G-PST/ESIG Webinar Series: Inertia Monitoring	
Question	**Answer**
What is the day-ahead inertia forecasting accuracy based on any of those measurements?	The investigation into accuracy of the forecast is still underway so no public information available at this time.
any success stories for grid-forming IBR contribution to inertia through synthetic inertia and how this could change the estimation methods in the future?	Yes are some real life examples. One is from Hornsdale battery where two inverters were undergoing testing in grid forming mode when a large coal unit tripped near by. It's visible from the measurements that two inverters that were under testing injected active power in inertial timeframe, ahead of the frequency nadir, while the response of the entire plant where the majority of inverters were in grid following mode responded more like a governor-type response. You can read more about this here...
Good night, are any of these inertia estimation methods applicable in a microgrid?	Anyone of them is in principle is applicable in a microgrid, but probably in a microgrid finding out inertia constants of the generators and motor loads could be a small effort and commitment-based monitoring would be cheap and sufficiently accurate.
Any information yet re impact of loss of the two 660MW units at Sizewell on April 18 1730 to 1735 BST? Although not simultaneous trips.	I don't have any information about these trips but will look into this. Thank you!
Do online stability analysis tools for inertia monitoring account for loss of DER on RoCoF (as seen in UK)?	Indirectly Reactive Technologies inertia monitoring tool does take it into account. It monitors inertia and based on RoCoF limitations (which is based on RoCoF that would trigger Loss of Mains protection on DERs) it determines if the largest MW loss, which may happen on the system at the time, is secure ("secure" meaning it will not lead to RoCoF which will trip additional DERs)
Have you seen instances where DER trip on high ROCOF? If so, what are the typical protection parameters for that trip point?	NG ESO has experienced DER tripping on high RoCoF, one of the examples is August 2019 load shedding events. At the time event though the project of increasing RoCoF settings on Loss of Mains protection relays (to 1 Hz/s) was already ongoing there were some relays that were still set at the original 0.125 Hz/s value and those tripped additional DERs during the event. I can imagine there has been other events as well both on EirGrid and NG ESO that tripped DER on high RoCoF but these events haven't led to load shed and therefore were more reported as widely as Aug 2019 event.

What tools are available to measure inertia?	I covered all available tools in my presentation. Basically so far GE Effective Inertia tool and Reactive Technologies' Grid Metrix tool. EPRI has developed their own in-house tool but it haven't been used in the field yet. There are also other research papers presenting methods similar to EPRI's and GE
Is maintaining inertia implicit in the maintenance of regulation?	I may be am not understanding this question correctly, but if question is if maintaining frequency reserves will bring about inertia implicitly because frequency reserves are provided by synchronous generators, this might have been true in the past but it is changing as loads and inverter-based resources are starting to provide frequency reserves. Therefore it becomes possible to have sufficient frequency reserves from resources that do not provide any inertia.
How to determine inertia distribution given impacts from location?	I had some publications linked to the proposed methods on my slides. These methods allow to evaluate if regional inertia is relevant for a given power system and how to divide the system into regions in each of which certain level of inertia should be maintained.
Where are require to install PMUs for the GE approach? How many PMUs are using for the example that you present?	Overall as with any measurements the more locations there is the better however to minimize the costs based on what I've heard 3-4 per region is sufficient + one on each interconnector between the regions to evaluate delta_P. When there are lines that are not measured in the boundary, the error will increase significantly as the tool will have to estimate the flow on the remaining unmeasured lines. This introduces a larger error in inertia estimation since inertia is heavily based on delta_P.
For grid stability, conventional reactive power management is important. What matters more in grid stability between inertia VS reactive power management?	Both are very important, however with growing shares of inverter based resources, especially in longer and skinnier systems with generation concentrated in the parts of it (rather than distributed evenly across the system), voltage stability and reactive power management becomes an issue earlier (i.e. at lower shares of IBRs) than inertia. There is an article in IEEE PES Power and Energy Magazine Nov/Dec 2021 issue that discusses this in more detail (the first article in the issue)
Please can you recommend us any report regarding FFR issues in week grids?	I've listed two sources on slide 7 of my presentation

