WECC

Changes in System Inertia

Changes in System Inertia Advisory Group

2021

Executive Summary

There are many incentives as well as state policy requirements for entities to invest in wind, solar, and battery storage energy (inverter-based resources, or IBR) to replace fossil-fueled generators (synchronous generation). This is forcing the displacement of synchronous generators and causing a reduction in system inertia, the total of kinetic energy stored in synchronously connected machines. Operating the system with reduced inertia could become a concern because a lack of adequate system inertia could cause frequency excursion during a large generation outage (e.g., two Palo Verde generating units). If system frequency drops below 59.5 Hz, the WECC Off-Nominal Frequency Load Shedding Plan (the underfrequency load shedding plan or UFLS plan) is triggered. This plan is a protection that starts dropping load to stabilize the system. The goal for system planners and operators is to design and operate the system so that typical contingency events, such as a generator losses, do not drop the frequency to a level at which the UFLS is triggered.

WECC conducted this study to investigate the following:

1. What is the potential minimum amount of inertia needed in the Western Interconnection to prevent a large generation outage from causing underfrequency load shedding?
2. What other reliability issues could occur with low system inertia?

To answer these questions, we ran simulations on three cases, each with unique system conditions and assumptions. During each simulation, we monitored the frequency of the Western Interconnection to identify how low system inertia could go before a large generation outage would cause system frequency to drop below 59.5 Hz and trigger the UFLS plan.

- The first case, the 2028 System Inertia Task Force (SITF) case, is a low-inertia case originally produced for the SITF study in 2019. It models 105,468 MW of load and inertia of 397,454 MW*s.
- The second case, the 2021 Heavy Summer (2021 HS3), is a near-term case and models a high load level, which represents the peak loads for the months of June through August between 1500 and 1700 hours MDT. The 2021 HS3 models 175,978 MW of load and inertia of 880,793 MW*s.
- The third case, the 2020 LS11_3AM (3AM), was initially created by the Bonneville Power Administration (BPA) and built from the 2020 Light Spring operating case; the case was then provided to the Changes in System Inertia Advisory Group (CSIAG). We made some changes to the case to better represent light load conditions throughout the Western Interconnection, which are typically seen during night and early morning hours in the spring. Specifically, we used load levels and initial generation dispatch from a state estimator snapshot[1] of 3:00 a.m. on April 11, 2020. Then, we made further modifications to increase wind generation in the California

[1] Snapshot of the Western Interconnection that gathers real-time data seen on the system at any given moment.

Independent System Operator (CAISO) footprint based on average wind generation production for the time of the study from CAISO. This case models a high wind generation scenario with low load—71,713 MW—and an inertia of 397,840 MW*s.

For each case, we replaced the synchronous generator models in the dynamics file with a generic IBR model (IBR model does not have any inertia values) according to the phases shown below.

We did this in four phases for each case based on the inertia constant "H" found in the dynamics models:

- Phase 1—Any unit that had an H greater than 5 sec.,
- Phase 2—H is greater than 3 sec. and less than or equal to 5 sec.,
- Phase 3—H is greater than 1.5 sec. and less than or equal to 3 sec.; and
- Phase 4—H is less than or equal to 1.5 sec.

We did not replace the generator models for hydro, renewable units that were already in the case, or synchronous condenser units.

For the generation outage, we used the double Palo Verde outage (2PV), the loss of two nuclear units at the Palo Verde Nuclear Generating Station. The 2PV outage is one of the standard disturbances used in the case-building process for the Western Interconnection. This simulation would drop between 2,600 and 2,700 MW (depending on the amount of generation output from each unit), subject to how the interconnection would respond to a large generation outage as system inertia decreases.

One more issue we saw during the simulations was with low voltages as more IBRs were energized. We saw local voltage instability followed by shedding load from the composite load model in each case we simulated. Removing synchronous generators reduced the short-circuit ratio at load buses, which made them more susceptible to voltage instability, particularly when loads had high percentages of motor and power electronic loads. We added fictitious synchronous condensers to mitigate the voltage instability in the desired areas before all the synchronous generators were replaced by IBRs. Investigation of low voltages was beyond the scope of the study, and we did not evaluate them any further.

Ultimately, the simulations showed that there are conditions under which the system frequency in the interconnection could drop below 59.5 Hz for a 2PV outage, triggering the UFLS plan. If a large generation outage occurs while the interconnection is lightly loaded (typically in the shoulder months), and most of the on-line generation is supplied from IBRs, it is possible that the UFLS plan could activate. As IBR generation replaces the synchronous generation, system operating and planning entities should continue to monitor the on-line inertia levels on their systems and continuously assess whether their systems are approaching a level at which a large generation outage could put the system at risk of underfrequency load shedding under light load and low inertia conditions.

It is difficult to determine a single inertia value needed to prevent a large generation outage from triggering the UFLS plan. This is determined by how much load and generation are online. However, our analysis has shown that, if the system is lightly loaded and the inertia on the system is about 300,000 MW*s, this scenario is possible.

Observations and Recommendations

Observation 1: As more IBRs energize and displace synchronous generation, the inertia value will decrease at the interconnection level. In this study, we have identified a scenario in which the UFLS plan could be activated following the 2PV outage.

Recommendation 1: Planning Coordinators, Transmission Planners, Balancing Authorities, and Reliability Coordinators should monitor system inertia and frequency response, especially under low inertia conditions.

Recommendation 2: The System Review Subcommittee (SRS) should track the amount of inertia and report frequency response under a large generation contingency in each of the Western Interconnection base cases. Additionally, SRS should consider developing a minimum system inertia case on an ongoing basis so that entities can evaluate for adequate system frequency response under low inertia conditions.

Observation 2: The simulations performed for this study showed significant changes in the rate of change of frequency (ROCOF) being observed for the simulation of the 2PV outage.

Recommendation 3: Planning Coordinators, through their participation in the UFLS Work Group, should investigate islanding scenarios and evaluate the UFLS plan to make sure the set points of the UFLS relays are still adequate due to the drastic change in the ROCOF caused by increased penetration of IBRs. The UFLS Work Group assessments should include minimum inertia cases to ensure the adequacy of the UFLS plan.

Observation 3: We saw local voltage instability followed by load tripping in cases with low synchronous generation. Removing synchronous generators reduces short-circuit ratio at load buses, which made them more susceptible to voltage instability, particularly when loads have a high percentage of motor and power electronic loads. Adding synchronous condensers mitigated the voltage instability.

Recommendation 4: Planning Coordinators, Transmission Planners, and Reliability Coordinators should perform additional studies to better understand the impact of reduction in synchronous resources on transient and voltage stability in the Western Interconnection. These studies need to evaluate the implications of shifts in generator locations.

Observation 4: Simulations showed that frequency response assumptions in the IBRs were able to prevent the UFLS plan from activating.

Recommendation 5: The WECC Modeling Validation Subcommittee (MVS) should ensure dynamic models provide a reasonably accurate representation of IBR frequency response that represents capabilities of wind and solar resources. The MVS should develop a guideline on frequency response modeling of various IBRs.

Recommendation 6: Transmission Planners should ensure that Generator Owners include frequency response characteristics and provide validated models.

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Purpose

As fossil fuel generators (synchronous generation) are being replaced by inverter-based resources (IBR) such as wind, solar, and battery storage, the Western Interconnection will see a decrease in system inertia.[2] Inertia is "the summation of kinetic energy stored in rotating masses of synchronously connected machines.[3]" Inertia helps dissipate the effects of unexpected generation outages on system frequency and mitigates system frequency excursions.

We performed this study to answer two questions:

1. What is the potential minimum amount of inertia needed in the Western Interconnection to prevent a large generation outage from causing underfrequency load shedding?
2. What other potential reliability issues could occur with low system inertia?

