8th December 2017

Ms Elizabeth Walters
Assistant Director Electricity
Economic Regulation Authority
Level 4, Albert Facey House
469 Wellington Street
Perth WA 6000

Dear Elizabeth,

RE: WESTERN POWER AA4 DISCUSSION PAPER

Emergent Energy welcomes the opportunity to make a submission to the Economic Regulation Authority (Authority) regarding Western Power's proposed AA4.

This submission sets out the increasing difficulty of applying traditional economic regulation principles to monopoly electricity network providers. As the electricity sector is rapidly transformed through the introduction of new technology, consumers gain access to new products and services relating to the supply of electricity. As often occurs when greater competition is brought to bear in a marketplace, incumbents, often utilising outdated business models, lose market share and subsequently, the value of their businesses decline.

The regulation of monopoly infrastructure, while complex in its application, is typically straightforward in principle. However, previous access arrangements, characterised by increasing assets bases accommodating increasing populations which lead to increased demand, are no longer the norm. While population may continue to grow, regulators can now expect asset bases to service declining consumption and peak demand.

Electricity supply is still viewed as an essential service, which makes the sector politically charged. While the principles of economic regulation must still be independently applied, the rapidly changing nature of the sector requires a combination of regulatory, policy and legislative manipulation to stay ahead of the game and to produce efficient and equitable outcomes for consumers and network owners alike.

Regards,

Shane Cremin.

Technological Disruption

The nature of technological disruption is that value is created as new technologies, competing against older technologies and their infrastructure, enter a market. The new technologies offer cheaper and more desirable products and services, which creates value for consumers. These products and services often displace those offered by incumbents.

An example of this is the rise of online retailers. Unburdened by the cost structures of bricks and mortar retailers, and using rapidly improving internet marketing and delivery logistics channels, consumers are offered a better range of products and services at a lower price. While there might be some growth of the overall pie, typically the online retailers take market share from traditional retailers, which must adapt their service offering to compete. As market share leaves the incumbents, the value of their businesses decline.

Within the electricity supply sector, a combination of Behind-The-Meter (BTM) solar and storage technologies[1] is either doing, or threatening to do, precisely this. These technologies are disrupting the traditional supply model and reducing the value of the incumbent suppliers' assets. But properly managed, the new technologies can lower the cost of electricity supply, including by eliminating the cost of meeting peak demand, thus leading to large efficiency benefits to all consumers.

Another aspect of technological disruption is that the rules and regulations of the sector are seldom appropriate to manage the new technology entrants. In other words, the playing field is not initially level. Nor should it be expected to. Technological disruption is characterised as being unexpected and sudden. In the case of online retailers, already boasting many advantages over their traditional competitors, the initial absence of GST levied against online sales provided an *unfair* advantage over the bricks and mortar incumbents. Similarly, in the electricity supply sector, the existing structure of (fixed and variable) pricing, for so long an adequate (if not particularly sophisticated) method of recovering the costs of providing the service, now place incumbents at a disadvantage.

Regulators and policy makers alike must recognise that the introduction of new technologies is rapidly and irrevocably changing nature of the electricity supply sector and make bold decisions to respond to and influence this disruptive change.

[1] It is an interesting premise, expanded upon later, that each of these technologies in-and-of-themselves would not pose too much of a threat to the traditional supply model – at least not the type of threat that cannot be remedied by careful regulation. But together, BTM solar and storage are a game changer to the traditional supply model and the manner in which this is regulated.

Regulating Monopoly Infrastructure Owners and Service Providers

The regulatory accord is premised on allowance to the owner of monopolistic infrastructure assets to an adequate return on their capital, in exchange for meeting certain obligations around the terms and standards of the services provided. Absent regulatory oversight, owners of monopoly infrastructure are able to seek monopoly rents, either through the price paid by customers to access the service, or the quality of the service offered. In essence, regulated returns are premised on the notion that the owner of the monopoly infrastructure acts in a manner in which a prudent owner of infrastructure would if in competition with other service providers. This inherently means: taking prudent investment risks; and responding to the needs of customers utilising the services, in a manner that would enable it to compete with other similar service providers (if competition did exist). Regulated returns allow the earning of a market risk premium for taking on these risks.

Competitive markets (which regulation attempts to mimic in its absence), contain both operational and market risks. An investment to meet a customer's needs has some level of risk attached to it. The customer should ultimately pay for the service and the service provider earn a profit from providing it, but in the face of genuine competition, where the ability to maintain that customer and its future income is under threat, investment decisions are sometimes less profitable than they otherwise might be. If competition is strong enough, losses can also occur[2]. And all businesses face broader market risks, whether operating in a competitive landscape or not. Supply and demand fluctuates with economic activity; and new entrants with competing services threaten incumbents… often in a disruptive manner.

What the regulatory accord <u>does not</u> entail is the guarantee of full cost recovery of investments made by the regulated utility[3]. *The risk premium inherent in the rate of return implies that an owner of regulated assets accepts and manages operational and market risks*. Problems manifest when these risks materialise. As occurs in actual competitive markets, when the cost of investment or operations increases faster than revenue (or do not decrease faster than revenue declines), then asset impairment is necessary.

