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Operational Security in 100% Inverter-Based Power Systems: Demonstration for Hawaii's Big Island System

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SUMMARY

Reliable power system operation with 100% inverter-based resources (IBRs) is an unsolved and challenging problem. One of the most challenging factors is ensuring power system stability after N-1 contingencies. This paper presents a promising solution using an operator support system (OSS). The OSS consists of two components: First, Dynamic Security Assessment (DSA) to evaluate the system resiliency and to identify critical N-1 contingencies that could endanger the system; second, Dynamic Performance Optimization (DPO), as the key technology behind the OSS. The DPO optimizes the control parameters of generators and inverters to improve the stability of the system towards critical N-1 contingencies. The OSS enhances the stability of the system along varying operating points, and helps the system mitigate the contingency by optimizing the controller parameter ahead of time. As emphasized in many recent studies, the key to system with 100% IBRs is to establish the system inertia with grid-forming (GFM) inverters. We show through high-fidelity Electro-Magnetic-Transient (EMT) real-time simulations of Hawaii's Big Island system with 100% IBR capacity that a system with 100% IBRs can be operated stably with the help of GFM inverters, with the controller parameters continuously adjusted by OSS. The effectiveness of the OSS is verified by 28 critical N-1 contingencies of Hawai`i Island system identified by Hawaiian Electric.

KEYWORDS

Dynamic security, 100% inverter-based generation, grid-forming inverter, low-inertia system, controller parameter optimization, EMT simulation.

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1. INTRODUCTION

The future power system envisioned with high penetration of renewable generation is already a close reality. Multiple islanded power systems nowadays have incorporated very high share of renewables through power-electronic inverter-based resources (IBRs) into their planning. For example, the island of Maui has reached 75% system non-synchronous penetration (SNSP, non-synchronous IBR generation over total load) level [1], and Ireland system reported 65% SNSP level [2], both in 2019. A few system operators, such as Australian Energy Market Operator (AEMO) [3], National Grid ESO [4] and Hawaiian Electric [1], have set road maps of reaching 75% and 100% SNSP by 2025, respectively. With the trend of replacing conventional synchronous machines with non-synchronous IBRs, the power system will be dominated by fast-acting power-electronic inverters. The lack of physical inertia of these devices will lead to power systems behaving very differently compared to conventional grids. This can be particularly challenging when systems transition into high SNSP. It is the main reason that today's large islanded power systems require at least 25% of the load to be supplied by synchronous generators at any time, e.g. gas turbines, steam turbines, or diesel generators, as documented in studies for Hawai`i and Ireland [5], [6].

To solve the challenge of reaching up to 100% SNSP level, numerous recent studies and field tests have pointed to the importance of deploying grid-forming (GFM) inverters. As of today, most of the existing IBR generators are grid-following (GFL). These units are in sync with the grid frequency via phase-locked loop (PLL), and produce power following their set point references. GFL inverters alone, however, cannot guarantee stable operation of power system. For example, in 2018 the island of Kaua`i was able to run with 100% IBRs for 9 minutes before a complete blackout [7]. The problem lies in the lack of frequency reference and inertia when the system is operated at high SNSP level. GFM inverters bypass this problem by acting as a fixed voltage source and frequency reference [8]. The necessity of GFM inverters has been proven in both simulation studies, e.g. [9,10,11] and islanded field tests, e.g. Siemens' hybrid power plant on Galapagos Island [12]. Despite the inertia support provided by GFM inverters, the question remains open on how to operate a system with up to 100% IBRs stably with N-1 security. The challenge comes from the unpredictability of the most common renewable resources, which are wind and solar. The generation from these resources can change on a minute-to-minute and even more from hour-to-hour. As a result, the future mix of resources dispatched at any given time in power systems will change drastically in just a 24-hour period, as well as during longer periods. The changing dispatch scenarios drastically change the requirements for ensuring stability if the resources dispatched have significantly different disturbance response characteristics and capabilities. Therefore, traditional methods to perform stability analysis on boundary base cases no longer suffices, as the resource mix will now change so drastically that no single set of analyses could capture the absolute system need for all probable scenarios.

To address this challenge, in this paper we introduce a promising solution – an operator support system (OSS) developed from the U.S. DOE ARPE-E funded project *ReNew100*, led by Siemens with Hawaiian Electric Company (HECO), Pacific Northwestern National Laboratory (PNNL), and OPAL-RT as partners. The OSS leverages a real-time Dynamic Security Assessment (DSA) and Dynamic Performance Optimization (DPO) of all grid resources, including the new GFM IBR control capabilities, to ensure a stable system response for all N-1 contingencies, even in 100% SNSP (zero inertia) dispatch cases. As the first component of OSS, DSA analyzes the state estimate of the system on the fly and evaluates the system performance and stability towards N-1 contingencies. The DSA is realized by Siemens commercial solution SIGUARD®DSA in our OSS. In cases where the system does not pass the stability criterion, DSA will provide the operator with mitigations to improve system stability. This mitigation is provided by DPO optimizing the controller parameters of synchronous generators and IBRs to improve the stability of the system with the current dispatch towards all N-1 contingencies. The OSS is designed specifically to meet the needs of varying dispatch scenarios as it runs in the same time scale of state estimation from energy management system (EMS) to evaluate the system N-1 security on the fly, e.g. ever 5-15 minutes. In case any instability is identified, the DPO continuously adapts the controllers of both conventional generators and IBRs to increase power oscillation damping. The most important point is that the controller parameter tuning is done a priori, before any contingency occurs. Therefore, the system can achieve N-1 reliable system operation under varying combination of conventional and IBR generation without the need for reliable real-time communication.

