SUBMISSION

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EUAA
Energy Users Association of Australia

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Introduction and Summary

The Energy Users' Association of Australia (EUAA) is the peak body representing Australian commercial and industrial energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing, building materials and food processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and in many cases are exposed to the fluctuations and challenges of international trade.

As large energy users, our members are highly exposed to movements in both gas and electricity prices and have been under increasing financial stress due to escalating energy costs. These increased costs are either absorbed by the business, making it more difficult to maintain existing levels of employment or passed through to consumers in the form of increases in the prices paid for many everyday items.

We appreciate the opportunity to respond to the CRIS. Our ability to respond to the questions asked has been constrained by the absence of detailed information in the relatively short CRIS. Normally a public consultation on a major policy proposal of this nature would have provided much more data and analysis in a public document and there would have been at least one public forum for the NWMP Options Team to make a presentation and stakeholders to ask questions. This is the approach taken in other jurisdictions to energy market issues that have similar major impacts on the price's consumers pay for the energy supply[1].

This submission is based on the information provided in the CRIS plus answers provided by the NWMP Options Team to questions the EUAA submitted. The NWMP Options Team's response to the questions seeking an explanation behind details of Option 2 was that the CuString modelling used to support the business case was 'commercially sensitive and cannot be shared'. This lack of information means we have had no ability to review the modelling – assumptions, methodology, sensitivities and results – of all three options.

Given the constraints in the information available, we make the following general observations:

(i) We understand the potential role for energy infrastructure supporting regional economic development, but the national electricity rules were specifically developed to ensure that electricity users only pay for the benefits they directly receive. Regional or national development benefits are rightly funded out of Government budgets, not by higher electricity prices for small and large Queensland consumers outside of the NWMP.

(ii) We agree with the Government's objective of providing current and potential large users in the NWMP with the ability to access an 'affordable, secure, reliable and sustainable supply of electricity'.

[1] For example, the standard approach of the AER to network revenue resets, the standard approach of the AEMC to rule change proposals and wider reviews such as the current Transmission Planning and Investment Review, and the current more specific State based reviews – the NSW Electricity Roadmap and the Victorian Gas Substitution Roadmap.

(iii) We are cautious about the implication from defining ‘affordable’ as the same delivered price as all other large customers connected to the NEM in Queensland. The cost of provision can vary greatly by location and large user energy pricing across the NEM (between jurisdictions and within a jurisdiction) does have a locational component, through marginal loss factors reflecting physics and a locational component in network charges, to improve market efficiency.

(iv) We support the current national rules framework around the use of the RIT-T process to assess the economic viability of proposed network investments and do not support derogations away from those rules; Options 2 and 3 do not pass that test and hence require substantial cross-subsidies from all (small and large) Queensland electricity consumers outside of the NWMP to large users in the NWMP

(v) Ensuring a competitive market at Mt Isa for the provision of secure electricity supply is a desirable objective. The limited information provided in the CRIS suggests that a modified version of Option 1 – which requires no subsidy from users outside of the NWMP - may be the best way to achieve that objective applying the CRIS criteria of equity, cost-effectiveness and practicality. A physical connection is not required to achieve the Government’s objective

(vi) Were the Government to decide that a physical connection was required, then we would prefer Option 3. As noted above, we strongly support the national rules framework around the RIT-T process. This is currently being reviewed as part of the AEMC Transmission Planning and Investment Review[2]. This review includes consideration of whether the RIT-T test should be expanded to include a wider definition of benefits that is a key consideration in Option 3.

(vii) Were Option 3 to be chosen, then before we are able to express a view, we would require further extensive and transparent consultation by the Government and Powerlink to understand the risks and costs that Powerlink consumers outside of the NWMP would bear.

On the basis of reviewing the limited information in the CRIS, we conclude that:

For Option 1:

- Appears to be capable of delivering a power price in the NWMP equal to or better than Options 2 and 3 for almost all time all demand scenarios/time periods without any cross-subsidy from small and large Queensland electricity consumers outside of the NWMP, though the detailed modelling supporting Option 1 pricing is not provided
- Does not discuss possible concerns that current and future large users in the NWMP might have around APA’s ability to exercise of market power when current contractual arrangements are re-negotiated or new contracts sought.

