Community Electricity

Alas, we perceive the emperor to be naked☹

Response to ERA Public Consultation

Effectiveness of the Wholesale Electricity Market 2017-18

Part 2: The Investment Environment

Standing

Community Electricity is:

- a a licensed Electricity Retailer** and provider of Electricity Retail Services & Market Consultancy;
- b a member of the Market Advisory Committee for the previous 12 years; currently representing Market Customers, originally representing Market Generators;
- c formerly a member of the Access Code Development Committee (2004)
- d formerly a member of the Economic Regulation Authority's Technical Rules Committees from time to time;
- e formerly the Chair of the Balancing & Ancillary Services Expert Team of the Market Rules Development Group (2004);

**** We announce that we are closing our retail licence and ceasing our pro bono publico contribution to the public consultations of the regulatory development of the electricity market.****

Please see Part 1 for the reasons.

If you want to be informed of our free stuff from time to time, please email us.

Introduction

The ERA has posed 15 questions for public comment. Our response is structured as two inter-linked parts addressing business-as-usual matters and the investment environment:

- Part 1: Business-as-Usual Matters, which we address primarily through responses to questions 1 to 9 plus 15; and
- Part 2: The Investment Environment, which we address through questions 10 to 14

In particular, through Part 2, we wish to call attention to dysfunction in the reform initiative, which we consider will not only deliver too little too late but will be superseded before its target commencement date by System Management (AEMO) drawing on its emergency powers to maintain system reliability & security. We consider that the reform process is excessively complex, expensive and slow, and its un-stated priority is to conceal its true objective of justifying a wealth transfer to Synergy from the private sector. We suggest that the primary strategy of constrained network access, while a sensible concept of itself, has been distorted to this objective and is plainly not supported by private industry or justified by the supposed business case. We suggest that the critical failing of the reform initiative is that it ignores the immediacy of the impending ancillary services crisis, which it proposes to solve through industrial-scale reforms to be implemented years after they are needed.

Part 2 is offered in stand-alone form to facilitate contributing to the PUO's electricity market reform consultation process without the distraction of peripheral business-as-usual matters.

ERA Issue

The future investment environment in the WEM may not be conducive to continued third-party investment. This may leave the State Government responsible for funding or underwriting future generation investments.

ERA Questions

10. To what extent do policy uncertainty and behind-the-meter changes in generation and storage influence decisions to develop projects in the WEM?

11. Do market participants consider the investment environment in the WEM is challenging? If so, why?

12. Do market participants consider the investment environment in the WEM will improve or worsen over the short to medium term? If so, what factors will drive this change?

13. What is the likelihood that the State Government will need to invest to replace generation assets?

14. What could organisations such as the ERA, AEMO, Western Power and the State Government reasonably do to improve the investment environment?

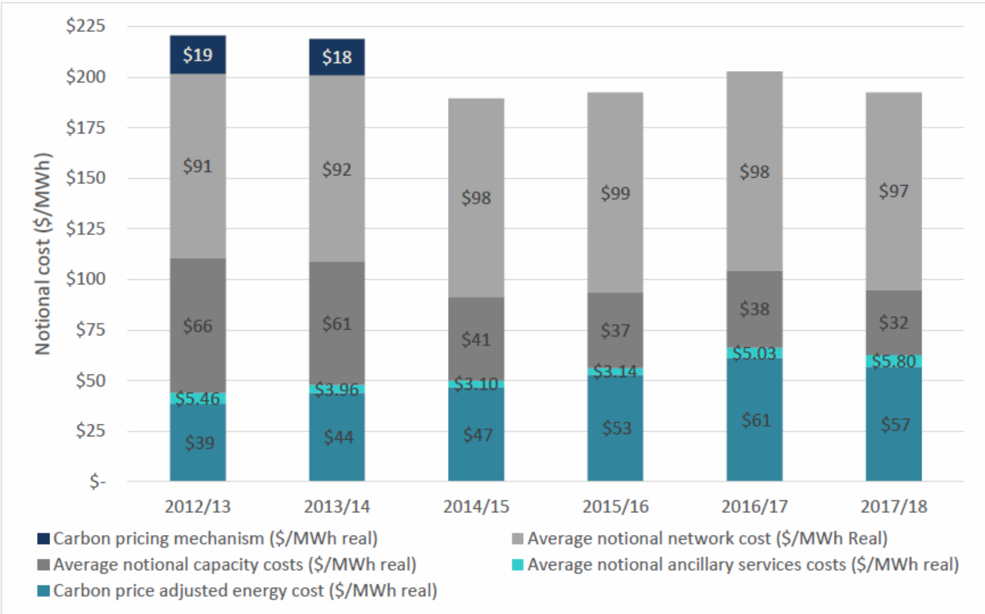
Benchmarks and Success Indicators

We propose the following simple benchmarks for gauging the appropriateness of the electricity market reforms.

The cost structure of electricity supply

We reference Figure 3 of the ERA's Discussion Paper, detailing the cost structure of electricity supply:

Figure 3: Notional costs of wholesale electricity supply per unit of energy consumed (real $2017/18)



Source: ERA analysis of AEMO and Clean Energy Regulator data.

NOTES: i) this excludes the costs of the commonwealth Clean Energy Regulations.
ii) the ancillary services cost includes the costs of administering the market, currently around $1/MWh

For illustration, we reference the 2017-18 data ($/MWh):

	$97	network	51%
	$32	capacity	17%
	$57	energy	30%
	$5.7	ancillary serves (including market fees)	3%
TOTAL:	$191.7		

Network charges dominate the cost structure at 51%, followed by energy at 30% and capacity at 17%.

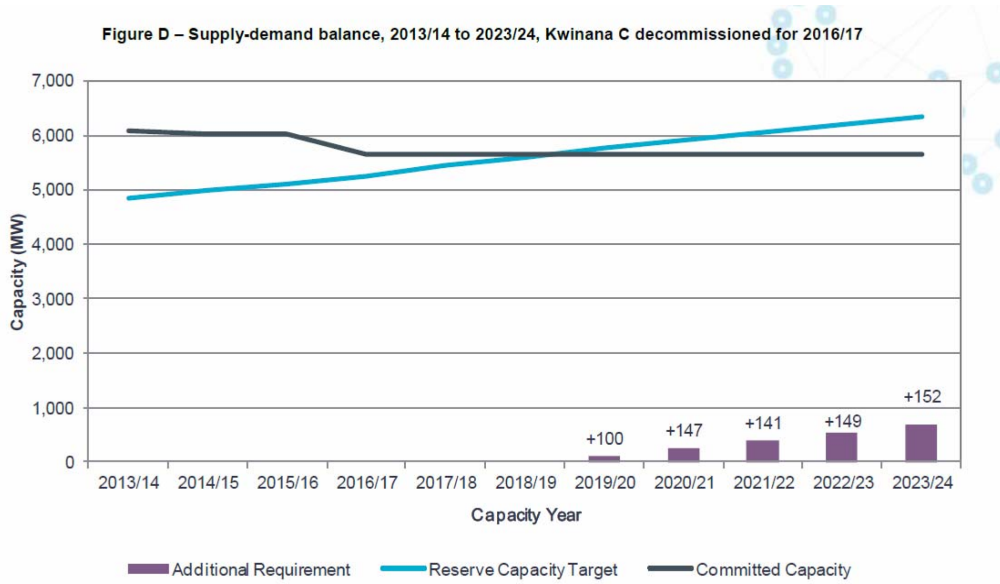
Put another way, "electricity production" (energy plus capacity) constitutes 47% and "transportation" 51%.

