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Reliability Impacts of Behind the Meter Distributed Energy Resources on Transmission Operations

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SUMMARY

The increasing amounts of customer-owned Distributed Energy Resources (DERs) limit the control and visibility of local Independent System Operators (ISOs) and utility operators. Most of these resources are non-curtailable and subject to several aggregation guidelines for wholesale participation. These units cannot be decoupled from the Transmission-Distribution (T-D) interface and have a direct impact on the economics and reliability of the grid. This paper reports the results of a study that investigated realistic dispatch conditions from a production and power flow co-simulation environment with increased behind-the-meter DER resources. The objectives of this study include: 1) understanding steady-state and transient voltage response of the system at the local T-D interface, 2) analyzing impacts on switching operations, 3) studying the system-wide frequency response of the Western Interconnection, and 4) examining scenarios that provide insight into the type of control strategies that best benefit local ISO and utility operations from a reliability perspective.

KEYWORDS

Distributed energy resources, frequency response, production simulation, power flow simulations, curtailments.

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1. INTRODUCTION

The recent advancements in technology and policies have driven the growth of Distributed Energy Resource (DER) into the grid. Several states, including California and New York, have established Renewable Portfolio Standards (RPSs), which would require close to 50% of their energy procurement to come directly from renewable resources by the year 2030. Over time, these targets have become more aggressive, resulting in 100% by the year 2045 [1].

Several potential impacts have been identified by industry and academic researchers that demonstrate the economic and operational impacts of these resources. The key challenges associated with DERs are directly attributed to their operating characteristics. This is coupled with state and federal policies driving the retirement of coal and nuclear plants [2]. The existing fleet of generation would likely need to operate at lower minimum levels if not already uncommitted. For example, there is an increased likelihood of over-generation resulting in reverse power flows at the Transmission-Distribution (T-D) interface, resulting in protection equipment failures. The displacement of large-scale units can severely impact the system-wide frequency response and NERC BAL-003 requirements [3]. The off-peak hours (particularly, high ramping) can result in voltage issues that arise from the offset of generation and load balance. Similarly, there can be scenarios of excessive shunt-capacitor and transformer-tap switching necessary to maintain scheduled voltages at the T-D interfaces [4]. The focus of this paper is on the operational reliability impacts of these resources directly associated with local and system-wide reliability.

DERs are currently divided into three categories, customer-owned/Behind-the-Meter DER (BTM-DER), Merchant DER, and microgrids. Among the three, most Independent System Operators (ISOs) have control over their merchant DERs, which are typically larger units that can be curtailed as per the ISO request. However, BTM units are not within the full visibility of ISO operations. Without visibility to these resources, ISO's cannot include them in the state RPS targets as firm procurements, even though they can impact the transmission grid more indirectly through the T-D interface.

Currently, these BTM-DERs are modified as a load modifier. BTM and Net Energy Metering (NEM) mask the generation within the available load schedule. However, for accurate modeling, it is imperative to distinguish load from generation and establish differentiated load and generation data. This level of accuracy should be included within the market assessment tools and the power-flow-based tools. In order to capture their response in power-flow studies during fault and outage conditions, it is essential to establish dynamic models as well.

While several studies have been performed highlighting the impacts of DER penetration into the grid [4–11], no study has analyzed the operational visibility considerations as they impact market and reliability aspects of the power system directly at the T-D interface. The thin line between controllable and non-controllable resources can have several implications on system operations. The objective of this study is to highlight some of the key aspects of DER penetration into the grid using the state of California as an example. The study will account for the larger merchant DER (controllable) and BTM-DER (non-controllable) to better capture all aspects of DER operations. A coupled market and power-flow simulation has been used to study this in detail; however, the focus of this paper will remain on the power-flow implications of the problem.

