

23 March 2018

Mr Noel Ryan
Acting Director Energy Networks
Public Utilities Office / Department of Treasury
David Malcolm Justice Centre
28 Barrack Street
PERTH WA 6000
Noel.Ryan@treasury.wa.gov.au

Dear Noel,

Response to Consultation Paper: Improving access to the Western Power network

1. Introduction

Merredin Energy Pty Ltd (MEPL) owns and operates the 82MW open cycle gas turbine power station in Merredin, Western Australia. The power station (known as “MEPS”) is connected to the South West Interconnected System (SWIS) via a single circuit 132kV overhead transmission line to Western Power’s Merredin Terminal north of the power station.

The financial performance of the plant is highly dependent on the revenue earned by providing Capacity Credits under the Reserve Capacity Mechanism (RCM). Proposed reforms that change network access arrangements, capacity certification processes and Reserve Capacity Prices (RCP) have the potential to significantly impact the profitability of the Merredin Plant.

Given the above, we have a significant interest in proposed reforms and provide this submission to assist in the EY modelling of the impacts of constrained access on incumbent market participants and the need for transitional assistance for adversely affected generators.

2. EY Modelling Scope

As part of process to implement constrained network access in the SWIS, the Public Utilities Office (PUO) is investigating the impacts of transitioning from the present network access regime in the SWIS (mixture of unconstrained and constrained access arrangements) towards a fully constrained network access regime.

The impacts of constrained network access are to be estimated by electricity market modelling that quantifies potential changes to generator dispatch outcomes, revenue projections and generation supply adequacy.

EY has been appointed by PUO to undertake the modelling and have prepared a methodology and assumptions paper for review by stakeholders.¹

¹ EY, Modelling the impacts of constrained access – methodology and assumptions, For the Public Utilities Office, 28 February 2018

The purpose of the EY modelling is to inform PUO advice to the State Government on the need for transitional arrangements to compensate generators for any adverse impacts of the reforms. The modelling is intended to quantify potential changes to generator dispatch outcomes and to identify trends in revenue projections.

The modelling *does not seek* to quantify the amount of transitional assistance to generators or the proposed mechanism for that assistance. A separate consultation process will be undertaken to design the mechanism for providing transitional assistance.

In our view, given future uncertainties, it is unlikely that any market simulation modelling will provide sufficient clarity on actual losses for individual generators in the SWIS over an extended period. There is just too much uncertainty about key input variables over the operating life of generation plant (i.e. 40-50 years for coal plant, 25-30 years for gas plant). This includes future plant retirements, new plant investment (including location in the SWIS), gas prices, operating consumption and peak demand, energy storage and electric vehicle penetration rates.

In a legal sense, no one party to a financial settlement for damages that may arise from the implementation of constrained access (i.e. WA Government and a market participant) has access to all the necessary information to determine whether the calculation of compensation is sufficient. Compensation amounts will have to be either broad approximations or calculated based on worst case scenarios for a generator.

To avoid compensation calculations, all existing generators should retain their existing rights. Any new plant entering the SWIS who may restrict the output from an incumbent generator (based on Western Power or technical consultant modelling) can negotiate with an incumbent generator to buy existing additional access rights from the incumbent generator (a process that could be facilitated by the PUO). The access right should exit beyond an Electricity Transfer Access Contract (ETAC) for an individual plant, since investments in incumbent plant were based on firm and unconstrained access for the anticipated life of the plant (e.g. 40 to 50 years coal, 25 years for gas and renewable plant). This overcomes any problems with removing contracted rights and claims for compensation from the WA government. It also helps to facilitate the economic dispatch of plant since the new generator (if it has a lower SRMC than the incumbent plant), can dispatch its full output into the market given it has purchased sufficient network capacity (via WP and the incumbent generator) to export at its maximum capacity level.

Disappointingly, the modelling does not provide an assessment of the *net market benefits of constrained access reforms*. It is still not clear to many market participants why the SWIS needs to migrate to a constrained network access model. The argument is that constrained network access will provide signals to generators to locate where there is spare capacity in the Western Power Network. In our view, 1500 MW of dispatchable generation could retire over the period 2018 to 2032 (e.g. coal power stations at Muja, gas turbines at Kwinana, Goldfields and Pinjar) and spare capacity will become available in the Collie, North Perth and Kwinana regions.

