Assessment of Inverter-Based Resources' Ability to Provide Voltage and Frequency Services

Phase 1 Results from the Energy Systems Integration Group's Reliability Services Project Team

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A Summary of Results from the Energy Systems Integration Group's Reliability Services Project Team

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1 Introduction

In recent years, the number of inverter-based resources (IBRs) connected to power systems around the world has grown exponentially, and this growth is expected to continue. With the increasing share of IBRs connected to a network come unique challenges and opportunities for system planning and operation (Matevosyan et al., 2021). Successful operation of a power grid relies on different grid services at different time scales in the form of energy, capacity, and essential reliability services (Liu et al., 2022).

With the increased share of IBRs, it is important to investigate the grid services that they could provide. It has long been established that IBRs can be used to operate small, isolated networks without any synchronous generation (Guerrero et al., 2013). However, studies looking at the ability of a larger network with a high level of IBRs to stay stable through a disturbance—specifically looking at the impact of frequency response/droop parameters—have shown that it may be possible for some systems with a very high level of IBRs to remain stable during certain disturbances by utilizing the active power-frequency and reactive power-voltage controls from existing IBRs without having to rely on a single large synchronous resource (Ramasubramanian, Baker, and Farantatos, 2020; Ramasubramanian, 2021).

This paper focuses on the services from IBRs within a short time scale, i.e., from a stability perspective. Running a system with high levels of IBRs may bring challenges in terms of frequency, voltage, angular, and control stability (Matevosyan et al., 2021). Traditionally, these services have been provided by synchronous machines, and as the percentage of IBRs increases, there may be different stability-related risks. Different stability services have also been identified for power systems of different sizes and with different penetrations of IBRs (Matevosyan et al., 2021). A greater understanding of such challenges is needed to highlight the different services that IBRs may need to provide to mitigate these risks and challenges around frequency, voltage, angular, and control stability. Stability needs have been divided in terms of synchronization and angle stability, damping, frequency regulation, and voltage regulation (Bialek et al., 2021). Such categorization (and others, such as that found in Chaudhuri et al. (2024) may aid in identifying the specific services needed from IBRs, enabling a focus on services needed by a particular network for ensuring stability through a particular set of disturbances and more accurate assessments of how IBRs should behave to provide these services.

1.1 Grid Services Needed from IBRs from a Stability Perspective

The different grid services needed from IBRs from a stability perspective may change as we go from moderate levels of IBRs to IBR-centric grids to grids operated by 100% IBRs (Chaudhuri et al., 2024). The various grid needs or services may or may not become market products; some needs may instead be incorporated into grid codes. Out of the various services possible from IBRs, some, such as voltage and frequency stability services, are being investigated and utilized today—several grid operators already have fast frequency response and low/high-voltage ride-through as some of the services or grid code requirements for IBRs (Ahmed et al., 2023). However, the existing grid codes/services are limited to a few services, and a study of the services provided by IBRs to satisfy the grid needs is still needed.

Out of the different grid needs/services identified from a stability perspective, fast frequency response has been given a great deal of attention in the research and utility community. Frequency response inherent to different generation technologies may differ by technology (Maurer, Wilson, and Chapman, 2021), and improving grid frequency response in a network with increased levels of IBRs may require a mix of technologies, rather than a single technology (as seen when synchronous generators provided most or all of this response) (Al Kez et al., 2023). In addition to fast frequency response, fast and robust voltage response is another service important for ensuring stable operation of a system with an increased level of IBRs (Ramasubramanian, Baker, et al., 2023). Hence, this report focuses on voltage and frequency response services from IBRs.

1.2 IBR Performance and Time Frame

In order for IBRs to be provided an incentive to deliver various services to the grid, it is important to identify the desired performance and the time frame during which this performance is required. Different services may be more relevant during particular disturbances. One common contingency considered for power systems is loss of generation. This typically results in a load-generation mismatch leading to a drop in frequency, which recovers as frequency response from different devices makes up for the lost generation. In the initial few seconds of this disturbance, voltage response may also be needed to maintain a stable voltage profile in the system. Hence, this paper investigates a few types of disturbances involving loss of generation, considering fast voltage and frequency response services from IBRs toward maintaining a stable grid operation in grids with high IBR levels for such disturbances.

1.3 Unlocking Unused Capabilities of Existing IBRs for Providing Grid Services

New IBRs with additional capabilities are usually looked at as a potential source for providing different grid services needed in a network with an increased level of IBRs. However, an important question is whether some of these services can be obtained from existing IBRs already installed on the network. In some cases the existing IBRs may have additional capabilities that are not being used, and using these capabilities could potentially decrease the amount of services needed from new IBRs. Hence, the report also assesses the impact of obtaining these services from existing IBRs to supplement services required from new IBRs. (It is important to note that there may be other aspects related to these identified services such as the impact of the IBR's location. While this report provides brief insights into locational aspects, nuances regarding this topic will require additional study.)

Even though there may be value in delivering different performance/stability services from IBRs, in a given power system footprint, many forms of performance behavior from IBRs are unavailable and/or under-utilized because the interconnection requirements or standards have not asked for these capabilities. Most often, if a particular capability is not required, either that capability will not be there in the equipment or it will remain locked and not utilized. In order to speed through the interconnection of IBRs, most plant developers incorporate and operate the equipment that complies with existing requirements in a minimal sense, i.e., not providing additional services when they are not asked for or when the appropriate market structures do not exist, for economic reasons. However, even under these circumstances there often exists a range of capabilities in large numbers of installed IBRs, capabilities that could be tapped for provision of grid services to contribute to stability.

For example, in some countries today there are gigawatts of wind, solar, and battery generation interconnected that do not have ride-through capability because it was not required at the time of interconnection. A similar amount of wind, solar, and battery generation has primary frequency response capability locked. This under-utilization of capability in the network can have unintended long-term consequences, as it can require the addition of larger capacity of advanced IBRs or other grid-supporting devices such as synchronous condensers in future years. This also implies an increased burden of maintaining grid reliability on few resources, which could be economically detrimental.

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Admittedly, the implementation of updated performance requirements retroactively is not the easiest process to follow, and at times is not possible. Further, one cannot know what performance requirements will be required in a future power network. But despite these challenges, since different interconnections are moving at different speeds with respect to percentage of integration of IBRs, there may be different lessons to be learned from the challenges and experiences of operating different networks with varying and/or increasing levels of IBRs and the different grid needs and services identified through these experiences. It is prudent and pragmatic to leverage such lessons learned from around the world to facilitate improvement in reliability.

1.4 Outline of the Report

In this paper we evaluate the advantages of leveraging the full capability of existing IBRs using a simulation exercise. The capability of delivering a service for an IBR plant lies at either a plant-level control or an inverter-level control. The impact of using one or the other can be substantial when a high percentage of IBRs is present on the grid. This study focused on leveraging inverter-level frequency response and voltage control to assess how using this additional capability can benefit the network in an extremely high-IBR case. This approach focused on performance-based specification rather than a particular inverter technology, and it highlights the value in considering particular services from IBRs rather than using a single term like "voltage source behavior" to explain the behavior that is needed or wanted from advanced or future IBRs.

Section 2 of the report describes the IBR models used for the study and assesses the models from a stability perspective. Then three case studies are presented in Sections 3, 4, and 5 for varying systems and conditions. Section 3 describes a microcosm network, while Section 4 uses an actual island network. Section 5 considers a large network and studies the impact of some of the assumptions considered when asking for frequency response services from IBRs. Section 6 recaps the key observations and insights from the studies performed.

2 Generic Models Used in the Study

For the purpose of this report, IBR devices are categorized in four buckets based on increasing capabilities in terms of services they can provide (Table 1). The four buckets—legacy IBRs, conventional IBRs, enhanced IBRs, and future IBRs—are listed in the order of increased capabilities. “Legacy IBRs,” which provide no grid services, are sometimes called grid-following IBRs, while “future IBRs,” with the capability to provide the maximum amount of services, are sometimes called grid-forming IBRs.

TABLE 1

Categorization of IBRs Based on Capability

IBR Bucket	Capability
Legacy IBR	Injects active power at unity power factor, and provides no grid services
Conventional IBR	Able to provide frequency and voltage response over multiple seconds
Enhanced IBR	May provide fast voltage and/or frequency response within 1 second of an event in addition to the slower response similar to conventional IBRs; as a group, can survive severe load/generation mismatch (if such functionality is activated)
Future IBR	Provides the above services, is capable of surviving/riding through severe load/generation mismatch as single entity, and can support voltage and frequency in the shortest time frames, with the response time/speed similar to or better than synchronous machinery

Source: Energy Systems Integration Group.

The categorization of a particular IBR into one of these buckets depends on the capabilities of the actual device (whether the hardware/controls are capable of providing different services) but may also depend on what services the IBR is allowed to provide depending on those required in the grid. Hence, an IBR may have the hardware and control options for an enhanced capability level, but these may not always be utilized and the IBR may act as a conventional IBR in a network. This categorization also does not correspond to a particular IBR technology: IBRs using different technologies may be categorized in the same bucket if they provide similar services. For example, providing fast voltage and fast frequency services may be possible using different IBR control architectures—with a single control loop or a hierarchy of multiple control loops with different primary control objectives. IBRs with all of these architectures may be put into the same bucket if they are capable of providing a particular level of services. With the advances in inverter technologies, it might initially appear to be attractive to focus only on services from a particular IBR technology. However, from a system perspective it is beneficial to focus on performance from a variety of IBRs. A performance-based specification was recently released under the UNIFI consortium for future IBRs (Ramasubramanian, Kroposki, et al., 2023). Existing standards such as IEEE Std 2800-2022 also focus on performance-based specification (IEEE, 2022). Hence, this study's focus was on investigating the services provided by existing or new IBRs that may be useful during grid disturbances. To carry out the study, two types of generic models were used.

With the advances in inverter technologies, it might initially appear to be attractive to focus only on services from a particular IBR technology. However, from a system perspective it is beneficial to focus on performance from a variety of IBRs.

2.1 Generic Model Representing Conventional or Enhanced IBRs

The first generic model was used to represent the conventional or enhanced IBRs. IBRs using this model can be configured to meet the minimum requirements laid out in IEEE Std 2800-2022 (IEEE, 2022). The technical minimum requirements in the standard have been developed bearing in mind the expected increase in percentage of IBRs in future power networks. As such, these technical minimum requirements mandate the capability to provide closed-loop voltage and closed-loop frequency support from an IBR plant. Hence, this generic model, constructed in an electromagnetic transient (EMT) simulation environment to represent the requirements expected from the IEEE Std 2800-2022, was used to represent conventional and enhanced IBRs (as well as legacy IBRs by disabling all the additional capabilities) (EPRI, 2022).

This model was used in this study to represent solar photovoltaic (PV) and battery energy storage system (BESS) resources. Here, the PV and BESS installations were assumed to have different capabilities based on the geographical spread of the plant. For the PV plant, it was assumed that voltage and frequency support was provided at the plant controller level, while at the inverter level the objective was to control active and reactive power. For the BESS it was assumed that there was no separate plant controller present/required and both voltage support and frequency support were at the inverter level, since BESS can have the ability to provide inverter-level responses. (Note that it is also possible for BESS plants to use plant controllers, and the response in that scenario can be treated as similar to the response from PV plants.)

Further, these IBR models were assumed to be equipped with a fault ride-through (FRT) mode and were assumed to continue to operate and not trip for the events considered in this study (unless otherwise mentioned as a part of a case study). Note that a distinct FRT mode can encompass different controls such as active/reactive priority. Unless otherwise noted, the FRT mode considered here corresponds to the reactive priority mode. However, the chosen FRT mode can be important to consider depending on the event/disturbance and the system. Most of the studies described in this paper were conducted in the EMT domain, but other generic models developed to be used with positive-sequence software packages (EPRI, 2023b) can be used for positive-sequence dynamic studies—some discussion regarding this aspect can be found in Section 4.

2.2 Generic Model Representing Future IBRs

The second type of generic model used in this study represented future IBRs that can be expected to continue to operate in a stable manner even after the trip of the last synchronous resource in the network and to ride through severe disturbances and conditions. These IBRs can also provide a large variety of services to the network such as fast inverter-level voltage and frequency control (Ramasubramanian, Kroposki, et al., 2023). In the near future, as a majority of such IBRs can be expected to be BESS resources due to the favorable DC-side characteristics they provide for the operation of the control structures, a generic model for such an IBR has been constructed in both EMT and positive-sequence simulation environments (Manitoba Hydro International, 2023). It was assumed that all controls were implemented at the inverter level, and no plant controller was present. If a positive-sequence dynamic study is desired, generic models described in (EPRI, 2021) can be used.

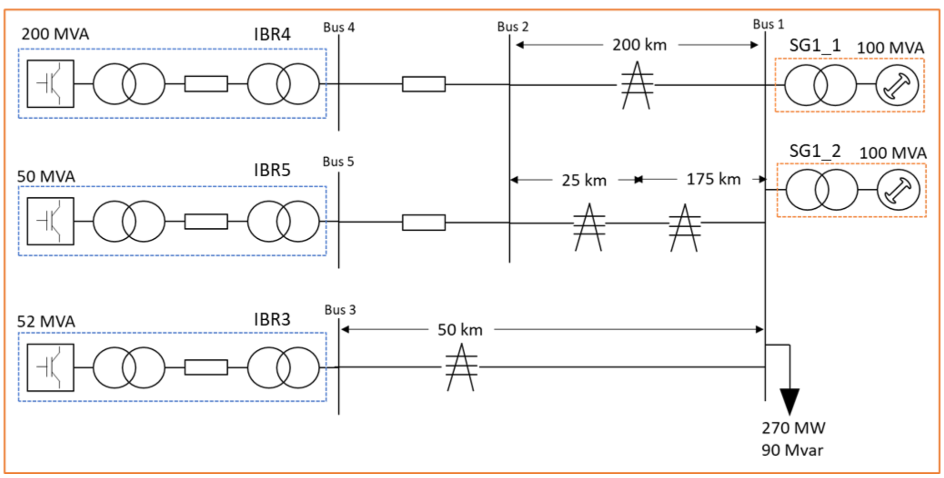
The control objectives of the different generic models and tests verifying fidelity of these models are described in the appendix.

3 Case Studies: Microcosm System

A microcosm system, shown in Figure 1, was considered for the case studies presented in this section. The microcosm system represents a transmission network and contains a 270 MW, 90 MVAr load cluster and two 100 MVA synchronous generators connected to bus 1, while the IBRs are connected at a distance on bus 4 (200 MVA), bus 5 (50 MVA), and bus 3 (52 MVA). In the steady-state solution considered, the IBRs at bus 4, bus 5, and bus 3 provide approximately 150 MW, 40 MW, and 50 MW, respectively. These IBRs are considered to be conventional IBRs; however, it is assumed that they have the additional capabilities described by enhanced IBRs (refer to Section 2 for details about conventional and enhanced IBRs). This assumption of existing IBRs exhibiting conventional capabilities is considered as the base case, and it could be the case in a given network that additional capabilities (described by enhanced IBRs) exist but are currently not utilized. One aspect of the case studies is to consider the impact of obtaining different voltage/frequency services from existing conventional IBRs that possess such capabilities but are not utilizing them initially. The load cluster is modeled using a static model.

FIGURE 1

A Schematic of the Microcosm Network Used in the Study



The performance of the modeled microcosm network under two disturbances is studied: (i) trip of one synchronous generator, and (ii) simultaneous trip of both synchronous generators creating a 100% IBR system.

Source: Electric Power Research Institute.

3.1 Trip of One Synchronous Generator

Using EPRI's Grid Strength Assessment Tool (GSAT) (EPRI, 2023a) on the selected network showed that some of the IBR locations potentially face a weak-grid condition if one synchronous generator is tripped (Table 2). The table shows the short-circuit ratio (SCR) and remaining short-circuit capacity (SCC) MVA calculated by GSAT on the original network as well as after tripping a synchronous generator. The short-circuit ratio at the IBR terminal for the IBR at bus 4 falls to below 1 after the trip of a synchronous generator (and the remaining short-circuit capacity MVA becomes negative)—potentially indicative of a weak-grid scenario where networks with IBRs that have conventional slow plant-level control may show unstable behavior. The unstable behavior is reflected in Figure 2, which shows the voltages and active powers with one synchronous generator (injecting 13 MW pre-disturbance) trip at 20.0 s. Note that this figure corresponds to the starting/base scenario where the three IBRs provide conventional capabilities, providing slower, multi-second voltage/frequency control.

TABLE I

Grid Strength Assessment of Microcosm Network

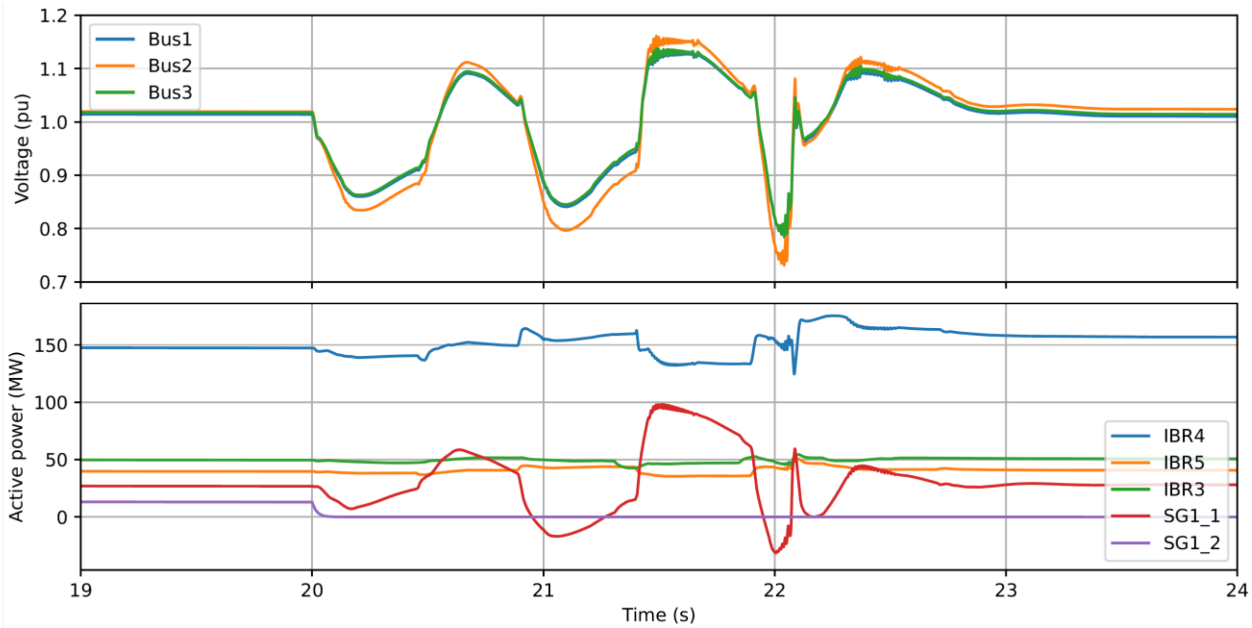
Location	Original Network		After Synchronous Generator Trip	
	Short-Circuit Ratio	Remaining Short-Circuit Capacity MVA	Short-Circuit Ratio	Remaining Short-Circuit Capacity MVA
Bus 1	12.36	1028	6.44	466
Bus 2	6.44	460	4.30	244
Bus 3	8.75	752	5.34	390
Bus 4	6.02	424	4.1	288
Bus 5	6.02	437	4.1	238
Bus 3 (IBR terminal)	4.91	197	4.17	151
Bus 4 (IBR terminal)	1.13	19	0.96	-16
Bus 5 (IBR terminal)	4.51	160	3.85	119

The short-circuit ratio and remaining short-circuit capacity MVA obtained through a grid strength assessment of the microcosm network, for the original network as well as after the trip of a synchronous generator. After the trip of a synchronous generator, short-circuit ratio less than one and negative remaining short-circuit capacity MVA at bus 4 indicate weak grid scenario with a potential of unstable behavior.

Source: Electric Power Research Institute.