2. MODELING, ASSUMPTIONS AND STUDY METHODOLOGY

2.1. Scenario Description

To study reliability impacts at the T-D interface, two scenarios are considered. The non-participating scenario, herein referred to as Scenario 1, represents current market operations where distribution-connected renewables deliver only active power. These units are non-curtailable, do not provide reactive power support or any form of frequency support, nor are they equipped with intelligent protection or ride-through settings.

The participating scenario, herein referred to as Scenario 2, considers a model where BTM units can contribute to reactive power support and frequency regulation within the rated capabilities. The model further includes ride-through settings and additional protection configurations for these units. These models also include latch/trip ranges for frequency and voltage response. Further, they represent a future market model evolution to be considered, where the ISO has control over the distribution-connected resources as well, either in the form of generation resources(energy) or ancillary services.

2.2. Modeling, Assumptions, and Study Methodology

Production simulations were performed using ABB's GridView software tool. The 2024 Transmission Expansion Planning Policy Committee (TEPPC) base cases were used, which included the most current statewide RPS requirements within the Western Electricity Coordinating Council (WECC). The objective was to mimic market operations and identify the worst-operating days and hours for the local ISO. These days were evaluated in further detail using power-flow and dynamic-transient simulations.

The DER penetration levels considered in this study are based on the published California Energy Commission (CEC) forecasts for self-generation in the year 2024 [12]. Detailed models were built, and the DER forecast was implemented at distribution and sub-transmission networks. Equivalent impedances were calculated to represent the distribution network model within commercially available transmission planning and market operational tools like GE Positive Sequence Load Flow (PSLF) [13] and ABB GridView [14]. With the models that were built for Scenario 1 and Scenario 2 conditions, studies were conducted at 100 and 200% CEC renewable penetration levels.

Within the production simulation, a detailed representation of the BTM-DER generation was modeled. The representation is highlighted by Fig. 1 below. To enable market participation, they were modeled as aggregations for each local utility within the state and assigned participation factors. A similar model was built out in the power-flow cases as well.

- The BTM- DER was modeled at several buses ranging from 4.7 kV to 230 kV and includes PV(residential) and non-PV (commercial generation) units. Based on the CEC forecast, the total generation added was 4,000 MW, which includes 2,100 MW of PV and 1,900 MW of non-PV generation for the 100% penetration scenario. For the 200% penetration scenario, the total generation added was 8,000 MW, which includes 6,100 MW of PV and 1,900 MW of non-PV generation. Under the assumption that load is being offset by a proportional increase in self-generation, a total of 4,000 MW of load was added at the locations (similar to the additional self-generation units added). For accuracy, loads and generations were modeled separately. The same load was assumed for both 100 and 200% scenarios.

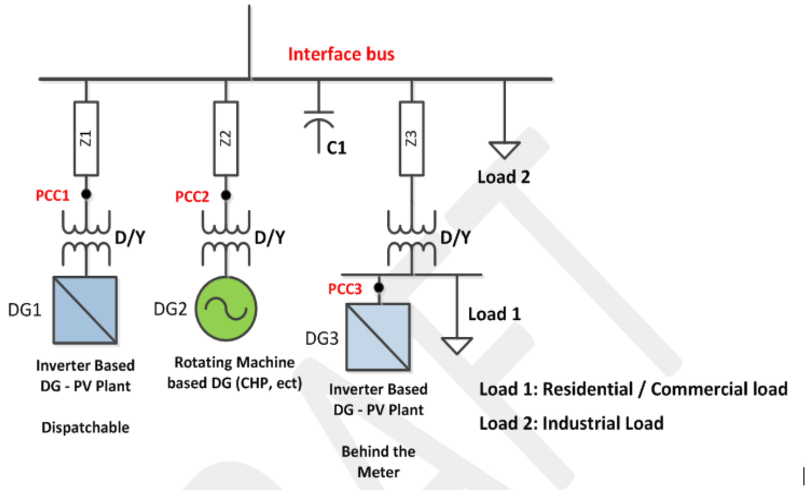

Fig. 1. BTM-Distributed Generation (DG) model for power flow and production simulation.

