12-14 Claremont Street
South Yarra VIC 3141
Australia

Elizabeth Bowron
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Our Ref: JC 2018-082 18 October 2018

Dear Ms. Bowron,

S&C Electric Company response to the AEMC Options Paper – Coordination of Generation and Transmission Investment (EPR0052)

S&C Electric Company welcomes the opportunity to provide a response to the Options Paper covering the Coordination of generation and transmission investment.

S&C Electric Company has been supporting the operation of electricity utilities in Australia for over 60 years, while S&C Electric Company in the USA has been supporting the delivery of secure electricity systems for over 100 years. S&C Electric Company not only supports the "wires and poles" activities of the networks, but has delivered over 8 GW wind, over 1 GW of solar and over 45 MW of electricity storage globally, including batteries in Australia and New Zealand. We have also deployed over 30 microgrids combining renewable generation, storage and conventional generation to deliver improved reliability to customers.

S&C Electric are particularly interested in facilitating the development of markets and standards that deliver secure, low carbon and low-cost networks and would be very happy to provide further support to the Australian Market Energy Commission on the treatment and potential of emerging technologies and approaches.

Yours Sincerely

Jill Cainey

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Responses to Questions

Questions		Feedback
Chapter 4 – Making the ISP an actionable strategic plan		
▪ **Question 1: Questions arising from the ISP -** The paper considers a number of questions about the role and regulatory implications of the ISP, including the links between the ISP and transmission investment decisions.		
A)	Are there any questions about the role and regulatory implications of the ISP that are not set out in the options paper?	No
B)	Is our approach to making the ISP actionable (i.e. strengthening the link between the ISP and investment decisions) appropriate?	Yes

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▪ **Question 2: Interaction between the ISP and government policies**		
▪ A)	▪ The ISP will necessarily have to take into account government environmental and industry policies in modelling ISP scenarios. Do stakeholders consider it would be helpful for the COAG Energy Council to provide formal advice to AEMO as to what government policies or scenarios should be modelled in the ISP?	If the COAG Energy Council can agree on national advice, then that would be helpful. However, the federal position is likely to be at odds with the States' positions, so understanding individual state policies will also be important. It could be assumed that as customers are also voters (and are all required to vote) that customers will have already indicated their policy preferences as they apply to energy. Additionally, the political cycle is significantly at variance with the investment and asset lifetimes. This is a risk, but AEMO has a role in delivering a future system that should have no political bias (AEMO should not be subject to political whim), but accounts for the policies that are in place at the time of preparing the ISP.
▪ B)	▪ Are there other ways in which government policies that impact on the NEM could be incorporated as modelled scenarios in the ISP?	The ISP should provide real actionable solutions, rather than options for a range of "scenarios" E.g. the National Grid Future Energy Scenarios provides a range of approaches, but is not actionable and takes the form of "advice" that can be ignored. In recent times, it has been shaped by National Grid's wider business interests, but this will change with the transition to an independent system operator. State policies will drive what the TNSPs (DNSPs) will see connecting to their networks. In that sense the NSPs are best placed to understand the impacts of policies on their operations. Ensuring the TNSPs have a strong role in initially informing the ISP, should also account for local policies.
▪ **Question 3: "Strategic, national" investments and regional investments**		
▪ A)	▪ It is proposed that the ISP only focusses on "strategic, national" investments. Do stakeholders consider this is appropriate?	Will a focus on "strategic national" investments result in a dominant focus on interconnector, rather than intra-region assets? The ISP should consider all types of assets, including augmentation, replacement and new.

