Q&A from AEMO and CIGRE System Strength Workshop, 6 November 2020

No	Question / Comment	Response to Question / Comment
1	**Will you share the slides or recordings?**	The recordings have now been uploaded on AEMO's website and on CIGRE Australia's YouTube channel. Please refer to links below. https://www.aemo.com.au/learn/energy-explained/system-strength-workshop https://www.youtube.com/playlist?list=PLwGHigN9C41BaJhk_rfXeoT8e67-m4aDX
2	**Why is "system strength & voltage" a millisecond issue? You define system strength and voltage in milliseconds – however converters use current loop controls referencing the grid voltage waveform and acting within 10s of microseconds to limit/protect the convertor. Are you comfortable your definition captures this?**	Yes, converters/inverters do typically have control systems in the order of microseconds rather than milliseconds. However, they rely on milliseconds range network information and their variations to make sense of what is happening in the network and whether they need to adjust their response when a contingency occurs. Another question also raised the point about narrowing down system strength to voltage-related matters, and we agree it might be prudent to revisit the definitions. System strength pertains to the supports required to maintain the integrity of the 50 Hz AC electricity network and its connected plants, so uninterrupted energy flow can occur between all users and the system recovers from disturbances. The power output from synchronous machines is modulated on timescales generally of 0.1 second or longer, and power output from inverters on timescales down to 1 millisecond. The transient switching dynamics of inverters at the microsecond level are relevant to their performance and to the production of harmonic distortion, but are not considered to directly influence the gross changes in power output that are material to the integrity of the power system.
3	**Can you explain what you mean by system strength ahead of addressing what are likely to be many queries on this point? For example, it is not clear why synchronous generation or VSM properly defined would denude system strength rather than improve it. I suspect you are referencing classical machine stability considerations which will always be present. For me system strength relates to sensitivity and stabilisation of the voltage waveform, which classically inertia and SCL have been shorthand for, but in reality are abstractions of the broader range of factors present.**	Real and virtual synchronous machines are often but not always a solution for low system strength conditions. However, they cannot be considered a silver bullet and their known issues must be accounted for. For example, small synchronous generators in remote parts of the network will have their own stability issues. Care therefore needs to be taken so the solution for the original problem does not cause secondary issues or have its own susceptibility mechanisms. Your last comment, that system strength has been used as an abstraction of several phenomena and factors, is certainly valid.
4	**What about small signal stability? Grid-following control is both capacitive and resonant in nature and frequency domain interaction at particular operating points/ network topology cannot be precluded.**	It will be helpful to develop a deeper shared understanding in the technical community of the role of inverters in the production and damping of oscillatory modes in power systems. Current tools are well developed for synchronous machine modes but often do not incorporate small signal inverter models. This is not primarily a system strength issue, but it may be addressed should issues arise in practice.

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5	**Do you have any challenges with adding synchronous condensers to alleviate low system short circuit strength issues? In other words, do you have situations where addition of synchronous condensers does not provide adequate system short circuit strength?**	EMT studies are required on a case-by-case basis to determine the optimal size, location, inertia and control system parameters for syncons. Syncons generally provide the necessary short circuit power for the IBR. However, if not carefully designed they can have their own side effects, including instability subject to a network fault if a small and low inertia syncon is used in remote parts of the network. It should be noted that synchronous condensers are not the only solution to system strength issues. Some issues, such as control interactions, may be better resolved through other means such as controller design and tuning, and the addition of synchronous condensers may mask the problem or may not fully resolve the issue. A thorough assessment of the issues is required to specify suitable solutions.
6	**If we have good/high system strength we will not have issues? What is the recommended (or target) system strength?**	Yes, higher system strength would mean lower risk (rather than no risk) of IBR interactions and power quality and protection system issues. There is no single target level, as the needs are determined by generation mix. For example, the required level would be higher if sources of system strength are synchronous generators and condensers only, due to their relatively higher fault level provision. The level would reduce if advanced grid-following inverters and grid-forming (virtual synchronous machines) play a part in providing those solutions. The higher the share of these inverter-based devices in the system strength solutions, the lower the required level of system strength would be. Beyond a certain level, higher system strength results in higher prospective fault currents in power systems, which can exhaust the design headroom built into network equipment such as circuit breakers and buswork. This was an issue for the Victorian network 15 years ago and resulted in offers to connect being refused due to the additional fault current contribution exceeding the available headroom in the system. Typical fault current ratings for substations are 31-40 kA.
7	**What is the AEMC doing with respect to large inverter-based loads, such as hydrogen?**	The impact of inverter-connected loads on system strength has not been considered as part of the current system strength review, except where a device can operate both as a load and as a generator (for example, battery energy storage systems).
8	**Any experience with simulation testing of latest HVDC technologies for improvement in system strength and system short circuit strength ?**	HVDC links are considered IBR and the fundamental principles and limitations of grid-forming and grid-following inverters apply to them. A large grid-forming HVDC link with virtual synchronous machines capability will have a positive impact on system strength.
9	**Can we consider weak system strength in areas where the value of short circuit current is low?**	Yes, there is generally a direct relationship.
10	**Is system strength an issue at a certain network voltage level like 500 kV, or is it across the whole transmission network including 220 kV, 132kV, etc?**	It is generally an issue for all those voltage levels, and there is no direct relationship between the voltage levels and severity of system strength issues. However, 220 kV and lower voltage levels are often in more remote parts of the network where system strength issues would be more pronounced (also refer to discussions on network sparsity in the workshop).
11	**Voltage support and voltage control is a network issue as much as it is a generator issue. Don't NSPs have obligations to plan for the voltage control of the network?**	Both generators and networks have obligations with regard to the voltage control. Generators' obligations are specified in their generator performance standards whereas networks' obligations are set out in their system standards described in Chapter 4 of NER. It is therefore a collective responsibility.
12	**Even offline EMT models require simplification, both for simulation efficiency and compatibility within a wider network model. How are you validating that the models you are using of IBR in PSCAD etc are realistic and sufficiently complete?**	These models are validated against testing and events in the real system through the commissioning process and through permanent disturbance monitoring requirements.