For Options 2 and 3:

- It involves a significant and uncapped shift of risk from the equity participants and large users in the NWMP to small and large electricity consumers in the rest of Queensland

[2] See https://www.aemc.gov.au/market-reviews-advice/transmission-planning-and-investment-review

- For various reasons, the level of cross subsidy resulting from this shift of risk from small and large Queensland consumers outside of the NMWP to large consumers in the NWMP in the CRIS - between \$1.1 – 1.7b for Option 2 and \$0.5-1.1b for Option 3 depending on the demand scenario and assumed capex - is likely to be an underestimate.

Given the advice from the NWMP Options Team that:

> “Some options, including direct subsidies, have already been investigated and ruled to be inefficient and unsustainable.
> In relation to the three options canvassed in the CRIS, the government has not made any decision about cost sharing."

We can only assume that small and large Queensland consumers outside of the NWMP will pay all of the cross-subsidy.

The cross subsidy is effectively uncapped if capex increases and /or demand falls lower than the low demand scenario. The CRIS has no information on how the demand forecasts were arrived at nor about the level of accuracy of that \$2.5b capex (the \$2.2b estimate for Option 3 is derived from Option 2). What we do know is that current capex estimates for this scale of project are increasing significantly due to a combination of social licence and supply chain pressures.

Section 2 provides summary answers to the three stakeholder feedback questions. Section 3 expands our views on the risks to all small and large Queensland consumers outside of the NWMP with particular focus on Option 2.

1. Responses to the stakeholder questions

A. What is the evidence of inefficiently high electricity prices in the NWMP? Are there enduring barriers (or market failures) to efficient electricity prices for industrial customers in the NWMP?

    - Does the difference in the delivered price of electricity between NWMP and NEM connected customers indicate a market failure that requires Government intervention to address?

Higher prices for mining and major industrial customers in the NWMP compared to the prices paid by NEM connected C&I customers in Queensland is not, prima facie, an indication that the prices are ‘inefficiently high’ and indicative of market failure. There are many reasons for a difference that have nothing to do with market power e.g. locational factors (it simply costs more to generate), a different allocation of risk between the seller and the buyer and a different PPA term. Forward and bilateral contract prices across the NEM differ all the time and that is not necessarily an indication of NEM market failure. The question is the same whether you are considering the NEM or an isolated grid like the NWMP – are the prices in those different locations the result of an efficient price setting mechanism i.e. does it reflect the efficient costs of generation and transmission/ distribution?

Our understanding of the current supply arrangements for large customers in the NWMP is that they resulted from a competitive process between APA and an earlier version of CuString where APA was the winner. If that understanding is correct then there is no current market failure. The fact that gas prices may be higher than assumed by large users when the PPA was put in place is not an indicator of market failure stemming from a decision to put in place a tolling arrangement with APA.

The question then becomes – is there a potential for market failure when existing large users in the NWMP seek to re-negotiate their PPAs or for new mining operations seeking to develop new deposits in the region given APA's position in the market? Again, the lack of information in the CRIS makes this a difficult call. That may be the case if APA is the monopoly provider for this re-negotiation/new negotiation. Factors influencing this would include:

(i) Will access to gas supply from the Jemena pipeline and the development of the Beetaloo fields in the Northern Territory provide competition for historical access via the Carpentaria pipeline?

(ii) Do current large users have risk mitigation terms in their current contracts? A common approach in the mining industry in these circumstances is to have options in existing contracts that prevent the supplier from exercising monopoly power at the time of a re-negotiation e.g. options to extend on the same terms and conditions, a deterministic method of setting the tolling change based on an agreed depreciated value of the power station at the end of the existing contract and an agreed methodology for setting the asset WACC

(iii) Whether existing and new users can draw on other sources e.g. develop hybrid systems – renewable generation, batteries and diesel back-up as a standalone system; to source part or all of their power needs through renewables.

As the CRIS notes (p3 and p.6):

> "Hybrid systems with a renewable energy component, such as solar and batteries, are also gaining traction in the mining sector."