This study is intended to determine the Western Interconnection's system-critical points and the potential minimum limits of inertia on system frequency. System frequency response is one of the metrics used in evaluating system reliability. To this end, we looked into how much inertia the Western Interconnection needs to prevent a large generation outage (e.g., 2 Palo Verde generating units) from initiating WECC's Off-Nominal Frequency Load Shedding Plan (the underfrequency load shedding plan or UFLS plan). This plan is a protection that starts dropping load to stabilize the system when system frequency falls below 59.5 Hz. The goal for system planners and operators is to design and operate the system so typical contingency events, such as a generator losses, do not drop the frequency to the level at which the UFLS is triggered. If this threshold was reached in our simulation, we enabled the frequency response capabilities in the IBR models to keep the interconnection's frequency above this threshold.

Case Assumptions

For this study, we looked at three cases, each with a different load level: low, medium, and high. Table 1 shows the three cases and their assumptions.

Table 1: Case Assumptions at a Glance

Case	Assumptions	Load, MW	Inertia, (MW*s)
2028 SITF	• Low inertia case with summer peak load, produced for the SITF study in 2019	105,468	397,454
2021 HS3	• Heavy Summer conditions	175,978	880,793

[2] This does not include synthetic inertia, which IBRs can emulate.

[3] NERC Inverter-Based Resource Performance Task Force (IRPTF), *Fast Frequency Response Concepts and Bulk Power System Reliability Needs*, March 2020

2020 LS11_3AM	• High wind generation, light spring load scenario	71,713	397,840

2028 System Inertia Task Force Case

The 2028 System Inertia Task Force (2028 SITF) case represents a medium loading day on August 4, 2028 hour 14. It was developed for the SITF study in 2019 and taken from the work that the SITF did for the 2019 Studies Subcommittee Study Program. We chose this case because it already had low inertia conditions represented, and many of the synchronous generators had already been replaced with generic IBR models.

Figure 1 shows the 2028 SITF generation profile—the online generation capacity. In this scenario, 79% of the generation came from hydro and IBR. We replaced the remaining 21% over four phases, as explained below in the Input Data section, with a generic IBR model based on the turbine types in the power flow, which are defined in WECC's Data Preparation Manual and shown here in Figure 1.The "Unknown" category means that there was no turbine type assigned to this generator.

Figure 1: 2028 SITF Generation Capacity Profile (MW)

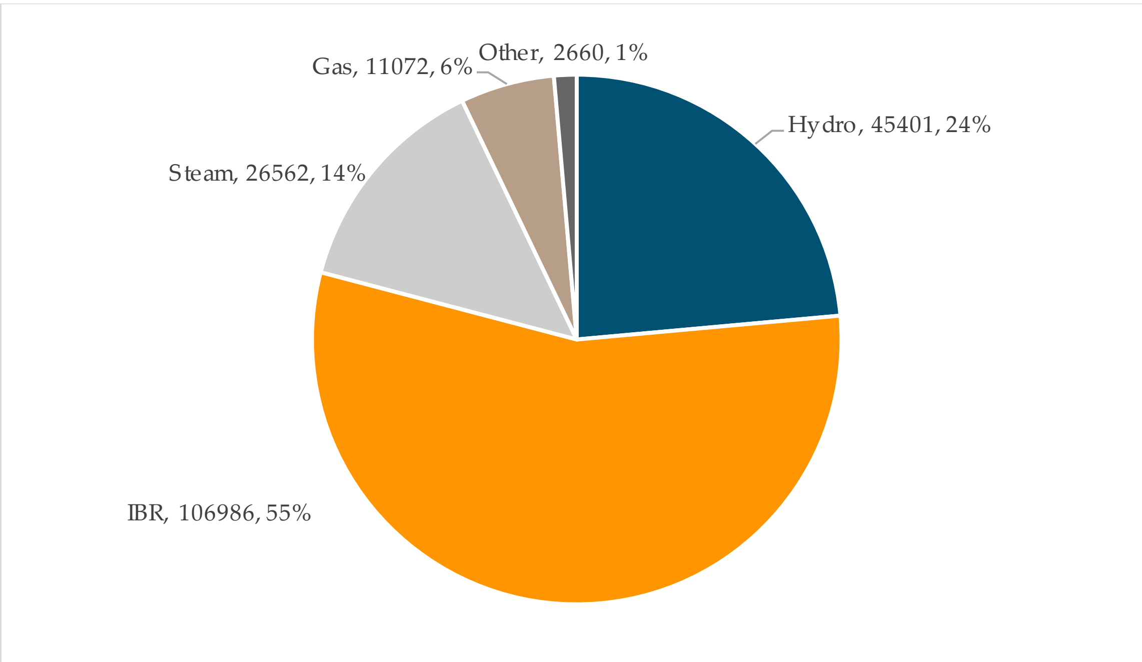


Table 2: Turbine Code and Turbine Type

Turbine Code	Turbine Type
6, 7, 11, 12, and 13	Gas
1, 2, 3, 4, and 29	Steam
5	Hydro
21, 22, 23, 24, 31, 32, 33	IBR
0, 19, 41, 99	Other

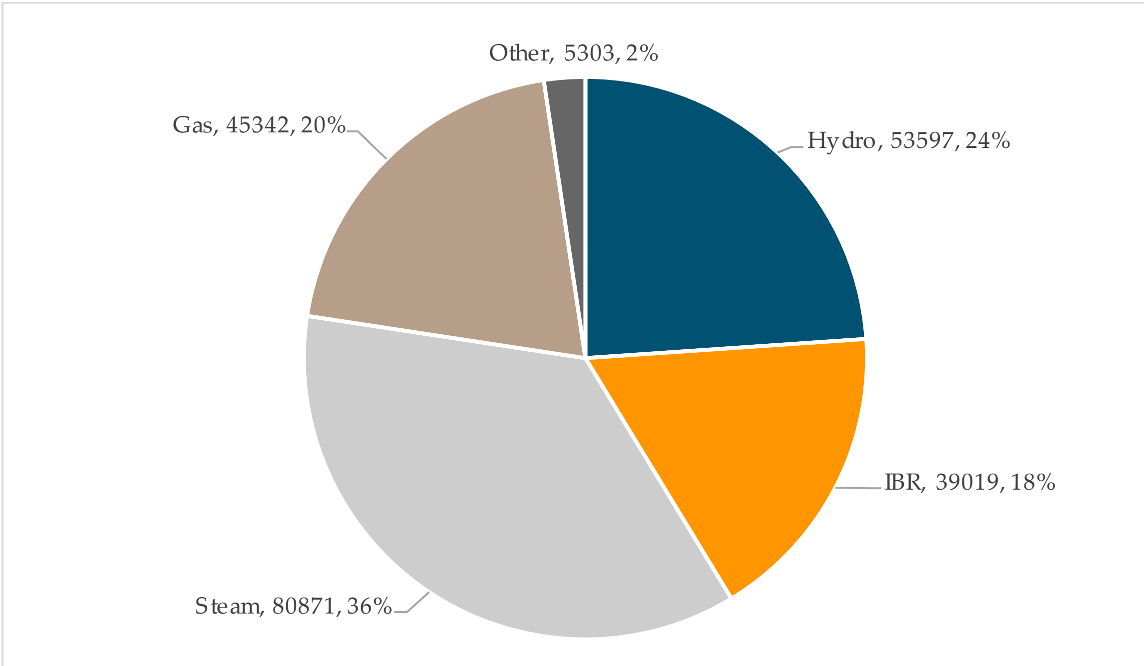
In the 2028 SITF case, we noticed there were many hydro units on-line that were providing minimal output. This is because the SITF case was an export from the 2028 Anchor Data Set Production Cost Model (PCM) based on how these hydro units are dispatched in the PCM. As the PCM exported this data, it distributed the hydro plant MWs to all the units representing that plant in the power flow case. In this study these hydro units were re-dispatched to reduce the on-line capacity from about 67,000 to about 45,000 MW by combining the generation output into fewer units and turning off the unneeded units. Also, 160 hydro plants (about 2,700 MW total capacity) that had an output of 0 MW were taken off-line. By re-dispatching the hydro, we made this case more realistic and eliminated the extra frequency response we would have gotten with these units on line. We also adjusted voltage profiles by re-dispatching reactors and capacitors on and off, and we adjusted the Pacific DC Intertie (PDCI) schedule from 2,240 to 500 MW north-to-south to eliminate the circulating flows between the California-Oregon Intertie (from about 1,400 MW south-to-north to about 21 MW north-to-south) and the PDCI.