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13	**Is it possible for us to reduce the speed of control of IBR (during the fault or steady-state) and increase the amount of connected generation compared with each IBR set control loop with high gains to satisfy the NER's Automatic Access Requirements?**	Please refer to answer to question #28 for further details.
14	**Why is there still a requirement for PSSE models assessment for weak grid connections if they do not truly reflect the model response?**	It's because PSSE models are still adequate to assess plant response to other, slower dynamic phenomena (e.g. frequency events), to understand basic plant performance/behaviour (e.g. how does a setpoint change manifest? What schemes are activated during a fault?), and are also used as a basic screening tool to identify potential issues (i.e. if something looks off in a PSSE model, it warrants further, detailed review in PSCAD). PSS/E remains as the workhorse for routine stability assessment of the system, because despite its relative simplicity it still captures (when using custom OEM models written to incorporate a representation of the actual plant controls) at least 90% of relevant stability phenomena with a fraction of the time and resource demands of EMT models. EMT models are still required to probe the remaining 10%, particularly as part of due diligence for new or altered connections, but this must be targeted to the plant and the critical phenomena in question to fit a reasonable resource budget.
15	**The AEMC refers to SCR and AFL as a means of a measure, and yet AEMO say that SCR and AFL are a very poor measure of SS, and not adequate. This presents as a disconnect?**	Coming up with metrics for system strength is something of a 'wicked problem', with a need to balance accuracy with practicality. There's a lot still to understand, but in the meantime metrics like AFL serve an important but imperfect purpose.
16	**To resolve the information sharing paradox – you can solve the problem if a) you fully represent the converter and b) you use validation processes to understand on an I/O basis what the likely vulnerabilities may be. These two insights allow focused study.**	Further clarification is required to be able to respond to this comment.
17	**Opal-RT can also allow hardware integration; this is particularly useful for protection analysis and project specific consideration which extends FAT principles.**	Indeed. This has been considered as an area of further expansion in the future.
18	**Powerlink recently announced they will invest in a synchronous condenser to assist IBR connection. If the synchronous condenser is a regulated asset, then consumers will pay for the locational decision of IBRs i.e. the no harm has been absorbed by consumers.**	This announcement is purely related to a non-regulated project and consumers do not pay for any non-regulated work.
19	**You mentioned Opal-RT in your tools slide. Are you going to be converting all your PSCAD models to Hypersim models? How difficult is it?**	The novelty of the approach Opal-RT has proposed in this investigation is that we don't need to explicitly convert the full PSCAD model into a Hypersim model, but instead run existing PSCAD models in the Hypersim platform in near real time. We want to avoid model translation as much as possible, so no translation errors are introduced.
20	**Can I please know whether there are any grid-forming inverters operational at present in any of the transmission networks in Australia or anywhere in the world?**	The main Australian example is still Hitachi ABB's ESCRI project at Dalrymple, SA, discussed during the workshop. Internationally I understand the Dershalloch wind farm (Ayrshire, UK) operates with VSM grid-forming technology.
21	**Is there any recommended approach/method to validate PSCAD model against reals system responses/measurements?**	AEMO uses two approach for validating models – the playback approach and the full integrated model approach. The playback approach is simple and can be used to verify model itself, while the full integrated approach can be useful for system validation.

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22	**It seems that PSSE is not considered trustworthy for anything beyond load flow, whether we're talking about fault response or even steady-state oscillations. It does seem like a lot of time is wasted on PSS/E given that PSCAD wide area modelling is maturing.**	PSSE still has value. Please see the response to question #14.
23	**The AFL methodology appears to assess synchronous generation as contributing positively to fault level, and subtracting the contribution from asynchronous generation. This is obviously not what happens in the physics of the situation. Is AFL valid?**	AFL has its merits and limitations. The confusion arises from the fact that system strength and fault level are sometimes used interchangeably. Both IBR and synchronous machines provide positive contribution to fault level, but some IBR have adverse impact on system strength. In other words, while IBR provides positive contribution to the fault level it can have a negative impact on system strength. Overall, there is merit in reconsidering the applications of AFL from both generator connections and power system planning perspectives. This is particularly true as more IBR gets connected and some of them are increasingly providing solutions to system strength issues without installing synchronous condensers.
24	**What is the % of projects that are not required to go through FIA (based on PIA)? This method leads to late changes in a project and has caused significant costs – the timing of the assessment is flawed.**	Given the increased penetration of IBR, 100% of IBR plants go through the FIA process. FIA must be carried out before an offer is made by the NSP. This helps proponents in understanding the risks associated with system strength remediation. In the CitiPower/Powercor network, since the System Strength Impact Assessment Guidelines were published, there are connection applications with a positive PIA result, meaning an FIA is not required. However, the percentage is lower than the one with a negative PIA result, and it is decreasing fast with more IBR plants connected. In addition, although some projects have a positive PIA result, they still need to go through the detailed PSCAD assessment since their connection point is within a low system strength zone, such as West Murray.
25	**We have had several PIAs stating that FIA is not required, only to be told at application that it is required for all projects. We are not averse to FIA but need to plan for it. Does AEMO intend to revise the guideline to reflect this?**	Often there is a significant time gap between enquiry stage (when PIA is performed) and application stage (when FIA is performed), and very likely other IBR commit during this time. This changes the outcome of the PIA that was done without considering any newly committed plants. Also, in the last 18 months, industry has learnt that the PIA doesn't predict the possibilities of control interactions (the most common system strength issues in the NEM), so PIA conclusions may be changed based on the new learnings.
26	**Do you have any thresholds to identify that 10% of the scenarios? Like weak grid locations? MW/MVAS Short circuit available**	System stability is the outcome of the interaction of many different generation types and technologies in wider power system together with the transmission and distribution networks. Therefore, we cannot only look at what criteria an individual IBR or a cluster of nearby IBR meets, but also how they interact with the rest of the power system. Simulation studies carried out by AEMO and several NSPs have consistently confirmed that even in parts of the network with higher system strength, detailed modelling and analysis is often required to capture the correct behaviour of IBR which cannot be adequately represented in conventional power system modelling. The same reasons are behind several attendees' questions on the veracity of preliminary impact assessment for system strength impact assessment.
27	**As you mention, SCL based impact assessment is a crude measure. Have you considered requesting z plots across a suitably wide frequency range to inform frequency scanning for complementary network/converter resonance, adapting SCL thresholds accordingly?**	This is being considered in academia and in some CIGRE working groups, in particular CIGRE WG C4.56. However, its merit in practical applications has not yet been fully demonstrated.