- PV and non-PV generation was interconnected at appropriate voltage levels through equivalent impedances and the DG interconnection transformer. The equivalent impedances represent the aggregate value of distribution and/or sub-transmission lines, as well as substation transformer impedances, as obtained from the short-circuit capacity of the system.

- Generation and load dispatches from production simulation were imported into multiple power-flow cases to analyze the 100 and 200% penetration levels. In this paper, spring off-peak conditions for 11 AM and 8 PM are considered. Operationally, these were identified as the most critical hours of the day.
- For dynamic simulations, “PVD1” model were used for the BTM generation. In Scenario 1, active power control is a priority and no reactive power support capability is associated with these units; in Scenario 2 simulations, the PF flag is set to 0, wherein reactive power control is a priority and reactive power support is provided by these units. Further, Scenario 1 did not include low/high voltage ride-through and frequency ride-through protection considerations. All loads were replaced with the WECC composite load model.
- The CEC generation non-PV units represent typical synchronous machine for combined heat and power (CHP) units. In the dynamic model the unit is represented by a GENROU model with an Exciter (EXST1), governor (GGOV1) and power system stabilizer (PSS1D). All protection considerations are applied to these units.

3. POWER FLOW STUDY

The local-area power flow study was conducted to analyze the impact of DER penetration on voltages. The larger penetration of DER can result in overvoltages, larger transformer tap swings, lower voltages during off-peak conditions with larger imbalance (generation vs load), while making the system more sensitive to critical contingencies.

3.1. Steady State Assessment

The region-wide voltage study was used to assess the impact of contingencies on voltages at all buses in the ISO region of 100 kV and above. The steady-state assessment was performed in adherence to WECC and regional ISO planning standards [15]. PSLF simulation environment was used for this study.

Results from the 100 and 200% penetration studies were analyzed for both Scenarios 1 and 2. Two different hours of the day were considered (11 AM and 8 PM). Several comparisons were drawn between these operating conditions that provide insight into the operation of the system:

1. Excessive capacitor-bank switching was observed in Scenario 1, without voltage control from local DER. Further, there were a total of 125 tap-changing operations recorded while moving from 11 AM to 8 PM on the same day (2.48% of tap-up and 6.875% of tap-down operation).
2. In Scenario 1 under 200% CEC penetration, there were reduced tap-down operations between 11 AM to 8 PM of the operating day but an increased percentage of tap-up operations. Several capacitor banks were at peak capacity by 8 PM in this operating scenario.
3. In Scenario 1, under 100 and 200% penetration, several undervoltages were observed in the system, with the lowest being 0.92 pu. Additional support from compensation devices is critical to prevent voltage from being significantly suppressed.
4. In Scenario 2, under 100 and 200% penetration, reduced undervoltages were observed in the system. Between the two cases, the lowest voltage recorded was 0.94 p.u..
5. Post-contingency responses were observed between both scenarios, and no delta V deviations of greater than 8% were recorded. Several high voltages were recorded throughout the system, with the highest being 1.11 p.u. at the 115-kV network.
6. Interestingly in both scenarios, while moving from 11 AM to 8 PM, larger tap-down operations were recorded in the 100% scenario than in the 200% scenario. The 200% scenario reported reduced transformer tap-change operations overall.
7. Table 1 presents a high-level overview of the highest and lowest voltages recorded for both scenarios at a sample substation in the PG&E operating area. The results at the T-D interface demonstrate that larger deviations are observable under Scenario 1 and at 8 PM. The results

indicated that the 230-kV T-D interface interconnections are less impacted by voltage deviations than the 115-kV network.

