NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs

December 2021

RELIABILITY | RESILIENCE | SECURITY




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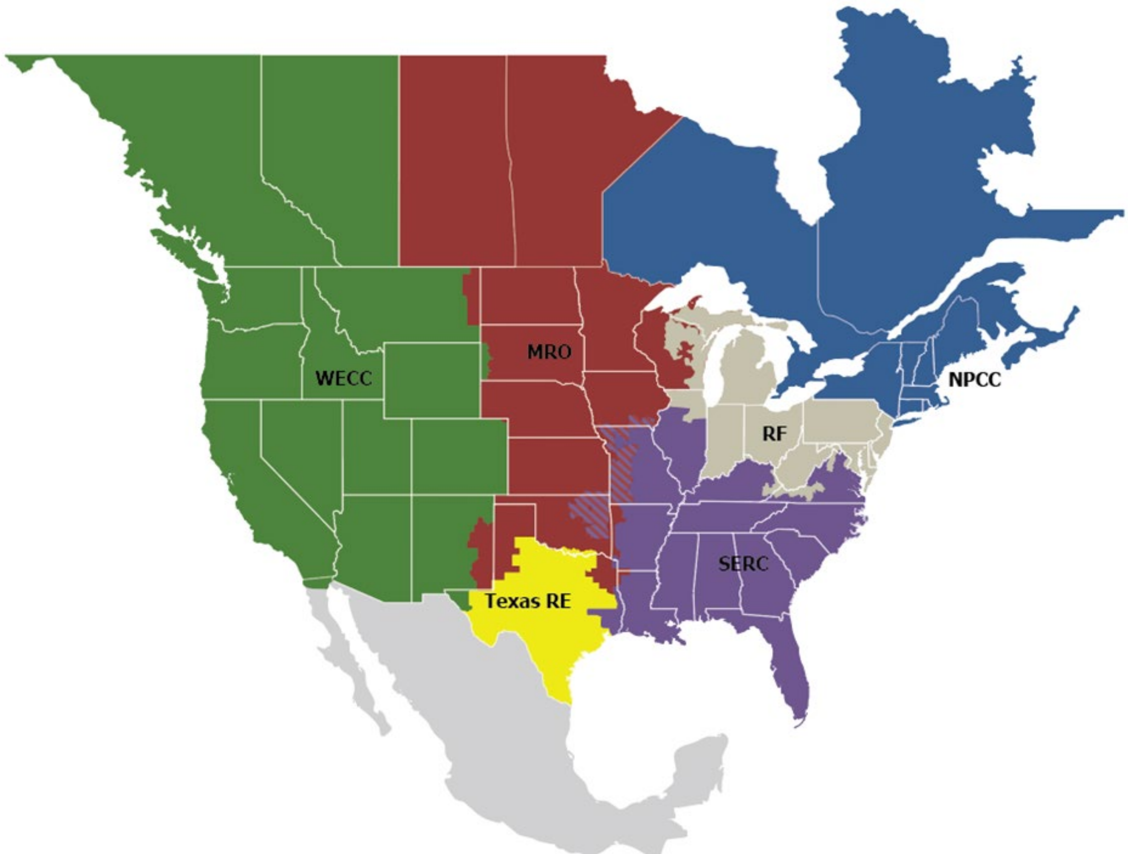
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners (TOs)/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Preamble

The NERC Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC Charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact BPS operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters nor are they Reliability Standards; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

Metrics

Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

Baseline Metrics

All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and Long Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments)
- Use and effectiveness of a reliability guideline as reported by industry via survey
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey

Specific Metrics

The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness.

- No additional metrics

Executive Summary

The System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) scope document, as approved by NERC's Planning Committee and replaced by the Reliability and Security Technical Committee (RSTC), identifies one of SPIDER's key activities is to "provide guidance on impacts that higher penetration of DER may have on system restoration, undervoltage load shedding, underfrequency load shedding (UFLS), and potential solutions or recommended practices to overcome any identified issues."[1] This document finds that UFLS program design can be impacted by DER in the studies conducted by the PC as well as the arming of UFLS relays in the implementation of the program. While the arming of UFLS feeders plays an important role in the implementation of the program, the major decision points on quantity of load armed for UFLS, intentional time delays, and study case setup demonstrate the need for best practices in the study process in order to mitigate any potential risk DER may have on UFLS schemes. In general, entities performing UFLS studies should do the following:

- Include dynamic models of both utility-scale DER (U-DER) and retail-scale DER (R-DER)[2] for a DER modeled in their simulation (at a minimum, U-DER voltage and frequency trip models should be included)[3]
- Ensure accurate modeling of BPS-connected generators, including the following:
  - On-line operating reserves
  - Governor response
  - Voltage and frequency trip protection settings
  - Over excitation limitations and under excitation limitations if present
  - Power system stabilizers if present
- Include additional cases reflecting other load conditions than peak load when developing the UFLS program.

[1] System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Scope Document (December 2018). Available here

[2] The terms U-DER and R-DER are modeling terms related to SPIDERWG's recommended modeling framework for a DER (as in Chapter 2). The set of terms for SPIDERWG documents is available here

[3] Note that a DER modeled as R-DER are usually operated at unity power factor without voltage control and may trip at or above UFLS load shedding trip settings. Furthermore, smart inverters with voltage and frequency control capabilities can challenge that assumption.

Introduction

Synchronous generators in North America operate around a nominal 60 Hz frequency, and frequency reflects the balance of generation and load. Situations where too much generation is produced cause frequency to increase, and situations where insufficient generation is available cause frequency to decrease.[4] The change in frequency allows a continuous balance of generation and load at all times.

UFLS is a critical safety net designed to stabilize the balance between generation and load when an imbalance between generation and load causes frequency to fall rapidly (e.g., during an islanded operation). Automatic disconnection of end-use loads, typically through tripping of predesignated distribution circuits or other predetermined end-use customers, is intended to help recover frequency back to acceptable levels such that generation can rebalance and frequency can stabilize to within reasonable levels. UFLS operations serve to prevent large-scale outages from occurring; however, the BPS is planned, designed, and operated such that these types of safety nets only occur as a last resort for extreme or unexpected disturbances. The concept of UFLS and other safety nets is that controlled tripping of portions of the BPS, including end-use loads, may mitigate the potential for a larger and more widespread blackout.[5]

UFLS programs are designed to disconnect predetermined end-use loads automatically if frequency falls below pre-specified thresholds. Some UFLS schemes include multiple levels of load disconnection to combat falling frequency to different depths. All UFLS frequency thresholds are set below the expected largest contingency event in each Interconnection[6] to avoid spurious load disconnection, and they are set to coordinate with generator underfrequency protection to avoid frequency damage.[7] Most commonly, the first stage of UFLS operation typically occurs around 59.5 Hz to 59.3 Hz; however, various regions of the BPS may have different thresholds for UFLS operation based on regional reliability needs.

A logic diagram that describes the high-level procedures of a UFLS program is provided in **Figure I.1**. The actions that the PCs conduct are highlighted in blue boxes and the UFLS Entity[8] actions are in grey boxes.

Where PCs have overlapping areas, coordination among PCs and the respective UFLS entities is required to ensure smooth operation of the designed scheme. As demonstrated in **Figure I.1**, there is a tight interchange of data between the PCs and the UFLS entities. Each PC is expected to provide studies based on knowledge of load and generation data, and the UFLS entities are expected to be able to provide a firm amount of load disconnection. These two main expectations can be tested with the increase of DERs, especially DERs that are unknown to the PC or UFLS entities.

[4] These increases and decreases cause electrical machines to speed up or slow down, respectively.
[5] *U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (2004) (Blackout Report).
[6] Refer to the latest version of NERC Reliability Standard BAL-003:
https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States
[7] Refer to the latest version of NERC Reliability Standard PRC-024:
https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States
[8] Per PRC-006, a UFLS entity can be a Transmission Owner or Distribution Provide

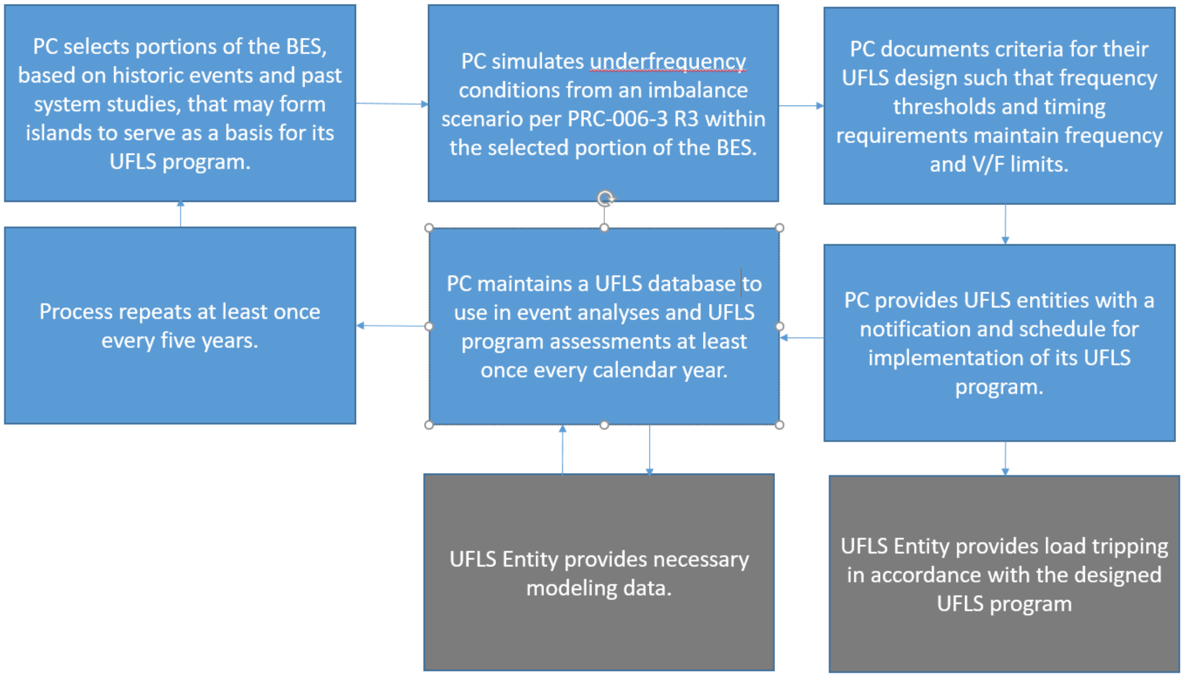


Figure I.1: Logic Diagram of Generic UFLS Schemes

This document provides guidance on impacts that a higher penetration of distributed energy resources (DER) may have on UFLS programs as well as recommended practices to overcome identified issues. The first section discusses the background and importance of UFLS to BPS reliability, as determined by FERC in Order No. 763.[9] The second section discusses impacts of a DER to electrical island-level frequency, which UFLS programs are designed to support.[10] The third section discusses impacts of a DER to UFLS program design. The fourth section concludes with recommendations.

In this document, DERs are defined as "any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES)."[11] The fundamental premise of this document is as follows:

> *If a significant percentage of load is served by DER, electrical island-level frequency will be impacted. UFLS program design will follow from those impacts.*

From this premise, the importance of studying precisely how electrical-island-level frequency will be impacted if a higher percentage of load is served by DERs is clear. While NERC has called attention to the potential impact of a DER to UFLS programs as early as 2011,[12] recent policy proposals and studies[13] have emphasized the increased need for examinations into the impact of DERs on UFLS programs. These programs are developed by Planning Coordinators (PC) and implemented by UFLS entities, possibly including TOs and Distribution Providers (DP).[14] This document aims to provide industry notice of and guidance on the impacts of a DER to UFLS programs.

[9] *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order No. 763, 139 FERC ¶ 61,098 (2012).
[10] The NERC Reliability Standard covering UFLS programs is PRC-006 available here
[11] The SPIDERWG Terms and Definitions Working Document is available here:
[12] See the Special Report: Potential Bulk System Reliability Impacts of Distributed Resources (August 2011) that is available here:
[13] Some of which are included in the appendices of this document. FERC Order 2222 is one example of an enacted proposal, available here
[14] See the IEEE Power & Energy Society Technical Report PES-TR68: *Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance* (July 2018) that is available here

UFLS Program Design and NERC Reliability Standard PRC-006

The Federal Energy Regulatory Commission (FERC) Order No. 763[15] adopted NERC Reliability Standard PRC-006-1 in May 2012, and subsequent non-substantive revisions[16] were made up to the currently implemented PRC-006-5.[17] In Order No. 763, FERC considered the impact of resources not connected to BES facilities on the development of UFLS programs. The primary focus was on ensuring an understanding and appropriate model to account for non-BES resources in UFLS design simulations. Specifically, in response to NERC's comments to the notice of proposed rulemaking (NOPR), FERC was "persuaded…that Reliability Standard PRC-006-1 does not limit the resources that can be modeled in the UFLS assessments and that power system models used in UFLS assessments generally model all qualifying generation, including resources not directly connected to the bulk electric system."[18] Therefore, while PRC-006 does not require all generating resources to be explicitly modeled in studies for UFLS program design, industry well understands that power flow and dynamic base cases typically represent the vast majority of BPS generating resources and aggregate end-use loads. In addition, more recently, aggregate representation of DERs have been modeled in certain regions. FERC also highlighted in their response to comments from the above NOPR that accurately predicting system performance is critical for UFLS program design simulations and that "inaccurate models can lead to invalid conclusions which can be detrimental to the analysis and operation of the bulk electric system." As this guideline will describe, a reasonable representation of BPS generation, aggregate load as well as aggregate DERs are critical for appropriate determination of UFLS programs moving forward.

PRC-006 establishes design and documentation requirements for automatic UFLS programs to arrest declining frequency, assist recovery of frequency following underfrequency events, and provide last resort system preservation measures. UFLS assessments include the identification of expected islanding conditions for each PC area and simulations of a frequency imbalance between generation and load of up to 25% that could occur from such island. The simulations should identify worst-case islanded conditions such that frequency thresholds of UFLS and the corresponding automatic load shedding will stabilize frequency acceptably.

