The regulatory arrangements required for a distributed energy market

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Abstract

In Australia, as electricity prices have increased, driven mainly by increases in peak demand, electricity use has decreased every year since 2008/09. The factors most responsible for these decreases include increased electricity costs, energy efficiency, solar water heaters and photovoltaics. Further increases in electricity prices and uptake of these technologies could result in further reductions in demand. This combined with the projected increases in peak demand and associated expenditure could put further pressure on utilities' traditional revenue and business models, especially those of networks.

Government responses to date to minimise electricity costs will most likely be ineffectual and are inconsistent with absolute reductions in electricity use. This is due to the limited attention given to alternatives to the Network Determination process used to establish future network expenditure, the lack of practical suggestions for decoupling network operators' revenue from electricity use, and the treatment of distributed energy (energy efficiency, demand management and distributed generation) as an 'add-on' to the existing market.

We propose the use of Integrated Resource Planning to ensure that distributed energy competes equally with network augmentation, and regulation of distribution network operators under a revenue cap and Overs and Unders process to decouple their revenue from electricity use, both in the context of a broader distributed energy market.

We describe how all these arrangements can be integrated in such a way that results in competition between supply-side and demand-side options at all levels: generation, networks and retail. We also provide examples of the types of policies needed for this to occur, as well as the most important issues that would need to be addressed.

The issues and approaches discussed here should be relevant to any country facing ongoing reductions in electricity use or high penetrations of distributed generation.

Introduction

In Australia, electricity is mainly produced by coal-fired generators, with black coal responsible for 46.3% in 2010/11, then brown coal (21.9%), natural gas (19.4%), hydro (6.7%), wind (2.3%), oil (1.2%), bioenergy (0.8%), and PV (0.3%) (BREE, 2012).[2] The residential sector contributes about 30% of electricity demand, with the commercial and industrial sectors making up 23% and 47% respectively (AEMO, 2010). The average

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[2] Since 2010/11, PV installations have increased about three fold and so PV would make up closer to 1% of generation in 2012/13.

household uses about 6,800kWh per year (18.6kWh/day), although this can vary significantly between households, between seasons and between states (ACIL Tasman, 2012).

Residential and commercial electricity prices in Australia have increased significantly over the last 3 years, by on average about 40% nationally (DRET, 2012), with residential prices expected to average AUD 0.32/kWh (€0.26/kWh) in 2012/13, increasing to AUD 0.338/kWh (€0.275/kWh) in 2013/14 (AEMC, 2011).[3] Electricity prices have recently increased in European countries, although by much less, with the average increase from 2009 to 2011 for the EU-27 being 12.2% (households) and 8.7% (industry) (Eurostat, 2012). Average electricity prices in the United States over the same period have increased very little, with residential increasing by 2.7% and commercial by 1.9% (EIA, 2012). The increase in electricity costs in Australia has become a political issue and resulted in a number of reports and reviews from government (e.g. SSCEP, 2012) as well as industry and community representative bodies (e.g. OG, 2012).

The Australian Electricity Market Commission (AEMC)[4] has recently released projections for average residential electricity prices for each jurisdiction out to 2013/14 (AEMC, 2011). Not only are electricity prices expected to continue to increase during this period, as shown above, there is a general consensus that they will continue to do so into the future, although by how much is uncertain (SSCEP, 2012; AEMC, 2012). In the absence of a carbon price, network expenditure is the main driver of increased electricity prices from 2010/11 to 2013/14, accounting for 50% of the increase (and 39.6% of the increase in the presence of a carbon price) – see Table 1. There is a significant level of concern that this trend in network expenditure will continue and so there is a large amount of discussion going into reducing peaks in demand as well as changing the regulatory framework under which networks operate. These are the focus of the recent AEMC ‘Power of Choice’ (PoC) Review, which is a major regulatory effort to give consumers more options to reduce their electricity costs (AEMC, 2012).

Table 1. Anticipated Contribution of Components to Retail Electricity Price Increases in Australia to 2013/14[5]

(AEMC, 2011; all prices exclude the 10% Goods and Services Tax)

	Percentage of total price increase attributable to component	
	No carbon (%)	With carbon (%)
Transmission	7.6	6.0
Distribution	42.4	33.6
Wholesale energy	24.1	40.2
Retail	13.2	12.1
Green component	12.6	8.1
Total	100	100

Electricity use in Australia has decreased in absolute terms every year since 2008/09, with a total decrease of about 6,800GWh (3.4%) by 2011/12. After dealing only with load growth since the introduction of the National Electricity Market (NEM), the Australian Energy Market Operator (AEMO)[6] had some difficulty anticipating these reductions, with, for example, the actual 2011/12 demand being 5.7% less than the forecast for that period made in August 2011. While AEMO’s most recent forecasts are now lower than earlier ones, energy use is still assumed to trend upwards in the near future, albeit at a slightly lower rate (AEMO, 2012). AEMO has attributed the decline in electricity use to a range of factors, including lower GDP, reduced manufacturing, the uptake of photovoltaics (PV), solar water heaters (SWH), and energy efficient technologies, as well as increasing electricity prices.[7] Although GDP and manufacturing may increase to previous levels, for electricity growth to return to trend would require electricity prices to decline, along with a reduced rate of uptake of PV, SWHs and

[3] It is difficult to obtain a reliable estimate of average commercial and industrial electricity tariffs because although regulated tariffs are publicly available, the actual tariffs are generally the subject of negotiation and are commercial in confidence, especially for the large customers – who are responsible for most of the electricity use.

