

Installations with capacity less than 100 kW do not receive compensation for the energy injected into the system. Installations with capacity higher than 100 kW can register to sell their surplus electricity at spot electricity prices, however, they are also liable for any levies applied to generators, including tariffs for feeding energy into the network (the €0.5/MWh tariff applied to generation).

One of the other main points of contention is the fact that self-consumers providing surplus electricity to the grid are charged on a gross metering basis – based on energy withdrawn from the grid without netting off the energy injected into the system. The introduction of a net-metering system as used in other countries has been considered in Spain in the past but never implemented.

6.3. Impact

Because of the new rules, most self-consumers have to pay ‘access tolls’ to the grid to contribute to its maintenance and operations. These access tolls are levied mainly in relation to the capacity contracted but also depend on the actual use of the grid (i.e. kWh consumed). In addition, all self-consumers must pay the “charges associated with the electricity system cost”, as well as the ‘charge for other services of the system’ (i.e. back-up provided by the electrical system) on all electricity consumed (including the self-generated energy). Some existing facilities (e.g. cogeneration, small generation of <50 MW) are also temporarily exempt from the charges until the end of 2019.

The ’sun tax’ reduces the incentive to invest in self-generation facilities and to locate behind the meter in order to avoid a share of the fixed costs. The solar PV industry complained that due to the new charges, it could take over 30 years for a new solar PV project to recoup investment costs. More recently, Spanish MPs have signalled that the 'sun tax' provisions may be reviewed, however the measures are still currently in place.[40]

There also seems to be some evidence of the impact of increasing capacity charges. Figure 6.4 shows a dip in contracted capacity in late 2013 for consumers connected to low voltage levels and contracted capacity less than 10 kW. This reduction in contracted capacity coincides with the introduction of higher capacity tariffs.

Figure 6.4: Evolution of contracted capacity of consumers connected to low voltage levels and contracted capacity less than 10 kW

Source: CNMC

Note: The red line shows annual contracted capacity (in kW). The blue line shows the monthly growth rate in contracted capacity.

6.4. Lessons for GB

Like the Netherlands, Spain offers an example where the balance of cost recovery has been shifted to capacity charges. Although capacity charges existed in Spain for many years, a shift from volumetric to capacity charges has taken place recently to deal with the problem of revenue under-recovery. Compared to GB, the cap on average tariffs applied to generation is much lower, hence the burden of cost recovery falls overwhelmingly on consumers.[41]

As network charges represent a significant proportion of the final electricity cost in Spain (particularly due to inclusion of costs associated with various support schemes), it might be expected that the tariff structure would have a noticeable impact on the behaviour of

[40] http://www.pv-tech.org/news/spains-new-minority-government-a-blessing-in-disguise-for-big-solar

[41] According to Regulation (EU) No 838/2010 (Annex Part B), the annual average generation transmission charges in Spain should not exceed €0.5/MWh while in GB the cap is set at €1.2/MWh.

network users. There are signs that (even) household consumers have responded to higher capacity charges by reducing the contracted capacity, although it is still to early to definitively determine whether this effect will be sustained or indeed significant.

Spain has also adopted measures which seek to make grid-connected consumers with self-generating facilities contribute more extensively to cost-recovery of fixed network costs. This has been met with widespread opposition from the affected consumers and the renewable energy industry. Particularly in Spain, where support schemes such as feed-in tariffs have already been removed, it is argued that these latest measures will significantly reduce the take-up of renewable energy technologies.

7. ITALY

Distribution charge as percentage of retail bill: 17% of bill[42]
Mature retail competition in place? No

7.1. The problem

Italy has experienced a revenue under-recovery for network companies, however, unlike in Spain, the deficit has been much smaller and has been eliminated by feeding the under-recovery into tariffs in subsequent years. Italy is one of the few countries where capacity charges are applied to households. All households in Italy are equipped with smart meters, which can be set to limit the maximum power delivered to the house.[43] In Italy, the electricity distribution grid tariff for household customers consists of three components:

- a flat component (€/point of delivery);
- a capacity component (€/kW); and
- a progressive volumetric component (€/kWh).

The progressive volumetric component of the Italian charging regime has been designed to reflect equity concerns about applying cost-reflective tariffs to all consumers. However, changes are being currently introduced that will see the progressive tariff being eliminated in the current tariff period. We discuss these changes in more detail further below.

7.2. Changes introduced

Italy has recently moved towards a larger share of distribution costs being attributed to fixed and capacity tariff components (in the past most of the costs were recovered through the volumetric charge).

In December 2015, the Italian Regulatory Authority for Electricity Gas and Water (AEEGSI) adopted its final decision on the fifth electricity transmission and distribution price control review (for the period 2016-2018).[44] Following this decision, the capacity component of the tariff tripled and the fixed component for households increased by 66%.

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[42] ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2015 Retail Markets p. 12.
http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016

[43] Capacity charges for households in Italy seem to predate smart meters however with the maximum power before smart meters being adjusted by a technician (Brattle report for AEMC)

[44] Decision 654/2015

Distribution tariffs

There is a defined "ideal" tariff structure for households towards which tariffs are supposed to evolve over time, but actual tariffs are currently different from the ideal in order to protect low-income customers.