FIGURE 2

Network Behavior After Trip of One Synchronous Generator



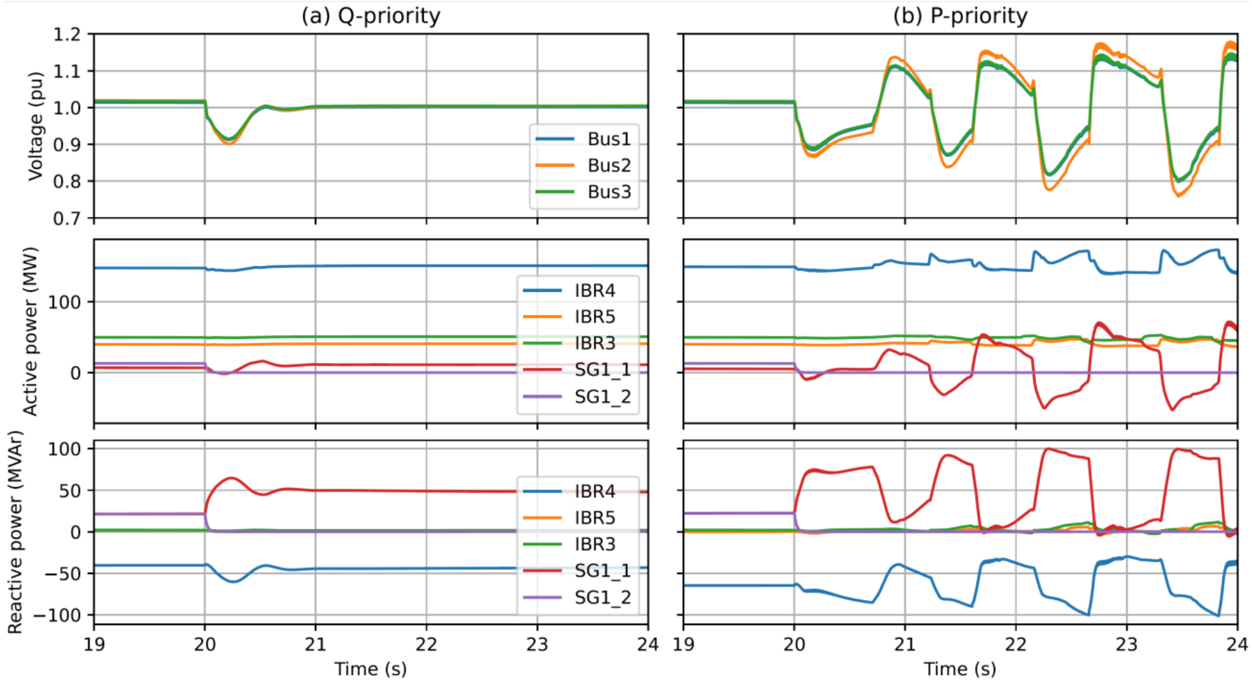
The microcosm system exhibits unstable behavior when subjected to a trip of one synchronous generator.

Source: Energy Systems Integration Group.

We then tested the ability of newly added IBRs with future IBR control capabilities to provide services keeping the grid stable in a weak grid scenario and added a new future IBR to bus 2. When a 25 MVA future IBR (with Q-priority) was added at bus 2, the system was able to ride through this event, as shown in Figure 3(a). Since a future IBR provides numerous services to the grid compared to a conventional IBR, the mere use of a future IBR does not necessarily highlight the services that were useful during this disturbance or the level or performance of services required.

FIGURE 3

Trip of One Synchronous Generator, with New 25 MW Future IBR at Bus 2 with Q-priority (a) or P-priority (b)



The response of the microcosm system for the trip of one synchronous generator. A new IBR with future capabilities is added to bus 2 to improve the network response; however, if this new IBR is operating close to its current limit, P/Q priority played a role in determining whether the network response was stable/unstable.

Source: Energy Systems Integration Group.

With 20 MW active power setpoint for the new future IBR, due to initial active and reactive power exchanged by this new IBR with the grid, it operates relatively close to the maximum current limit of 1.2 p.u. considered, and the limit is hit after the synchronous generator is disconnected. Future IBR controls with Q-priority and P-priority were tested, since these dictate whether the IBR gives priority to active/d-axis or reactive/q-axis current once the maximum current limit is hit. Figure 3(a) corresponds to the simulation with the future IBR with a Q-priority mode. However, as seen in Figure 3(b), if P-priority mode is used instead for the 25 MVA future IBR, the system loses stability—and with P-priority a larger-size IBR (30 MVA) is needed for the system to remain stable through this disturbance. These simulations are summarized in Table 3 and indicated that the grid service needed during these network conditions and disturbance is potentially voltage/reactive power support.

TABLE II

Impact of P/Q Priority of the New Future IBR on the Stability of the Network

System Description	New IBR Bus	New IBR Size	New IBR P/Q Priority	Stable?
Base	N/A	0	N/A	Unstable
Future IBR	Bus 2	25 MVA	P	Unstable
Future IBR	Bus 2	30 MVA	P	Stable
Future IBR	Bus 2	25 MVA	Q	Stable

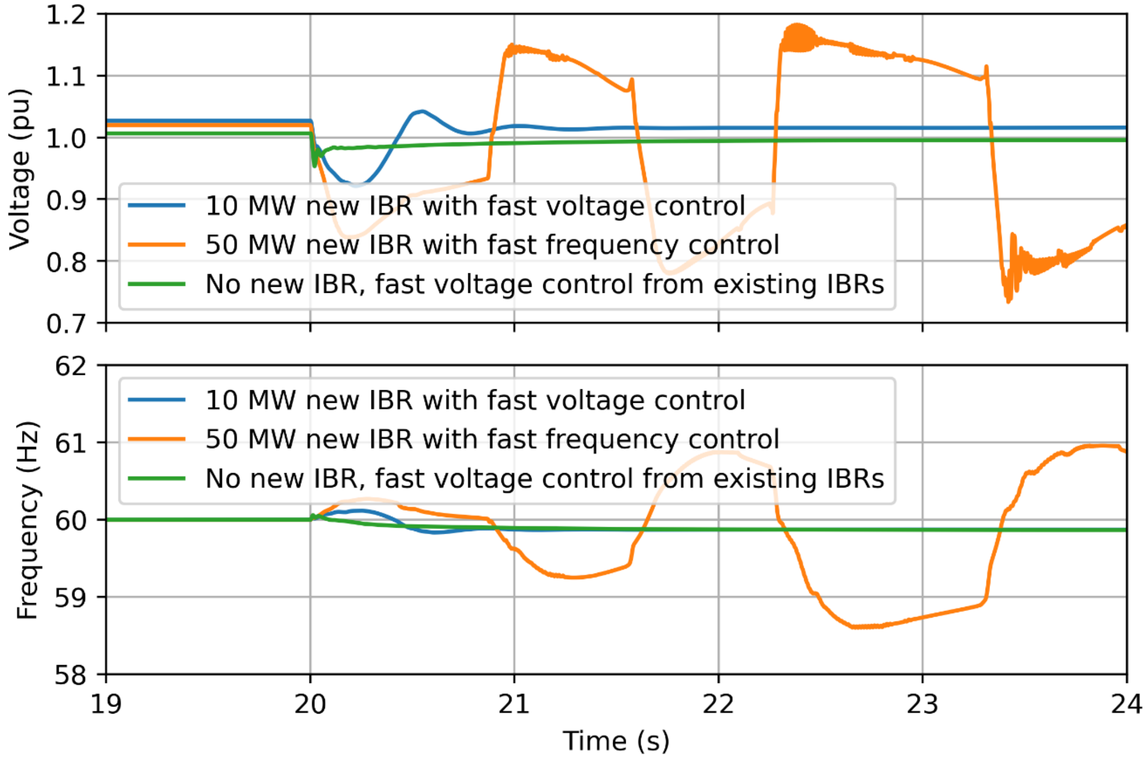
This table summarizes the stable or unstable response of the microcosm system for trip of one synchronous generator. The base network was unstable for this contingency. The new IBR with future capability was able to ensure a stable response; however, the size of the new IBR depended on factors such as IBR P/Q priority for the new IBR.

Source: Energy Systems Integration Group.

To further test this hypothesis that the grid service needed during this disturbance is primarily fast voltage/reactive power support, instead of adding a future IBR to bus 2, we added an enhanced IBR with the capability for inverter-level voltage and/or frequency control. With just the fast voltage control enabled (i.e., the IBR had slow/conventional plant-level voltage and frequency controls and the fast inverter-level voltage control, but no fast inverter-level frequency control), a 10 MW new IBR was sufficient to keep the network stable through the disturbance, as seen in Figure 4 (blue trace). However, even a 50 MW new IBR with just the fast frequency control enabled (i.e., slow/conventional plant-level voltage and frequency controls and the fast inverter-level frequency control, but no fast inverter-level voltage control), the network was not able to stay stable during the disturbance, as shown in the orange trace. In fact, if all the existing IBRs are capable of delivering fast inverter-level voltage control and if it is utilized on all of the existing IBRs, no new IBR with enhanced or future capabilities is required for the system to remain stable through this disturbance, as shown in the green trace. The different simulations are also summarized in Table 4 and Figure 5.

FIGURE 4

The Voltage and Frequency at Bus 2 for Different Combinations of Services from New/Existing IBRs



The microcosm network where the existing IBRs did not provide fast voltage/frequency control was able to achieve a stable response for trip of one synchronous generator with a new enhanced IBR providing fast voltage control; however, if the new IBR provided fast frequency control, this did not result in a stable response. Additionally, if the existing IBRs were able to provide fast voltage response, the network was able to achieve a stable response for this contingency without any new IBR.

Source: Energy Systems Integration Group.

TABLE 4

Impact of the Fast Voltage/Frequency Control from New and/or Existing IBRs on Stability

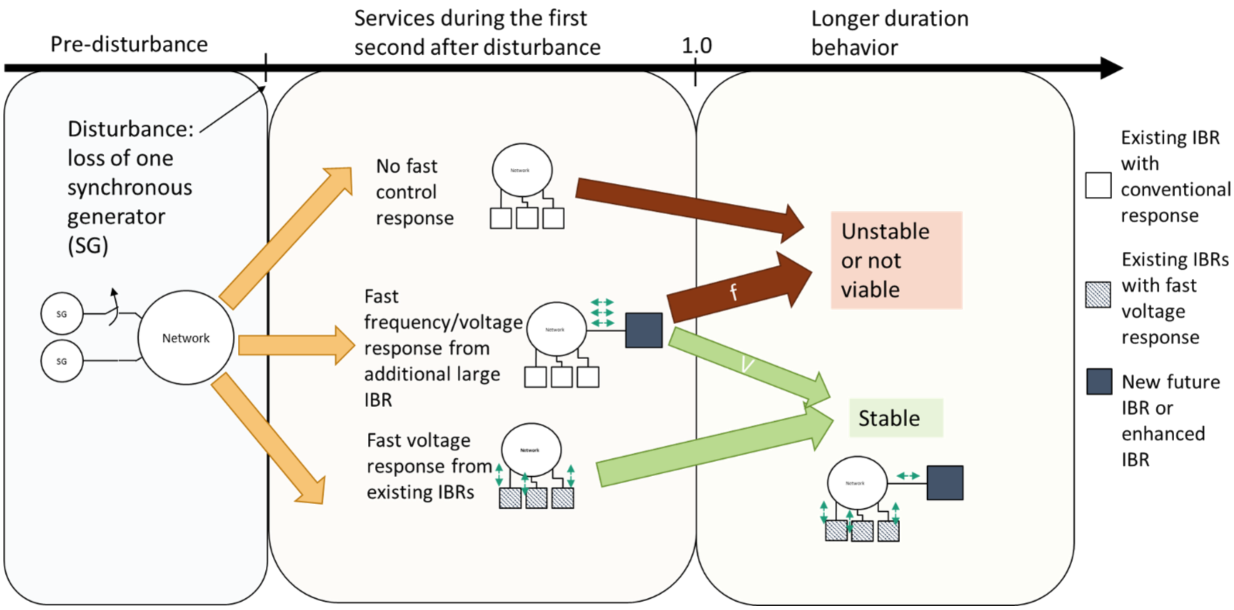
System Description	New IBR Location	New IBR Size	New IBR Control	Existing IBR Control	Stable?
Base	N/A	N/A	N/A	Conventional	Unstable
New future IBR	Bus 2	25 MVA	Future IBR	Conventional	Stable
Fast voltage control from new IBR	Bus 2	10 MVA	Enhanced, fast voltage control	Conventional	Stable
Fast frequency control from new IBR	Bus 2	50 MVA	Enhanced, fast frequency control	Conventional	Unstable
Fast voltage control from existing IBRs	N/A	N/A	N/A	Enhanced, fast voltage control	Stable

The microcosm base network was unstable for a trip of one synchronous generator, and a new IBR with future capabilities was a potential solution that led to a stable response. Upon further investigation into what service is required, it was found that instead of the new IBR with future capability, a new IBR with fast voltage control (or even existing IBRs providing fast voltage control) was able to permit the network to reach a stable response; however, fast frequency control on the new IBR was not sufficient to ensure a stable response.

Source: Energy Systems Integration Group.

FIGURE 5

Impact of Different Services from Existing/Newly Added IBRs on the Network Behavior After a Trip of One Synchronous Generator



Key observations for the microcosm system studies for a trip of synchronous generator where the base network was unstable were that fast voltage response from existing IBRs or fast voltage response from a new large IBR was able to ensure a stable response; however, fast frequency response from a new IBR was not sufficient to ensure a stable response in the absence of any fast voltage response from existing IBRs. The orange arrows going from the pre-disturbance region indicate the different possibilities of combinations of services that may be supplied by different existing and new IBRs. The brown arrows indicate the cases where the network was unable to reach a stable and viable operating point, and green arrows indicate the scenarios in which the network was able to reach a stable and viable operating point.

Source: Energy Systems Integration Group.

These results further indicate that for this disturbance and system conditions, fast voltage/reactive power support was the grid service needed to keep the grid stable. While this result is intuitive (power cannot be pushed into a weak voltage), it deserves to be repeated to highlight its importance in a system with a high percentage of IBRs.

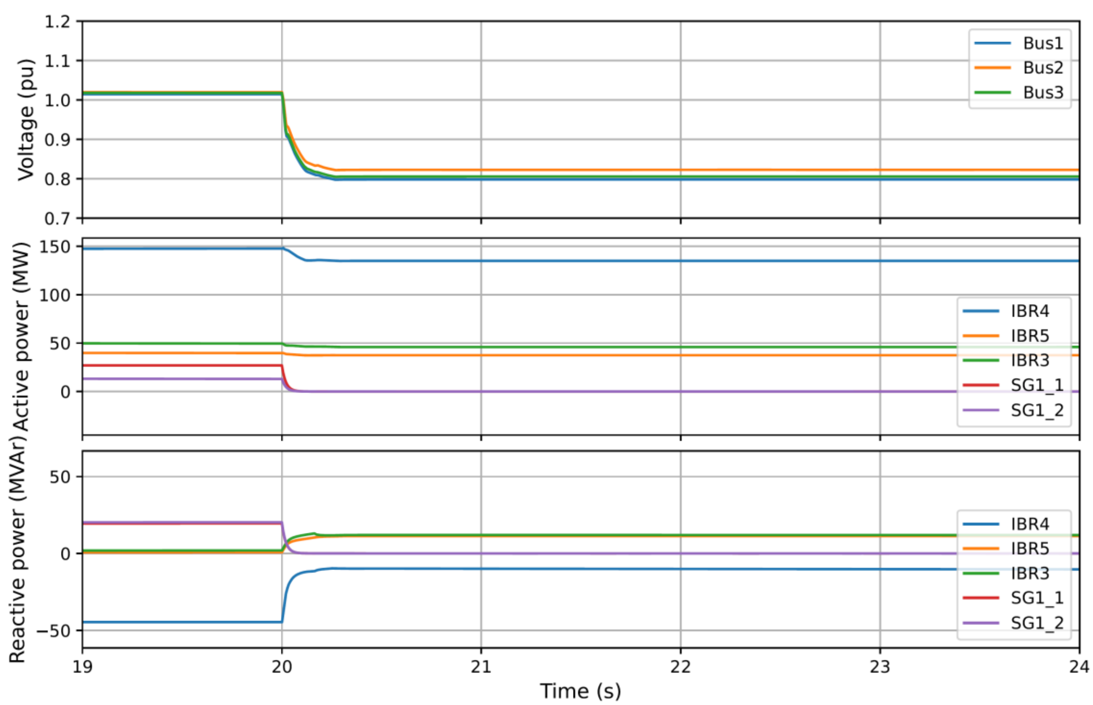
Note that the purpose of these simulations was not to specifically compare a 25 MW future IBR with a 10 MW enhanced IBR with fast voltage control in terms of stabilizing the grid; rather, the cases illustrate what *services* are needed from the IBRs. Such a comparison does not necessarily imply that the enhanced IBR is “better” than the future IBR or that a smaller enhanced IBR is, in general, equivalent to a larger future IBR, since the exact size of IBR required in a system will depend on factors such as controller tuning, and it would be possible to obtain similar responses from different control architectures with proper controller tuning. The aim here is to showcase the performance obtained from different technology and the methods by which this performance is provided.

3.2 Trip of Both Synchronous Generators

The second contingency considered a simultaneous trip of both synchronous generators, where the resultant system would have a 100% IBR penetration. In Figure 6 the voltages at different buses and active/reactive powers by different devices are plotted for the base network with three IBRs with conventional control (providing slower, multi-second voltage/frequency control). The voltages dropped below 0.85 after both synchronous generators tripped, and all three IBRs went into the fault ride-through (FRT) mode, freezing the control states. Hence, the network was unable to achieve a viable operating point. Similar to the previous case study, the different cases considered the impact of obtaining different services from the existing IBRs on the need to install new IBRs with enhanced or future capabilities to help the grid reach a stable and viable operating point.

FIGURE 6

Network Behavior After Trip of Both Synchronous Generators



The microcosm network was not able to reach a viable operating point when both synchronous generators were tripped simultaneously. The low voltages due to the disturbance led the existing IBRs in the system to go into fault ride-through (FRT) mode and freeze the controls, resulting in a non-viable operating point.

Source: Energy Systems Integration Group.

3.2.1 Initial Investigation

For a less severe generation-loss disturbance of a single generator trip as seen in the previous case in Sub-section 3.1, a stable response was observed with either the addition of a new IBR with future capabilities of a sufficient size or by utilizing/obtaining fast voltage response from all the existing IBRs (switching them from conventional IBRs to enhanced IBRs). These two options were also tested for this more severe disturbance.

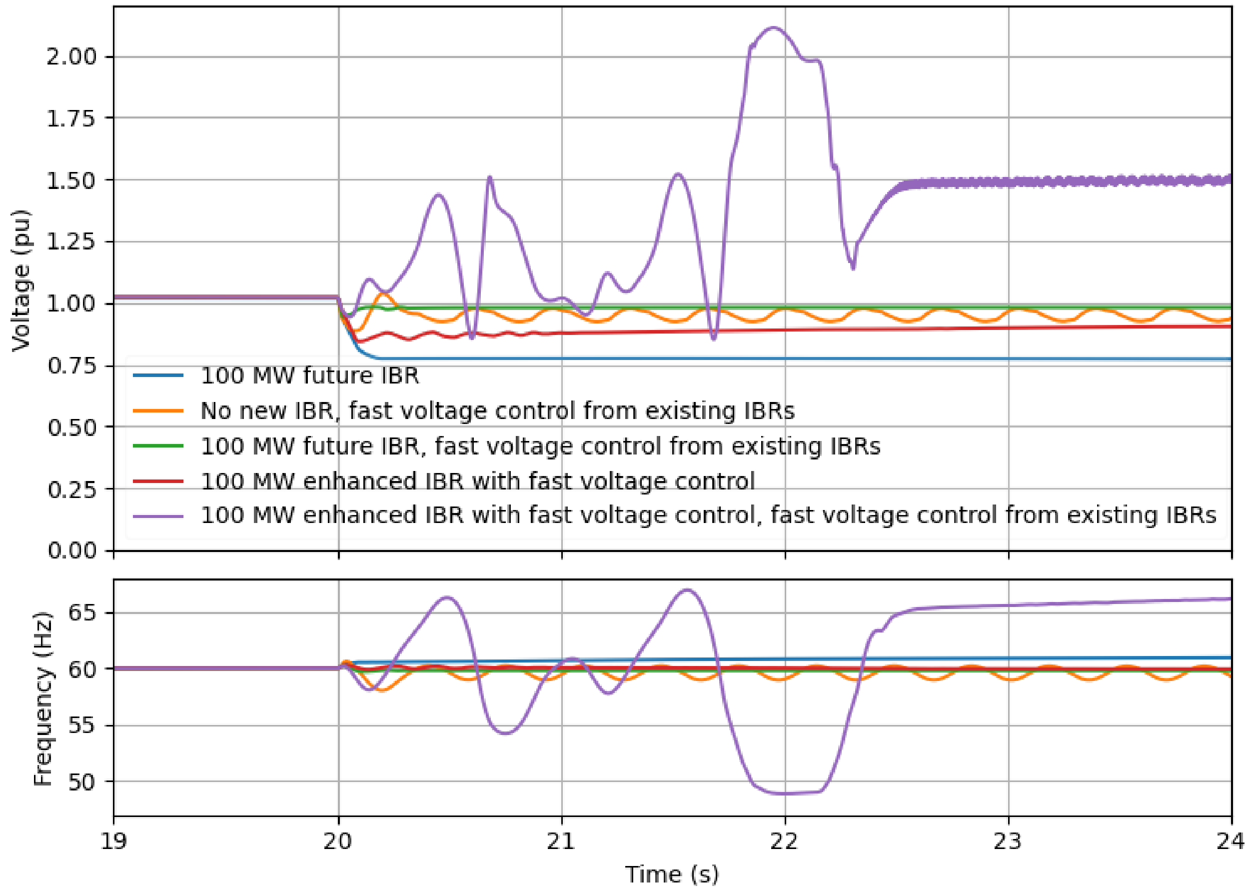
First, we changed the existing IBRs from conventional (no fast inverter-level voltage control) to enhanced *(with* fast inverter-level voltage control) and did not add any new IBR to the network. With this configuration a viable operating point was not achieved—in fact, sustained oscillations were observed, as shown in Figure 7 (orange trace).