The operator support system (OSS) is unique because it allows for the first time reliable power system operation with up to 100% IBRs by leveraging controller tuning of GFM inverters. Recent studies on Hawai`i by Electranix [13] confirms the risk of undamped oscillations and need for controller tuning in low-inertia systems. For example in [13], several contingencies show significant stability issues related to GFM controller tuning for relatively large projects. The effectiveness of the OSS and DPO is demonstrated in a real-time simulation of high-fidelity EMT models of Hawai`i Island system, where we verified that a system with 100% IBRs can be operated N-1 securely with the help of grid-forming inverters and the OSS. Moreover, the OSS has been verified for 28 critical N-1 contingencies identified by Hawaiian Electric, tested on total nine generation dispatch profiles, that correspond to 80%, 90% and 100% SNSP. In all of these cases, the OSS demonstrate significant stability improvement towards the critical N-1 contingencies. Offline verification results of the OSS have been previously reported in [14], [15]. In this paper, we show the online configuration and operation of the OSS, and demonstrate the online verification results of OSS based on the real-time simulation model of Hawai`i Island system. The results in this paper provide a promising solution for stable and N-1 secure system operation with high inverter-based renewable generation. This also shows how to transition existing power system into 100% SNSP level.

The rest of the paper is organized as follows. In Section 2 we describe the mechanism of the operator support system. Section 3 introduces the Dynamic Security Assessment through Siemens SIGUARD®DSA. Section 4 explains the algorithm of Dynamic Performance Optimization. In Section 5, we demonstrate the online operation of OSS based on real-time simulation of Hawai`i Island system. Section 6 concludes this paper, and provides some future directions.

2. OVERVIEW OF OPERATOR SUPPORT SYSTEM

Today, N-1 security is analyzed using simulation studies to analyze critical contingencies. If certain contingencies lead to large power oscillations or even blackouts, controller parameters are manually tuned to avoid this behavior. If this tuning is not enough, additional assets for grid stabilization are installed, such as power system stabilizers or synchronous condensers. This traditional, offline means of N-1 security assessment and dynamic performance optimization is feasible because traditional power systems are dominated by synchronous generators that run 24/7. Therefore, the power system dynamics remain relatively constant over days, weeks, months and even years. New, large power plants are only connected after extensive grid-extension studies show that N-1 security is still maintained with these new assets.

The increase in IBRs like wind turbines, solar power plants, battery storage and electric vehicle chargers leads to structurally different N-1 security challenges because the power system dynamics change fundamentally and become time-varying as the generation mix changes. The power system dynamics change fundamentally because the dynamics of power systems dominated by synchronous generators are primarily determined by the electro-mechanical properties of these generators – for example, their inertia and impedances, in conjunction with the power line and transformer impedances. As synchronous generators are replaced by power-electronic inverters, the dynamics of the resulting power system are determined by the software of the inverters – for example, the control structures and parameters for grid-forming and grid-following IBRs. Moreover, the dynamics become much faster because power electronic inverter controls respond much faster to voltage and current changes at their connection point compared to synchronous generator controls. The power system dynamics become time-varying because of the intermittent generation from renewable sources. Over the course of a day, the ratio of synchronous generator-based to inverter-based generation changes, as does the geographical location of online synchronous and inverter-based generation.

To solve these structurally different N-1 security challenges, we have developed an online operator support system (OSS) comprising dynamic security assessment and dynamic performance optimization to achieve N-1 security as the generation mix changes, as shown in Figure *1*. This OSS has been implemented and validated in a demonstrator consisting of a high-fidelity real-time simulation of the power system of Hawai'i Island in OPAL-RT eMEGASIM, the commercial Energy Management System (EMS) Spectrum Power™ 7, the commercial Dynamic Security Assessment tool SIGUARD®DSA, and a custom implementation of Dynamic Performance Optimization.

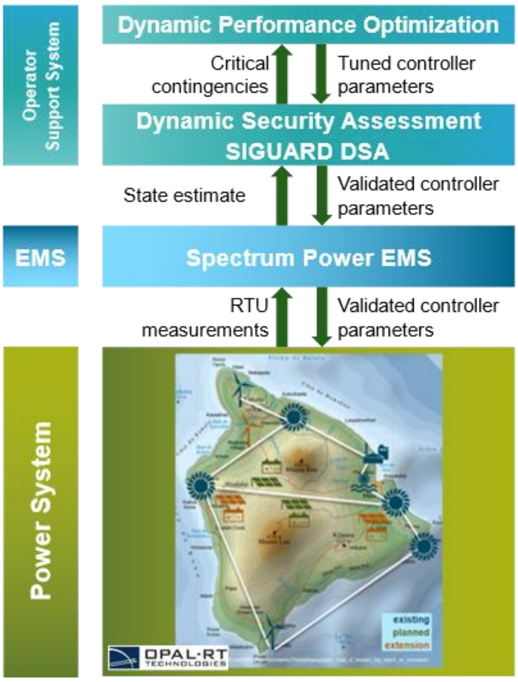

Figure 1 Architecture overview of operator support system.