The Northeast Power Coordinating Council (NPCC), SERC, WECC, and the Québec Interconnection[19] have regional differences, particularly related to the UFLS program design considerations and the underfrequency and overfrequency modeling curves. Refer to PRC-006 and the applicable regional variances of the standard for more details. **Figures I.2–4** show illustrations of the design performance and modeling curves for various Interconnections as well as how UFLS frequency set points and generator underfrequency trip thresholds can differ across North America.

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[15] https://www.ferc.gov/CalendarFiles/20120507124509-RM11-20-000a.pdf

[16] Note that PRC-006-1, PRC-006-2, and PRC-006-3 (effective October 1, 2017) are substantively similar. As stated in FERC's letter order on the *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-006-2* (March 4, 2015), PRC-006-2 revised R9 and R10 (added language requiring the implementation of corrective action plans) and R15 (added a requirement for PCs to develop corrective action plans). And as indicated in NERC's *Informational Filing regarding Reliability Standard PRC-006-3* (September 5, 2017), PRC-006-3 revised the regional variance for the Québec Interconnection but made no other changes to PRC-006-2.
https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/PRC-006-2%20Letter%20Order.pdf
https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Ltr%20to%20Sec%20Bose%20re%20PRC-006-3.pdf

[17] https://www.nerc.com/pa/stand/reliability%20standards/prc-006-5.pdf

[18] NOPR available here and response available here

[19] The Quebec Interconnection is part of the NPCC variance. but has specific requirements associated with its UFLS program.

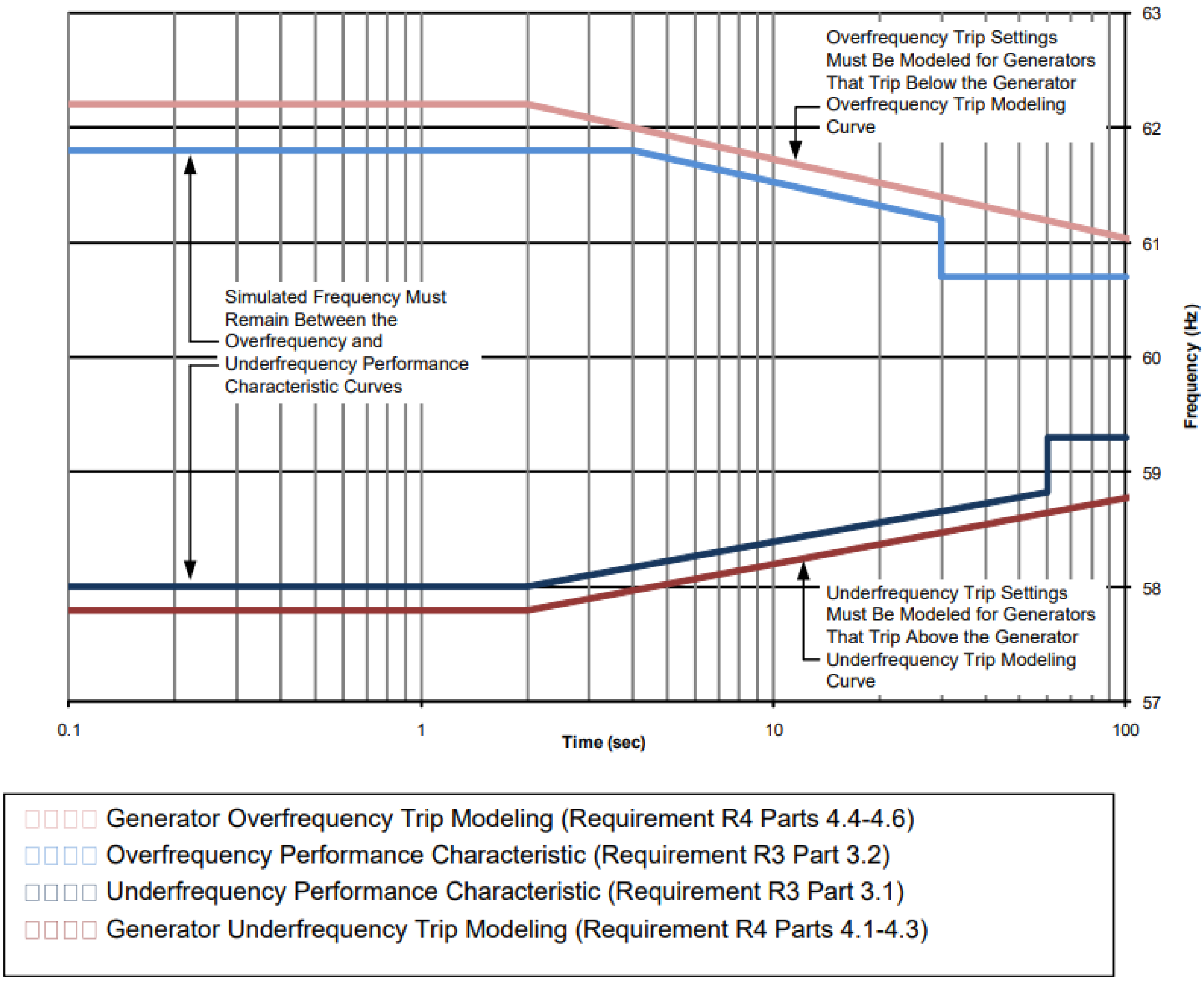

Figure I.2: UFLS Design and Modeling Curves for Most Interconnections [Taken from PRC-006]

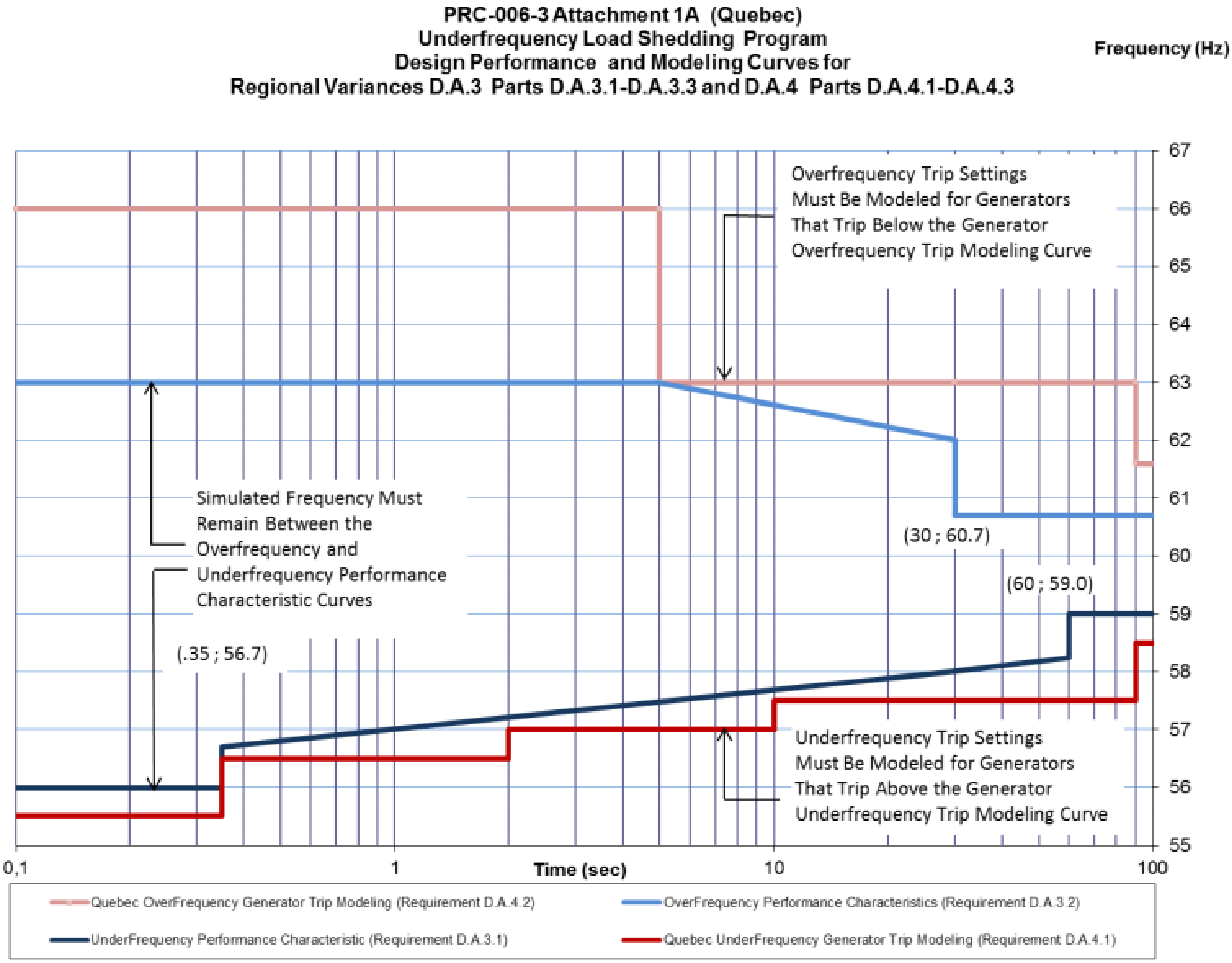

Figure I.3: UFLS Design and Modeling Curves for the Quebec Interconnection [Taken from PRC-006]

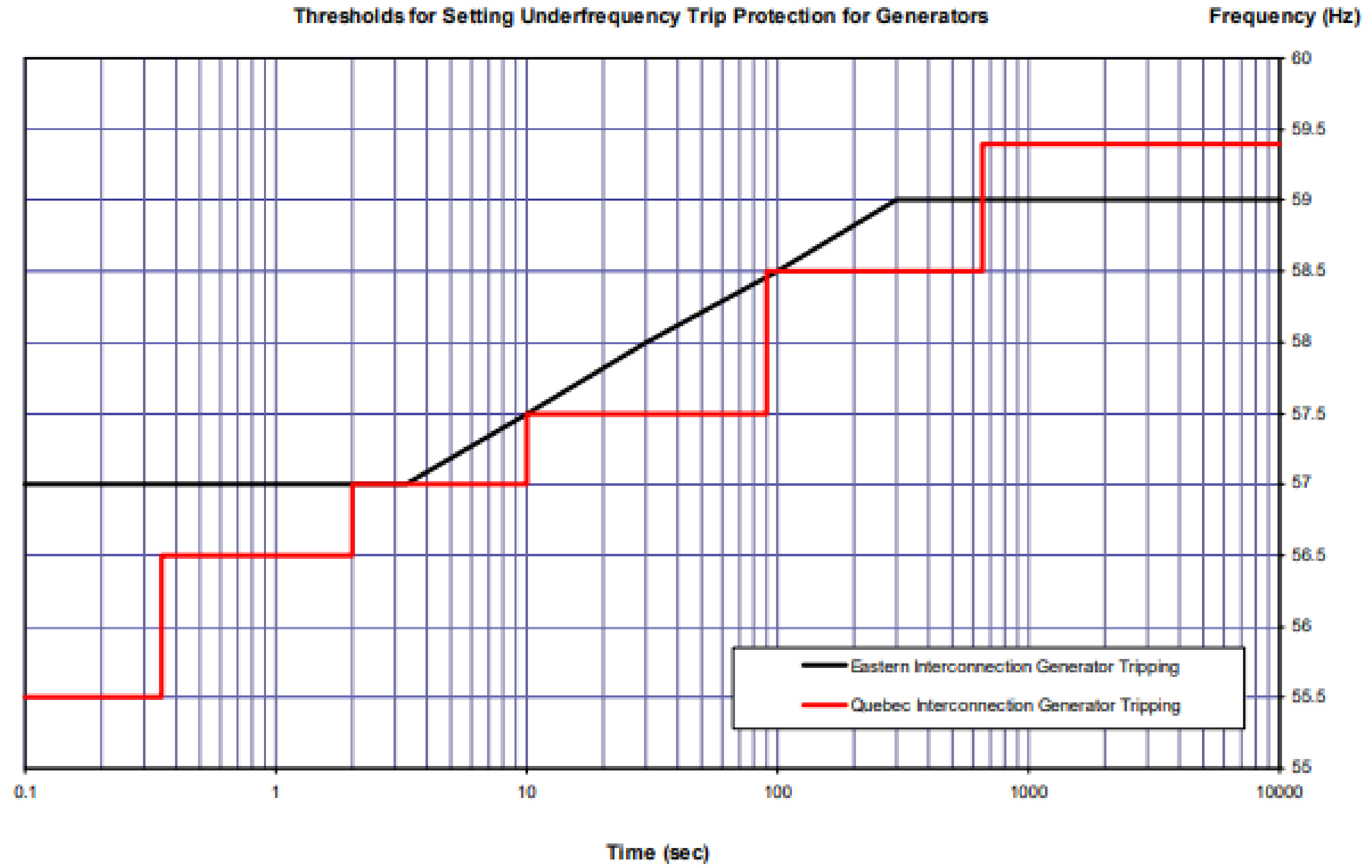

Figure I.4: UFLS Design and Modeling Curves for the Eastern Interconnection and Quebec Interconnection [Taken from PRC-006-NPCC]

PRC-006 defines "UFLS entities" as entities that are "responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program" established by the PC. UFLS entities may include TOs or DPs. UFLS entities are responsible for implementing the UFLS programs developed by the PCs by determining the appropriate end-use loads or distribution circuits to use in the UFLS program and arming these feeders and circuits with UFLS relays. These activities are intended to meet the load shedding requirements developed by the PCs in order to stabilize any severe imbalance between generation and load after an electrical island has been formed.

To illustrate load shedding requirements in different PC areas, consider **Table I.1**, which shows the UFLS program frequency set points and amount of load shed at each UFLS stage for ERCOT, ISO New England, and PJM. In ERCOT, all distribution service providers (DSP) are subject to the same load shed requirements. ISO-NE requires different stages of load shed depending on MW peak net load. PJM, in contrast, requires different levels of shedding for its Mid-Atlantic Control Zone (MACZ), West Control Zone (WCZ), ComEd Control Zone (CECZ), and South Control Zone (SCZ). **Appendix A** provides a more comprehensive set of UFLS program settings across North America.

