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26 April 2019

Mr John Pierce
Australian Energy Market Commission
PO Box A2449
Sydney South NSW, 1235

Dear Mr Pierce,

**Re: EPR0073 COGATI Implementation – Access and charging**

Flow Power welcomes the opportunity to make a submission in response to the COGATI Implementation – Access and Charging consultation paper (Paper).

Flow Power is a licenced electricity retailer that works with business customers throughout the NEM. Our model aims to give customers control over their energy costs by exposing them to regional reference prices (spot prices). Customers can manage exposure to price volatility though physical or financial hedges.

- A physical hedge takes the form of a demand response or onsite generation (supported by our proven systems).
- A financial hedge may include purchasing financial hedges from markets such as ASX Energy Futures or entering into a PPA[1] with generators.

Our unique PPA model, Virtual Generation Agreement, plays an important role in supporting the development of large-scale renewables by providing price certainty and confidence to investors, and at the same time creating a product for business customers to access low electricity prices and take control of their energy cost.

We support the need for coordination to address the issues discussed in the Paper and we also support the proposed changes allowing generators to negotiate firm transmission access rights with TNSPs and fund the transmission infrastructure. We agree this will reduce energy costs to all consumers from lower TUoS charges recovered through network tariffs.

The Paper[2] though, proposes that the transmission access right will provide generators a firm hedge between the dynamic regional price and the spot price. However, no explanation is given on how this will work during times of congestion, when generators are exposed to dynamic regional prices.

Flow Power seeks clarification on this matter.

[1] Refer to Appendix 1 for an example of how our Virtual Generation Agreements provides a financial hedge to a customer exposed to spot prices
[2] Clause 3.1.4, second paragraph, p 19

We note in the Supplementary Information Paper[3], a key driver for introducing dynamic regional pricing is to resolve the issue of disorderly bidding behaviour by generators. We support steps that lead to efficient generator bidding behaviour. However, it is essential that any rule change, targeting one category of market participants, does not create issues to other participants and their customers or disrupt existing long-term commercial arrangements that were negotiated between parties based on existing market rules.

We believe the implementation of dynamic regional prices, as proposed in the Paper, is likely to create the following issues:

1. Generators could interpret the proposed change in settlement price as a change in law to shift the risk associated with their exposure to dynamic regional pricing to other market participants or customers who have entered into PPAs.
2. Distorts market price signals during congestion by creating a disconnect between the price received by the seller (eg generator) and that paid by the buyer (eg retailer or a customer exposed to spot prices).
3. Creates a zero-sum game at the wholesale market level, through distribution of settlement revenue[4] amongst affected generators, begging the question if the proposed change will yield net benefits to customers.
4. Defeats the purpose of sending signals to generators located behind the congestion because the allocation of settlement revenue amongst those generators will compensate them for the reduction in dispatch revenue[5].
5. May improve but will not eliminate disorderly bidding behaviour.

Instead of implementing dynamic regional prices as a first step, we propose the following alternative solution, where all parties settle based on the spot price:

1. AEMO to publish the locations and frequency of transmission congestion. This information can be used by investors for planning new generation capacity.
2. Implement the proposed “Generators fund transmission infrastructure” phase first, in July 2022.
3. Establish a three-year transition period (from July 2022 to June 2025) to provide generators enough time to negotiate and purchase firm access rights from TNSPs. The three years will also support the time required for TNSPs to carry out augmentation works.
4. AEMO to establish and maintain a register for all firm access rights purchased by generators.
5. Following the transition period (ie from July 2025), when congestion occurs, AEMO will refer to the register and give a generator with firm access right a dispatch priority over a generator without access right, when the offer prices are the same. Using Figure B.2, page 35 of the Paper as an example, if G1 purchased an access right for its full 500 MW capacity and G2 did not, then G1 will be dispatched for 500 MW and G2 will be dispatched for only 100 MW. As a result, G1’s margin will increase by $9,000 whereas G2 margin will reduce by $6,000.
6. Review the situation after 3 years of implementation (July 2028) to assess if further action is required.