The operation scheme of the OSS is shown in Figure 2. The OSS is built upon standard EMS functions for state estimation from RTU measurements. The OSS first utilizes the state estimate to identify critical contingencies using dynamic security assessment (DSA). This is achieved by fast parallel simulations of critical N-1 contingencies such as generator or power line outages, starting from the current system operating state. If the assessment finds that some contingencies lead to unacceptable power oscillations or even blackouts, Dynamic Performance Optimization is executed to tune the controller parameters of different generation assets such as IBRs and conventional power plants. We will explain this optimization in Section 4 in detail. The optimized parameters are then validated by re-executing the Dynamic Security Assessment. If this assessment is successful, the optimized and validated controller parameters are applied to the real system. It is important to note that the OSS is executed and the controller parameters are applied before any contingency happens. This ensures that the system withstands N-1 contingencies intrinsically – that is to say, without interaction with the control center or any function that would require real-time communication and decision making. This operator support system can be executed regularly – every 15 minutes, for example, or whenever there is a major change in the power system dynamics, for instance, because of a major change in the generation dispatch.

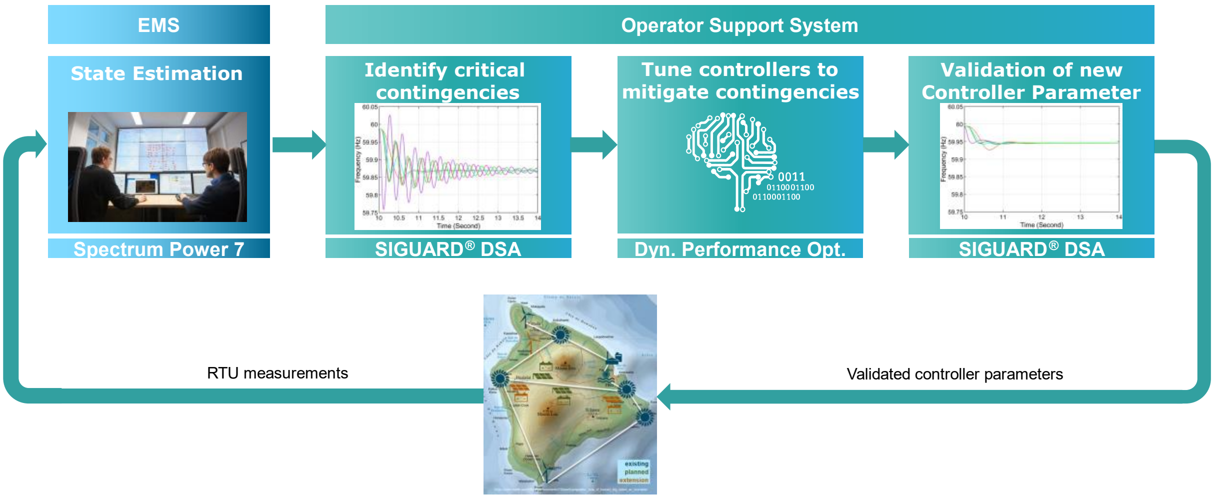

Figure 2 Operation scheme for dynamic N-1 security assessment and dynamic performance optimization.

3. DYNAMIC SECURITY ASSESSMENT

The dynamic security assessment solution used in this project is the commercially available SIGUARD®DSA from Siemens. This tool uses the widely known grid simulation software PSS®E and PSS®SINCAL as simulation engines. Unlike these grid simulation software, SIGUARD®DSA is not a simple desktop application, but is instead designed as a solution that can be deployed inside the critical infrastructure of an energy management system. It focuses on the operator's daily work and aims at assisting the operator instead of just showing simulation results.

The principle, however, is very straightforward. The DSA performs a contingency analysis based on the current or forecasted power system states. The current state comes from the state estimator running in the SCADA/EMS system. The contingencies can be single events, such as outages, or more complex sequences of events, such as a short circuit and its clearing followed by the outage of a power system element. The results of the simulations, which contains voltage and frequency responses at each bus, are evaluated over different voltage and frequency performance metrics defined by the user/operator. The performance metrics we use for N-1 security analysis in OSS are summarized in Tableau *1*. Afterwards, the performance metrics are aggregated so that in the end, one number between 0 and 1 indicates the power system criticality. The visualization is similar to a traffic light, as shown in **Error! Reference source not found.**. This way, the operator can easily perceive whether an action is required or not.