Table I.1: Load Shedding Requirements in ERCOT, ISO New England, and PJM								
Frequency Set Point (Hz)	ERCOT*	ISO New England			PJM***			
	All DSPs	Peak ≥ 100	50 ≤ Peak < 100	25 ≤ Peak < 50	MACZ	WCZ	CECZ	SCZ
59.5		6.5–7.5%	14–25%	28–50%		5%		
59.3	5%	6.5–7.5%			10%	5%	10%	10%
59.1		6.5–7.5%	14–25%			5%		
59.0							10%	10%
58.9	10%	6.5–7.5%			10%	5%		
58.7						5%	10%	
58.5	10%				10%			10%
59.5 (10s)		2–3%						
Total % Shed	**25%**	**29.5–31.5%**	**28–50%**	**28–50%**	**30%**	**25%**	**30%**	**30%**

*See ERCOT Nodal Operating Guide Section 2.6.1(1) for further information20.
**See PRC-006-NPCC-2 for further information21. Note that Peak values are in MW of the TOs', DPs', and DPUFs' load.
***See PJM Manual 36: System Restoration Section 2.3.2 further information[22].

Prior NERC Activities Related to Increasing DER and UFLS

NERC has been focusing on DER impacts on UFLS programs for the past decade. In 2011, the NERC Integration of Variable Generation Task Force (IVGTF) published a special report, *Potential Bulk System Reliability Impacts of Distributed Resources,*[23] highlighting that at "high levels of DER, the effectiveness of existing UFLS schemes may need to be reviewed." The report described that "the profile of circuit loads can change and may no longer conform to the assumed circuit demand curve" with increasing penetrations of DERs, and the report used solar PV DERs as an example of offsetting gross demand during daytime periods. The example described that "if the circuits are part of an UFLS scheme during periods of high DER production, the reduction in system demand may be less than assumed in the design of the scheme and will not result in the loss of load being proportional to the overall demand curve. If the quantity of DER is large enough to actually result in export to the bulk power system, isolation of the circuit as part of a load shed scheme could result in increasing, rather than reducing, system demand." Similarly, in 2017, the NERC Distributed Energy Resource Task Force published the report *Distributed Energy Resources Connection Modeling and Reliability Considerations,*[24] which highlighted that high levels of DERs can have an impact on system protection (including safety nets) and will require closer coordination among DPs and transmission entities.

These prior activities serve as a foundation for further exploration into the impacts that DERs can have on UFLS program design, simulations to study UFLS settings, and appropriate operation of UFLS for large system imbalances in generation and load. The planning assessments to develop a UFLS program rely on power system models that should suitably represent the expected system conditions that the BPS faces in the future. This may require representing non-BES generating resources as well as end-use loads and DERs. Without appropriate accounting of the performance of these resources, PCs will be challenged when developing UFLS programs that are assured to operate appropriately for expected frequency excursion events. The critical aspects of designing UFLS programs that pertaining to considering DERs in studies is described in the following chapters.

[20] https://www.ercot.com/mktrules/guides/noperating
[21] https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-006-NPCC-2.pdf
[22] https://www.pjm.com/~/media/documents/manuals/m36.ashx
[23] https://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf
[24] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

Chapter 1: Impacts of DERs on Electrical Island Frequency

With the increasing penetration of DERs in North America, it is important to understand how DERs may impact or contribute to BPS frequency control and electrical island frequency response with respect to a large imbalance of generation and load. Understanding these impacts or contributions is paramount to developing effective UFLS programs in the face of higher penetrations of DERs in the future. Currently, the dominant technology used in DERs is solar PV but can include other technology types. The guidance here reflects the continuation of inverter-based resources (IBR) sourcing the majority of DERs. High levels of DERs can impact BPS frequency response in at least the following ways:

- Lower system inertia and higher rate-of-change-of-frequency (ROCOF)[25]
- Higher percentage of generating resources unable to provide additional power injection during underfrequency conditions[26]
- Risk of DER tripping on off-nominal frequencies and high ROCOF prior to UFLS operation[27]
- Lack of visibility of DER output by BAs
- Variability and uncertainty in DER output

Consistent with FERC Order No. 763, each of these impacts further emphasizes the importance of modeling aggregate DERs in UFLS studies to ensure appropriate operation of UFLS actions if needed. Even assuming that the ROCOF is slow enough for UFLS to operate effectively and that sufficient frequency responsive resources are available to arrest frequency decline, PCs will need to ensure appropriate modeling of aggregate DER UFLS trip settings as inadvertent tripping of DERs post-UFLS action could exacerbate any underfrequency condition.[28] Furthermore, the variability of aggregate DER output and its impact on variations in net load during different operating conditions poses challenges for PCs when performing UFLS studies and determining appropriate UFLS arming levels.

As the percentage of end-use load that is served by DERs increases, the performance characteristics of DERs will have an increasing impact on the imbalances between generation and load in an electrical island. Modeling aggregate amounts of DERs in BPS planning studies, particularly related to PC studies of UFLS program design per PRC-006, is of critical importance to "accurately predict system performance."[29]

Impact of Modeled DER on UFLS Studies

While each of the identified major impacts of DERs can be explored in further detail, a high-level overview of a recent exploratory study by ISO-NE effectively summarizes the impacts that DERs may have on the study outcomes for UFLS. A more detailed report can be found in **Appendix D**. Of most important note is the difference between use of net load versus gross load in the simulation and the impacts that a DER has on the simulation to meet the regional requirement. The impacts for ISO-NE are presented in **Figure 1.1.** In the figure, the blue line would not meet the criteria set for the ISO-NE operating as an electrical island as the deficiency caused by a DER tripping after UFLS action would not recover the frequency in time. ISO-NE tested a potential design change to their UFLS studies that compensated for the effect that DERs have on the island during these deficiencies, resulting in the orange line that met the requirement. Again, more detail is found in **Appendix D**.

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[25] This is of primary concern in areas with high inverter-based resources

[26] Since, currently, the vast majority of DERs operate at maximum available power. This is particularly the case for renewable inverter-based DERs (e.g., solar PV and small-scale wind DERs). Additionally, this can be due to DERs that do not have a governor to assist in frequency regulation.

[27] This is primarily of concern with regard to legacy DER. However, some distribution utilities are implementing their own DER interconnection protections or are requiring that a DER to have trip settings that are not coordinated with UFLS.

[28] **Appendix D** contains a section on how this can occur in simulations for the design of UFLS programs.

[29] Order No. 763, 139 FERC ¶ 61,098 (2012) at Paragraph 29.

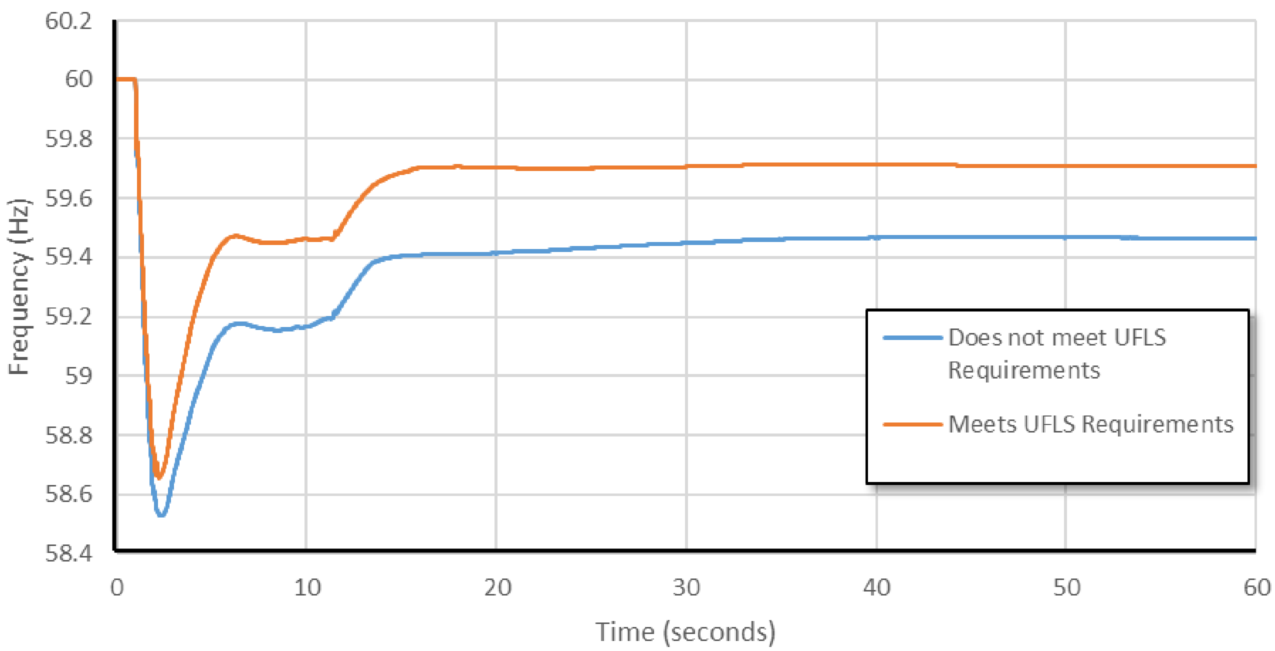

Figure 1.1: UFLS Program Design Changes Based on DERs

Lower System Inertia, Higher ROCOF, and Displaced BPS Generation

Decreasing amounts of on-line synchronous inertia and the effect that it can have on higher ROCOFs have been observed in some Interconnections across North America and also internationally.[30] As the penetrations of both BPS-connected IBRs and DERs (predominantly inverter-based) continue to increase, these resources may offset on-line synchronous generating resources that contribute to system inertia.[31] In response to a sudden loss of generation, kinetic energy is automatically extracted from the on-line synchronous machines, deterring the speed at which frequency will decline. Total system inertia depends on the number and size of on-line synchronous generators and motors. Greater system inertia reduces the ROCOF[32] following a disturbance, giving more time for primary frequency response to deploy and help arrest frequency decline prior to any UFLS operation. Therefore, smaller islanded systems (e.g., Texas Interconnection, Quebec Interconnection, Ireland, Hawaii) are particularly prone to high ROCOF, low system inertia issues, so these systems will need to ensure appropriate mitigating steps to ensure reliable operation of the BPS.

Increasing penetrations of aggregate amounts of DERs across each Interconnection may displace BPS-connected generating resources. Furthermore, BPS-connected IBRs are already offsetting BPS synchronous generating resources. Therefore, it is expected that the displacement of synchronous inertia by both resources will cause system inertia to decline and the ROCOF to increase. This becomes a problem only when the ROCOF rises to a level that becomes unmanageable by the Balancing Authority (BA) in terms of ensuring adequate primary and secondary frequency control.[33] High ROCOF in an electrical island may pose threats to UFLS programs since the available time

[30] NERC, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs," Atlanta, GA, March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

[31] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

[32] Classical factors that determine the ROCOF are system inertia, generation/load imbalance, and load damping response to declining frequencies

[33] See the IEEE Power & Energy Society Technical Report PES-TR68: *Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance* (July 2018) that is available here

to operate to adequately recover island frequency becomes shorter. Although UFLS programs could be redesigned to trip at lower frequencies—that is, trip with less intentional time delay or trip more selectively to accommodate higher ROCOF and changing frequency dynamics—such an option may only provide PCs with a temporary solution as system inertia continues to decrease.[34] Alternatively, more UFLS tripping is not a desirable option from a reliability perspective as the system undergoes continual change in terms of its generation mix.

In the future, DERs may be able to provide fast frequency response (FFR) to support high ROCOF conditions during low synchronous inertia; however, this is not an expected operating mode for DERs based on current market rules and interconnection requirements at this time. Very high penetrations of DERs and other IBRs will require changes to these paradigms to ensure adequate frequency responsive reserves and performance of BPS frequency during normal and abnormal grid conditions, such as large power imbalances. Future studies should take into consideration these changes.

Refer to **Appendix B** for a description of high ROCOF conditions analyzed by the Australian Energy Market Operator (AEMO) in the South Australia area of their system. Additionally, ISO-NE analyzed the same impact of reduction of inertia due to DERs and found that not only did the ROCOF increase, but the settling frequencies also were altered as the DERs offset the inertia by providing resources in the simulation. In **Figure 1.2**, the 60-second window of the simulation is shown with the colors representing an amount of R-DERs displacing BPS generation; this is tabulated in **Table 1.1**. The inertia was reduced in the simulation from the offset discussed above. Looking at the first few seconds of the same comparison in **Figure 1.3**, the recovery of the island frequency is also shown to be much slower with the increase of DER behind UFLS feeders. More details on this particular study can be found in **Appendix D**.

Key Takeaway

DERs displace BES and BPS connected generation. This impacts the island level frequency by increasing the ROCOF and reduces the island's ability to recover from the imbalance scenario

[34] Furthermore, the underlying protection philosophy for UFLS should be reconsidered in high-IBR settings as the current UFLS program design protects against first swing stability of synchronous machines.