[3] Clause 2.1.2, p 8
[4] Settlement residue arising from dynamic regional pricing
[5] According to the example given in the Paper, Figure B.3, page 36, generator G1’s margin of $16,500 is higher than the $13,500 achieved under disorderly bidding behavior (Fig. B.2) or the $7,500 achieved in the absence of congestion (Fig. B.1). Similar conclusions also can be made for generator G2

The advantages of this alternative approach are:

1. Bringing forward the "Generators fund transmission infrastructure" phase will speed up reducing electricity costs to all consumers from lower TUoS charges.
2. Generators will be incentivised, and given enough time, to negotiate firm access rights with TNSPs in order to improve their margins as a result of being placed at the top of the dispatch priority queue during transmission congestion.
3. In the long-term, as transmission infrastructure is upgraded, congestion will be minimised and so will generators disorderly bidding behaviour.
4. Market price signals will be maintained because the price paid to the seller matches that paid by the buyer.
5. Existing commercial PPA arrangements between generators and customers will not be disrupted.

We are a growing business that is actively responding to the changing electricity market and the needs of our customers, particularly in providing cost effective solutions that are directly linked to market price signals. It is essential that these market price signals are left to work as intended to drive the intended investment and innovation in the sector.

We have provided more specific comments in relation to the issues we raised above, and the questions explored in the Paper within Appendix 1.

If you have any queries about this submission, please contact Nabil Chemali, on 0417 971 032 or nabil.chemali@flowpower.com.au

Yours sincerely

Matthew van der Linden
Managing Director
Flow Power

# Appendix 1

## Example: Virtual Generation Agreement as a financial hedge

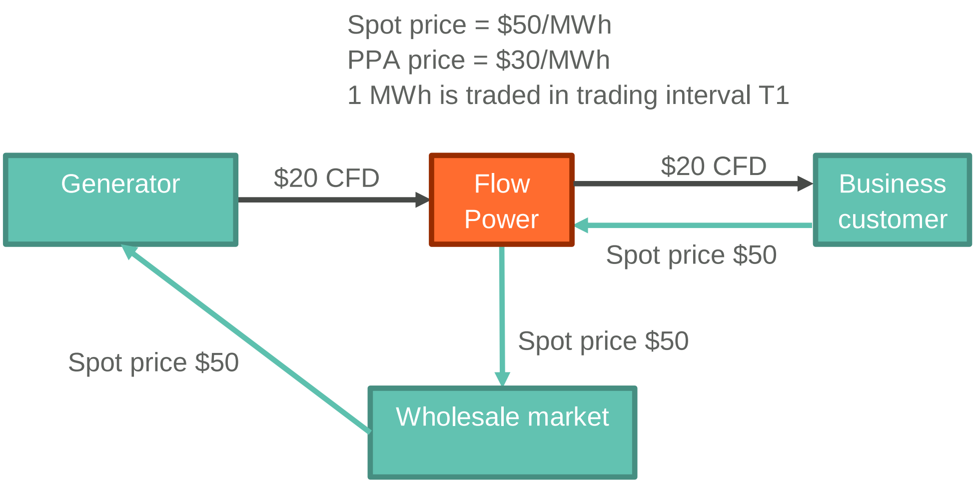
To provide context to the issues we raised in the covering letter and to our responses to the questions raised in the Paper, we provide the following hypothetical example of how a typical PPA works for a Flow Power customer exposed to the spot price.

Note, under the Flow Power Virtual Generation Agreement (VGA) model, Flow Power enters into a PPA contract for difference (CFD) with a generator for a given output and the agreement is then passed through to multiple customers in the form of VGAs.