The Cannington Mine in the NWMP recently installed a 3MW solar farm integrated with the existing gas fired power station to reduce gas consumption[3]. Hybrid approaches are becoming very popular in Western Australia as an alternative to connecting to the existing gas pipeline infrastructure.

Even if after taking these factors into account there is still concern about the ability of APA to exercise market power, it does not automatically require Government intervention through extensive derogations to the National Electricity Rules to support building an estimated $2.5b connection to the NEM to deliver a forecast 'high demand' case peak demand of 556MW. A much simpler, and less costly, alternative might be for the Government, through the QCA, to consider how it might be able to regulate prices in the NWMP to replicate what a competitive market might produce.

B. How can the Queensland Government facilitate an affordable, secure, reliable and sustainable supply of electricity in the NWMP? What are the feasible options that best address the issue, while considering equity, cost-effectiveness and practicality?

There is no clear statement in the CRIS about what the Government regards as affordable. In response to a question about this the NWMP Options team responded:

[3] See https://www.south32.net/our-news/solar-to-power-cannington-mine

> "The CRIS did not seek to target a specific energy price"

Nevertheless, it seems that 'affordable' means the same price paid by other large users currently connected to the NEM in Queensland. We are cautious about the implication from defining 'affordable' as the same delivered price as all other large customers connected to the NEM in Queensland. The cost of provision can vary greatly by location so the only way common prices across the State can be achieved is by (large and small) consumers outside of the NWMP would need to pay more.

Given the lack of detail in the CRIS and the commercial in confidence CuString modelling it is difficult to answer the question. So, the first recommendation would be to provide much greater transparency of the modelling behind the discussion of the three options and direct engagement with stakeholders to assist them to understand the issues.

At a general level the EUAA favours market-based solutions and sees large cross subsidies from one user class or user location to another user class or location as inconsistent with the criteria of equity, cost-effectiveness and practicality. Option 2 involves a very large, uncapped, subsidy from one group of consumers to another, Option 3 a smaller but still very large subsidy that seems to have cap. Equity objectives are more efficiently achieved through Government budget measures.

C. Is a physical transmission connection to the NEM required for the NWMP?
    - The contribution the NWMP should make to the connection.
    - The contribution the rest of Queensland should make to the connection.

The limited information in the CRIS on the prices over time for each option and each demand scenario suggest that a physical connection may not be required to produce prices that could be considered 'affordable' i.e. similar to Option 2 prices.

Were access to the detailed modelling of the three options to show that a network connection is the best option to meet the Government's objectives, then we submit that:

(i) We prefer Option 3 to Option 2 given the lower level of cross-subsidy flowing from application of the national rules, and
(ii) The relative shares between NWMP large users, all small and large Queensland consumers outside of the NWMP and the State and Federal Governments should be the subject of an extensive consultation process where all the modelling is transparently available. The share borne by small and large consumers outside of the NWMP should be subject to a cap over the life of the project.

D. What else the Government should consider?

Given the CRIS results for Option 1, the Government should undertake more detailed analysis of Option 1 that is then presented to stakeholders for consultation. This analysis would include investigating large user concerns around APA's ability to exercise market power. This may lead to some form of regulation through the QCA to give large users in the NWMP confidence that the prices offered by APA reflect what a competitive market in the NWMP would offer.

2. Comments on the risk profile for small and large Queensland consumers outside of the NWMP

This section reviews the information provided in the CRIS to seek to understand the risks that large users in the NWMP may face with the three options. Our conclusions, based on the limited information in the CRIS, are:

(i) The potential for Option 1 to meet the Government's objectives should be examined in more detail including a potential role for the QCA in preventing the exercise of market power by APA, and
(ii) The prices forecast by CuString for the NWMP seem to be an underestimate given the methodology for forecasting NEM wholesale price and exclusion of potentially significant cost factors
(iii) The risks, and hence level of cross subsidy, from small and large Queensland consumers outside of the NWMP to large consumers in the NWMP from Options 2 and 3 could be considerably higher than described in the CRIS.

Is security of supply under Option 1 less secure?