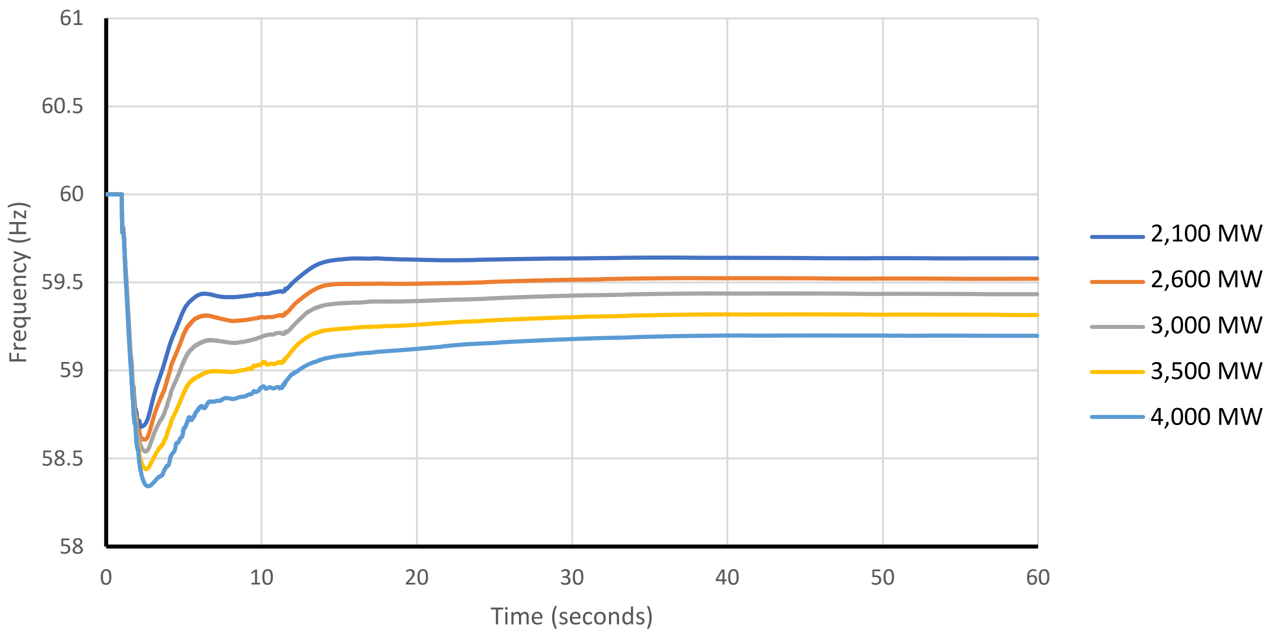

Figure 1.2: Impact of Increasing DER tripping from UFLS Action on Island Frequency Performance

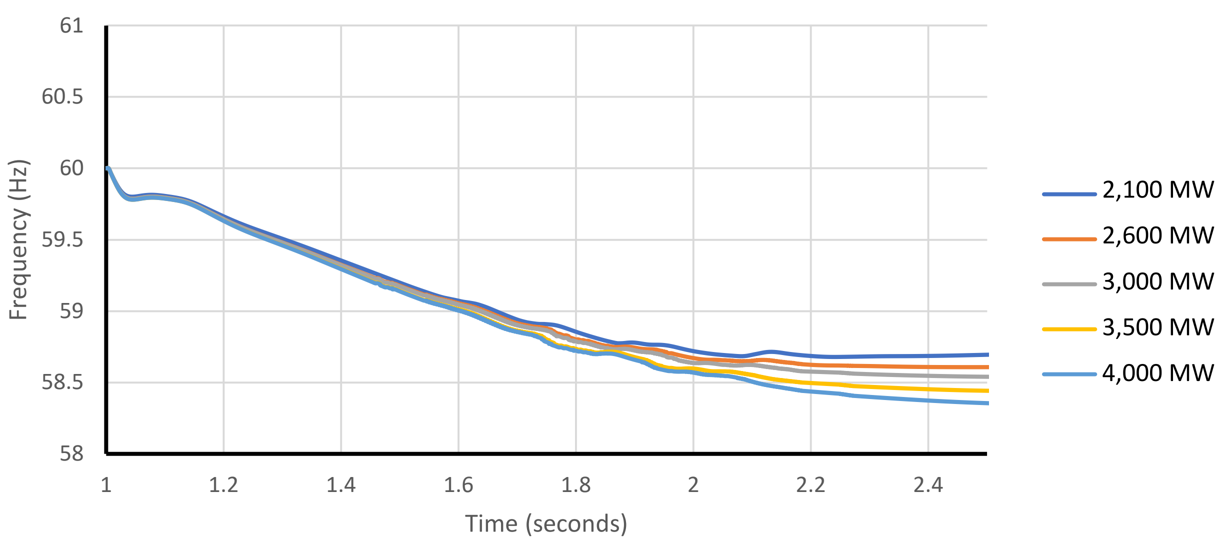

Figure 1.3: Zoomed in Comparison of Increasing DER tripping from UFLS Action on Island Frequency Performance[35]

[35] Note that the plot also demonstrates a change in ROCOF between the 2,100 MW modeled R-DER that trips on UFLS action scenario and the 4,000 MW scenario.

Table 1.1: Scenario List of DER and UFLS Studies for Island Frequency Performance					
Scenario	U-DER (MW)	R-DER (MW)	Total (MW)	U-DER Tripped (MW)	R-DER Tripped (MW)
1	3,097	2,100	5,270	652	2,100
2	3,097	2,600	5,670	685	2,600
3	3,097	3,000	6,070	689	3,000
4	3,097	3,500	6,570	721	3,500
5	3,097	4,000	7,097	755	4,000

Higher Percentage of Generation Not Providing Frequency Response

Increasing penetration of DERs means that end-use load is increasingly served by DERs rather than BPS-connected generators. Many newly interconnecting resources, particularly renewable energy resources (i.e., IBRs) with low energy costs are often run at maximum available power. Specifically, BPS-connected IBRs are usually operated in this manner unless a curtailment signal[36] has been given by the BA and inverter-based DERs are operated in a similar manner. DERs that are not under the control of the BA are not able to receive a curtailment signal and are typically programmed to provide maximum available power at all times. Therefore, the combination of BPS-connected IBRs and inverter-based DERs that operate at maximum available power and unresponsive to curtailment signals will continue to put pressure on the BAs to ensure that sufficient frequency-responsive reserves are available to arrest any large underfrequency events.[37] A lower number of units providing frequency response would result in a smaller subset of resources providing more incremental power to arrest frequency decline. This may put BAs in challenging situations unless long-term studies ensure that sufficient frequency responsive reserves are available.

For UFLS studies, it is important for PCs to ensure their studies are representative of actual system conditions, particularly the dispatch of BPS-connected frequency-responsive resources, the coincident gross load, and gross load dynamics. As DERs continue to offset BPS generation, accurately representing generation dispatch will become more important.

Risk of Legacy DER Tripping

One key risk that DERs, particularly legacy DERs, may pose to BPS reliability during severe off-nominal frequency events is the potential for tripping off-line during the event. As a resource that provides generation to the BPS, the loss of DER generation will exacerbate any imbalance between generation and load in an underfrequency event and cause frequency to fall further. With high or increasing penetrations of inverters that do not ride through off-nominal frequency events, this could pose a risk to BPS reliability either now or in the future. Furthermore, understanding this risk is critical to designing UFLS programs and performing UFLS studies because these effects will need to be modeled appropriately with reasonable modeling assumptions built into the studies. An example of legacy DER tripping was explored by ISO-NE (See **Appendix D** for specific details) and demonstrates that the tripping of legacy DERs can impact the performance of the feeder in the simulation greatly, as seen in **Figure 1.4**. The blue color is electrical power from the U-DER model, showing a trip due to the overvoltage condition, represented by the orange line. With the legacy DER tripping on overvoltage conditions after the UFLS action, a noticeable decline in frequency can occur.

Key Takeaway
DER tripping due to UFLS actions can pose a negative impact on the overall performance of the island in the UFLS simulations.

[36] Note that a curtailment signal issued by a BA or other grid operator may enable resources to have additional frequency responsive reserve to support BPS frequency; however, this should be coordinated by the BA and RC to ensure no other BPS performance metrics are adversely impacted.

[37] Synchronous DERs may or may not be frequency responsive; there are generally no requirements to provide that capability.

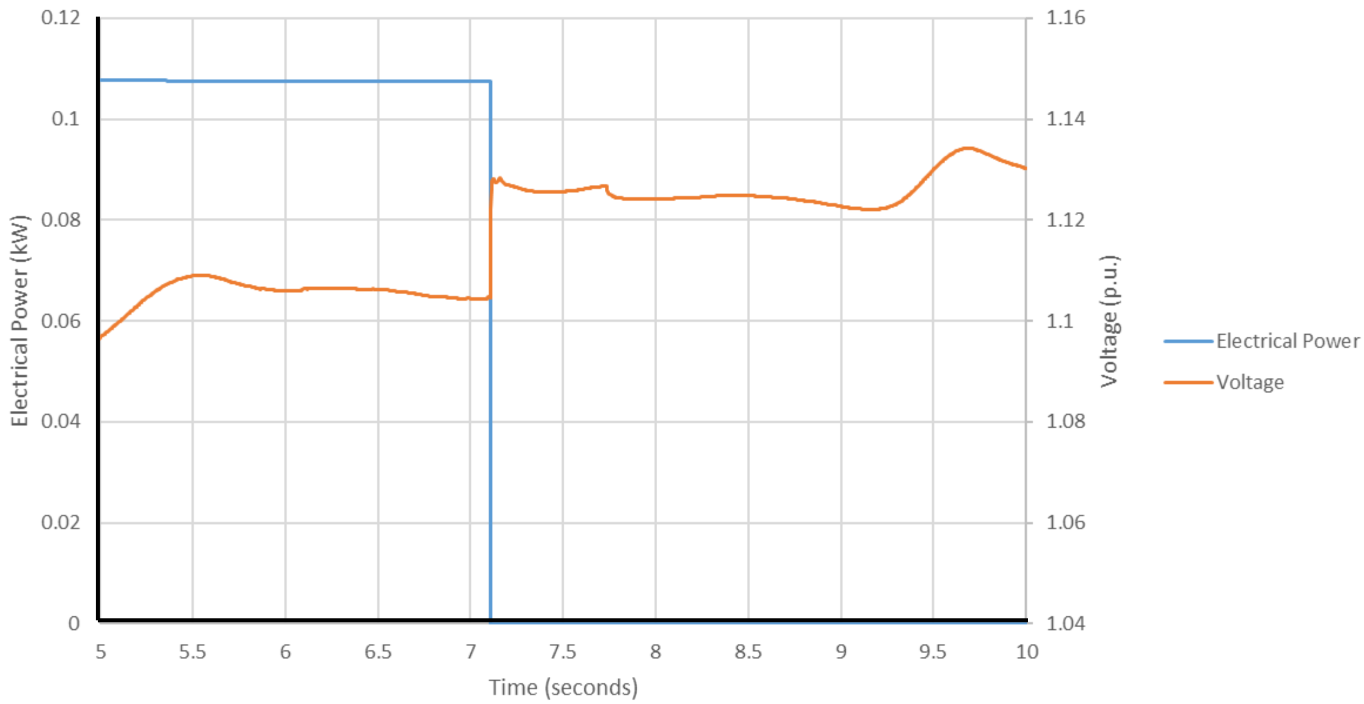

Figure 1.4: DER Tripping from Voltage Fluctuations after UFLS Actions

The vintage of a DER plays a key role in whether the resource is prone to tripping on underfrequency conditions. Older, legacy DERs that are subject to early versions of IEEE 1547 may have a propensity to trip at frequencies closer to nominal than newer DERs compliant IEEE 1547-2018, which will ride through a wider range of disturbances.[38] BPS-perspectives on the implementation and adoption of IEEE 1547-2018 are found in the *Reliability Guideline: BPS-Perspectives on IEEE 1547-2018.*[39] Consider the following recommendations when developing modeling assumptions for DERs:

- **Availability of DERs Compliant with IEEE 1547 Standard Versions:**[40] DERs installed across North America will have varying vintages based on the availability of DERs compliant with the various revisions of IEEE 1547. **Table 1.2** provides a rough estimate of the availability of compliant DERs that can be used to determine appropriate DER underfrequency trip settings and assumptions for use in UFLS studies.

[38] While the default frequency trip settings specified in IEEE 1547-2018 should ensure that a DER remains connected during frequency events, some distribution utilities are requiring trip settings consistent with the previous IEEE 1547-2003 settings, even on DER projects applying equipment certified to the new standard. Some distribution utilities are also applying their own protection equipment (e.g., reclosers) in series with DER interconnections set for very sensitive frequency tripping. These approaches, that is to add equipment or implement settings that are more restrictive than IEEE 1547-2018, are not supported by SPIDERWG.

[39] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Guideline_IEEE_1547-2018_BPS_Perspectives.pdf

[40] Inverter manufacturers stated that inverters were still shipped with IEEE 1547-2003 default settings even after UL 1741 SA inverters became available on the market since only a few entities required or desired longer trip times. PCs should assume worst-case trip settings unless authorities governing interconnection requirements (e.g., State regulators) have mandated specific ride-through capabilities and trip settings.

Table 1.2: DERs Compliant with IEEE 1547 Revisions [Source: EPRI]		
Standard Revision	**Test Procedures***	**Availability of Compliant DERs†**
IEEE 1547-2003	IEEE 1547.1-2005/UL 1741 "utility interactive"	After January 1, 2007
IEEE 1547a-2014	IEEE 1547.1/UL 1741 SA "grid support utility interactive"	After September 1, 2017
IEEE 1547-2018	IEEE 1547.1/UL 1741 SB "grid support utility interactive"	After January 1, 2022

* UL 1741 for inverters only[41]

† These are estimated dates only with conservative assumptions and known implementation plans.

- **DERs Compliant with IEEE 1547-2003:** DERs compliant with IEEE 1547-2003 have the trip characteristics, per the standard, described in **Table 1.3**. During the period of development of IEEE 1547-2003, the general approach was for DERs to disconnect from the grid in the event of any major grid disturbance. This was the predominant mentality at the time since the focus was primarily distribution impacts (i.e., anti-islanding and coordination with reclosers) with minimal BPS considerations due to the low DER penetrations at the time. The general belief is that nearly all DER installations greater than 30 kW compliant with IEEE 1547-2003 used the most conservative trip settings of tripping when frequency falls below 59.8 Hz for more than 0.16 seconds. Therefore, applying this assumption in studies is also reasonable. However, this may require further investigation by the PC and DP and possible verification with frequency disturbance data that could inform modifications to models of aggregate DER once more information is available.

Table 1.3: Underfrequency Trip Settings for IEEE 1547-2003 [Source: IEEE]		
DER Size	**Frequency Range**	**Clearing Time [s]†**
≤ 30 kW	< 59.3	0.16
> 30 kW	< {59.8–57.0}*	0.16–300*

† For DER ≤ 30 kW, maximum clearing time; for DER > 30 kW, default clearing time.