Tableau 1 Performance metrics of N-1 security analysis used for OSS

Maximum frequency deviation index (MFDI):	Frequency deviation at the end of an N-1 contingency simulation, compared to defined maximum deviation.
Frequency recovery time index (FRTI):	Recovery time for frequency oscillation after an N-1 contingency to settle within the dead band, compared to defined time limit.
Frequency gradient index (FGI):	Maximum frequency rate-of-change after an N-1 contingency, compared to defined maximum gradient limit.
Quasi-stationary voltage index (QSVI):	Voltage deviation at the end of an N-1 contingency simulation, compared to defined maximum deviation.

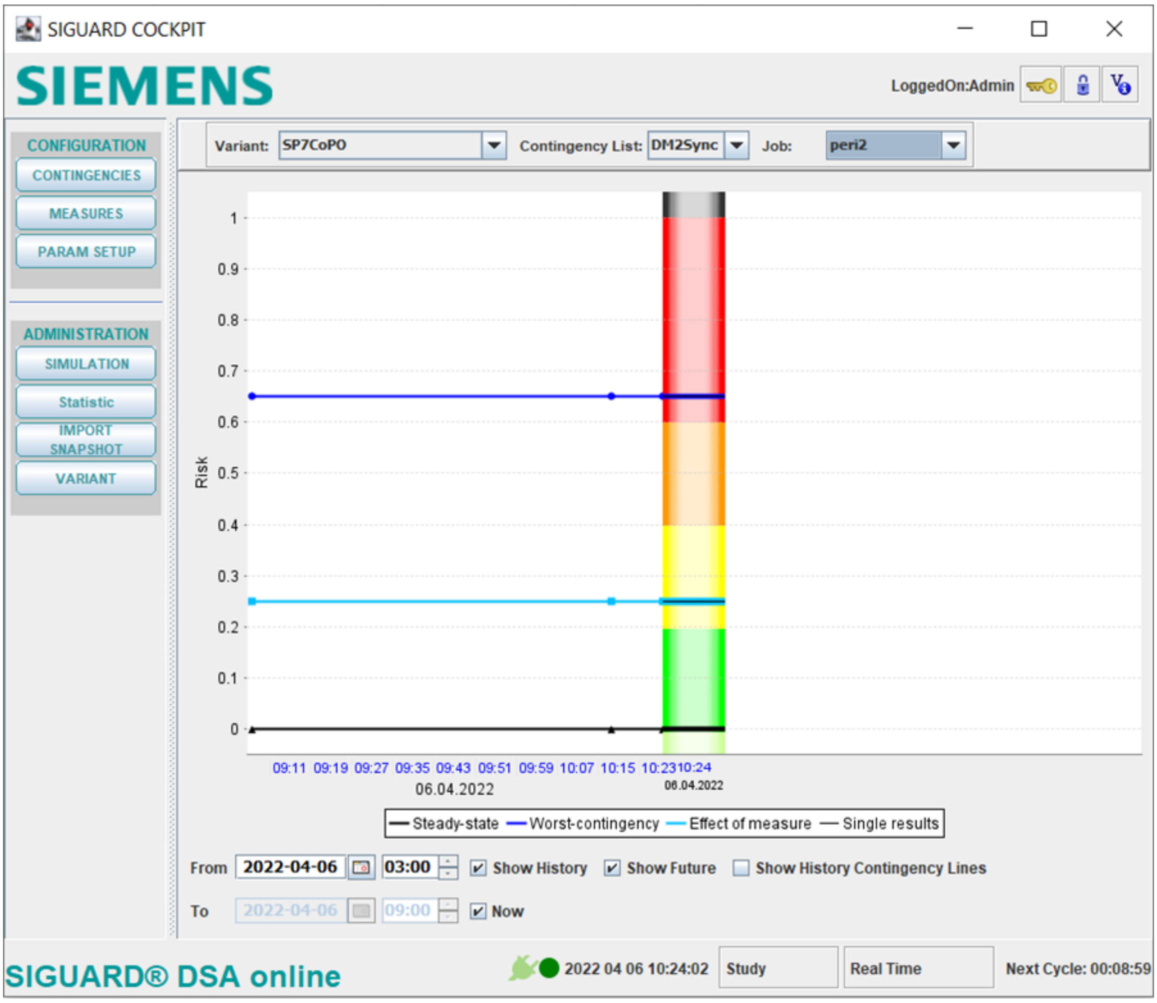

Figure 3 Screenshot of SIGUARD®DSA showing the improvement of N-1 security by means of the suggested measures (light blue curve compared to dark blue curve).

The Dynamic Security Assessment describes the situational awareness part of the operator support system. The operator knows the system might face stability problems if any critical contingency actually occurs. The facet that turns such an application into an assistance system is the fact that it automatically processes possible remedial actions and informs the operator whether the actions would relieve the power system, for example the light blue curve in Figure 3. Remedial actions can be any kind of action that the operator could take either prior to or after a dangerous event, such as topological changes or changes in setpoints of compensation or generation assets. The range of actions also includes activation or deactivation of automatic actions schemes, such as Dynamic Performance Optimization or other wide area control and protection schemes.