[4] The AEMC is a national, independent body that makes and amends the detailed rules for the National Electricity Market (NEM) and elements of natural gas markets. It also provides strategic and operational advice to the Council of Australian Governments’ Ministerial Council on Energy - www.aemc.gov.au.

[5] Note that the Ministerial Council on Energy agreed on 7th December 2012 to implement a number of changes to Network regulations which are expected to reduce these projected increases.

[6] AEMO is a national, independent body and is the National Energy Market Operator and planner. It both maintains critical services and sets new directions in energy sector planning.

[7] Due to lack of reliable data it is difficult to attribute the decline to particular factors. However, about 1.38GW more PV was installed in 2011/12 than in 2008/09 (APVA, 2012), which would account for about 1,500GWh, or 20% of the decrease.

energy efficiency (EE) technologies – none of which appear likely. Therefore it is possible that electricity use will not increase at the same rate as it has before, and could even continue to decrease. While it is impossible to accurately predict the actual level of electricity use in the future, should demand continue to decrease or even increase at a significantly lower rate than in the past, this would have important consequences for the electricity industry, especially network operators, who face increasing costs. Regardless, as discussed below, it is likely that significant uptake of distributed generation[8] (DG) and EE will require changes to the structure and operation of the electricity industry.

The following firstly outlines the consequences of reduced electricity demand for electricity utilities and then examines the various government responses to help consumers reduce their electricity costs. These responses are covered in some detail because they serve to highlight the difficulty faced by governments attempting to both reduce costs for consumers while maintaining revenues for utilities (decoupling). This section also discusses some of the options proposed by governments that could actually assist with the development of a distributed energy market, before finishing with some fundamental limitations in their approaches to date.

The benefits of replacing the current process used to determine the need for network augmentation with an Integrated Resource Planning (IRP) process is then discussed. A framework that can be applied to drive competition at all levels of a market for DG and EE is then described, as are some of the types of market arrangements that are likely to be necessary – for both incumbents and new entrants. These are then combined together with a proposed approach to decouple network operator revenue from electricity use. A discussion, highlighting some of the issues to be addressed in establishing a distributed energy market, concludes the paper.

Consequences of reduced demand for electricity utilities

The lower than expected electricity use has caused problems for the incumbent electricity industry, as discussed in the recent Energy White Paper released by the Australian Government. Generators operating in the wholesale market have suffered not only from reduced sales but also from reduced wholesale market prices resulting from reduced demand and increased large-scale renewable energy generation (DRET, 2012).[9] According to the Energy White Paper, 30% of the revenue from the wholesale market comes from just 30 hours of critical peaks a year. This means that while wholesale generators' operating costs may be covered (because they won't bid into the market at less than their short run marginal cost), they may have difficulty paying off their capital costs (for which they need to sell electricity at their long run marginal cost).

Network operators are regulated monopolies and receive the majority of their revenue from tariffs linked to electricity use.[10] Decreases in electricity consumption, especially per customer, therefore put increasing pressure on network operator revenue. Although their operating costs are low, their capital costs are high. The need to maintain revenue is compounded by the fact that only about half the current network expenditure is used to meet load growth and increases in peak demand, with the remainder for the replacement of aging sections of existing networks (Ernst & Young, 2011).[11] This means that even if peak demand decreases, a significant amount of network expenditure will be required regardless.

The current retail market depends on kWh sales and a daily connection charge.[12] While these vary between retailers, an average residential customer would provide the retailer with 85% to 90% of their revenue through the usage charge.[13] Although reduced sales result in reduced profit, retailers have low capital costs, can scale

[8] In Australia, PV is by far the most common type of DG. In August 2012, 9.9% of all houses in Australia had PV, which translates to 16.7% of suitable housing stock (CEC, 2012). In 2011, of the renewable energy certificates produced by DG, PV contributed 99.988%. This was followed by wind (0.011%) then hydro (0.001%) (ORER, 2012).

[9] In Australia, the wholesale market operates on a competitive basis, which essentially means that the least-cost generation options are dispatched at any one time. Renewable energy generators can bid into the market at, or close to, zero, which lowers the dispatch price. Even when bidding in at zero they maintain a revenue stream through renewable energy certificates.

[10] For example, for the New South Wales Transmission Network Service Provider Transgrid, charges related to usage make up about 80% of total revenue projected for the 2009/10 to 2014/15 period (Transgrid, 2010).

[11] In 2010/11, 44.7% of Distributed Network Service Providers (DNSP) expenditure was to meet load growth and increases in peak demand, while 52.5% of TNSP expenditure was for this reason (Ernst & Young, 2011).