* Adjustable values

- **DERs Compliant with IEEE 1547a-2014:** For the amendment to IEEE 1547-2003, frequency trip requirements moved to a set of default values with ranges of adjustability, as shown in **Table 1.4**. DERs compliant with IEEE 1547a-2014 are expected to trip, based on the UF2 default value, when frequency falls below 59.5 Hz for more than 2 seconds. While the range of adjustability for both UF1 and UF2 is wider, it is not expected that the default settings were widely changed at this time. Therefore, it is reasonable to assume that DERs will trip at 59.5 Hz within 2 seconds and at 57.0 Hz within 0.16 seconds. Further investigation by the PC and DP may be needed.

Table 1.4: Underfrequency Trip Settings for IEEE 1547a-2014 [Source: IEEE]				
	Default Settings		**Ranges of Adjustability**	
Function	**Frequency [Hz]**	**Clearing Time [s]**	**Frequency [Hz]**	**Clearing Time [s]†**
UF1	< 57.0	0.16	56–60	10
UF2	< 59.5	2.0	56–60	300

† Adjustable time, up to and including

- **DERs Compliant with IEEE 1547-2018:** The new IEEE 1547-2018 version of the standard sets much wider frequency trip settings that ensure DERs can ride through large frequency excursion events to support BPS operation during these abnormal conditions. **Table 1.5** shows the default settings and ranges of adjustability. Note that IEEE 1547-2018 requires that the mandatory trip settings for abnormal frequency conditions be coordinated with the area electric power system (EPS) operators as well as the RC. It also mentions that the settings should be coordinated with regional UFLS program design such that unexpected tripping of DERs

[41] https://standardscatalog.ul.com/standards/en/standard_1741_2

compliant with IEEE 1547-2018 is unlikely for abnormal frequency conditions where UFLS operation would occur (i.e., DERs are able to ride through these events and continue providing power to the grid to support system frequency).

Table 1.5: Mandatory Underfrequency Trip Settings for IEEE 1547-2018 [Source: IEEE]				
	Default Settings*		Ranges of Adjustability	
Function	Frequency [Hz]	Clearing Time [s]	Frequency [Hz]	Clearing Time [s]
UF1	< 58.5	300	50–59	180–1,000
UF2	< 56.5	0.16	50–57	0.16–1,000

* Frequency and clearing time set points are field adjustable, and the actual applied trip settings must be specified by the Area EPS operator in coordination with the regional reliability coordinator (i.e., the RC) and typical regional UFLS programs. If the Area EPS operator does not specify any settings, the default settings shall be used.

Potential DER Tripping on High ROCOF

High ROCOF during islanded conditions may potentially cause legacy DERs to trip based on the settings programmed into the inverter. For example, during the large-scale disturbance in the United Kingdom on August 9, 2019, which resulted in UFLS operation, approximately 350 MW of DERs tripped on ROCOF protection.[42] The disturbance report stated that "some parts of the system may have experienced a ROCOF of 0.125 Hz/s."[43] The potential for DERs to trip on high ROCOF, particularly for legacy DERs, should be a consideration when designing UFLS programs.

In North America, there were no direct requirements for ROCOF tripping or ride-through in IEEE 1547-2003 or IEEE 1547a-2014. Clause 4.4 of IEEE 1547-2003 includes a requirement that DERs "shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island" and included examples of ways to meet the requirement. Early methods employed by inverters may measure the ROCOF to determine if an island exists with relatively tight thresholds on this protection. Without any standardization, PCs will need to use engineering judgement to ensure that any potential DER tripping on high ROCOF does not pose an unnecessary risk to BPS reliability or UFLS operation. PCs should monitor the ROCOF in their simulations and compare it to experienced ROCOFs in their system to determine the thresholds in their engineering judgement. When the simulation experiences a higher ROCOF, PCs are recommended to perform sensitivity studies that trip various amounts of DER to determine the impact such ROCOF tripping will have on the UFLS program.

IEEE 1547-2018, on the other hand, does address ROCOF ride-through, stating that DERs "shall ride through and shall not trip for frequency excursions" with magnitudes defined in the standard. **Table 1.6** shows the requirements for Category I, II, and III DERs[44] related to ROCOF ride-through. Lastly, the standard states that the ROCOF should be an average value over a measurement window of at least 0.1 seconds.

Table 1.6: ROCOF Ride-Through for DER Compliant with IEEE 1547-2018 [Source: IEEE]		
Category I	Category II	Category III
0.5 Hz/s	2.0 Hz/s	3.0 Hz/s

[42] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report

[43] Many islanded networks are expected to have a ROCOF greater than this level, and some Interconnections already have ROCOF conditions that exceed this level for generation loss contingencies. In the UK, a minimum ROCOF setting of .5 Hz/s is required.

[44] Category I, II, and III are defined in the IEEE 1547-2018 standard and are described more in detail in the reliability guideline on the subject referenced previously.

Potential DER Tripping on High or Low Voltage

During severe contingency events on the BPS, system voltages may experience large variations or swings that could potentially trip DERs. This is more likely a concern or consideration for legacy DERs. Reliability studies should have reasonable assumptions for any potential aggregate DER tripping for abnormal voltage conditions. Refer to the appropriate vintage of IEEE 1547 to determine if voltage-related tripping should be modeled. The DER vintage alone may not fully indicate voltage-responsive protection settings of the inverters. DPs may or may not allow the utilization of DER voltage ride-through capability. Furthermore, feeder-level overvoltage and undervoltage settings may not be coordinated with DER protection.[45] In addition, the load response during events may lead to high or low voltages that may lead to DER tripping. Each of these instances illustrates the need for reliability studies to have aggregate DER tripping parameters.

Lack of Visibility of DER Output by BAs

Many DERs (particularly behind-the-meter DERs) are not yet observable by, visible to, or controlled by the BA in their efforts to control BPS frequency. While aggregate DERs have an impact on the generation-load balance since they provide power to the end-use loads like any other generating device, in many cases they are not under the control of the BAs like BPS-connected or utility-scale DERs. For example, larger DERs may participate in ISO/RTO wholesale markets so may be observable and controllable by the BA; however, smaller behind-the-meter DERs likely are not participating in any markets (nor aggregation) at this time and so are not observable or controllable. While this is more commonly associated with balancing and ramping concerns that the BA must manage (i.e., secondary frequency response), the lack of visibility and controllability poses challenges for establishing UFLS programs and overall frequency control. Without a complete understanding of how generation is serving load, TPs and PCs will have to use engineering judgment for long-term planning studies, and BAs and RCs will also need to use engineering judgment for short-term reliability studies or real-time analyses.

Variability and Uncertainty in DER Output

Most newly interconnecting DERs are renewable energy resources with output dictated by atmospheric and meteorological conditions. The industry is becoming increasingly aware of the challenges of variability and the potential risks this poses to BPS reliability for BPS-connected resources, such as wind and solar PV. However, adding this degree of variability and uncertainty to the distribution system will pose additional challenges in the future. This, coupled with the lack of visibility of DER output, may pose a risk to UFLS programs in their design and implementation.

DER variability affects the amount of net load being served by the BPS at any given time. Increased variability of net load will affect the necessary amount of feeders selected[46] for load shedding needed to arrest and stabilize frequency in the event of a major imbalance between generation and load. Using a single study performed in the long-term planning horizon once every five years, the minimum required (per PRC-006) will become increasingly obsolete as the system rapidly changes operating conditions and expected net loading conditions. Further, it becomes increasingly important for PCs to study a wider range of expected operating conditions, particularly with respect to DER output levels, to understand the worst case scenarios regarding UFLS operation. The likelihood and severity of potential under-arming or over-arming of end-use loads as part of the UFLS program design increases drastically when studies performed years prior become obsolete by rapidly changing system conditions presented by DER variability and uncertainty.

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[45] To complicate the matter, FERC frequency and voltage ride-through requirements may impact local areas depending on the applicability based on the Small Generator Interconnection Procedure and Small Generator Interconnection Agreement for a particular DER installation. Still, SPIDERWG recommends using IEEE 1547 as the basis for DER voltage trip settings in simulation.

[46] Assuming all feeders need to be selected beforehand at time of study and not to change seasonally. Historically, UFLS schemes were designed in a manner that could arm for all seasons, making this a good assumption. To reiterate, increased variability on the amount of load shed per armed feeder will increase the total number of feeders armed in the case of a large imbalance between generation and load.

Illustration of DER Output Affecting UFLS Arming

To illustrate, consider a hypothetical PC developing a UFLS program when faced with a reasonably high solar PV DER penetration in their footprint. The PC footprint is summer peaking, so winter conditions are not typically studied for UFLS operation. The scenarios considered by the PC in this example include the following:

- **Summer Peak Load (Evening Hours):** During summer peak conditions,[47] around 6:00 p.m. on a hot summer day, gross load is around 5,000 MW and DER output is near zero. Gross load is therefore the same as net load, and the 25% deficiency studied in this case (as required by PRC-006 Requirement R3) is 1,250 MW. Since DER output is not variable at this time, there is no concern of overtripping or undertripping the amount of necessary load to ensure safe recovery of frequency.
- **Spring Light Load (Daytime Hours with High DER Output):** During spring light load conditions, around 12:00 p.m on a spring day, gross load is at 3,000 MW and solar PV DER output is around 1,500 MW. Therefore, the net load is 1,500 MW and the 25% deficiency studied in this case is only 375 MW. Since DER output is assumed at its maximum, there is concern of overtripping or undertripping the amount of necessary load to ensure safe recovery of frequency.
- **Spring Light Load (Daytime Hours with No DER Output):** During spring light load conditions, around 12:00 p.m. on a cloudy spring day, gross load is at 3,000 MW but solar PV DER output is at 0 MW. Gross and net load are 3,000 MW and the 25% deficiency studied in this case is 750 MW. If only the aforementioned spring light load case with DER output assumed was modeled, then the amount of net load tripping would be short by 375 MW (750 MW–375 MW). This could pose a risk of the UFLS program failing to operate due to the DER variability.
- **Spring Light Load (Nighttime Hours):** During spring light load conditions, late in the night on a mild spring day, gross and net load are again 3,000 MW since solar PV DER output is at 0 MW. This matches the case with no DER output during the daytime hours (assumption made here that day and nighttime light load are the same), and the previously studied case can suffice.

The introduction of DERs, especially in high penetration, presents a need for increased studies for UFLS program design due to the variability and uncertainty of DER output on any given day in the future. Even with accurate forecast values, the variability poses challenges to ensuring that the UFLS scheme will operate as necessary for any imbalance presented. As shown above, if an overrepresentation of how many DERs are on-line is made, there may be a risk of underarming. Conversely, if an underrepresentation of how many DERs are on-line is made, there may be a risk of overarming during DER output conditions. Where the existence of the amount of DER is unknown, PCs should perform sensitivity studies that range from minimal DER output to a large penetration of DER output when designing a UFLS program.

Some entities have moved to adaptive UFLS program designs in the face of high DER penetration conditions as the only viable solution to ensure correct operation of UFLS at any given time. For example Hawaii Electric Light (HELCO) has implemented an adaptive UFLS program that has seen successes and challenges with high penetrations of DERs that is described in more detail in **Appendix C**.

[47] Some electrical islands formed for summer peak loading conditions may include a high penetration of single-phase motor load composition that may have a higher impact during the daytime hours (opposed to the evening hours in the bullet). PCs are encouraged to use this list as an example when identifying the cases to consider when performing studies for UFLS program design.

Chapter 2: Impact of DER on UFLS Program Design Studies

As described in Chapter 1, DERs can have a significant impact on BPS frequency control and Interconnection frequency response. UFLS programs are built on long-term planning studies of expected future conditions that often use Interconnection-wide base cases as the starting point in which an islanded footprint for each PC is created. PCs will often adjust the dynamic models and operating conditions to represent conservative yet realistic assumptions of generation, load, transmission equipment, and DERs. Chapter 1 highlights the effects that DERs can have on BPS frequency response; this chapter will focus on how those effects are represented in planning studies used to design the UFLS program. Following FERC Order No. 763, PCs will need to model DERs within their respective studied island network to account for the performance and potential tripping of DERs. Specifically, PCs should consider the following impacts of DERs when performing UFLS studies:

- Modeling DERs in the steady-state and dynamic case used for the UFLS study
- Appropriately allocating DERs to aggregate load representations
- Accurately performing any expected frequency- and voltage-related tripping from DERs in simulation
- Potential responsiveness of DERs to changes in frequency
- Variability and uncertainty in DER output
  - DER output masking the total gross load
- Selection of distribution circuits or end-use loads

Recommended DER Modeling Framework

To account for the steady-state and dynamic effects that DERs can have on BPS performance during abnormal grid conditions, it is recommended that aggregate DERs be modeled in planning assessments with the guidance proposed in previous NERC reliability guidelines (see Figure 2.1).[48] The DER modeling framework characterizes DERs as either U-DERs or R-DERs. These definitions are intended to be adapted to specific TP and PC planning practices and specific DER installations, as needed. These adaptable definitions are provided here as a reference from the previous DER modeling recommendations:

- **U-DERs:** DERs directly connected to, or closely connected to, the distribution bus or connected to the distribution bus through a dedicated, non-load-serving feeder.[49] These resources are typically three-phase interconnections and can range in capacity (e.g., 0.5 to 20 MW).
- **R-DERs:** DERs that offset customer load, including residential,[50] commercial, and industrial customers. Typically, the

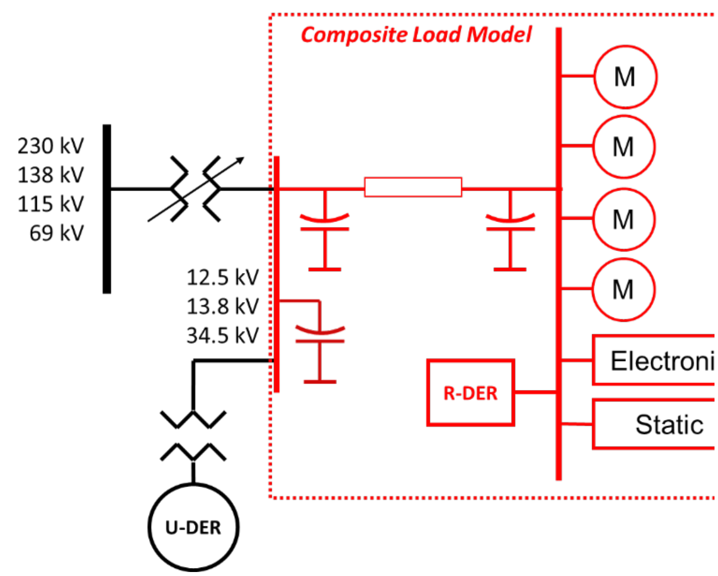

Figure 2.1: DER Modeling Framework

[48] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

[49] Some entities have chosen to model large U-DER that are connected to load-serving feeders as U-DER explicitly in the base case as well. This has been demonstrated as an effective means of representing U-DER as well and is a reasonable adaptation of the definition above.