However, it is likely that most new capacity that enters the SWIS will be intermittent generation in North Country (predominantly wind farms), East Country (predominantly solar farms) and Muja (predominantly wind farms) regions over the next 20 years.² New transmission upgrades will be required to support investment in renewable plant, otherwise some of this capacity will need to be constrained. The economics of intermittent plant is only minimally impacted by network constraints which coincide with peak times on the SWIS

² These regions are defined as transmission load areas by Western Power. North Country is the region north of Pinjar, East Country includes farming and wheatbelt regions from Northam to Merredin, while the Muja region covers Collie, Kemerton, Kojonup and Albany.

because capacity revenue is not a significant percentage of the total revenue earned by wind and solar farms (assuming no storage facilities). The plants will continue to locate in these constrained regions because the resources for these plants (e.g. wind, solar radiation, land availability etc) are in those regions.

However, the economics of dispatchable generation (such as peaking and mid-merit plant) is more dependent on unconstrained network access, especially at peak times in the SWIS (e.g. high energy prices, accreditation of capacity credits). In fact, some peaking units are only profitable if they can receive close to the nameplate capacity of the unit. These units will attempt to locate in regions where network constraints are not binding (now and in the future). They will be able to do so because spare capacity will be available in Kwinana, North Perth and at Muja (also need to be located near gas transmission pipelines which may exclude Muja).

In our view, the pattern of future investment in generation will not change because of the introduction of constrained access. Unless Western Power reinforces the network in those new generation hubs (e.g. North Country, East Country and some parts of the network in the established Muja region), renewable generators will face constraints. This will result in wind farms constraining each other in the North Country region (no dispatchable generation in that region), new solar plants being constrained in the Wheatbelt, and a mixture of wind and thermal generation being constrained in the Muja region.

Western Power will have to constrain the operations of generators under current access arrangements (e.g. runback arrangements). It is claimed that Western Power can't support any further runback arrangements and that this may interfere with the optimal dispatch of plant in the WEM – out of merit order dispatch. However, the reality is that most of the constraints are not binding (except for wind farms in the North Country region). Moving to constrained network access and constrained economic market dispatch of plant helps transfer the responsibility for constraints to the market to manage (i.e. AEMO and market participants).

Yet the likely future evolution of the market is that network constraints will not be binding in many regions that dispatchable plant can locate (e.g. Muja, Kwinana and North Perth). New intermittent plant will be constrained because of a lack of reinforcement of the network in those new generation precincts. Given the changing mix of plant in the SWIS, it is likely to be beneficial to expand the transmission system in those regions to ensure that the value of intermittent generation (e.g. emission reductions, LGC's, cheap energy) can be fully realised. This is a separate decision (e.g. New Facilities Investment Tests) from how network constraints are to be managed in the SWIS under constrained access.

Provided the grid is expanded to accommodate increased renewables (which is being driven by customer's desire for low emission electricity), the constraints in the SWIS will not be severe.

However, we are undergoing major reforms of network access, the wholesale market and potentially disadvantaging existing generation so that a limited number of binding future constraints in the SWIS can be managed better. This does not appear to be a business case that would earn a positive return on investment.

Significant time and effort by the WA Government and market participants is going into this reform process, yet the significant issues that can impact costs, reliability and energy security are ignored or deferred until we complete constrained access and associated wholesale market reforms. This includes:

- Current practice of treating embedded generation as a net reduction in load and not as a generation source by the market implies that market participants and AEMO do not have good visibility of the potential generation pattern of embedded generation in the SWIS. This results in inaccurate pre-dispatch forecasts by the market and lost opportunities by market participants (e.g. incorrect market bids etc). Embedded generation needs to be

aggregated and be able to participate in wholesale market processes (e.g. retailer/aggregator could bid and control embedded generation in a region and be the market generator for that aggregated embedded generation portfolio).