[12] In the retail market, electricity retailers supply customers on either regulated tariffs or under competitive market arrangements. Prices of regulated tariffs may be set by the retailer (and approved by the jurisdictional regulator), or where retail price regulation is still in place, would be set by the jurisdictional regulator. Regulated retail tariffs are offered in all jurisdictions except for Victoria, and in all cases market-based tariffs are also available (AEMC, 2011).

[13] Based on 7,000kWh per year, an AUD 27.53c/kWh usage charge and 69c/day connection charge – from http://www.originenergy.com.au/3986/NSW-pricing-tariffs.

down their operations, and their fixed customer costs (such as customer acquisition and retention) are covered by the daily connection charge.

Thus, while decreased electricity use could result in decreased costs for consumers from the wholesale and retail sectors (if these reductions are passed through), this is not the case for the networks, because under the current regulatory arrangements, network investments must be paid for, and network operators are allowed to apply for tariff adjustments to ensure that they are.[14] The latter pass through of network costs is considered to contribute to the recent high network expenditure, since it reduces the incentive for demand management or other lower cost alternatives (SSCEP, 2012).

Responses by government to reduce electricity costs

A large number of government reviews and reports are currently being undertaken, or have recently been completed, that to differing degrees examine ways to reduce electricity costs for consumers. The most relevant of these here is the PoC Review where the Australian Energy Market Commission (AEMC) reviewed the market and regulatory arrangements that are needed to facilitate efficient investment in, and operation and use of, 'demand side participation' (DSP)[15] in the NEM, with the aim of reducing electricity costs for consumers.

As outlined above, network expenditure is one of the main drivers of increased electricity costs, and peak demand is projected to continue to increase in all Australian states and territories (Ernst & Young, 2011). The effectiveness of measures to reduce electricity use as a means of reducing customer costs will be limited by the need to pay for the networks' capital costs. The Final Report for the PoC Review (the Report) recently released by the AEMC included a number of recommendations that reflect the difficult task of both reducing costs for consumers while maintaining payments for networks (AEMC, 2012). One of the Report's main points regarding EE is that: "Schemes need to consider and address the secondary impacts that they are likely to have on the electricity market and its participants. It is important that these schemes do not impose unintended impacts on the market, for example, upward pressure on electricity prices" (AEMC, 2012, page 242). This refers to the possibility that EE which simply reduces average demand, without reducing peak demand, will reduce the distribution network's utilisation and so increase the 'per unit' costs of distribution prices. Thus, rather than focussing on broad-based EE measures, the Report has emphasised (i) ensuring that price signals reflect network costs (e.g. via time of use tariffs),[16] then (ii) ensuring that consumers are exposed to those price signals and have access to the information and technology required to respond.

The intention is that this might not only produce a short term increase in revenue (paid mainly by large residential and commercial consumers)[17] but also reduce peak demand and so reduce future network costs – and hence costs to consumers. The emphasis is clearly on reducing long-term costs: "…. it is important that the arrangements for managing expenditure changes (the first round effects) do not undermine the ability to capture the benefits of better asset utilisation and lower system costs (second round effects)" (AEMC, 2012, page viii).

In addition to recommendations to better align price signals with network peaks, in order to further protect network operators' income, the Report lists four options to decouple network income from changes to energy use.

The first option proposed by AEMC was that, instead of being regulated under a Weighted Average Price Cap (WAPC),[18] the distribution network operators should be regulated under a revenue cap. Thus if sales were to decrease, tariffs could be increased to compensate, as long as revenues didn't exceed the cap. This is essentially one of the types of decoupling used in the United States (RAP, 2011), and in fact already applies to distribution network operators in the Australian state of Queensland, as well as to transmission network operators Australia-wide (AEMC, 2012). A detailed comparison of these two approaches is beyond this paper, however, it is worth

[14] Being natural monopolies, networks are regulated, and the exact form of this regulation differs between transmission and distribution networks as well as between different jurisdictions (which in Australia refers to the different states and territories).

[15] DSP refers to energy efficiency, demand side management and distributed generation, and so is the same as distributed energy.

[16] According to the recently released Energy White Paper, energy-intensive domestic devices, such as air conditioners and large flat screen TVs are the main drivers in peak demand growth, with a 2kW air conditioner that costs $1,500 estimated to impose costs of $7,000 on the electricity system (DRET, 2012).

[17] Under the PoC recommendations, smaller and financially vulnerable consumers would have the option of remaining on a flat tariff.

[18] Under the WAPC approach, a network operator's volume-weighted price revenue can increase from one year to the next, so as total volumes increase, total revenue can also increase, and vice versa. The WAPC can be altered in the next Determination period (discussed below), which is typically 5 years.

noting that the Report rejected a revenue cap on the basis that it would reduce the incentive to set cost-reflective tariffs, and would provide an incentive to maximise profit by decreasing expenditure. It is unclear why a revenue cap would reduce the incentive to set cost-reflective tariffs since such tariffs should decrease the need for network expenditure and so increase the network operator's profits. Similarly, network operators are currently subject to strict regulations regarding the availability of networks to provide both power quality and quality of supply, which should be adequate to ensure sufficient expenditure. The potential use of a revenue cap in a distributed energy market is discussed further below.