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28	**Control theory indicates that high control gains can cause oscillatory response. If you relax the speed requirements for response, it is possible in many cases to avoid oscillation – should we change the rules to allow this to occur?**	It is correct that the fastest response under low system strength conditions can increase the likelihood of adverse interactions. The ability to reduce the speed of response is currently permitted by the NER, where a range between automatic and minimum access standards can be negotiated depending on the needs of specific projects and agree on a negotiated access standard. We also note that: • Experience from actual projects in various regions indicates that a reduction in the speed of response by itself is not adequate to mitigate low frequency oscillations, and many other changes were required to ensure a stable response under low system strength conditions. • A reduction in the gain of associated loops should only be considered if improving overall stability without compromising other aspects of system stability. • AEMC determinations on technical rules support the philosophy that where rules treat particular control settings, they prescribe a plant capability only, and do not mandate application of specific settings in the field. There are arguments for more flexibility in the range of settings permitted (particularly on matters such as voltage thresholds for special fault ride-through control modes). In other areas, the focus of rules on performance outputs of the plant rather than inputs is appropriate.
29	**With the prevalence of PWM inverters producing a significant amount of +ve sequence harmonics, do you foresee any problems with the network and what are the mitigation solution available to us?**	PWM converters produce positive-, negative-, and zero-sequence harmonic contents. Low order harmonics have not been significant to date with moderate levels of IBR penetration. Interaction with other IBRs or excitation of a network resonance frequency could amplify these harmonics.
30	**Harmonic voltage issues are normally defined in standards via 20-minute averaged compatibility limits, aligned with thermal considerations. It looks from the data you're presenting and the control interaction concern it's about transients – do codes cover this?**	Harmonic issues are generally divided into emissions and susceptibilities. It is correct that harmonic standards are primarily for the emissions aspect and don't often address the transient and event drive aspects. This is a known gap worldwide, and would merit the development of appropriate standards.
31	**What are some of the mitigation techniques used by generators to resolve system strength issues? The question relates to the last presenter who said they perform revised studies to confirm that mitigation measures put forward by a generation proponent are OK.**	Existing remediation schemes generally comprise inter-trip schemes or syncons. System strength mitigation techniques can be generally categorised into three classes: • Hardware-based solutions, which involve deployment of additional plant such as synchronous condensers which address the fundamental electrical properties such as effective/Thevenin impedance and fault levels of the affected regional network. • Control system tuning-based solutions for cases where the fundamental underlying mechanism for the system strength issue relates to the adverse interaction of dynamic plant control systems within the affected regional network. • Deployment of appropriate active damping control system(s) within the affected regional network. The first two approaches have been used/demonstrated in the NEM; the third is an active area of development and research internationally.
32	**Can the harmonics issues generally be solved by installing filters?**	They are often effective to deal with harmonic emission issues, but not for harmonic susceptibility issues. The potential for creating high steady-state over-voltages and anti-resonances in the network should also be considered.
33	**Have you encountered protection challenges at distribution level? You would expect more overcurrent protection and some distance on complex tee-ed arrangements – would it mean this is a topic for you?**	At CitiPower/Powercor, we have encountered new protection challenges at both the sub-transmission and distribution levels with more generators, especially IBR connected; examples include more runback and inter-tripping schemes being required, and changes to our existing AVR protections.

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34	**To better manage the DER at DNSP level, which organisations have started to implement the DERMS (distributed energy resources management system) solution, and what were the results?**	At EQL, we are looking at DER orchestration, in particular around dynamic operating envelopes driven by distribution state estimation. CitiPower/Powercor is working on a DERMS platform but it is still in its early stage of implementation. We expect to fully roll out in the next couple of years.
35	**Is it possible for TNSPs to plan ahead for adequate system strength in a REZ assuming generic IBR without knowing the detailed project models?**	Planning based on generic IBR would minimise the risk of system strength issues during the connection process. However, detailed study using site specific models must be done at the time of connection to understand the system strength requirements for a particular project.
36	**In addition to understanding system strength (via EMT simulation) for assessing new connections to the grid, how much work has been done on estimating system strength using online measurements?**	At present online estimation of system strength is limited to the calculation of fault level in Tasmania. The actual system strength comprising other factors than just the fault level is not currently estimated online. Pilot projects are currently occurring in the NEM to estimate inertia online. This is much simpler than estimation of system strength. Following this trial, online estimation of system strength requiring more complex algorithms will be pursued.
37	**Does a generation owner operate remediation (RAS/SPS) if installed by them?**	The answer is yes, but not always. In the case of Kiamal, TransGrid is operating the syncon. This is not the case for all syncons installed as system strength remediation.
38	**"In the long-term interest of consumers" has been rejected as having any relationship to environment. Consumer is an economic concept not a social one.**	We understand this is an observation on the regulatory regime and no response is required.
39	**Is there a clear way, apart from running studies and multiple testing, to identify the precise size of syncon required to bring a connection point with low system strength (certain SCR, XR ratio) to an acceptable level for the connection of a renewable farm?**	One can estimate the size of a synchronous condenser by determining the SCR needs of IBR for which synchronous condensers are intended. However, detailed EMT studies are always required to confirm the exact size. In our experience, the two approaches could provide answers differing by several tens of MVA. The rule of thumb is to estimate the fault current contribution from the syncon for a three-phase fault at the point of interest and equate this to the equivalent MVA fault level increase relevant to the SCR measure of system strength. But ultimately metrics like fault level and SCR are only partial indicators of adequate system strength, and the actual performance of plants is a function of system attributes and the behaviour of the plant control system itself.
40	**Is there a requirement to curtail generation when the syncon is out of service?**	In the case of Kiamal, yes, the present arrangement is that the solar farm cannot generate without the syncon.
41	**Is there any public information on the Total Eren contract with AEMO for system strength (e.g. cost/price or allocation between SF needs vs. AEMO need)?**	No, this information is confidential.
42	**Harmonic measurement is performed with inadequate measurement equipment such as a standard CVT. How are TNSPs and AEMO aiming to address this challenge? Note the current IEC and AS standards do not provide a detailed specification for measurement equipment.**	CVT's are only inadequate if they are used without appropriate compensation. Direct measurement of voltage via a CVT will not enable the harmonic content to be accurately determined. However, if proprietary devices such as PQSensors are installed to the CVTs, it is possible to observe The full harmonic spectrum up to the normal limits (usually 50th). NSP's are now applying such measurement systems on a routine basis and are therefore able to continue managing power quality issues across their networks irrespective of whether they have access to CVT's or inductive VT's are their substations.
43	**Actual power theory and fault current from synchronous machines always has Iq and Id in each phase.**	It's correct that the natural fault response of machines always includes both active and reactive current components. These adapt automatically to the changing characteristics of the system as the fault is applied and cleared, with overall stability of this behaviour being assured as a consequence of Ohm's law behaviour for voltage sources and the assumed passive (dissipative) nature of the network

