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Submission to the Power of Choice Review

Introduction

I thank the Australian Energy Market Commission for the opportunity to provide a submission to address the important issue of electricity market demand side participation. This submission is a slightly modified version of a submission I provided to the Senate Select Committee on Electricity Prices on 14 September 2012. Herein I will focus on the appropriate metric for the pricing of network tariffs, which comprise about 40 percent of the retail electricity price. Currently, prices for accessing electricity networks in Australia tend to be expressed in ¢/KWh or $/MWh, i.e. in money units per unit of *energy* consumed (this is certainly the case in my home state of Western Australia). This pricing approach spreads the cost of meeting system-peak demand across all of the energy consumed during the year. In the AEMC Power of Choice Draft Report the proposal is to gradually phase in time-of-use network tariffs. A justification for this is that a time-of-use network tariff "...reflects the marginal costs of network use...". In this submission, I will argue that the only 'time varying' network tariff that could possibly reflect the marginal cost of network augmentation is one that is based on *system-peak power demand*.[1] If the objective is to have a network tariff that signals to consumers the costs of network augmentation, it would be a mistake for the AEMC to administer an energy-based time-of-use network tariff.

I will argue that energy-based pricing metrics cannot be cost-reflective or cost-signalling and that network tariffs should instead be priced entirely in ¢/kW$_{system\text{-}peak}$

[1] In the context of the NEM the concept of a system-peak would obvious require some level of disaggregation, at least to the level of regional reference bus-bars. As the AEMC has pointed out in its Draft Report (page 84) the choice between nodal pricing and system-wide pricing involves a trade-off between the efficiency of the cost-signal and the inefficiency of administrative complexity.

or \$/MW $_{system\text{-}peak}$ (or equivalent),[2] i.e. in money units per unit of *system-peak power demand*. It is my view that the absence of an appropriate price signal for annual system-peak demand results in excessive system costs which translates into unnecessarily high electricity prices.

My submission is, in summary, this: the AEMC could improve the way in which electricity bills transmit true network cost information to consumers and consequently empower consumers to significantly reduce their electricity bills. The AEMC would just need to exercise its rule making powers to require all NEM network tariffs be expressed in ¢/kW$_{system\text{-}peak}$ or \$/MW$_{system\text{-}peak}$ and be properly reflected in not just wholesale but, most importantly, in *retail* electricity prices. Such amendments to the pricing system would allow for the true cost of network augmentation to be reflected in consumers' bills. This would change the way in which consumers think about their contribution to those few half-hourly trading intervals of the year when most of the system costs are incurred. Given that network costs make up such a large proportion of a consumer's bill, the effect of this change would be to incentivise consumers to reduce their contribution to system-peak demand and therefore lessen the need for network augmentation. It would enable more economically efficient decisions that relate to investments in energy efficiency, distributed generation, peak generation capacity, smart metering and the use of appliances that contribute to system-peak demand such as air conditioners.

Unbundling the Electricity Price

Electricity supply is made up of three cost components. First, there is the variable cost of generating the energy itself. This is mainly a fuel cost, but carbon price and renewable energy target related costs also fall into this category as does output related wear and tear on plant and equipment. Annually, such costs are a function of the total amount of electricity consumed. Therefore, the appropriate price metric for this cost component is ¢/KWh. The more energy that is consumed the higher the cost, so an energy-based metric is cost-reflective for this component.

Second, there are general overheads such as marketing, insurance and licensing costs that are not directly related to capacity. These costs, which are often recovered through fixed charges, are not a focus of this submission.

Third, there is the capital intensive cost of investing in generation assets, transmission and distribution infrastructure, and the associated cost of servicing the debt and equity required to fund them. Unlike most other commodities, electricity cannot be stored economically for long periods of time. This fact, combined with the engineering requirement to avoid blackouts by keeping system frequency within a

[2] Another approach would be to have the price expressed on a per kVA$_{system\text{-}peak}$ basis.

narrow technical envelope, means that instantaneous supply must be made continuously available to meet instantaneous demand. This makes electricity market equilibrium an engineered solution that depends upon sufficient investment in generation and network capacity. In this context, capacity is measured in MW *not* in MWh, i.e. in units of power rather than units of energy. This is because power is a measure of instantaneous load placed on the system, whereas energy is a measure of power over time. In other words, energy is the area under a curve that describes power as a function of time.