A monopoly infrastructure asset owner earning a regulated return, comprising an adequate premium for managing risks, is not immune to asset write downs. And if full-cost recovery is to be contemplated, then a commensurate decrease in the risk premium must be implemented, such that the investment more closely resembles a riskless asset class.

Which brings us to the case of Western Power and AA4.

[2] Indeed, the WEM experienced a period from around early-2014 through to the end of 2016 where retail electricity contracts for contestable customers were set at very low margins, and were often loss-making, as retailers fought to maintain market share in a highly competitive market.
[3] Whether the regulated utility is in private or public ownership is irrelevant.

Declining Demand – Exposure to Market Risk

Page 11 of the Authority's Issues Paper states: *"While the regulated asset base continues to increase, unless the customer base increases at the same or a higher rate, customer bills will increase."*

This is only true if it is assumed that Western Power should fully recover all previous investment, whether it was deemed efficient at the time or not. This ignores a clear market risk. In this case, the expected increase in revenue to cover the expanded asset base has not materialised, likely through a combination of a downturn in economic activity; increased per-capita energy efficiency; and the rapid uptake of BTM solar PV. Western Power receives a premium in its rate of return to take on and manage this market risk. It does not follow that Western Power is *entitled* to the revenue required to cover their previous expenditure – in the same way a private company is not guaranteed a return on its investment when market conditions become unfavourable. Increasing prices to customers to cover falling demand would not occur under competitive supply conditions. Instead, profits are reduced and the value of a business or asset is impaired on its balance sheet. In fact, increasing the cost to consumers for a service, which is no more valuable to those consumers, in order to prop up declining revenues, is exactly what a monopolist service provider would be expected to do, without the influence of competition or the oversight of regulation. This is a case of 'You can't have it both ways'. The risk premiums explicit in regulated returns require downside revenue risks to be absorbed when they materialise… or, if full recovery of investment is the objective, then the risk premium must reflect the nature of that investment.

There is not a great deal of literature or precedent on how to manage asset stranding for regulated monopolies[4]. How stranded assets are devalued on a balance sheet; what proportion of the investment should be written down; over what timeframe this should occur; and who should pay for the portion of stranded assets that are not written down (that otherwise might be in a non-regulated environment) are all difficult questions which are likely to be influenced by local factors as much as economic theory. One aspect of significance when considering regulated asset stranding is determining what caused the assets to be stranded. This will impact the measures to be put in place to determine parameters such as efficiency and equity when allocating value amongst the regulated entity and its customers.

For the first time since the regulation of Western Power began, the sector is faced with a structural decline in growth. This is important to understand. The mismatch between actual demand, and until very recently what was a forecast growth in demand, is unlikely to be due to one-off factors such as an economic 'bust' following a 'boom', or through poor demand forecasting. While it is true that economic growth is historically weak – and could indeed pick up again, this structural decline in demand is technology based. A combination of energy efficiency (translating to declining per-capita energy demand) and more importantly, distributed generation (principally solar PV, and soon, battery storage) means that even with modest population growth, demand is likely to decline for the foreseeable future. The magnitude of this decline is difficult to predict – as Western Power attest to in the AA4 supporting documentation (Attachment 7.3.5), which creates further risk of projected revenue being inadequate for cost recovery.

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[4] The December 2016 Working Paper titled "Monopoly regulation, discontinuity and stranded assets" by Paul Simshauser provides a recent and relevant discussion on this topic.

Of concern has been the poor ability of anybody in the energy sector to accurately predict the pace of the growth of solar PV. From the International Energy Agency, through to national energy regulators in Australia and down to the local AEMO (and IMO before it), recent history is littered with annual forward curves for solar uptake being revised upwards each year while annual demand forecasts are revised downward. It appears as though Western Power's forecasts in Attachment 7.3.5 may similarly be on the low side, especially for the uptake of commercial solar. Forecasting methodologies typically look at observable trends. What is difficult to observe early in a time-varying stochastic data-set is an exponential trend. The form of the exponential trend is that early on, it appears linear (and with a low growth trajectory at that). But in the short space of time that we have witnessed solar PV's penetration of particular markets, its uptake has had more of an exponential trajectory[5]. While many external factors have impacted the rates of adoption in different jurisdictions and customer segments, such as regulatory or technical barriers being implemented or removed; or variable policy settings around feed-in tariffs or subsidies imposed, *the fact that the underlying price of BTM solar has fallen so far means that adoption rates will likely transcend much of these external influences*. Those familiar with the BTM solar sector anticipate that commercial customer adoption will be larger and occur at a greater pace than residential adoption, which has accounted for the vast majority of BTM solar to date. The large 'industrial' customer segment will likely follow suit.