Though not shown at this conceptual level, transport charges also contribute to electricity production charges through energy losses and the network connection & access costs of generators (via the Benchmark Reserve Capacity Price).

We observe: **the Electricity Market Reform programme focuses on the cost of producing electricity and apart from a second order contribution via the capacity price does not address the cost of transporting the electricity, which constitutes more than half the cost of supply.**

Scale of the issue - expected investment in new scheduled generation

We reproduce below the forecast supply balance in the SOO prevailing at the time of commencement of the reforms(IMO, 2013).



In 2013, some 150MW of new generation was expected to be required over the coming decade, but there were also several unknowns such as the reliability of DSM capacity (around 550MW, which the reform subsequently all but abolished) and possible retirements of ageing plants, potentially another 200 to 400MW or so.

Having regard to the fact that the future is unknowable and the lead times for establishing new generation are several years, in the region of 1,000MW of new certified (reliable) capacity had to be planned for.

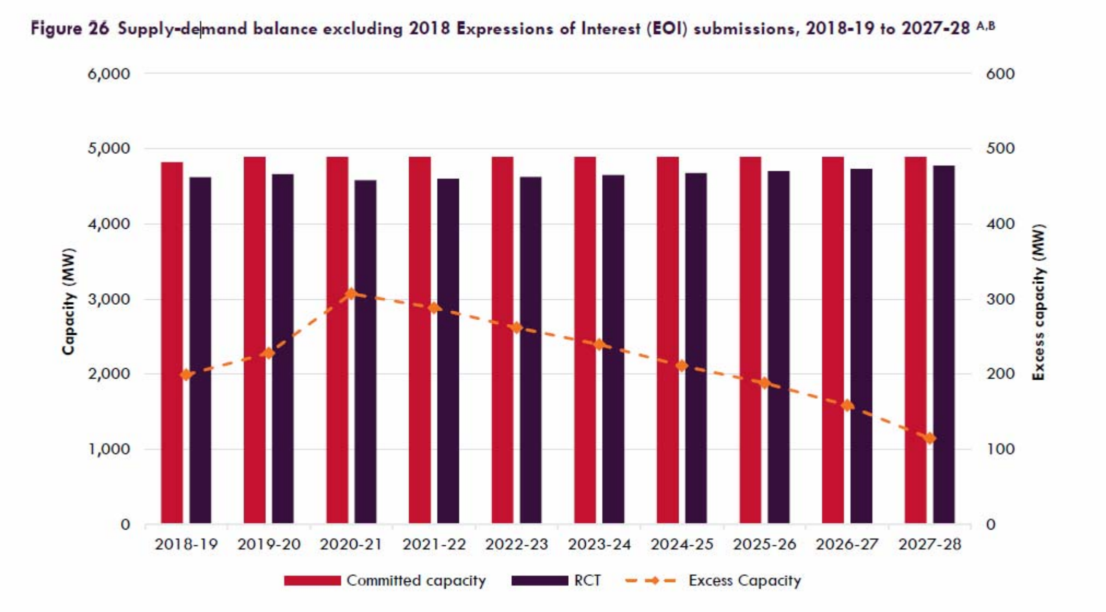
Costing this at the Benchmark Reserve Capacity Price, **this represents new investment of, say, 1.5 to 2 billion over 10 years, give or take a billion.**

As matters have turned out:

i. no new scheduled generation has been committed;

ii. some 500MW of intermittent generation has been committed, but its contribution to system reliability is still being debated and is, perhaps, in the region of 250MW;

AEMO's most recent (2018) forecast supply imbalance for the next 10 years is similar to the 2013 forecast cited above, albeit for different reasons.



The constrained network access reform contemplates around 600MW of new scheduled generation (OCGT) at a cost of some $1 billion.

Status of the Electricity market Reforms

The state government commenced the Electricity Market Reform programme on 6-MAR-14, nearly 5 years ago.

The original programme sought to:

- remove the need to subsidise Synergy's loss-making supply of its monopoly market segment;
- remove from government the financial burden of underwriting new generation;
- attract to the SWIS market participants with investment grade balance sheets capable of underwriting scale operations and new generation investments;

We emphasise: **the reform recognised that best-cost production of electricity relies on debt-leveraged projects underwritten by investment grade balance sheets. The high-level objective was to entice investment grade balance sheets into the market as an alternative to the state using its balance sheet. By extension, the programme also assumed that bulk capital was required for transmission-connected power stations.**

The reform team recommended that, amongst other things:

- Synergy be disaggregated into several smaller competing entities;

- the market be opened to Full Retail Contestability (FRC);
- market operations be transferred to AEMO for uniformity with the national market (benefiting from scale, uniformity and existing relationships);
- the SWIS network regime be converted from its current "unconstrained" access to the "constrained" access ethos of the national market;
- the SWIS network be regulated by the national regulator instead of the local regulator (ERA);
- energy dispatch be security-constrained using systems derived from AEMO's national systems which are already integrated with the constrained network ethos;

The principal recommendation of disaggregating Synergy was not accepted by the government, but it otherwise pursued the remainder of the recommendations. This created the challenge of mitigating Synergy's market power if entry of new institutional capital was to be relied upon to reduce prices. Failing such entry, the reliance shifted to the Reserve Capacity Mechanism to underwrite new generation, presupposing that the "missing money" could be obtained from an energy market that was likely to be dominated by zero-SRMC renewable generation.

The government proceeded with the remainder of the recommendations and most importantly decided to retain the SWIS Reserve Capacity Market. [In a separate consultation processes, we support the PUO's recent draft recommendations for reform of capacity pricing.]

On change of government at the beginning of 2017, the reform programme had up to that time:

- abolished the IMO and replaced it operationally by the national market operator, AEMO;
- terminated the IMO's development planning role;
- transferred Rule Change Administration from the IMO to the Rule Change Panel;
- implemented the "Lantau Curve" as the basis of the reformed Capacity Market pricing;
- substantially reduced the capacity contribution of Demand Side Management;

The reform funding expired on change of government, momentum was lost and the original team and its leadership largely dispersed.

The new government restored Synergy to profitability by increasing electricity tariffs to its monopoly market segment. It also cancelled FRC and cancelled adoption of the national regulatory structures, especially network, in favour of adapting local instruments.