FFR in Ireland start's at 2sec, but in ERCOT is like 15 cycles (0.25 sec). Why we have so great difference between ISO/TSO definitions?	For a given MW loss inertia defines rate of frequency decline and with that also time available for frequency response to respond and arrest frequency before additional generation trips or underfrequency load shed happens. There is a trade off between inertia and speed of frequency response. One can bring more inertia online or have faster response and then less inertia is needed. In Ireland EirGrid when with the former approach while ERCOT went with the latter. There are also a couple of nuances there EirGrid requires FFR response within 2 seconds (not starting at 2 seconds!) so faster than 2 seconds would work as well. Also EirGrid were one of the pioneers with their FFR requirements and at the time even 2 second response seems fast, while by the time ERCOT approved 0.25 s requirement OEMs were confirming that it was possible and there were test results available proving it was possible from technology perspective. Again, faster response allows lowering inertia more, but care should be take not to cause any instability with responding too fast (as per slide 7 of my presentation).
Which is (or are) the best method(s) / approaches to evaluate the inertia of a single power plant?	It's a good question. Ideally, OEMs should provide H constant based on the plant design. Otherwise having PMU or other high speed recorder at the generator and evaluating plant response to nearby real life frequency events over long period of time should help. Similar method to e.g. GE or Reactive technologies inertia monitoring can be applied, I believe, where instead of an inertia region you only have one plant.
Can you tell us about the cost and modern relays available in the market that will be suitable for the low-inertia systems?	I am not sure what relays the question is about, I'm sorry. Low inertia system would not necessarily call for different kind of relays compared to high inertia system. Relay settings may need to be changed if e.g. RoCoF-based loss of mains protection is used (as in GB and Ireland)
Does CAISO have Inertial measurements studies? Due to their high NCR & DER's penetration	I don't believe they do. CAISO is synchronously interconnected with the rest of the Western Interconnection so system-wide inertia is certainly not an issue yet. I am not sure if there may be regional inertia concerns but either way haven't seen any studies about that

any cost benchmarking for the inertia monitoring system developed by GE or GridMatrix or other, rough numbers is enough to get insight?	GE ~€1.2M, Reactive ~€6.1M as per: https://ted.europa.eu/udl?uri=TED:NOTICE:335838-2019:TEXT:EN:HTML&src=0. For GridMetrix supercapacitor is the most costly element while their XMUs are relatively cheap and many can be placed across the system. But for GE tool installing PMUs is the main cost. The PMUs themselves, although more expensive than XMUs, are not that expensive (a couple of thousand dollars each), however installing PMUs at the substations is the largest cost contributor for GE tool and this is not catered for in the €1.2M figure.
why do we need grid forming IBR. can't grid following IBR do the same if the frequency response was based on delta F	My understanding is grid following inverter needs to measure frequency change first before responding and providing extra power. This measurement and response can be fast (i.e. FFR) but still will have a small time delay, during this time if RoCoF is high additional events may be triggered (such as gen trips or UFLS). However grid forming inverter keeps it's internal voltage and angle constant in the transient timeframe and as voltage angle at the inverter terminals change (as a result of e.g. generator trip) it will inherently provide additional active current in response, somewhat similarly to a synchronous machine.
What is the benefit of having a control center display regarding ROCOF by areas? It requires to define a critical inertia by area?	Yes you are right. It requires determining either critical inertia by area or, as you said, critical RoCoF by area and/or even a secure MW loss by area.
When or for what kind of systems is require to use a inertia estimation using stimulus vs inertial monitoring as is using ERCOT?	As inertia starts getting to a critical level a system operator will need to be taking action to bring more inertia online. At this point it's an additional cost (regardless if more inertia is brought online through out of market action or if there is an inertia ancillary service product). This is when being more accurate at inertia estimation, i.e. capturing load inertia and inertia from distributed synchronous generation may say costs. Cost benefit analysis then can be conducted comparing savings from having more accurate inertia estimation with costs of having more accurate and expensive inertia monitoring.
What degree of observability would be needed to obtain a good estimation of inertia using interface lines flow measurements?	There is a similar question above. For GE's method, I heard that 3-4 PMUs per area + a PMU per interconnector between the regions is sufficient. For Reactive Technologies' monitoring there are more XMUs across the system (about 40 for the GB system). This is because XMUs are relatively inexpensive, and the number of XMUs is rather a function of having sufficient places with secure and good quality internet than the cost of the devices itself and their installation costs (which is the case with the PMUs).