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▪ B)	▪ If so, how could this threshold be defined, or what criteria could be used to define it?	AEMO's role is to operate the market and deliver good market outcomes for consumers. Any asset that improves outcomes for consumers in a region or nationally should be considered, but it is difficult to know what that threshold would be (likely to be $ saved, rather than $ asset cost). The option is to allow TNSPs to "nominate" projects, via the TAPR process, which AEMO can consider or "improve" (because they have national oversight an may find slight variations that can deliver more value to consumers).
▪ **Question 4: Risk allocation**		
A)	▪ The paper canvasses a number of options for making the ISP actionable. How may the existing risk allocation for consumers, TNSPs and generators change under the proposed options?	Any option that places the investment decision with AEMO will need the AER to properly scrutinise that decision. If the decision rests with AEMO, then the TNSP should not bear the risks associated with that decision. It is not clear whether AEMO is currently subject to regulatory oversight that would encompass this or whether it has sufficient incentives (elsewhere perhaps) to ensure efficient outcomes for consumers on investment decisions. There are incentives in terms of market operation, but these may not explicitly apply to transmission investments. What model is used in Victoria?
▪ B)	▪ What other regulatory changes may be required in order to mitigate against changes in the risk allocation?	No comment
▪ **Question 5: Level of consultation required under each of the options for how the ISP could be made actionable**		
▪ A)	▪ What do stakeholders think about the level of consultation that would be required under each of the options considered for how to make the ISP an actionable strategic plan?	The ISP should undergo the same level of scrutiny and consultation as a RIT-T, particularly for options where the RIT-T would not be required. It would be inefficient (cost consumers more) to have a model where both the TNSPs and AEMO undertake "RIT-T-like" processes for a single asset.

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▪ B)	▪ Should there be more consultation for options that fall to the right-hand side of the table?	Not more, but perhaps if the ISP is to be the vehicle to make actionable investment decisions, then the initiation process (inputs) and the methodologies used should be consulted on. Similar to the processes considered in the consultation on placing an obligation on AER to determine VCR. Could the TAPRs inform (provide inputs to) the ISP, that is TNSPs indicate to AEMO where they see the critical "nationally" important projects should be?
▪ **Question 6: Role of the ISP, option 1 – Requirement for TNSPs to consider ISP- identified needs in their TAPRs**		
▪ A)	▪ What are stakeholder views on this option for how to make the ISP an actionable strategic plan?	Only explore option 4.
▪ B)	▪ Would the effective delivery of this option have an impact on the speed with which "strategic, national" investments are made?	
▪ C)	▪ Are there any regulatory or other implications that are not raised in the discussion of this option?	
▪ **Question 7: Role of the ISP, option 2 – Requirement for TNSPs to conduct RIT-T on ISP-identified needs and options**		
▪ A)	▪ What are stakeholder views on this option for how to make the ISP an actionable strategic plan?	Only explore option 4
▪ B)	▪ Would the effective delivery of this option have an impact on the speed with which "strategic, national" investments are made?	
▪ C)	▪ Are there any regulatory or other implications that are not raised in the discussion of this option?	
▪ **Question 8: Role of the ISP, option 3 – AEMO determines "best" option**		
▪ A)	▪ What are stakeholder views on this option for how to make the ISP an actionable strategic plan?	Only explore option 4

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▪ B)	▪ Would the effective delivery of this option have an impact on the speed with which "strategic, national" investments are made?	
▪ C)	▪ Are there any regulatory or other implications that are not raised in the discussion of this option?	
▪ **Question 9: Role of the ISP, option 4 – AEMO directs TNSP to proceed with the "best" option**		
▪ A)	▪ What are stakeholder views on this option for how to make the ISP an actionable strategic plan?	This option, with the appropriate initiation (which would need to fully involve the TNSPs, perhaps via TAPR or nominating key projects in their region), appears to be the one that would minimise duplication (e.g. RIT-T-like processes) and result in a quicker decision. AER oversight probably sits best at stage 3, leading to stage 4. If the investment decision is AEMO's, then the risk should be borne by AEMO, not the TNSP, although the TNSP should be the entity to deliver the asset.
▪ B)	▪ Would the effective delivery of this option have an impact on the speed with which "strategic, national" investments are made?	Yes, except that the environmental and planning processes probably dominate the delivery of any new TN asset. While this is not within the remit of AEMC, it might be worth asking the COAG Energy Council, if there is the possibility that "national strategic infrastructure" can have an accelerated planning/environmental process (nationally overseen versus state?)
▪ C)	▪ Are there any regulatory or other implications that are not raised in the discussion of this option?	As well as regulatory oversight, what incentives would drive AEMO to deliver efficient investment (versus market) outcomes for consumers? The RIT-T is covered by the NEO: of "efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers.". Would this autmatically apply to AEMO and the ISP?
▪ **Question 10: Role of the ISP, option 5 – AEMO directs TNSP to implement the investment**		
▪ A)	▪ What are stakeholder views on this option for how to make the ISP an actionable strategic plan?	Too little involvement of TNSP, who is best placed to understand the local needs.
B)	▪ Would the effective delivery of this option have an impact on the speed with which "strategic, national" investments are made?	See early comments on planning and environmental processes.