Then, a new 100 MW IBR was added at bus 1 as an option to help the network reach a stable and viable operating point after the disturbance. Based on the results in Sub-section 3.1, we tested two control capabilities for this new IBR—a 100 MW enhanced IBR with fast voltage control (no fast frequency control) and a 100 MW future IBR, which had fast voltage control and fast frequency control as well as additional capabilities (see Section 2 for more details of different IBR categories based on control capabilities). When a 100 MW enhanced IBR with fast voltage control was added to bus 1, the system was not able to reach a viable operating point with the existing IBRs with conventional control, as shown in Figure 7 (red trace). We then tested the second type of new IBR. If a 100 MW future IBR was added to bus 1 (with either P-priority or Q-priority) with existing IBRs still having conventional control, a viable operating point was again not achieved, as shown in Figure 6 (blue trace).

As observed, the two options of obtaining fast voltage control from all the existing IBRs and installing a new IBR with enhanced or future capabilities, on their own, did not result in a stable and viable network response. Hence, the next set of cases to be tested included a combination of obtaining additional services from the existing IBRs (by utilizing/enabling and shifting from conventional control on existing IBRs to enhanced control) and adding a new IBR (100 MW at bus 1) to the network with enhanced/future capabilities. Unstable behavior was observed when the new IBR was considered to be an enhanced IBR providing fast voltage control (but no fast frequency control), and if the existing IBRs were assumed to be enhanced IBRs providing fast inverter-level voltage control (but no fast frequency control), as shown in Figure 6 (purple trace). Please note that for this case (purple trace), if the under-frequency load shedding (UFLS) was explicitly modeled, it would have triggered on the first backswing. On the other hand, when the new IBR was considered to be a future IBR, if the existing IBRs were assumed to be enhanced IBRs (IBRs providing fast inverter-level voltage control), the network was able to achieve a stable and viable operating point, as shown in Figure 7 (green trace). The different cases simulated thus far in Sub-section 3.2 are summarized in Table 5.

FIGURE 7

The Voltage and Frequency at Bus 2 for Different Combinations of Services from New/Existing IBRs



Different combinations of services from existing and new IBRs were tested for the microcosm system for the trip of two synchronous generators. Fast voltage control from existing IBRs and a new IBR with future capabilities on their own were not sufficient to ensure a stable and viable response, but together they were. Fast voltage control from the new IBR led to a non-viable operating point if existing IBRs did not provide any fast voltage response, and resulted in unstable response if the existing IBRs also provided fast voltage response.

Source: Energy Systems Integration Group.

TABLE 5

A Summary of Different Scenarios for the Trip of Two Synchronous Generators

System Description	New IBR Location	New IBR Size	New IBR Control	Existing IBR Control	Stable?
Base	N/A	N/A	N/A	Conventional	Non-viable
Existing IBRs with enhanced control	N/A	N/A	N/A	Enhanced, fast voltage control	Unstable
New enhanced IBR	Bus 1	100 MVA	Enhanced, fast voltage control	Conventional	Non-viable
New enhanced IBR	Bus 1	100 MVA	Enhanced, fast voltage control	Enhanced, fast voltage control	Unstable
New future IBR	Bus 1	100 MVA	Future	Conventional	Non-viable
New future IBR	Bus 1	100 MVA	Future	Enhanced, fast voltage control	Stable and viable

Different combinations of services from existing and new IBRs were tested for the microcosm system for the trip of two synchronous generators. The base network did not reach a viable operating point for this contingency. Fast voltage control from existing IBRs and a new IBR with future capabilities on their own were not sufficient to ensure a stable and viable response, but together they were able to. Fast voltage control from the new IBR led to a non-viable operating point if existing IBRs did not provide any fast voltage response, and resulted in unstable response if the existing IBRs also provided fast voltage response.

Source: Energy Systems Integration Group.

In this set of tests we saw that a new future IBR helped the system reach a stable response (Figure 7, green trace), and a new IBR with (enhanced) fast voltage control led to unstable behavior/oscillations (shown by the purple trace in Figure 7), when the existing IBRs provided fast voltage response.

3.2.2 The "What Services?" Question

In light of our results showing that, for the system and disturbance considered here in Sub-section 3.2, the new IBR with enhanced fast voltage control resulted in oscillations while the new IBR with future control was able to help the system reach a stable state (as long as the existing IBRs were assumed to be enhanced, providing fast voltage response), an important question to ask is, what services does the future IBR provide here over the enhanced IBR with fast voltage control, that help the system reach a stable operating point? The different cases presented in this sub-subsection were conducted to try to answer this question. For all of these cases, the existing IBRs in the network were all assumed to be enhanced, providing fast voltage response but no fast frequency response.

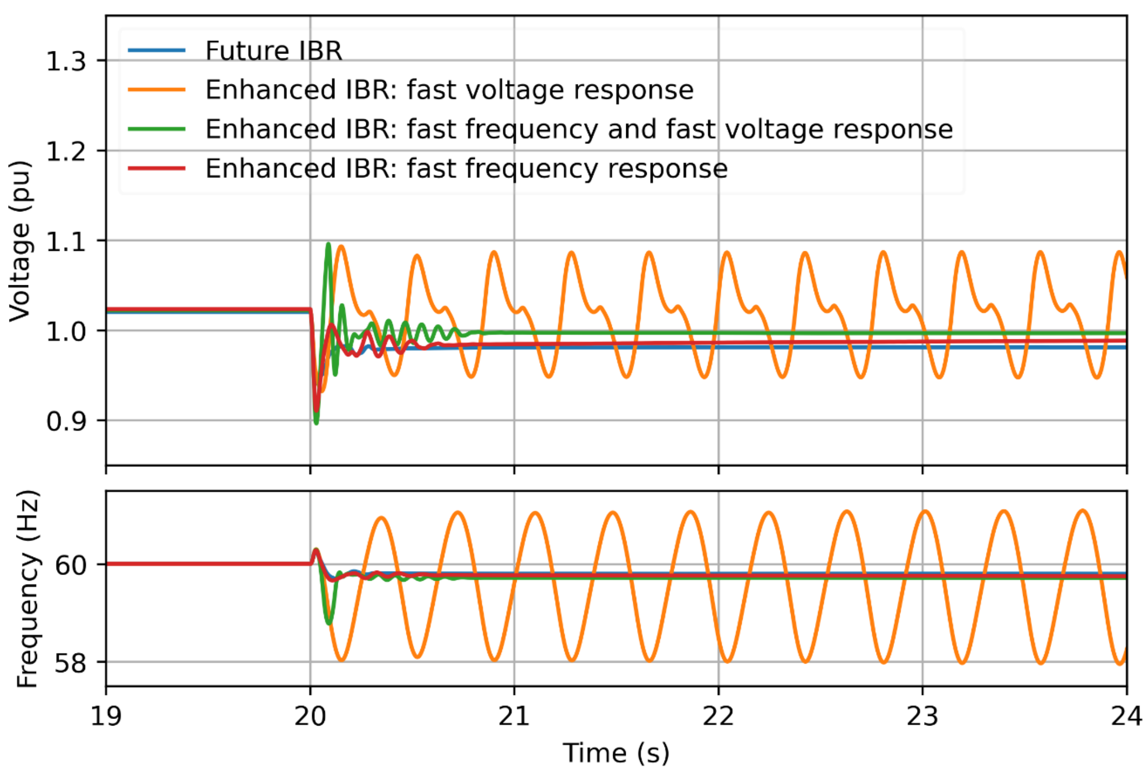
> What services does the future IBR provide here over the enhanced IBR with fast voltage control, that help the system reach a stable operating point?

One possibility was that all the required services were provided, but oscillations were observed for the case with the new IBR with enhanced fast voltage control for the particular controller parameters. If this was the case, then the oscillations would be eliminated when the controller parameters were changed. To a certain extent, these oscillations were reduced by tuning the control parameters related to the fast voltage response, but some oscillations remained (shown in Figure 8, orange trace), indicating that these oscillations may not be eliminated without acquiring additional services from IBRs. (Further controller tuning may be possible, but exploring that is not the intent here.)

One service provided by the future IBR but not the enhanced IBR with fast voltage response is fast frequency response (in addition to fast voltage response). When the new IBR with enhanced control is assumed to have fast frequency response as well as fast voltage response, the system is able to reach a stable operating point for appropriate controller parameters (Figure 8, green trace). In fact, when the new IBR provides fast frequency response but no fast voltage response, since the existing IBRs are providing fast voltage response, the system is able to reach a stable operating point (Figure 8, red trace). The different simulations for this case study (including the simulations from Sub-section 3.2.1) are summarized in Table 6—the simulations from this Sub-section 3.2.2 are presented in green text.

FIGURE 8

The Voltage and Frequency at Bus 2 for Different Configurations of Services from New 100 MW IBR



The existing IBRs were assumed to provide fast voltage response—in this case when the new IBR also provided just fast voltage response, oscillatory behavior was observed, but when the new IBR provided fast frequency response, the network was able to reach a stable and viable operating point.

Source: Energy Systems Integration Group.

TABLE 6

A Summary of Different Simulation Cases for a Trip of Both Synchronous Generators for Different Services Obtained from Existing and New IBRs

System Description	New IBR Location	New IBR Size	New IBR Control	Existing IBR Control	Stable?
Base	N/A	N/A	N/A	Conventional	Non-viable
Existing IBRs with enhanced control	N/A	N/A	N/A	Enhanced, fast voltage control	Unstable
New enhanced IBR	Bus 1	100 MVA	Enhanced, fast voltage control	Conventional	Non-viable
New enhanced IBR	Bus 1	100 MVA	Enhanced, fast voltage control	Enhanced, fast voltage control	Unstable
New future IBR	Bus 1	100 MVA	Future	Conventional	Non-viable
New future IBR	Bus 1	100 MVA	Future	Enhanced, fast voltage control	Stable and viable
New enhanced IBR	Bus 1	100 MVA	Enhanced, fast frequency and voltage control	Enhanced, fast voltage control	Stable and viable
New enhanced IBR	Bus 1	100 MVA	Enhanced, fast frequency control	Enhanced, fast voltage control	Stable and viable

Different combinations of services from existing and new IBRs were tested for the contingency of trip of two synchronous generators. Without existing IBRs providing fast voltage response, the different combinations of services from a new IBR did not lead to a stable and viable response. When the existing IBRs provided fast voltage control, if the new IBR also provided fast voltage control, the response was unstable, but if the new IBR provided fast frequency control or had a future control capability, the network was able to reach a stable response.

Source: Energy Systems Integration Group.

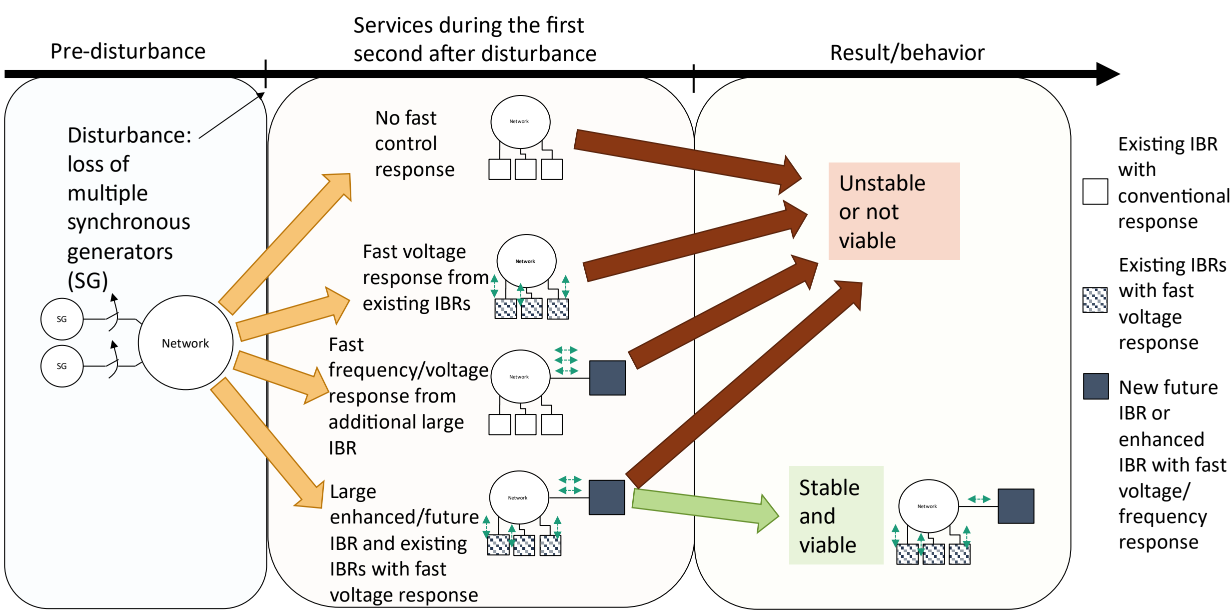
This case study shows that the provision of services by existing IBRs may help reduce the burden of providing grid services from a new IBR.

This case study shows that the provision of services by existing IBRs may help reduce the burden of providing grid services from a new IBR. In this example, although neither the new 100 MW future IBR nor the fast voltage control on the existing IBRs led to a viable operating point on their own, when fast voltage and fast frequency response was supplied among all the resources, they were able to share the burden of the services to be provided and ensure a stable and viable operating point through this disturbance. Further, there might be a locational aspect to the provided services, as the grid did not reach a viable point when fast voltage/frequency response was provided by just the new future IBR at a single bus, but did reach a stable and viable operating point when the existing IBRs provided fast voltage response and the new IBR (be it enhanced or future control) provided fast frequency response (and may or may not have also provided fast voltage response).

The findings from this case study (Sub-section 3.2) are illustrated in Figure 9. The figure shows different configurations of services from existing or new IBRs, focusing on the services provided during the first second after the disturbance. (A conventional IBR that can provide slow frequency/voltage response over multiple seconds is not shown to provide any voltage/frequency response in the figure.) Again, the purpose here is not to compare the response from enhanced vs. future IBRs per se, since the IBR performance depends on factors such as controller structure and tuning, but rather to study the general trends in terms of the impact of different services obtained from existing and new IBRs on the network response.

FIGURE 9

Impact of Different Services from Existing/Newly Added IBRs on the Network Behavior After a Simultaneous Trip of Two Synchronous Generators



Different combinations of services from existing and new IBRs were tested for the contingency of trip of two synchronous generators. The orange arrows going from the pre-disturbance region indicate the different possibilities of combinations of services that may be supplied by different existing and new IBRs. The brown arrows indicate the cases where the network was unable to reach a stable and viable operating point, and green arrows indicate the scenarios where the network was able to reach a stable and viable operating point. Without existing IBRs providing fast voltage response, the different combinations of services from a new IBR did not lead to a stable and viable response. When the existing IBRs provided fast voltage control, if the new IBR also provided fast voltage control, the response was unstable, but if the new IBR provided fast frequency control or had a future control capability, the network was able to reach a stable response.

Source: Energy Systems Integration Group.

Note that with different operating points or disturbances as well as different control configurations/parameters, the response of the system may vary. For example, in the case study in Sub-section 3.1, either a newly added future IBR or fast voltage response from existing IBRs was sufficient to ensure stability following the trip of one synchronous generator, whereas in this case study, following the simultaneous trip of two synchronous generators a combination of both measures (and both fast voltage and fast frequency services) was needed from the IBRs.

3.3 Factors Influencing the Grid Services Required

The case studies presented in Sub-sections 3.1 and 3.2 considered fast voltage and frequency responses from IBRs as two grid services potentially needed following a trip of one or two synchronous generators connected to the microcosm system. However, the services required by the grid will depend on many different factors stemming from particular scenarios. Some of these factors are:

- Phase-locked loop (PLL) control parameters
- IBR protection settings
- Interplay between the fast voltage/frequency IBR response and the IBR low/high-voltage trip according to protection settings

The intention in this section is not to cover all possible factors exhaustively, but rather to illuminate the need to consider such factors that may impact the system behavior. More factors and interactions would need to be considered according to the scenario/contingency and network, and a systematic study of such factors would lead to further insights about the grid services needed from IBRs.

3.3.1 Phase-Locked Loop

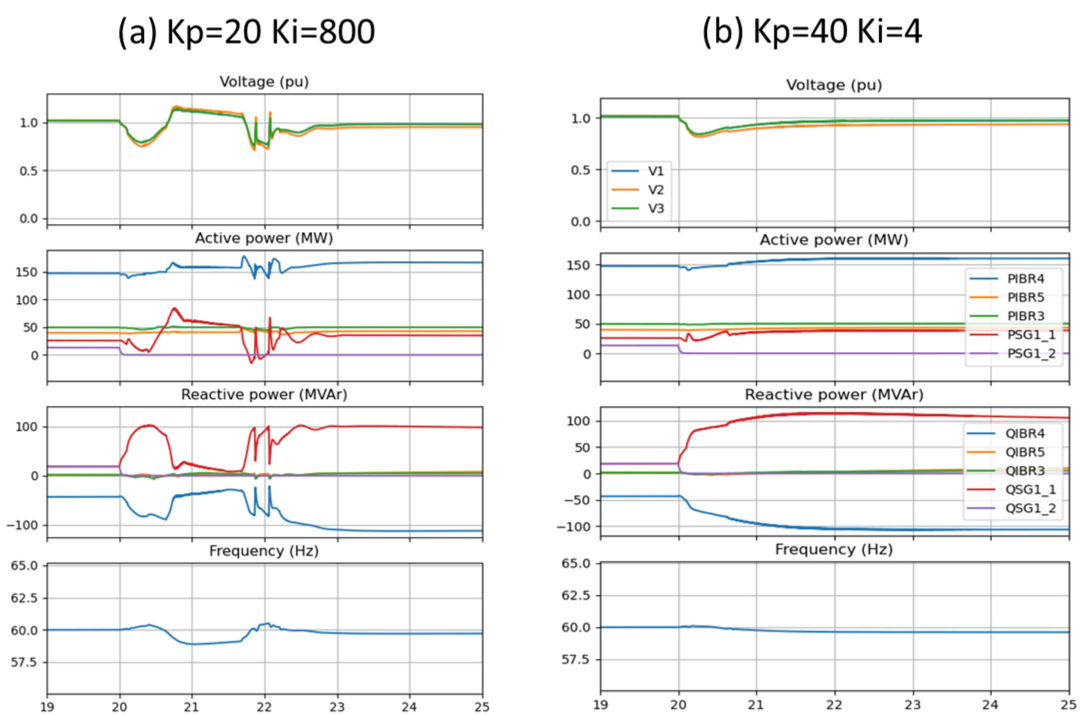
In the case studies presented in Sub-sections 3.1 and 3.2, fast and slow controls were differentiated in IBRs' control structure and/or parameters. In this sub-subsection, it is shown that control parameters not directly linked to the services under study (in this case, fast voltage and/or fast frequency services) can also influence the need for grid services. Here we investigated the impact of phase-locked loop parameters given the role of PLL in the stability of an IBR-dominated network (Wen et al., 2016). PLLs are an important component when designing and deploying an IBR; therefore, original equipment manufacturers (OEMs) take great care in developing advanced PLLs and tune the parameters to balance different factors—for example, how slow or fast a PLL needs to respond, or PLLs' impact on stability, as shown by the simple sensitivity in this study. Another important factor to consider is that PLL gains are typically not user-settable; hence, in an actual network it would be important to carefully and accurately model the PLLs to determine the actual needs of the network. This study used a simple SRF-PLL (synchronous reference frame-PLL) model to illustrate how IBR controller parameters may impact the grid needs.

For this study, the contingency considered was a loss of one synchronous generator followed by a load increase. Here, two sets of PLL parameters were considered. The first set of parameters (low-bandwidth PLL) correspond to the PLL parameters used for the existing IBRs in simulations of the microcosm system discussed in Sub-sections 3.1 and 3.2 and depicted in Figure 1. These existing IBRs are considered to be conventional IBRs (providing slower voltage and frequency response but no fast voltage or frequency response). The contingency considered was the trip of one synchronous generator (similar to Sub-section 3.1), but made more severe by following it with a load increase at bus 2. We first tested a low-bandwidth PLL. For this PLL (Kp=40, Ki=4), the bandwidth of the PLL can be calculated to be approximately 0.1 Hz. When the existing conventional IBRs used these low-bandwidth PLL parameters, a 25 MVA future IBR installed at bus 2 eliminated the unstable behavior.