Charging for Capacity Costs When They Actually Occur

Future capacity requirements are not entirely predictable, but forecasts can be made with confidence intervals attached to them. From these forecasts a probability of exceedance (PoE) metric can be derived. The PoE reflects the fact that there is some randomness to capacity requirements; i.e. that an extreme weather event in any particular year might push air-conditioning demand above the available system capacity or that an unplanned outage of plant and equipment may occur while demand is high. For example, if a network operator plans for a ten percent PoE, then blackouts due to insufficient plant and network capacity may be expected to occur one year in ten. Therefore, in essence, a electricity network's capacity requirement is equal to the forecast system-peak demand plus some safety buffer that corresponds to an accepted PoE standard. The capacity requirement is basically a planning criterion that can be addressed in two ways, by increasing capacity or by reducing system-peak demand. Of course, increasing capacity pushes up network costs and hence electricity prices, but reducing system-peak demand puts downward pressure on network costs, electricity prices and consumers' bills.

Now, let us consider what it means to have network access tariffs priced in ¢/kWh rather than in ¢/$kW_{system\text{-}peak}$. One way of doing this is to conduct a simple thought experiment. Imagine two cities, A and B, that are identical in every way except one: half of the residents of city A leave and take a winter holiday far from either city's electricity grid, whereas all of the residents of city B stay and work throughout the winter. Suppose this causes city A's electricity consumption to fall to 80 percent of city B's electricity consumption. Now imagine both cities have exactly the same system-peak demand in summer. Which city has the most expensive network capacity costs? The answer is that they are both exactly the same. Because the electricity system operated at its peak in summer, the cost of meeting system-peak demand in each city is identical. In other words, the total amount of energy consumed over the year has nothing to do with the capital cost of the required network capacity. Rather, the annual capital cost of the required network capacity is a function of the system's maximum power reading recorded in summer.

Referring to the previous example, consider two residents of city A who contribute exactly the same amount to system-peak demand but one resident is a winter holiday taker and the other is not. If the network costs are spread over annual kWhs instead of system-peak kWs, then the resident who took the winter break would pay ~80 percent of the network access charge of the non- holiday taker. This is not economically efficient, because the holiday taker pays a smaller network price than the non- holiday taker, *even though both residents are responsible for exactly the same share of the network capacity requirement*. Moreover, for both residents, any price signal for reducing system-peak demand is muted by the fact that the network charge calculation and system-peak demand are not contemporaneous.

This simplified example reveals the fundamental flaw in spreading network costs that occur due to system-peak demand across units of energy consumption in other billing periods of the year. Energy-based average pricing of this nature, whether time-of-use or not, does nothing to signal the actual cost of network augmentation to consumers. Similar logic also leads to the conclusion that pricing based on the customer's individual annual peak demand rather than the customer's contribution to the annual system-peak demand is not efficient. A customer's individual peak demand will not affect the capacity requirement of the system unless it happens to coincide with the system-peak. It is the customer's demand at the time of the system-peak that reveals their impact on network augmentation costs. So under energy-based network tariffs, or tariffs based on a customer's individual peak demand, residents and businesses have few incentives to reduce their contribution to system-peak demand and, therefore, network costs.

In practice, each customer's contribution to system-peak demand could be evaluated, for example, by determining their median demand across the twelve highest load trading intervals of the year, and then comparing this to the regulated capacity requirement. This is the approach taken in determining the Individual Reserve Capacity Requirement in the Western Australian Wholesale Electricity Market. That mechanism applies to the capacity of generation assets rather than network augmentation requirements. However, the general concept underlying the mechanism is similar to the one I propose here.

