Distribution Network Adaptation in the Energy Transition; Addressing Barriers and Realising Benefits, an Australian Perspective.

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Introduction

The transition away from fossil fuels in the electricity sector is under way, however, not all parts are moving at the same speed. In Australia, uncertain policy settings, notably the implementation of a successful price on carbon and then its subsequent removal, have hindered the development of regulatory frameworks that would facilitate a rapid transition. Combined with a mix of public, private and complex arrangements falling somewhere in between, ownership structures of distribution networks result in unreconciled competing interests of public policy and network operators.

The public have already voted with their feet at their end of the network with their appetite for residential PV in Australia far exceeding policy makers expectations. The subsequent removal of incentive schemes was negated by the fall in unit costs leading to some of the highest levels of PV penetration in the world and distribution companies struggling to adapt.

Electricity distribution networks are facing an unprecedented range of challenges; from network underutilisation, electricity losses, residential demand driven evening peaks, the steepening duck curve with increasing solar surplus in the day and an uncertain regulatory environment.

This article will look at the Australian context and how regulatory inefficiencies and misaligned incentives combined with ownership pressures have served as a barrier to decarbonising the electricity sector under an uncertain national energy policy framework.

The regulatory side

Australia created the National Energy Market (NEM) as a result of the National Competition Act in 1997 in order to reduce state owned surplus generation capacity, and drive efficiencies in the energy sector through a market settlements system combining the east coast states and the South Australia State based networks that were linked through high volume interconnectors. A national market was formed. The retail sector was largely privatised and has subsequently been concentrated into three dominant national retailers. However, the distribution and transmission sectors stayed largely in state government hands, with the exception of Victoria and South Australia.

In Queensland, the focus of this case study, two distribution companies were present at the outset of the NEM; Ergon Energy – covering all rural and regional areas outside of the densely populated south east which was covered by Energex.

From the formation of the NEM energy prices remained stable as surplus generation capacity was run down. However, energy prices began to rise in 2007; doubling over the next ten years resulting in public outcry. The most significant contributor to the price rises was found to be the distribution network spending outbreak and how prices were set and why they were rising became a significant political issue.

Distribution network spending plans and return on regulated asset base (RAB) were set every five years and approved by the Australian Energy Regulator (AER). The review process proved to be less than robust with any reduction in approved funds able to be challenged in federal court under the Limited Merits Review (LMR) which occurred in 19 out of 24 submissions. After a review in 2016 the LMR mechanism was quietly scrapped.

The review process aside, the spending outbreak was subsequently attributed to a lack of incentives for capital efficiency under the regulated asset base (RAB) funding model, dividend extraction and inflexible risk weighting approaches to network planning.

The matter of misaligned incentives is amply illustrated by the issue of dividends extracted from the DNSPs over this period of time. The combined level of network revenue for Ergon Energy and Energex is compared with the combined dividends and state equivalent income tax extracted over this period are shown in Figure 1.

The cumulative effects of this failure to efficiently allocate capital can be seen in the rise in combined network value in Queensland from $8.5 Billion in 2008 to $26 Billion in 2016/17.

Where the distribution networks were privatised, notably in Victoria in 1997, network spending also rose however not as significantly as in Queensland and New South Wales, however, retail prices also rose by

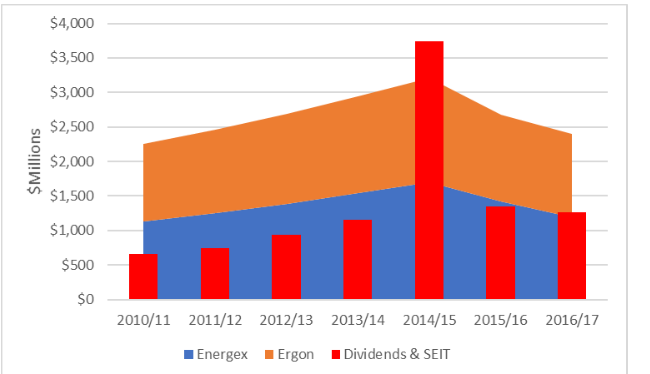

Figure 1 Network revenue vs dividends and State Equivalent Income Tax (SEIT)(Ltd., 2019)

a similar amount. This was found to be due to higher levels of retail margin and cost of customer acquisition than in other states. Other states have followed with complex partial privatisations, such as in New South Wales, that lock state governments into long term agreements that potentially will leave them open to compensation claims if markets are restructured. Utility investments are sold as safe and reliable long-term returns which brings us to the question of what are the incentives to private investors in that case to pursue the radical reshaping of the network?

The resulting mix of public and privatised sectors raise considerations of what would be the most effective model to achieve the transition (Cahill, 2018). While operations of public sector utilities have seen the extraction of value, in the privatised sector rent-seeking behaviour raises the same issue and yet has fewer public accountability mechanisms in place.