### Settlement based on current market rules - all parties settle based on the spot price

Fig 1 below illustrates the flow of settlement money amongst the parties based on current arrangements

*Fig 1 – PPA transactions between all parties based on existing market settlement rules*




Settlement results for trading interval T1

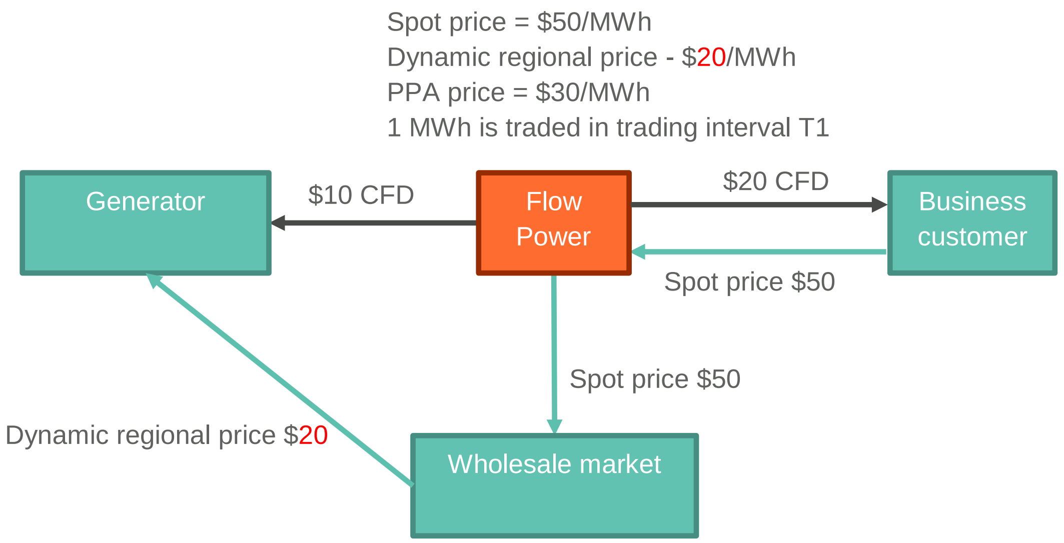
1. Customer net position – payment of $30 (VGA price), being the $50 spot price payment less $20 CFD receipt.
2. Generator net position – receipt of $30 (PPA price), being the $50 spot price receipt less $20 CFD payment.
3. Flow Power net position - $nil

As can be seen from the settlement results above, the VGA has provided the customer a financial hedge against its exposure to the spot price. Flow Power net position, as an off-taker, is $nil

### Settlement based on proposed change to market settlement arrangement - generators settle based on dynamic regional price

A Generator that is exposed to the proposed dynamic regional price may interpret this change as change in law to renegotiate their PPA with retailers to settle based on the dynamic regional price in order to protect their agreed PPA price. If this occurs the risk will transfer to the retailer as shown in Fig 2 below.

*Fig 2 – PPA transactions between the generator and Flow Power based on dynamic regional pricing*