In its demand forecasts, Western Power has recognised that while residential BTM solar uptake has been high (and will continue to grow), that a large portion of the BTM generation is not actually consumed behind the meter, meaning the energy is imported into Western Power's network rather than decreasing demand. It assumes a reasonable uptake of BTM battery storage will result in a larger portion of BTM generation being consumed behind the meter over time. This is sensible. Forecast error here will be impacted by the rate of uptake for BTM storage (batteries). At such an early stage of battery adoption, these rates are hard to predict, however Western Power's net present cost assumptions for partial grid defection rates appears to use very conservative numbers. There is a significant chance that battery uptake (and higher BTM solar utilisation) will be greater than forecast. While not explicitly accounted for in the documentation, discussions with Western Power suggest their assumption is that around the same amount of BTM solar is injected into the grid (i.e. not consumed behind the meter) than is produced and consumed. This implies a self-consumption rate of 50%. This self-consumption accounts for the majority of the annual decline in distribution connected demand over the AA4 period, with additional declines coming from: energy efficiency; price elasticity[6]; and lower economic activity[7].

BTM commercial solar however will naturally have a far greater utilisation behind the meter, given the load duration curve for the majority of commercial businesses is highest during daytime hours[8]. Without adequately accounting for a rapid uptake and high utilisation of BTM commercial solar, along with a potential underestimate of residential battery uptake and solar self-consumption,

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[5] The most recently published data from the Clean Energy Regulator shows a clear exponential trend to commercial solar adoption rates.

[6] As prices rise, consumers choose to use less electricity.

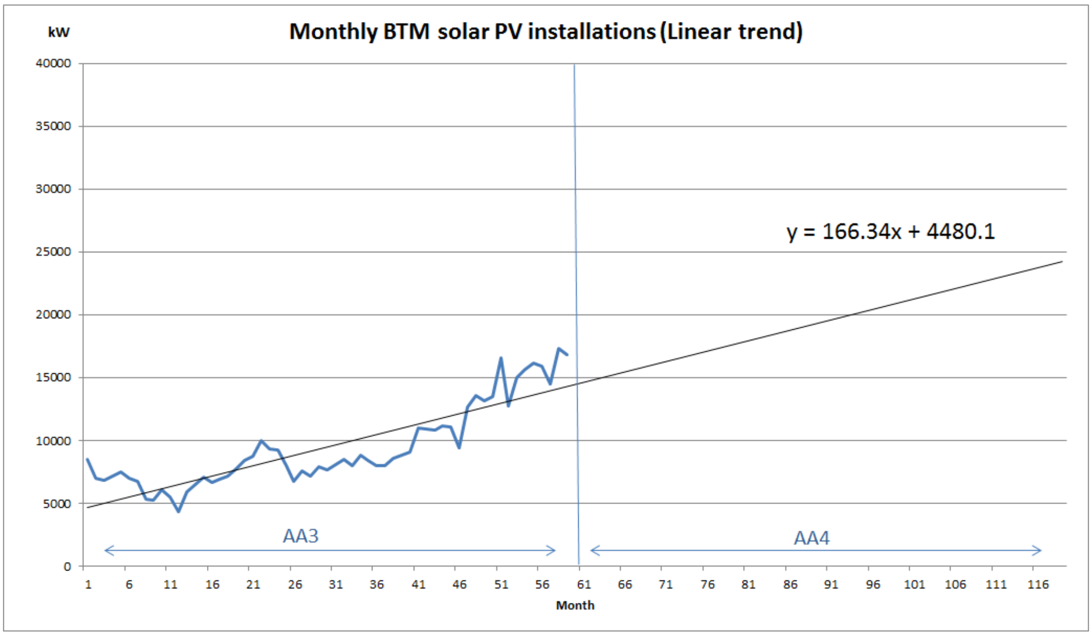
[7] Fewer new connections are business customers, meaning the average demand per-connection is lower.

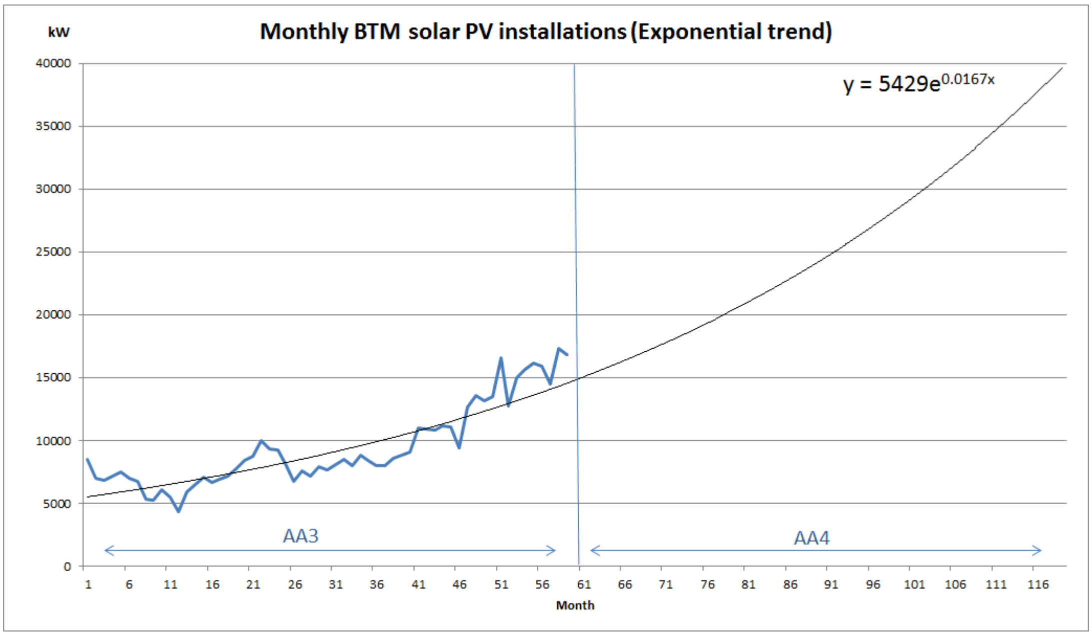
[8] Solar providers specifically size commercial solar to maximise self-consumption. Even considering low weekend utilisation, commercial solar self-consumption should average between 70% and 80%.