The cancellation of FRC compromised the attractiveness of the SWIS to investment grade balance sheets. The existing deregulated market is so competitive that profitable entry at scale isn't practicable.

The commonwealth government also expanded the Clean Energy subsidy and caused a surge in utility-scale wind and solar projects. With the state facing the prospect of missing that window of opportunity due to a policy vacuum, Western Power stepped into the leadership void and developed its Generator Interim Access programme - one of the most critical value-adding innovations since deregulation began some 25 years ago, albeit despite the reform programme rather than because of it.

The neo-reform programme now comprises:

- "Network Access" Programme
- WEM Reform Programme
  - Security Constrained Market & Dispatch System (SCEDS)
  - Power System Security and Reliability (PSSR)
  - Market Power Mitigation
  - Reserve Capacity Pricing further-Review

We again emphasise: the reforms are focused on the cost of producing electricity and exclude the cost of its transportation. While there is a substantial "network access" programme, it is only titular; its focus is on electricity production costs via connection of new generators and the impact of the network on the capacity price and the merit order of energy prices.

Network Prices

The cost of transporting the electricity is regulated by the ERA under periodic resets of "Access Arrangements" under the Electricity Networks Access Code.

The ERA is currently overseeing the fourth access arrangement (AA4) which was instigated as a last minute urgency when the original transfer of network regulation to the national regulator was cancelled on expiry of the previous government's term of office.

AA4 was originally scheduled to commence on 1-JUL-17 for a 5 year period but commencement has been postponed to 1-JUL-19 with the same end-date (3 years).

The 2016-17 network prices have been retained during the delay and the ERA has intervened strongly to limit future network charges to approximately CPI escalation of the current prices. We support the ERA's achievement as being another of the largest value-adds to the market since the reform programme began - again, notwithstanding that it isn't part of the reforms.

We also call attention to an important outcome of the AA4 process: **transmission network prices are expected to increase** from \$19.3/MWh to \$28.1/MWh (46%) over the next 3 years **while distribution network prices are expected to decrease** from \$83.5/MWh to \$78.2/MWh (-6%). The ERA's summary tables are reproduced below:

We suggest that this is the network death spiral.

The ERA forecasts that average prices paid by customers will increase by around 3.4% over the three years, where the distribution and transmission network charges are blended.

Western Power proposed to subsidise the transmission charges through increasing distribution charges, in effect subsidising utility scale fossil-fired generation through higher charges on behind-the-meter generation, but the ERA overruled it.

Table 8 Forecast change in average charges for the transmission network based on Western Power's amended proposed target revenue ($ real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22
Unsmoothed revenue ($ million)	325.0	350.2	359.2	367.4	381.1
Smoothed revenue ($ million)	281.9	282.1	340.0	407.7	486.9
Energy transported (GWh)	17,698	17,663	17,628	17,502	17,309
Average charge ($/MWh)			19.3	23.3	28.1
% change			**20.8%**	**20.8%**	**20.8%**

Table 9 Forecast change in average charges for the distribution network based on Western Power's amended proposed target revenue ($ real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22
Unsmoothed revenue ($ million)	1,352.7	1,088.8	1,053.9	1,033.3	1,063.0
Smoothed revenue ($ million)	1,192.5	1,178.7	1,127.8	1,072.7	1,022.8
Energy transported (GWh)	13,691	13,656	13,505	13,276	13,083
Average charge ($/MWh)			83.5	80.8	78.2
% change			**-3.2%**	**-3.2%**	**-3.2%**

We emphasise: while the electricity market reform focuses on optimising half the cost structure, the ERA is left with its finger in the hole in the dyke of the other half..... and the costs of transmitting electricity from power stations and distribution are diverging to the upside as system demand reduces and more energy is produced and consumed in the distribution network.

Private (behind-the-meter) capital

As detailed above, the market reforms originally sought to attract to the SWIS investment grade balance sheets to underwrite new transmission-connected generation. The unconscious assumption was that future electricity supply would continue to be dominated by capital-intensive bulk power stations connected to the transmission system and owned and operated by institutions.

The practical experience has been that no new scheduled generation has been committed for some 10 years and transmission charges are diverging rapidly to the upside while distribution charges decrease.

The only new power stations to be committed during the last decade are some 200MW of utility-scale solar PV capacity and 310MW of wind-farm capacity, all coming or due on line in or after 2019. [Congratulations to western Power's GIA]. All of these stations are partly underwritten by subsidies (or in some cases avoided costs of funding the subsidy) provided under the commonwealth Clean Energy Regulations.

In parallel with this relative lack of investment on the transmission system, **since the reform programme commenced, some 1,000MW of 'rooftop' (behind the meter) solar PV has been installed on the distribution system and is growing at 150+MW per year.**

System management speak of rooftop PV as the largest generator on the system and lament that it is largely invisible to them (acting as a negative load) and is uncontrollable. Western Power laments that rooftop PV is reversing power flows on the distribution network.

The changing paradigm due to demand management, rooftop PV and energy efficiency has become a cliché; we suggest the real meaning is that **private balance sheets have displaced institutional balance sheets.** These in turn are largely underpinned by personal mortgages secured on real estate.

Rooftop PV is underwritten by private capital subsidised by the commonwealth Clean Energy Regulations and earns a return from the state REBS subsidy and avoided electricity charges. At today's prices, SWIS-installed rooftop PV comprises some $1.5 billion of investment, continuing at $225 million per year plus REBS of around $50 million per year. It is totally unmanaged, with no attempt made to optimise it or limit the system issues it causes.

We emphasise: the avoided network charge is the principal component of the 'avoided cost' incentive and is the natural means to manage the uptake of behind the meter investments: the ERA forecasts it to be an average of $106.3/MWh in 2021-22.

We emphasise: while the reform programme fumbled and failed to attract a couple of billion dollars of institutional investment, private residences and businesses replaced it with System Management noticing.... and they flagged the operating problems before the surge happened.

Price signals for private capital

We consider that the reform process has overlooked the most critical opportunity to manage the price signals that govern commitment of private capital behind the meter: the network tariff price restructure afforded by Access Arrangement 4 (AA4).

Again, network charges constitute half the cost of supply and amongst other things AA4 was an opportunity to optimise the time structure of the network tariffs.

Western Power did proposed new tariffs and adjustments to existing tariffs but through the consultation process was challenged on their suitability. In addition to our grave misgivings, two former network tariff specialists (Noel Schubert and Craig Hoskin) also offered their contrarian advice (available on the ERA website).

Western Power advised that it would press on regardless**#1** and the ERA decided that it had no mandate to interfere with the specific design of network tariffs. However, the ERA requested from Western Power the analytical details that underpinned their tariff designs. Western Power advised that it didn't have any; it had guessed them (our emphasis added):

" .... the new tariffs .... are designed to better reflect Western Power's system peak than the existing time of use tariffs ..... Short peak and shoulder times and longer off-peak provide customers with more options to adjust their energy consumption in a cost-reflective manner.