The second option, the only one recommended by the AEMC, recompenses network operators for foregone profits resulting from DSP. However, this is suitable only for network operators' own programs – not DSP independently sourced and implemented by consumers or by 3rd parties, and so has limited effectiveness for a wider distributed energy market. A form of this option, the Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS), is currently in operation but is considered by the PoC Review to be ineffective, and so the suggested changes aim to improve it.[19] The AEMC's Draft Report discussed two improvements that highlight the difficulty in providing a network operator regulated under a WAPC with an incentive to implement DSP projects that still has benefits for consumers (AEMC, 2012a). In one, where a DSP project delivers wider market benefits, the distribution business would earn a share of those benefits – however this would apply only to projects that deliver wider market benefits, which may be too small to justify implementation. In the other, the distribution business would retain the capex[20] savings due to deferral of capital investment for long enough to justify that investment (based on a regulated rate of return), with all future savings going to consumers. In this case, the only benefits delivered to consumers would be those in excess of what is required to justify implementation.

The third option was to have high fixed daily connection charges, however this was not discussed, presumably because it would reduce the financial viability of both DG and EE if combined with lower usage charges, and so would be in conflict with Recommendation 16 of the Report: "Amend the NER [21]distribution pricing principles to provide better guidance for setting efficient and flexible network price structures that support DSP" (AEMC, 2012, page iii). Note, however, that retailers have already increased daily connection charges quite significantly in recent years (IPART, 2010).

The fourth option involved establishing a "comprehensive DSP incentive mechanism, which, while not expressly designed to recover lost revenues, can nonetheless mitigate financial attrition and remove disincentives if well designed" (AEMC, 2012, page 217). This does not appear to be further discussed but may be the same as one of the proposals in the Executive Summary: "Building a framework that will provide a commercially sound and sustainable basis for making DSP part of the network planning and investment process" (AEMC, 2012, page iv). Although this also does not appear to be further discussed, it very nicely describes the IRP process, which as discussed below, could be an integral part of a distributed energy market.

Other proposals in the PoC Report are: a particular demand response mechanism, measures to promote increased competition, that consideration should be given to the benefits of network operators owning and operating DG, and that AEMO's role in short and long-term demand forecasts be clarified and enhanced.

The demand response mechanism would reward large energy users who reduce their demand by paying them the marginal price of the avoided wholesale electricity. While this may be useful,[22] it is interesting to note that the consumer is not paid for reducing network peaks and so reducing augmentation costs – which reflects the Report's emphasis on maintaining revenue for network operators.

The measures proposed to increase competition are certainly a step in the right direction for a distributed energy market. Together they serve to open up the market to more competition from third parties and, importantly, may allow network operators to do more than just build networks. Specifically, they require that:

1. Consumers be able to source their electricity from, and sell their DSP to, entities other than their retailer (also known as portability),
2. A new category of market participant for non-energy services be introduced in the National Electricity Rules (NER) to unbundle the sale and supply of electricity from non-energy services, such as ancillary services,[23]

[19] DMEGCIS is intended to provide incentives to DNSPs to implement efficient non-network alternatives, to manage the expected demand for standard control services or to efficiently connect embedded generators.
[20] Capital expenditure
[21] National Electricity Rules
[22] This mechanism values demand reduction compared to counterfactual estimates of demand compared to what would have happened otherwise and so is entirely dependent on the accuracy of such estimates.
[23] These include market ancillary services, reactive power, and network control support ancillary services.

3. The National Energy Customer Framework be amended to include a framework which governs third parties (non-retailers and non-regulated network services) providing energy services to residential and small business consumer.

Allowing network operators to own and operate DG could have significant benefits, not only to provide network support but also to help reduce generation costs at peak times. However, although the AEMC suggest that ring fencing arrangements could be put in place to avoid network operators preferring their own DG rather than what might actually be a least-cost option, it is not clear how this would work in practice. It is likely that a better solution would be the use of the IRP process discussed below, which would open up the market for third party DG.

Demand forecasting is used by AEMO for a variety of processes including volume dispatch and pricing, as well as system planning and investment decisions. DG, EE and Demand Side Management (DSM) do not bid into the market, and therefore can only be estimated, and so as more are deployed, forecasting becomes increasingly difficult yet more important (AEMC, 2012). Enhancing AEMO's ability to forecast demand would be helpful for a distributed energy market because it will provide information on the price-responsiveness of demand (ideally in particular regions) as well as how demand is affected by weather (both energy use and DG). This sort of information will be helpful both at the network planning stage (especially where IRP is incorporated), and during operation – for example, it will provide participants with information they can use to better target their services to minimise demand peaks.

Another major recent review into the causes of high electricity prices has culminated in the Senate Select Committee on Electricity Prices report on 'Reducing energy bills and improving efficiency' (SSCEP, 2012). This report's primary conclusion was that the main reason for high electricity prices is inefficient over-investment in electricity networks driven by perverse incentives inherent in the regulatory environment. It recommended a range of changes to limit the incentives for networks to over-invest in capacity and for such investment to be reviewed ex-post.