[50] This also applies to community DERs that do not serve any load directly but are interconnected directly to a single-phase or three-phase distribution load-serving feeder. Also, this can apply to U-DER that is not connected close to the distribution bus or on dedicated feeders.

residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.

Both U-DERs and R-DERs can be differentiated and modeled in power flow base cases and dynamic simulations. TPs and PCs have successfully adapted these general definitions for their system and often refer to U-DERs and R-DERs for the purposes of modeling aggregate DERs. Aggregate amounts of all DERs should be accounted for in either U-DER or R-DER models in the base case, and TPs and PCs may establish requirements for modeling either individual large U-DER as well as aggregate amounts of the remaining DERs as R-DERs.

Studied Operating Conditions for UFLS Studies

Many of the fundamental concepts of UFLS program design do not change with the introduction of DERs in the islanded network. PCs still need to determine the operating conditions and dynamic response of interconnected resources (including generation and load-side resources) that cause the most severe frequency deviation for a defined percentage deficiency between generation and load in their islanded system. However, determining these conditions requires close consideration of aggregated DER levels, particularly as DER penetration levels increase.

Selecting Islanded Networks, Tripping Boundaries, and Study Techniques

Per requirements R1 and R2 of PRC-006, each PC is required to "select portions of the BES (including portions of neighboring systems) that may form islands" and to "identify one or more islands to serve as a basis for designing its UFLS program." In many parts of the North American BPS, UFLS programs are regional in nature and as such the Regional Entity may conduct all or part of the reliability studies.[51] Choosing the PC area is the most logical and convenient island for study purposes for each PC. However, some areas may span multiple PC footprints (e.g., the northern part of the New England system with the New Brunswick system) and are therefore used in the same islanded system and coordinated among PCs.

The islanding boundary is critical to determine because it creates a complete island separated from the rest of the interconnected BPS for study purposes. Therefore, attention can be devoted to accurate modeling within the islanded network boundaries.

There are multiple ways to simulate the imbalance scenario, including (but not limited to) the following:

- **Reduced Power Flow Case Converting Tie Lines to Equivalent Loads:** A reduced power flow base case is created for each electrical island. All tie lines connecting the electrical island at the predefined island boundaries are replaced with equivalent loads or generators. In the dynamic simulation, those equivalent loads forming the electrical island and any additional BPS generation necessary to create the required load-generation imbalance are tripped simultaneously.
- **Islanding during Dynamic Simulation:** This approach uses the entire Interconnection-wide or regional dynamic model rather than a reduced power flow model. The overall base case is configured with appropriate intertie flows into the PC area, and the electrical island is formed during the dynamic simulation by simultaneously tripping interties and any additional generation. Since this method uses the full Interconnection-wide dynamic model with multiple islands formed, the simulations tend to run slow due to computation limitations in the commercial tools, so this method may not be used by PCs.
- **Island in Power Flow Base Case:** In this case, the electrical island is the same as the PC area (i.e., islanded networks, such as ERCOT), and this is reflected in the power flow base case. Therefore, the full amount of imbalance is created by tripping generating resources during the dynamic simulation.

[51] In some instances, it may be possible that nearly all of the program design, including threshold setting, is done by the Regional Entity. This, however, does not alter the guidance this document sets forth for those conducting the studies and obtaining necessary information.

Recommended Interpretation of Generation-Load Imbalance

Requirement R3 of PRC-006 states that each PC shall develop a UFLS program that meets a set of performance characteristics in simulations of underfrequency conditions that result from an imbalance scenario[52] defined as follows:

$$\boldsymbol{imbalance} = \frac{\boldsymbol{load - actual\ generation\ output}}{\boldsymbol{load}} \tag{1}$$

The term "load" is not capitalized[53] so is subject to interpretation in PRC-006 regarding whether equation (1) refers to gross load or net load in situations of DER penetration. A lowercase "load" term is only used in requirement R3 of PRC-006-5 (although it shows up in other places in regional variances of the standard); however, how this term is used should be closely reviewed by PCs.

Consider how equation (1) is implemented in UFLS studies. The generation-load imbalance has historically been simulated by tripping boundary tie lines importing power to the island. This island can be formed in a single PC's boundary or during the formation of an island with multiple PC's boundaries. These ties lines, referred to in the following equations, are based on the formed island for the study and are not necessarily (but can include) the interties for area-to-area connection or between PCs. They are the lines that connect the identified island in the study to other areas of the Interconnection. Any additional power needed to make up the imbalance will come from BPS generators within the island being tripped off-line at the same time as the tie lines are tripped. Therefore, historically this equation actually should be as in equation (2).

$$\boldsymbol{imbalance} = \frac{\boldsymbol{load - (BPS\ generator\ output + (tie\ line\ imports - tie\ line\ exports))}}{\boldsymbol{load}} \tag{2}$$

Now consider the inclusion of DERs into the scenario differentiated from gross load. DERs are inherently generating resources that should be explicitly considered. This can be accounted for by adding a term, resulting in equation (3).

$$\boldsymbol{imbalance} = \frac{\boldsymbol{gross\ load - (BPS\ generator\ output + (tie\ line\ imports - tie\ line\ exports) + DER\ output)}}{\boldsymbol{gross\ load}} \tag{3}$$

With a fixed imbalance (i.e., 25%) set per the requirements of PRC-006, equation (3) can be rearranged equation (4).

$$\boldsymbol{BPS\ generator\ output + (tie\ line\ imports - tie\ line\ exports) + DER\ output = 75\% * \ gross\ load} \tag{4}$$

The combination of BPS generation output, net tie line interchange (imports–exports), and DER output needs to be reduced to 75% of the gross load to meet the requirements of PRC-006. To determine the worst case scenario (albeit more extreme than even the 25% imbalance itself), the reductions are typically prioritized using the following rules of thumb:

- **Tie Line Imports and Exports:** The base case should be set up with reasonable expectations for imports and exports. Creating an artificial base case with heavy tie line imports that exceed any expected operating condition does not reflect a reasonable operating state and should not be used in simulation. However, the case can be set up to utilize the import capability to a reasonably justifiable level, and exports can be minimized to the extent possible. Therefore, when the dynamic simulation trips the boundary lines of the islanded network, the reduction in tie line imports (less any exports) can be used to cover a portion of the deficiency.
- **BPS Generation Tripping:** The next group of resources that should be tripped are BPS-connected generating resources that should generally be resources able to provide frequency response since this creates a

[52] Note that this imbalance is limited to 25% in PRC-006 and may have regional variances.

[53] As in, does not refer to a term used in the NERC Glossary of Terms: https://www.nerc.com/files/glossary_of_terms.pdf

reasonable yet conservative assumption. If non-frequency responsive resources were tripped, this would lean towards an optimistic assumption with additional frequency responsive resources on-line than may occur in reality. Therefore, the remaining imbalance should consist of tripping frequency-responsive resources or a mix of responsive and non-responsive resources with engineering judgment.

- **DER Tripping:** DERs should be tripped last as part of the imbalance created to satisfy the requirements of the standard. As described in the preceding step, these resources are not typically frequency responsive, so tripping them to create the imbalance will lead to an optimistic assumption. Furthermore, legacy DERs may have a risk of tripping on underfrequency conditions prior to reaching UFLS threshold, which will exacerbate the imbalance during the dynamic simulation. This needs to be analyzed by the PC as part of the dynamic simulation results separately from creating the imbalance. This is described in subsequent sub-sections of this chapter.

Each PC (or entity performing the UFLS study) is encouraged to make judgement calls that are consistent with their system when creating the imbalance scenario to study their UFLS scheme. If this entails DER tripping as part of the imbalance, such decisions should be documented with technical rationale so that the impact of DER on the program design is fully captured in the program.

Example of System Setup using the Priority List

Consider an example system with the following assumed conditions for study:

- Condition: Spring Light Load
- Time of Day: 12:00 p.m.
- Gross Load: 2,000 MW
- DER Output: 500 MW
- Imports: 300 MW
- BPS Generation: 1,200 MW

The PC needs to determine an imbalance for this study case that is based on 75% of the 2,000 MW gross load; meaning that BPS generation and net intertie flows collectively must be reduced to 1,500 MW (i.e., reduced by 500 MW). In this case, imports are at 300 MW and will be cut as part of the contingency definition, so an additional 200 MW of BPS-connected generation would be tripped at the same time as the severance from the rest of the system. Alternately, the imports may be modified to 0 MW and an electrical island formed prior to the dynamic simulation, where then 500 MW of BPS-connected generation would be tripped.

Key Takeaway
Assuming net load for calculating the deficiency per PRC-006 may not fully test the robustness of the UFLS program.

Assuming net load when calculating the generation-demand imbalance per PRC-006 may not fully test the robustness of the UFLS program and could lead to under-tripping of sufficient load to arrest severe frequency excursions. Studies of the performance of an electrical island need to fully test the robustness of the UFLS program.

Selecting Appropriate Study Cases

There are not specific requirements in the latest version of PRC-006 that require a specific operating condition to be studied (i.e., season, demand levels, BPS-connected IBR levels, or DER output levels). Many entities may currently use summer peak conditions since these are traditionally the most stressed scenario in terms of a generation-load imbalance. However, electrical islands with high penetrations of IBRs and DERs will likely change those most severe conditions. The risk of UFLS operation will likely increase during conditions of low gross load and high IBRs (due to higher ROCOF, lower amount of on-line frequency responsive reserves, etc.). A one-size-fits-all approach likely will not work in the future, and PCs will need to evaluate which scenarios are most appropriate. Selecting an appropriate set of study cases is an important aspect of performing UFLS studies and developing a robust UFLS program. Table 2.1 illustrates an example consideration of two distinct operating conditions.

Table 2.1: Example Comparison of Study Case Scenarios

Characteristic	Peak Summer Scenario*	Light Spring Scenario†
Demand	Maximum	Minimum
Synchronous Generation	Relatively higher dispatch, units on-line	Relatively lower dispatch, units off-line
Synchronous Inertia	Higher	Lower
BPS-Connected Inverter-Based Generation	Likely moderate solar PV and wind outputs, may be more conservative based on time of day and other assumptions	High solar PV and wind output, high renewables scenario
DER	Moderate to low DER (likely solar PV) output	High DER (likely solar PV) output
Imbalance	Highest level of imbalance due to gross load being at its maximum	Lowest level of imbalance due to gross load being at or near its minimum
ROCOF	Relatively lower ROCOF, less ROCOF concern	Relatively higher ROCOF, high ROCOF concern based on Interconnection
DER Tripping	Less DER output so less potential magnitude of DER tripping with UFLS operations; possible DER tripping on frequency and ROCOF conditions	Higher DER output so greater potential magnitude of DER tripping with UFLS operations, possible DER tripping on frequency and ROCOF conditions

* Peak Demand, Moderate Renewables Output, Moderate DER Output
† Light Demand, High Renewables Output, High DER Output

For each study case selected, an appropriate imbalance condition and setup of dynamic simulation will need to be conducted, and multiple study cases should be used to determine the worst-case frequency response[54] performance for the electrical island. In most cases, at least a summer peak load and a spring light load operating condition are used to perform UFLS studies to ensure that the UFLS program is able to securely operate under these diverse sets of operating conditions. As the penetration of DERs continues to increase, additional cases should at least be considered by the PC and potentially studied based on identified risks. These cases include, but are not limited to, the following:

- **Summer Peak Demand (Evening Hours):** Summer peak conditions often occur during the early or later evening hours when DER output may be significantly reduced due to solar irradiance at that time. For systems that are summer-peaking, this condition will mathematically result in the largest imbalance necessary to meet the percentage defined in PRC-006.
- **Winter Peak Demand (Nighttime Hours):** Systems with winter-peaking demand will need to consider these operating conditions as their highest peak gross demand conditions for the same reasons described in the summer peak demand case above.

[54] As identified by the PC or entity performing the UFLS study for the UFLS program (Note that selection of "worst" here will vary between areas.)

- **Light Demand with High Renewables:** Light demand conditions typically occur during the shoulder season and most notably during the spring. Furthermore, situations with high renewable output for BPS-connected IBRs can drive low-inertia operating conditions with the potential of high ROCOF.[55] This can pose a challenge for UFLS schemes to operate correctly. Regarding DERs, there are two considerations that should be made:
  - **Light Demand with High DER Output:** Systems with a notable penetration of solar PV DERs should consider studying daytime light demand cases coupled with high output from BPS-connected IBRs. Ensure that a reasonable amount of BPS frequency responsive and spinning reserves are carried in the simulation to reflect realistic operating conditions and that BPS generators are dispatched at reasonable output levels.
  - **Light Demand with Low DER Output (Nighttime Hours):** Systems with or without a notable penetration of solar PV DERs should also consider studying nighttime light demand hours (where solar PV DERs are off-line where applicable) as an alternative dispatch scenario. It is possible that these conditions are prone to higher wind power output. Other dispatch considerations may exist that warrant an additional data point to ensure UFLS operates as designed.

As mentioned, these are example considerations that should be made when selecting simulation cases for UFLS studies. Multiple cases should be studied to ensure reliable and secure operation of the UFLS under different operating conditions.