- High penetration of intermittent generation in the SWIS, which does not have extensive energy storage options like the NEM (e.g. pumped storage), will result in the system having minimum loads (and in some cases positive net generation) well below the minimum generation levels for baseload plant in the SWIS. It is likely that older base load units will not be able to do multiple start-ups in a day, with the result that some coal units will have to retire. Increasingly, more gas plant will be required to effectively load follow intermittent plant in the system. These impacts will certainly increase wholesale energy costs and reduce the amount of inertia in the power system. Inertia is important to maintain the frequency in the power system and it is likely that new markets for providing this service will be required in the future.
- Introduction of cost reflective tariffs (both for import of grid energy and export behind the meter energy to the grid) to ensure that customers are incentivised to use and supply energy to reduce peak demand or manage minimum demand. This includes the utilisation of behind the meter energy storage.
- Ensuring that there are adequate incentives for dispatchable generation to remain and be built to ensure the reliability and security of electricity in the SWIS. This includes establishing inertia services markets, putting in place a state based National Energy Guarantee scheme, or ensuring the capacity market can provide sufficient incentives for new dispatchable plant (includes intermittent plant with energy storage) entry.
- Business case for Western Power to expand and reinforce the network to better absorb embedded generation as well as the new generation hubs that will be created by large-scale renewable investment in the SWIS.

These are the pressing issues that need to be addressed given that around 1000 MW of intermittent generation will enter the SWIS prior to 2022 (includes rooftop PV), while around 420 MW of dispatchable generation exits the market in 2018. These substantive issues are being deferred while we look at the marginal benefits (and most likely not net benefits) that result from moving to constrained network access – something which already permitted under the current network access regime.

3. Modelling Assumptions Supporting Model Cases

The paper outlines two cases to be modelled. **Fully constrained case** whereby all generators connected to Western Power are subject to generation curtailment in response to network congestion. **Partially constrained case** whereby existing generators retain access rights and only new entrant generators (from 2018) are subject to generation curtailment in response to network congestion. In both cases, network constraint equations are defined to set power transfer limits for use in the dispatch engine. The partially constrained case represents the business as usual case (and in our view the preferred way forward to introduce constrained network access in the SWIS).

For each case, all demand and supply related assumptions will be identical. We comment briefly on each of the assumptions made by EY and the PUO.

a. Emission Reduction Target

The Commonwealth Government has committed Australia via the Paris Agreement to an emission reduction of 26-28% reduction on 2005 levels by 2030.³ It is likely that under the National Electricity Guarantee (NEG), targeted emission reductions for electricity retailers will be (at a minimum) set at this level. There is also the possibility that because the marginal costs of reduction in emission reduction in the stationary energy sector is significantly lower than for other sectors (e.g. agriculture, transport etc), the target for the stationary energy sector could be set higher than 26 to 28 % reduction in emissions.

However, in our view, establishing a WEM based emission reduction of 26 to 28 per cent by 2030 looks like a reasonable assumption for this analysis.

There have been no formal emission reduction targets established post 2030, although as a signatory to the Paris Agreement, Australia has committed to global action to limit global warming to well below 2 degrees, aiming for 1.5 degrees. For a developed economy such as Australia, this means Australia must reach net zero emissions by or before 2050.

This suggests emission reduction targets will be increased further beyond 2030 and that some mechanism may be required to incentivise high emission plant to exit the market and permit low emission technologies to enter the market. Potential generators that may exit the market over the study period are outlined below (see section (d)).

b. Operational Energy Forecast

It is proposed that annual energy consumption (GWh) and demand forecasts (MW) will be sourced from the AEMO 2017 Electricity Statement of Opportunities. AEMO adjusts energy consumption and demand for the impact of rooftop and battery storage. It was estimated that in the Expected Case, operating consumption would grow at a Cumulative Annual Growth Rate (CAGR) for the period 2016-17 to 2026-17 of 1.19 per cent per annum).

In our view, there is a potential risk that the annualised growth rates in the 2017 ESOO may not occur as forecast. This is due to the decline in per capita energy consumption by households and small business customers due to higher than expected penetration of rooftop PV and increasing energy efficiency of energy using appliances and equipment.