2021 Heavy Summer

We chose the second case, the 2021 Heavy Summer (2021 HS3), because it is a near-term case modeled with a high load level, which represents the peak loads for the months of June through August between 1500 and 1700 hours MDT. We made adjustments to voltages to help meet the desired voltage schedule in the case by turning on and off capacitors or reactors.

The 2021 HS3 generation profile is shown in Figure 2. Hydro and IBR make up 42% of the case. We replaced the remaining 58%, mostly fossil-fired generation, with IBR in four phases, as explained in the Input Data section.

Figure 2: 2021 HS3 Generation Capacity Profile (MW)



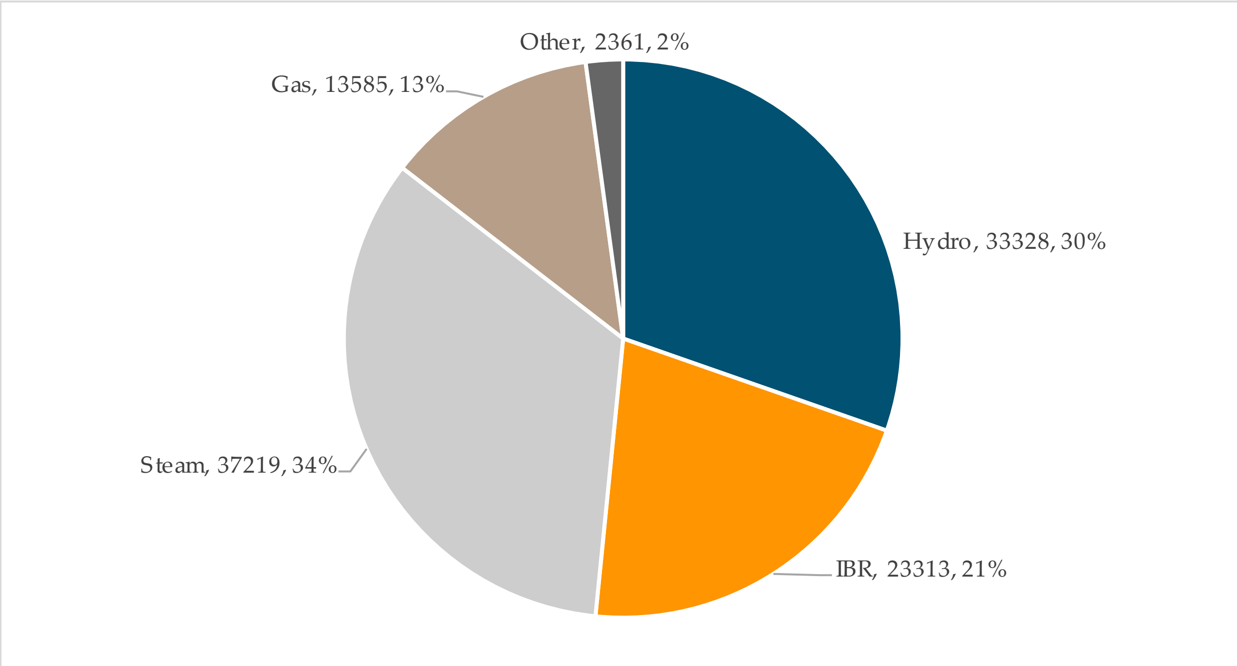
2020 LS11_3AM Case

The third case, the 2020 LS11_3AM (3AM), was created by the Bonneville Power Administration (BPA) and built from the 2020 Light Spring operating case. We made changes to the case to better represent light load conditions throughout the Western Interconnection, which are typically seen during late night and early morning hours in the spring. Specifically, we used load levels and initial generation dispatch from a state estimator[4] snapshot of 0300 PDT on April 11, 2020. We scaled down the loads in each region to match state estimator data, and we matched generation output from the state estimator case to the WECC case. Next, we increased wind generation and took thermal generation off-line across the Western Interconnection. We then increased exports from the Pacific Northwest to represent an over-supply scenario seen during hydro runoff in spring season. Further modifications were done by the advisory group to model higher wind generation in the CAISO footprint based on the average production at the time of the study.

The 3AM case generation profile can be found in Figure 3., this case had 51% of its generation composed of hydro and IBR resources, and we replaced the remaining 49% of the generation with IBR over four phases, as explained in the Input Data section. We made minor modifications to a few areas by re-dispatching capacitors or reactors on-line or off-line to help achieve the desired voltage scheduled in the area.

[4] Snapshot of the Western Interconnection that gathers real-time data seen on the system at any given moment.

Figure 3: 3AM Generation Capacity Profile (MW)



Input Data

With the cases selected, the next step was to take the synchronous generator models in the dynamics file and replace them over four phases with new models that represented generic IBR models. We used the REGC_A—generator/converter model, REEC_A—renewable energy electrical control model, and the REPC_A—power plant controller model. The data we used for these IBRs was the generic data that General Electric (GE) supplies in its Positive Sequence Load Flow manual.

To activate the frequency response in the REPC_A model, we had to adjust a few parameters from what GE provided:

- *frqflg* = 1
- *Pmax* = [(PGEN in MW)*1.1] / (MVA Base of REPC_A)
- Droop was set to 4% *ddn*=*dup* = 25
- Deadband was set to 36 mHz *dbd1* = -0.0006, *fdb2* = 0.0006

The droop and deadband values were set based on the NERC Reliability Guideline—Primary Frequency Control. The default *Pmax* value in the REPC_A model is 1, which would allow the unit to respond to any available capacity up to the maximum MVA rating of the unit. In order to only allow the IBRs to provide up to a 10% increase in generation, we used the above equation to set the *Pmax* value in the REPC_A model. The REPC_A model was disabled unless the simulations showed that the interconnection's frequency reached the 59.5 Hz threshold to trigger the UFLS plan.

We replaced the dynamics data for the synchronous generators in four phases based on the inertia constant H found in the dynamics models:

- Phase 1—Any unit that had an H greater than 5 sec.,
- Phase 2—H is greater than 3 sec. and less than or equal to 5 sec.,
- Phase 3—H is greater than 1.5 sec. and less than or equal to 3 sec.; and
- Phase 4—H is less than or equal to 1.5 sec..