Various international research projects and initiatives like MIGRATE [16], UK Stability Pathfinder [17], Dynamic Grid Control Center [18], and ReNew100 [19] have shown dynamic security assessment to be a crucial part of the operational planning process for electrical power systems with an increasing share of renewable energies. The increasing number of possible operator actions drastically increases the degree of complexity. Remedial action schemes are sometimes the only way to keep systems stable. Therefore, it is very important to establish the dynamic security assessment as part of the operational planning process (day ahead, intraday and real-time). However, to accomplish this, this process needs to start during the planning process itself. Remedial action schemes like Dynamic Performance Optimization are, in the end, nothing more than controller logics that have an impact on the dynamic behavior of the power system, similar to the control system of a synchronous generator. Hence, the models of such automatic systems must be seamlessly transferrable from network planning to operational planning. The SIGUARD®DSA ensures seamless transition from planning to operation because it uses the planning simulation engines and models and embeds them in the operational environment.

4. DYNAMIC PERFORMANCE OPTIMIZATION

SIGUARD®DSA is used to identify critical contingencies and provides several ways of computing and evaluating measures to improve the dynamic security of a power system. A very new Dynamic Performance Optimization (DPO) method to increase power oscillation damping is online controller parameter optimization. As described above, the transition from SG-dominated to IBR-dominated power systems also leads to much more volatile power system dynamics that heavily depend on the controller parameters in the inverters. Hence, the best way to damp power oscillations between IBRs is to tune their controller parameters. The DPO has been introduced in [20,21,22]. We describe this algorithm as follows.
It is worth mentioning that the EMT model of Hawai`i system is simulated in OPAL-RT to demonstrate the OSS. The methodology developed for DPO, however, is based on RMS linearized model of the power system so that system operators can easily adopt the DPO based on their existing RMS models. In Section 5, the OSS demonstration uses EMT models to validate the optimization results of DPO based on linear RMS models. This analysis shows that the optimization with RMS models is successful. Expanding DPO to optimize EMT models is also possible, and is an ongoing work. Consider a power system supplied only by n synchronous and IBR generators, the nonlinear representation of the system follows

$$\dot{x} = f(x, d, \boldsymbol{K}) \tag{1}$$

$$0 = h(x, d, \boldsymbol{K}) \tag{2}$$

where $x \in \mathbb{R}^N$ contains states of all n generators, $\boldsymbol{K}$ is the vector of tunable parameters of all generators, function f represents the dynamics of the generators, h represents the algebraic power flow equations, and $d = [d_1, \dots, d_n]^T \in \mathbb{R}^m$ is the disturbance input into the system, where d_i, $i = 1, \dots, m$ represents drop out of a single component in the system, namely the N-1 contingency. The goal of DPO is to optimize the controller parameters in $\boldsymbol{K}$ to increase the stability margin and power oscillation damping of the system against the disturbance input d. The controller parameters in $\boldsymbol{K}$ may contain gains and filter constants for various controllers of conventional generators such as exciter, governor and Power System Stabilizers (PSS), and droops gains and time constants for primary control or secondary control of IBR generators. We show examples of tunable parameters in standard PSS1A model and one grid-forming control structure in Figure *4* and Figure *5* in red, respectively. In general, there are no restrictions in designating parameters into $\boldsymbol{K}$, and the system operator has the freedom to choose any controller parameters available and tunable in the system up for optimization.

Figure 4 Overview of power system stabilizer model PSS1A with tunable parameters highlighted in red

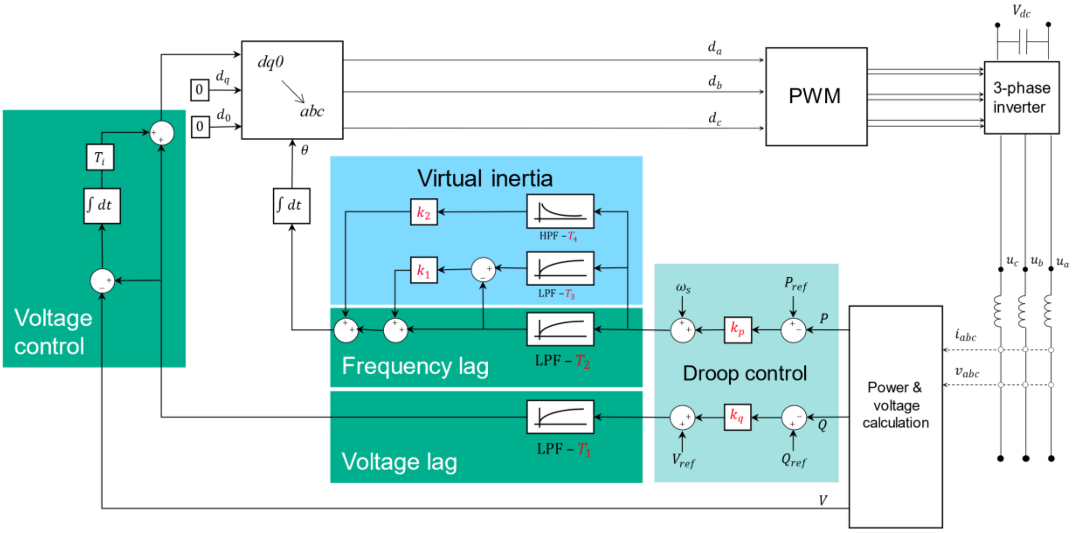

Figure 5 Example control structure for grid-forming inverter model with tuneable parameters highlighted in red