Currently, there are no customers on these new tariffs which represents complexity in estimating uptake levels and cost allocation. It is expected that the new customers will migrate to [new tariffs] over time. Therefore, the initial shoulder rates of the tariffs are set on the same levels as RT1 for RT17 and RT2 for RT18. The peak component of the tariff is initially set with 10% increase in price, while off-peak provides 10% discount, that way ensuring the tariffs broadly reflect the costs of a typical customer on comparable tariffs.

This pricing approach will be reviewed in the next access arrangement period [note: in 3 years time], **when sufficient customers are on these tariffs to analyse their costs more appropriately. For now, it is assumed that given they are effectively the same customers as were previously on RT1 and 2, they will have the same costs to supply as these customers."**

The ERA responded by requiring Western Power to bear the consequences of its decision and revoked the mechanism by which Western Power annually quantifies its forecast inaccuracies and passes them through to the market in the following year. [Another superb intervention by the ERA.] Western Power sought to revoke its newly innovated tariffs and the ERA disallowed it, requiring that they be retained as options available to retailers.

AA4 prices will apply from 1-JUL-19 for 3 years. During that time, the public will invest perhaps another $0.5 billion under dysfunctional price signals, plus whatever happens in the battery space.

#1 Please see our references too Western Power performance as a "Reasonable and Prudent Person" in Part 1 of our response.

Constrained network access

Framing the issue

Constrained network access is the centrepiece of the electricity market reforms, both directly and indirectly via its impact on the dispatch of energy. We reiterate: both are concerned with the cost of electricity and not its transportation. The motivation for constrained network access pertains primarily to the connection and operation of utility scale power stations which are for the most part connected to the transmission network.

As originally envisaged by the reform programme, energy was to be dispatched under an adaptation of AEMO's national systems and constrained network access was to be regulated under the national regulator. Under that approach, the SWIS market had to adapt to the national market. However, that has now been cancelled and replaced by development of local instruments.

We confirm our support for fit-for-purpose constrained network access and the corresponding fit-for-purpose security-constrained dispatch of energy. However, we consider we should start with what we have and modify it sufficiently and minimally in order to achieve the objective. We emphasise:

- sufficiently, to work effectively and efficiently;
- minimally, to avoid unnecessary expense, delay, disruption, sovereign risk and administrative complication;

In respect of constrained network access, the PUO and its consultants have conducted modelling studies centred on three scenarios:

- Fully unconstrained
- Fully constrained
- Partially constrained

In terms of the PUO's semantics, we do NOT support any of these scenarios. We say again: start with what we have and modify it sufficiently and minimally in order to achieve the objective.

In particular, we emphasise that the modelling study is fatally deficient because it excludes utility scale storage.

Storage

We consider that the exclusion of storage solutions from the constrained network modelling over its 60 year timeframe is a fatal and self-evident flaw.

In particular, the national market recently achieved a world's best-practice innovation: the Hornsdale Power Reserve (100MW-129MWh battery) has dramatically improved system security and mitigated the risks of the inexorable penetration of intermittent generators.

The first utility battery in the SWIS was at Alkimos, being 1.1MWh a few years ago.

Western Power is planning to develop some 60 diesel, solar, storage microgrids. The first of these is at Kalbarri, which will have a 4.5MWh battery capable of delivering 5MW. They have also identified more than 15,000 sites where customers could benefit from stand-alone power systems over the next decade, greatly improving power reliability and avoiding the need to upgrade the existing poles and wires. They are trialling deployment of up to 60 stand-alone power systems in varying geographical locations.

We observe that one of the recommendations of the national Finkel report was that future intermittent generators should be required to incorporate energy storage as a precondition of connecting. While that has never been floated for the SWIS, we consider the point to be that combined battery-wind and battery-stations are potentially commercially viable and should be planned for.

On this theme, and a portent of things to come for the SWIS, Alinta recently installed a 30MW-11.4MWh battery at its (off-SWIS) 180MW gas fired Newman Power Station to permit running the station flat (at higher fuel economy) instead of peaking. The project cost $1.5 million per MW, which is similar to the cost of an OCGT. Alinta is also planning a second unit at their (off-SWIS) Port Hedland station.

We consider that batteries also have a key role to play in alleviating network constraints.

The constrained network access public consultation

The PUO released a consultation paper on 9-AUG-18 with a closing date of 10-SEP-18. Community Electricity responded with the response repeated here in the Appendix.

Amongst other things we observed that the claimed benefits of the change to constrained access were trifling and lost in the inaccuracy of the assumptions. We remarked:

- We suggest that the reliance of the PUO "business case" for constrained access on an improvement of at most 0.4% is either preposterous or disingenuous to an extent that merits investigation by the Auditor General;

- We speculate that the principal issue is that Synergy has legacy capacity rights that aren't being used (hoarded) and are crowding out prospective users. We note that the issue is shrouded in confidentiality and we speculate that Western Power is being permitted to reframe a problem caused by Synergy in order to obfuscate its own problem of accounting for funds that it is seeking to avoid spending. To this end, the PUO has been captured and is being shepherded to a 'solution' that involves having the market fund compensation in return for an unnecessary imposition of constrained access.

We also called attention to the following statements in the report (our emphasis added):

> "**Legacy contractual arrangements** mean a number of electricity generators are entitled to 'unconstrained network access', which means Western Power is required to ensure its network has sufficient capacity to transmit up to the maximum output of these generators under normal operating conditions."
>
> ".... **in many cases there is actually sufficient physical capacity in the network, but the unconstrained access rights of incumbent generators mean that 'spare' network capacity is contracted out, effectively locking it up** and reducing the amount of capacity available for other generators to connect."

We challenge: how does Synergy's access rights compare to its scheduled generation cap? Why would they need more access than they are permitted to use? We speculate that Synergy possesses those access rights because it has a legacy form of access contract that is unavailable to new entrants.

In our original response (in the Appendix) we noted that the claimed total market payment reduction of $288 million over 50 years ($6 million per year) equated to around 0.4% of total wholesale costs per year but was subject to considerable and unquantified inaccuracies.

On 1-OCT-18 the PUO published the technical paper underpinning its analysis and re-opened the public consultation until 12-OCT-18. Most responders adapted their responses to include the new information but Community Electricity did not have the resources- so we now respond here.

The PUO announced in its 1-OCT-19 paper that it had adjusted the benefits to $800 million over 60 years ($13 million per year) because the analysis had failed to account for a technical limitation known to exist but not previously accounted for (Kwinana Fault Level).

We emphasise: the original forecast contained a $512 million (180%) error due to an unrealistic assumption.... without knowing the specifics, confirming our concerns.