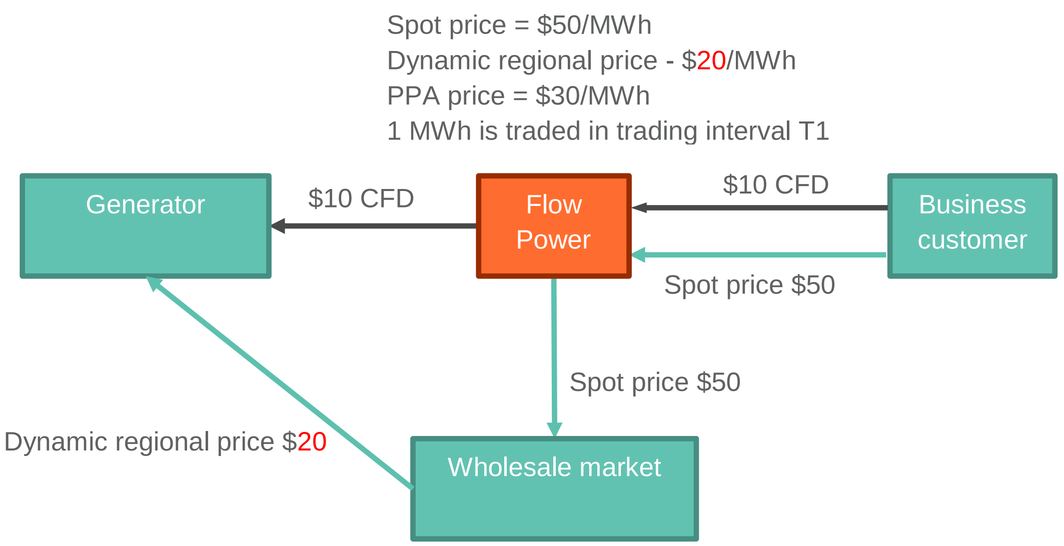

Settlement results for trading interval T1

1. Customer net position – payment of $30 (VGA price), being the $50 spot price payment less $20 CFD receipt.
2. Generator net position – receipt of $30 (PPA price), being the $20 dynamic regional price receipt plus $10 CFD receipt.
3. Flow Power net position - $30 out of pocket

As can be seen from the settlement results, the generator has protected its agreed PPA price by shifting the risk of exposure to the dynamic regional price to Flow Power, that ends up being $30 out of pocket

This situation will force Flow Power to renegotiate their VGAs with their individual customers to also settle based on the dynamic regional price. If the renegotiation was successful, the risk will transfer to the customer as shown in Fig 3 below

*Fig 3 – PPA transactions between all parties based on dynamic regional pricing*



Settlement results for trading interval T1

1. Customer net position – payment of $60, being the $50 spot price payment plus $10 CFD payment.
2. Generator net position – receipt of $30 (PPA price), being the $20 dynamic regional price receipt plus $10 CFD receipt.
3. Flow Power net position - $nil

Under this scenario, not only did the VGA not provide the customer with a financial hedge against the spot price but exposed them to a higher price.

Nevertheless, in both cases (whether the retailer or the customer takes the risk) the generator was able to shift the risk of its exposure via the dynamic regional price to other parties.

The following responses are in relation to specific questions raised in the Paper and our concerns noted above.

## Question 1: Phasing of access reforms

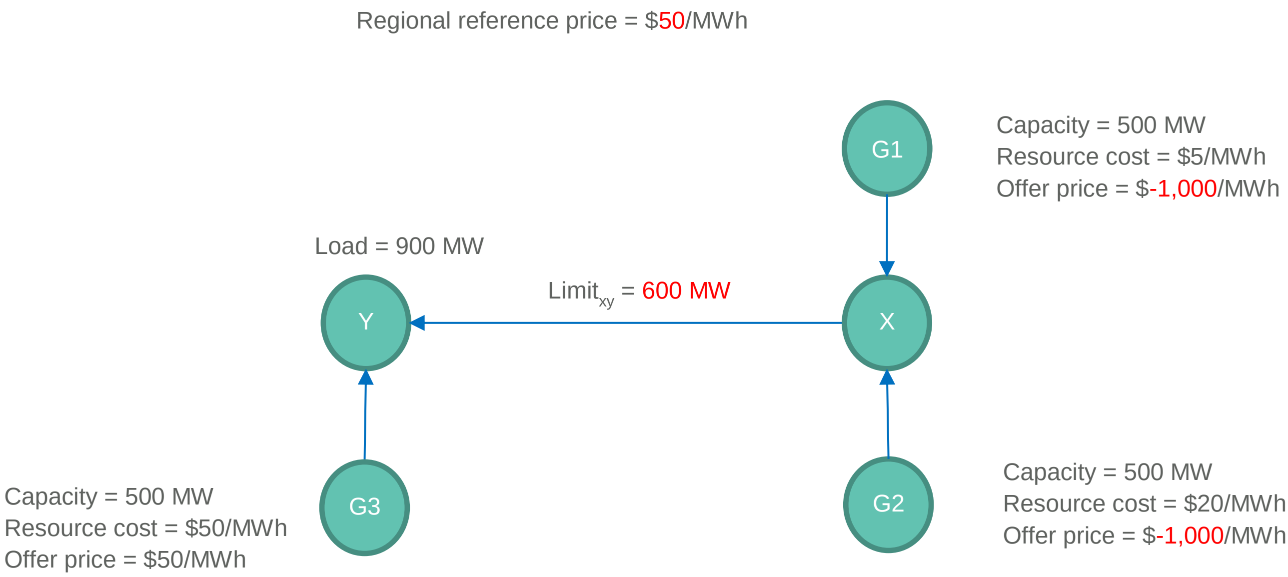
- We do not support the implementation of dynamic regional pricing based on the grounds listed in our covering letter and the explanations provided in the examples above.
- Our covering letter proposes an alternative approach by implemented phase 3 first to bring forward benefits that will lower electricity cost to all consumers.
- Notwithstanding our concerns with dynamic regional pricing, if it was to be implemented:
  - The change may have implications on the Retailer Reliability Obligation.
  - It will be time consuming for participants with medium-to-large portfolios of PPAs to agree with counterparties how a change in law is, or is not, triggered. If agreement cannot be reached and dispute resolution processes are triggered, the time period will extend further. As such, it is important to allow for as much time as possible between the date the rule change is made and the commencement date.
- It is also important that enough data is collected and in-depth assessment of the potential financial impacts of the change is made before deciding on whether to proceed with implementing dynamic regional pricing.