In addition, in recognition that increases in peak demand were driving prices higher, a series of recommendations in the Senate Select Committee report correspond to those of the PoC Report, i.e. cost-reflective pricing with protection of vulnerable consumers, technologies to enable responses to these prices, such as smart meters, the provision of reliable information to consumers, and changes to the regulation and operation of the Australian NEM that would encourage and allow consumers, or authorised third parties, to sell their demand response in the wholesale electricity market. It also focussed on the network design, connection and cost barriers to embedded generation feeding electricity into the grid and so recommended there be appropriate regulatory and operational reforms to overcome them.

In summary, the PoC Report and the Senate Select Committee's report agree that electricity prices are getting too high and that they need to be reduced. They emphasise the need to pay for networks, and that demand peaks should be reduced as they are a major contributor to price rises. Both support cost-reflective pricing, information and increased competition, all of which should significantly assist the development of a distributed energy market. However the reports also diverge slightly, with the former focussing more on maintaining the network operators' revenue through existing business models, and viewing DG and EE that doesn't target demand peaks as a risk to that revenue. The latter emphasised the cessation of inefficient over-investment by network operators and enabling the connection of embedded generation.

However, and most importantly, both are limited in three particular areas. The first is the very limited attention given to the consideration of alternatives to the Network Determination process,[24] the second is the treatment of DG, EE and DSM as 'add-ons' to the existing market (which remains essentially unchanged), and the third is the lack of practical suggestions for decoupling network operators' revenue from electricity use.

Integrated Resource Planning

IRP formalises the incorporation of demand-side participation into the network planning and investment process. Currently used in some states of the United States (e.g. California), this process was first developed for vertically integrated power systems that included a component that was a natural monopoly and so was regulated (e.g. electricity networks) (Tellus, 2000). In Australia, IRP could be applied both instead of the Network Determination process as well as on an ongoing basis for particular network augmentations.

While there are variations on the IRP process, the core principles are that it (Tellus, 2000):

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[24] In Australia, the Australian Energy Regulator conducts 5-yearly Network Determinations to assess the network's capacity requirements and associated costs that can be passed through to end-users.

1. Considers a full range of feasible supply-side and demand-side options and assesses them against a common set of planning objectives and criteria;
2. Is transparent and participatory throughout, meaning that parties other than the network operator can propose both supply-side and demand-side options;
3. Is subject to oversight by an independent (normally government) body; and
4. Is subject to regular review.

In addition, IRP can include objectives in addition to simply ensuring provision of electricity. Such objectives may be in qualitative terms and can include minimisation of environmental impacts, use of local resources, social benefits such as increased electrification of disadvantaged areas and minimising amenity impacts of infrastructure, and local employment and capacity building (Tellus, 2000).

The steps in the IRP process are illustrated in Figure 1 and are to:

1. Establish objectives;
2. Survey energy use patterns and develop demand forecasts;
3. Investigate electricity supply-side options;
4. Investigate demand-side options;
5. Prepare and evaluate supply-side plans;
6. Prepare and evaluate demand-side plans;
7. Integrate supply-side and demand-side plans into candidate resource plans (which can involve a number of iterative steps to reach an optimal supply/demand outcome);
8. Select the preferred plan; and
9. During implementation of the plan, monitor, evaluate, and iterate

Thus, IRP helps to identify areas where DG is cost-effective and requires the network operators to acquire it through a competitive procurement process. This helps to develop a competitive and transparent distributed energy market, and so opens it up to new entrants.

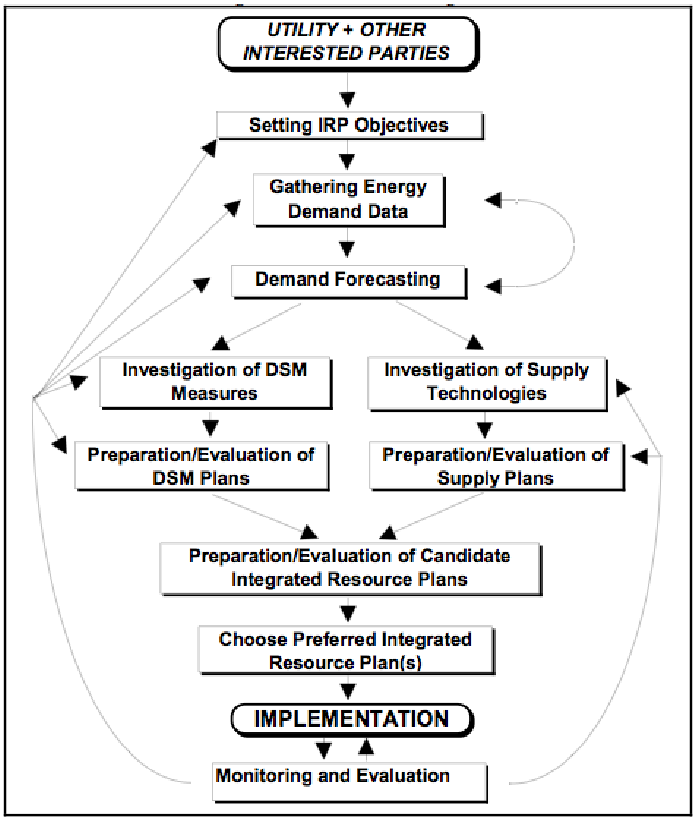

Figure 1 The Integrated Resource Planning process (Tellus, 2000)

This compares to the existing Network Determination process where a certain level of demand is assumed and the networks are then designed to meet that demand. Particular network augmentations undergo a similar process where the network operator generally designs the default network solution, then possibly calls for alternatives, then assesses them through an internal procedure – see Figure 2.