Table 1: Pre and post contingency voltage deviations at T-D interfaces

Pre- and Post-Voltage Deviations @ San Ramon 230 kV substation			200% - Scenario 1			200% - Scenario 2		
			11 AM	**8 PM**	**Δ V**	**11 AM**	**8 PM**	**Δ V**
Pre-Cont.	**Base Case**		1.021	1.012	0.01	1.015	1.012	0.003
Post-Cont.	**C2_8**		1.008	0.989	0.019	0.993	0.993	0
		Δ V	**0.013**	**0.023**		**0.022**	**0.019**	
Post-Cont.	**C2-11**		1.015	0.99	0.025	0.993	0.993	0
		Δ V	**0.006**	**0.022**		**0.022**	**0.019**	

Pre and Post Voltage Deviations@ 115 kV substation			100% - Scenario 1			100% - Scenario 2		
			11 AM	**8 PM**	**Δ V**	**11 AM**	**8 PM**	**Δ V**
Pre-Cont.	**Base Case**		1.053	1.033	0.01	1.04	1.029	0.011
Post-Cont.	**SL-10117**		1.038	1.018	0.02	1.026	1.024	0.002
		Δ V	**0.015**	**0.015**		**0.014**	**0.005**	
Post-Cont.	**SL-10235**		1.041	1.021	0.02	1.028	1.027	0.001
		Δ V	**0.012**	**0.012**		**0.012**	**0.002**	

4. TRANSIENT DYNAMIC SIMULATIONS

To perform dynamic simulations, a three-phase-to-ground bolted fault was applied at the remote bus, followed by an immediate line loss connecting the remote bus to the T-D interface. The logic behind using a remote bus was to examine the behavior of PV units in scenarios where their tripping is not always certain. Further, if a three-phase fault was applied at the T-D interface directly, there is certainty that the PV unit will trip, not providing much ground to explore the exact transient response from these units. The fault was applied at 0.1 seconds in all simulations and cleared in 6 cycles. Composite load models were evaluated in detail.

In order to evaluate the transient voltage response at the T-D interface, two substations are presented below. For, the San Ramon 230-kV T-D interface, a fault was applied at Moraga 230-kV bus, and the line was cleared after 6 cycles. An average reduction of 2-MW output was observed at all loads in the composite load model for the 11 AM case, and a reduction of 1-MW output observed at all loads in the composite load model for the 8 PM case for Scenario 1 with 200% injection. It was observed that the bus voltage settles down at the nominal value after the fault is cleared and no PV-unit trip was recorded. The behavior of the composite load for 200% penetration at San Ramon is presented in Fig. 2.

The voltage overshoot post-fault clearing was more pronounced at 11 AM than 8 PM in both scenarios. Interaction from neighboring PV units in the system also contribute to the post-fault clearing voltage overshoot. This is presented in Fig. 3.

Table 2 summarizes the results obtained from the studies in Scenario 1. It includes the MW generation tripped from the PV unit and the cause for tripping. “N/A” indicates scenarios where no PV-unit trip was recorded.

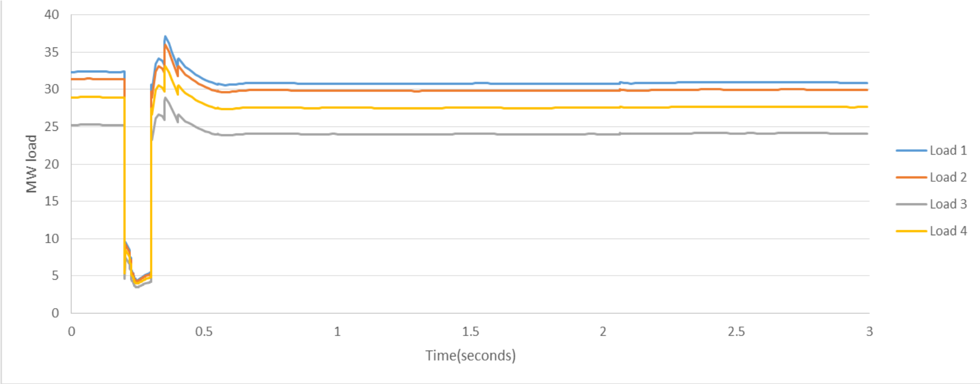

Fig. 2. Composite load model at San Ramon T-D interface - 200%, Scenario 1.