The PUO subsequently, without announcement, secreted the consultation responses onto its website over the Christmas holiday, some 3 months later. Having now reviewed submissions to the consultation, we additionally cite the following responses from 3rd party market participants:

<u>Bluewaters & NewGen-Kwinana</u>

- "Having reviewed the consultation paper and results from the modelling, Bluewaters [and NewGen-Kwinana] cannot support the move to a constrained network under the current circumstances. Following Stakeholder requests to articulate the issue and outline the benefits, the business case presented by the PUO does not justify the proposed approach. The subsequent modelling exercise has demonstrated that there is no imminent problem with network congestion and that the potential savings to the market over a 60 year period do not demonstrate a compelling case for incurring the cost that the market and participants will bear as a result."

- "There are virtually no network constraints until 2028 in either the partial of fully constrained case, with no capital investment required in the network in that time. This suggests there is little case to progress the reforms in the aggressive timeframes proposed."

- "There are no unserved energy outcomes and no capacity credit shortfalls in any modelled scenario."

- "A 10 year NPV benefit of $200m is negligible (notionally $20m/annum) when compared to the high degree of risk over such a change, and to the high cost of operating the WEM in general."

- "The case for change, as articulated in section 2 of the consultation paper, has not been supported by the outcomes of the modelling. Considering the uncertainty in future technological advancements and the apparent lack of constraint issues in the short term, a constrained network model is not immediately required in its own right."

- "Based on the inadequate benefits of moving to a constrained model, Bluewaters' view is that the broader reform would be better served by deferring the constrained network work stream and replacing this with reforms that are more beneficial to the WEM in incentivising the optimum future generation mix. The electricity industry is experiencing a major disruption from renewable technologies, yet the size and structure of the WEM remains largely unchanged since market start, and is unlikely to change in the foreseeable future. In perfect hindsight, it is unlikely such a complex and costly market would have been implemented under this scenario. It may be prudent to pause before implementing even more complex and costlier market reforms."

- "To achieve the lowest efficient cost to end consumers the existing assets must be utilised to the maximum extent possible. Without addressing the correct investment environment with appropriate cost allocations and price signals, the reform is likely to incentivise investment in a generation mix that is inappropriate and a demand pattern that is inefficient, which will lead to higher costs to the end user.

<u>Perth Energy</u>

- ".....we are concerned that one of the key objectives for moving to constrained access was that it would increase network capacity available and allow more generators to connect. The results of the modelling show that this will not occur....."

- "We question whether the overall cost of the reform package, of which this forms a part, can be justified on the benefits established to-date. The PUO has not modelled the cost of the reforms, including the costs associated with the systems and processes required to facilitate a constrained network access regime. As such, it is not clear that the move to a fully constrained access regime is the more efficient way forward.

- "We are also not comfortable that the EY modelling is sufficiently robust to be used to determine an amount of financial compensation for the removal of existing generators' network access rights. We consider the EY modelling is unreliable and has insufficient granularity to be able to determine the compensation costs with a reasonable degree of accuracy."

ERM Power

- "The modelling results appear to be incomplete, inconsistent between scenarios and do not demonstrate a clear consumer benefit for adopting constrained access..."

- ".....the modelling as it currently stands demonstrates that network congestion is not forecast to commence until 2028 in the constrained scenario and 2031 in the partially constrained scenario. Given the long lead time until network constraints start binding, the business case to adopt a fully constrained or unconstrained access environment should be properly developed and considered over a longer time frame, instead of being rushed through due to the desire to get legislation into place to meet a deadline that from a market efficiency perspective has little meaning........
We contend that AEMO can build new systems, based on the NEM dispatch engine that should be able to dispatch facilities in a partially constrained world, including the co-optimised dispatch of ancillary services, without having to resort to changing the current access arrangements."

- "Given the relatively small positive net benefit of adopting a fully constrained network environment, it seems inconceivable that network augmentation costs to meet supply reliability and secure operation of the power system, in particular the need to ensure system strength services where intermittent VRE generation displaces dispatchable synchronous generation, would not impact the business case for adopting a fully constrained network."

The cost side of the business case

A business case properly assesses benefits relative to costs, but thse seem to have been omitted from the analysis.

We note that AEMO is preparing its application for Allowable Revenue 5 and is seeking funding of circa $50 million to implement the reform programme.

We further observe that the following costs appear to have been omitted from the assessment:

- The PUO's direct costs of the reforms. While these aren't published (another potential benefit of transparency), we expect that they at least double the figure that the ERA is contemplating here;

- Participant's direct costs of the reform programme;

- The consequences of cancelling ready-to-go remedies. At the instigation of the market review, the IMO's evolution programme was suspended along with a dozen or so rule change proposals in development. Those rule changes were materially very similar to the direction to date of the reform process. With the pace of reform being so slow, some of the suspended changes are now being implemented some 5 years after being suspended and still 3 or 4 years before any prospective remedy is likely to be realised from the reform programme.

- The continuing conflict of interest between low energy prices and the financial returns of the state-owned utilities, which is a primary influence on the electricity market, is now unrestrained;

- The reform process has now created a situation where the Rule Change Panel has limited resources to progress rule change proposals and no authority to initiate them, AEMO has limited budget to contribute, and the ERA has been inactive in that venue. The PUO has initiated some very necessary rule changes in recent months but this is the exception as it prefers to address matters via the broader former measures, with the attendant delay to 2022 and possibly beyond.

- The political and social consequences of not preventing the impending compromise of reliability and security of the power system

Residual modelling errors

Having ourselves now reviewed the modelling paper, we suggest further unrealistic assumptions and sources of error exist in the analysis as follows:

i. Batteries are excluded from the study - over 60 years - despite having been successfully deployed in the national market and by Alinta in non-SWIS locations;

   We quote from the Modelling Report:

   "Large-scale storage was originally considered for potential inclusion in the modelling. However, in consultation with EY, it was decided by the PUO not to include the technology in the modelling due to the increased complexity that would result from its inclusion, and it being determined not to be a material factor in the outcomes with respect to forecasting the impact of Fully Constrained Access compared to the other cases."

ii. Future emissions and carbon policies are excluded.

iii. No account is taken of Rule Change 2018-06 - Full Runway Allocation of Spinning Reserve Costs. This is very likely to free up at least 40MW of baseload generation (20%-equivalent of the average system load throughout the year) that is currently uneconomic because of Spinning reserve charges;

iv. The modelling contains an anomaly with respect to the impact of the Kwinana fault level limitation. We quote from the modelling report (our emphasis added):

"Two locations are considered at Kwinana, with the 132 kV location having a 100 MW limit and the 330 kV location having a 350 MW limit..... **In the High Scenario case, the PUO instructed EY to assume that Western Power builds the necessary equipment to allow sufficient capacity to connect at Kwinana**."