## Question 2: Phase 1 Dynamic regional pricing

- As discussed above, from Flow Power's perspective the obvious risk is the pricing disconnect between Flow Power's generation PPAs (at the dynamic regional price) and its customers VGAs (at the spot price), potentially with no ability to align those prices.
- One issue to consider is how acceptable a pass-through of dynamic pricing impacts will be to Flow Power's retail customers, particularly when Flow Power might not have adequate access to information about the probability of network constraints.
- Often PPAs make provision for negative pricing, providing protection to renewable energy generators. With generators receiving the dynamic regional price, a situation may arise where the generator exposure to dynamic regional pricing would prevent them from receiving the benefit of a negative spot pricing.

- We note under the proposed change, retailers and their customers exposed to market prices will settle based on the spot price regardless of whether a congestion is present or not. To ensure equity of treatment between all parties, storage must also settle based on spot price when importing from the grid.
- We question the effectiveness of dynamic regional pricing in resolving the issue of generators disorderly bidding behaviour. The examples provided in the two dot points below demonstrate that generators located behind the transmission congestion can still bid in a disorderly manner under either regime (status quo or dynamic regional price arrangement) and make the same margins:
  - Fig. 4 below is a replicate of Figure B.2 provided in the Paper[6], showing that under the status quo open access, the disorderly bidding behaviour of generators G1 and G2 has resulted in G1 and G2 making margins of $13,500 and $9,000 respectively, compared to $7,500 (G1) and $zero (G2) that would have resulted from orderly bidding behaviour in the absence of congestion[7].

*Fig 4 – Generators disorderly bidding behaviour under the status quo open access*