The Clean Energy Regulator's latest rooftop PV data⁴ indicates that investment in rooftop PV in Western Australia in calendar year 2017 amounted to 180.71 MW. Eighty-four per cent of the population is in the SWIS, so if we assume 84 per cent of the rooftop PV systems installed are in the SWIS, then rooftop PV capacity in the SWIS increased by 151.8 MW in 2017. This is appreciably higher than all PV installation scenarios estimated in the ESOO 2017. The AEMO Expected Case had rooftop PV increasing by 103 MW from 2016-17 to 2017-18, while the AEMO High Case had rooftop PV increasing by 119 MW over the same period.

Because of significant concerns that the ESOO 2017 growth rates were "bullish", the AEMO directed an independent consultant responsible for developing gas use forecasts by Gas Powered Generation (GPG) in the SWIS for the 2017 GSOO to use lower SWIS demand growth rates. The independent consultant assumed that operating consumption growth in the

³ Australian Government 2015, Australia's 2030 climate change target. Available from: <http://www.environment.gov.au/climate-change/publications/factsheet-australias-2030-climate-change-target>. [14 August 2017].

⁴ <http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations> [accessed 18 March 2018]

Expected Case for the SWIS was 0.96 per cent per annum, compared to 1.19 per cent per annum in the ESOO 2017.

In our view, operating consumption growth in the High Case should be around 0.96 per cent per annum, while operating consumption for the Expected Case should be around 0.6 per cent per annum, with a Low Growth scenario having almost zero growth.

Peak demand forecasts should also be adjusted downwards to reflect the lower operating consumption forecasts due to higher than expected energy efficiency measures and the penetration of rooftop PV.

c. Large-scale renewable plant investment in the SWIS

EY has assumed that around 500 MW of new large-scale renewable energy capacity will enter the SWIS prior to 2022. The following table summarises the specific plant that will enter the market prior to 2022.

Table 1: Specific Investment in Large-scale Renewable Plants prior to 2022

Project	Load area	Technology	Capacity (MW)	Energy (GWh)
Byford Solar	Kwinana	Single axis tracking PV	30	76.2
Greenough River 2	North Country	Single axis tracking PV	30	76.2
Emu Downs Solar Farm	North Country	Single axis tracking PV	20	50.8
Northam Solar Project	East Country	Single axis tracking PV	9.9	23.4
Badgingarra	North Country	Wind turbine	130	501.1
Warradarge Stage 1	North Country	Wind turbine	180	693.8
Cunderdin Solar Farm	East Country	Single axis tracking PV	100.0	245.3
Total			499.9	1666.8

It is our understanding that the Cunderdin Solar Farm will only have a nameplate capacity of 75 MW (ac), so the investment in large-scale renewables totals 475 MW by 2022.

Currently there are more than 1500 MW of large-scale renewable projects being developed in the SWIS. It is likely that at least 700 MW of renewable projects will be developed prior to 2022. This could include an additional wind farm (around 200 MW) and major solar facilities (120 MW), as well as several waste to energy projects (60 MW) in the Perth region.

EY has assumed that additional investment in large scale renewables will occur, but will only be in response to market conditions (e.g. emission reductions, plant retirements, wholesale prices). However, given that EY is assuming no plant retirements over the study period and no WEM based emission reduction targets (or incentives provided to achieve the target), then there will be no further investment in renewables in the SWIS.

This outcome is not likely. As discussed, at a minimum, a emission reduction target of 28% should be factored into the analysis for 2030, with a higher target post 2030. In addition, there are likely to be plant retirements in the WEM as outlined below.