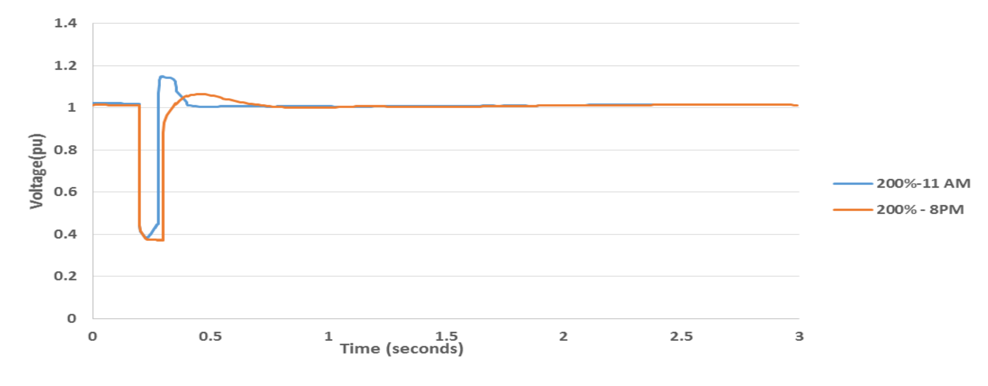

Fig. 3. Voltages at T-D interface, 11 AM and 8 PM.

Table 2: Select T-D interfaces and cause for PV trip in Scenarios 1 & 2

Bus Name	Scenario	Scenario 1		Scenario 2	
		Generation tripped (MW)	**Load Tripped (MW)**	**Generation tripped (MW)**	**Load Tripped (MW)**
San Ramon	200% - 11AM	40	8	N/A	4
Huron	200% - 11AM	20 (Frequency)	2	N/A	2
San Ramon	100% - 11AM	N/A	13	N/A	8
Huron	100% - 11AM	35	7	10	5

In Scenario 2, the CEC generator models were equipped with reactive power capability. Low/High voltage/frequency ride through configurations were implemented based on distribution consensus standards. In this scenario, the number of PV units tripped was less than for Scenario 1. This can be observed in Table 2.

The following observations can be made from the system-wide voltage study and local T-D interface study.

- It was observed from dynamic simulations that the composite load models recorded a maximum of 10-MW reduction post-fault clearing.
- PV DG tripping recorded due to frequency and voltage swings are more significant in the sub-transmission network.
- In Scenario 2, voltages at the T-D interface buses are supported by reactive power contribution from PV and non-PV units. Since no low-voltage/high-voltage scenarios were encountered at the interface bus in the base case, most of the Q variations in these units were observed in response to fault conditions.

The plots in Fig. 4 demonstrate the dependence of frequency on the MW output of the power-flow model under Scenario 2. Faults near and downstream from the 115kV network reduce the plant output significantly until the frequency recovers. Under Scenario 1, the tripping of several PV units was observed throughout the region. Most of the trips were in response to frequency swings measured at the bus.