The CRIS (p.11) refers to the:

(i) 'low reserve capacity' requiring demand response from large customers in the event of an unplanned outage or longer than expected maintenance period
(ii) Two loss of power events in 2021
(iii) Potential shortage of firmed power '…potentially leaving a demand/supply gap'.

The only additional generation investment assumed is a 200MW solar farm.

The CRIS presents an alternative Option 1 ('greater renewable penetration') that is:

> "…built out with higher volumes of renewable (solar and wind) and firming (battery) generation technology, to meet the same demand outcomes. This would involve higher development costs than gas fired generation development given the additional requirements to firm the load, however the delivered costs of energy would be lower."

Little detail is provided on the level of 'firmness' but if there are some concerns the costs to improve security/reliability are likely to be a small fraction of the cross-subsidy under Options 2 and 3. Many mining operations are now being supplied by isolated grids at an acceptable level of security/reliability.

Options 2 and 3 do have the benefit of a connection to the grid, but there are still risks e.g.:

- Flood risk in the wet season
- System security e.g. the events following the failure of a unit at Callide power station in May 2021
- Exposure to significant RERT costs as will be the case for large users in Queensland following events on the 1st February 2022[4].

Our conclusion is that it is not obvious which option has the highest reliability/security of supply.

Do Options 2 and 3 deliver a lower delivered price than Option 1?

There are a range of forecast delivered prices in the CRIS e.g. the discussion of Option 2 quotes $90/MWh as:

> "…what CuString anticipates what it could reduce the cost of electricity for large NWMP customers to…"

[4] This was nearly $40m excluding participant compensation costs https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2022/rert-activation-estimates-report-for-1-feb-2022.pdf?la=en

The advice from the NWMP Options Team is that the CRIS 'did not seek to target a specific price' and when we asked the NWMP Options Team about the modelling supporting the $90/MWh price, the response was:

> "CuString model outputs are based on assumptions within the CuString Financial Model which is commercially sensitive and cannot be shared."

It is not clear whether this price fits the Government's definition of 'affordable'? But then the price resulting from Options 2 and 3 is driven by the level of cross subsidy from small and large Queensland electricity consumers outside of the NWMP. Increase the subsidy further and delivered price could be $80 or $70 or less. Decrease it and the price increases above $90/MWh.

The following table draws together the delivered price forecasts from the CRIS modelling of the three demand scenarios - low, flat (status quo) and high demand which we discuss further below. The limited information in the CRIS means that it is not clear whether the modelled prices include particular components:

- Option 1 – the costs to investment to meet a similar level or security/reliability to Options 2 and 3; the benefits of a depreciated asset in Option 1 are considered e.g. a PPA price with a dedicated generation asset would reflect the depreciated value of those dedicated assets - these benefits do not occur with purchases at the prevailing wholesale prices
- Options 2 and 3 - appear to not include a range of costs that are discussed further below e.g. existing PPA termination, MLF, cost of connecting remote mines to the CuString network, ancillary services, NEM fees and the retailer margin.

In the absence of detailed modelling information for all three options, we think it is reasonable to assume that these additional costs would be greater for Options 2 and 3 vs Option 1.

The CRIS shows that even without those additional costs, the prices in Option 1 (greater renewable penetration) are lower or very close to Option 2 and Option 3 in all but one demand scenarios and time periods. There are no details provided on what level of renewable generation and storage assets would be built by the private sector in Option 1.

The green shading shows the lowest price forecast for each option under the three demand scenarios. If the Option 2 price is considered to meet the 'affordable' definition then Option 1 is also 'affordable'.

Demand Level		Contribution by RoQ ($m NPV)	FY 2025 $/MWH	FY 2031 $/MWh	FY 2041 $/MWh
Low	Option 1	0	121	82	83
	Option 2	1,733	104	105	102
	Option 3	1,093	104	104	101
Flat	Option 1	0	119	82	76
	Option 2	1,187	105	101	95
	Option 3	555	105	100	94

High	Option 1	0	95	101	88
	Option 2	1,084	103	100	92
	Option 3	474	102	100	92

As best can be judged from the CRIS, it seems that Option 1 has the potential to meet the Government's 'affordable, secure, reliable and sustainable' objective without any cross subsidy from small and large consumers in the rest of Queensland. However, no option can 'guarantee' their claimed prices. What seems to be the case is that the only way that Options 2 and 3 can come close to Option 1 is through the payment of a very large cross subsidy from small and large Queensland consumers outside of the NWMP.