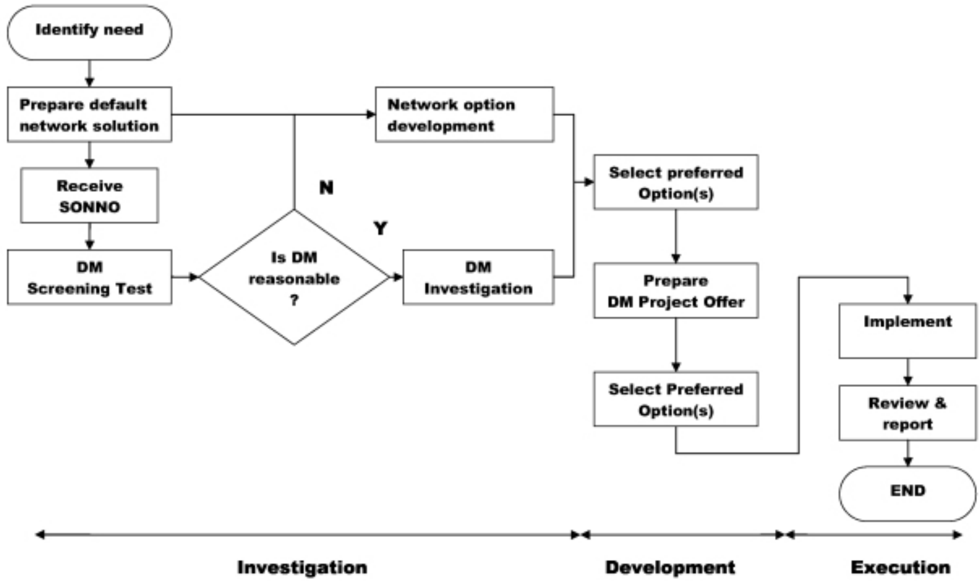

Figure 2 Simplified diagram of Ausgrid's demand management process (Ausgrid, 2012)

Achieving Competition in a Distributed Energy Market

When 'disruptive technologies' such as DG and EE are introduced into a well-established industry (e.g. the Australian NEM), they don't simply seamlessly integrate into the existing electricity industry, but exert change in doing so[25] – as is already occurring according to the government reviews and reports discussed above. In addition, given that the distributed energy technologies will not be completely replacing the existing technologies, but will be integrated with them, it is likely that new institutional and organisational changes will be needed to accommodate both. Thus, over the longer term, to achieve optimal levels of distributed energy uptake, it is likely that much more significant changes to the electricity market will be required than apparently envisaged by the various government reviews. Rather than having the existing market with DG and EE integrated where possible, a fully integrated distributed energy market may need to be developed.

A fundamental principle of such a distributed energy market as defined here is that of equal competition between supply-side and demand-side options at all levels: generation, networks and retail. There should also be competition between supply-side options and between demand-side options. For a distributed energy market these types of competition are illustrated in Table 2.

Table 2. Types of competition possible in the wholesale, network and retail markets

	Wholesale	Networks	Retail
Demand vs demand[26]	EE/DSM vs EE/DSM	EE/DSM vs EE/DSM	EE/DSM vs EE/DSM
Supply vs demand	Centralised and DG vs EE/DSM	Augmentation and DG vs EE/DSM	Electricity sales and DG vs EE/DSM
Supply vs supply	Centralised vs DG, DG vs DG	Augmentation vs DG	Electricity sales vs DG, DG vs DG

Different approaches are required to achieve full competition in each of these markets. The wholesale market operates on a competitive basis, and the factors that influence distributed energy's ability to compete with

[25] This is possibly best illustrated by the impact of the mobile phone market on fixed line telephony.
[26] While DSM doesn't happen directly in either the wholesale or network markets, it does affect the operation of these markets.

wholesale generation occur in the network and retail markets. Therefore, the wholesale market is not a focus here, but will nonetheless be affected if an extended market is established.

In Australia, in the absence of effective competition, price control is introduced to networks through the Network Determination process and through some requirements that alternatives to network augmentation have to be assessed.[27] However, it is clear from the PoC Review and Senate Select Committee on Electricity Prices reports that the current processes are insufficient to drive alternatives to network investment. The Network Determinations essentially lock in network investments for 5 years, and so it is important that alternatives, such as the IRP process discussed above, be considered. While IRP could be the foundation for introducing more market-based competition between supply and demand side options into networks, in order for the market to be able to incorporate new technologies and to respond to changing circumstances, it is likely that full supply/demand competition (excluding network operators) needs to operate on a day-to-day basis, not just for long-term planning purposes.