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C)	▪ Are there any regulatory or other implications that are not raised in the discussion of this option?	No Comment
▪ **Question 11: Other options and considerations**		
A)	▪ Are there other options to strengthen the link between the ISP and individual TNSP investments that are not raised here?	Is there a role for the TAPR to feed into the ISP (rather than, as in option 1, the ISP informs the TAPR)? Or can TNSPs nominate projects for consideration? TNSPs have the local knowledge and should provide direct input into the commencement of the ISP process.
B)	▪ Are there any other matters that should be taken into account when considering options to strengthen the link between the ISP and TNSPs' individual investments?	No Comment
Chapter 5 – the regulatory investment test for transmission		
▪ **Question 12: RIT-T benefits**		
A)	Are there any additional benefit categories that should be considered in the RIT-T?	Facilitating a reduction in carbon emissions.
B)	Why have no network businesses sought approval from the AER for additional benefits to be considered in RIT-T assessments as allowed for under the current NER?	No need to? Too Complex? Not perceived to be as "worthy" as other benefits (e.g. environmental benefits)?
Question 13: Potential concerns with the RIT-T process		
A)	What are stakeholder views on current limitations with the RIT-T process?	No Comment
B)	Setting aside the ISP and how to make it more "actionable," what other issues warrant attention when considering the objective of the RIT-T?	No Comment
C)	What changes may make the existing RIT-T process "faster"?	No Comment

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Questions		Feedback
D)	What is the role of a dispute process in the RIT-T? How could spurious disputes be minimised?	No Comment
Chapter 6 – Renewable Energy Zones		
Question 14: REZ options – enhanced information provision		
A)	Do stakeholders agree with our conclusions for how this model can occur under current regulatory arrangements?	No Comment
B)	Do stakeholders agree with our assessment of whether this REZ model is consistent with the options discussed for making the ISP actionable? What other considerations should be taken into account?	No Comment
Question 15: REZ options – generator coordination		
A)	Do stakeholders agree with our conclusions for how this model can occur under current regulatory arrangements?	No Comment
B)	Do stakeholders agree with our assessment of whether this REZ model is consistent with the options discussed for making the ISP actionable? What other considerations should be taken into account?	Yes
Question 16: REZ options – TNSP speculative investment		
A)	Do stakeholders agree with our conclusions for how this model can occur under current regulatory arrangements?	No Comment
B)	Do stakeholders agree with our assessment of whether this REZ model is consistent with the options discussed for making the ISP	Presumably a speculative investment would be for an asset that has not already been deemed to be a “nationally strategic” project in the ISP?

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	actionable? What other considerations should be taken into account?	
Question 17: REZ options – TNSP prescribed services		
A)	Do stakeholders agree with our conclusions for how this model can occur under current regulatory arrangements?	No Comment
B)	Do stakeholders agree with our assessment of whether this REZ model is consistent with the options discussed for making the ISP actionable? What other considerations should be taken into account?	No Comment
Question 18: REZ options – clustering		
A)	Do stakeholders agree with our conclusions for how this model can occur under current regulatory arrangements?	No Comment
B)	Do stakeholders agree with our assessment of whether this REZ model is consistent with the options discussed for making the ISP actionable? What other considerations should be taken into account?	No Comment
Question 19: REZs and access		
	Do stakeholders agree with our conclusion about the types of REZ models that are feasible under the current transmission access framework?	No Comment