Is it reasonable to assume that the final capital cost for Options 2/3 will be no greater than $2.5/2.2b?

The arguments supporting the price outcomes in Option 2 and 3 are based on capex of $2.5b and $2.2b respectively. The NWMP Options Team notes that the lower capex in option 3 comes from an interpretation of AER rules.

The NWMP Options Team said that the Option 2 capex is sourced from the CuString model that is commercial in confidence. What we do know is:

(i) The $2.5b capex is nearly a 50% increase on the $1.7b cost at the time of the EIS submission in January 2021[5] and a 250% increase on what was on the CuString website in 2020[6]
(ii) There is no indication on the level of accuracy (e.g. AACE cost class)[7]
(iii) All costs increase prior to financial close would be added to the project's RAB, and
(iv) 70% of subsequent cost overruns are put into the project's RAB.

The experience across the NEM in recent years is that the costs of major transmission projects has increased considerably as the project has progressed through its stages of project development until a final investment decision and contingent project application to the AER. The two major factors are social licence and supply chain pressures[8].

Project Energy Connect increased from $1.53b in its submission to the AER's 5.16.6 review to $2.4b at the time of its CPA (September 2020) with the AER allowing $2.3b (May 2021).

In the case of HumeLink, the PACR capex estimate (July 2021) for the preferred option 3C was $3,317m, a nearly 250% increase compared with the PADR (January 2020) estimate of $1,350m. Lines and substations increased 230% from $1,030m to $2,380m and biodiversity costs increased nearly 300% from $320m to $935m. The PACR estimate is classified as an AACE Class 4 estimate and hence still has a considerable degree of uncertainty (-30% to +50%). AEMO's experience in its development of the Transmission Cost Database for the 2022 ISP was that the majority of cost estimates increase over time[9].

[5] See https://www.statedevelopment.qld.gov.au/coordinator-general/assessments-and-approvals/coordinated-projects/current-projects/copperstring-project

[6] See https://reneweconomy.com.au/north-queensland-the-case-for-copperstring-link-to-mt-isa-and-renewable-mirogrids-14946/

[7] See https://web.aacei.org/docs/default-source/toc/toc_96r-18.pdf?sfvrsn=12

[8] These issues are being considered as part of the current Material Change in Network Infrastructure Project Costs rule change that the EUAA and others have proposed. Our submission to the AEMC discussion paper discusses these cost pressures in more detail. While there would also be cost pressures for the investment in Option 1 these are considered considerably lower given investment in Option 1 is focussed on renewable generation and batteries where costs are falling over time.

[9] See Slide 28 https://www.aemc.gov.au/sites/default/files/2022-02/aemc_cost_est_accuracy_roundtable_16_feb_2022.pdf

The timetable for building Option 2 or 3 will coincide with the timetable for major network investment – ISP actionable projects and State base REZ projects. It has been nearly 20 years since the last major interconnector was built (QNI). Infrastructure Australia's October 2021 report on the Market Capacity to deliver transmission projects concluded[10]:

> "The build-out of electricity generation and transmission infrastructure will create pressures on market capacity to deliver the supply of labour and materials required for a smooth, efficient energy system transition." (p. 6)
>
> Labour and skill shortages may become a significant factor for the build out of renewable generation and transmission infrastructure, especially in regions with tight labour markets. (p.7)
>
> "The current projections for labour demand in the energy sector could significantly underestimate growth, especially under 'energy superpower' scenarios where there is mass electrification and growth in renewable hydrogen for heavy industry, transport fuels and export with associated demand on labour and materials. (p.7)

The CRIS does discuss the risks of increased capex given the Project Energy Connect experience. It notes (p.16):

> "Modelling shows that increases in project costs flow through to electricity customers in rest of Queensland. An increase in the allowable revenue of CopperString of $31 million in FY25 results in an increase in cost to the rest of Queensland contribution of $17 million."