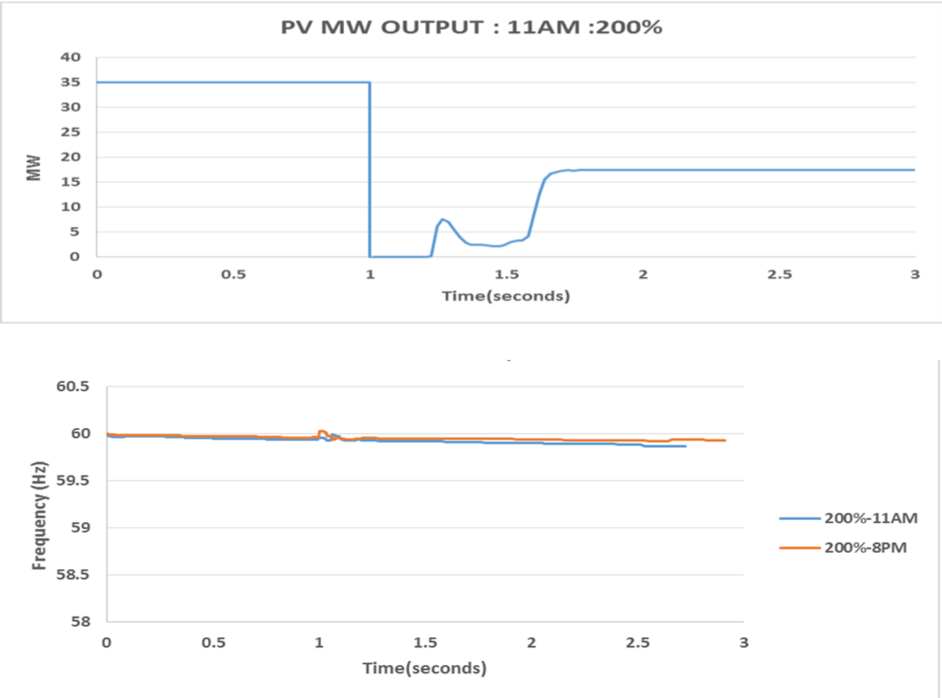

Fig. 4. PV plant output and frequency at T-D interface bus (Huron)

5. SYSTEM WIDE FREQUENCY RESPONSE STUDY

Frequency response has recently gained a lot of attention across the Western Interconnection. The purpose of this study is to investigate the frequency performance of the California region in response to events of sudden generation loss , particularly those targeted by NERC standard BAL–003 under near-future conditions with high levels of renewable generation. This study addresses the overall frequency response of the Western Grid, with special attention to the response within the local California region. Some of the major system impacts resulting from increased renewable generation include lower system inertia and displacement of primary frequency control reserves [16].

The objective was to capture the frequency response of the entire WECC system and California Independent System Operator (CAISO) region for the Palo Verde double outage; simulation was performed for 60 seconds. The original production simulation results were used to create the seed case – herein referred to as Case 1.

A more conservative scenario was developed from Case 1 using reduced headroom in the WECC and CAISO regions – herein referred to as Case 2. The frequency performance metrics for the two cases are tabulated in Table 3. The frequency at the Round Mountain 500-kV facility is shown in Figs. 5 and 6 for Case 1 and Case 2, respectively, under Scenario 1. For Scenario 2, with the cases in the study having the same headroom as shown in Table 4, it was observed that the results obtained are comparable to the results obtained in Scenario 1 and were not reproduced.

From the performance metrics, it was observed that the frequency performance within WECC for Scenario 1 and Scenario 2 was acceptable. WECC system response slightly reduced in Scenario 2. However, for the CAISO the response improved. This is due the marginal differences between dispatches in Scenario 1 and Scenario 2. This response could also be attributed to a large PV unit's frequency self-resettling capability and wider frequency range for Scenario 2.

Table 3: Frequency performance metrics

	Case 1			
	Scenario 1		Scenario 2	
	WECC	CA	WECC	CA
Frequency Nadir (Hz)	59.685	59.68	59.691	59.691
Frequency Nadir time (seconds)	6.94	6.79	6.88	6.8
Settling Frequency (Hz)	59.83	59.83	59.836	59.836
Frequency Response (MW/0.1Hz)	2236	269	2210	278
	Case 2			
	Scenario 1		**Scenario 2**	
	WECC	**CA**	**WECC**	**CA**
Frequency Nadir (Hz)	59.54	59.54	59.56	59.55
Frequency Nadir time (seconds)	9.22	9.12	9.18	9.1
Settling Frequency (Hz)	59.751	59.751	59.758	59.758
Frequency Response (MW/0.1Hz)	1324	168	1320	170.9