For the second set of IBR parameters, we considered a high-bandwidth PLL (Kp=20, Ki=800), representing a situation when existing IBRs are configured for an aggressive PLL response. In this case, the added 25 MVA future IBR was not able to eliminate the unstable behavior, as observed in Figure 10 (right). This difference between two different sets of PLL parameters shows the importance of representing the system accurately, since the grid services provided by the 25 MVA future IBR maintained stability in one case while showing unstable behavior in the other. The example also shows how other IBR parameters can influence the amount of services needed by a grid.

FIGURE 9

System Response for a Trip of One Synchronous Generator Followed by a Load Increase for Two Sets of PLL Parameters on Existing IBRs and a 25 MVA Future IBR on Bus 2



The response of the microcosm system with a 25 MVA future IBR on bus 2 was tested for trip of a synchronous generator followed by a rise in load for two sets of PLL parameters for the existing IBRs. The difference in responses shows that such control parameters not directly related to the voltage and frequency support services under consideration may also play a role in the system response.

Source: Energy Systems Integration Group.

3.3.2 IBR Protection Settings

In the discussion of system services presented thus far, we have not considered the "services" associated with IBR protection settings in the form of fault ride-through and trip/no-trip response. However, for certain contingencies such as faults, these can be very important in determining the system's needs. Often, the appropriate level of fault ride-through is specified as a requirement in the grid code. In a system with a high level of IBRs or for island systems these settings can be even more critical. In this case study, the contingency of a fault close to the IBR buses was considered as one that would potentially trigger IBR trips due to low or high voltages, allowing us to study the impact of different levels of IBR fault ride-through and trip settings on the system response.

The generic models used for the IBRs (EPRI, 2022) are able to represent three kinds of trip settings: low voltage (LV), high voltage (HV), and transient overvoltage (TrOV). Wherever enabled, the LV, HV, and TrOV functions were kept the same across the tests, and settings based on IEEE Standard 2800-2022 were used for these functions, so the case with all functions enabled corresponds to an IBR following the minimum ride-through requirements from IEEE Std 2800-2022, and other cases represent IBRs providing ride-through beyond that minimum. Hence, four different levels of IBR ride-through were considered:

1. IBRs trip for all three of the LV, HV, and TrOV functions.
2. IBRs ride through for the TrOV voltage/time range (the TrOV function was disabled in the model), but trip for the LV and HV functions.
3. IBRs ride through high voltages (the TrOV and HV functions were disabled in the model), but trip for the LV function.
4. IBRs are capable of riding through extreme low and high voltages (all three functions were disabled in the model).

The results for these four cases for the contingency of a balanced fault at bus 2 sustained for 0.5 s are shown in Figure 11. In these scenarios, no new IBR was considered, and no advanced control from IBRs (apart from low/high voltage ride-through) was considered—the IBRs were assumed to operate with conventional control.

For the first case (Figure 11(a)), one IBR tripped due to LV function, and two IBRs tripped for the TrOV function due to the high voltage experienced after the fault was cleared. Overall, the system was unstable, and the system frequency had oscillations.

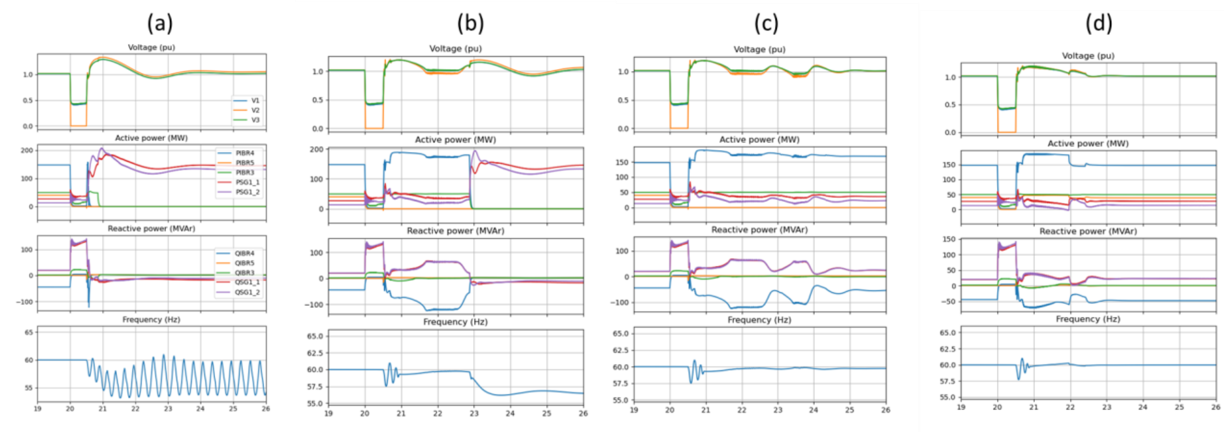
In the second case (Figure 11(b)), the two IBRs that tripped in the first case due to the TrOV function now tripped due to the HV function, since the high voltage after the fault was cleared persisted long enough to trigger the HV function. Hence, all three IBRs tripped even in this case; however, instead of an oscillation in frequency, the frequency settled down to a low value (low enough that it may not be acceptable for operating a system).

In the third case (Figure 11(c)), only one IBR tripped due to low voltage experienced at the IBR terminal—in this case the frequency returned to approximately 60 Hz, and the system did not show unstable behavior.

In the last case (Figure 11(d)), no IBRs tripped, and a stable response was obtained.

FIGURE 11

Response of the Microcosm System for a Balanced Fault at Bus 2 with Varying Levels of IBR Ride-Through Capabilities



Different levels of IBR fault ride-through capabilities were tested for a fault on bus 2 for the microcosm system. Progressively increased levels of ride-through capabilities for IBRs in this study impacted and improved the system stability for this contingency.

Source: Energy Systems Integration Group.

This exercise shows that for certain contingencies, other services not considered in detail in this paper, such as fault ride-through, may be very important. The next case study provides a preliminary investigation tackling the question of the role played by fast voltage/frequency services by IBRs for such a fault contingency.

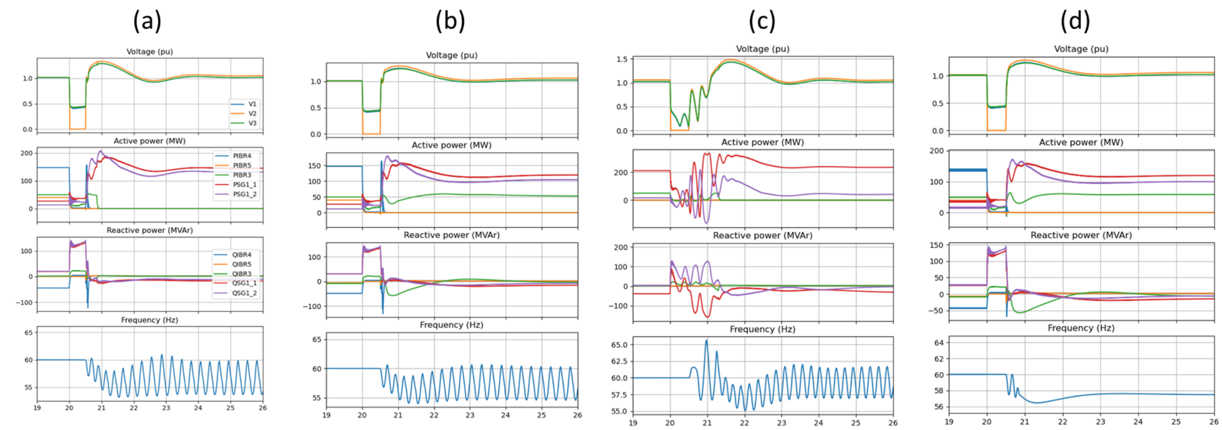
3.3.3 IBR Protection Settings and Fast Voltage/Frequency Control

In Sub-sections 3.1 and 3.2 we studied the impact of fast voltage/frequency response services, and in Sub-subsection 3.3.2 we examined the importance of fault ride-through services. For certain contingencies, these different services may act together to alleviate the adverse impacts. Here, we tested four cases to assess IBRs' tripping behavior for different combinations of fast voltage/frequency services obtained from the IBRs. No new IBR was considered, and we assumed the same fault contingency (as Sub-section 3.3.2) of balanced fault at bus 2. The system responses for these four cases are plotted in Figure 12. In all these cases, it was assumed that the IBRs would trip for all three trip functions, TrOV, HV, and LV (i.e., that they had the minimum ride-through capability as described by IEEE (2022). The four cases were as follows:

1. The IBRs followed conventional control with no fast voltage/frequency control.
2. The IBRs additionally had inverter-level fast voltage control, but no fast frequency control.
3. The IBRs had inverter-level fast frequency control in addition to conventional slow controls, but no fast voltage control.
4. The IBRs had inverter-level fast voltage as well as fast frequency control in addition to the conventional slow plant-level controls.

FIGURE 12

The Response of the Microcosm System for a Balanced Fault at Bus 2 with Different Voltage/Frequency Control Settings for IBRs



The impact of fast voltage/frequency control services from IBRs in the microcosm system was studied for a fault on Bus 2. When the IBRs did not provide any fast voltage/frequency response or provided *either* fast voltage or fast frequency response, the system resulted in oscillations in the frequency; however, when the IBRs provided both fast voltage and fast frequency response, the frequency settled down, although at a lower than nominal frequency value.

Source: Energy Systems Integration Group.

For the first and the third cases (Figure 12(a) and Figure 12(c)), with no fast voltage/frequency control or only fast frequency control, all three IBRs tripped for the contingency of a 0.5 s fault at bus 2. For the second case (Figure 12(b)), with the fast voltage control, the IBR at bus 3 did not trip—however, the system still experienced frequency oscillations and was unstable.

In the fourth case (Figure 12(d)), where the IBRs had fast voltage as well as fast frequency control, the IBR at bus 3 rode through the contingency, and, additionally, the frequency did not exhibit oscillations. Note that the frequency still settled at a low value due to the rest of the IBRs tripping, but this case study indicates that there may be a value in having fast voltage and frequency response even just for keeping more IBRs connected to the system after a contingency, and that different services may act together to improve the system response for certain contingencies. Hence, for some IBRs in the system where the capability of providing such fast response services exists but is not currently utilized (i.e., currently the IBRs provide only conventional capability even though they are capable of providing enhanced capability), it may be valuable to utilize these services to help mitigate adverse impacts of different contingencies.

4 Island-Wide Case Study

In the case studies in Section 3, we examined the impact of fast voltage and fast frequency services as well as fault ride-through services for a microcosm system. However, even the slower response from IBRs obtained over several seconds may be valuable in some instances—this case study examines one such example of a real network. The system under study was fed entirely by IBRs and contained 8.25 MVA of PV capacity, 8 MVA of BESS capacity, 3.25 MVA of distributed energy resource (DER) capacity, and a 2.75 MVA synchronous condenser, and had a load level of 2.9 MW (Table 7). This is the light load scenario for this network (the installed generation is relatively high compared to the load). This system represents the power system of a real island network that was graciously provided to us by the power utility of this region.

From the 16.25 MVA of PV and BESS capacity connected at the transmission level, a total of 10 MVA was AC-coupled PV-BESS hybrid plants, with each plant being 5 MVA in capacity. It was also assumed that the BESS portion of the hybrid plant was not controlled by the plant controller: the PV and BESS portions could be controlled independently and provide different control capabilities. The remaining PV (3.25 MVA) and BESS (3 MVA) were standalone units. The total inverter resource capacity in the system was thus 19.5 MVA.

TABLE 7
Different Resources Connected to the Island Network

Resource	Size
PV-BESS hybrid plant (2.5 MVA PV and 2.5 MVA BESS controlled independently)	5 MVA
PV-BESS hybrid plant (2.5 MVA PV and 2.5 MVA BESS controlled independently)	5 MVA
PV plant	3.25 MVA
BESS plant	3 MVA
DER capacity	3.25 MVA
Total	**19.5 MVA**

The island network was primarily fed by IBRs and has 19.5 MVA IBR capacity installed.

Source: Energy Systems Integration Group; data from EPRI.

The load dynamics were represented using a constant current formulation for active power with frequency dependency and a constant impedance formulation for reactive power. This is the load representation used by the utility in this region for its studies. While dynamic load is present in this region, the utility does not have sufficient data to represent all dynamic characteristics. The DERs in the study were considered to be operating in constant power factor mode and did not provide any system support services. This is the operation mode of the DERs in this system as determined by the utility. However, all of the DERs in the study were split into three categories with different momentary cessation and voltage/frequency trip thresholds to represent different abnormal voltage/frequency momentary cessation/trip settings possible for different DERs. This split of DERs for the study has also been determined by the utility in this region. The impact of using DERs to complement system services will be part of a future study. It should be acknowledged that locational aspects in a small island network can have different implications relative to those aspects in a larger network. In a smaller system, electrical distances are often smaller, which can increase the impact of stability concerns as larger groups of elements can be affected by disturbances and can interact.

4.1 Frequency Response Study

The objective here was to identify the size of an added future IBR such that frequency stability is maintained in the network. We tested a case with 10% generation loss and identified the size of a future IBR device such that frequency stability was maintained in the network, testing 10 different combinations of existing IBRs having different control configurations and capacities and the size of a future IBR to be installed. To evaluate the frequency response of the system with an increase in inverter installed capacity above the 19.5 MVA IBRs already installed, the event applied was the trip of the synchronous condenser followed by the tripping of one 2.5 MVA conventional PV generation resource. This resulted in around 10% generation loss in the network. Various control configurations were considered as tabulated in Table 8. The new IBR was connected at the same bus as the synchronous condenser. For this contingency event, the network was unstable in the absence of the new future IBR and without any frequency or voltage support from the legacy PV and BESS devices.

In Table 8, the absence of frequency support from the ith conventional device is denoted as $\cancel{\omega}_i$ while the absence of voltage support is denoted as $\cancel{V}_i$. The presence of frequency or voltage support is denoted without the cancelation mark. The percentage of new IBR capacity is evaluated as $\frac{MVA_{new}}{19.5+MVA_{new}} \times 100\%$. In an attempt to decouple frequency and voltage response services, the BESS was assumed not to provide any voltage response service.

TABLE 8

Control Configurations Considered for Frequency Response Study

Case	Scenario Description	PV1, PV2, PV3	BESS1, BESS2, BESS3	Capacity (MVA) of the New IBR	New IBR % of Total IBR
A	Voltage response from PV, no voltage or frequency response from BESS	$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, V_1V_2, V_3$	$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, \cancel{V_1}, \cancel{V_2}, \cancel{V_3}$	2.5	11%
B		$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, V_1V_2, V_3$	$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, \cancel{V_1}, \cancel{V_2}, \cancel{V_3}$	6.0	24%
C		$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, V_1V_2, V_3$	$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, \cancel{V_1}, \cancel{V_2}, \cancel{V_3}$	4.0	17%
D		$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, V_1V_2, V_3$	$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, \cancel{V_1}, \cancel{V_2}, \cancel{V_3}$	3.0	13%
E		$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, V_1V_2, V_3$	$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, \cancel{V_1}, \cancel{V_2}, \cancel{V_3}$	3.5	15%
F	Voltage and frequency response from PV, frequency response from BESS	$\omega_1, \omega_2, \omega_3, V_1V_2, V_3$	$\omega_1, \omega_2, \omega_3, \cancel{V_1}, \cancel{V_2}, \cancel{V_3}$	2.5	11%
G		$\omega_1, \omega_2, \omega_3, V_1V_2, V_3$	$\omega_1, \omega_2, \omega_3, \cancel{V_1}, \cancel{V_2}, \cancel{V_3}$	1.5	7%
H		$\omega_1, \omega_2, \omega_3, V_1V_2, V_3$	$\omega_1, \omega_2, \omega_3, \cancel{V_1}, \cancel{V_2}, \cancel{V_3}$	1.0	5%
I	Voltage response from PV, frequency response from BESS	$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, V_1V_2, V_3$	$\omega_1, \omega_2, \omega_3, \cancel{V_1}, \cancel{V_2}, \cancel{V_3}$	1.5	7%
J		$\cancel{\omega_1}, \cancel{\omega_2}, \cancel{\omega_3}, V_1V_2, V_3$	$\omega_1, \omega_2, \omega_3, \cancel{V_1}, \cancel{V_2}, \cancel{V_3}$	2.5	11%

Considering different combinations of services from the PV and BESS units in the island network, we tested the addition of different sizes of a new IBR to see whether the network could achieve a stable and viable response following a synchronous condenser and generation trip contingency.

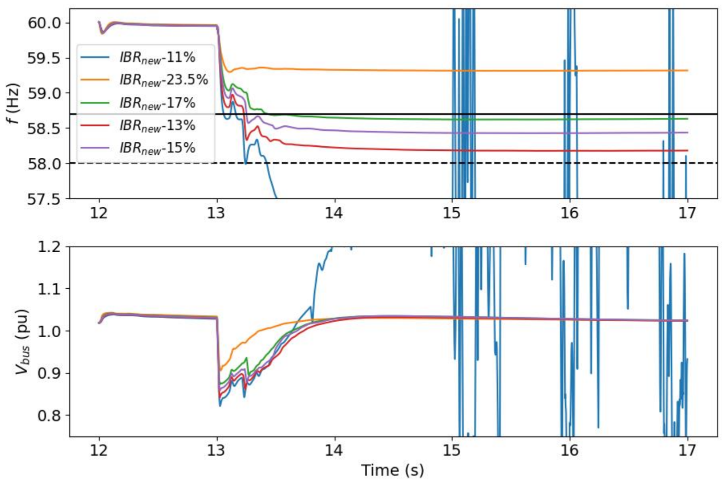
Source: Energy Systems Integration Group.

4.1.1 Cases A – E: Voltage Response from PV, No Voltage or Frequency Response from BESS

The results showed that when none of the existing IBR devices provided frequency support, none of the BESS provided voltage support, and only the PV plants provided slow voltage support at the plant control level (Cases A - E), in order to survive the loss of generation and prevent the triggering of UFLS relays, a minimum new IBR capacity of greater than 20% of the total IBR capacity on the network may be required, as shown in Figure 13. In this network, the first stage of UFLS was activated at 58.7 Hz with a timer of 4.0 s (denoted by the solid black line in the figure), while the fastest stage of UFLS was activated at 58.0 Hz (denoted by the dashed black line) with a timer of 0.4 s. When the capacity of the new IBR was closer to 10%, the system was unable to survive the loss of generation. Further, when the new IBR's MVA capacity was closer to 15% of the total IBR MVA of the network, the first stage of UFLS can be expected to trigger. For a new IBR with a capacity greater than 15% of the total network capacity, there is a chance of triggering UFLS, as the frequency trajectory lies along the boundary of the UFLS region. Only an additional increase in size of the new IBR was able to prevent the triggering of the UFLS regions.

FIGURE 10

Frequency Response and Voltage Magnitude in Island Network with No Frequency Support from Existing IBRs



When the new IBR with future capability was too small, the system response was unstable, while a medium-sized new IBR was able to result in a stable response, though would still trigger UFLS. A new IBR with future capability of around 25% of the current system installed capacity was required to achieve a stable response and prevent UFLS.

Source: Energy Systems Integration Group.

This value of around 25% of IBRs (by capacity) having future capabilities aligns well with results obtained from other research (Hoke et al., 2022). It is important to understand that this percentage value is dependent on the nature of support provided by other IBR devices in the network. Further, these percentage values are also determined by the criteria used to evaluate stability and reliability of a network. For example, in this scenario, preventing the trigger of UFLS was used as a criterion. However, let us ponder upon the necessity and validity of the UFLS scheme in a 100% IBR network. The UFLS scheme was introduced primarily to help synchronous generators remain in synchronism upon the occurrence of a large disturbance. The UFLS settings are system-specific and are based on highly non-linear behavior. The UFLS settings, delays, and acceptability play an outsized role in the stability of small island systems where some planning events might trigger UFLS. But if IBRs replace synchronous machines in these systems, there might be a possibility that the UFLS scheme is no longer required or can be set at a lower frequency trigger since helping synchronous generators remain in synchronism will not be needed. In such a situation, a lower future IBR capacity closer to 10% of the system installed capacity might be sufficient to maintain stable operation.