Traditionally the industry has been dominated by an engineering mindset and structures that have changed little since the formation of the first networks. The defensive response to the rise of residential PV has illustrated the protective mindset that has prevailed. In Queensland the rapid uptake of PV presented a ready challenge to volumetric energy-based pricing. An example of the defensive mindset could be seen in Ergon Energy's increase in the business tariff 46 daily connection charge from $42 a day to $488, or 1100%, with the assumed intention of reducing the spread of solar to commercial premises (Parkinson, 2014).

What would change look like?

DNSPs will need to reduce the barriers to entry to new aggregation entities in order to allow the network to evolve. Allowing aggregators such as virtual power plants (VPP), microgrid operators, peer to peer trading and virtual net metering (Shaw-Williams and Susilawati, 2020) access onto the grid will provide the quickest path to establishing the investment in data and communication protocols necessary to speed the digitalisation of the network. These entities will be able to coordinate and manage their own areas of the network in a decentralisation of the network control structure. Control is something not often given up readily so it will not happen without a concerted push by policy makers to mandate the opening up of the network.

The rapid uptake of batteries and the digitalisation of the network are the two key drivers of the transition. Simply put batteries to shift surplus generation to when it is needed and digitalisation providing the means for automation and optimisation of the network will enable all subsequent benefits to flow.

Digitalisation, meaning data, analytics and connectivity, will provide the platform for new market entrants to bring new services and capabilities to the network. The network will become a platform that will provide incentives for innovation and new services. Markets for demand management and ancillary services with dynamic network pricing down to a local level will provide the opportunity for new capabilities to manage the network to be developed and rewarded.

What role does that leave for network operators? Instead of being the defenders of legacy business models DNSPs can move to the alignment of standards and data protocols; which in turn will be crucial to avoid fragmentation of systems that would hinder the platformisation of the network.

Overly burdensome registration requirements and connection agreement processes remain a significant barrier to entry and will have to be reduced. With more entities, large and small, co-locating generation and demand, and network supporting behaviour being incentivised, the capability of the network to self-regulate through automated optimisation will be based on standardised data and communications protocols.

Benefits

For too long inaction on decarbonisation has been defended on the basis of cost. However disingenuous these claims may have been in the past there are a wide range of auxiliary benefits that can be achieved. The material benefits flowing from the means to shift energy and optimise the network will be widespread. They will be obtained initially through reduced network spending, reduction in losses and increases in reliability (Shaw-Williams et al., 2018).

In Western Australia Horizon Energy, the reginal DNSP, has successfully run a trial of providing stand-alone power systems (SPS) and removing the poles and wires in remote areas. With the initial small scale trial of modular solar, batteries and diesel generation backup they have been able to save $6 million (Parkinson, 2019). Western Power, the state's main grid operator has identified 15,000 customers it could potentially take off the grid potentially saving $400 million. The implications for Queensland, a large sparsely populated state, outside of the south east corner and coastal regional centres, are immense. Ergon Energy has 64,000 km of single wire earth return (SWER) network that is 45% of their total network length but only under 5% of their customers (Arefi and Ledwich). The cost of servicing such a wide area is spread over the entire network resulting in a $498 million cross subsidy in 2019/20. This amount represents a clear commercial incentive and indeed self-funding aspect of the energy transition if only the motivation was sufficient.

Batteries, even in an uncoordinated fashion, have the potential to address many of the low voltage (LV) restrictions on moving to higher penetration rates. Previous work looked at the saturation benefits of higher rates of an LV area in terms of imbalances on phases, and found that up to 50% of households in an area if having PV combined with batteries could potentially address voltage issues without intervention by the DNSP (Shaw-Williams et al., 2019a). With residential peaks being a primary driver of network spending if this was addressed by onsite generation and storage then it is a radically different model of network that will be required.

Distribution networks account for the greatest proportion of losses on the network. The opportunity to avoid them through the co-location of generation and demand is the low-hanging fruit of the transition and the benefits arising from households adopting PV already has resulted in tangible economic benefits for all consumers through reduced loss factors (Shaw-Williams et al., 2019b).

It is to be noted that these are all additional benefits that would justify the rapid evolution of existing business models let alone the threat of catastrophic climate change. These are tangible benefits that can be achieved with forward looking policy settings that will force the reduction of barriers to the network and incentivise innovation on it.

Conclusion

The role of DNSPs as gatekeepers to the network is the crucial fulcrum point of the transition. Households equipped with solar arrays and combined with battery units provide the means by which the network can be managed effectively, and midday surplus be shifted to meet residential evening peak. With the challenge of residential peak adequately addressed the issue of what to do with surplus capacity in the network becomes the crucial challenge. The sunk costs of the large-scale overinvestment in the network is a millstone around the neck of a rapid transition in Queensland. Without the write down of a significant portion of the network value on one hand, and a relaxation of restrictions of access to the network on the other, the transition will lag.

With residential generation and storage to address the evening peaks, stand alone systems enabling the removal of thousands of kilometres of poorly utilised lines and large scale solar meeting the business hour needs of industry, and with automated and localised optimisation of the network a path to a decarbonised energy sector becomes clearer.

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