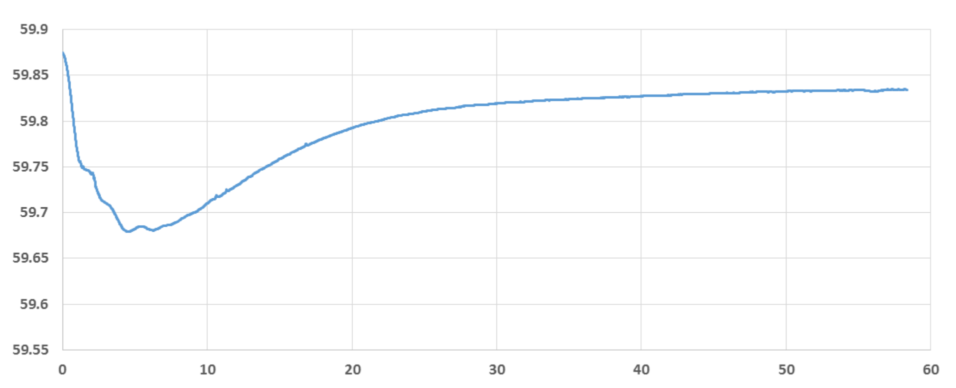

Fig. 5. Frequency at Round Mountain 500 kV facility for Case 1 Scenario 1

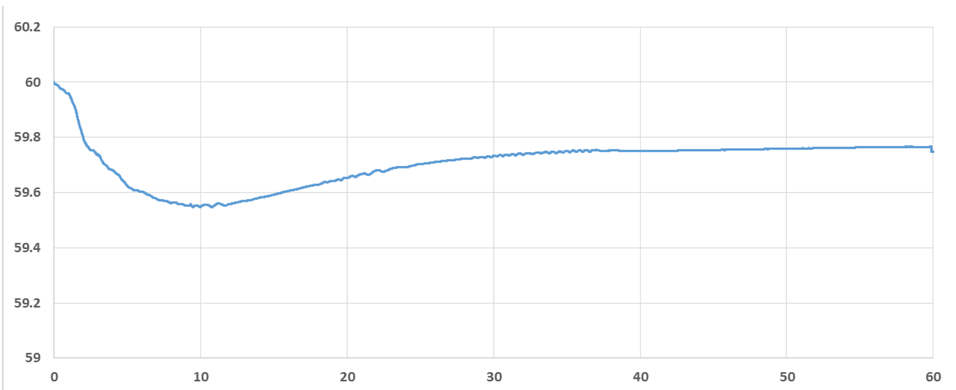

Fig. 6. Frequency at Round Mountain 500 kV facility for Case 2 Scenario 1

Table 4: Headroom in study cases

Case	Headroom (GW)	
	WECC	CAISO
Case 1	~ 19	~ 3.95
Case 2	~13.7	~2.3

6. CONCLUSIONS

This paper evaluated the impact of uncontrolled BTM resources on the T-D interface. A coupled production/power flow simulation environment was used to capture all aspects of the problem. The study did not identify any serious concerns at the T-D interface. The reliability of the system can be successfully ensured with good system planning and power system engineering practices. At a minimum, local voltage and thermal problems were identified that will require capacity expansion to accommodate the increased penetration. Scenarios with active participation from BTM resources demonstrated considerable improvement in system reliability. The system frequency response was observed to deteriorate without active DER controls allocated to all participating BTM units. Distribution is not decoupled from transmission and will continue to impact bulk power system operations, largely from a system-wide frequency-response perspective. From a steady-state and transient voltage perspective, the issues were largely localized in nature, with the strength of the grid at the point of interconnection and switching action of compensating devices influencing voltage response.

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