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44	**Are system strength issues largely solved by engineering solutions, or is it a two-pronged solution also involving consumers (i.e. consumer engagement and network tariff reform to bring consumer load on e.g. irrigated farming & generator load of pumped hydro & batteries)?**	System strength can be a wide network issue or a local issue. For wide network system strength issues, engineering solutions are often required (e.g. upgrade network, install synchronous condensers, re-tune existing control system). For local system strength issues (e.g. a particular area in a distribution network), apart from the engineering solutions mentioned earlier, consumer engagement is also a potential solution.
45	**Can we have a discussion on ensuring O/C & E/F Protection Operation where there are Low Short Circuit Ratios relative to Load currents as Inverter Interfaced DER Penetration increases with 1.0PU max output i.e. FLC?**	As far as the operation of over-current based relays are concerned there is no known difference on whether the fault current comes from synchronous generators or inverter-based resources. The key question is therefore whether there is enough quantity of fault current rather than specific type of fault current provision. With regard to specific reference to the DER, to the extent it would change the direction of power flow it could impact correct operation of directional relays. An indirect impact of increased uptake of DER is to reduce the need for online synchronous generators which would otherwise be needed to supply the demand. This would mean that a lower fault current will be available to over-current protections in the distribution networks.
46	**Grid-forming inverters – are the IBRs connected to the grid? Is there an example of grid-following inverter technology?**	Grid-forming and grid-following inverters are collectively classified as inverter-based resources (IBR). The vast majority of existing wind, solar and batteries in the NEM are grid-following inverters. More grid-forming inverters and their evolutions, e.g. virtual synchronous machines, are expected to connect in the NEM in the next few years. However, in the short term, grid-following inverters will still be the dominant type of IBR in the NEM and worldwide. Grid-forming inverter controls are common when inverters operate in standalone fashion with a passive load. The relative novelty in grid-forming applications is operating in this mode when connected to the grid; as discussed, this is a very different proposition technically to operating in standalone fashion. Most inverters that operate connected to the grid still use a grid-following control methodology.
47	**Can installing filters be effective or economic mitigation solution for +ve sequence harmonics? What are the impacts of excessive +ve harmonics on the system?**	Harmonic filters can interact with control system of IBR and destabilise the system if appropriate care has not been taken while designing and installing harmonic filter.
48	**Do you have any thoughts on some standardisation approaches to allow minor setting changes or firmware updates to be implemented quickly?**	Designing standard products for relatively lower system strength conditions in Australia's NEM would certainly assist. However, there is no guarantee that such a product will work for all network locations and conditions depending on the presence of other nearby IBR and their control system responses. At present Generators and their respective OEMs cannot have access to the wide-area EMT model which according to the NER is only available to AEMO and NSPs conducting the analysis. Industry wide access to these models would ensure that new, improved softwares and associated settings could be tested under realistic conditions, hence reducing the process time and the risks involved otherwise in not accounting for response of other nearby IBRs.
49	**How do you optimise the inverter controls for low SCR conditions under the N-1-1 or outage conditions?**	Generally, there is a trade-off between a fast and accurate set point response and a robust system. For weak grids, it can be an advantage to tune the PLL, current and power controllers and power ramps slightly slower than in strong grids. This of course has to be agreed with the TSO and can only be done to the extent that it improves the overall system stability.
50	**Negotiating appropriate control to suit the local conditions is a fundamental underpinning intention in the rules that has been subverted by a risk allocation adopted in the recent rule changes. Perhaps the auto standard for S5.2.5.13 needs to change to require what is most useful for the network.**	Agree that negotiating appropriate control to suite local conditions is important. Reactive power and voltage control is specified in S5.2.5.13 and the automatic standard includes the 3 most common forms of voltage control.

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51	**How does a TNSP proactively supply system strength under the current RIT-T process which is more 'just in time' or late?**	The current NER process requires TNSPs to maintain minimum levels of system strength at particular network nodes and this is factored into the network planning process. This minimum level is to ensure the security of the power system but it is not intended to enable new generator connections. Connecting generators are required to address system strength adverse impacts associated with their connection.
52	**This is my understanding about what is being practiced currently, however I am exploring the possibility of having an initial way of assessment and sizing before getting to investigating that by testing.**	This question seems to stem from whether a system strength remediation option could be precisely defined without any detailed PSCAD studies. The answer is no as without detailed studies there is a high risk that either the solution proposed is over-sized or does not meet the intended objective due to not accounting for interactions with other nearby IBRs which can only be identified by power system studies.
53	**Why is the Power Factory not used for EMT studies?**	When a decision had to be made on which EMT tool to use, we found more manufacturers had PSCAD models than Power Factory EMT models. We also want to avoid, as far possible, changing simulation tools, because every change brings compliance costs to the industry.
54	**Do you see any fundamental barriers to operating a system only with syncons and grid-forming inverters (plus sufficient wind, solar, and batteries)?**	There is no fundamental barrier to operating a system like this without any synchronous generators, as long as we can replace all characteristics of synchronous generators with other generation mix. This can be provided by a combination of different devices rather than one type of device providing everything a synchronous generator does.
55	**AS/NZS 61000.3.6: 2001 or 2012 in the rules?**	The rules current refers to AS/NZS 61000.3.6:2001. A stakeholder would need to submit a rule change to change this.
56	**Please explain a bit about online monitoring of system strength. Is there an optimisation algorithm behind that too, or it is derived only by the SS limits?**	Currently, it is derived by a measure of fault level at fault level nodes specified by network service providers.
57	**Can AEMO provide an example constraint equation for system strength management?**	There are two examples: Q_NIL_STRGTH_MEWF and N_FINLYSF_FLT_30. Information on these constraints is available on AEMO's website. Please refer to https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource
58	**Would an AI platform make this work easier?**	Not necessarily. An AI would still need to be fed with data to learn from, so PSCAD studies would still be needed.
59	**What avenues are there for proponents to work together with the relevant NSP and AEMO to develop appropriate Limit Advices and Constraint Equations to manage generator output rather than transfer trip schemes which may be undesirable?**	This would normally be discussed between the proponent and the TNSP at the connection enquiry/design stage.
60	**How does AEMO/NSP determine the threshold of likelihood for the need for a constraint given of the likelihood of an event moving outside the acceptance criteria identified within system standards (for example, P(N-1 ∩ network condition A))?**	AEMO manages the power system for the next credible contingency (which is generally the loss of a single element, but can be multiple elements). Constraint equations are built to align with the credible contingency requirement.
61	**Perhaps highlights one of downsides of reducing active current during the fault to achieve reactive current injection at POC (to reduce reactive losses across the reticulation and Q-priority current capability) during fault to meet S5.2.5.5 requirements. Is this caused by prioritising Iq and limiting Id as a result of tuning for the "capacitive reactive current"?**	Even in a traditional system based on synchronous machines, withdrawal of P will be seen during faults. The issue is really about the ability of the balance of generation to accept load in time, which we can express in terms of inertia+ FFR. I strongly suspect there will be circumstances where it's of most benefit to the system to just forget Iq and maximise Ip during the fault.