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Questions		Feedback
Chapter 7 – Congestion and access		
Question 20: Conclusion on need to consider access issues		
	Do stakeholders agree with the Commission's conclusion in this Chapter that access and congestion management issues are likely to need to be addressed in the near term, once the role of the ISP has been addressed?	No Comment
Chapter 8 – Treatment of storage		
Question 21: Storage and TUOS		
	Do stakeholders agree with the way the Commission has framed the issue of whether or not storage should pay transmission use of system charges?	Electricity storage should be treated as a single asset, not as two separately connected assets, one load, one generation. It is inefficient to force electricity storage to bid as two entities and creates risks. This will require an "electricity storage" classification and a definition for electricity storage (e.g. "Electricity Storage" in the electricity system is the conversion of electrical energy into a form of energy which can be stored, the storing of that energy, and the subsequent reconversion of that energy back into electrical energy; "Electricity Storage Facility" in the electricity system means a facility where Electricity Storage occurs." Used in GB) to accommodate regulatory treatment that is applicable only to electricity storage. Electricity storage cannot be treated as "generation" or as "load", it is storage.
Question 22: Storage and TUOS - current arrangements		
	Do stakeholders have any comments on the Commission's initial views on storage and transmission charges? Are there any other arguments that are not discussed?	There should be no change to TUOS to "promote" or "incentivise" the uptake of electricity storage. Rather it should be treated fairly and in a way that doesn't penalise end consumers. Electricity storage cannot always be assumed to operate in a way that has minimal impact on the system. By treating electricity storage as both load and generation, electricity storage is unfairly penalised in

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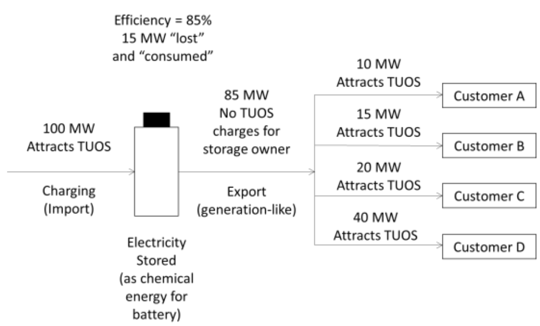
		comparison to other parties connected to the system (e.g. a generator). This is the view of Ofgem following a code review, which encouraged industry to take forward amendments to the grid code (CMP280 and 281) to exempt electricity storage from import TUOS (and import Balancing Services Use of System) charges. It is also the view of the European Commission, following amendments to energy legislation.
Question 23: Storage and TUOS - considering changing existing arrangements		
	Are there any matters the Commission hasn't discussed that should be addressed if a change to the existing arrangements for transmission charging for storage is considered?	**<u>Large-Scale Electricity Storage directly connected</u>** A very real risk of double-charging TUOS exists if TUOS is levied on large-scale electricity storage when importing (charging). Electricity storage imports, temporarily stores and then re-exports the electricity, where an "end consumer" then "consumes" the electricity. Some of the electricity used to charge the electricity storage is retained in the device, due to the efficiencies of storage. See diagram below:  If the import into electricity storage attracts TUOS and then attracts TUOS again, this is double charging and will result in higher costs to the consumer, contrary to the NEO. While it is true that the import of electricity into electricity storage is "use of system", export is also "use of system", but for historical reasons we deem "generation" to be "good" and so it avoids UOS (at all levels in the system). Export (generation) has technical impacts on the network, that result in NSPs investing to resolve, that is