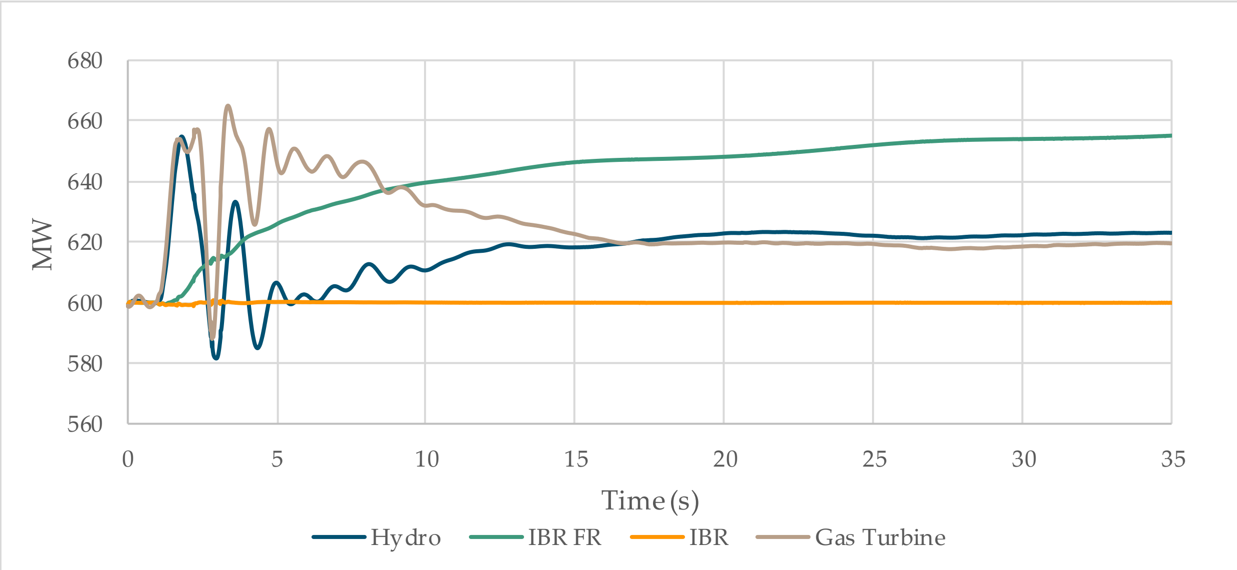
The generator models for hydro, renewable units already identified in the case, and synchronous condenser units were not replaced.

Approach

We simulated the loss of two nuclear units at Palo Verde—this outage is referred to as the "double Palo Verde" (2PV) outage and is one of the standard disturbances used in the case-building process for the Western Interconnection. This simulation drops between 2,600 and 2,700 MW of generation, depending on which case is being used. We monitored frequency as the system inertia was being reduced as IBRs replaced synchronous generators.

To understand how each type of generator would respond to the 2PV outage, we took a hydro, gas turbine, IBR, and an IBR with the Frequency Response active (IBR FR) and simulated the 2PV outage. To compare these results, normalization was applied (the same generator's response was observed by changing the dynamics data to represent each of the unit types). The IBR response shown in Figure 4 is typical of how nearly all IBR units in the Western Interconnection respond to a frequency event; i.e., they do not adjust their output during a frequency event. Such IBRs are commonly referred to as "grid following inverters." The IBR FR is how the units respond when the REPC_A model is activated (dynamics data is specified in the Input section of this report).

Figure 4: Generation Response



We took frequency plots from the Malin 500 kV bus throughout each run. We chose this bus because this area is in a strong system in the Northwest. Frequency depends on the proximity to the disturbance.

We simulated the 2PV outage on each case before any modifications were done to the dynamics file to establish a baseline system response (Base), which was then compared to the system response after making inertia adjustments in the dynamics data in each phase.

SITF Case Simulation Results

We replaced synchronous generators with IBR models as described before and applied the 2PV outage in each phase. Table 3 shows how much inertia was on the system for each phase, along with how many units were replaced with IBR models and the change in inertia for every phase. We used the rate of change of frequency (ROCOF) as an indicator to measure the system's performance, which we calculated by:

$$ROCOF_{0.625} = \frac{f_{0.625} - f_0}{0.625\, sec}$$

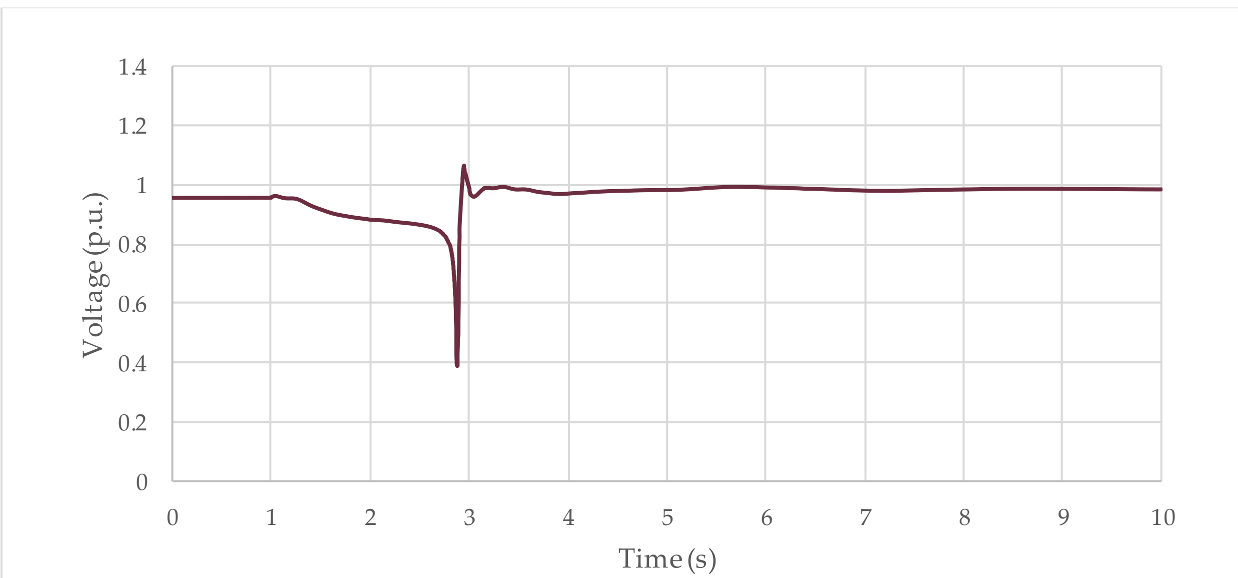
Table 3 : Summary of 2028 SITF Case Simulation Results

	Inertia (MW*s)	Units replaced/reduction in inertia (MW*s)	Frequency Nadir (Hz)	ROCOF (Hz/s)
Base	397,454	N/A	59.72	-0.188
Phase 1	312,402	173 / 85,052	59.68	-0.267
Phase 2	248,979	218 / 63,926	59.62	-0.396
Phase 3	218,448	136 / 31,979	59.58	-0.541

Phase 4	210,220	88 / 7,961	59.56	-0.579

In simulating Phase 2, there were a few areas in which low voltages were causing the composite load model to shed load. Because of the load loss on the system, the frequency response greatly improved and the system frequency recovered well above the 59.5 Hz threshold. To counter this effect, we added fictitious synchronous condensers to areas that were showing low voltages to help maintain the voltages so we could watch the frequency dip without the mitigating effects of the load loss due to the relay settings in the composite load model. Figure 5 shows an example of the bus voltage that dropped to about 0.4 per unit. This caused the composite load model relays to activate and shed load to increase the voltages surrounding these loads. Removing synchronous generators reduced the short-circuit ratio at load buses, which made these load buses more susceptible to voltage instability, particularly when loads had a high percentage of motor and power electric loads, which is characteristic of the composite load model. Investigation of low voltages was beyond the scope of the study and further evaluation was not done.

Figure 5: Observation of Low Voltage



An example of a composite load model shedding load for an area during the simulation can been seen in Figure 6. In this plot, there is an initial spike that jumps to about 4,600 MW, then settles to about 750 MW, which is the load that it shed permanently for this area. Once we added the fictitious synchronous condensers to the case, voltage profiles improved and, consequently, there was no more load tripping.