Two-Part Tariffs and System-Peak Demand Side Management

At this point I need to be clear what I am *not* saying. I am not saying that that the variable fuel and carbon costs of energy consumption should be charged in ¢/kW. These should be billed in ¢/kWh as part of a multi-part tariff. Two-part tariffs are a common feature of electricity pricing. Therefore, modification of existing two-part tariff structures to properly unbundle energy costs with network capacity costs should pose few administrative challenges. Ideally quarterly electricity bills for autumn, winter and spring would be made up of variable energy charges only; these would be considerably lower than current bills for the same time of year under current pricing structures.

However, summer bills - and by 'summer' I mean the season of system-peak demand - would comprise a network access charge reflecting the customer's contribution to system-peak demand in addition to the variable energy charge. This may make the summer bill several times larger than the other quarterly bills, *but the annual sum total of the average customer's expenditure on electricity would be considerably less under a system-peak power network tariff scheme than it would be under current energy-based pricing arrangements*. This is because, under system-peak power based retail pricing, consumers would be given the opportunity to engage in *system-peak demand side management* to dramatically reduce their annual electricity expenditure. Such activity would in turn lessen the electricity price burden on other customers by lowering the system's overall forecast capacity requirement and, therefore, associated network tariffs.

For this proposal to work, consumers would need to be properly forewarned of the risk that a system-peak may be approaching; in Australian cities, this usually occurs in the afternoon on a very hot week day. Warnings that a peak power day may be approaching could be issued by the network company in a similar way to severe weather warnings issued by the Bureau of Meteorology; i.e. provided to consumers as part of local media weather reports. Once warned, consumers could dramatically reduce their annual electricity bill by taking action on that day to avoid or lessen their contribution to the peak. This may involve turning down their air-conditioning system, substituting a fan for an air-conditioner, installing a west-facing photovoltaic (PV) system or, for residential customers, switching off appliances and leaving the house to go shopping or to the cinema.

Metering Issues

One objection to system-peak demand retail pricing that may be raised by network businesses is the prevalence of out-of-date metering technology. Most meters at residential and small commercial properties are accumulation meters, meaning that those customers' contributions to system-peak demand cannot be readily measured. However, wholesale consumers of electricity in Australia are usually required to install an interval meter which is able make such measurements. Similarly, network businesses have insisted that interval meters be installed at properties with PV systems that are connected to the grid. Therefore, there will be many customers for which an accurate measure of their system-peak demand contribution is readily available. Moreover, the peak demand contribution of the customers without interval meters could, as a group, be easily determined through subtraction of all metered demand readings from total system load, a calculated value known in the Western Australian context as the wholesale 'notional meter'. The retailer responsible for the group of consumers without interval meters would then pay the wholesale notional meter derived peak-demand charge for the group. This charge would then be passed on to customers in that group, weighted according to each member's overall summer energy consumption. Although this is a departure from the optimal system-peak pricing arrangement that could be achieved with widespread interval metering, it improves on the existing price signal under energy- based tariffs. In general, customers in this group would be made better-off under system-peak network tariffs compared to energy-based network tariffs, because of customers outside the group having the incentive to reduce upwards pressure on network capacity requirements. That is, autumn, winter and spring bills would be considerably smaller, and summer bills considerably larger, *but the annual sum of the average customer's bills would be smaller than under energy-based tariffs*. For those customers under financial stress, summer bills could be paid in a series of instalments.

Moreover, this arrangement would provide accumulation metered consumers, that may want to be rewarded for participating in system peak-demand management, the incentive to invest in interval meters. The fact is, with system-peak demand retail pricing in place, many customers (especially commercial customers) will be able to *justify the cost of an interval/smart meter in the first-year through the savings achieved by participating in system-peak demand side management*. Over time, as interval meters spread, more and more individual's contributions to system peak demand will be able to be accurately metered, thus ensuring that it is the users of the system's capacity requirement that end up paying for it.