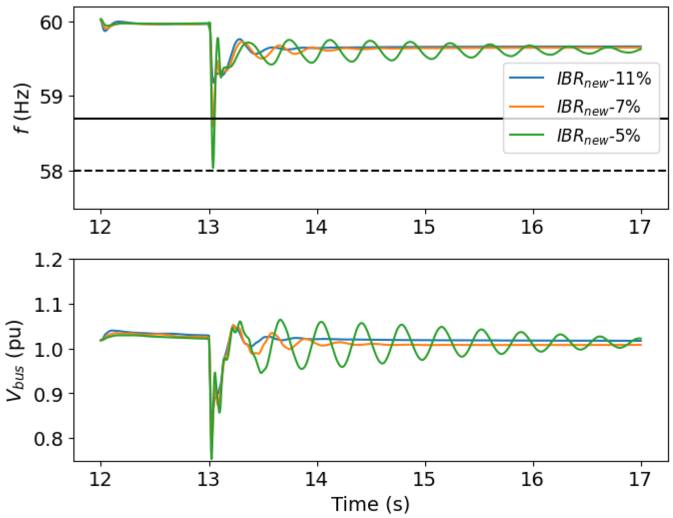
4.1.2 Cases F – H: Voltage and Frequency Response from PV, Frequency Response from BESS

With the evolution of IEEE standards such as IEEE Std 2800-2022 (IEEE, 2022), newer IBR generation facilities connecting to the transmission network are expected to have the capability to provide frequency response. In a majority of PV plants, this required capability translates into the PV plant's controller having the ability to provide a droop-based frequency response in addition to plant-level voltage control. Hence, cases F – H considered frequency response in addition to voltage response from the PV units in the network (compared to cases A – E where the PV units were assumed to only provide voltage response). For these cases, the contingency considered was the same—a trip of the synchronous condenser followed by a trip of one of the PV units, and new IBRs with future capabilities added to try to ensure frequency stability. Further, since the BESS was assumed to not have a plant controller (to evaluate the ability of services provided at device level), droop-based frequency response was implemented at the inverter level but with a time constant of 0.1 s. These configurations are tabulated as Cases F – H in Table 8 (p. 31).

For this configuration, the frequency response and voltage magnitude in the network are shown in Figure 14 for the contingency event studied. Here, with the new IBR capacity of only 5% of the system installed capacity, oscillatory behavior ensued following the contingency. (While it may be possible to damp these oscillations through either controller tuning or the use of supplementary devices, such an exercise is outside the scope of this project.) However, with only the new IBR with a capacity of 7% of the system installed capacity, the response of the network was stable. Although the filtered frequency trace went below the threshold for the fastest stage of UFLS, the frequency recovered above the threshold before the timer of 0.4 s timed out. The ability of a lower level of new IBR capacity to bring about stable operation highlights the importance of considering the frequency support services that are provided in the network.

FIGURE 14

Frequency Response and Voltage Magnitude in an Island Network with Slow Frequency Support from Existing IBRs



When the PV units in the network provided voltage response, a new IBR of a reduced size was able to ensure that the network reached a stable response of the contingency.

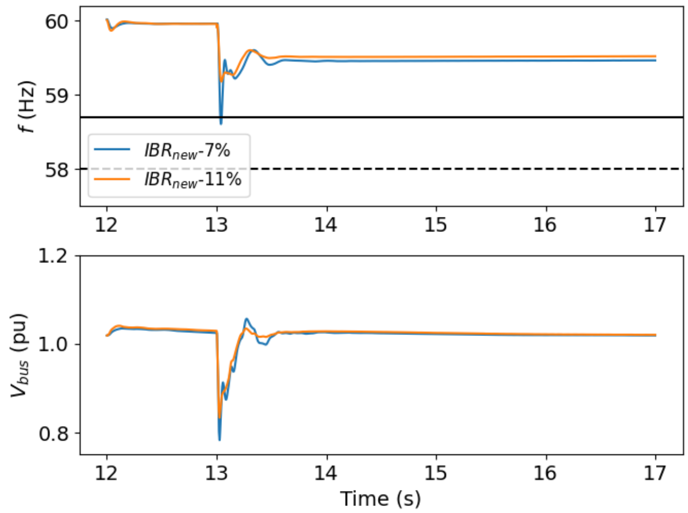
Source: Energy Systems Integration Group.

4.1.3 Cases I – J: Voltage Response from PV, Frequency Response from BESS

Finally, it may be unreasonable to expect PV plants to provide under-frequency support all the time, as they might be scheduled to operate at their maximum power output. In such a scenario, among the existing devices, only the BESSs may be expected to provide under-frequency response. These cases are denoted as Cases I – J in Table 8 (p. 31). The contingency considered was the same as the earlier cases, a trip of the synchronous condenser followed by one of the PV units tripping, and a new IBR with future capability added at the same bus as the synchronous condenser to help the network retain frequency stability. In cases I – J, the PV units provided plant-level voltage response, whereas the BESS units provided frequency response with a time constant of 0.1, the same as cases F – H. For cases I – J, the frequency response and voltage magnitude are shown in Figure 15. Here, too, it can be seen that potentially a new IBR with a capacity of only 7% of the system installed capacity is required to maintain stability of the 100%-IBR-fed system for the generation loss event.

FIGURE 11

Frequency Response and Voltage Magnitude in an Island Network with Slow Frequency Support Only from Existing BESS



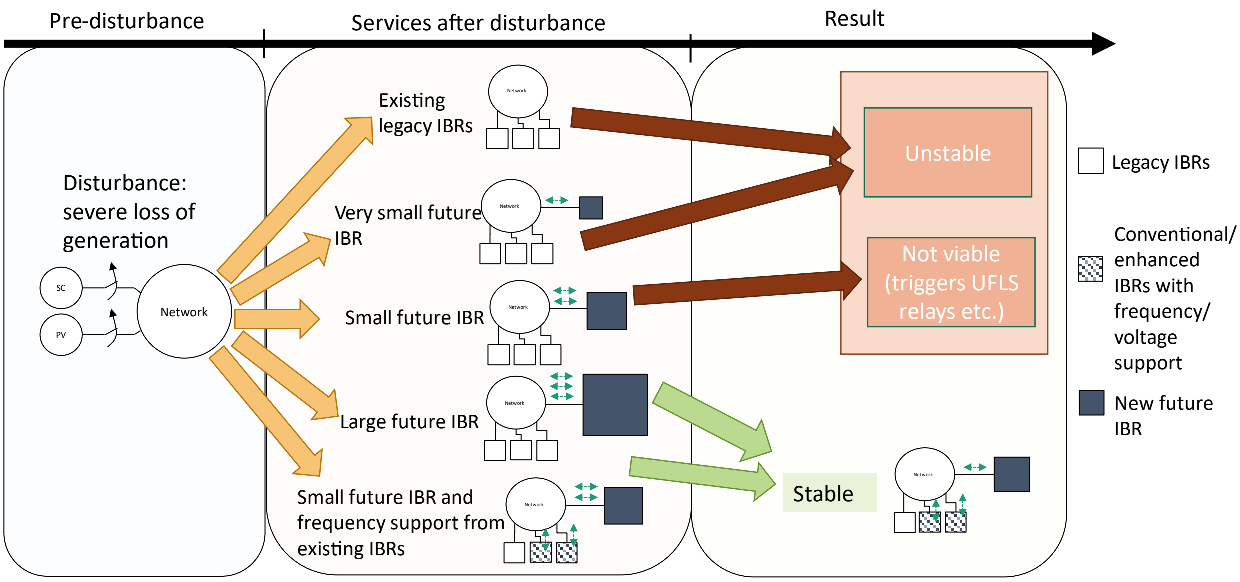
When the PV units in the network provided voltage response and the BESS units provided frequency response, a new IBR of a reduced size was sufficient to ensure that the network reached a stable response following the contingency.

Source: Energy Systems Integration Group.

The key observations from these cases are presented in Figure 16. For this contingency, the size of a new IBR with future capabilities needed to ensure a stable and viable response that does not trigger UFLS was reduced when frequency support was utilized from existing IBRs.

FIGURE 12

Impact of Different Services from New/Existing IBRs on the Generation and Synchronous Condenser Loss Contingency in the Island Network



For the island network, for the contingency of generation loss and synchronous condenser loss, the addition of no new IBR or of a small new IBR resulted in unstable response. A medium-sized IBR resulted in a stable response but still triggered UFLS, requiring a large new IBR. If existing IBRs provide frequency support, a much smaller new IBR was found to be sufficient to ensure that UFLS does not trigger. The orange arrows pointing to the right from the pre-disturbance region indicate the different possibilities of combinations of services that may be supplied by different existing and new IBRs. The brown arrows extending from the center section indicate the cases where the network was unable to reach a stable and viable operating point, and the green arrows indicate the scenarios where the network was able to reach a stable and viable operating point.

Source: Energy Systems Integration Group.

4.2 Positive-Sequence Domain Frequency Response Study

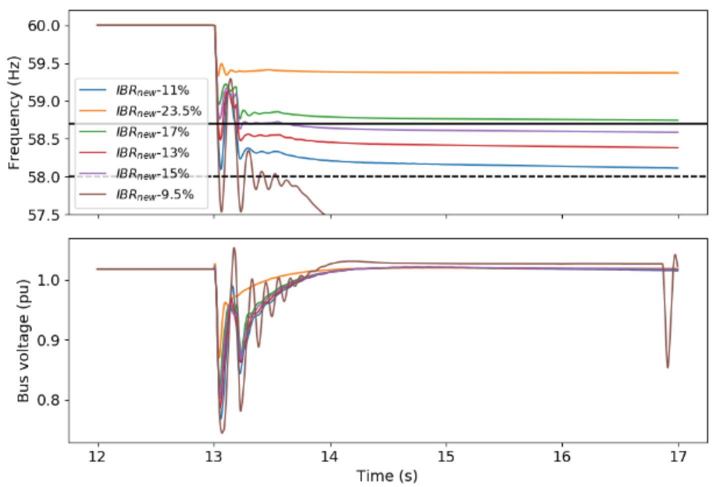
The case studies presented thus far were conducted in the EMT domain. One of the challenges in modeling larger networks in the EMT domain for such case studies is the large amount of computational time and resources required. Hence, the same scenarios were also tested in the positive-sequence domain in order to assess whether case studies conducted in the positive-sequence domain indicate similar trends as the detailed EMT simulations.

4.2.1 Cases A – E: Voltage Response from PV, No Voltage or Frequency Response from BESS

Figure 17 shows the behavior of the system in Cases A – E from Table 8 (p. 31), when none of the existing IBR devices provided frequency support, none of the BESS provided voltage support, and only the PV plants provided slow voltage support at the plant control level. Upon comparing the response with that from the EMT domain (shown in Figure 13), it can be observed that the trend of the response is similar across both simulation environments. This result by itself is encouraging as it showcases the applicability of the positive-sequence models. However, a more interesting result is with the lowest value of new IBR capacity. In the EMT domain, the system was unable to maintain stability when the capacity of the new IBR fell below 13% of that of the network (shown in Figure 13). However, in the positive-sequence domain, the response was initially shown to be numerically stable even for a new IBR whose capacity was as low as 9.5% of the network's total; however, at such a low value, since the present UFLS thresholds would be triggered, this is not a viable solution. Further, as seen from the result, the simulation does show the occurrence of a simulation challenge at the low value of 9.5% indicated by the sudden voltage drop around 17 s. Despite this, the inference from this result is that the positive-sequence simulation provides a lower bound to the minimum capacity of an IBR with future capability that needs to be added to the network to ensure a stable response for the considered contingency that is close to the results obtained from the EMT domain.

FIGURE 17

Frequency Response and Voltage Magnitude in Island Network with No Frequency Support from Existing IBRs, Simulated in Positive-Sequence Software



Similar to the EMT domain study, in the positive-sequence domain it was observed that when the new IBR with future capability was too small, the system response was unstable, while a medium-sized new IBR was able to result in a stable response though it would still trigger UFLS. A new future IBR with a capability of around 25% of the current system installed capacity was required to achieve a stable response and prevent UFLS.

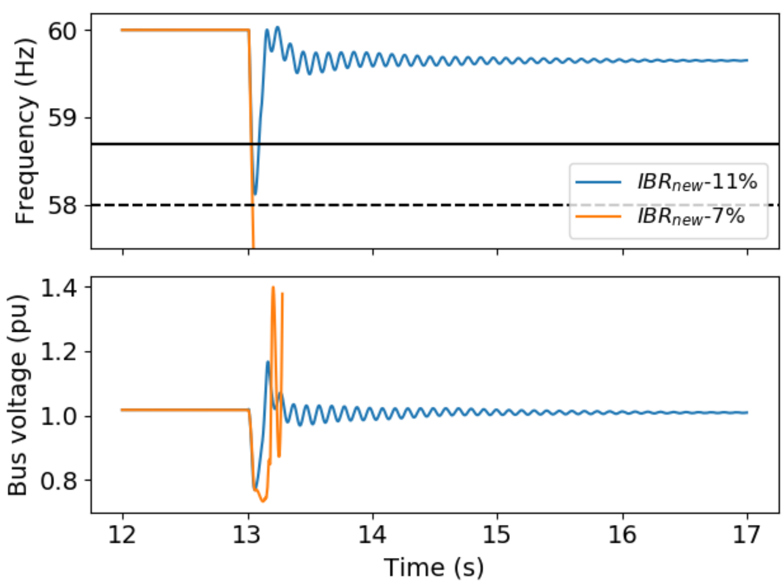
Source: Energy Systems Integration Group.

4.2.2 Cases F – H: Voltage and Frequency Response from PV, Frequency Response from BESS

We then performed positive-sequence domain simulations for cases F – H from Table 8 (p. 31), considering the trip of the synchronous condenser followed by the trip of a PV unit; the PV units were assumed to provide frequency and voltage response, and BESS units were assumed to provide frequency response. The response obtained from positive-sequence domain simulations for these cases is shown in Figure 18. Here, the positive-sequence simulation was unable to provide a stable result with the capacity of a new IBR as low 7% of the total network installed capacity, whereas the similar scenario simulated in the EMT domain showed a stable result for a new IBR with capacity as low as 5% of the network (Figure 14). This difference in results can be attributed to the version of the positive-sequence software used. The generic model used for the plant controller and the inverter controller in the positive-sequence environment is not the latest and most robust model; however, due to the use of other user-defined models (such as protection models), the simulation was restricted to the use of this older version of the software. A similar result was observed when simulating the scenario wherein only existing BESS provided frequency support (cases I—J from Table 8 (p. 31)) as shown in Figure 19. Here again, due to the restriction of not having the ability to use the latest and improved versions of the plant controller, a conservative estimate of the capacity of a new IBR of 11% of the network installed capacity was obtained wherein the EMT simulation for the same scenario shows that potentially a lower capacity is possible (Figure 15).

FIGURE 18

Frequency Response and Voltage Magnitude in Island Network with Slow Frequency Support from Existing IBRs, Simulated in Positive-Sequence Software

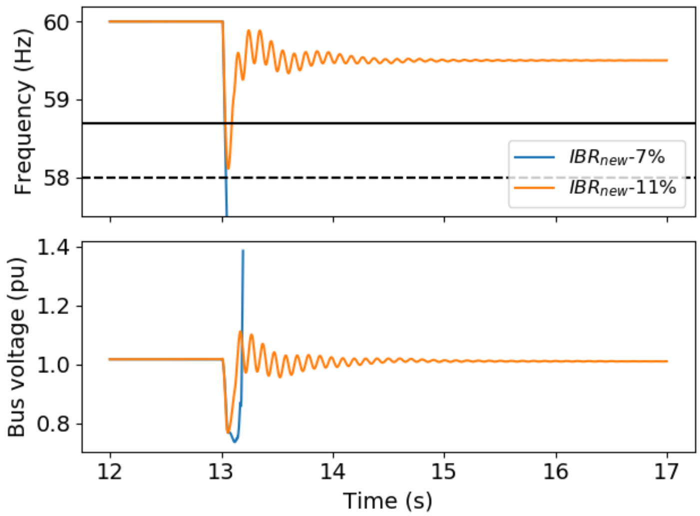


When PV units provided voltage and frequency support, a lower capacity of new IBR was able to avoid triggering UFLS in positive-sequence domain studies, similar to the observations from EMT studies

Source: Energy Systems Integration Group.

FIGURE 13

Frequency Response and Voltage Magnitude in Island Network with Slow Frequency Support Only from Existing BESS, Simulated in Positive-Sequence Software



When PV units provided voltage support and BESS units provided frequency support, a lower capacity of new IBR was able to avoid triggering UFLS in positive-sequence domain studies, similar to the observations from EMT studies.

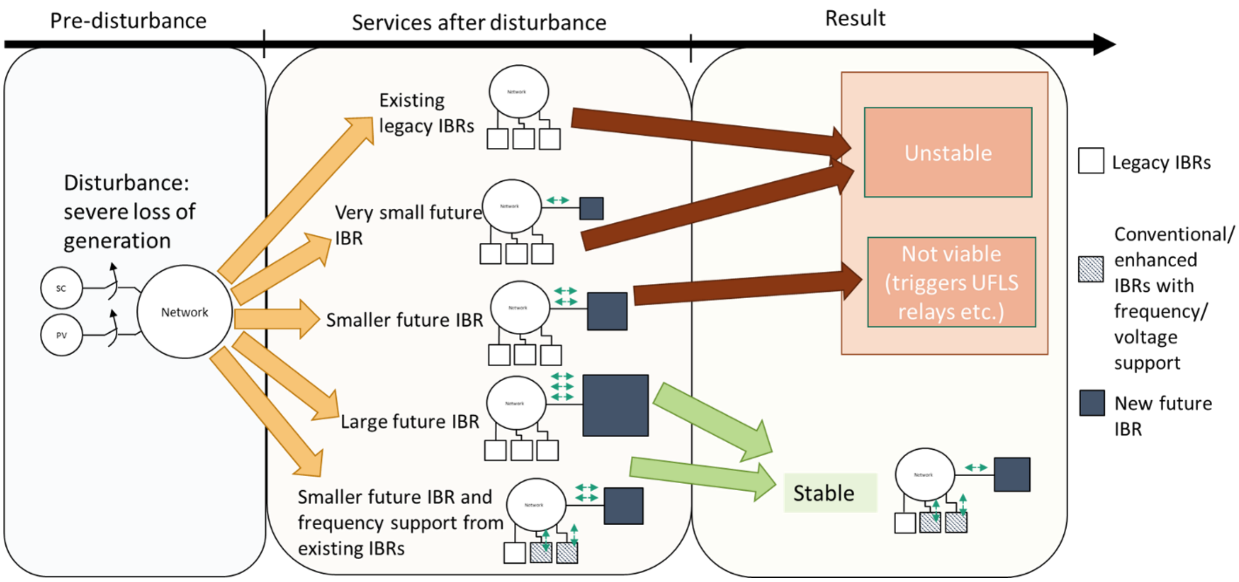
Source: Energy Systems Integration Group.

The positive-sequence simulation results are, however, still beneficial. Despite having restrictions with regard to the use of appropriate robust/improved models, the results still showcase that when existing PV and BESS provide frequency and voltage support services as determined by standards such as IEEE 2800-2022, the requirement for new IBR capacity can be as low as 11%. This inference is also corroborated from the EMT results.

The key lessons from the island system case study are depicted in Figure 20. In this figure, the time frame concerned for judging the services/support provided is over several seconds after the disturbance is applied. It is observed that if the potential unstable or non-viable behavior (that could trigger UFLS) is to be mitigated using just the new future IBR, the size of the future IBR required might be large. On the other hand, if some of the existing IBRs are able to provide frequency support, they can share part of the burden and reduce the size required for this new future IBR.

FIGURE 14

Impact of Different Services from Existing/Newly Added IBRs on the Network Behavior for the Island System After a Severe Loss of Generation



Similar to EMT-domain studies, positive-sequence domain studies showed that for the considered contingency, a large new IBR with future capabilities may be required to ensure stable and viable response, but a smaller new IBR may be sufficient if existing IBRs provided frequency support. The orange arrows pointing to the right from the pre-disturbance region indicate the different possibilities of combinations of services that may be supplied by different existing and new IBRs. The brown arrows extending from the center section indicate the cases where the network was unable to reach a stable and viable operating point, and the green arrows indicate the scenarios where the network was able to reach a stable and viable operating point.

Source: Energy Systems Integration Group.

How applicable are these results to large systems? Island systems have unique characteristics in terms of their small size, both geographically and in terms of the total generation and load. Due to their small size and lack of connection to a larger network/interconnection, island systems can have a much higher level of IBRs and have to keep the grid stable with the limited resources available. Hence, island systems were a good candidate for this study, since they may face some of the challenges with operating a grid with a high penetration of IBRs well before large systems. One thing learned from this study is that existing resources can help provide fast voltage/frequency control and alleviate the burden of these services from new IBRs with advanced controls. These results would be useful for large network studies as guiding principles and starting points. However, island systems and larger interconnections differ, for example, regarding geographical size, and the location of existing/new IBR resources will likely play an important role when assessing the services from these IBRs in larger interconnections. This study can be extended in the future to the study of large networks.