Figure 6: Composite Load Model Shedding Load

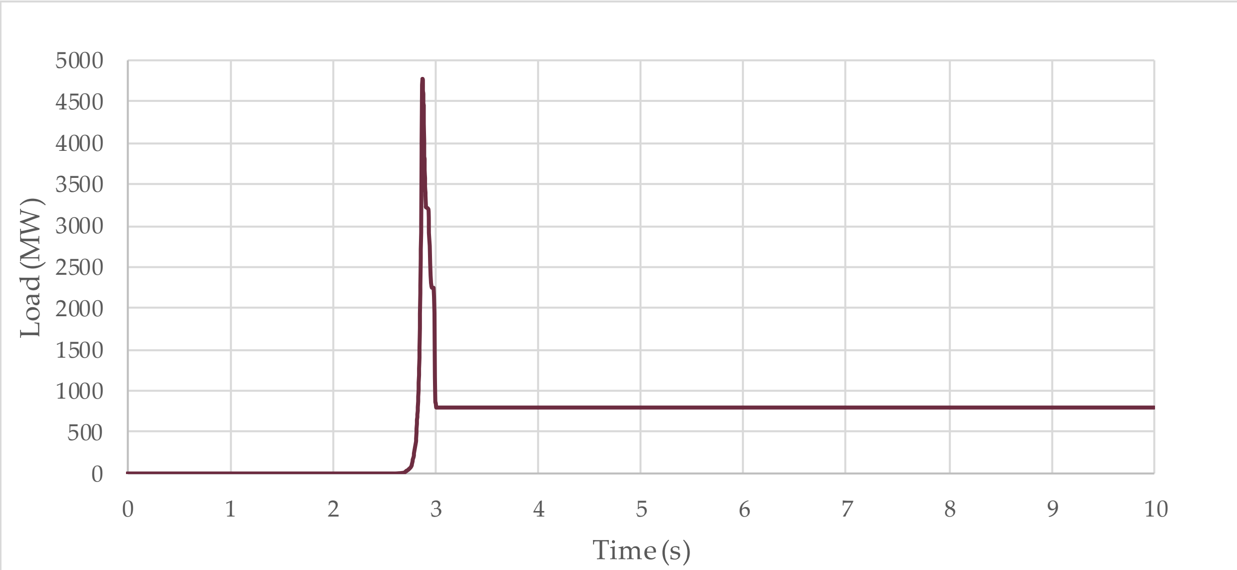
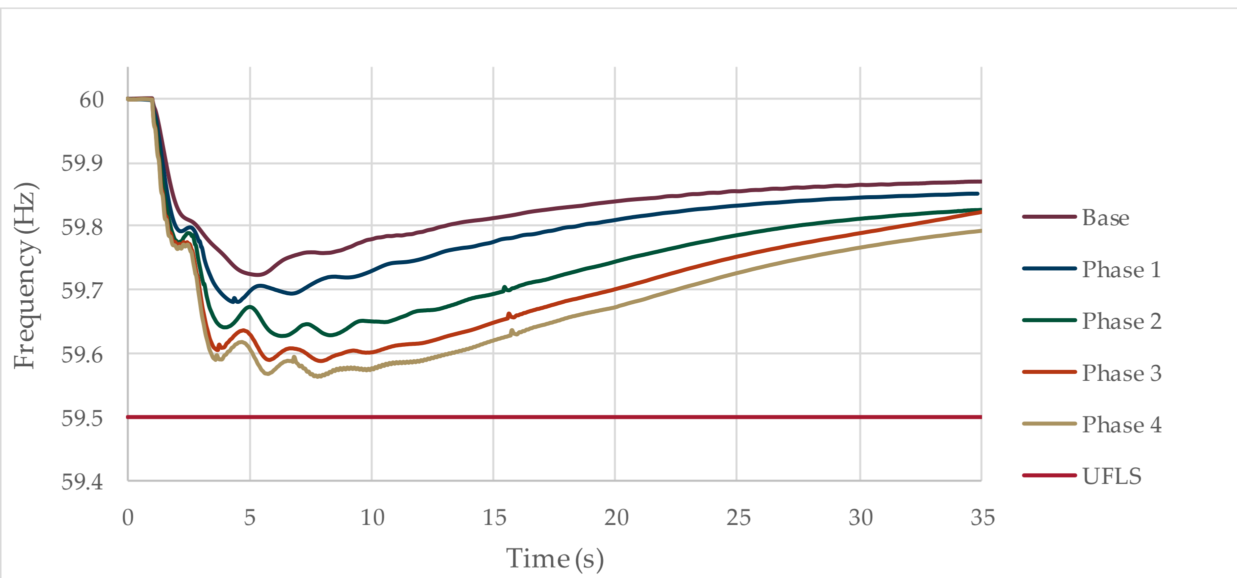


Figure 7 shows the trends in the frequency drop between the Base and each phase. In Phase 4, the frequency nadir is at 59.56 Hz, which is still above our 59.5 Hz threshold.

Figure 7: 2028 SITF Frequency Response



2021 HS3 Case Simulations

The 2021 HS3 case had the highest load level of 175,000 MW, which is higher than the all-time peak in the Western Interconnection of 162,017 MW on August 18, 2020. In this case, the loss of the two Palo Verde units caused the frequency nadir to drop to 59.845 Hz, as seen in Table 4. The ROCOF drop was 0.01282 Hz/sec. In this case, the "Base" frequency nadir did not dip as low as the previous case because more generation was on-line.

Table 4: 2021 HS3 Case Simulation Results Summary

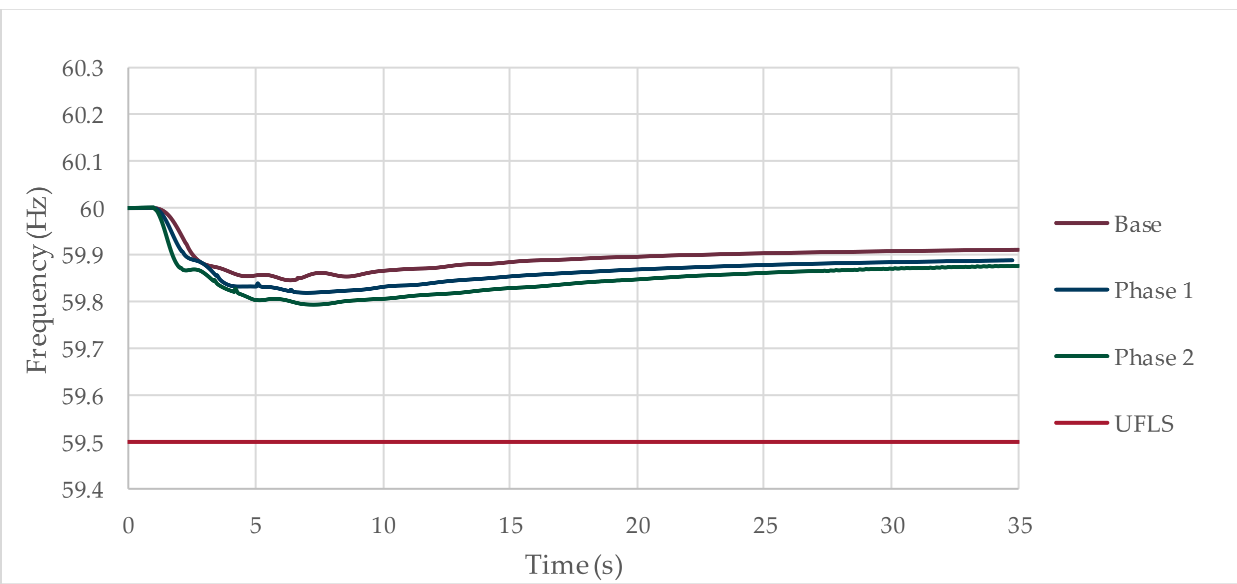
	Inertia (MW*s)	Units replaced/ reduction in inertia (MW*s)	Frequency Nadir (Hz)	ROCOF (Hz/sec.)
Base	880,793	N/A	59.845	-0.012
Phase 1	593,396	348 / 287,397	59.818	-0.028
Phase 2	391,516	347 / 201,880	59.793	-0.067
Phase 3	NA	NA	NA	NA
Phase 4	NA	NA	NA	NA

During Phase 1, after removing almost a third of the inertia (287,397 MW*s), the system frequency did not waver much. The frequency nadir dropped by 0.027 Hz, but the ROCOF doubled to -0.02893 Hz/sec., also shown in Table 4.

During Phase 2, several fictitious synchronous condensers were added to help keep the voltages up. The frequency nadir dropped by 0.025 Hz, but the ROCOF went to 0.0672 Hz/sec.