Example of Study Case Selection and Creation

Consider an example comparison between summer peak and light spring conditions as well as how different system conditions affect case setup and generation dispatch assumptions. **Table 2.2** shows the CAISO base case setup from the 2019 CAISO Transmission Plan. The starting cases were modified to match imports to the 25% required generation-demand imbalance for each case, so interties can be tripped during the contingency to match the required imbalance. This resulted in only a 3,500 MW change in tie line flows in the summer peak case but a 19,500 MW change in the light spring case. Lastly, the percentage of local demand served by DER and BPS-connected internal island generation were calculated. In the summer case, DERs in the local island are only serving 0.5% of demand and will likely have little to no impact on UFLS. However, in the light spring scenario, DERs make up over 48% of the local island generation mix for the modified case from the light spring base case opposed to the 0.5% for the modified case built on the summer peak conditions. This illustrates how DERs can have a substantial impact to UFLS design, particularly during conditions when DER output is expected to be at or near its peak output conditions (which can often be coincident with low demand conditions, particularly for distributed solar PV).

Table 2.2: Example Comparison of Study Cases using CAISO Base Case Data

Characteristic	Peak Summer Scenario	Light Spring Scenario
Time of Day	Hour Ending 19	Hour Ending 13
Gross Demand (MW)	57,510	31,050
DER Output (MW)	280	15,050
Pre-Contingency Case Imports (MW)	17,840	-11,860 (export)
BPS Generation On-line (MW)	41,160	29,060

[55] NERC, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs," Atlanta, GA, 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

Table 2.2: Example Comparison of Study Cases using CAISO Base Case Data		
Characteristic	**Peak Summer Scenario**	**Light Spring Scenario**
25% Gross Demand Deficit	14,378	7,763
Modified Case Imports (MW)	14,378	7,763
Modified Case BPS Generation On-line (MW)	44,622	9,437
DERs as a Percent of Gross Demand	0.5%	48.4%
Local BPS Generation as a Percent of Gross Demand	77.6%	30.4%

Modeling DER Tripping

Modeling any tripping of aggregate DERs is an important aspect of performing UFLS studies. As described in **Chapter 1**, DERs can trip for different reasons, and each of those reasons will be described here regarding how to account for or model these potential initiators of DER tripping. The aspects worth considering include, but are not limited to, the following:

- **DER Tripping on Underfrequency Conditions:** DERs across the electrical island may trip if their terminal measurement of frequency falls below predefined threshold values. Trip thresholds are likely based on existing regional or local interconnection requirements or may be default values specified in equipment standards, such as IEEE 1547. These thresholds can be modeled in the DER dynamic models or with supplemental dynamic models.
- **DER Tripping on High ROCOF Conditions:** During the initial onset of the frequency imbalance, the ROCOF within the electrical island may be high and may lead to tripping. Considerations for potential tripping on high ROCOF should be made; however, existing dynamic models may be limited in capturing aggregate DER tripping on the ROCOF.
- **DER Tripping as Part of UFLS Operation:** Modeling considerations will need to be made to accurately represent the potential of DER tripping as part of the UFLS operations. Modeling potential DER tripping from UFLS operations will determine the appropriate modeling practices for power flow and dynamic models.

Each of these modeling considerations is described in more detail in the following subsections.

Dynamic Modeling of Aggregate DER Tripping on Underfrequency

As described previously, the DER modeling framework recommends aggregate modeling of DERs in planning assessments, either as a U-DER or R-DER representation in the power flow base case and in dynamic simulations. U-DERs are modeled with a generator record and can have an associated DER_A dynamic model applied; R-DERs are accounted as part of the load record and can also have a DER_A dynamic model applied. The DER_A dynamic model includes frequency-related tripping as described in NERC *Reliability Guideline: Parameterization of the DER_A Model*.[56] In the model, a filtered frequency signal is passed to frequency relay logic within the DER_A model. The frequency

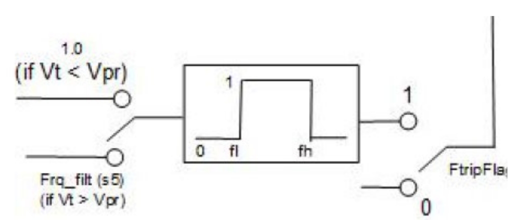

Figure 2.2: DER_A Frequency Tripping Logic [Source: PSS®E]

56 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

tripping logic is shown in **Figure 2.2**. If frequency tripping is enabled by the *ftripflag* parameter, voltage is above a defined threshold,[57] and frequency falls below the defined underfrequency trip setting the full amount of DERs modeled for that specific instance of the model will trip with a time delay set with the *tfl* and *tfh* parameters.

As DERs trip off-line due to underfrequency, frequency will continue to decline. Therefore, reasonable modeling of potential DER tripping is important since it may exacerbate the generation-load imbalance. Sensitivity studies should consider any conservative assumptions on potential DER tripping to determine if this has any adverse impacts to the UFLS program.

Modeling Potential DER Tripping on High ROCOF

As mentioned in **Chapter 1**, high ROCOF during electrical island conditions could cause legacy DERs to trip.[58] Since there are no requirements or standards to develop ROCOF protection models, PCs should use engineering judgement[59] to determine any potential risks that additional DER tripping on high ROCOF could pose to electrical island frequency control. There are currently no known dynamic models in commercially available software tools that can be applied to both U-DERs (generator records) and R-DERs (either as part of the load record or as a component in a modular dynamic load model) for ROCOF protection.[60] Therefore, the best approach is for PCs to perform dynamic simulations and to identify the highest ROCOF observed during the simulation. If the ROCOF exceeds a pre-determined threshold where DERs may be prone to trip (based on engineering judgment), then the PC should determine an appropriate amount of DERs to trip at that point in the simulation and re-run the simulation to see how this sensitivity affects frequency response of the electrical island. Sensitivity studies are recommended to ensure that any excess DERs tripping does not affect performance of the UFLS program.

Modeling DER Tripping as Part of UFLS Operation

Modeling considerations should capture potential tripping of aggregate DERs as part of UFLS operations once frequency has fallen below UFLS thresholds. There are many different ways to model and represent this tripping in the dynamic simulations, requiring coordination between power flow and dynamics modeling practices. UFLS programs often have multiple load shed set points that trigger local load shedding relays based on predefined frequency trip settings. This includes specific distribution feeders or individual large end-use customers based on the UFLS program design. In the power flow and dynamic models, the individual feeders or groups of loads are often lumped together as an aggregate load and may need to be separated or partially tripped in the studies based on utility practices.

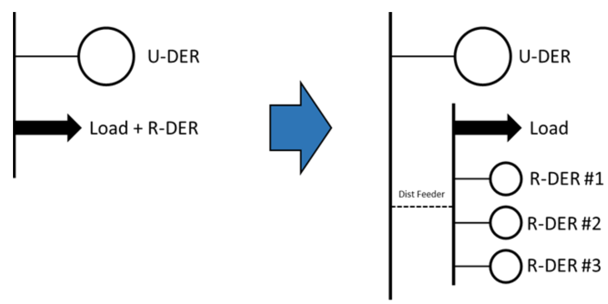

Figure 2.3: Example Modeling of Aggregate DERs Tripping with UFLS

Consider **Figure 2.3** to illustrate this concept. Assume that this system has the U-DERs modeled as individual generator records and the R-DERs included as part of the load record and composite load model (in dynamics). Assume that U-DERs mainly are fed from the distribution substation so are generally not tripped as part of the UFLS program. Therefore, there is no issue with modeling the consequential tripping of these resources as part of the UFLS operation. However, this is a concern for the R-DERs since some amount of R-DERs may be tripped when distribution circuits are tripped during UFLS operations. In this case, different amounts of DERs will be tripped at different UFLS

[57] Low voltage inhibit logic prevents frequency passing to the relay model if terminal voltage is less than or equal to the defined threshold.

[58] Additional ROCOF protections implemented by, or required by, the DP may also result in DER tripping.

[59] Discussions with equipment manufacturers that supply equipment to a DER may prove useful in developing a ROCOF threshold.

[60] Some load shedding relay models, such as *lsdt7* or *lsdt8*, are able to model ROCOF-based tripping; however, these models are applied to load records; therefore they will trip the load component in addition to any DERs. Therefore, these models are generally not well suited for capturing DER tripping for R-DER modeled as part of the composite load model.

operations based on the percentage of load tripped (assuming an equal distribution of R-DERs across the various feeders).

Now assume that the load and R-DERs will be tripped at three stages (i.e., at 59.5, 59.1, and 58.7 Hz). An issue arises in the dynamics modeling of the R-DERs included as part of the load record and composite load model. The DER_A dynamic model trips the full amount of DERs once the frequency trip threshold is crossed and does not include staged trip settings in the dynamic model. Therefore, the R-DERs will need to be separated out into individual models that can be separately tripped. In the dynamic model, the frequency trip settings can be configured for each R-DER to trip once the pre-established thresholds are crossed. For example, R-DER #1 may trip at 59.5 Hz, R-DER #2 may trip at 59.1 Hz, and R-DER #3 may trip at 58.7 Hz.

Regarding the stand-alone load record (since the DER elements have been separated), load shedding relay models, such as *lsdt7* or *lsdt8*, can be used to trigger various levels of load tripping all combined into one dynamic load model record.

As mentioned, there are multiple ways this can be set up in the power flow and dynamics models; however, this modeling practice is described here as a reference for consideration.

Performing Dynamic Simulations for UFLS Studies

As UFLS program design requires a PC-level study to initiate the design of the UFLS program, the PC will need to make sure a few key parts in the dynamic simulation are maintained in order to effectively capture the impacts DERs have on the design of the UFLS program. These considerations will provide a heightened confidence that the UFLS program captures the impact of DERs. Key considerations for PCs performing UFLS studies with aggregate DERs represented include the following:

- PCs should include dynamic models of both U-DER and R-DER. At a minimum, U-DER voltage and frequency trip models should be included.[61]
- PCs should ensure accurate modeling of BPS-connected generators, including the following:
  - On-line operating reserves
  - Governor response
  - Voltage and frequency trip protection settings
  - Over excitation limitations and under excitation limitations, if present
  - Power system stabilizers, if present
- PCs should ensure that additional cases are tested that reflect load conditions other than peak load.

[61] Note that a DER modeled as a R-DER are usually operated at unity power factor without voltage control and may trip at or above UFLS load shedding trip settings. Furthermore, smart inverters with voltage and frequency control capabilities can challenge that assumption.

Chapter 3: Coordinating with UFLS Entities

PRC-006 includes the term "UFLS entity," referring to "all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the [PCs]." These entities may include TOs, DPs, or both. Requirement R3 describes that the PC, upon developing its UFLS program, will notify UFLS entities within its area of the program and a schedule for implementation by UFLS entities. Requirement R9 states that each UFLS entity shall "provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation…" for any PC areas in which it owns assets. UFLS entities are provided discretion regarding how specific levels of load are armed and automatically tripped to meet the requirements outlined by the PCs as part of the UFLS program. This leaves flexibility for UFLS entities to determine which distribution circuits, feeders, or specific loads will be selected. UFLS entities often will consider excluding critical loads (e.g. hospitals) when selecting feeders with system elements to disconnect. With the growing penetrations of DERs, it is important for UFLS entities and PCs to closely communicate how specific loads or feeders are selected and to what degree DERs could impact effective UFLS operation. Figure 3.1 shows the continuous feedback loop needed as DER penetrations continue to increase.

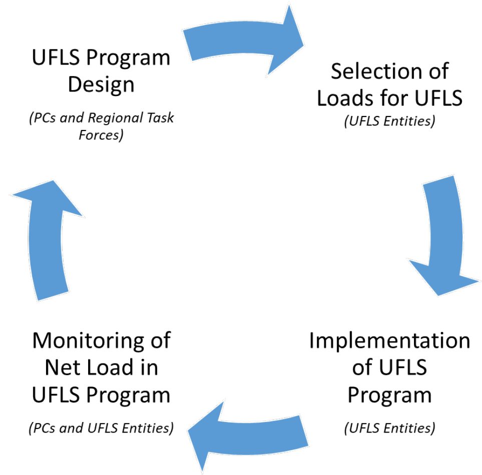

Figure 3.1: Continuous Feedback Loop of UFLS Program Design

There are key factors that should be considered by UFLS entities in coordination with their respective PCs when developing and implementing effective UFLS programs in the face of increasing DER penetrations. These include, but are not limited to, the following:

- Selection of loads participating in the UFLS program
- Impacts of DER aggregators or other DER management systems
- Coordination of any advanced DER controls (i.e., frequency response capability) with regional UFLS settings and BPS frequency control needs
- Coordination of UFLS with distribution-level hosting capacity analysis

These are described in more detail in the following subsections.

Selection of Loads Participating in the UFLS Program

The primary focus or concern regarding the coordination between UFLS program design and implementation is the selection of feeders or end-use load customers participating in the UFLS program. UFLS studies are only required to be performed on a periodic basis; however, DER penetrations are rapidly growing in many areas of North America and can potentially impact the effectiveness of UFLS operations. An unexpected growth in DERs on a distribution circuit selected for participating in a UFLS program can reduce the effectiveness of the UFLS operation to ensure reliable operation of the BPS. Therefore, it is appropriate for the UFLS entities to monitor their net load armed for their UFLS program in order to ensure the targets are correct for a given snapshot in time.

> **Key Takeaway**
> An unexpected growth in DERs on a distribution circuit selected for participating in a UFLS program can reduce the effectiveness of the UFLS operation to ensure reliable operation of the BPS

For example, assume a UFLS entity has been assigned 50 MW of net demand that should be armed and automatically shed as part of UFLS operations. The UFLS studies performed by the PC did not account for DERs in this area since penetrations were not significant. However, in the last few years, the DP has observed fairly significant DER growth on many of its feeders. The PC had previously only used peak summer conditions for UFLS studies, which assume peak demand around 6:00 p.m. Therefore, during peak demand conditions, the UFLS would likely still operate as expected since DER output may be low at this time. However, during low demand, high solar DER output, low system inertia conditions, the DERs may reduce the net demand on those feeders. Assume now that instead of having 50 MW armed, the UFLS entity inadvertently is only arming 30 MW. The deficit of 20 MW of net demand armed will cause insufficient amounts of load shedding to ensure the UFLS operates as expected. Furthermore, if this is observed across multiple DPs (i.e., UFLS entities), the issues may be further exacerbated across a wider PC footprint.