We challenge: what is the cost of this augmentation, has it been included in the modelling, would it pass the Code's New Facilities Investment Test, and why is it confined to the High Scenario case? And we reiterate our question - how much unused capacity rights does Synergy have locked up in that part of the network?

v. No account is taken of the network death spiral in the transmission system as revealed by AA4;

vi. No account is taken of the PUO's ongoing study of the future generation mix;

vii. The modelling assumes knowledge of Synergy's prospective stand-alone facility bidding into the energy market. Synergy currently offers its energy as a portfolio and is not required to reflect the constitution of its portfolio offer in its real-time operations. The ERA reports that Synergy sets the Balancing Price in 80% of trading intervals and it is investigating 6,000 anomalies in its pricing behaviour that occurred over a period of 15 months (27% of offers over that time). The investigation is likely to approach its 2nd anniversary before reporting. It is unclear to what extent Synergy offers have been non-complying over the last 3 years and how they might change, or whether they suspended the investigated behaviour and may revert to it when given the all-clear.

We also cite the following matters raised by 3rd party market participants in their responses to the consultation:

<u>Synergy</u>

viii. "... as demonstrated by the recent significant revisions made to the modelled benefits of constrained access, modern power systems are notoriously complex, making any attempt to model benefits and costs over a 60 year horizon is fraught with a high risk of forecast error."

"...modelling cannot account for the impacts of other planned market reforms - including the proposed development of ancillary services markets, and the implementation of the new reserve capacity allocation mechanism - both of which will significantly alter future revenue streams and affect new generation entering the market."

Alinta Energy

ix. "...it is vital that the inputs and assumptions reflect the most recent and up to date information available..... Specifically, Alinta is concerned that the modelling, among other things:
• does not include Yandin Wind Farm. [*Alinta-footnote*: Alinta recommended that the PUO include Yandin Wind Farm in its response to the Modelling inputs and assumptions paper stakeholder consultation in April 2018 and further recommended this in its meeting with the PUO where the Alinta specific outcomes were discussed.];
• significantly underestimates the Reserve Capacity Price that existing generators will receive by not reflecting the PUO's proposed recommendations on potential reforms to the reserve capacity pricing arrangements;
• appears to include anomalous outcomes for intermittent facilities; and
• significantly underestimates new block loads, which haven't been accounted for in AEMO's ESOO"

"The effect of the above is a gross underestimation of the net revenue reduction to generators as a result of the implementation of constrained access. Alinta considers that it is vital that the PUO addresses these concerns to ensure that the modelling best reflects the impacts on existing investors which is required to ensure current investors will be compensated appropriately for any losses incurred because of this regulatory change."

Australian Energy Council [21-SEP-19]

x. "...In particular it is important that the modelling assumes all known committed development projects and closures. Some projects committed within the current temporary access arrangements are likely to add considerably to the amount of congestion post constrained access reform, so these need to be incorporated."

"Some concerns have arisen around the modelling details, particularly the currency of its input assumptions which may justify a degree of recalculation or post-modelling adjustment."

Perth Energy

xi. "This degree of variation gives rise to significant concerns about the robustness and reliability of the model.....While Perth Energy supports the transition to a constrained network access regime, we are concerned that the PUO is relying on modelling that:

- Should only be relied upon for general, rather than specific facility-based, modelling of the WEM;
- Includes incorrect and often unreasonable assumptions for specific facilities;
- Is not transparent in its design;
- Includes assumptions that are inconsistent with other areas of the PUO's industry reforms; and

- Includes scenarios that are misleading, including for example, the "unconstrained access scenario"."

xii. "Quantity of Capacity: The various scenarios of plant entry and existing patterns do not reflect what we would consider reasonable. The PUO should have developed more realistic high and low case scenarios based on real-world assumptions to provide market participants a more useful range of outcomes (e.g. a low carbon emissions scenario)."

xiii. "Location of New Capacity: EY models the installation of 335MW of wind generation in the Eastern Goldfields. This region has very limited dispatchable generation and is connected to the rest of the SWIS by a single circuit transmission line. It is questionable that this level of additional intermittent capacity could be added without major investment in the transmission system but these costs appear to have been ignored."

xiv. "Energy Price Decreases: One outcome that seems counter-intuitive is that none of the low operating cost coal fired plant is being closed in the various scenarios. This coupled with significant investment in wind, and continued investment in behind-the-meter solar PV should show prices decreasing. However, the modelling shows balancing market prices increasing. This should be explained or corrected."

xv. "Input Costs: The cost assumptions for OCGTs are not realistic. Investors and financiers will finance plants over a period not longer than 15 years. The annual fixed variable costs for a gas turbine are reduced to $4,000 per kW per year compared to the Benchmark Reserve Capacity Price determination of around $30,000. We cannot see any cost savings that could reduce our variable costs to anywhere near $4,000. This leads to the modelling showing that 250MW of OCGT will enter service in 2022-23 which is inconsistent with actual outcomes. No new OCGT has been installed since 2012 despite the capacity price being well above the modelled assumption."

xvi. "Transmission Use of System Charges: We question whether the current transmission use of system charge is expected to remain in place. The charges do not appear to have been removed for the purposes of the EY modelling, however, a reference service is no longer being provided. Perth Energy recommends that the TUOS charge is removed from the costs modelled."

xvii. "We are concerned that the EY modelling does not consider the proposed changes to the RCM as the two are intrinsically linked – the need for increased network access is driven by plant entries and exits. The PUO need to determine the impact of the proposed RCM changes on the network access modelling outcomes. Similarly, the RCM workstream recommends that demand side management will be paid the same capacity price as generation. The EY modelling indicates a capacity price of around $90,000 per MW per year. This price would justify a substantial increase in investment in demand side resources in the SWIS, which would in-turn change both the capacity and energy prices. This is also not factored into the EY modelling."

xviii. "With the significant differences in input assumptions, we consider sensitivity testing is prudent. However, EY has not indicated what degree of error bounds should be applied to the results of their modelling. For example, energy price savings are only in the order of $2-3 per MWh on a base of around $55 so it is unclear whether this is really a significant difference. Sensitivities must be presented to assist market participants in making their own assessment."

xix. "Zonal or Regional Constraints: We maintain that other options to those modelled by the PUO remain viable and should have been assessed. Specifically, in our initial submission, we proposed that a zonal or regionally-based constraint model could be introduced to better optimise the benefits with the cost of implementation. The PUO has not assessed this option, despite it being a more measured approach, and arguably more suited to the size and design of the WA network and market."

Bluewaters & NewGen-Kwinana

xx. "Both the base case and high demand scenarios are higher than Western Power's own forecast demand scenarios in its most recent AA4 submission. No low scenario is modelled."

xxi. "It is unclear from the report as to whether the wholesale price component of 'market payments' is attributed to only the Net Settlement component of the market (under 10% of wholesale energy). All other wholesale energy is bilaterally contracted and is based on either existing and continuing historical prices, or the cost of underwriting a new-entrant facility."

xxii. "There is no rationale to compare the NPV of the fully constrained and partially constrained case over 60 years, given there is no network capex assumed in either case."

xxiii. "The base case of maintaining a partially constrained network assumes that no investment will be made in grid infrastructure. However this fails to consider that small investments may achieve a commercially acceptable constrained outcome for generators."

xxiv. "The 60 year NPV assumes the average of only the last 3 years of 'market payments', which is the largest differential in the modelling.