Western Power is likely to underestimate the decline in grid facing demand (or grid export, as Western Power refers to it).

The Western Power forecast for BTM solar entering the grid in 2022 is 1,048GWhs. If this represents 50% of BTM solar generation (with 50% self consumption), then Western Power's forecast for BTM generation in 2022 is around 2.1TWhs

Some further analysis on actual solar trends is shown below. The actual monthly capacity installed[9] from 2013 to 2017 (YTD), or the AA3 period, is extended using both linear and exponential regression trends.





[9] This is capacity data for Western Australia. It is assumed the SWIS accounts for 95% of future BTM capacity installed.

As at the end of October 2017, there was 785MW of solar PV in the SWIS. It can be assumed that there will be at least 800MW installed by the end of 2017[10]. Forecasting new solar installations based on the above trends and using the average capacity factors of residential solar in the SWIS[11], the BTM installed capacity and generation quantities in 2022 will be:

Linear trend: 1,913MW and 2.85TWh

Exponential trend: 2,262MW and 3.37TWh.

The table below summarises the potential for Western Power under-forecasting the decline in distribution connected demand[12]. It uses, 2022, the final year in the AA4 period. The Western Power forecast total distribution demand is 13.083TWh (with 1.048TWhs consumed behind the meter).

		Self-consumption [TWh] (forecast error)			
	2022	50%	60%	70%	80%
BTM Generation	Linear (2.85TWh)	1.42 (-2.9%)	1.71 (-5.1%)	2.20 (-7.2%)	2.28 (-9.4%)
	Exp (3.37TWh)	1.68 (-4.9%)	2.02 (-7.4%)	2.34 (-10.0%)	2.70 (-12.6%)

Forecast error is the difference between the Western Power assumed self-consumption (1.048TWh) and the self-consumption under each scenario divided by the total forecast distribution demand (13.083TWh).

The point of this is to illustrate that there is already an acknowledgement that distribution demand is declining; and that there is a significant possibility for the forecast rate of decline to be on the low side, meaning distribution connected customers will not be consuming the quantity of grid provided energy required to meet revenue projections. And with distribution connected demand in *structural decline*, there is a case to be made that asset stranding is occurring; that it will take some time for the process of BTM solar and storage growth to run its course and demand growth to pick up again – if at all[13]; and so at least some value of the distribution asset base should be written down over the course of AA4.

[10] Installations are as per the Clean Energy Regulator's measure of registered STC's, which are typically lagging of actual installations. At a monthly average of over 14MW for Western Australia for 2017, there should be at least 800MW in the SWIS by the end of 2017.

[11] This is assumed to be around 17%. Solar cell and inverter conversion efficiency will increase over time. And any incentive to orientate panels east-west will likely soon dissipate with the addition of batteries. A northerly orientation (maximising production) will be preferred.

[12] This analysis does not account for a larger exponential trend. With solar PV (and battery storage) costs continuing to decline; with grid supplied energy prices continuing to rise; and new financing models (i.e. PPAs and no up-front cost models) as well as the lower general financing costs of larger solar facilities, there is scope for the exponential trend to increase at an even greater rate.

[13] There is of course a limit to the roof-space that can host BTM solar. However, what cannot be predicted is the introduction of newer solar and storage technologies (e.g. solar glass, solar tiles or other coating products) which, over time, might enable significantly more solar to be installed behind the meter.