As we moved to Phase 3, there were several areas in which the voltages dropped and tripped load as part of the composite load model. We also saw this on a small scale in the SITF. Figure 8 shows the trends in the frequency drop between the Base and Phase 2. We would have been able to replace all the units with IBRs if these issues were not present. As such, we did not pursue Phases 3 and 4 due to the amount of tuning this case needed during this high-load period.

Figure 8: 2021 HS3 Frequency Response



3AM Case Simulations

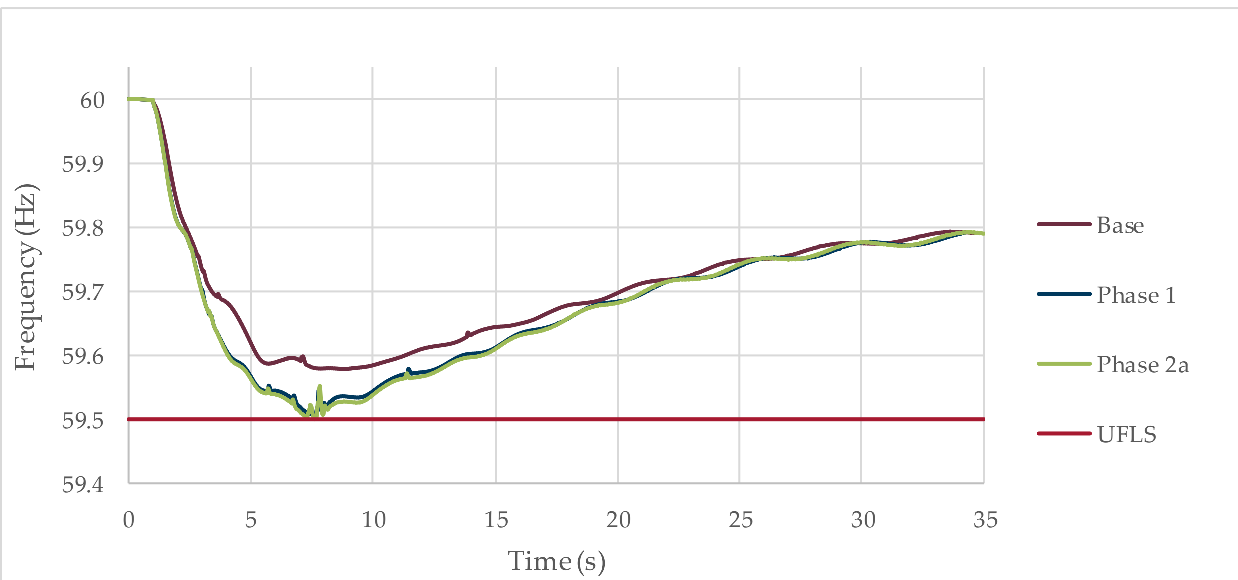
This case involves about 71,000 MW of load on the system and is the lightest load case that we studied. Table 5 shows that, in the base simulation, the frequency dropped to 59.57 Hz, coming close to activating the UFLS plan before any synchronous generators were replaced with IBR models.

Table 5: Summary of 3AM Case Simulation Results

	Inertia (MW*s)	Units replaced/reduction in inertia	Frequency Nadir (Hz)	ROCOF (Hz/sec.)
Base	397,840	N/A	59.570	-0.113
Phase 1	310,015	130 / 87,825	59.507	-0.179
Phase 2a	308,056	2 / 1,959	59.500	-0.180
Phase 2b—IBR FR	308,056	Added REPC_A model	59.572	-0.181
Phase 2c—IBR FR 10%	308,056	Limited the head room up to 10% of unit's response	59.571	-0.181
Phase 2d	218,692	149 / 89,664	59.573	-0.436
Phase 3	177,018	220 / 41,674	59.552	-0.750
Phase 4	173,769	100 / 3,249	59.549	-0.797

In Phase 1, the frequency nadir dropped to 59.507 Hz, just above the load shedding threshold. Around 7.5 seconds into the disturbance, the frequency jumped. This was caused by underfrequency load shedding relay (*lsdt9*) models activating and shedding all or part of the load for a total load loss of 237 MW, as seen in Figure 9.

Figure 9: 3AM Frequency Response

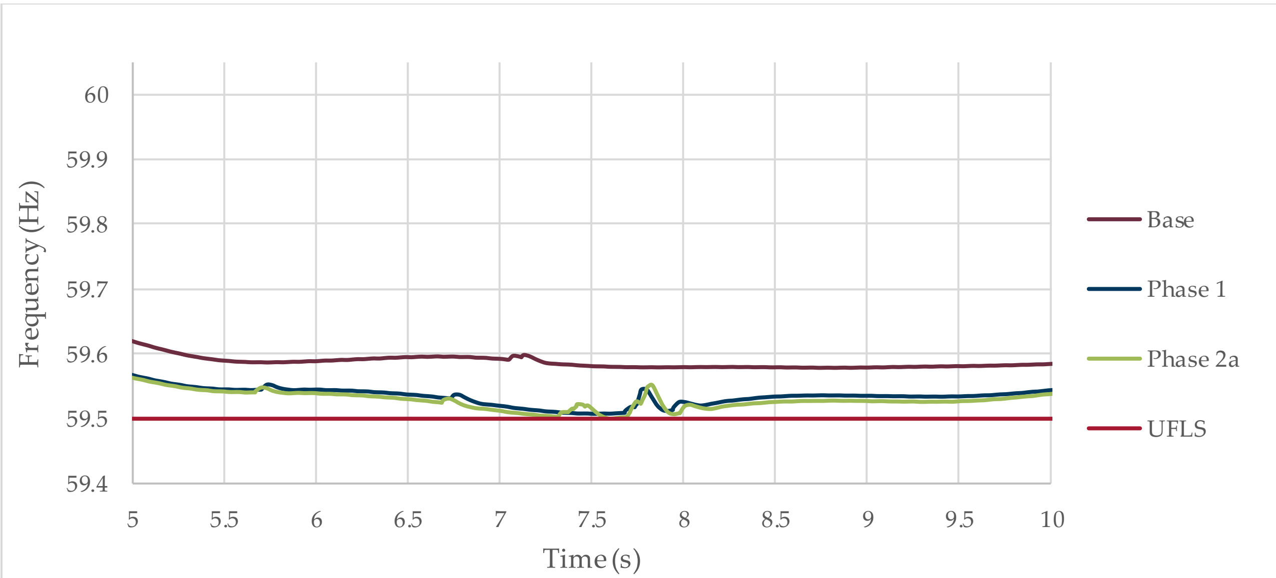


We saw that the *lsdt9* models that were activating were in the southern portion of the system where the loss of generation happens. Therefore, the frequency would be slightly different from that being recorded at Malin, as seen in Figure 10. Malin did not hit the 59.5 Hz threshold.