The ideal tariff is considered to be a cost-reflective tariff. The fixed charge (€/point of delivery) covers the cost of metering and some other customer related costs. The capacity charge and variable charge cover the cost of the network.

Figure 7.1 shows household tariff structures for the previous regulatory period. For households there are three tariffs defined:

- D1 tariff is the 'ideal' reference tariff for households. It is deemed a cost reflective tariff but it is not currently applied to customers;
- D2 tariff is for households in their place of residence, with contractual power up to 3.3 kW (about 80% of customers);
- D3 tariff is for:
    - households in their place of residence with contractual power over 3.3 kW; and
    - households in their spare homes (about 20% of customers).

The variable charge for tariffs D2 and D3 is progressive - i.e. with a kWh unit cost that grows for bands with increasing withdrawals. The tariff structure means that customers with lowest consumption pay tariffs below the cost reflective level (i.e. below the ideal tariff rates) while those with highest consumption pay tariffs above the cost reflective level. The progressive tariff structure provides incentives to reduce consumption from the grid.

Figure 7.1: Illustration of Italian distribution tariff structure for households

D1, D2, and D3 Tariffs
For Low Use Customers (< 1,800 kWh/yr)

	Fixed Charge (€)	Demand Charge (€/kW)	Variable Charge (€/kWh)
D1	20.7	15.6	0.016
D2	6.1	5.7	0.005
D3	20.7	15.6	0.025

Sources:
D1, D2, and D3 tariffs from
http://www.autorita.energia.it/allegati/docs/11/199-11TITtab_new.xls.

Variable Charge (€/kWh)

Annual Consumption	D1	D2	D3
0 to 900 kWh	0.016	0.005	0.025
901 to 1,800 kWh	0.016	0.005	0.025
1,801 to 2,640 kWh	0.016	0.042	0.042
2,641 to 3,540 kWh	0.016	0.082	0.082
3,541 to 4,440 kWh	0.016	0.082	0.082
4,441 kWh and up	0.016	0.124	0.124

Sources:
D1, D2, and D3 tariffs from
http://www.autorita.energia.it/allegati/docs/11/199-11TITtab_new.xls.

Source: Brattle report for AEMC based on AEEGSI published tariffs[45]

[45] http://www.brattle.com/system/publications/pdfs/000/005/076/original/The_Structure_of_Electricity_Distribution_Network_Tariffs_and_Residual_Costs.pdf?1422374425

Changes introduced in the current regulatory period aim to gradually replace the current progressive structure of the distribution network tariffs. At the end of the current regulatory period (2018), the network tariff (i.e. costs paid for the transmission, distribution and measurement of electricity) and the system charges tariff (i.e. costs for supporting activities of general interest for the electric system) will be the same for all consumption levels.

Distribution network charges in Italy are uniform across all regions of the country despite the fact that DNOs receive different revenues. The uniform network charge is calculated so that, on aggregate, the sum of the DNO allowed revenues equals the amount expected to be raised through tariffs. The DNOs are then made whole through an 'equalisation' process (called 'perequazione'), which provides for any differences between total revenue raised nationally from charges and the total revenue that should be earned by the electricity DNOs in total.

Transmission tariffs

From 2016, Italy adopted a new transmission tariff structure. The tariff for all final users but households is differentiated by class:

- A two-part tariff (capacity and energy) was introduced for HV and EHV users only:
  - TRASp (€cents/kW); and
  - TRASe (€cents/kWh);
- For LV and MV users a single part tariff TRASe (€cents/kWh) still applies.

Previously a single part tariff (€/MWh) was charged to DSOs for injecting or withdrawing energy from the transmission network. Transmission costs are included in the distribution tariff paid by households. Generation does not pay transmission tariffs in Italy.

In Italy, self-consumption projects are gradually called to contribute to the grid costs, depending on their capacity:

- < 20kW, exempted from grid and system costs;
- 20-200kW partially exempted; and
- >200kW exempted only from system costs.[46]

7.3. Impact

The impact of the changes taking place in this regulatory period would see tariffs rise at the lowest consumption levels and reduce at the highest consumption levels – this should lower the incentives to reduce consumption from the grid.

[46] http://ec.europa.eu/energy/sites/ener/files/documents/1_EN_autre_document_travail_service_part1_v6.pdf

However, it may be too early to see any actual evidence of the impact of tariff structure changes introduced in 2016.

7.4. Lessons for GB

Italy provides yet another example of a European country that has moved towards a greater reliance on capacity charges as the basis for network cost recovery. The tariff structure appears to be broadly in line with efficient charging principles – i.e. recovering (most) fixed costs through fixed and capacity charges. The tariff structure has been supported by the widespread availability of smart meters in Italy.

Italy also proves an interesting example of where consumers have not been charged the 'cost-reflective' tariff due to equity concerns. This however is being eliminated in the current tariff period which may result in regressive distributional impacts.

Given that the changes described in this study have been introduced relatively recently, the lessons that can be drawn from this case study are limited.