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62	**Based on actual experience with Hornsdale Power Reserve and the expected further benefits with the upgrade that includes a Virtual Machine Mode (synthetic inertia), how does the panel view BESS with synthetic inertia as a tool to assist managing the system?**	The HPR currently provides fast frequency response that has been shown to be a useful capability in assisting with managing the system. Appropriately designed synthetic inertia would also be beneficial. Synthetic inertia even from grid-following inverters will contribute to frequency stability, and the magnitude and speed of the response will be an interesting subject for further study. In theory, a grid-forming inverter makes a more robust contribution, but gathering empirical evidence from both types will be key.
63	**For voltage-induced frequency events presented by TasNetworks, can we have a bit more elaboration on how 'overall' system frequency is determined? Did TasNetworks collaborate the 'overall' system frequency against actual shaft speed of synchronous generator?**	TasNetworks does not have access to real time shaft speed measurements on synchronous generators. The results presented were from TasNetworks phasor measurement units (PMU's) which have been deployed across the network. It is true that frequency derived from voltage measurements will differ across the network during system transients, especially during large rotor angle swings on nearby synchronous generators or during fault ride through of adjacent wind farms. Material differences are usually only observable during and immediately after a network disturbance, with measured frequencies normally being very well aligned by the time the frequency nadir (or zenith) is reached. It is possible to calculate an 'average' system frequency by combining PMU measurements across the network and calculating an appropriate mean value.
64	**Due to the higher penetration of DER, the ROCOF is also likely to increase because of lower system inertia. Will this also encourage a change in UFLS?**	Increased penetration of DER will have two impacts: • Increasing the size of contingency than otherwise would have occurred due to their unexpected disconnections. • Reduction in the available load on UFLS. The combined effect of these two factors means that UFLS could be less effective under high DER scenarios. This specific issue has been investigated in South Australia for several months, which has resulted in adjustment of some of the constraints. Additional work is currently ongoing in South Australia, and similar work is likely required in some other regions.
65	**In some cases, oversized inverters can actually support their Iqmax (reactive current) while still maintaining some level of Id (active current) – however, reactive losses caused by the active current in reticulation encourages actually setting Id to 0. Synchronous machines always have both Id and Iq components in fault current.**	There are instances where additional equipment has been installed at generation sites, not for the purpose of boosting reactive capability in normal operation, but rather to meet a deemed standard of adequate reactive current during fault conditions. In certain cases, it is also found that a modest reduction in active current at the inverters can materially increase reactive current at the point of connection, even when the reactive current at the inverters is held constant. The industry would benefit from work to place fault current injection on a firmer theoretical foundation, so it is clear when a particular numerical level of active and reactive current injection during faults is beneficial or detrimental to system stability.
66	**What sampling rate of PMU was used for this application?**	50 Hz is sampling rate used by most of the PMUs across the NEM.
67	**Loads don't go away during system faults, hence critical clearing times due to change in loading on machines in the system.**	The significance of nearby loads in assisting in IBR stability was discussed in Vestas's presentation. It is correct that a lower nearby load would have some adverse impact on stability.
68	**Please comment on the requirement of "Fault Throwing" Test as stipulated in AEMO's Latest R2 Guideline published in Feb 2020 – (a) its purpose and (b) methodology, real-life fault?**	Such faults had been applied in Tasmania in two instances. However, the preparatory works required and impact on the market means that most often it cannot be practically conducted. Other methods with which one can gain sufficient insight in accuracy of FRT aspects of simulation models are the use of natural system disturbances captured via high-speed data recorders and application of staged system testing, which introduces much smaller changes in the system but could still provide useful information on system response.
69	**Is there any role for new small-scale rooftop/battery inverters in managing these issues? Many coming, in particular in Victoria.**	There's work to be done on developing 'resilient' inverters in these mass applications. The introduction of Volt/Var control and similar standards is a step toward this, but 'soft grid-forming' attributes may also evolve – not sure we yet know just how. Disturbance ride-through capabilities (voltage and frequency) are also an important aspect of new small-scale rooftop solar/battery inverters.

No	Question / Comment	Response to Question / Comment
70	**What studies are required to be performed with PSCAD for solar and wind generation?**	As the minimum, these studies are required when full impact assessment is required as described in AEMO's System Strength Impact Assessment Guidelines. As many panellists discussed, there has been a growing need for most connections to undergo EMT (PSCAD) studies for assessing various clauses of generator performance standards (GPS), in the same manner RMS (PSS/E) modelling has been used in the past.
71	**Can high speed data available for voltage, power, frequency and CB status be made available to generators to use a fast run back scheme to help in grid stability in case of lower system strength condition post fault?**	In theory yes. High speed data from one site can be made available to another site to implement runback/trip. However, this needs an agreement between multiple participants.
72	**Should the bespoke monitoring equipment be installed at sites with local recording and detection of anomaly (like the control loop problem)? Automatic recognition and exception reporting to attract human observation may help early detection of issues.**	Yes.
73	**Have you considered using DIgSILENT PowerFactory for all these analyses (voltage oscillations)?**	It is indeed possible but is dependent on model availability. When a decision had to be made on which EMT tool to use, we found more manufacturers had PSCAD models than Power Factory EMT models. We also want to avoid, as far possible, changing simulation tools, because every change brings compliance costs to the industry.
74	**Would a better trade off be to limit Iq to 0.7 pu as this will only limit Id to 0.7 pu? The current requirement of 1.0pu limits Id to zero.**	The alternative of over-sizing the inverters by 22% permits 1.0 pu reactive current to be delivered simultaneously with 0.7 pu active current. In practice it is often recommended that inverters be over-sized by a magnitude similar to this, to provide required steady state reactive capability over the normal voltage range.
75	**Why not include unbalance fault in your fault level reports?**	Current NER requirements specify three-phase fault levels only. Note that this is used as a simplified metric to give insight into system stability challenges rather than the efficacy of protection systems. Such an approach is consistent with worldwide use of fault level as a proxy for system strength. However, changes may be required if system strength is treated as a broader issue rather than fault level only. For the purpose of understanding system strength, the positive-sequence behaviour of the system is the most relevant.
76	**Does Psymetrix pick up 19 Hz oscillations? 7-10 Hz?**	Psymetrix as it stands now is unlikely to pick up these oscillations as they are observed within a small part of the network. These oscillations are different from electromechanical oscillations.
77	**With the anticipation of 63% of coal-fired sync generator retirement and combined rapid increase of harmonic sources from both loads and IBR, is there any plan to increase harmonic absorption capability in the network?**	Power quality is not currently considered as part of system strength under the existing regulatory frameworks. Therefore, there is no opportunity currently to plan for this specific impact of changes in the generation mix. However, the problem raised in the question is valid, and warrants careful consideration of harmonic aspects when looking at overall system strength issues. Note that power quality issues can also be dealt with by IBR themselves (e.g. active inverter filtering), and do not necessarily require harmonic filters or synchronous machines as the traditional sinks of harmonics.
78	**Is there an issue with AS4777.2 where distribution connected inverters, rather than disconnecting, cease to energise or active power goes to zero, so they remain connected but not providing power? Will this impact strength and/or harmonics?**	Detailed PSS/E models of loads and DER have been developed by AEMO recently and used by AEMO and some TNSPs for various studies and in particular impact on the size of contingency and interconnector transfer limit. PSCAD models of loads and DER are being currently developed and expected to be finalised by January 2021. Following integration of these models into wide-area PSCAD models, one would be able to determine the impact on system strength, which is not possible in the PSS/E platform.