While Price Determinations are performed for the retail markets in most jurisdictions, they essentially just pass through the network costs according to the Network Determinations, set a price that can be passed through for wholesale costs, and apply a retailer margin. Customers are also offered market-based tariffs from a number of different retailers in these markets,[28] and so, rather than introducing competition during the Price Determination process, the focus should be on expanding this competition from essentially being between tariffs to being full competition between all supply and demand-side options, again on a day-to-day basis.

Day to day operations

As part of the process of developing an operational framework for a distributed energy market, here the required day-to-day market arrangements have been divided into three types:

1. Those related to the operation of the incumbents;
2. Those related to the operation of the distributed energy market itself (and therefore new entrants); and
3. Those that then stimulate the broader distributed energy market and enhance the interaction and operation of all participants.

The following examples are not meant to be exhaustive but are used to illustrate the types of arrangements that may be possible.

Operation of incumbents

The market arrangements related to the operation of the incumbents can be further subdivided into those that decrease utility barriers to distributed energy and those that enable utility participation in distributed energy. An example of the former is the modifications to the DMEGCIS, which is used to compensate network operators for lost revenue due to EE and DSM. Another example, discussed below, is that regulating network operators under a revenue cap should decrease their opposition to distributed energy. An example of the latter would be allowing retailers to act as energy service providers and so provide EE options to reduce energy use (as can occur under some White Certificate Schemes).

Operation of the distributed energy market

Measures related to the operation of the distributed energy market itself can similarly be subdivided into those that remove barriers to it and those that enable it, although the distinction may be less clear. An example of the former is the removal of barriers that restrict operation of new distributed energy businesses in the electricity market – such as the PoC Draft Report recommendations that consumers be able to source their electricity from, and sell their DSP to, entities other than their retailer; and that the arrangements that apply to third parties providing 'DSP energy services' be clarified to enable them to better operate in the electricity market (AEMC, 2012a). There are a number of changes that could directly enable the distributed energy market. These include the demand response mechanism recommended by the PoC Report (as well as any like it that reward end users for reducing demand), as well as their recommendation of better forecasting of both short and long-term demand (AEMC, 2012). Another is the formalisation of solar access rights, which is important not only for solar-based DG, especially PV, but also for EE technologies such as SWHs and even for lighting and heating passive solar designed buildings.

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[27] For example the NSW Code of Practice Demand Management for Electricity Distributors requires DNSPs to investigate and report on demand management strategies when it "would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion [of a distribution system] by implementing such strategies" (DEUS, 2004, page 4).

[28] Note that there is still some uncertainty whether the retail markets can currently be classed as fully competitive (for example IPART, 2011). Also, not all jurisdictions (e.g. South Australia) offer time of use tariff options.

Stimulation of the broader distributed energy market

Measures that can stimulate the distributed energy market are all those that, once the market has been established, enhance the operation of all participants (both incumbents and new) and so drive the uptake of distributed energy technologies. Policy measures to promote distributed energy can be broadly categorised into:

1. Support mechanisms such as the provision of information and training;
2. Command and control mechanisms such as minimum energy performance standards, building standards and license conditions; and
3. Price mechanisms that change the energy 'price' seen by decision-makers for different energy options, such as direct subsidies and white certificate schemes.

Integrating IRP and Decoupling into a Distributed Energy Market

A fundamental problem currently facing the Australian electricity market is that network costs have been increasing and demand has been decreasing. The approach proposed by the PoC Review is essentially to use ToU tariffs to reduce network peaks, keep the Network Determination process unchanged, rely on very limited decoupling and have a variety of incentives to increase access to information and drive increased but limited competition.

Here it is proposed that IRP should be used instead of the current Determination process. It is more likely to minimise increases to network peaks because it would draw on a broader range of options than just price signals (such as ToU and critical peak pricing etc), yet is still compatible with such price signals.

To decouple network operators' revenue from electricity use, they should be regulated under a revenue cap combined with an Overs & Unders (O&U) process, as is currently used for transmission network service providers in Australia. Essentially the O&U process means that any over (or under) recovery of transmission network costs in a given year must be paid back (or recovered) in the following year (including interest impacts) by adjusting the following year's charges.[29]

Whereas the current Determination process relies solely on information provided by the network operator to the regulator, in an IRP process all costing must be transparent and subject to competition from third parties. Thus, it is likely that an IRP process would be more accurate than the current Determination process in forecasting network costs because it brings market forces to bear in the costing process. This means that the network operators' regulated revenue cap is also more likely to be accurate.

To the extent that network costs still increase, they can be incorporated into usage charges as they currently are. It is possible that increases in per kWh usage charges could reduce electricity use further, which would require prices to be increased again, which could further reduce electricity use, theoretically resulting in what has been termed an 'energy market death spiral' (Simshauser and Nelson, 2012). To the extent that this becomes a problem, network operators could be allowed to increase the fixed component of their tariffs to cover increased network costs. Note that reducing the usage component would decrease incentives for EE and DG and so should be discouraged.