Peak-Power Pricing vs. 'Gold Plating' of Assets

The current approach to the regulation of electricity transmission and distribution assets in Australia can be summarised as follows. Either the network business or an independent system operator conducts a forecast of future system-peak demand requirements over an access arrangement period of usually five years. The network business then proposes a network augmentation plan and a required level of revenue (including a rate-of-return) to service/fund the plan. After a process of regulatory assessment, and possible appeal to administrative law tribunals, a final determination is made as to the efficient level of investment and the tariffs that the network can charge over the period of the access arrangement.

Even if an independent system operator conducts system adequacy forecasts, rather than the network business itself, such forecasts can be influenced by technical claims made by the network business and by the data they provide. If network tariffs are expressed as energy-based prices, one way the network business may be able to 'game' the regulatory process would be to understate their energy consumption requirements while overstating their peak demand requirements. This would result in over-investment or 'gold plating' of the electricity network. As a simplified example, suppose a network business estimates that their annual energy throughput will be 50 TWh, that peak demand will be 4.8 GW and that the cost of meeting that capacity requirement (i.e. peak demand plus a safety buffer) will be $3 billion. This cost could be recovered by charging $3 billion / 50 TWh = 6¢ / kWh for all energy consumed during the year. However, suppose the actual peak demand turned out to be only 4 GW while the actual energy throughput ended up being 55 TWh. Then instead of earning the regulated revenue of $3 billion, the network business would earn 6¢ / kWh x 55 TWh = $3.3 billion. *This is $300 million more than the regulator intended to award the network business, for delivering 800 MW of unneeded capacity*.

Alternatively, suppose system-peak demand pricing was instead implemented. Then the regulator would approve a tariff of $3 billion / 4.8 GW = $625 / $kW_{system\text{-}peak}$. In this case, with actual peak demand at 4 GW rather than the overstated 4.8 GW, the network business would earn $625 / $kW_{system\text{-}peak}$ x 4 GW = $ 2.5 billion. *This is $500 million less than the regulator awarded the network business*. In this way, the network business is automatically penalised for their 'gold plating' of the network. The risk of an overly high peak demand forecast is thus placed on the regulated entity rather than on electricity consumers. Moreover, as stated earlier, consumers with interval meters would be able to avoid network charges by participating in system-peak demand side management.

Distributed Generation as Negative Demand

Dramatic falls in the price of PV systems over recent years are set to continue which will incentivise their uptake. The ongoing increase in PV installation will play a major role in reducing network costs, provided barriers are removed to use PV to offset system capacity requirements. In general distributed generation technologies - especially west-facing PV arrays - compete directly with transmission lines. Essentially, a transmission line delivers power from distant sources of generation to major demand nodes. A PV array that is able to provide power at the same time as the system-peak offsets the need for transmission capacity and is therefore a competing technology.

In most Australian cities, the system-peak almost always occurs in summer on a hot and sunny weekday afternoon under the influence of a high-pressure weather system. For a typical 4.00pm - 4.30pm system-peak in Perth, an optimally positioned west facing PV system would reduce system capacity requirements by about 75 percent of the PV system's rated output. This is before taking into account the fact that power supplied by distributed PV suffers almost no line losses compared to the substantial transmission line losses that occur during a system-peak. Therefore, distributed rooftop PV is a potentially low cost means of reducing system capacity requirements.

However, there are no incentives in Australia to point PV arrays to the west at the optimal angle to correspond to the likely system-peak. Rather, existing incentives - such as upfront renewable energy certificate payments - penalise west facing PV arrays. This is because such incentives are based on energy production rather than system-peak power production. Energy production incentives favour north facing PV arrays since they produce more energy over the year than do similarly located west facing arrays.