We asked NWMP Options Team what the second sentence means and their response was:

> "This is based on the CuString Financial Model which is commercially sensitive and cannot be shared."

Even if the cost ends up being no more than $2.5b, this is an enormous cost to supply, in the high demand case, a peak of 556MW and an average of 395MW over the life of the project.

Applying an 85% load factor means an average of just under 3 TWh is delivered each year. This gives a RAB/MWh of ~$850/MWh. Currently the total Powerlink RAB is around $7b and RAB/MWh is ~$150[11].

<u>Where are other costs that we expected to be included?</u>

It appears that the following costs are not included in the forecast prices for Options 2 and 3:

(i) Termination of existing PPAs – we understand existing PPAs with major users in the NWMP extend until 2030 when CuString wishes to start operations in 2025; the advice from the NWMP Options Team is that:

 "Option 2 does not contemplate break costs or other fees associated with existing contractual arrangements."

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[10] Infrastructure Australia "Market Capacity for Electricity Generation and Transmission Projects" October 2021 https://www.infrastructureaustralia.gov.au/sites/default/files/2021-10/Market%20Capacity%20for%20Electricity%20Infrastructure%20211013.pdf

[11] See Chapter 8 https://www.aer.gov.au/system/files/Powerlink%20-%20TRP%202022-27%20-%20Revenue%20Proposal%20-%20January%202021.pdf

(ii) Marginal loss factor – given there is no mention of MLFs in the CRIS we can only conclude that it is assumed to be 1 and this is supported by the selection of the $50/MWh wholesale price on the basis of the ASX futures last November; if so, it would be interesting to see the analysis supporting that assumption; prima facie we think that it is very unlikely given the assumption in Options 2 and 3 of 100% east west flows (p.21) at least from Hughenden.

(iii) Cost of connecting remote mining sites to the CuString grid – this is likely to be an expense of the mining operation but it will influence whether grid connection is cheaper than self-supply through a hybrid option

(iv) Ancillary services – the NWMP Options Team advises that:

"Option 2, CuString's proposal, assumes no costs for ancillary services in Mt Isa. Option 3 also adopts this assumption."

(v) NEM fees and retailer margin

<u>How reliable are the demand forecasts?</u>

The CRIS presents three demand forecast scenarios:

(i) Low demand – existing mining operations run to completion and demand in the NWMP declines over time.
(ii) Flat demand - status quo levels of demand continue (i.e. 373 megawatts (MW))
(iii) High demand - CuString's target demand case and assumes an increase in mining activity as a consequence of a lower electricity price (i.e. NEM connected electricity demand peaks at 556MW and averages approximately 395MW over the life of the project).

No information is provided in the CRIS on the methodology used to calculate to 'high demand' case. Advice from the NWMP Options Team is that:

> "…the high demand case is CuString's target demand case and assumes an increase in mining activity as a consequence of the lower electricity price"

No information is provided on important variables underpinning the high demand forecast:

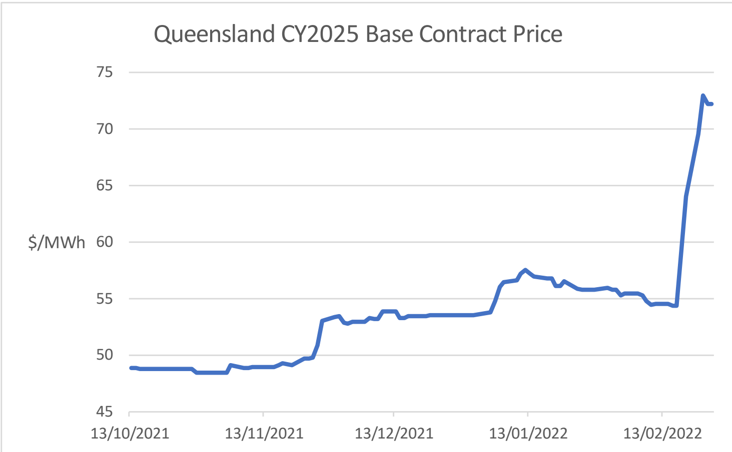
(i) How the demand forecast incorporates existing contracts with major users in the region that extend to 2030
(ii) Demand elasticities for current and future mining operations
(iii) Sensitivity testing on the impact of different NEM wholesale prices e.g. when hybrid self-supply might become cheaper; the forecast expansion in total electricity demand from mining activity could occur but that does not translate into the forecast high NEM demand.
(iv) Whether in referring to "NEM connected electricity demand peak" it assumes all electricity demand from the NWMP is NEM sourced or there is additional demand that is locally sourced within the region
(v) Even if new mines are developed will they continue to be developed over the 60-year CuString asset life? Apart from the main operation in Mt Isa, other mines have had a limited life as economic reserves have been exhausted e.g. Century Mine which started operations in 1999 processed its last ore in 2016; continual development of new mines is required to minimise stranded asset risk but the CRIS provides no comfort that