As we moved into Phase 2a, the Malin frequency was at 59.507 Hz, and the southern portion of the system began to activate the UFLS plan. We knew it would not take much more to get the frequency at Malin to the 59.5 Hz threshold. Two more units were replaced with IBR models and the frequency would have dropped below the 59.5 Hz at Malin, but the UFLS models started to trip load, as seen in

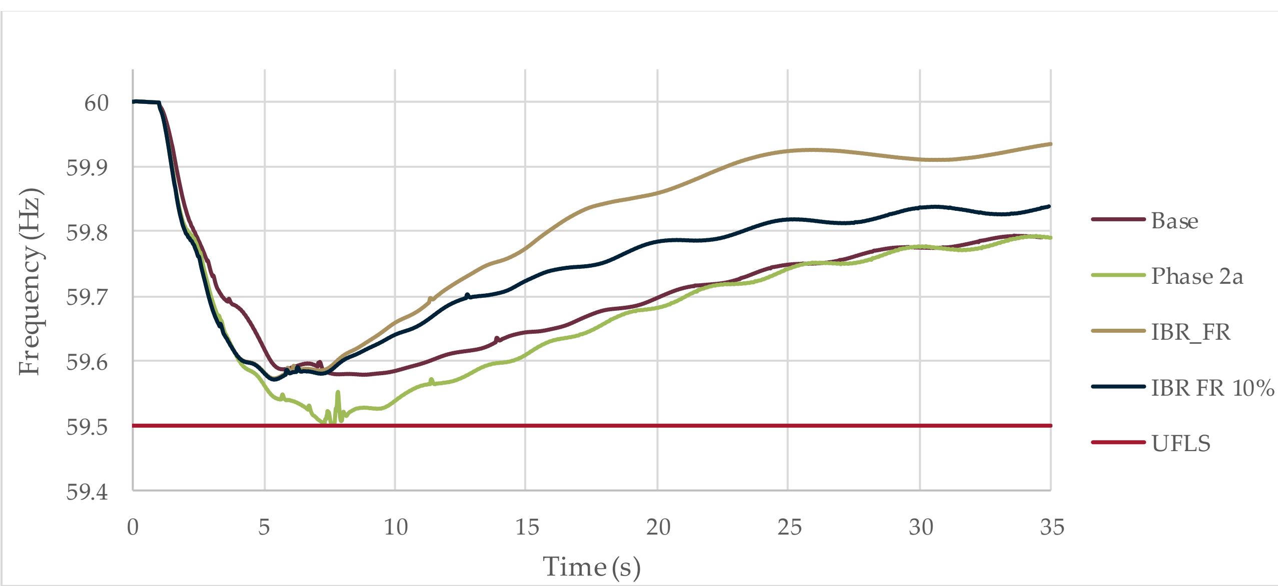
Figure 10. The frequency jumps in Figure 10 are due to the several *lsdt9* models shedding all or part of the load for a total load loss of 277 MW to keep the system above the 59.5 Hz, but there was still no widespread activation of the UFLS plan.

Figure 10: 3AM Phase 2 Hitting Load Shedding Threshold



As the interconnection reached the 59.5 Hz threshold, we activated the REPC_A models with the frequency response into the Phase 2b IBR FR. We added this REPC_A model to all the units that were replaced in Phase 1 and the other two units in Phase 2. We then re-ran the same simulation as Phase 2a. As seen in Figure 11, the frequency response for Phase 2b is very similar to the base simulation with all the added IBR able to respond to this frequency event (labeled IBR_FR).

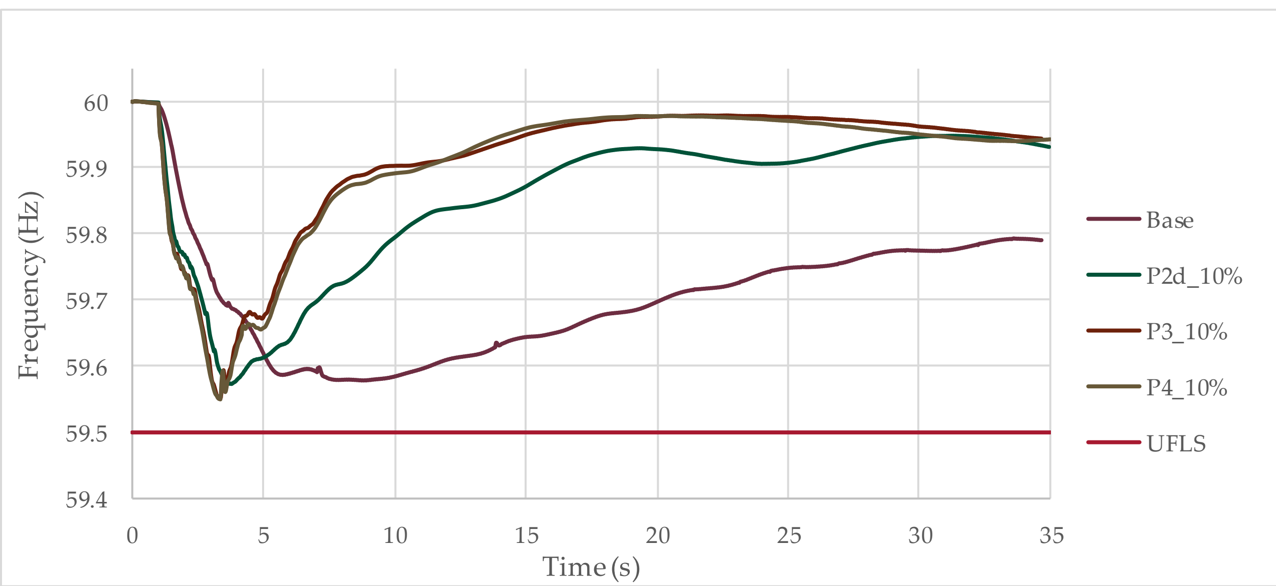
Figure 11: 3AM IBR Frequency Response



We saw that the IBR_FR frequency recovered faster than the "Base" frequency. In this simulation, the IBR models could respond to the available capacity up to the maximum MVA rating. To limit this response, we added a cap to these IBR models and added the parameter of *Pmax* to the REPC_A model that was identified in the Input section. The cap only allowed these IBR units to increase their generation output by up to 10% of what the plant output was before the 2PV outage was simulated. We re-ran the Phase 2a simulation and labeled this run "Phase 2c IBR FR 10%." Phases 2a, 2b, and 2c were identical simulations but with different dynamics parameters such as adding the REPC_A model and then adjusting the *Pmax* parameter in this model. We used the results from Phase 2c as we moved on to the rest of Phases 2, 3, and 4. In Figure 11, the IBR_FR 10% is showing system recovery sooner than the base response but worse than the IBR_FR response. The ROCOF and the frequency nadir stayed nearly the same as Phase 1 results.

We simulated Phase 2d, which was the remainder of the synchronous generators that were replaced with the IBR models in Phase 2. The IBR models for the rest of this simulation included the frequency response functionality, and, as expected, the frequency nadir stayed close to the "Base" simulation, but the ROCOF tripled to 0.436 Hz/sec. The results of Phases 3 and 4 were very similar and a few fictitious synchronous condensers were added to help with low voltage, resulting in the composite load model dropping load, which improved frequency response. The ROCOF dropped between 0.750 and 0.797 Hz/sec., respectively, which was drastic compared to the base of 0.113. The frequency nadir also started to drop, but it did not reach the 59.5 Hz threshold with all the synchronous generators replaced with IBRs, and the frequency response after the event recovered rapidly to 60 Hz, as seen in Figure 12, due to the IBRs ability to respond to the frequency decline.

Figure 12: Frequency Response with up to 10% Increase in Generation Output



To better see how the generation mix was dispatched between each phase and how much IBR was responding to this event, a detail of the generation profile over each phase is provided in Table 6.

Table 6: Generation Progression Through Each Phase (MW capacity)

Turbine type	Base	Phase 1	Phase 2	Phase 3	Phase 4
Hydro	33,328	33,328	33,328	33,328	33,328
IBR with no frequency response	23,313	35,142	23,313	23,313	23,313
IBR with Frequency Response	0	0	33,368	50,213	53,165
Steam	37,159	33,226	16,178	1,135	0
Gas	13,585	6,037	2,843	1,650	0
Other	2,361	2,073	776	167	0

Findings and Conclusions

In analyzing the cases considered, we see that the Western Interconnection can have a scenario in which the UFLS plan could activate for the 2PV outage. If the interconnection is operating at a lightly loaded day, typically in the off-peak months in the spring, and most of the on-line generation is IBRs without frequency response capability, it is possible that WECC's UFLS plan will activate under a large generation disturbance like the 2PV outage. The size of disturbance it would take to cause this to occur, and the amount of frequency dip, depends on the system conditions (i.e., amount of load and on-line generation) at the time of the disturbance.