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		export has a real cost to "use the system", but we currently ignore those costs. Arguably, as demand falls it is generation that results in higher costs to operate the system, but it attracts no UOS charge and has no role in funding network investment. This is inequitable (for many reasons) and an outdated approach. Import and export use the system and both should attract a charge. In the current regulatory framework, where only import attracts a charge, the imposition of TUOS on imports into electricity storage results in double charging of TUOS. Additionally, generators may claim "auxiliary load" for their imports, avoiding TUOS. This places electricity storage (currently deemed to be a generator in the NEM) at a disadvantage to conventional generators, who compete in the same service markets. The electricity "retained" by electricity storage may attract TUOS, as it is properly consumed (this means metering both import and export to determine the consumption). It may also be deemed to be auxiliary load, as this loss is necessary to operate the electricity storage device. Creating an "electricity storage" classification would remove the need to electricity storage to register as a "load" and resolve the need to pay TUOS. In system terms electricity storage will be seen as load and this will need to be managed by AEMO. The model used for data/communications where costs are recovered on download (import) and upload (export) demonstrates use of system in both directions and consumers readily understand this concept. **Large-scale electricity storage located behind a connection** Where the electricity storage is not charged from beyond the connection (does not import) it should not attract TUOS (e.g. fully charged by generator, either conventional or low carbon, option 1, page 106). If the electricity storage imports to charge, this should not attract TUOS, but care is needed to ensure that export, from a low carbon generator, is not "mixed" or that export from the electricity storage (where charged

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		external to the connection) does not count as low carbon electricity. **<u>Small-scale (domestic) electricity storage located behind a meter</u>** (Applies to electric vehicles) Where electricity storage is located behind a meter, import to charge that device should attract TUOS. When the electricity is removed from system (to power a car – converted to kinetic energy) it will not be re-exported. (e.g. option 2, page 106)
Question 24: Storage and TUOS - additional considerations		
	When considering the approach to the recovery of transmission charges, are there any additional factors worthy of consideration that the Commission has not listed?	No Comment

Storage charging

Summary note

February 2018

Purpose of this note

This note explains how network charges apply to storage, and how the industry is reviewing the residual element of transmission network charges, and BSUoS charges, for electricity storage.

Executive summary

Storage operators currently pay transmission (TNUoS) and distribution (DUoS) network charges – including forward-looking and residual charges – when they 'import' electricity from the networks (treated as demand) and when they 'export' it back onto the networks (treated as generation). Storage also pays Balancing System Use of System (BSUoS) charges both for demand and for generation.

Ofgem set out its provisional view - in the Targeted Charging Review (TCR) consultation and its Smart Systems and Flexibility Plan – that storage should not pay the 'demand residual' element of network charges, and that storage providers should pay only one set of balancing system charges. In the TCR Significant Code Review launch letter, Ofgem confirmed that view. It is Ofgem's view that storage should continue to pay forward-looking network charges for both import and export (noting that forward-looking network charges are currently under review in the Electricity Network Access project).

Industry is currently working on modification proposals to remove the demand residual element from TNUoS and BSUoS for storage (and generation, which may also face residual demand charges if it needs to import electricity at times). Two industry modifications, CMP280 and CMP281, propose to remove the demand residual element from TNUoS from storage (and generation), and the demand BSUoS charge from storage, respectively.

There is not at present an active modification proposal relating to the residual element of distribution charges for storage. However, the Distribution Charging Methodology Development Group (DCMDG) has recently discussed a potential modification proposal that may be raised in future.

Depending on the detail of the final proposals, these changes could address some of the differences in charging treatment between storage and generation. Ofgem will need to consider the final proposals, and any evidence submitted with those, in making a final decision on these modifications.

What's driving change?

Storage is currently treated under today's residual and cost-recovery charging methodologies as follows:

- For TNUoS, transmission-connected and larger (above 100MW) distribution-connected storage (and generation) pay both the generation and demand TNUoS residual elements.
- For BSUoS, transmission-connected and larger distribution-connected storage (and generation) pay BSUoS charges on both imports and exports of electricity.
- For DUoS, distribution-connected storage pays residual demand charges.

Storage competes with generators in providing services to suppliers, customers and network operators. Storage providers competing with generators in the provision of ancillary services are therefore at a competitive disadvantage, which is likely to distort market outcomes and so disadvantage consumers.