that will not be considerable risk for consumers in the rest of Queensland in the latter stages of the 60-year life of the transmission asset.

The forecast delivered electricity prices in Options 2 and 3 assume a $50/MWh ($2021) NEM wholesale price for the 40 year life of the project. The advice from the NWMP Options Team on the source of the $50/MWh number was:

> "The wholesale cost of energy (prior to delivery charges) is based on the ASX Contract price from November 2021 ($63 in FY23 reducing to $50 in FY25) held constant over the project life."

This is not a proper basis on which to build a forecast of long term delivered prices and a 40-year CuString business case. The figure shows the calendar year 2025 price since it started trading on the ASX in October 2021:



The lack of information in the CRIS means we are unable to test the demand forecast sensitivity to prices significantly above $50/MWh ($2021) for the next 40 years. The higher wholesale prices go after the NEM connection is built:

- the less likely new mining developments will occur - there is no information provided on how sensitive existing and future operations might be to say a 10-15% reduction in power costs compared to Option 1 when factors like reserves, LME price and $A exchange rate are also major factors in mining profitability.
- The less likely existing users will source from the NEM if local hybrid supply is more attractive.

What is clear is that small and large Queensland consumers outside of the NWMP will be exposed to considerable risk in option 2 if the high demand forecast is not met with the cross subsidy paid by small and large consumers outside of the NWMP increasing from $1.1b (High demand) to $1.7b (low demand). Option 3 has similar risk but at a lower level.

<u>What are the rules that the Independent Expert will follow?</u>
The extensive derogations mean that an Independent Expert will fulfil many of the roles normally undertaken by the AER to promote the long term interests of consumers in the National Electricity Objective. In particular the Independent Expert, rather than the AER under the CPA process, will approve the level of initial capex, contingency,

overruns, initial opex and sustaining capex for the first 5 years. While the AER operates on transparent and detailed guidelines[12], the CRIS gives virtually no indication of the rules under which the Independent Expert will operate:

> "…based on a test similar to that applied by the AER but adapted to the 'greenfield' nature of the project and adjusted to be timelier. Overruns of pre-approved expenditure will also be approved if the Independent Expert determines they are efficient. Some expenditure, including some financing costs and development fees and costs will be automatically approved."

When we asked the NWMP Options Team to provide additional details, the response was:

> "The Independent Expert will verify whether:

- the Initial OAB-MAR values proposed by CuS have been calculated in accordance with the MAR Methodology; and
- the building block elements of the proposed Initial OAB-MAR values satisfy the Efficiency Test

No details were provided on the Efficiency Test in the CRIS or the NWMP Options Team's response. Without that detail we are concerned about the additional risks for all small and large Queensland consumers outside of the NWMP. We wonder why the QCA, with its well established expertise, was not appointed as the Independent Expert.

Why is the guaranteed rate of return higher than the current AER regulated WACC?

CuString proposes a nominal 5.03% guaranteed WACC for 23 years compared with the AER 'placeholder' Powerlink nominal WACC of 4.65% the current AER regulated WACC for the next 5 years of 4.65%[13]. The argument from CuString justifying the higher rate is that equity investors are passing up the right to have the WACC reset every 5 years for the 40 year project period to give consumers the benefit of the current low interest rates.