PRICING – INCENTIVISING ACTIVITY

While a decline in demand leads to lower variable revenues, which is a clear market risk, it does not mean that the pricing mechanisms are well structured in the first place. It is widely acknowledged that the split between variable and fixed cost recovery is skewed too highly toward the variable side. A large portion of Western Power's assets are built to service peak demand. Peak demand however is also falling – a trend acknowledged by Western Power. While it may not fall as quickly relative to consumption, the decline again appears to be structural. While this is not amenable to recovering the previous capital expenditure required to construct network assets to meet demand peaks that are unlikely to exist anymore, it is a good result for the longer-term efficient use of the network. As more solar PV is added to the grid (both behind the meter and utility-scale grid connected), the price of energy, as well as the demand for energy, will continue to fall during the middle of the day. Peak demand will be pushed further into the evening, when prices also spike back up as solar PV output declines. It can be expected that peak demand will be less than it otherwise would have been if, absent solar PV, the peak had occurred earlier in the day, however the grid will none-the-less still experience peaks and there will be less variable revenue available to pay the fixed costs of meeting them.

Western Power, regulators and policy makers face a difficult choice here. It is clear that over this next regulatory period, BTM battery storage will emerge as a key component of the network. The following regulatory period will likely see adoption trends increasing. BTM battery storage's primary objective will be to time-shift BTM solar generation into the evening. This will have a significant impact on peak demand – and the network assets constructed to meet it. Again, a structural change in the market for electricity supply and consumption is upon us. And while BTM battery storage is complementary to BTM solar, they are completely different technologies. In fact, it should be regarded as fortunate that both technologies have appeared in the mass market at roughly the same time[14].

Over the AA4 regulatory period, the largest expenditure in the electricity sector, outside of the network expenditure itself, will be made by consumers installing BTM solar and storage. Somewhere in the order of $1.5 to $2 billion is likely to be spent by the end of 2022. Right now, solar PV is an obvious place for consumers to spend money with BTM generation cheaper than grid supply (often significantly so). Battery storage is likely to take a little longer to proliferate. Without incentivising the uptake of BTM storage, the solar-skewed peak demand issue discussed above will continue throughout most of the AA4 period. While solar PV is a wonderful technological addition to the energy supply mix, battery storage is the real game changer. Being able to store low cost electricity changes the nature of how the grid is used and how electricity is generated and consumed. Incentivising consumers to install storage with their BTM solar will provide large, long-term efficiency benefits to the electricity sector. Reducing the peaks (both evening and morning) not only reduces the price and volatility of generation, but it reduces the requirement for peak network infrastructure.

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[14] And if another newish technology – reverse cycle air-conditioning, had also appeared at the same time, much of Australia's networks might have escaped the need to spend billions on meeting the explosion in peak demand brought on by the rapid uptake of air-conditioning in the first decade of this century.

Herein lies a problem. By applying price incentives for the expedited uptake of storage, increasing market efficiency and reducing the cost of electricity to consumers, Western Power is likely stranding significant previous capital expenditure in its asset base. While this may not well-satisfy the code objective relating to promoting efficient investment[15], it certainly meets the objective of promoting the economically efficient use of networks and services; and it certainly promotes competition – especially with regard to new technology entrants.

So new pricing mechanisms are required to better align with recovery of the fixed cost to Western Power in maintaining the network… but if those pricing mechanisms are properly structured to incentivise even greater efficiency (and lower costs to consumers), then by implementing them, Western Power faces a likely devaluation to its business. Similarly, if not structured effectively, higher fixed prices will stymie the uptake of BTM assets to the detriment of network efficiency[16].

The manner in which properly structured price incentives are to be implemented must cut across a number of regulatory and policy levers. While the Authority has only a mandate to deal with those levers provided under the Access Code, it should be recognised that as technology changes the nature of the network, a collaborative response from policy makers and rule makers alike is required to respond to, influence and even harness this change. Responses might include:

<u>Residential peak demand network pricing</u>: This requires a rollout of smart meters. While that statement of fact sounds innocuous, it is in no means a trivial exercise. It is an indictment on the lack of policy foresight in the electricity sector that over the past five years, around 20% of residential customers have installed solar PV and hence been required to install a new electricity meter… however not one of these has been a communications enabled smart meter. None-the-less, smart meters are required to be installed. Other jurisdictions have struggled with this in recent times. But typically, this is because this large-scale rollout has been contemplated under an old-supply-model way of thinking… when the very notion of installing smart meters screams new-supply-model. While it may not be in the interests of network owners, there is no reason for the networks to own electricity meters. In fact, as the sector enters a period of extended disruption (BTM assets, peer-to-peer trading platforms, new service and product delivery methods – including grid defection, and whatever other unknown disruptions await), it is *preferable* that networks do not own smart meters, which are an enabler of these new supply models. There is no requirement for networks to own BTM generation and storage assets, yet these have more impact on the management of the network than electricity meters do. By thinking outside of the box in this manner, the rollout of smart meters becomes a different proposition. Customers can be incentivised, via a 'carrot and stick' approach, to install smart meters themselves. Customers have already spent over half a billion dollars on BTM assets over the past five years and are likely to more than triple that expenditure over the next five. Their ability and propensity to outlay capital for the superior utility brought by investing in new technology has been demonstrated and should be harnessed by policy makers.

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[15] Although, just because an investment may have been deemed efficient at one point in time does not mean it continues to be efficient in the future, as the dynamics of the sector change.