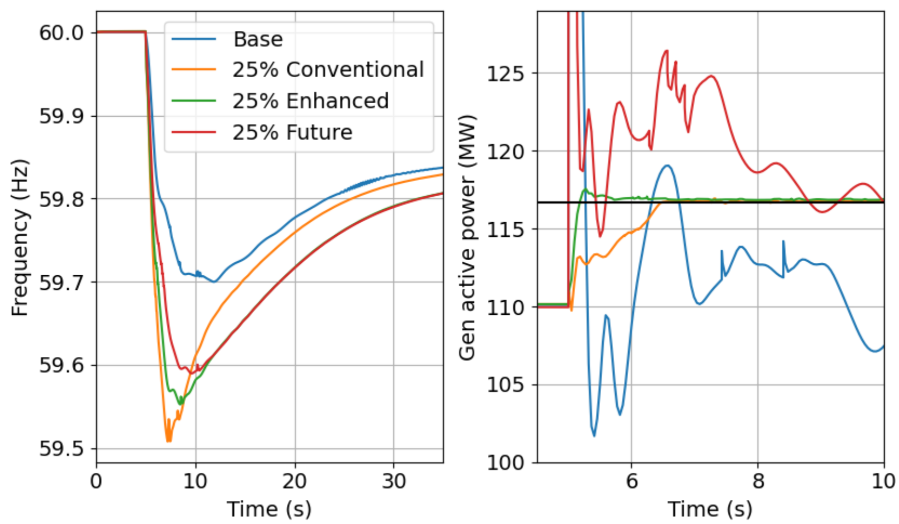
5 Impact of Headroom Assumptions

Since this study looked into various services that might be required from IBRs, both enhanced and future IBRs, it is important to understand the impact of various assumptions on the final results. Specifically, one of the constraints limiting active power is whether the device in question has enough headroom available. For example, if a plant is operated at its maximum active power capacity determined by the available input active power from the primary source, it may not be able to increase the active power injected to the grid further in response to a disturbance, which limits the services it can provide to the grid. The manner in which active power limits are enforced can, however, have an impact on the final frequency response. Here, the impact of active power limit assumptions will be highlighted from the perspective of frequency response in a large interconnected system.

We simulated the frequency response of a large interconnected system following a loss-of-generation event. Here, the base case is a low load/low inertia scenario. Subsequently, 40% of the generation mix was assumed to be IBRs, and the response was compared against the base case with minimal IBRs. Out of these, it was assumed that 25% of the IBRs were conventional, enhanced, or future, with 6% headroom (in all three cases), and the rest were legacy IBRs. The results with the different cases are shown in Figure 21. As expected, with the increase in IBRs there was a drop in the frequency nadir. Further, as more of the IBR capability was utilized (by changing the 25% IBRs from conventional IBRs to enhanced IBRs to future IBRs), the frequency response improved.

FIGURE 21

Frequency Response (left) and Active Power Output of a Single Unit (Right) in a Large Interconnected Network with IBRs



In a large, interconnected network, a generation-loss contingency was studied with 25% of the IBR resources considered with different control capabilities. The cases where 25% of the IBRs were considered to have enhanced or future capabilities had progressively higher frequency nadirs, and it was also observed that IBRs with future capabilities (depending on the control) allowed their active power output to rise beyond the active power limit for a few seconds, resulting in an improved frequency response. (When conventional IBRs were considered, the disturbance observed in the frequency trace is attributed to discrete behavior in the load models at that region of operation.)

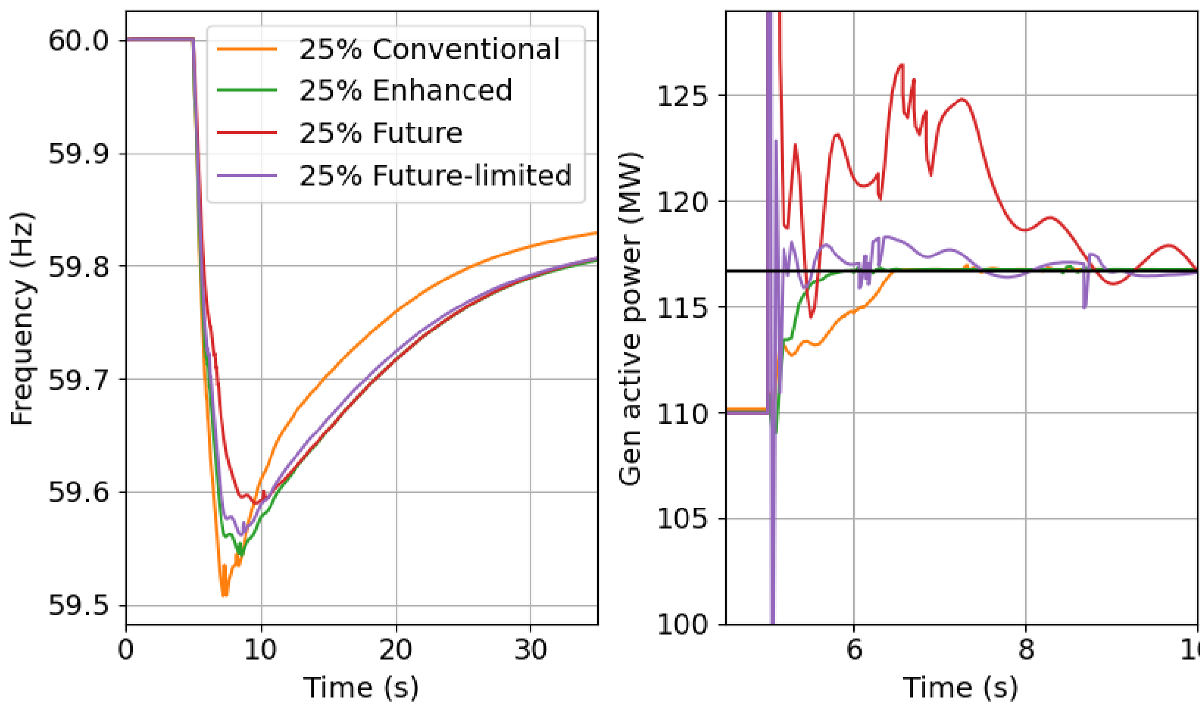
Source: Electric Power Research Institute.

Here, however, a deeper look into the active power output of one generation unit (synchronous in the base case and replaced by an IBR in all other cases) is required. As shown in Figure 21 (right), the active power output provides detailed insight into the reason behind the difference in the frequency responses of different cases. Since a restricted headroom of 6% was assumed for IBRs (maximum power denoted by the black line in the figure), the observed generation unit hit its maximum output when represented as an IBR. Here, across all scenarios the headroom on the synchronous machine fleet was kept the same. This headroom was decided based on the frequency response obligation for the region. However, the time to reach the limit differed between conventional, enhanced, and future IBRs, and the impact is reflected in the frequency response. The enhanced IBR, due to its fast frequency response characteristics, reached the maximum output within 1 s and did not increase the active power further due to reaching the limit (and hence limited the further contribution to providing the frequency response service). However, the future IBR, having a different control paradigm, treated the modeled active power limit as a soft limit and allowed power output above the limit for many seconds before settling down. This IBR was able to continue to provide frequency response service for longer, which resulted in a higher frequency nadir.

Note that this soft limit assumption is an important nuance of future IBR controls, which will vary from OEM to OEM. Also, the assumption here is that the future IBR has only a 6% headroom. Whether it can operate above this limit for a short duration will depend on the manufacturer. This additional power above the limit injected by the future IBR during those 5 seconds helps the frequency response nadir to be higher.

FIGURE 22

Frequency Response of a Large Interconnected Network with IBRs and Strict Power Limits on Future IBRs



When the active power limit was enforced more strictly in the future IBRs, the system response was much closer to the response with enhanced IBRs. (When conventional IBRs were considered, the disturbance observed in the frequency trace is attributed to discrete behavior in the load models at that region of operation.)

Source: Electric Power Research Institute.

This impact of additional power injected above the limit leading to a higher frequency nadir can be verified by forcing the future IBR to meet its active power limits in a more strict/timely manner as shown in Figure 22 (purple trace on left). Although the response is more oscillatory in the few initial cycles (purple trace on right) (which can be improved with further tuning of the controls), the power limit is enforced quickly, which results in the frequency nadir dropping and in fact being similar to the response when 25% of the IBRs are enhanced IBRs.

Note that the intention here is not to state that future IBR controls are not required or need not be developed. Rather, the intention of these studies is to provide more insight into the behavior of power networks with high shares of IBRs, to allow a reader to go further and study the actual services provided at different time scales by the IBRs in their system. Rather than assume that the improved behavior of a network is due to the “voltage source” nature of future IBRs, identifying these services can lead to more clearly defining the behaviors needed or wanted from existing and future IBRs.

6 Conclusions

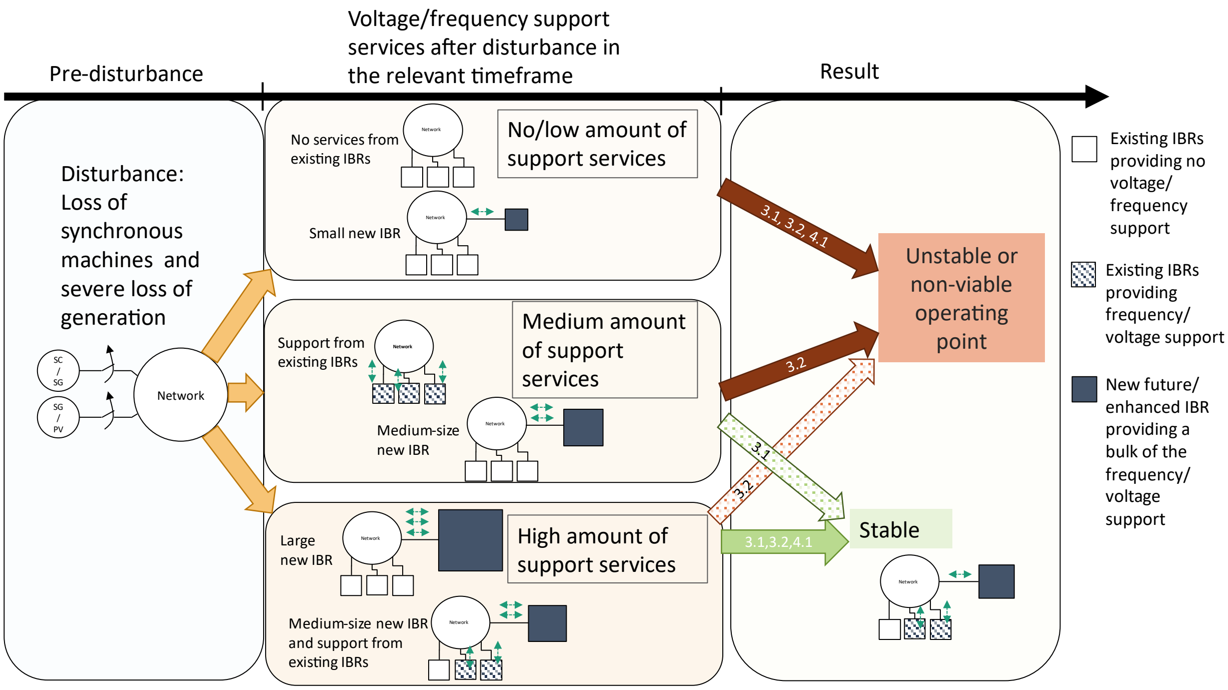
This paper assessed the system needs for new grid services in IBR-dominated grids, focusing on how the services provided from existing IBRs affect the ability of enhanced IBRs with different control capabilities, as well as a "future" IBR model with advanced capabilities, to contribute to network stability. Case studies were presented for a microcosm network and an island network, as well as an interconnection-wide study, looking at shorter as well as longer time frames. This study examined some of the grid services that may be needed from IBR devices, either existing or newly added, especially in IBR-dominated networks, considering the network performance in response to contingencies or disturbances such as trips of synchronous generators. The studies showed that the grid services required from IBRs by the network may vary depending on the contingency.

The IBRs were categorized in four buckets: legacy IBRs that do not provide any service; conventional IBRs that only provide slower response over multiple seconds; enhanced IBRs that provide faster voltage/frequency response; and future IBRs that provide these services, may have advanced capabilities of riding through severe load-generation mismatch, and may provide very fast response. Hence, in this framework, the services required by a grid under a contingency can be provided either by a single (or a few) new "future" IBRs with advanced capabilities or through a combination of these new IBRs with additional services being provided by conventional or enhanced IBRs already installed on the network. Here, we used generic models to represent IBRs with different control capabilities and found similar trends between positive-sequence and EMT models.

Figure 23 summarizes the results from the case studies conducted on the microcosm and island network involving generation-loss contingencies. The performance of the system was studied for different levels of services—namely, frequency and voltage support—provided by existing and new IBR resources (either with enhanced or future capabilities). The numbers on various brown/green arrows indicate the case study (sub-section number of this report) where an example of the behavior indicated by that arrow was observed.

FIGURE 23

Key Observations from the Case Studies



The different studies in this paper show a trend of a higher amount of services leading to stable and viable operating points, though the exact service and the exact amount needed depends on the system and the disturbance. Further, the service may be provided by a combination of existing and new IBRs with different control capabilities. In the figure, the orange arrows going from the pre-disturbance region indicate the different possibilities of combinations of services that may be supplied by different existing and new IBRs. The brown arrows indicate the cases where the network does not reach a stable and viable operating point, and the green arrows indicate the scenarios where the network reaches a stable and viable operating point.

Source: Energy Systems Integration Group.

Key takeaways from this study include:

- **When existing IBRs provide additional services or support (in some cases using capabilities they possess but had not been activated), this can reduce the burden on (and need for) new resources.** The studies showed that additional services/support provided by existing IBRs can reduce the burden on a few new resources to provide a high amount of services and may help the system to remain stable even if the new IBR added is relatively small.
- **The amount of grid services needed by the grid depends on the disturbance.** This study showed a general trend indicating a stable response when a higher amount of services were provided, though there are nuances to be considered when discussing specific cases. For the chosen contingencies, when there were no (or a low amount of) relevant voltage or frequency services provided in the relevant time frame, the system could become unstable or reach a non-viable operating point with voltage or frequency outside the allowed steady-state operational ranges. For some contingencies, a medium amount of services (through voltage/frequency

support provided either by existing IBRs or by a medium-sized new IBR) might be sufficient to alleviate this, but it may not be sufficient in other cases. For example, for more severe contingencies, a high amount of services provided through enhanced capabilities from existing IBRs or enhanced/future capabilities from new IBRs may be required to keep the grid stable. The grid services needed by a network are not determined in a vacuum but may vary according to the severity of the disturbance(s) under consideration. Further, the exact service required would depend on the system and the disturbance—for example, for the disturbance presented in Section 3.1, voltage support was found to be useful in ensuring a stable response, whereas in Section 4.1, frequency response provided by the existing IBRs was shown to reduce the capacity of future IBRs needed for a stable and viable response.

- **More than one service may be needed.** It may be that more than one service needs to be provided to reach a stable and viable operating point for some contingencies, as observed in Section 3.2. In that case study both voltage and frequency response services were required to be provided by IBRs in order to reach a stable and viable operating point.
- **Other factors such as location might play a role**. In the contingency considered in Section 3.2 of a simultaneous trip of two synchronous generators for the microcosm system, fast voltage and frequency services provided at multiple locations (existing and new IBRs) were found useful in ensuring a stable response, while the services provided at a single location by a single new IBR did not result in a stable and viable response. Hence, the locational aspect may play a role for some disturbances and some networks—a separate study may be needed to investigate this locational aspect further.
- **The ability of a new IBR to provide stability to the network depends on the fast services provided by the IBR.** For example, a new enhanced IBR providing only fast frequency response services may not be able to ensure stability in all cases in which a new enhanced/future IBR of the same size that provides *both* fast voltage and fast frequency response does result in a stable response. There may also be other subtle differences in the different IBRs in terms of strict enforcement of active power limits. For example, if an IBR allows violation of active power limits for a short duration, it may be able to provide a greater amount of frequency/active power response than if the limits are strictly enforced.
- **The time frame of the response depends on the disturbance and the system.** The time frame during which a response or service is required may also change according to the disturbance and the system. For the synchronous generator trips considered for the microcosm network, the impact on the network behavior of acquiring fast voltage and frequency response services from existing IBRs was studied in Section 3; whereas even slower responses from existing IBRs over a longer time frame were able to reduce the capacity of the new IBR needed for the island system to reach a stable operating point and avoid triggering UFLS in Section 4.1. An IBR may provide services in one time frame but not another; for example, conventional IBRs only capable of providing slower responses may be considered as not providing any service in the faster time frame. So, depending on the services needed by the system in different time frames, different IBRs may be considered to provide these services.

- **Consider the nuances in the models**. This paper provides insight into the impact that assumptions and control tuning may have on the network response, allowing the reader to go beyond a reasoning of “voltage source” behavior. A narrow focus on the “voltage source” behavior may not capture how the models behave in different time frames or the different services that the IBR models provide that impact the network behavior. For example, a “future” IBR may inject active power beyond its active power limit over a short period, or it may provide multiple services such as fast voltage response and fast frequency response at the same time, and consideration of the nuances in the IBR models and responses enhances our understanding of the most impactful specific aspects.
- **Different simulation domain studies may be useful**. It is understood that EMT studies allow for a more detailed representation of the network and connected devices such as IBRs and enable the study of services from IBRs during the faster timescales. However, EMT studies can be computationally burdensome, particularly for large systems. The simulations in the positive-sequence and EMT domains for the island system yielded similar trends, indicating the usefulness of positive-sequence simulations for conducting simulations of larger systems, particularly for cases where slower services and phenomena are under study.

The approach presented here can be extended to include other factors such as the impact of IBR locations; the IBR services needed in different network conditions and topologies, as well as different disturbances such as fault scenarios; and the interactions between the different services for the various cases. Such an effort may provide a more holistic picture of the services needed from IBRs and may be useful to IBR manufacturers, IBR operators, and network operators by establishing the value added to the network through asking for different services from new and existing IBRs. Lastly, it would be useful to have a systematic categorization and assessment of a range of services and grid needs that can be provided by IBRs in a network with a large and growing share of these resources.

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Appendix: Fidelity of Generic Models Used in the Study

This appendix describes the control objective of the generic models used and the tests verifying the fidelity of these models.

A.1 Generic Model for Conventional and Enhanced IBR Resources

This generic model can be used to represent conventional or enhanced IBRs. IBRs using this model can be configured to meet the minimum requirements laid out in IEEE Std 2800-2022 (IEEE, 2022). The technical minimum requirements in the standard have been developed bearing in mind the expected increase in percentage of IBRs in a future power network. As such, these technical minimum requirements mandate the capability to provide closed-loop voltage and closed-loop frequency support from an IBR plant. A generic model has been constructed in an EMT simulation environment to represent the requirements expected from the IEEE Std 2800-2022 (EPRI, 2022). In this study, PSCAD® was used for EMT simulations, and Siemens PTI PSS®E was used for positive-sequence simulations.

A.1.1 EMT Model Fidelity

This model can be used to represent PV and BESS resources. Here, the PV and BESS installations were assumed to have different capabilities based on the general geographical spread of the plant. For the PV plant, it was assumed that voltage and frequency support is provided at the plant controller level, while at the inverter level the objective is to control active and reactive power. For the BESS, it was assumed that there is no plant controller present and both voltage support and frequency support are at the inverter level.