No	Question / Comment	Response to Question / Comment
79	**Why is fault level a proxy of system strength and not the system strength?**	When a synchronous machine experiences a grid fault, the level of fault current is directly related to the characteristic impedance of the network, and it is this latter quantity that defines the strength of the system in terms of the sensitivity of voltage (and indirectly frequency) to power flow. The fault current from a (grid-following) inverter, on the other hand, is a programmed response that does not relate directly to the impedance of the network, so does not provide a direct measure of system strength. Another consideration is that system strength is a multi-dimensional property of a power system, and not all these aspects are directly captured by measuring fault currents. An example is the network X/R ratio, which also influences voltage sensitivity.
80	**Is there any discussion within AEMO or AER to align market pricing nodes and the system strength nodes to improve the correlations of pricing signals against network augmentation needs?**	This issue is being considered in the AEMC review of "Coordination of generation and transmission investment implementation – access and charging"
81	**AEMO is continuing to maintain this fault level for a long time, even with the retirement of Loy Yang/Yallourn generators. Could any generator/equipment connecting near the area assume this will be the minimum fault level available in future?**	Fault level nodes may change in future especially as synchronous generators retire associated with some of those fault level nodes, and if more IBR are being connected in other parts of the network. In relocating the fault level node to the other parts of the network, care must be taken to ensure the performance of network and generation assets will not be adversely impacted, e.g. generators are still able to meet their agreed generator performance standards.
82	**May I have a clarification of the direct and quadrature frame in the above discussion, either at a synchronous machine frame or at the network synchronous frame?**	A notional synchronous frame is often invoked so we can speak about the specific components of current associated with active power and reactive power. For practical purposes, this can be thought of as a network synchronous frame where the frame angle is the common-mode component of the generator voltage frame angles (and also includes an offset that depends on location within the system). In normal operation with effective frequency control, this can be equated with a constant 50 Hz phase reference with some arbitrary fixed offset.
83	**Can an aggregation of mini synchronous generators (i.e. mini PHES) – say 20 x 5MW on 33 or 66 kV – be as effective a single 100 MW synchronous fossil plant connected to 132 kv or above, with respect to system strength?**	Fault level (FL) contribution can be maximised when series impedance between the FL sources and the system strength node/bus of interest is minimised. Therefore, the FL contribution of any MV/distribution-connected (33/66kV in this example) synchronous generators when measured at the HV/transmission node (132 kV in this example) will be reduced by the effective series impedance presented by 33/66/132kV transformer(s), as well as any significant network impedance that may be present between the generator buses and system strength bus-of-interest. As for aggregation (i.e. multi-generator configuration), for a given generator short-circuit current (ratio) specification, the total FL should be the same as a single large unit of the same total MVA nameplate rating, as long as all the units in the multi-unit setup is online/synchronised to the grid.
84	**Will the synchronous condensers run continuously, or will they be switched? If so, what criteria?**	Network synchronous condensers are generally required to run continuously and their outage might result in a constraint. Synchronous condensers installed by a generator would be treated the same if they provide support to other plant beyond their generating systems. In circumstances where a synchronous condenser is only needed for one generating system, the decision to disconnect or keep it online lies with the relevant generator.
85	**With a possible increase of syncons in SA, to satisfy the OTR's inertia requirements, do AEMO and the NSP expect stability issues when these distributed syncons interact with the those at Davenport and Robertstown?**	This would need to be carefully considered by EMT type studies. Factors such as the location, size, excitation system control and inertia of those syncons will play a part. Note that this is not just an interaction between large and small syncons but the whole system. The question is what generation mix and technologies would ensure a stable outcome. In summary, no general answer can be provided. However, it is correct to sat that care must be taken to avoid the intended solution for a particular problem to cause other problems.

No	Question / Comment	Response to Question / Comment
86	**When we talk about these oscillations, it would be very useful if NSPs advised (potential) connection applicants of any and all known existing network behaviours (e.g. oscillations) to be aware of when developing the models for application submission.**	NSPs are required to comply with their system standards which sets out the permissible level of short-term flicker and damping of oscillations. For frequency range of 7-10 Hz this would mean a maximum permissible short-term flicker of less than 0.5%. The approach taken to determine the residual contribution of an upcoming generator is based on calculation of oscillations before and after the disturbance, and the generator will only be accountable for the residual contribution rather than the whole system-wide level. Note that good industry practice in model development is to use the actual control code of the inverter as adopted by many OEMs. Such a model not only predicts known phenomena but would also be helpful in identifying unknown phenomena not experienced so far.
87	**It sounds to me that the tuning of the controller from the Powerlink presenter should be viewed as improving resilience to poor system strength, not referred as improving system strength.**	If a plant that is the cause of the oscillations is tuned, this would be considered as improving resilience. However, in the example presented, tuning nearby plants that were not the cause of the oscillations provided damping to the plant that was the cause of the oscillations, so this case is referred to as improving system strength.
88	**Are the methodologies for re-tuning multi plants controls similar to tuning multi-machine PSS ?**	Multi-machine PSS tuning for synchronous generators is primarily based on small-signal stability analysis. This can be readily done for a synchronous generator with much simpler control and associated transfer function, where characterising poles and zeros of the control system as function of PSS parameters can be conveniently done. The control system and transfer function of IBR is much more complex than that of a synchronous generator. This coupled with lack of visibility on the control loops of the inverter due to IP issues, and presence of significant non-linearities, make small-signal analysis for multiple IBR tuning rather difficult. Methods are currently being developed in academia to characterise salient small-signal aspects of an IBR using a black-box model. However, they have not yet been fully demonstrated in practical applications.
89	**Regarding oscillations; are source of these oscillation investigated? are damping ratio considered? how these oscillations are differentiated from expected power flow waveform, which are generally not perfectly sinusoidal?**	Yes, causes of oscillations were investigated and contributing IBR were identified. It is noted that not all IBR were contributing to these oscillations. Calculating the frequency and magnitude of oscillations is a key part of determining where or not adequate damping as required by NER is provided. Calculating the difference between pre- and post-disturbance oscillations allow segregating the residual adverse impact of IBR under consideration and ensuring they won't be accountable for any other possible background oscillations.
90	**Is tuning of controls a temporary solution for alleviating/improving the network?**	Controller tuning is solving the problem from the root, and as such it is a permanent solution. Appropriate tuning of PI control gains can improve performance but needs to consider the full range of system conditions. Re-tuning may be required after a change in network configuration.
91	**Can multiple grid-forming converters from different manufacturers synchronise with each other? If so, how?**	Yes. The virtual synchronous machine (VSM) layer is key to parallel grid forming converters with other voltages sources (grid or sync. machines). They will operate as an independent voltage source but are coupled via this layer, allowing tuning of the response to share and contribute in parallel with the power system and other nearby voltage sources. If you don't have VSM it is a challenge to integrate but they do not need to synchronise to each other. Different technologies have no difficulty operating in synchronism with each other; indeed every source and load in an AC system must do so.
92	**In Hitachi's presentation on grid-forming inverter response to islanded operation, what is the source of the harmonic contents on the current?**	It is not clear. The local network draws this waveshape but it also looks like possible saturation. While it is unclear - the fact the grid forming converter provides a smooth voltage waveform in all scenarios is clear.
93	**Indicative incremental costs of different converters (following vs forming vs VSM)?**	In short they are the same, but usually grid-forming has higher overload capability which comes at a hardware cost – maybe 1.5 times for a 2-3pu overload. If you use the overload it is cost-effective.