Recall that the DSA results contain critical N-1 contingencies and system state. In this sense, the disturbance input d represents these N-1 contingencies received from DSA. The system state contains the operating point x_0 of the system. With these information, system (1-2) is linearized around steady state operating point x_0 at $t = t_0$. Linearization of conventional power system modules along with synchronous machines follows standard models described in [23]. We refer interested readers to [20,21] and references therein for linearization of GFM and GFL inverter models. The linearized models of system (1-2) with respect to m contingencies can be written as

$$\dot{x} = A_i(\boldsymbol{K}) + B_i(\boldsymbol{K})d \tag{3}$$

$$y = C_i x \tag{4}$$

for $i = 1, \dots, m$. Equation (3) describes the dynamics of all generator states, where matrices A_i and B_i are parameterized by vector $\boldsymbol{K}$. In (4), a performance output y is defined to extract the angular frequencies at each generator, i.e.

$$y = [\omega_1 \quad \cdots \quad \omega_n]^T. \tag{5}$$

This output will be used in the optimization to minimize the frequency oscillations, and thus to suppress the active power oscillations in the system. The transfer function matrix from d to y can be written as

$$G_i(s, \boldsymbol{K}) = C_i[sI - A_i(\boldsymbol{K})]^{-1}B_i(\boldsymbol{K}) \tag{6}$$

for $i = 1, \ldots, m$. For ease of notation, we omit the dependency of $G_i(s)$ over $\boldsymbol{K}$, and for the rest of this paper $G_i(s)$ is always a function of $\boldsymbol{K}$. In this notation, the $\mathcal{H}_\infty$ norm of a stable transfer function $G_i(s)$ is defined as

$$\|G_i(s)\|_{\mathcal{H}_\infty} = \sup_{\omega \in \mathbb{R}} \bar{\sigma}[G_i(j\omega)] \tag{7}$$

where $\mathbb{R}$ denotes the set of real numbers, and $\bar{\sigma}$ denotes the largest singular value of a matrix. The $\mathcal{H}_\infty$ norm is chosen because it represents the maximal amplification of the amplitude of any harmonic input signal in any output direction. Thus, minimizing the $\mathcal{H}_\infty$ norm minimizes the worst-case amplification of oscillation frequencies, and system robustness can be improved as a result. Given this rationale, the DPO can be formulated as an $\mathcal{H}_\infty$ optimization problem

$$\begin{aligned} \min_{\boldsymbol{K}} \quad & \|[G_1(\boldsymbol{K}), \ldots, G_m(\boldsymbol{K})]\|_{\mathcal{H}_\infty} \\ \text{s.t.} \quad & G(K) = [G_1(K), \ldots, G_m(K)] \text{ is stable} \\ & \underline{K} \leq \boldsymbol{K} \leq \overline{K} \end{aligned} \tag{8}$$

where vectors $\underline{K}$ and $\overline{K}$ respectively contain lower and upper limits for the tunable parameters. Hence, optimization (8) tries to find the controller parameters of $\boldsymbol{K}$ within limits that maintain the stability of the system while suppressing the frequency oscillations that is represented by the $\mathcal{H}_\infty$ norm. Interested readers can refer to [24] for a more detailed discussion of $\mathcal{H}_\infty$ optimization. The optimization (8) can be solved by an iterative algorithm, we refer the readers to [13] for the detailed discussion.

5. DEMONSTRATION FOR THE HAWAI`I SYSTEM

We validated the OSS in a virtual operational environment representing Hawai'i Island. To do this, we developed a high-fidelity real-time EMT simulation of the power system of Hawai`i Island in OPAL-RT based on HECO's PSS®E model for power system planning. We extended this model with additional IBRs (see Figure 6 left) to achieve up to 100% inverter-based generation for nine different scenarios based on different demands at noon, in the evening and at night, as well as different IBR percentages ranging from 80% to 100% (see Figure 6 right). Today's baseline is around 60% inverter-based peak generation.

Generation	Capacity
Wind	50MW
Centr. PV	120MW
Distrib. PV	110MW
Centr. ESS	120MW
Distrib. ESS	40MW
Synchr. Renew.	90MW
Conventional	160MW