This should all occur in the context of a broader distributed energy market such as that described above. Regulating network service providers under a revenue cap with O&U would provide them with an incentive to allow third parties to implement DG, EE and DSM. Any losses in reduced sales would be compensated in the O&U process, and savings in avoided network augmentation would be captured by the network operator. In order to avoid network operators capturing too much profit (for example because EE and DG are reducing network peaks more than expected), and to ensure that savings are passed on to customers as much as possible, the IRP process could be three years rather than the five years used for the Network Determination process. Note that savings from offsetting energy use and the associated retailer margin will still accrue to the customer.

This approach would also address the other concerns of both the PoC Review and the Senate Select Committee on Electricity Prices: network operators' revenue would be maintained, DG and EE that simply reduce electricity use would not be a problem for network operators, the incentive for inefficient over-investment by network operators could be removed and there would be reduced opposition to the connection of embedded generation (because they would not reduce network operators' revenue).

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[29] According to Clause 6.18.2(b)(6) of the National Electricity Rules.

Discussion

If, as projected, electricity tariffs in Australia continue to increase, there will be ongoing interest in options to reduce electricity costs, including various combinations of DG, EE and DSM. This in turn will place further pressure on the revenue streams of wholesale generators, network operators and retailers under the current regulatory arrangements.

The measures proposed by the PoC Review and the Senate Select Committee to minimise electricity costs for consumers will be ineffective in maintaining network revenue if overall demand continues to decline – because network operators revenue will still be based on electricity sales. Thus, the financial viability of the current electricity market is based on a model that precludes absolute reductions in electricity use. Indeed, the PoC Report warns against broad-based EE measures for this very reason (AEMC, 2012).

Our proposal is for IRP to be the foundation for introducing more market-based competition between supply and demand side options into networks, all in the context of a broader distributed energy market that should encourage competition on a day-to-day basis. Regulating network operators under a revenue cap with an O&Us process should both decouple network revenue from sales and encourage network operators to allow DG, EE and DSM on their networks. Care will be needed to ensure that as much of the savings driven by distributed energy as possible are passed on to customers.

It is important to note that for competition to be effective, and so result in EE and DG being taken up to economically optimal levels, there is a need for the benefits they provide to be accurately incorporated into the price signals that the electricity industry participants, including customers, are exposed to. EE and DG provide a range of benefits including reduction of energy use and associated environmental impacts including greenhouse gas emissions, reduction of demand peaks in both the transmission and distribution networks, reducing line losses, and potentially improved power quality and reliability.

Although we have provided some examples of how the development of a distributed energy market could be achieved, it would be a far from simple process. Issues to be addressed include, but are certainly not limited to:

1. *Responsibility for security of supply and power quality*: Currently the network operators are held responsible, however when a third party supplier of distributed energy provides network support, there needs to be some mechanism for transfer of accountability, as well as compensation for services provided.
2. *Independent oversight:* There will often be a need for an independent body to oversee any IRP-based process. In Australia, state governments own many of the networks and so they would not be appropriate.
3. *Ensuring competition:* Mechanisms will need to be established to ensure there is equal and open competition between supply-side and demand-side options at all levels (with the exception of networks, which would be exposed to market forces through the IRP process).
4. *Increased complexity:* As more distributed energy is introduced to the electricity market, the operation of the networks will become more complex and appropriate mechanisms will need to be put in place to optimise cost reductions (e.g. from reduced peaks and perhaps from maintenance of low load lines which could effectively be serviced by distributed energy) and minimise cost increases (e.g. due to more complex power flows and control required).
5. *Maximising DG, EE & DSM interactions:* Mechanisms will need to be developed to maximise the value of such interactions. For example, where storage can be used as a form of DSM to shift DG output to reduce demand peaks, and where DSM can be used to shift loads to times of DG generation to avoid export (to avoid low export payments, reverse power flow, voltage rise, etc.).

A fully competitive distributed energy market, as discussed here, is something that would develop over time, but the required institutional and organisational changes need to begin now and will need to accommodate both the incumbents and new entrants, on an ongoing basis. In the longer term, rather than having a separate 'distributed energy market' operating alongside the existing NEM, it could be desirable for the NEM itself to operate as a single energy market for centralised and decentralised energy supply and demand.

Conclusions

The various options proposed by Australian governments to maintain network operators' revenue and drive uptake of distributed energy are likely to have limited success. Use of an IRP process where network operators are regulated under a revenue cap and O&Us process, all in the context of a broader distributed energy market, is more likely to be successful. Such an approach requires a number of important issues to be addressed, and while a fully competitive distributed energy market can only be introduced gradually over time, the process should begin as soon as possible.

While government responses to increased distributed energy uptake can be designed to enable integration in a manner that minimises disruption, they may also be designed to restrict the uptake, and therefore impact, of new technologies. If the latter approach fails, the incumbents could be exposed to a greater level of disruption. As discussed above, the current approach in Australia seems to be somewhere between the two.

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