Storage can also sometimes compete with demand, to take excess generation off the network and help to balance the system. However, a key difference between demand and storage is that demand is an end user of electricity. When the electricity provided by the storage operator is consumed by an end user, demand residual charges apply. So under the current system, electricity that is stored, then exported and used, attracts demand residual charges twice, with the storage operator and the end user both paying.

Ofgem's provisional view is that residual charges should apply to storage in a similar way as to generators.

Under the current charging methodology, transmission-connected and larger distribution-connected storage providers pay BSUoS on both their import and export volumes. Storage providers are therefore contributing more towards the cost of balancing the system than other users.

The table below sets out the current charging arrangements for transmission-connected and both large and small distribution-connected generation and storage.

		T Final Demand	T Generation	T Storage†	D Larger EG**	D Larger Storage**†	D Smaller EG*	D Smaller Storage*†	D Demand
Transmission residual	Generation		✓	✓	✓	✓			
	Demand	✓	✓	✓	✓	✓	Paid††	Paid††	✓
Distribution residual	Generation				Only EHV pay#	Only EHV pay#	Only EHV pay#	Only EHV pay#	
	Demand				✓	✓	✓	✓	✓
Balancing	Generation		✓	✓	✓	✓			
	Demand	✓	✓	✓	✓	✓	Paid	Paid	✓

✓ - Pay the charge Paid – can get paid the inverse of the charge when generating
* <100MW EG **>100MW EG
† - may be affected by ongoing storage modifications CMP280 & CMP281
†† - will be replaced by dedicated embedded export tariff following CMP264/5 WACM4 implementation
# - only those connected at HEV level pay distribution demand residuals. All other are exempted

Where is this issue today?

Industry has put forward two modifications to change the TNUoS demand residual and BSUoS charges: CMP280 and CMP281.

The working group has met five times so far, and work is progressing to further refine the modification proposals before industry consultations in early 2018.

There is currently no active modification proposal that would remove the residual element of distribution demand charges from storage. Ofgem's provisional view is that this element of network charges should not apply to storage in future. The DCMDG, an industry stakeholder group considering distribution network charging, has recently discussed a possible new modification that may be raised in future.

How might this change in future?

To address TNUoS charges, CMP 280 would amend the CUSC definition of those parties liable to TNUoS demand residual charges to remove the reference to generator parties, including storage. A new generator demand TNUoS tariff, consisting of only the forward-looking elements of the demand TNUoS tariff, would apply when storage and generators import electricity.

The current proposal would apply to storage and generation that is connected at transmission level, and larger (over 100 MW) storage and generation connected at distribution level. The working group set up to examine this proposal is exploring whether to extend the proposal to smaller generation and storage, and will work to understand the impact of extending or not extending the proposal in this way.

On BSUoS charges, CMP 281 would change the BSUoS charging methodology to remove the BSUoS liability from storage facilities' import volumes. This can be achieved by defining an 'Exemptible Storage Balancing Mechanism Unit (BMU)' and removing the liability for this party to pay BSUoS on its imports from the National Grid system. This exemption would mirror that in place for BMUs and trading units associated with interconnectors.

The working group is exploring alternative ways to remove the import BSUoS liability, and has developed other options to be further discussed at future meetings.

What are the next steps?

Working groups for both CMP280 and CMP281 will meet over the next three months to finalise the proposals before issuing a consultation early next year. We expect the proposals will come to Ofgem for decision in the first half of 2018.

How can you get involved or find out more?

Contribute

- Follow developments and respond to the upcoming consultations (see links below).

Learn

- CMP280 – Draft proposal and other material available on NG website: https://www.nationalgrid.com/uk/electricity/codes/connection-and-use-system-code/modifications/creation-new-generator-tnuos
- CMP281 – Draft proposal and other material available on NG website: https://www.nationalgrid.com/uk/electricity/codes/connection-and-use-system-code/modifications/removal-bsuos-charges-energy

Ask

- National Grid as CUSC Code Administrator at CUSC.Team@nationalgrid.com