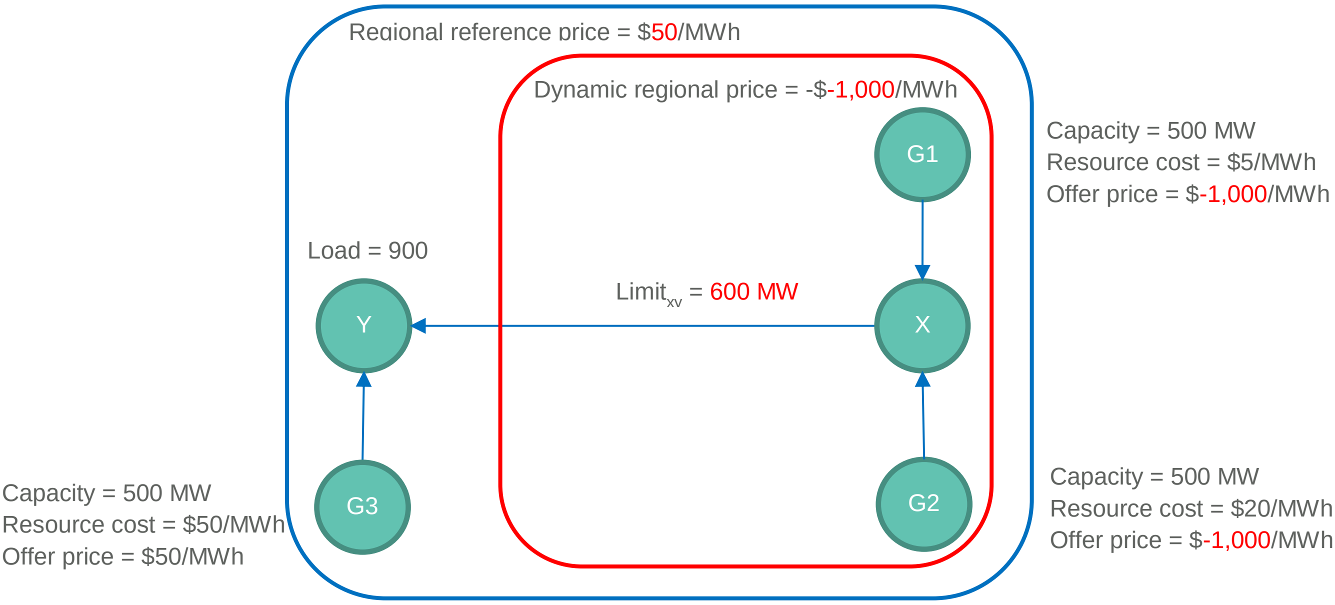



| GENERATOR | CAPACITY (MW) | CONGESTION HEDGE ($) "A" | RESOURCE COST ($/MWH) "B" | OFFER ($/MWH) "C" | DISPATCH (MW) "D" | DISPATCH PRICE ($) "E" | DISPATCH REVENUE ($) F = D * E | RESOURCE COST ($) G = B * D | MARGIN ($) A + F - G |
|---|---|---|---|---|---|---|---|---|---|
| G1 | 500 | 0 | 5 | -1,000 | 300 | 50 | 15,000 | 1,500 | 13,500 |
| G2 | 500 | 0 | 20 | -1,000 | 300 | 50 | 15,000 | 6,000 | 9,000 |
| G3 | 500 | 0 | 50 | 50 | 300 | 50 | 15,000 | 15,000 | 0 |
| **Total** | **1,500** | **0** | | | **900** | | **45,000** | **22,500** | **22,500** |

[6] Figure B.2: Open access, transmission constraints binds, page 35
[7] Paper, Figure B.1: No congestion, page 34

– Fig. 5 below shows that using the previous scenario under dynamic regional pricing arrangement, G1 and G2 can still bid in disorderly manner and earn the same margins. This is because the allocation of the settlement revenue ($630,000) between G1 and G2 has more than offset the negative dispatch revenue from being dispatched at the dynamic regional price.

*Fig 5 – Generators disorderly bidding behaviour under the proposed dynamic regional pricing*




| GENERATOR | CAPACITY (MW) | CONGESTION HEDGE ($) "A" | RESOURCE COST ($/MWH) "B" | OFFER ($/MWH) "C" | DISPATCH (MW) "D" | DISPATCH PRICE ($) "E" | DISPATCH REVENUE ($) F = D X E | RESOURCE COST ($) G = B X D | MARGIN ($) A + F - G |
|---|---|---|---|---|---|---|---|---|---|
| G1 | 500 | 315,000 | 5 | -1,000 | 300 | -1,000 | -300,000 | 1,500 | 13,500 |
| G2 | 500 | 315,000 | 20 | -1,000 | 300 | -1,000 | -300,000 | 6,000 | 9,000 |
| G3 | 500 | 0 | 50 | 50 | 300 | 50 | 15,000 | 15,000 | 0 |
| **Total** | **1,500** | **630,000** | | | **900** | | **-585,000** | **22,500** | **22,500** |

## Question 3: Information from dynamic regional pricing

AEMO already has access to the locations and frequency of congestion. This information can be published without the need to establish dynamic regional pricing.

## Question 4: Generators fund transmission investment

We recommend that the AER be given the task of developing guidelines on how TNSPs should calculate and recover the cost of transmission infrastructure from generators to avoid overcharging or double dipping.

## Question 5: Access reform timeframes

Please refer to our response to question 1.