ERM Power

xxv. ".... the modelling fails to consider that the network augmentation costs could be less if the impact of battery and other storage technologies was different to the conservative assumptions contained in the modelling."

xxvi. "We believe the modelling needs to better consider the likely impact of new technologies and the use of emergency or dynamic network ratings as a benefit to reducing network augmentation costs.... the EY report appears to indicate that network constraints do not commence binding until 2028 and significant changes in actual generation commissioning and consumer demand can reasonably be expected in the intervening period."

xxvii. "ERM questions the choice of transmission assets as the key criteria for the modelling assessment and believes that the life expectancy of Variable Renewable Energy (VRE) generation is just as critical to any economic assessment....... Given that the life expectancy of a number of VRE generators and potential battery storage projects is less than 25 years, we believe the 60 year period is too long and the modelling assessment should not exceed a 20 year period."

xxviii. "Who is to say that all the renewable projects which are trying to connect or that those assumed in the modelling will in fact actually connect or connect in the location assumed and become viable projects in the SWIS. Without a viable offtake agreement, funding of the project may be difficult, and in a constrained network access model, dispatch of its energy would not be guaranteed.... To base a decision on the concept of changing the network access environment and disrupting the existing Market to encourage new intermittent VRE generation build may be a "red herring"."

xxix. "We have concerns that the results of the modelling most recently released by EY are overstating the benefits of the constrained access scenario over the partially and fully unconstrained access scenarios. Key reasons for this conclusion are the modelling does not factor in low demand scenarios. The EY report acknowledges uptake of rooftop solar PVs combined with battery storage would reduce the values of grid supplied maximum demand, yet this fact is not reflected in the modelling...... That is, EY has taken into account a 10% and 50% POE situation but to provide a balanced view of future possibilities it should have also taken into account a 90% POE case."

xxx. "We are concerned that system costs have not currently been included in the analysis."

Recommendations

We reiterate that we speak as the Chair of the former Balancing & Ancillary Services Expert Team of the Market Rules Development Group (2004).

We consider that the constrained network access aspects of the electricity market reforms are the central strategy for promoting new generation investment and that they are plainly ill-considered, dysfunctional and do not support development of an efficient and effective wholesale market.

Rather, we consider that the fix is in and the modelling has been corrupted to support a pre-determined conclusion based on unstated objectives. We suggest, but because of the opacity of the market have no proof, that the unstated objectives are a blend of allowing Synergy to hoard unused network rights and giving Western Power (treasury) legal immunity from having to make contracted investments for which it has already been paid.

We suggest that the simplest, quickest, remedy of the "constrained access" issue is to confiscate Synergy's hoarded network rights. Insofar as the proposed constrained network regime is a subterfuge for a wealth transfer from private participants to Synergy, we suggest that should be done expressly through a market levy rather than surreptitiously through a disingenuous administratively complex and expensive frolic.

In terms of genuine reform intended to frame the investment environment, we suggest the emphasis ought to be placed on management of private investment in the distribution system through carefully designed network tariffs and review of state subsidies, supplemented by enabling state investments.

We suggest that this aspect has been entirely overlooked despite installation of over 1,000MW of rooftop PV over the past 5 years at an indicative investment of $1.5 billion and continuing at $225 million per year.

This contrasts with the reform emphasis on facilitating 600MW of transmission-connected OCGT power stations at an indicative cost of $750 million over the next 10 years, notwithstanding that institutional capital has not committed one for the last decade and there is no evidence of any desire to build one in future.

We suggest that new investment in rooftop PV will exceed the presumed investment in OCGTs before the enabling reforms even take effect (OCT-2022), and then again - a second time - before a single OCGT could be commissioned. Plus there will be a further $50 million per year whammy from the REBs subsidy.

We recognise that emphasis is placed on OCGTs because of the ancillary services dislocation that is being caused by the penetration of intermittent generation and from the archaic perspective that OCGTs have traditionally provided that service.

However, we cite the success of the Hornsdale (Tesla) 'Big Battery in the national market and contrast that with the express assumption of the reform modelling that batteries are to be excluded for the 60 year period of the assessment. We also suggest that utility scale batteries are already at comparable cost to OCGTs as proven by Alinta.

While it is true that batteries are not contemplated in the wholesale market rules, we suggest that providing for their inclusion ought to be a centrepiece of the reforms. Not only will it fix the perceived problems, it will be procedurally fair, faster, far cheaper, and would reduce disruption rather than cause more.

We cite that the Rule Change Panel has already tabled an excellent scoping paper to include storage in the market rules. the ERA has also tabled a review of international practice. All policy makers have to do is empower these and take the credit. If we are right and the reforms will implement remedies to yesterday's problems after they are needed and based on yesterday's technology, the panic remedy of the future will in any case be to urgently install batteries.

We recognise that the dispatch systems need to be remedied and suggest proceed urgently with that, decoupled from the network contemplations. The alternative is to persist for longer than is necessary with a plainly dysfunctional dispatch system that unnecessarily elevates energy prices (please see Part 1 for more information). Under the original reform programme, the new dispatch system was supposed to be in place in mid-2018. Now the target is mid 2022.

Ancillary Services Crisis

The constrained access issue is especially poignant as it distracts attention from the immediacy of system instability caused by the penetration of intermittent generation. On the face of it, the targeted remedy is to introduce constrained access in conjunction with a security constrained dispatch engine OCT-2022. However, we suggest that the power system is likely to be in crisis during the current year and that System Management will be routinely using its emergency powers in the next few months.

We suggest that reform efforts should be focussed on solving this issue.

Alas, it's no longer personal

This is our final contribution to the public forums. We've been barred from better pubs than this. Please see appendix 1 of Part 1 for the philosophical basis.

If you want to be informed of our future thinking, please email us.

Contact

For further information or comment, please contact:

Dr Steve Gould
[redacted]

8 February 2019

APPENDIX

Response to PUO Public Consultation

Proposed approach to implement constrained network access

Standing

Community Electricity is:

- a a licensed Electricity Retailer and provider of Electricity Retail Services and Market Consultancy;
- b a member of the original Access Code Development Committee (2003 to 2004)
- c a member of the Rule Change Panel's Market Advisory Committee;
- d a member of the Economic Regulation Authority's previous Technical Rules Committees from time to time;

Further information is available at: www.communityelectricity.net.au

Context

1. The instant PUO consultation paper is part of a series of consultations intended to progress reform of the SWIS electricity market to the broad objective of optimising value for money and least cost to consumers. In response, Community Electricity has lodged two comprehensive and well-researched papers which are available on the PUO website.