To verify the fidelity of the models, a set of evaluation tests were first conducted on each model using a single-machine infinite-bus (SMIB) set up for a chosen level of X/R ratio of 10. The tests conducted were the following:

1. Change in SCR at the point of interconnection
2. Step change in voltage, frequency, or phase angle at a given value of SCR
3. Balanced fault applied near the point of interconnection at a given value of SCR

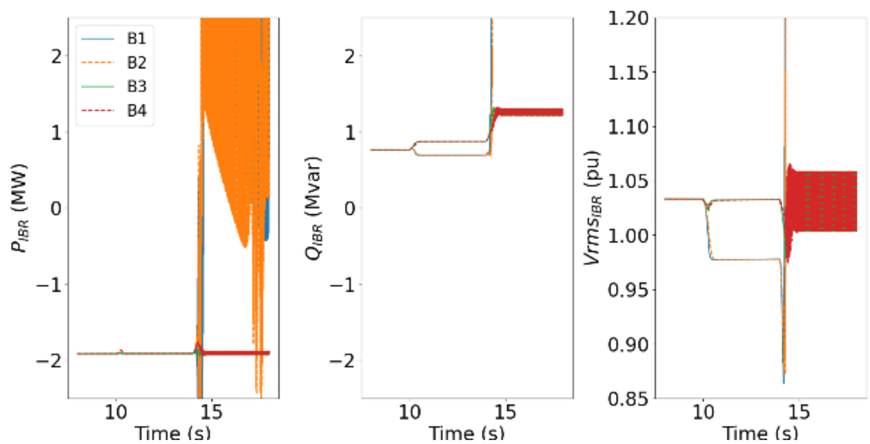
For each model, the fidelity was shown for various combinations of control modes. For BESS, the following control modes were evaluated:

1. Control B1: Open-loop reactive power (Q) control without active power frequency droop (P)
2. Control B2: Open-loop reactive power (Q) control with active power frequency droop (ω)
3. Control B3: Closed-loop voltage (V) control without active power frequency droop (P)
4. Control B4: Closed-loop voltage (V) control with active power frequency droop (ω)

Note that these control modes denote some of the different enhanced controls possible from an IBR. The size of the BESS device chosen for evaluation was 2.5 MVA, and it was assumed to be operating at an active power set point of approximately -1.9 MW (charging). The inverter was connected to the grid via a transformer, and all test results are shown at the high-voltage side of this transformer. First, a comparison of response across the control modes is shown for a change in SCR at the point of interconnection in Figure A-1. The SCR was reduced from a value of 2.0 to a value of 0.5, in steps of 0.5.

FIGURE A-1

Comparison of Control Modes Response for the Generic BESS Model with Reduction in SCR from 2.0 to 1.5 at 9 s and a Further Reduction to 1.0 at 14 s



When reducing the SCR for the generic BESS models, they exhibit oscillations at an SCR of 1.5.

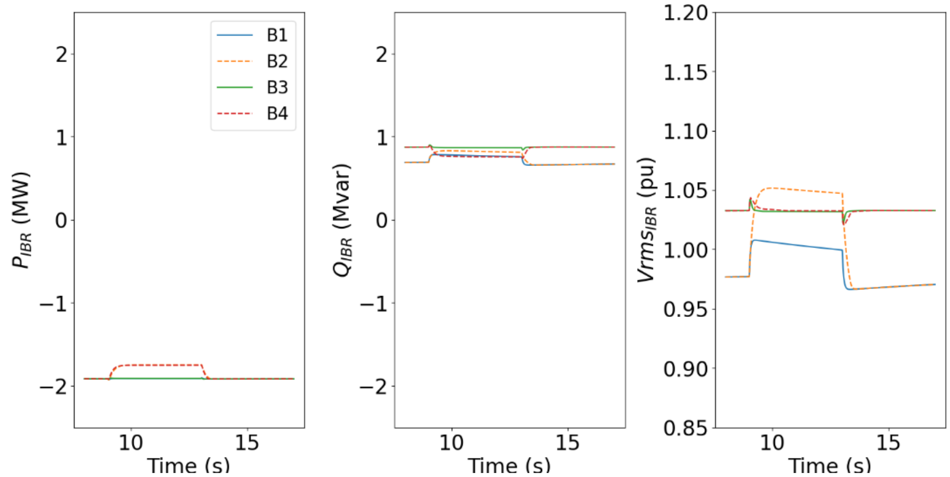
Source: Energy Systems Integration Group.

Here it can be seen that all four combinations of control modes were stable when SCR changed from 2.0 to 1.5 at t=9s. However, when SCR was further reduced to 1.0 at t=14s, different forms of instability manifest. Control modes B1 and B2, which have open-loop reactive power (Q) control, resulted in the powers/voltages shooting up (bifurcation scenario), whereas control modes B3 and B4, which have closed-loop voltage control, resulted in sustained oscillations of high magnitude (limit cycle). It may be possible to tune control modes B3 and B4 to have positive damping at an SCR value of 1.0 (Ramasubramanian, Baker, et al., 2023), but that is out of scope for this study. The takeaway from this evaluation was to understand the limits of applicability of the control system, which seem to be an SCR value of 1.5.

At this value of SCR = 1.5, the response of the model for a 0.2 Hz step change in frequency is shown in Figure A-2 and the response for phase jumps of 20 degrees shown in Figure A-3. In both cases, the disturbance was applied at 9 s and removed at 14 s, restoring the frequency/phase to the original value. Both figures show a stable operation of the model at this SCR limit value. With frequency support (control modes B2 and B4), the BESS model shows a typical frequency support response in accordance with a 5% droop percentage. For phase jumps, too, the response is as expected.

FIGURE A-2

Comparison of Control Modes Response for the Generic BESS Model with 0.2 Hz Step Change in Frequency at an SCR of 1.5

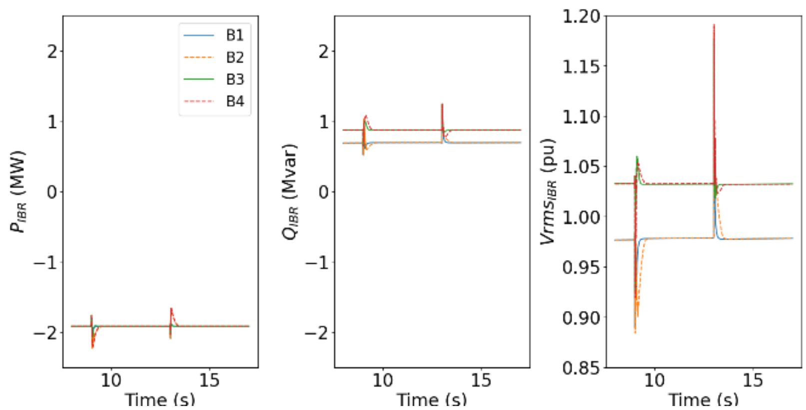


All four BESS controls showed stable response for the generic BESS model for a frequency step change at 1.5 SCR.

Source: Energy Systems Integration Group.

FIGURE A-3

Comparison of Control Modes Response for the Generic BESS Model with 20 Degree Step Change in Phase at an SCR of 1.5



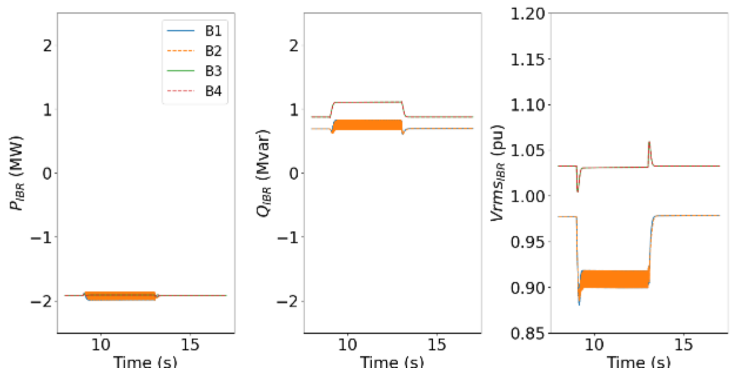
All four BESS controls showed stable response for the generic BESS model for a phase angle step change at 1.5 SCR.

Source: Energy Systems Integration Group.

However, the results of a 5% voltage step change at an SCR of 1.5 that was applied at 9 s and removed at 14 s (shown in Figure A-4) provide further insight into the limits of applicability of the model. With controls B1 and B2 (Q control) a limit cycle manifests while with controls B3 and B4 (V control) a stable operation is observable. All four control modes were found stable at an SCR of 2.0 while the tests/figures presented show that at an SCR of 1.5, control modes B1 and B2 may lead to unstable behavior for certain disturbances. This can imply that for small-signal disturbances, the limit of applicability of controls B1 and B2 is an SCR of 2.0, while for controls B3 and B4, the limit of applicability is an SCR of 1.5.

FIGURE A-4

Comparison of Control Modes Response for the Generic BESS Model with 5% Step Change in Voltage at an SCR of 1.5



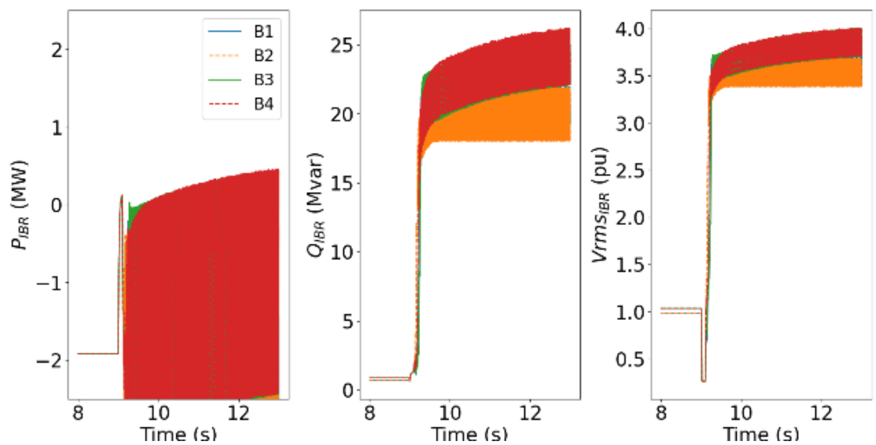
BESS controls B3 and B4 showed stable response for the generic BESS model for a voltage step change at 1.5 SCR; however, controls B1 and B2 exhibited oscillations.

Source: Energy Systems Integration Group.

The disturbances applied so far are step disturbances in different variables, and now we turn to the behavior of the models for large-signal disturbances. At an SCR level of 1.5, for a 6-cycle balanced fault applied on the line connecting the point of interconnection with the source, at a distance of 20% of the length of the line away from the point of interconnection, the response across all four control modes is shown in Figure A-5. It can be seen that all four control modes had difficulty in ensuring robust fault ride-through at this SCR level, indicated by the oscillations as well as the off-nominal values observed in the active power/reactive power/voltage plots. In contrast, a stable fault ride-through at an SCR of 2.0 was observed in Figure A-6. It should again be mentioned that the aim of this study was not to tune controllers or make controls more robust. It may be possible to obtain stable ride-through at an SCR of 1.5 for control modes B3 and B4. However, for this study, the controls were not altered (as should be the case if OEM-provided models were used), and an SCR of 2.0 can be the limit of applicability.

FIGURE A-5

Comparison of Control Modes Response for the Generic BESS Model with 6-Cycle Balanced Fault at an SCR of 1.5

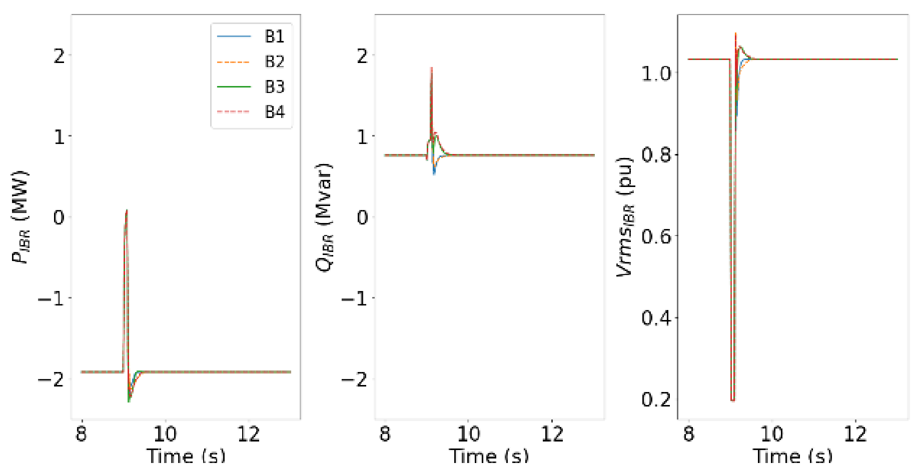


All four control modes for the generic BESS model exhibited oscillations if a fault was applied at an SCR of 1.5.

Source: Energy Systems Integration Group.

FIGURE A-6

Comparison of Control Modes Response for the Generic BESS Model with 6-Cycle Balanced Fault at an SCR of 2.0



All four control modes for the generic BESS model resulted in a stable response if a fault was applied at an SCR of 2.0.

Source: Energy Systems Integration Group.

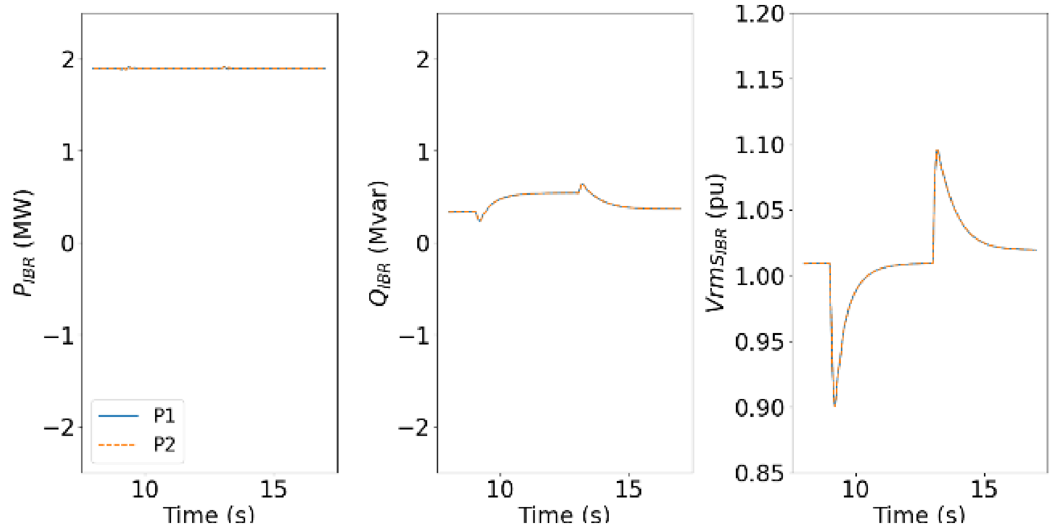
For PV, the size of the device was again 2.5 MVA, and it was assumed to be operating at an active power setpoint of approximately 1.9 MW. The control modes evaluated were:

1. Control P1: Closed-loop voltage (V) control without active power frequency droop (P)
2. Control P2: Closed-loop voltage (V) control with active power frequency droop (ω)

Again, these modes represent some of the control modes possible for enhanced IBRs. The results of the PV model for an SCR change were similar to the results for the BESS model and indicate a limit of applicability at an SCR value of 1.5. At this SCR value, a stable response was obtained for a 5% step change in voltage, 0.2 Hz step change in frequency, and 20 degree change in phase angle, shown in Figure A-7, Figure A-8, and Figure A-9, respectively.

FIGURE A-7

Comparison of Control Modes Response for the Generic PV Model with 5% Step Change in Voltage at an SCR of 1.5

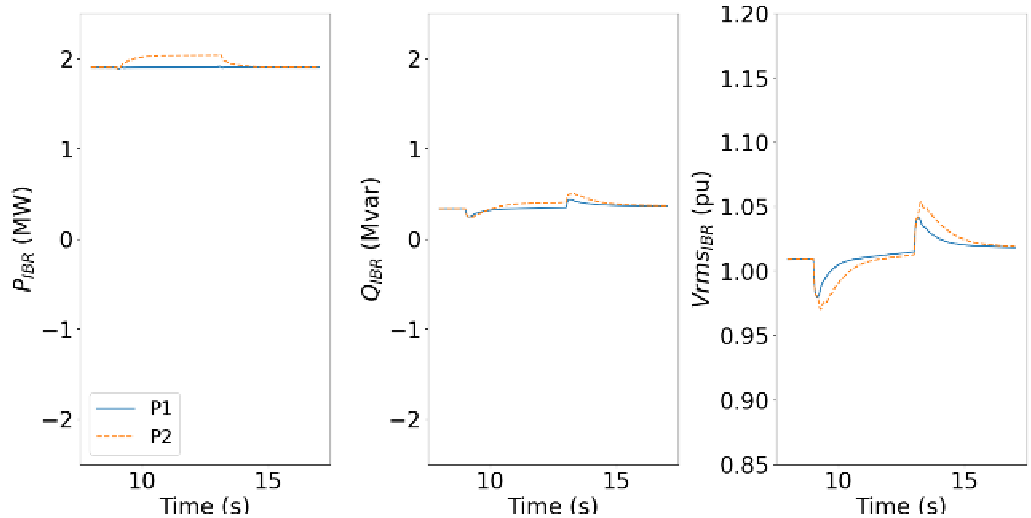


Both PV controls for the generic PV model were stable for a voltage step change at an SCR of 1.5.

Source: Energy Systems Integration Group.

FIGURE A-8

Comparison of Control Modes Response for the Generic PV Model with a 0.2 Hz Step Change in Frequency at an SCR of 1.5

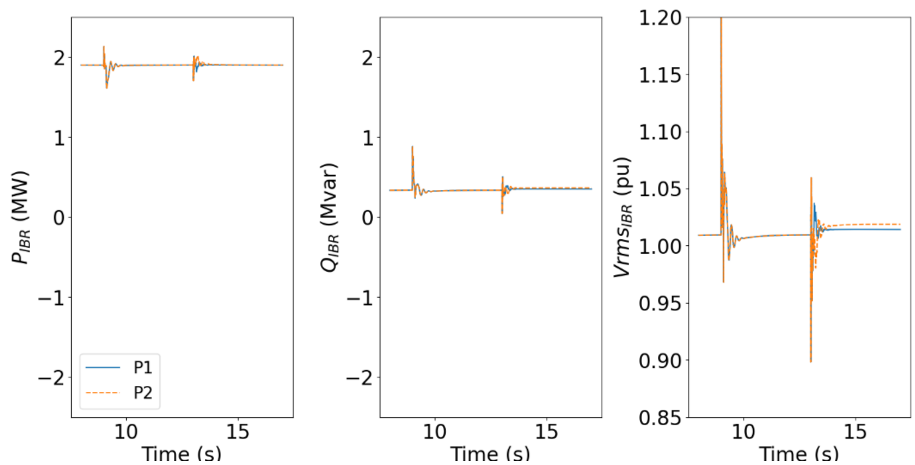


Both PV controls for the generic PV model were stable for a frequency step change at an SCR of 1.5.

Source: Energy Systems Integration Group.

FIGURE A-9

Comparison of Control Modes Response for the Generic PV Model with a 20 Degree Step Change in Phase at an SCR of 1.5



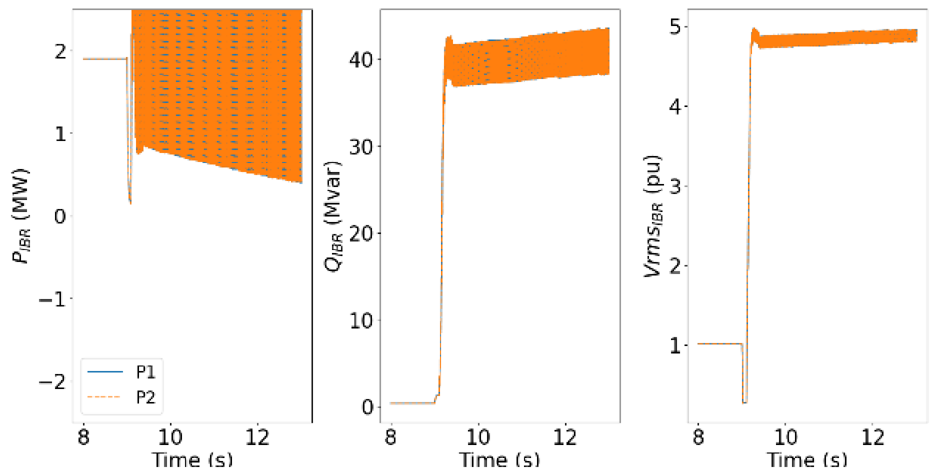
Both PV controls for the generic PV model were stable for a phase angle step change at an SCR of 1.5.

Source: Energy Systems Integration Group.

However, again, similar to the BESS model, the response for a 6 cycle fault at an SCR of 1.5 and applied 20% away from the point of interconnection shows an unstable response as shown in Figure A-10 while for an SCR of 2.0, a stable and robust fault ride-through behavior is obtained (Figure A-11). So again, the limit of applicability of the controls can be an SCR of 2.0.