On the ambient data-based method, some literature have reported +10% error. Is the EPRI method with around 2% error based on ambient or event measurements?	Ambient.
Considering the delay and ramp-up time for FFR, how do you see the applicability of FFR over the synchronous condenser to limit the RoCoF?	They are fundamentally different but complementary. Synchronous condenser provides inertia response, i.e. inherent (without intentional delay) response from energy stored in it's rotating mass. FFR will always have some delay to detect frequency decline and then respond with active power injection. Having faster and more aggressive frequency response (provided that it doesn't deteriorate stability of the system, as per slide 7) allows operating at higher initial RoCoF because it quickly gets slowed down by FFR. Having more inertia online from synchronous machines (including SynCons) reduces initial RoCoF and reduces the need for FFR
In much literature, it's reported to have an inertia constant of IBR. What are your comments on defining the inertia constant of IBR sources (Battery, Solar PV)	I think it doesn't make sense to be honest. Fundamentally, if for example a generator trips offline, lost power from that generator needs to be temporarily replaced to maintain balance between production and consumption. Inertia is where synchronous machines are providing this power from for a few seconds (until it is replaced through frequency response). Inverters are not rotating machines and therefore they do not have inertia. However they can be designed to inherently provide active power injection in the first seconds after an event. Defining this response as inherently provided power*seconds (i.e. energy terms) makes most sense, I think. We can come up with a new term for it but I think it's misleading to use a term inertia because it already has a physical meaning in synchronous machine world, I think using it fro something else only causes confusion.
What is the scale of the power that you inject for the stimulus in the direct injection method and what is sensitivity of the measurement needed to detect this?	The size of the MW injection is based on the total capacty and inertia of the system. So really depends on the system but a rough rule of thumb is around 0.025% to 0.05% of total demand. For example 10 MW in UK which has demand between around 20 GW and 60 GW. Reactive Technologies is using a standard PMU to measure the power at the direct injection location and for frequency they need to measure within 1 mHz error. Some good quality PMUs are capable of this level of accuracy but some filter the frequency too heavily for this to be measured.

I got the impression that GE Effective Inertia and Reactive Technologies Solutions are actually complementary to each other?.	They use different methods for event detection, i.e. for determining delta_P: Reactive Technologies uses known stimulus while GE uses changes on interconnection flows. Both methods use the same equation for inertia calculation based on measured RoCoF and known (in case of Reactive)/estimated (in case of GE) delta_P. The methods can be compared for benchmarking purposes. Overall one tool would be sufficient and both methods are not needed simultaneously but NG ESO is the first one to deploy these tools in the field and, understandably, they want to test both for some time and compare the results. Additionally the cost for taking corrective actions to maintain inertia is high and the relative cost of these solutions is small in comparison.
In Grid Forming it was mentioned that there are additional costs, is there an estimate of how much more with respect to other technologies? do	I don't have any numbers on costs unfortunately. Based on what I understand the change that needed is in controls (i.e. software change) and this is inexpensive per se (though inevitably include R&D cost recovery in it). This applies to solar and battery inverters. For wind turbines to be grid forming may require some changes to design of the tower and drive train due to increased mechanical stress. Additionally, depending on what grid forming inverter is required to do there'll be a need for energy buffer (this may be battery, supercapacitor or keeping margin on a resource, i.e. not generating full available MW) and there may be a need to oversize an inverter if it is required to have overcurrent capability beyond its rating. Both of these design considerations will lead to higher hardware costs
If grid forming DER solve the problem of transient energy transaction (due to the power reserve that can be established). Do we need to worry about the inertia?	Why just DER? If inverters are capable of providing inherent MW (and without any intentional delay) injection in inertial timeframe for a few seconds in response to sudden generation or load change event, no inertia is needed from synchronous machine. It doesn't matter if inverters are part of DER or transmission connected plant
One question: Can you have multiple grid forming IBR co-exist in a grid?	The short answer is yes and it's been shown in studies (also GFM inverters with different types of control were tested there, i.e. droop control and VSM control), but as with grid following inverters today there will be a need for parameter tuning to make it all work together. It's also possible that parameter tuning will be needed throughout IBR life as the resource mix and grid topology are changing