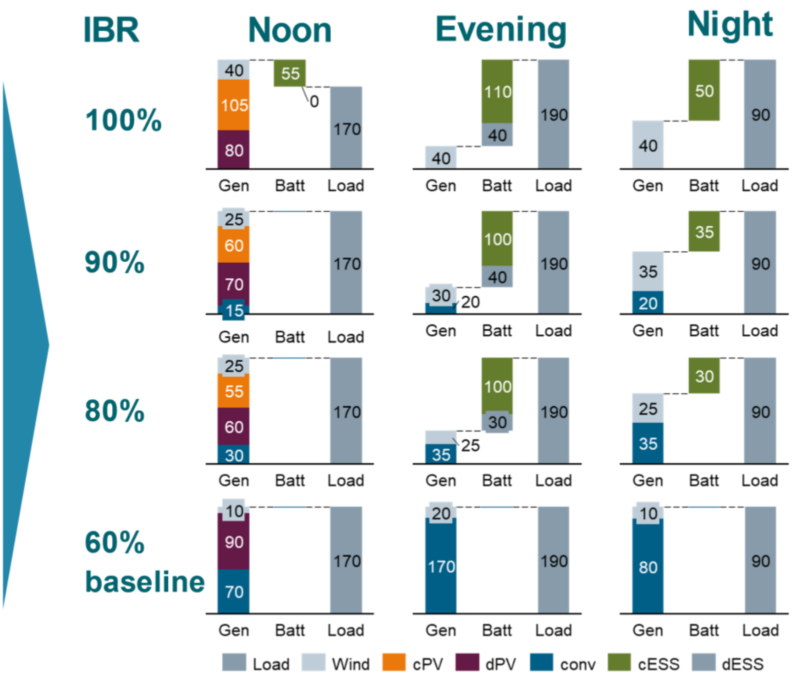

Figure 6 Overview of the considered generation capacity and dispatch for all nine scenarios (in MW) with centralized PV (cPV), distributed PV (dPV), centralized Energy System Storage (cESS), distributed Energy System Storage (dESS), and conventional generation

For each of these nine scenarios, we considered up to five different N-1 contingencies: (1) loss of largest synchronous unit, (2) loss of most critical power line, (3) loss of one GFM Energy Storage System (ESS), (4) loss of one utility-scale PV plant and (5) loss of 50% of distributed PV. These cases are the critical N-1 contingencies identified from practical operation of Hawai`i island system. The last case is particularly challenging because the distributed solar covers almost 50% of the load at noon.

We validate the OSS in an online setup. As previously shown in Figure 2, for each of the nine dispatch scenarios, we start by running their EMT model for real-time simulation in OPAL-RT. The RTU measurements are sent to Spectrum Power 7 EMS through DNP3 communication. The state estimation is executed every 1 minute, and its result is sent to SIGUARD®DSA server every 1 minute through standard CIM format. The OSS is configured to run every 15 minutes using the most update state estimate solution. The optimized controller parameters from OSS are verified in OPAL-RT real-time simulation against the corresponding contingencies.

Figure 7 and Figure 8 shows the online validation results of the OSS. Figure 7 summarizes the screenshot of SIGUARD®DSA illustrating the dynamic security assessment results before (left column of the chart graph) and after (right column of the chart graph) the Dynamic Performance Optimization (DPO) for each N-1 contingency (each row of the chart graph). Darker color indicates worse stability performance, ranked from black, red, orange, yellow to green. In all the nine scenarios, the DPO significantly improves the stability performance of the system towards the critical N-1 contingencies. The only exception is in day minimum 100% SNSP case, the DPO turns the stability evaluation of a line loss from green to orange. This is mainly due to a slightly lower voltage at the bus connected to the line loss. This deteriorates the overall stability score after DPO. The performance of all frequency metrics, however, are significantly improved, in consistency to other cases. Figure 8 shows the comparison between frequency responses at the terminal bus of one centralized battery system from the real-time simulation in OPAL-RT for some selected N-1 contingencies. Frequency oscillations are shown here because they are easier to show with high zoom-in for multiple plants compared to the corresponding active power oscillations. In today's power systems, these frequency oscillations are accompanied by significant active power oscillations between generation units. For each of the nine scenarios, we show one example contingency and compare the oscillations with and without Dynamic Performance Optimization (DPO). Without optimization, many of the contingencies lead to significant oscillations. In all cases, the optimization significantly reduced the oscillations between generation units. This demonstrates the effectiveness of the controller tuning in improving N-1 security in IBR-dominated power systems.