FIGURE A-10

Comparison of Control Modes Response for the Generic PV Model with 6-Cycle Balanced Fault at an SCR of 1.5

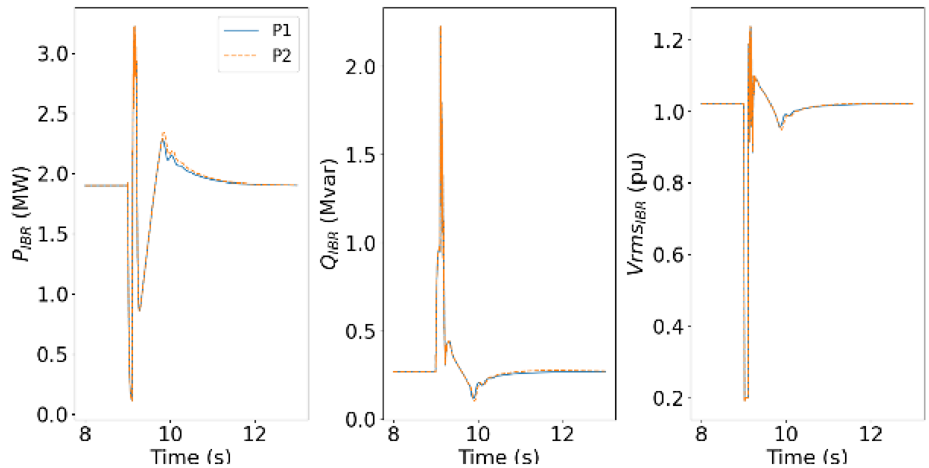


Both PV controls for the generic PV model exhibited oscillations for a fault at an SCR of 1.5.

Source: Energy Systems Integration Group.

FIGURE A-11

Comparison of Control Modes Response for the Generic PV Model with 6-Cycle Balanced Fault at an SCR of 2.0



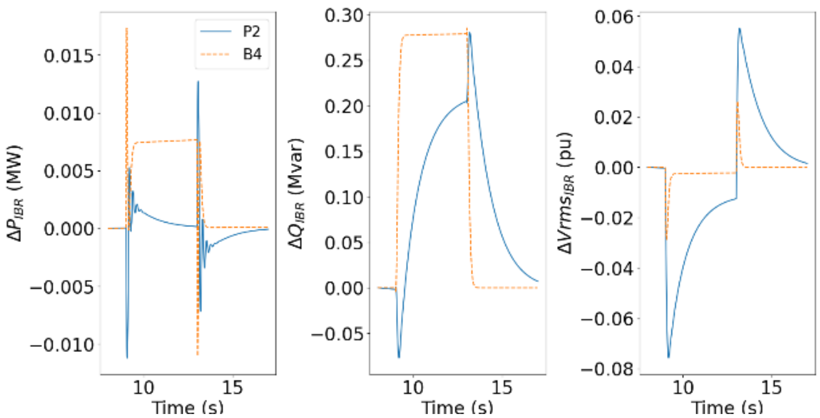
Both PV controls for the generic PV model resulted in a stable response for a fault at an SCR of 2.0.

Source: Energy Systems Integration Group.

Finally, a comparison of response across the PV and the BESS models is shown in Figure A-12 and Figure A-13, respectively, for a voltage change and frequency change. Here, only one control mode of each model was compared at an SCR of 2.0. Further, the plots only show the deviation from the pre-disturbance value. It can be seen that the response from the BESS model is faster than the response from the PV model. This can be attributed to the support features being at the inverter level in the BESS model rather than at the plant level as in the PV model.

FIGURE A-12

Comparison of Response Across PV and BESS Model for a 5% Step Change in Voltage at an SCR of 2.0

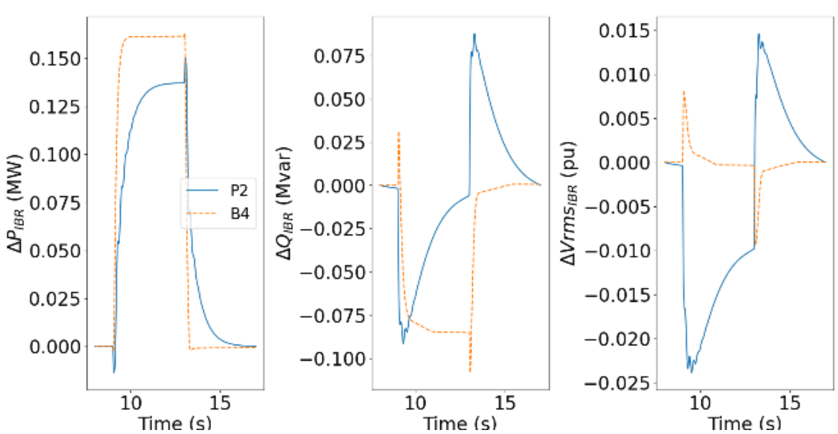


The response from the BESS model was faster than the response from the PV model for a voltage step change.

Source: Energy Systems Integration Group.

FIGURE A-13

Comparison of Response Across PV and BESS Model for a 0.2 Hz Step Change in Frequency at an SCR of 2.0



The response from the BESS model was faster than the response from the PV model for a frequency step change.

Source: Energy Systems Integration Group.

A.1.2 Positive-Sequence Model Fidelity

In addition to running EMT studies, transmission planners also carry out positive-sequence dynamic studies. Here, with the increase in IBRs, a major concern can be the fidelity and applicability of positive-sequence models. It is therefore imperative that the performance of the positive-sequence model be compared against the performance of the EMT model.

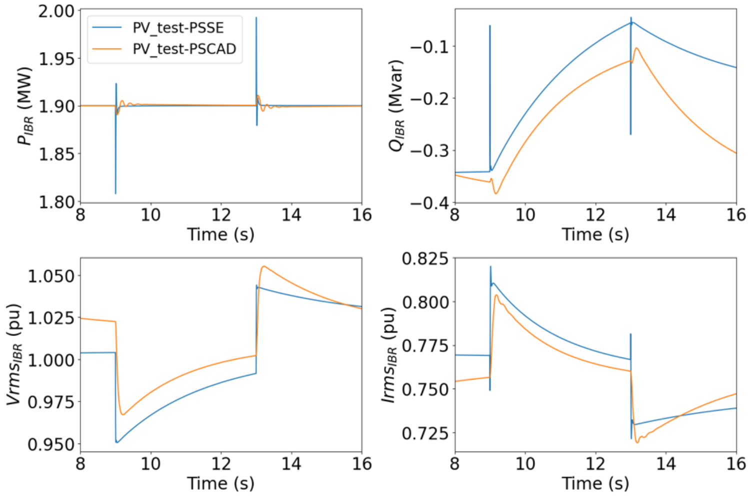
To represent PV and BESS in the positive-sequence simulations, generic models (EPRI, 2023b) were again utilized. Although generic models are used both in positive sequence and in EMT, there are a few differences between the two sets of generic models. One difference is with relation to control mode B2 and B4. In the EMT model, active power frequency droop control for the BESS is implemented at the inverter level (as offered by some manufacturers). However, this capability is not available in the generic positive-sequence models, and all functionality related to active power frequency droop is housed with the plant controller model. Therefore, to approximate the response of the generic plant controller model for BESS, its control objective was set to be the terminal quantities of the inverter.

To verify the fidelity of the positive-sequence model performance against the EMT model, similar tests were carried out. An example result for a step change in voltage with control mode P2 is shown in Figure A-14. Here, an SCR of 3.0 was used due to the limitation of positive-sequence models used in the older version of the PSS/E software package that was used in this study. The response showed a reasonable match between the EMT and positive-sequence models. The response to a change in frequency is shown in Figure A-15. A similar response was obtained for the BESS device. Since the EMT simulation did not start from an initial power flow solution, and due to the presence of dead bands in the control loop, there were a few differences in the initial pre-disturbance steady-state response of the model across both simulation domains. However, since the trend of response was similar, for the purpose of this study the model was deemed to be sufficient.

Here, a commentary on the version of the positive-sequence software is relevant. Generic models for IBRs in positive-sequence software have been continually updated and improved. However, for many commercial software packages, these newer and improved versions of the generic models are only available in newer versions of the software. Therefore, if an older version of the software continues to be used for studying a particular network (as may be the case when the network model contains user-defined models, restricting the version of the software that can be used), then one is restricted to using older versions of the generic models, which may bring about limitations in the study results.

FIGURE A-14

Comparison of Response Across EMT and Positive-Sequence Model of PV Resource for a Step Change in Voltage at an SCR of 3.0

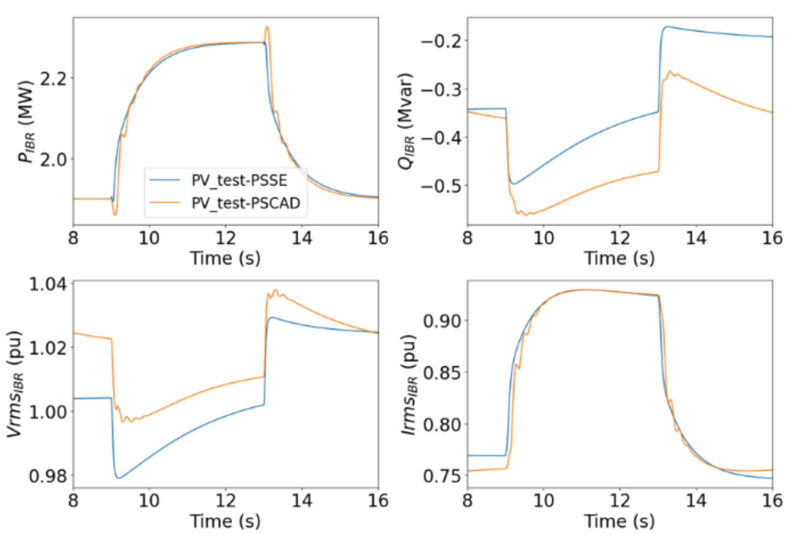


Positive-sequence and EMT models showed a similar trend of response for a step change in voltage.

Source: Energy Systems Integration Group.

FIGURE A-15

Comparison of Response Across EMT and Positive-Sequence Model of PV Resource for a Step Change in Frequency at an SCR of 3.0



Positive-sequence and EMT models showed a similar trend of response for a step change in frequency.

Source: Energy Systems Integration Group.

A.2 Future IBRs

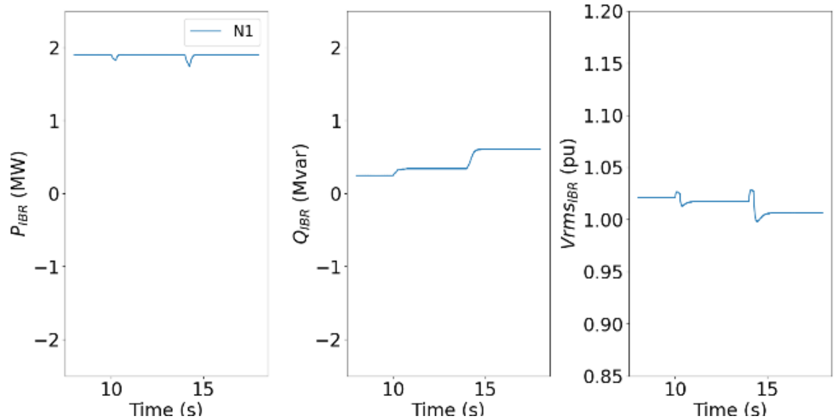
The second type of generic model used in this study was a generic model to represent IBRs that can be expected to continue to operate in a stable manner even after the trip of the last synchronous resource in the network and ride through severe disturbances and conditions. These IBRs can also provide a large variety of services to the network such as fast inverter-level voltage and frequency control (Ramasubramanian, Kroposki, et al., 2023). The control structure used to represent the future IBRs is labelled as "N1." In the near future, since a majority of such IBRs can be expected to be BESS resources due to the favorable DC-side characteristics they provide for the operation of the control structures, a generic model for such an IBR has been constructed in both EMT and positive-sequence simulation environments (Manitoba Hydro International, 2022). Our study assumed that all controls were implemented at the inverter level, and no plant controller was present.

A.2.1 EMT Model Fidelity

For a resource with an MVA rating of 2.5 MVA and an active power operating setpoint of approximately 1.9 MW, the response of the model for a reduction in SCR from 2.0 to 1.0 at an X/R ratio of 10 is shown in Figure A-16. It can be seen that this model was stable even at an SCR of 1.0, where the models described in Sub-section 2.1 showed unstable behavior with all control modes. In Figures A-17 and A-18 its response is compared with the PV and BESS model at an SCR of 2.0 for a 5% step change in voltage and a 0.2 Hz step change in frequency, respectively. The speed of the response from this model, measured at the high-voltage side of the transformer, can be observed to be faster than the response of the BESS model that provides a response in accordance with IEEE 2800-2022. This faster response, and being more robust at low levels of SCR, can be beneficial to a future power system. However, as in the previous section, before using the model in a larger network, the robustness of the model for large-signal disturbances has to be evaluated. For a 6-cycle balanced fault applied 20% away from the point of interconnection, Figure A-19 shows the response for both an SCR of 2.0 and an SCR of 1.0. The robustness of the model can be observed from this plot.

FIGURE A-16

Response of New IBR Control with Reduction in SCR from 2.0 to 1.5 at 9 s and with a Further Reduction of SCR to 1.0 at 14 s

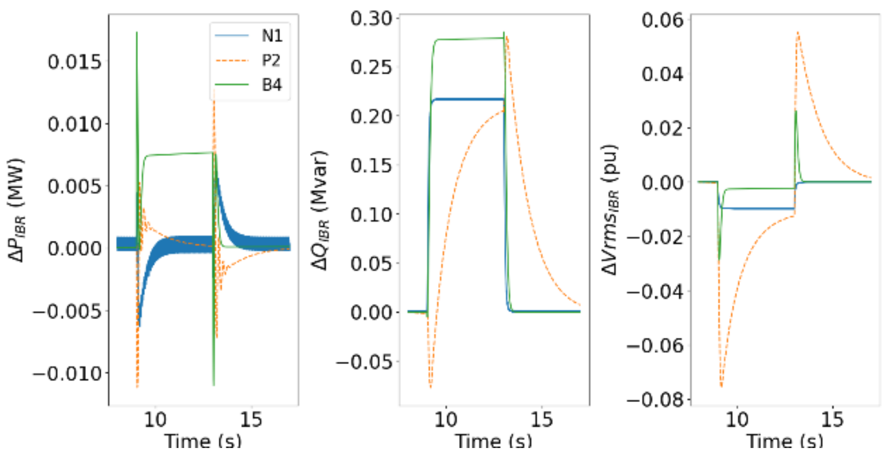


The new IBR remained stable even at an SCR of 1.0.

Source: Energy Systems Integration Group.

FIGURE A-17

Comparison of Response Across New IBR, PV, BESS Model for a 5% Step Change in Voltage at an SCR of 2.0

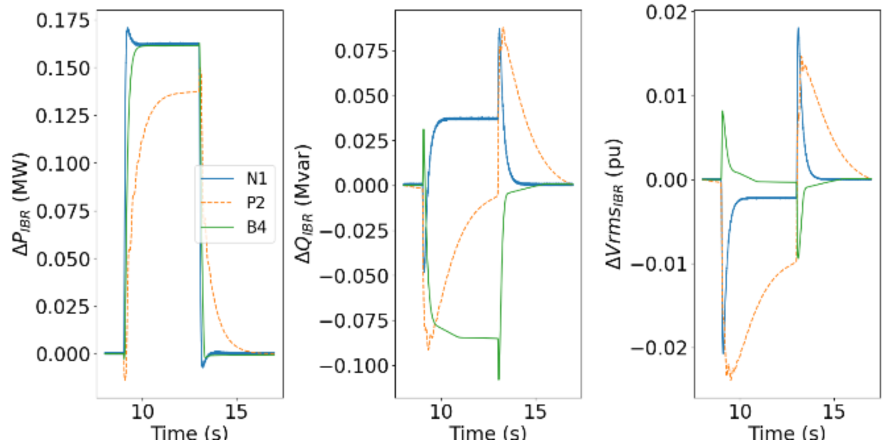


The new IBR had a faster response compared to BESS and PV generic models for a voltage step test.

Source: Energy Systems Integration Group.

FIGURE A-18

Comparison of Response Across New IBR, PV, BESS Model for a 0.2 Hz Step Change in Frequency at an SCR of 2.0

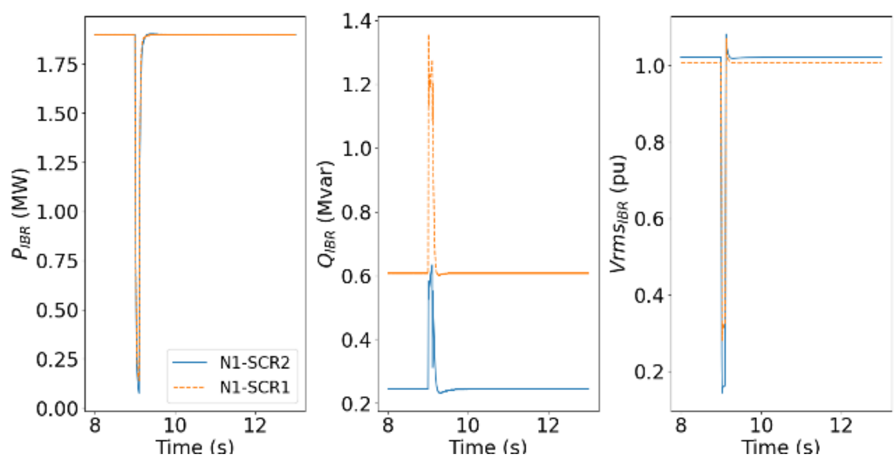


The new IBR had a faster response compared to BESS and PV generic models for a frequency step test.

Source: Energy Systems Integration Group.

FIGURE A-19

Comparison of Response of a New IBR for 6-Cycle Balanced Fault at an SCR of 2.0 and an SCR of 1.0



The new IBR was able to remain stable for a fault response test at SCR values of 2.0 and 1.0.

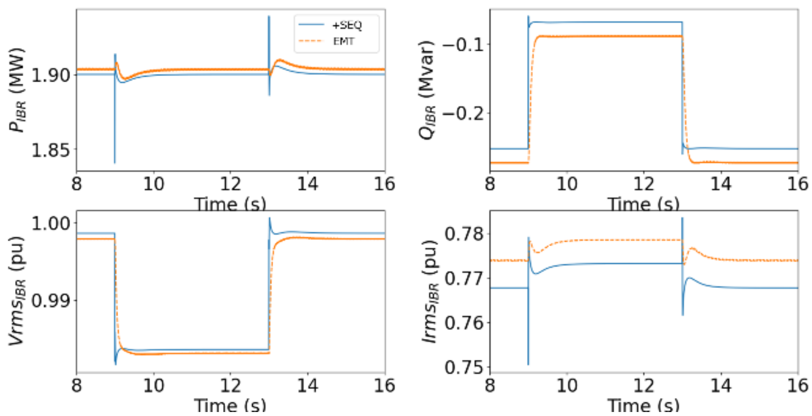
Source: Energy Systems Integration Group.

A.2.2 Positive-Sequence Model Fidelity

To represent this new IBR technology in planning studies, a generic positive-sequence model was developed (EPRI, 2021). It is understood that the generic model in positive sequence may not represent every nuance and detail that can be observed in the EMT domain. However, the expectation is that the positive-sequence model can represent the trend of the response. Further, due to the presence of transformers in the EMT model with non-ideal characteristics, there are a few differences in the response of reactive power between the two simulation environments. The comparison of response for voltage and frequency step changes is shown in Figure A-20 and Figure A-21, respectively.

FIGURE A-20

Comparison of Response Across EMT and Positive-Sequence Model of New IBR Resource for a Step Change in Voltage at an SCR of 2.0

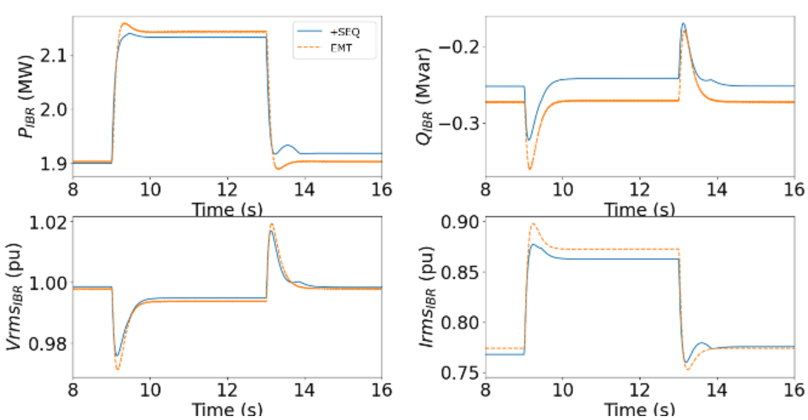


The EMT and positive-sequence models of the new resource had similar trends of performance for a step change in voltage.

Source: Energy Systems Integration Group.

FIGURE A-21

Comparison of Response Across EMT and Positive-Sequence Model of New IBR Resource for a Step Change in Frequency at an SCR of 2.0



The EMT and positive-sequence models of the new resource had similar trends of performance for a step change in frequency.

Source: Energy Systems Integration Group.

Assessment of Inverter-Based Resources' Ability to Provide Voltage and Frequency Services

A Summary of Results by the Energy Systems Integration Group's Reliability Services Project Team

The report is available at https://www.esig.energy/reports-briefs.

To learn more about ESIG's work on this topic, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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