[16] Fixed tariff increases, without providing any incentives to change customer behaviour, is a blunt and economically inefficient instrument to recover revenue.

By deeming a peak demand level for individual customers[17], based on some formula utilising historical usage patterns, customers will pay a higher, but fair fixed price to access the grid. However, customers will have the opportunity (and incentive) to install a smart meter in order to set an actual peak demand level, rather than have it deemed. They will be further incentivised to modify their consumption, as well as to adopt BTM storage earlier than they otherwise might, which will reduce their actual peak demand[18]. They will pay less to use the network because the more efficient network will cost less to operate[19]. This would be a significant exercise to implement, but it will have the potential for dramatic impacts around the way in which customers access electricity supply services into the future. Multiple retail models are possible. As seen in the telecoms and internet markets, ownership of phones and modems quickly passed from the service provider to the customer under lease, outright ownership, BYO or other mechanisms. And as grid defection becomes a reality, network owners face the increasing likelihood that electricity meters will disappear from their asset base at any rate. As the role of networks change and regulated revenue drops, it is preferable to not embark on an exercise that would require a large new set of assets (smart meters) to be added to the already overweight distribution asset base.

<u>BTM assets and the capacity mechanism</u>: BTM assets – particularly storage, do not hold any currency in the current capacity mechanism… despite playing a large and growing role in the changing electricity supply model. While this would entail a large and complex reform, not addressing this issue will lead to poor efficiency outcomes (or possibly an irreconcilable capacity mechanism), likely within the period for which AA4 runs. At a very high level, consideration should be given to a range of options, including: Permitting the deemed certification of some portion of BTM solar and storage (similar to a combination of the differential treatment to both intermittent generation and DSM in the market currently); Permitting a market participant, which is not necessarily the retailer of the NMI, to aggregate and bid a portfolio of BTM assets into the market (similar to the treatment of DSM currently); or altering the methodology for setting the IRCR obligations of retailers (e.g. on a monthly basis) such that the value of BTM assets, with regard to reducing peak energy demand and prices, is better recognised.

<u>Residential Renewable Energy Buyback Scheme (REBS)</u>: Synergy is mandated to buy back any surplus energy from residential customers[20] for around $7c/kWh. This is equivalent to $70/MWh wholesale energy price (with no capacity credit or other green energy value attached). This is not only a high wholesale price for energy currently delivered in the middle of the day (especially on weekends), but as more BTM and utility solar is added to the grid, the future value of energy produced at this time

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[17] Similar to the switch from analogue to digital TV, a date is set where customers will switch to peak demand pricing. Those customers who have not already installed the required smart meter will have their peak demand level deemed. There will be issues relating to financial hardship customers… but these will be evident no matter what pricing model is employed, so should not be used as an excuse to not pursue new models.

[18] A pre-set fixed floor price would be the minimum demand permitted.

[19] This implies that full cost recovery of past investment is not guaranteed and that some asset stranding and write downs are necessary, rather than increases to prices to recover revenue.

[20] Customers with a maximum of up to 5MW of inverter capacity.

will decrease further. By removing the REBS[21], customers will be incentivised to add BTM storage, which will be used to time-shift low-cost energy into peak periods. Network efficiency will be improved (though some previous capital expenditure in network assets will be stranded).

Subsidies for BTM storage: A simple subsidy program provided for the early adoption of BTM storage would provide greater benefits to electricity consumers than the cost of REBS. It would also lead to greater long-term network efficiency.

[21] This would admittedly be politically contentious. It would be anticipated that new BTM solar systems would not qualify for REBS and existing systems would transition away over a number of years.

Summarising – The Twin Disruptions of Solar and Storage on Regulated Networks.

In-and-of-themselves, both solar and storage do not pose a huge threat to the prevailing rationale for regulating monopoly network assets when taken in isolation.

A rapid uptake in BTM solar alone would reduce variable revenue as demand disappears behind the meter. But solar is only active during a portion of the day and peak demand is not greatly impacted, occurring later in the evening. Rearranging the fixed and variable price components can offset these impacts. While it can be argued that some degree of market risk has occurred (lower demand), and in a competitive landscape, a complete rearranging of price components would not be possible (i.e. some value is lost by the network owner), this would be minimal.

Storage on the other hand has the ability to take low cost energy (e.g. overnight – in the absence of BTM solar) and time-shift it behind-the-meter to higher priced peak demand periods, thus reducing both peak demand prices and network costs. But if the energy itself has been generated in front of the meter, then the energy demand does not change, only the distribution of when it is used. Again, an appropriate mix of fixed and variable price components can be used to provide a return to the network provider – even though some previous capital investment in peak demand infrastructure may be stranded.

Combining both BTM solar and storage creates an obvious problem for the network operator and regulator alike. Peak demand is reduced and infrastructure is stranded; and the variable quantity of energy declines at the same time. When the decline is structural and likely to last indefinitely (or at least, not return to the previous paradigm), a rethink on how monopoly assets are regulated is warranted.