In the 2028 SITF case, Phase 4, we saw that inertia was at about 210 GW*s with the load levels at about 105,000 MW when the system frequency dropped to 59.56 Hz, which is significant, but it did not cross the UFLS threshold. In the 3AM case, however, which was showing an inertia level of 308 GW*s, with IBRs having no frequency response capabilities, and a load level of about 71,000 MW, the system did reach the 59.5 threshold and activated the UFLS plan.

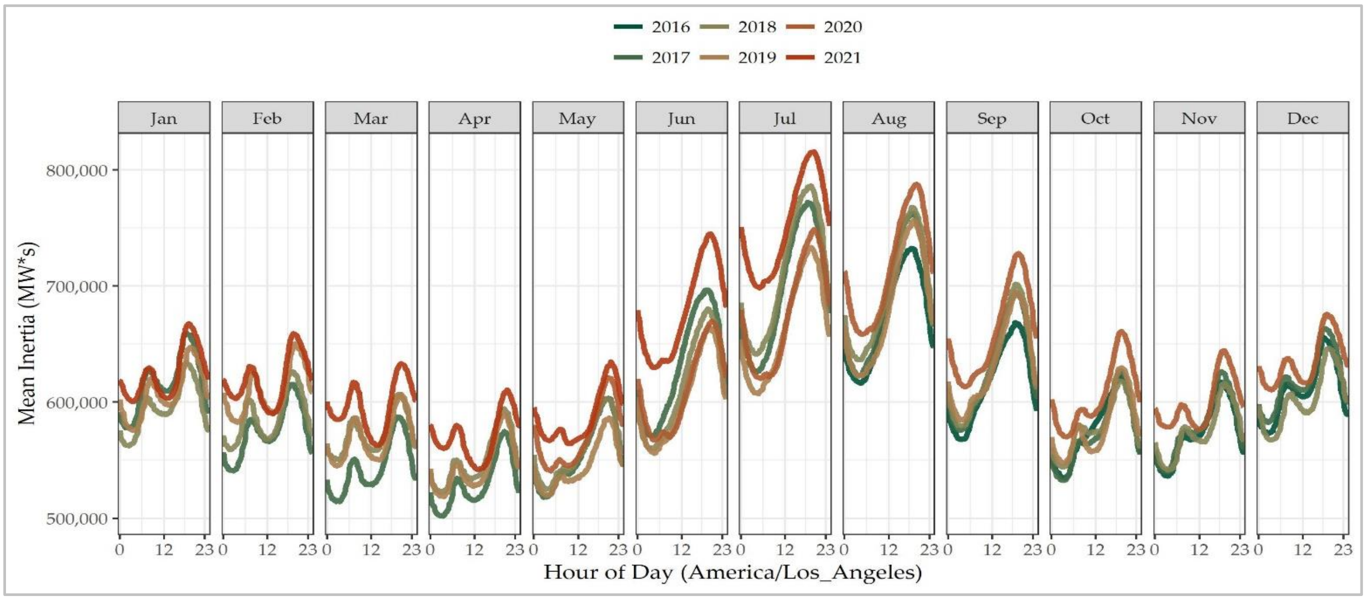
With these results, it is challenging to determine the exact level of inertia needed to prevent a large generation contingency from triggering the UFLS plan, which was one of the objectives of the study. However, the simulation results show that, if the system is lightly loaded, with IBRs having no frequency response capabilities, and the inertia on the system at about 300 GW*s, this scenario could occur.

Figure 13 shows the trends of inertia that Reliability Coordinators (RC) are reporting to NERC[5] for the Western Interconnection. The lowest amount of inertia seen was about 500 GW*s in April of 2017,

[5] This is based on our current understanding of the data, and we will continue to work with NERC and the RCs to correct any errors we identify in this reporting

which is 40% higher than the inertia value in the 3AM case. According to the RC data given to NERC, the Western Interconnection has never seen inertia of 300 GW*s on the system in the past six years. However, the CSIAG recommends that system operating and planning entities continue to monitor system inertia as IBRs replace synchronous generation, and that they continue to evaluate the risk of triggering the UFLS plan due to a large generation disturbance, especially under a light load with high IBRs online with no frequency response capability.

Figure 13: Multiple-Year Inertia Overlay Reported by RCs in the Western Interconnection



One more issue we saw during the simulations was with low voltages as more IBRs were energized. Local voltage instability followed by load shedding from the composite load model occurred each case we simulated. Removing synchronous generators reduced the short-circuit ratio at load buses, which made them more susceptible to voltage instability, particularly when loads had high percentages of motor and power electronic loads. We added fictitious synchronous condensers to mitigate the voltage instability in the desired areas before all the synchronous generators were replaced by IBRs. In the 3AM scenario, we ran into low frequency before low voltages, but, after the REPC_A model was added, low voltages were observed before all the synchronous generators could be replaced. Most of the low voltages occurred in Phases 2, 3, or 4, but, in the HS3 case, we saw low voltages during the 2PV outage in Phase 2 after about 488 GW*s of inertia was removed, which was about 55% of the original inertia value combined with a heavy loaded day. The IBR models used in this study had limited voltage control capabilities. It is very possible that low voltages could be seen on the system as more IBRs replace synchronous generation, which typically has ability to control voltages, in the Western Interconnection. Investigation of low voltages was beyond the scope of the study, we did not evaluate it any further.

In the 3AM case, in which we allowed these IBRs to respond to a frequency event with a 10% headroom, frequency was no longer an issue, and subsequently having low inertia on the system did not drastically affect the frequency. However, the ROCOF, dropping from 0.18 to about 0.75-0.79 Hz/sec. could require further analysis as to whether the UFLS would stop frequency decline soon enough to prevent a system collapse.

Observations and Recommendations

Observation 1: As more IBRs energize and displace synchronous generation, the inertia value will decrease at the interconnection level. In this study, we have identified a scenario in which the UFLS plan could be activated following the 2PV outage.

Recommendation 1: Planning Coordinators, Transmission Planners, Balancing Authorities, and Reliability Coordinators should monitor system inertia and frequency response, especially under low inertia conditions.

Recommendation 2: The System Review Subcommittee (SRS) should track the amount of inertia and report frequency response under a large generation contingency in each of the Western Interconnection base cases. Additionally, SRS should consider developing a minimum system inertia case on an ongoing basis so that entities can evaluate for adequate system frequency response under low inertia conditions.

Observation 2: The simulations performed for this study showed significant changes in the rate of change of frequency (ROCOF) being observed for the simulation of the 2PV outage.

Recommendation 3: Planning Coordinators, through their participation in the UFLS Work Group, should investigate islanding scenarios and evaluate the UFLS plan to make sure the set points of the UFLS relays are still adequate due to the drastic change in the ROCOF caused by increased penetration of IBRs. The UFLS Work Group assessments should include minimum inertia cases to ensure the adequacy of the UFLS plan.

Observation 3: We saw local voltage instability followed by load tripping in cases with low synchronous generation. Removing synchronous generators reduces short-circuit ratio at load buses, which made them more susceptible to voltage instability, particularly when loads have a high percentage of motor and power electronic loads. Adding synchronous condensers mitigated the voltage instability.

Recommendation 4: Planning Coordinators, Transmission Planners, and Reliability Coordinators should perform additional studies to better understand the impact of reduction in synchronous resources on transient and voltage stability in the Western Interconnection. These studies need to evaluate the implications of shifts in generator locations.

Observation 4: Simulations showed that frequency response assumptions in the IBRs were able to prevent the UFLS plan from activating.

Recommendation 5: The WECC Modeling Validation Subcommittee (MVS) should ensure dynamic models provide a reasonably accurate representation of IBR frequency response that represents capabilities of wind and solar resources. The MVS should develop a guideline on frequency response modeling of various IBRs.

Recommendation 6: Transmission Planners should ensure that Generator Owners include frequency response characteristics and provide validated models.

Contributors

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