No	Question / Comment	Response to Question / Comment
94	**What limitations will ElectraNet be placing on IBR when you do take one Sync Cond OOS for maintenance? has maintenance been considered to allow capacity for it to occur without impacting the customers?**	It is important to note that the SA synchronous condensers are being installed to address the TNSP minimum system strength requirements and remove the need to direct synchronous generation to maintain the minimum required system strength. In addition to these requirements, the maximum dispatch of IBR in SA is restricted at times to ensure system security. The installation of the syncons will ease constraints on the maximum IBR, but the complete removal of these constraints was not the justification for the syncons (i.e. syncons are required to provide minimum system strength). Under the maintenance outage of a syncon, the minimum system strength requirements are met.
95	**With the VSM what is the transient fault contribution of these plants? Isc/In**	The fault current of Hitachi ABB Power Grid's converter is 2-3pu for 2 seconds. There is no transient - it is provided for a much longer duration which can have different impact and effect.
96	**How is the angle between the system and the VSM measured?**	Grid-forming inverters still measure voltage at their terminals but it isn't locked to the grid waveform. There is no PPL. If the voltage moves, it responds based on the equation shown and catches up based on VSM control loop parameters.
97	**During operation of grid-forming converters with grid, are their PLL expected to be affected by high ROCOF?**	Many grid-forming converters don't actually have a PLL, because their low level control is different.
98	**Does a grid-forming inverter need to overrate its inverter in order to supply current needed when VSM and system grid has a big deviation? How big is this overrating need to have a similar performance as conventional synchronous generator?**	It requires power system studies to determine because there are a number of interdependencies. Fault current can be provided for much longer (not just a transient or sub-transient peak fault current), inertia can be tuned and other such factors play a role that means you can't just compare peak fault current contribution.
99	**Assuming multiple grid-forming are inverters operating based on their clock at 50 Hz and sync to GPS, How can they be brought online so that their phases are aligned?**	Synchronising grid-forming inverters to the grid is more straightforward than for synchronous machines, as there is no need to mechanically align a spinning rotor to a required phase position. In the inverter a PLL can be used at startup to determine the correct modulation phase angle to align the equivalent AC source correctly. Once this alignment is established, fast-acting closed-loop control of the active power output suffices to align the voltage source with the grid without a PLL, subject to protective limits being placed on power output to ensure no loss of synchronism.
100	**Does the virtual synchronous machine still need to measure the network voltage to provide an input into the calculation of the simulated local frequency, or does it just use a measurement of the P leaving the inverter?**	It does measure the voltage at its terminals, it just isn't locked on to the voltage via a PLL. The voltage is measured and if it moves away the VSM will respond as the equation shown initially and then per its control parameters over time to re-align with the power system. The voltage at other nodes or P and Q setpoints can be fed to the system to regulate voltage at the PCC for example or respond to markets, but this is over a longer timeframe than the core VSM.
101	**What measurement is needed to determine the deviation angle between VSM and the system grid if PPL is not used?**	It measures the voltage at its terminals, it just isn't locked on to the voltage via a PLL. The voltage is measured and if it moves away the VSM will respond as the equation shown initially and then per it's control parameters over time to re-align with the power system.
102	**The inverter response to voltage change was mentioned, this means settings would operate within one second.**	The response to RoCoF or voltage is immediate and then the system responds dynamically over time based on its various virtual synchronous machine settings.
103	**How expensive is grid-forming IBR compared to grid-following? Should this be part of grid code?**	In short they are the same but usually grid-forming has higher overload capability which comes at a hardware cost. Maybe 1.5 times for a 2-3pu overload. If you use the overload it cost-effective.
104	**If system response can be made better by re-tunning the SVCs or IBG to suit to the grid condition, then can incoming generators advise neighbouring generators tunning so that interaction is reduced? It will impact no harm to neighbour working of NER.**	Current framework does not enforce neighbouring IBR to retune to host a new IBR. However, this can be done with mutual agreement between existing and new IBRs.

No	Question / Comment	Response to Question / Comment
105	**When a connection study is undertaken, the control system settings are set based on the maximum and minimum short circuit level at the connection point. If the fault level nodes fault levels change significantly the settings will need to be retuned.**	The design and tuning of control systems should be done with sufficient margins to ensure robust performance. It is not expected that changes to fault level requirements at nodes would be sufficient to cause issues in practice.
106	**On the PLL of grid-forming inverters, frequency feedforward, and current/voltage control still require an angle reference even for VSG operation. However, these PLLs are less critical to the inverter operation compared to a grid feeding one.**	Grid-forming inverters may incorporate a PLL in their control system for secondary control purposes. The primary control however can maintain synchronism by closed-loop control of active power output which can be measured without a PLL.
107	**We have enough of a problem on min gen now, let alone once DER is Dominant like in SA.**	The two are highly inter-related, i.e. high DER penetration is one of the causes of low demand conditions. Under these conditions, voltage control would become more challenging even in system intact conditions. Operating an interconnected region as an island would further exacerbate the issues. This is because the unexpected disconnection of DER under these conditions could create a larger contingency than that system security can be maintained for. Pre-emptive disconnection of DER, improved FRT standard, and the use of fast frequency response devices have been pursued as some of the solutions to these conditions.
108	**Given re-tuning is considered a promising solution, would the current 5.3.9 process facilitate timely retuning?**	S5.3.9 is required when a change is applied to the connected equipment and control systems, including firmware, which also impacts performance relative to any schedule 5.2 access standard. However, only the relevant GPS will need to be reassessed rather than all clauses. S5.2.2 applies to IBR setting changes that do not affect performance relative to GPS requirements. Both processes require an appropriate level of disclosure, diligence and documentation so the NSP and AEMO are aware of and can verify the plant responses. The time needed for a 5.3.9 process is determined mainly by the extent and nature of the changes. Good cooperation and engagement between generator, NSP and AEMO (and OEM involvement if needed) will speed up the process.
109	**Do you expect all future IBR to be of grid-forming type only?**	There is no demonstrated technical need for all IBR to be grid-forming type, and at present the additional cost may be prohibitive. Also note that in some instances a grid-forming inverter is neither necessary nor beneficial, e.g. a small solar farm in a strong grid. This will be driven by the physical and commercial requirements of the application, grid-connection technical-regulatory requirements, the relative cost of solution options, and other secondary drivers. Given ongoing developments in the technical, market and regulatory aspects as of November 2020, its quite likely that grid-forming IBR would be the preferred option for weaker connection points to ensure satisfactory regional supply security and quality performance, reduced risks relating to the grid connection process, and to avoid potential additional remediation requirements (and hence complexity and cost) associated with the proposed AEMC System Strength Frameworks (draft final determination expected in Dec 2020). Grid-following IBR is likely to continue to have a role for strong connection points, and applications where commercial and market drivers (especially Capex) have high priority.
110	**Is it correct to think it makes more sense to use grid-forming inverter with BESS other than SF/WF, since they need to ensure there would be enough energy available when they see a phase shift?**	Solar has an MPPT which is current controlled and limits response. You need a voltage source behind the grid-forming inverter to get the speed of response so we see you will have a capacitor or battery with DC coupled solar.
111	**Do you foresee inertia to be supplied by both grid-forming and following inverters or just grid-forming alone?**	Physical inertia can only be provided by synchronous rotating mass. The services available through grid-forming and grid-following devices can help to reduce the physical inertia required.