The regulatory accord does not guarantee full recovery on previous investment – no matter if it was deemed efficient at the time. Markets change, often disruptively. And network owners are paid a market risk premium to manage operational and investment risk. When a market turns against a monopoly service provider, raising prices to maintain returns is monopolistic pricing behaviour. And while it cannot be expected that asset write downs are of the same magnitude as they would be if a non-regulated entity faced similar disruptive market risks, some asset stranding is unavoidable.

Specific responses to selected issues

Issue 1: While it can be argued that Wester Power has still not adequately addressed the pricing principles for cost recovery in a fundamentally changing market, it is pleasing to see its investment strategy is adapting to meet the new supply models. While the ERA and its experts are best placed to assess the proposed scope of investment and operational expenditure, care must be taken when considering how Western Power implements new delivery models.

Where Western Power eschews 'conventional network management', or poles and wires, for new technology (such as distributed generation and storage), it is moving from a natural monopoly service model into what is a very competitive sector. If it is more efficient to install distributed generation and storage, rather than replace aging poles and wires, should Western Power be able to replace one with the other on its asset base? The market for providing distributed generation and storage services is not a natural monopoly. But only Western Power has access to the 'benefit' of the obligation-cost of replacing an existing monopoly asset.

This issue raises questions about the ability to apply 'postage stamp' tariffs to all consumers. It also raises questions about whether a consumer at the end of a remote distribution line, which has enjoyed subsidised (postage stamp) tariffs, should be allowed to leave the grid for an alternative supply model at a point in time when the network assets are still useful[22].

Issue 3 (connection services): Monopoly service providers must be regulated for both the price of the service they offer as well as the quality of that service offering. It is fair to say that the AQP, and the CAG process within it, has been inadequate in providing the services required by customers.

Project proponents have often spent years and large amounts of money navigating the AQP process, often with no evident progression. A problem with the provision of services from a monopoly service provider is that there is no competition to benchmark against; and indeed, no competitive structure to require it to take risks in order to be chosen as the service provider.

While the provision of connection services to customers is not a regulated part of the business, the quality of the services provided would be unlikely to be acceptable, and Western Power would have suffered significant customer leakage, in a truly competitive environment. As it stands, Western Power has received significant revenue through the provision of poor quality connection services. Whether this is performed on a cost-recovery basis or not is irrelevant.

Issue 4 (smart meters): Western Power should not be responsible for the rollout of advanced interval meters. The distribution asset base is already too large to provide an adequate return on capital from a customer demand in structural decline. While some changes to the fixed and variable tariff structure may offset some of this discrepancy, adding a large new set of assets will exacerbate the problem

[22] There is an argument that every customer of a networked utility enjoys the benefit of the regulated price model, where access is paid for over the long-term depreciation and management of the assets rather than as an up-front cost; and that grid defection is essentially opting out of the network connection compact before the customer has fully paid its way.

Like BTM solar and storage, advanced interval meters are an enabler of new service delivery structures. Western Power do not need to own BTM assets, and consolidating smart meters within the regulated monopoly business will stymie the adoption of new service models. Additionally, with the threat of grid defection real, Western Power should not be required to recover the cost of new smart meters either from the grid defector, or from those remaining on the grid.

Alternative models for rolling out smart meters, more akin to internet or mobile phone plans, would be preferable, where the customer is ultimately required to deploy a smart meter at their own expense[23]. As with mobile phone and internet plans, the increased utility of the service offering, coupled with other incentives should make this transition relatively palatable to customers.

Additionally, it is preferable (and ultimately likely) that metering services are contestable. This will be better implemented without meters being owned by a monopoly service provider.

Issue 4 (time of use and demand tariffs): Time of use and demand tariffs should be encouraged. Properly implemented, they will incentivise peak demand reduction and, ultimately, the adoption of BTM storage, leading to greater network efficiency. It should be recognised that such a tariff structure will ultimately reduce the value of the network due to the stranding of peak infrastructure assets.

As with the suggestion of smart meters being mandated and owned by customers, properly implementing demand tariffs requires coordination with policy makers and law makers.

Issue 4 (fixed and variable charges): As explained in this submission, it is likely that the prevailing fixed and variable pricing structure is not appropriate, given the new technological forces re-shaping the sector. A higher fixed portion, offset by lower variable portion may provide a more appropriate cost recovery structure, given the previous requirement to investment in peak demand infrastructure. But higher fixed tariffs must be implemented in a manner that provides incentives to customers to change their behaviour. That is, fixed tariffs should be attributed to a customer's contribution to peak demand. By increasing fixed tariffs without any accompanying price signal, Western Power is simply recovering costs when those costs are becoming inefficient due to technological changes to the electricity supply model.

Issue 4 (other tariff developments – transmission price path): Western Power favours Option 4 in returning transmission cost recovery back to its building block revenue cap. It is likely that when the Authority reviews the proposed WACC (and its parameters), the capital expenditure provisions and other adjustments, the transmission building block revenue cap will not be nearly as high as in the AA4 proposal. A transmission price path will therefore likely be more manageable – if required at all. However, in the event that some form of price path is required, Option 4 is not appropriate.