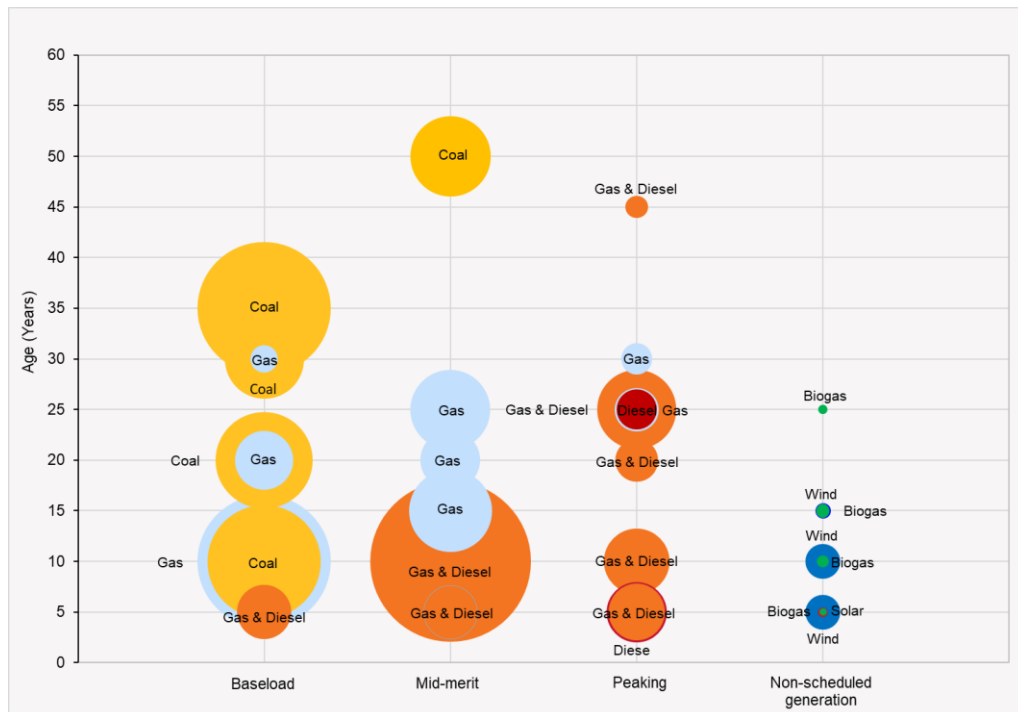
d. Plant retirements in the SWIS

EY has assumed no plant retirements over the study period 2022 to 2032.

Shown below is the age profile of generation facilities in the SWIS by dispatch type (e.g. baseload, mid-merit, peaking, and intermittent). What this shows is that there are significant coal units (e.g. Muja C and Muja D) that are around 34 to 35 years of age (in 2017). By 2029, Muja C will be around 48 years of age, while Muja D will be 44 years of age. Coal fired owned stations can have lives up to 50 years, but this depends on the particular condition of the units resulting from plant operating regimes (e.g. station cycling) and the maintenance program.

In addition, several gas stations are over 20 years old (e.g. Pinjar gas turbines) and could retire over the forecast period (typical plant life is around 25 years).

Figure 1: Age Profile of SWIS Generators



Source: AEMO, 2017 Electricity Statement of Opportunities, For the WEM, June 2017

Muja C and Muja D are prime candidates for plant retirement over the study period. To some extent the life of the plant will be dependent on the level of investment in intermittent plant in the SWIS. If minimum demand falls below 1000 MW, then baseload plant may be forced to cycle on and off. This can further lessen the life of a coal fired plant and may it uneconomic to operate.

In addition, if no plant is retired and there is between 500 to 700 MW of renewable plant entering the market, then it is likely that wholesale energy prices could fall to levels that are around \$40/MWh. Such low prices are likely to result in financial losses for market generators (won't cover incremental operational and capital costs), which provides an incentive for portfolio generators to retire plant early to improve financial returns for their generators.

It is our view that there will be plant retirements over the study period. In the case of Muja C, this could be as early as 2022 or as late as 2029.