2. We note that the instant PUO paper presents the findings of modelling provided by EY and enjoys the patronage of the Treasury Department.

Inadequate business case

3. We quote from the PUO paper, our emphasis added:

   "Modelling indicates that overall, the most efficient solution is fully constrained access. A key finding is that **total market payments are forecast to be $288 million less over 50 years** in the fully constrained case than the partially constrained case. This means consumers are forecast to be better off under a fully constrained network access framework than they would be under partially constrained network access framework."

   Footnote 20: "Forecast savings to consumers from lower market payments will be offset by the quantum of transitional assistance payments to generators with firm access rights."

   ".....the details of the transitional assistance scheme are yet to be defined and will be discussed further with market participants."

> "..... transitional assistance to eligible generators in the form of a financial payment to cover the reasonable losses the generator may incur as a result of the implementation of constrained network access.."

4. We note that the proposed saving equates to is $5.8 million per year minus the unknown costs of the transitional assistance.

5. We quote from the ERA's media statement of 2-MAY-2018 in respect of AA4:

   "The ERA's draft decision sets target revenue of $7.38 billion that Western Power can earn over the five-year period."

6. We note that this a simple average of $1.5 billion per year for network alone; wholesale market costs of a similar amount would also be incurred. Forecasts of these cost are known to the PUO but have not been released.

7. We conclude that the "business case" for proceeding with Constrained Access is a saving of at most 0.4% assuming zero transitional assistance. More realistically, the proposed saving is perhaps half that. More realistically yet, the forecast saving is entirely dependent on accurate assumptions holding for 50 years in the face of major disruption by battery penetration and the dysfunction of commonwealth policy for subsidising renewable energy.

8. As examples of normal forecast error, we cite:

   i. the dysfunction of the system load forecasts in recent years is a principal cause of the WEM dysfunction that the reform seeks to remedy;
   ii. less than 2 years ago, the PUO forecast the 2018-19 capacity price (effective from October 2018) to be around $105,000 per MW compared to the actual value of $138,800 per MW - nearly a third higher than the government's expectation.

9. We suggest that the reliance of the PUO "business case" for constrained access on an improvement of at most 0.4% is either preposterous or disingenuous to an extent that merits investigation by the Auditor General.

10. We challenge the PUO to specify the net market benefits of the proposal in terms of an annual percentage of the total costs and to release the 'high' and 'low' estimates that would automatically accompany a competent forecast. We also challenge the PUO to specify the impact on its business case of the abandonment of the commonwealth National Energy Guarantee.

The concealed agenda: Western Power's liabilities

11. We quote further from the PUO paper, where we have added emphasis and track-deleted ~~in this style~~ a claim that we wish to challenge:

"Legacy contractual arrangements mean a number of electricity generators are entitled to 'unconstrained network access', which means Western Power is required to ensure its network has sufficient capacity to transmit up to the maximum output of these generators under normal operating conditions."

"Under the proposed implementation approach, providing Western Power with a statutory immunity is necessary to eliminate Western Power's exposure to claims arising as a result of a purported failure to provide a level of physical access to its network in accordance with contractual obligations (or other contractual commitments) ~~due to the introduction of constrained access~~."

".... **in many cases there is actually sufficient physical capacity in the network, but the unconstrained access rights of incumbent generators mean that 'spare' network capacity is contracted out, effectively locking it up** and reducing the amount of capacity available for other generators to connect."

"..... a substantial proportion of all new generation facilities connected since 2006 (regardless of fuel type) are owned by (or contracted by) one of the small group of electricity industry participants that existed at market start."
[Synergy, perhaps? Perhaps a breach of confidentiality to name what everybody already knows?]

12. We note that when Western Power enters into an access agreement with a generator, it makes an estimate of the expected income arising under the applicable network tariff. Insofar as there is a shortfall relative to its cost of investing in the necessary network assets, Western Power requires the generator to fund that shortfall as a capital contribution. Western Power then includes the required investment in its long term capital programme, which programme is subject to government and ERA approval. The timing of investments is also subject to operational conditions.

13. On this basis, we challenge the presumption that it is new generators that have to pay all the cost of the claimed $700 million network augmentation. We seek express confirmation of how much of that augmentation has already been funded by existing generators and what has happened to the funds collected. We suggest that the real purpose of the initiative is to tax the market to raise the funds needed to rebate unconstrained generators for Western Power not having made their contracted investments, and to rebate Synergy for seizure of its hoarded network capacity. We suggest that is the purpose of the legal immunities. It is also the absurdity of imposing a new market tax in order to "reduce costs".

14. We note that Access Contracts between Western Power and generators have evolved over the lifetime of the WEM and that the original incumbents (primarily Synergy) have materially different access rights. We speculate that the principal issue is that Synergy has legacy capacity rights that aren't being used (hoarded) and are crowding out prospective users. We note that the issue is shrouded in

confidentiality and we speculate that Western Power is being permitted to reframe a problem caused by Synergy in order to obfuscate its own problem of accounting for funds that it is seeking to avoid spending. To this end, the PUO has been captured and is being shepherded to a 'solution' that involves having the market fund compensation in return for an unnecessary imposition of constrained access.

Alternative reform approaches

15. We quote further from the PUO paper, with our emphasis added:

    "The WEM reforms will require analysis of what energy and ancillary services are required in various parts of the SWIS, to help inform the timing and nature of network and power system investment in the future. This may also aid **the development of suitable locational pricing signals to provide generators an incentive to build generating facilities in the parts of the network where it is most valued**."

16. On this basis, we suggest that a potential alternative solution would be to simply confiscate hoarded network capacity from Synergy and to provide generation-location cost signals in the Access Arrangement.

Confidentiality

17. We quote from the PUO paper:

    Footnote 2: "Due to the commercially sensitive nature of the findings, the Public Utilities Office cannot provide open access to the modelling. The detailed results of the modelling relevant to each market participant will be shared with individual market participants during one-on-one meetings with the Public Utilities Office."

    " Generators that currently have some sort of (unconstrained) physical firm access right would receive a financial payment to cover reasonable losses resulting from constrained dispatch. This would be negotiated individually with affected parties."

18. We note that AEMO publishes generator production data by Trading Interval since market commencement, from which a generator DSOC can be deduced for all generators with the exception of hoarded capacity that isn't used. Constrained operation can also be discerned. Indeed, this in combination with outage transparency is central to the cost reductions that have occurred since the introduction of the Balancing market in 2014.

19. We suggest that the simplest, most cost effective tool for cost reductions is basic transparency. We note that the former IMO attempted to switch the ethos from "confidential unless right to know" to "public unless right to conceal". However, on replacing the IMO, AEMO revoked this initiative.

20. With acknowledgement and apologies to Dr Samuel Johnson, we suggest that confidentiality in respect to these publicly owned assets is the first refuge of the scoundrel.

Contact

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