We do not consider that a convincing argument. A 23 year WACC should be set on the basis of the risk sharing set at the time of making the investment. The extensive derogations from the national rules provide for considerable risk to be moved away from equity investors to consumers outside the NWMP when compared with the risk allocation under RIT-T process. This should result in a 40 year WACC below the AER rate, particularly given the benefit the owners receive by obtaining a component of debt from the NAIF at a concessional rate.

How reliable are the estimates of the cross-subsidy from consumers outside of the NWMP?

This is in two parts:

(i) Are small and large Queensland consumers outside of the NWMP paying all the cross-subsidy or is the Queensland Government (taxpayers) sharing some of the cost?

(ii) What risks are there that the indicative cross-subsidy numbers in the CRIS are underestimates?

On (i), the CRIS has a variety of statements about who pays the cross-subsidy:

[12] E.g. "Guidance Note – Regulation of actionable ISP projects" https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulation-of-large-transmission-projects/final-decision

[13] See p.4 https://www.aer.gov.au/system/files/AER%20-%20Powerlink%202022-27%20-%20Draft%20decision%20-%20Attachment%203%20-%20Rate%20of%20return%20-%20September%202021_0.pdf

> "The balance of the project cost after the NWMP contribution would be paid by customers in the rest of Queensland through electricity network charges." (p.3)

> "Electricity customers in the rest of Queensland pay less than a third of the amount they would pay under Option 2, and the beneficiaries pay the larger share." (p.21 referring to Option 3)

The Tables summarising the prices forecasts for Options 2 and 3 (Tables 6 and 8) have a column headed "Contribution by RoQ (taxpayers and electricity customers)"

The Tables on Impact analysis for Options 2 and 3 have separate stakeholder boxes for "Queensland Government (taxpayers)" and 'Rest of Queensland electricity customers", both of which under 'disadvantages' say:

Queensland Government (taxpayers)	Disadvantage The Queensland Government and electricity customers in the rest of Queensland are required to pay between \$1.1 billion (high demand) and \$1.7 billion (low demand) (including GOC network businesses augmentation expense) over a 40-year period, depending on demand levels.
Rest of Queensland electricity customers	Disadvantage The Queensland Government and electricity customers in the rest of Queensland are required to pay between \$1.1 billion and \$1.7 billion over a 40-year period, depending on demand levels. For a typical residential customer, this will be a negligible bill increase of approximately \$5 bill increase per annum. Major industrial customers, currently connected to the NEM, are likely to experience greater impact and could pay more in transmission charges annually.

But it seems reasonable to assume for the rest of this discussion that the Government (taxpayer) will not be making any contribution in the first 40 years of project life while the owners will be operating. At the end of 40 years the Government will acquire ownership and assume responsibility for the forecast \$1.1b remaining debt (\$170m in \$2021).

No information is given on the likely bill impact on large users.

On (ii) the key risks for large consumers outside of the NWMP are:

(i) The level of demand - the lower the demand the higher the cross-subsidy; the discussion above concluded that, in the absence of more information in the CRIS, we are unable to get comfort that the level of cross-subsidy will be close to that in the high demand scenario
(ii) The level of capex – capex above \$2.5b increases the cross subsidy amounts in the CRIS; the discussion above
(iii) The level of other costs apparently not included in the analysis
(iv) Decisions by the Independent Expert under rules that are not publicly available

In all four the discussion above has led us to have conclude that the level of cross subsidy in the CRIS may be underestimated. The quoted subsidy of 26% is simply a back calculation to get a $90/MWh delivered price in the high demand case. As we noted above, this is not referred to as a target price but may be indicative of what ‘affordable’ has been defined to mean. Whatever the ‘affordable’ price is it seems the level of subsidy will be adjusted to ensure the ‘affordable’ price (whatever that is) will be achieved. Any increase in project capex, any fall in demand or increase in capex will simply result in a higher cross subsidy. The level of cross subsidy is effectively a ‘goal seek’ to achieve a particular price and effectively uncapped.

Do not hesitate to be in contact should you have any questions.

Kind regards,

Andrew Richards
Chief Executive Officer