No	Question / Comment	Response to Question / Comment
112	**Has any thought been given to the movement of fault nodes? i.e.. protection settings, increasing of fault levels at substations and affecting the earthing?**	Current fault level nodes have been determined based on four different factors: 1. Area of concentration of synchronous generators. 2. Areas of concentration of IBR. 3. Metropolitan areas. 4. Remote areas. In doing so, three success criteria need to be considered, which are stability, power quality and power system protection. As discussed in the workshop, protection aspects have not been considered in great detail.
113	**Could it be dangerous to tune the control system only to one or a few oscillating conditions?**	We agree that tuning should aim for overall robustness as well as ensuring there is no adverse effect on damping of critical modes. Trying to optimise solely for damping (notwithstanding the appropriate emphasis on this in S5.2.5.13) could degrade overall performance if inter-relations between different forms of stability is not accounted for.
114	**Are is the AEMC putting effort into a regulatory framework in place to allow for coordinated tuning?**	Not at this stage. The changes being considered at present allow re-tuning as an option where it is practical to do so.
115	**Talking of interactions between inverters, are interactions more pronounced in low system strength areas?**	Yes, often the lower the system strength the higher the likelihood of adverse interactions.
116	**May I know if we need to retune the controller parameters of the existing IBR if new IBR will connect to the same area?**	Current framework does not enforce neighbouring IBR to retune to host a new IBR. However, this can be done with mutual agreement between existing and new IBR.
117	**Addressing system strength issues requires best available info being shared by AEMO, NSPs and proposed new generation. Problem is ISP only includes committed and committed * projects. How do AEMO, NSPs and proposed new generators "economically" resolve this?**	This issue is partly because uncommitted projects generally desire to keep their future generation plants confidential for commercial reasons. In 2019 the AEMC made a rule to improve publicly available information about new grid-scale generation projects. Further details can be found at: https://www.aemc.gov.au/rule-changes/transparency-new-projects Furthermore, AEMO considers a category called "anticipated projects", and uses market modelling processes to anticipate financially and technically feasible locations for new generation connections. The 2020 ISP Generation Outlook can be accessed at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp#Final%202020%20ISP.
118	**Did EPRI studies on protection impact considers grid-forming inverters or just conventional PLL-based? Also just simple 6-pulse Graetz bridge or MMC topologies?**	Thus far, we have only considered conventional (not grid-forming) inverters. We have not considered MMC either. We plan to study them in 2021.
119	**This percentages depends on the capacity of IBRs or location of IBRs and SGs? or etc.?**	I guess you are referring to the IBR percentage scenarios in the power swing case study (i.e., 0%, 25%, and 50% IBR)? The percentage indicates how much of the total load MW is being supplied by IBRs. The IBRs are randomly located throughout the test system. The location is expected to impact the rate of change of impedance trajectory; however, we have not studied the impact in detail.
120	**Is I2 for faults only required at HV and MV in Germany? Is there any consideration for this requirement for LV connected IBR?**	Our study considers transmission-level IBRs only, and the German code specifies requirements for I2 injection by such IBRs. I am not sure about such requirements for LV DERs.
121	**Do system strength issues arise when there is no control over the locational decisions of new VRE and retirement of fossil fuel generators in the NEM?**	The aim of the proposed changes is for AEMO and the NSPs to consult with stakeholder to identify parts of the network where inverter-based generation will connect so that system strength can be provided proactively.

No	Question / Comment	Response to Question / Comment
122	**In protection, any specific level of short circuit ratio which may cause power swing detection difficult, due to fast movement of locus? I mean what values of fault level cause the power swing to avoid the delay?**	The IBR level is one of the factors contributing to power swing protection mis-operation. Other influential factors include available synchronous inertia and power swing relay setting. Hence, the IBR level which causes mis-operation may vary from system to system. We have not particularly quantified the dependence of mis-operation on IBR integration level. This is an interesting future study.
123	**Assuming a major hydrogen industry is developed in Australia, will electrolyser demand in areas with system strength issues be a positive or negative? It's possible a new hydrogen industry may not use regulated networks.**	Electrolysers based on power electronic converters are considered inverter-based resources and can exhibit similar challenges and provide similar opportunities. From an impact on system strength perspective, they can have positive, negative or no impact on system strength, depending on control system design and tuning, and presence of other nearby IBR.
124	**I recall a conclusion earlier today a type III wind turbine comply with the voltage shift requirement, is this the same concept in Vestas "Class III"?**	Vestas's presentation refers to ENTSO converter classifications, not the WECC wind turbine classifications.
125	**With the fault level decreasing, is it worthwhile to use transient reactance of generators especially when performing distribution protection minimum sensitivity checks?**	We're not sure if this is what you're asking, but the fault current of an IBR does not have the same sub-transient/transient/synchronous characteristics as that of a traditional synchronous generator. In fact, the IBR fault current typically has an initial transient response (first 1/2 cycle to 1.5 cycles for Type IV wind turbine generator) during which it can exceed the nominal values, and after that it is limited to values close to nominal current. During this short time period, which is considered to be the converter controls "reaction time", the fault current response is uncontrolled. The amount of time which an inverter can continue to inject current into the grid during a fault, depends on the inverter control design and thermal limits of the power electronics. For Type III WTG, the initial transient response is quite different than the initial response of Type IV WTG, and the fault current can reach up to several times of the nominal current depending on the electrical parameters of the induction machine.
126	**Will grid-forming inverters/VSM have the same low voltage ride-through characteristics as grid-following inverters?**	No, they can be set and ride through zero volts and island. The current will be load or fault dependant so if it sees zero volts or low volts it will provide fault current and this will need to be in line with its overload capability.