While it may seem a useful way to make up a (potential) shortfall, using deferred revenue from one distinct asset class to offset a shortfall in another is not recommended, particularly in the case of the distribution asset base. Customer demand, as well as the peak demand of this asset class, is in structural decline. And it is unavoidable that full cost recovery within this asset class will not be possible into the future. Deferred revenue owed to this class of assets should be used to lessen the impact of future asset write downs.

[23] This needs to be managed by policy makers and would likely require changes to regulations and legislation.

Issue 6 (price controls – variation in demand): As both peak demand and overall consumption falls (due to the introduction of disruptive competition), Western Power must not simply raise prices to fully recover their proposed revenue cap. The Authority should consider backward solving for a revenue cap, based on an appropriate tariff escalation regime which takes changes to the sector, and the risks associated with it, into consideration. If the Authority-derived revenue cap is less than that required for cost recovery, then some asset write down is necessary.

Care should be taken with such an approach. While regulation is designed to mimic competition, and fully written down assets are common in competitive environments, a regulated utility's credit rating and access to capital does require some consideration – lest write downs lead to greater losses in efficiency for consumers as debt premiums and other associated costs rise.

Issue 9 (rate of return): In every regulatory price setting process, too much time and resource is spent analysing the WACC and its parameters. It is pretty much assured that Western Power, no different to how others act, have set out arguments for a WACC that sits at the top of the range of realistic outcomes. This is a rational action (as will be an appeal or counter-argument on any WACC set below their reasonable expectation by the Authority).

The Authority, with access to substantial capabilities in this area, should be trusted to act in accordance with the objectives of the Access Code, in the interests of both customers and Western Power alike, to set appropriate WACC parameters.

A summary of the points made within this submission is that: the structures of both the electricity supply sector and the approach to regulation are changing irrevocably through the introduction of new and disruptive technologies; that regulated utilities are expected to manage operational and market risks, are paid a premium to do so, and are not immune to value destruction; and that should full cost recovery be seen as best meeting the code objectives, then a rate of return commensurate with the risk class of the investment should be applied.

Issue 12 (proposed tariffs): The transmission tariff price path is an obvious standout in the AA4 proposal. As identified above, once reviewed by the Authority, it is likely the building block revenue cap will be reduced and any price path required be set at more manageable levels.

With regard to the TEC being recovered from fixed tariff components: Given the decline in demand (and variable revenue risk), and given the TEC is an obligation imposed on Western Power by the government, then it is appropriate that Western Power is not exposed to TEC recovery risk.

It should be noted (for the umpteenth time), that recovering the TEC from SWIS customers as part of the Western Power tariff structure is a poor policy position. And that removing it is one of the most obvious and immediate policy reforms the government can make in this sector.

Issue 14 (force majeure events): This issue crystallises the concept of market risks. Western Power is, by definition, a captive Market Participant in the WEM. The WEM does not recognise force majeure

(FM)[24]. There are many other Market Participants in the WEM who operate within a competitive environment. While FM provisions will exist in commercial contracts, Market Participants are exposed within the market itself.

An example of Western Power's exposure to risk is the multiple failures of Western Power transformers at Muja in early 2014. Market Participants, forced to meet supply obligations, were unable to recover their full costs and incurred losses. Western Power, whether negligent in its operational risk management, or just unlucky[25], did not suffer penalties.

As far as exposure to the WEM is concerned, other Market Participants are not covered for the adverse impacts of any government 'Energy Market Reform' initiatives. And Participants, who contract with each other (as Western Power also does), will transfer wealth between one another as the contractual ramifications of FM become apparent – i.e. there are winners and losers. Enabling Western Power a future cost recovery for the negative impacts of FM risk (whether due to Energy market Reform or not), is internalising the upside, and socialising the downside. If this is an appropriate risk position for a regulated entity (and indeed, provision for future cost recover of FM risk is contained within the Access Code), then it should be reflected in the rate of return on its investments.

And given Western Power is owned by the government, it follows any reforms implemented would be made knowing the impact on its utility.

<u>Issue 21 (trigger events):</u> The trigger event clause in Western Power's AA4 states *"A trigger event may include without limitation…"*. Such a broad definition would not appear to require the specification of particular triggers.

However, it is preferable that rather than being included as an FM event (and any costs recovered in subsequent arrangements), 'Energy Market Reforms' are treated as a defined trigger event. In this way, the Authority has the ability to properly assess the impact of reforms to Western Power, and whether these impacts form part of the expected operational and market risks that are expected to be prudently managed by Western Power.

[24] FM provisions, whether in the Market Rules or otherwise, are required to meet the most basic levels of contractual commerciality.

[25] The WEM is filled with 'unlucky' Market Generators who have lost significant revenue in capacity refunds (amongst other things), who would have appreciated the application of FM in the Market Rules.