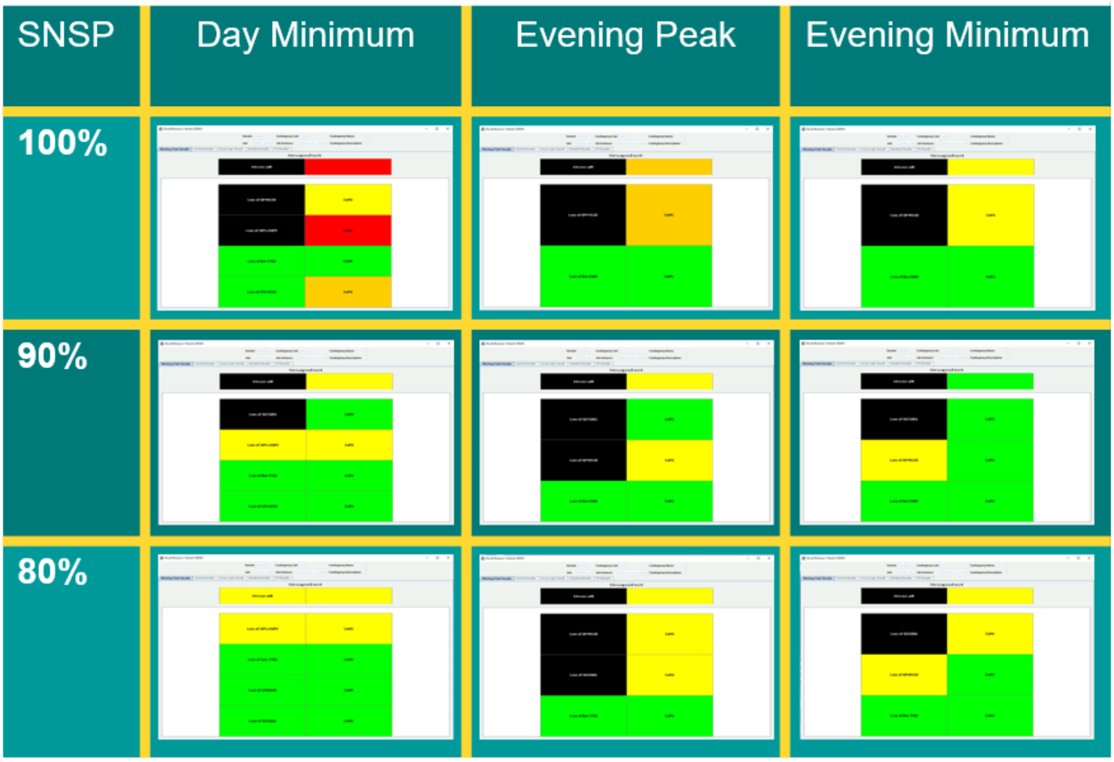

Figure 7 Online validation results of the Operator Support System: the dynamic security assessment results from SIGUARD®DSA show the stability performance for different N-1 contingencies before (left) and after (right) Dynamic Performance Optimization (DPO).

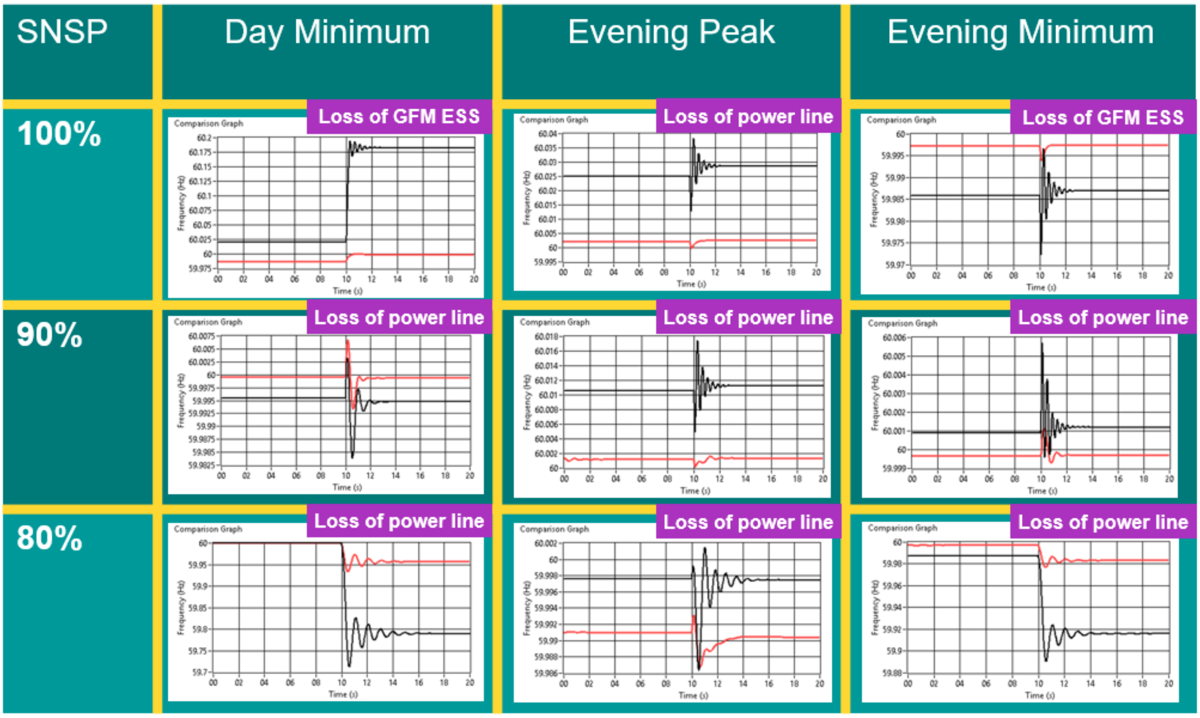

Figure 8 Online validation results of the Operator Support System: the online results from OPAL-RT show the frequency responses at the terminal bus of one centralized battery system after an N-1 contingency with (red) and without (black) Dynamic Performance Optimization (DPO).

6. CONCLUSIONS

An exponential increase in inverter-based renewable resources such as wind and solar is imperative to reduce climate change. To support this transition, power system operators must solve multiple challenges, including operational N-1 security to avoid blackouts. We have shown that our proposed operator support system can solve these operational N-1 security challenges in a virtual operational environment representing Hawai’i Island with 100% inverter-based generation. Next, we want to solve the implementation challenges outlined above and proceed with a large-scale field test.

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