In the same way, energy-based tariffs, including time-of-use tariffs, disincentivise west facing PV. Perversely, if network tariffs are spread over the year on a per unit of energy basis, a customer with a north facing array will pay less network charges than they would if the array were oriented to the west. However, under system-peak demand pricing, commercial and residential businesses with the appropriate roof space would have a real incentive to install a west facing PV system. Moreover, their installation would benefit other customers without PV by reducing system-peak demand and, therefore, overall network costs. PV output during a system-peak can be thought of as negative demand. A west facing 1.5 kW PV system could easily offset the contribution to system-peak demand created by a 1 kW air conditioning unit. Under system-peak pricing, those customers with PV arrays that feed power into the grid during a system-peak, rather than draw from it, should be rewarded with a credit on their bill rather than a debit.

In Western Australia, a curious situation has arisen where in 2010 the Economic Regulation Authority (ERA) authorised a request by the Western Power network to charge customers with a installed PV system a *higher* time-of-use energy-based network tariff for electricity consumed between the hours of 2pm and 8pm compared to those customers without a PV system. This is despite the fact that Western Power's own forecasts indicate that the current stock (of mainly north-facing) PV systems connected to the South West Interconnected System (SWIS) will be likely to offset the summer peak by 120 MW in 2013/14. 120 MW is equivalent to the output of a large peaking plant. This suggests that PV on the SWIS will, in the short term, reduce network and generation capacity costs equal to the asset valuations of a large peaking plant and the transmission lines and substations required to connect it to the grid.

The fact that PV is a competitor to transmission infrastructure may explain Western Power's motive in requesting this 'bi-directional tariff'. I am also aware of proposals in Queensland to introduce higher network tariffs for customers with PV. In my view the ERA's approval of the bi-directional tariff is a case study in regulatory capture. To the extent that distributed generation can compete with high-voltage transmission lines, the latter can no longer claim natural monopoly status. But the influence, indeed the very existence, of a natural monopoly regulator depends upon the maintenance of natural monopolies. So the long term interests of the ERA and Western Power may be in alignment on this issue while being aligned against the interests of electricity consumers. In other words, it seems to me that the bi-directional pricing arrangements approved by the ERA are intended to serve the interests of the regulator and the regulated entity rather than the interests of the public. Regulated pricing barriers designed to work against network competitors would be more difficult to implement if network tariffs were required to be based on system-peak demand rather than being energy-based. Although the AEMC is focused on the NEM, lessons can be drawn from the Western Australian experience in this area.

Conclusion

Conventional wisdom often takes the view that modern metering technology needs to be rolled-out by government before cost-reflective and cost-signalling retail tariffs can be implemented. However, what I have argued above is that essentially the opposite is true. If network tariffs based upon system-peak demand rather than energy-based tariffs are implemented, consumers will have a strong incentive to invest in interval meters without a government roll-out. The fact is that the move to retail interval/smart meters has already begun through the rapid uptake of rooftop PV. However, more customers, with or without PV, will want to join the interval meter club if retail electricity bills are designed to reflect the actual costs of network augmentation. These costs are incurred at system-peak demand, i.e. on one or at least a small number of half-hourly trading intervals in the year. By requiring retail network tariffs to be based on system-peak demand, there will be direct incentive for consumers to respond in a way that moderates that peak. A retail customer knowing that they have the option to cut their annual electricity bill in half, with little or no inconvenience, has a real incentive to install an interval meter to enable them to participate in system-peak demand reduction. Those retail customers that choose to not directly access the tariff will still be exposed to it indirectly via their retailer. They will see substantial falls their autumn, winter and spring bills, but their summer bill will rise, and so even customers without interval meters will still have an incentive to reduce their contribution to system-peak demand. However, customers not actively seeking to reduce their contribution to the system-peak will still benefit from system-peak based tariffs, because the peak-demand reduction activities of other customers will put downward pressure on network costs and therefore network tariffs across the board.

These benefits will not be realised if the AEMC instead administers a move towards time-of-use network tariffs that are spread across units of energy. It would be a lost opportunity if the AEMC's Final Report did not specify that time-of-use network tariffs should correspond to system-peak demand.

Yours sincerely,

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