e. Fuel Prices

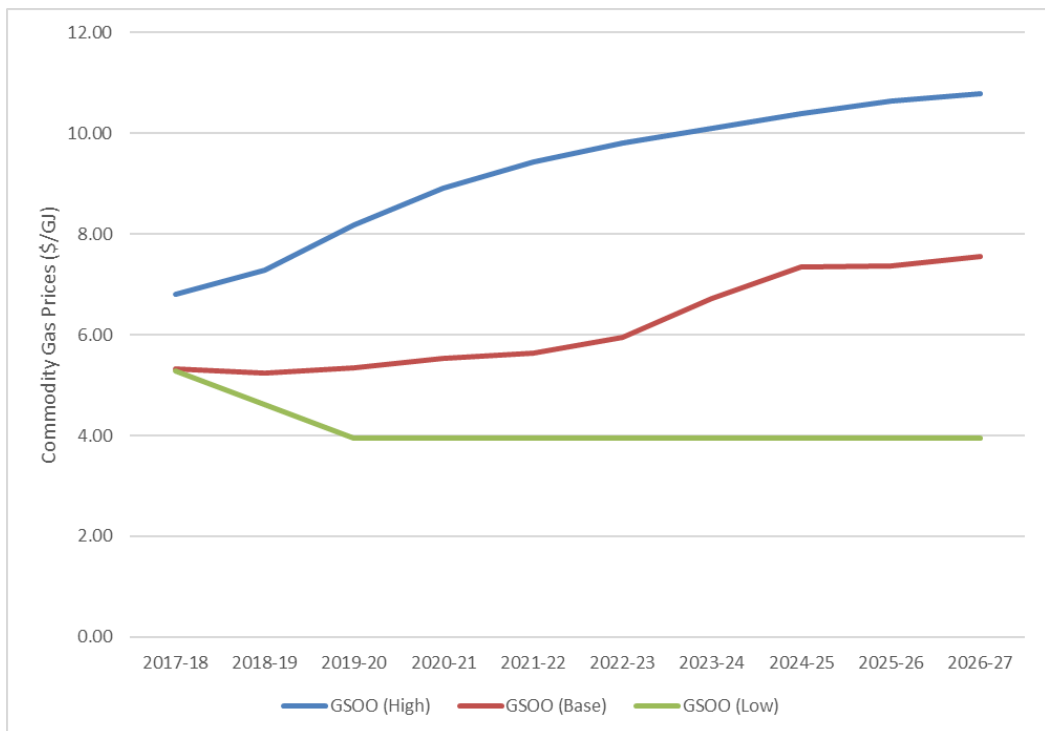
A coal price of \$2.61/GJ in 2016-17 dollars for the study period looks too low. Because of poorer quality coal that has been mined in recent times, it is likely that the real price of coal will gradually increase over the study period.

In addition, the current coal mines continue to be unprofitable and for them to continue in the longer term (i.e. provide a target rate of return and not just cover cash costs), it is likely that prices will need a one-off upward adjustment at least by the early 2020s.

In the medium term (5 years), gas input prices in the WEM can reflect contracted levels and/or spot market prices for unhedged generators. In the longer term, gas generator prices can reflect LNG netback prices for co-located LNG and domestic gas facilities and/or the costs of underwriting domestic only gas facilities in WA (e.g. Perth Basin gas fields). It all depends on which supply sources will be marginal (i.e. determines wholesale gas prices) in the longer term.

EY proposes to use the AEMO Gas Statement of Opportunity (December 2017) commodity gas price forecasts (excludes gas transmission costs), which are shown below. The range for these prices is considerable, reflecting differences in future demand and supply conditions (e.g. oil price, domestic demand etc).

Figure 2: Domestic Gas Price Forecasts (\$/GJ, 2017 dollars)



Source: EY, AEMO GSOO 2017

In our view, it is unlikely that domestic gas prices will remain \$4.00/GJ (GSOO Low Case) for the entire study period. At these levels, new gas projects would not be developed which would result in prices rising gradually overtime for a given level of gas demand.

Given WA’s dependence on gas for power generation to support mining and public electricity supply (both in the SWIS and the NWIS⁵), commodity prices exceeding \$8.00/GJ in WA

⁵ North West Interconnected System

(which implies delivered gas prices of around \$9.30/GJ) are not sustainable in the long term. Delivered prices at these levels would result in the closure of mineral processing facilities (e.g. alumina) and baseload generation facilities in the SWIS and NWIS (encourage coal fired power generation). Demand for gas would fall which would result in lower gas prices. In addition, new domestic gas supplies would be developed at these prices (even tight gas resources might be developed).

In our view, there is a natural ceiling on delivered gas prices in WA which is around \$8.00 to 9.00/GJ – implying a ceiling on gas commodity prices of between \$6.70 to 7.70/GJ. Delivered gas prices exceeding these levels are highly unlikely for a sustained period.

The AEMO Base Case gas prices look reasonable.

Regards,

John Delicato
General Manager
Merredin Energy