During the selection of loads participating in the UFLS program, UFLS entities, in particular DPs, should consider the following:

- PRC-006 does not specify which specific end-use loads, distribution circuits, or feeders should be chosen by DPs for inclusion in the UFLS program and automatic tripping if BPS frequency reaches these levels. That discretion is left to the DP based on their specific system needs and characteristics.
- Most commonly, the PC is specifying a net load quantity in terms of demand (MW) needed to be armed at the T–D interface. DPs should confirm with their PCs that the amount of arming is representative of a net demand quantity.
- Distribution circuits or feeders that have DERs intermixed along the circuit, resulting in variable net loading at the monitoring point (i.e., head of the feeder) inherently create more variability in the amount of net load that may be armed at any given point. Therefore, it is common practice for DPs to attempt to select circuits, loads, or feeders where DERs are not prevalent.
- As the penetration of DERs increases in any given area, the likelihood of identifying feeders with minimal DER impacts may be significantly reduced. Therefore, feeders with DERs may need to be used as part of UFLS programs. In these cases, close coordination between the DP and PC is needed. DPs and PCs should coordinate on at least the following:
  - DPs should confirm that the installed and forecasted DER penetrations used for simulations performed by the PC are correct. DP selection of UFLS-armed feeders or loads to meet the UFLS program objective at all times will increasingly become a challenge. Tripping feeders with high DER output will cause less net load to be tripped; tripping feeders with low DER output will cause more net load to be tripped. To further illustrate this point, feeders that export to the BPS should not be selected for UFLS arming as tripping the feeder would exacerbate the imbalance. This needs to be accounted for in studies conducted by the PC and in monitoring of feeder flows for the implementation of the UFLS program.
  - DPs should confirm that the simulations are performed by the PC model aggregate DER with appropriate voltage and frequency trip settings. DERs that are expected to trip during voltage or frequency excursion events further complicate selection of UFLS-armed circuits and may lead to unexpected generation loss during the contingency that could further exacerbate the underfrequency conditions.
  - DPs should clearly articulate which feeders are selected for UFLS arming and automatic tripping (that is simulated in the PC’s studies) and identify any cases where DER variability could affect the net demand armed:
    - Variations of time of day, season, etc., should be considered by the DP when informing the PC of any variability in DER output that affects net loading of UFLS-armed circuits. The output of metering can be sent to the PC for use in the PC’s study work for the PC to identify these variations.

- Targeting specific loads, circuits, or customers for inclusion in the UFLS program may require greater granularity in the future compared to past experience, particularly as the penetration of DERs for any given UFLS entity continues to increase:
  - Conventional UFLS relaying (i.e., on a circuit-level basis) may become obsolete or may require additional solutions when faced with increasing DER penetrations. For example, battery energy storage systems (BESSs) may be able to provide fast-responding net load reduction by providing either fast discharging capability or fast reduction of charging capability[62] when UFLS levels are reached. This may offset the need for tripping of end-use load customers in the future and may help compensate for a depleting number of eligible UFLS feeders.
- Improve awareness of DERs connected to their system and monitor real-time output of the aggregate DERs impacting the feeders armed for UFLS to the greatest possible extent. The UFLS entity is encouraged to also provide the aggregated signal of the output to the RC and PC for situational awareness during frequency excursions and to help enhance modeling efforts for UFLS program design.

The considerations listed above are important for the DP to consider when selecting feeders or end-use loads for participating in the UFLS program; however, they are also relevant for PCs to consider as they design their overall UFLS program with increasing DERs across their PC footprint. PCs may consider working with their DPs to develop ranking criteria on feeder selection for UFLS programs, consider possible modifications to UFLS thresholds or trip levels, and establish regular communications with UFLS entities to ensure DERs are being sufficiently accounted for during UFLS program design. PCs, DPs, and entities governing distribution are encouraged to coordinate on the transfer of DER information necessary to assess the risk to the BPS for the purposes of designing a UFLS program. **Appendix C** describes a situation where the UFLS program in the HELCO footprint required an adaptive setting due to high DER penetration levels. This requires close coordination across the PC and DPs to implement these advanced types of tools.

Impacts of DER Aggregators or Other DER Management Systems

DER management systems (DERMSs) or DER aggregators are new functions that are appearing across the industry in the face high penetrations of DERs. DERMSs or other DER aggregators do not modify the electrical connection of DERs or other load modifiers (e.g., demand response); however, a DERMS may modify the behavior of these resources to provide a specified or contracted response to support the grid. For example, a DERMS may be used to provide frequency responsive reserves or contingency reserves or could be used for ramping or balancing, depending on the contracts or markets put in place that could enable this technology. While this is an evolving area, it will have an effect on UFLS operations and UFLS program design. Some questions that PCs and UFLS entities should consider include the following:

- How are the implementation and operation of DERMS or DER aggregators tracked and accounted for in UFLS studies?
- Which entity is sending any control signals to the DERMs in response to BPS disturbances?
- Are the DERMS configured or contracted to provide grid-supportive functions, such as frequency response to underfrequency events?
- How will a DERMS's response affect overall UFLS program design, and how is this modeled appropriately?

These questions all highlight the complexity of introducing DERMs or other aggregation components to the overall grid. Reliable operation of a UFLS program to avoid widespread outage conditions is a critical function of BPS safety

[62] The exact method depends on the battery's state of charge and if the battery is charging, idle, or discharging. It should be noted that the BA will need observability of any such devices that perform frequency service in order to perform their responsibility to maintain frequency.

nets and a critical element in reliable operation of the BPS. As such, it is anticipated that any operation of a DERM or DER aggregator to provide frequency response will likely invalidate the feeders for use in UFLS programs.

Coordination of UFLS Program with Possible DER Frequency Response

The inclusion or exclusion of feeders or circuits from participating in UFLS programs and potential automatic tripping during UFLS operations should not be confused with any prohibition of DERs from providing grid-supportive functionality or other essential reliability services. For example, if circuits are not chosen for UFLS operation due to increasing DERs, this should not affect the development of any interconnection requirements regarding those resources having frequency response capability and being able to provide that service to the BPS either now or in the future. This does mean, however, that the UFLS program design should reflect the changing nature of the grid.

UFLS is a safety net function for severe contingency events when an imbalance of generation and load requires a fast-responding and automatic disconnection of select end-use loads from the system to rebalance system frequency. Prior to reaching those UFLS frequency thresholds, all generating resources (including DERs, if able to respond) and end-use loads[63] can help arrest frequency declines. DERs and BPS-connected generation can increase active power output if configured in a manner to do so to support overall BPS frequency response. As mentioned above, DERMSs or other aggregators may control many individual DERs in the future to provide this service to the BPS. Furthermore, existing DERs participating in wholesale electricity markets may also be capable of providing these services to support BPS operations. These functions support overall frequency control and in some ways help mitigate the potential operation of UFLS in the first place. PCs and UFLS entities should ensure that DERs that are relied upon to support BPS frequency and provide essential reliability services are not impacted by UFLS relays and have adequate ride-through capability so that they are able to reliably provide these services. It is recommended to coordinate frequency capabilities and the availability of frequency response to the applicable BAs in addition to the PCs in order to carry out the BA's function to balance generation and load.

Coordinating UFLS Programs with Distribution-Level Hosting Capacity

Some state-level regulatory authorities require DPs and TOs (UFLS entities) to facilitate interconnection of DERs in areas of the distribution system with ample "hosting capacity," defined by the Electric Power Research Institute (EPRI) as "the amount of DER[s] that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades."[64] According to EPRI, hosting capacity is a function of location, DER type, and circuit configurations (see **Figure 3.2**). Distribution circuits or feeders that already have DERs intermixed along the circuit have less available hosting capacity; distribution circuits or feeders that do not have DERs have more available hosting capacity.

Key Takeaway
State-level regulatory authorities should align hosting capacity analysis with UFLS program design to ensure that sufficient load, or load resources, are enabled to trip to arrest declining BPS frequency.

[63] Either through inherent frequency sensitivity of direct-connected motor loads or through dedicated end-use loads providing frequency responsive services.
[64] https://www.esig.energy/blog-methods-applications-hosting-capacity/

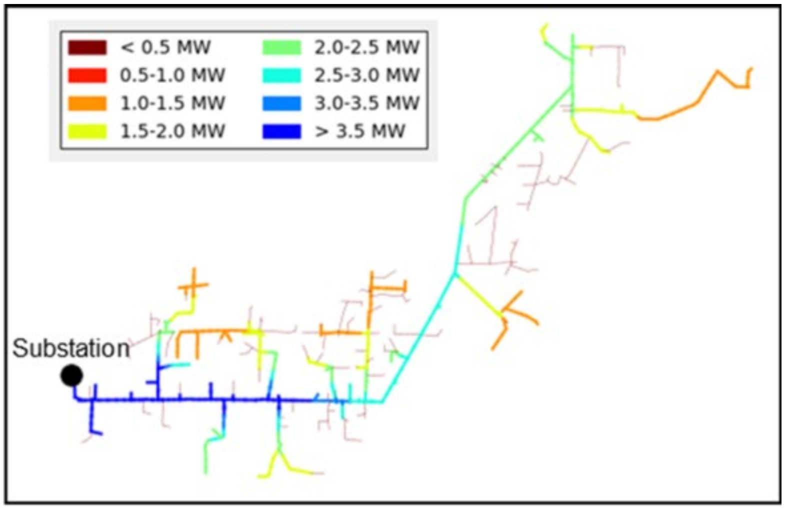

Figure 3.2: Example Hosting Capacity Heat Map [Source: EPRI]

Thus, state-level requirements facilitating the interconnection of DERs on feeders with hosting capacity (i.e., more load, less DERs) will likely result in DER development on the same feeders that are designated for UFLS (again, more load, less DERs). Greater levels of load enabled to trip on UFLS will in turn be required. PCs, UFLS entities, and state-level regulatory authorities should coordinate hosting capacity analyses with UFLS program design to ensure that DER interconnection does not inadvertently result in the degradation of UFLS required to support reliable operation of the BPS.

Appendix A: UFLS Programs across North America

This appendix compiles some of the presently effective UFLS program settings across North America as a useful industry reference. **Table A.1** to **Table A.3** show the frequency set points and amount of net demand tripped when frequency reaches each set point for the Eastern[65], Western, and Texas Interconnections, respectively. Note that cells that are greyed out are not in effect for that specific entity.

Table A.1: Various Eastern Interconnection UFLS Program Settings

Frequency Set Point (Hz)	NPCC*			PJM				MRO/MISO			SERC
	Peak ≥ 100 MW	50 MW ≤ Peak < 100 MW	25 MW ≤ Peak < 50 MW	MACZ	WCZ	CECZ	SCZ	3-Step (15 UFLS Entities)	5-Step (5 UFLS Entities)	1-Step (9 UFLS Entities)	Target Load Shed
59.6											7.4%
59.5	6.5–7.5%	14–25%	28-50%		5%						
59.4											5.2%
59.3	6.5–7.5%			10%	5%	10%	10%	8.3–15.3%	5.1–12.6%	32.1–100%	
59.2											5.2%
59.1	6.5–7.5%	14–25%			5%						
59.0						10%	10%	7.2–16.4%	5.9–12.6%	100%	5.2%
58.9	6.5–7.5%			10%	5%						
58.7					5%	10%		6.3–13.1%	4.7–10.7%	100%	6.3%
58.5				10%			10%	8.3–12.3%	0.6–6.5%	100%	
58.4											4.3%
58.3								8.7–12.7%	0.2–6.8%	32.1–63.8%	
58.2											2.2%
59.6 (15 +/-.5s)											2%
59.6 (22 +/-.5s)											3%
59.5 (10s)	2-3%										
Total % Shed	**29.5-31.5%**	**28-50%**	**28-50%**	**30%**	**25%**	**30%**	**30%**	**28-43%**	**29-43%**	**32.1-100%**	**40-44%**

*NPCC load is based on total TO, DP, and DPUF load in these columns. Also note that the Québec Interconnection has five threshold stages and four rate-of-change (slope) stages of load shedding.

[65] The Québec Interconnection requirements are found in the NPCC variance in the Eastern Interconnection table.

Table A.2: Western Interconnection[66] UFLS Program Settings			
Frequency Set Point (Hz)	Coordinated Plan	NWPP Sub-Area	Southern Island Sub-Area
59.6			.07%
59.5			4.0%
59.3		5.6%	
59.2		5.6%	
59.1	5.3%		2.8%
59.0		5.6%	
58.9	5.9%		6.5%
58.8		5.6%	
58.7	6.5%		7.4%
58.6		5.6%	
58.5	6.7%		7.4%
58.3	6.7%		7.3%
Total % Shed	**31.1%**	**28%**	**35.4%**
59.3 (stalling)	2.3% (15 sec)	2.3% (15 sec)	2.9%
59.5 (stalling)	1.7% (30 sec)	1.7% (30 sec)	2.1%
59.5 (stalling)	2.0% (1 min)	2.0% (1 min)	2.3%

Table A.3: Texas Interconnection UFLS Program Settings	
Frequency Set Point (Hz)	ERCOT
	All DSPs
59.5	
59.3	5%
59.1	
59.0	
58.9	10%
58.7	
58.5	10%
59.5 (10s)	
Total % Shed	**25%**

[66] https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Off-Nominal%20Frequency%20Load%20Shedding%20Plan.pdf&action=default&DefaultItemOpen=1

Appendix B: AEMO Analysis of High ROCOF Conditions

System inertia has declined in South Australia since 2012 due to retirement of synchronous generation as shown in **Figure B.1**. In August 2016, AEMO issued the *Future Power System Security Program Progress report*, which highlighted concerns over historical frequency response trends and system inertia. Specifically, the report described the possibility that the decline in system inertia (which causes a rapid increase in ROCOF following large disturbances) may cause frequency to decline too rapidly in South Australia for "UFLS to produce a well-coordinated and well-graded disconnection of load to arrest the frequency" during historical "non-credible" separation events.[67,68,69] Under Australia's National Electricity Rules, 60% of expected demand must be available to shed "in manageable blocks spread over a number of steps within underfrequency bands from 49.0 Hz down to 47.0 Hz as nominated by AEMO."[70]

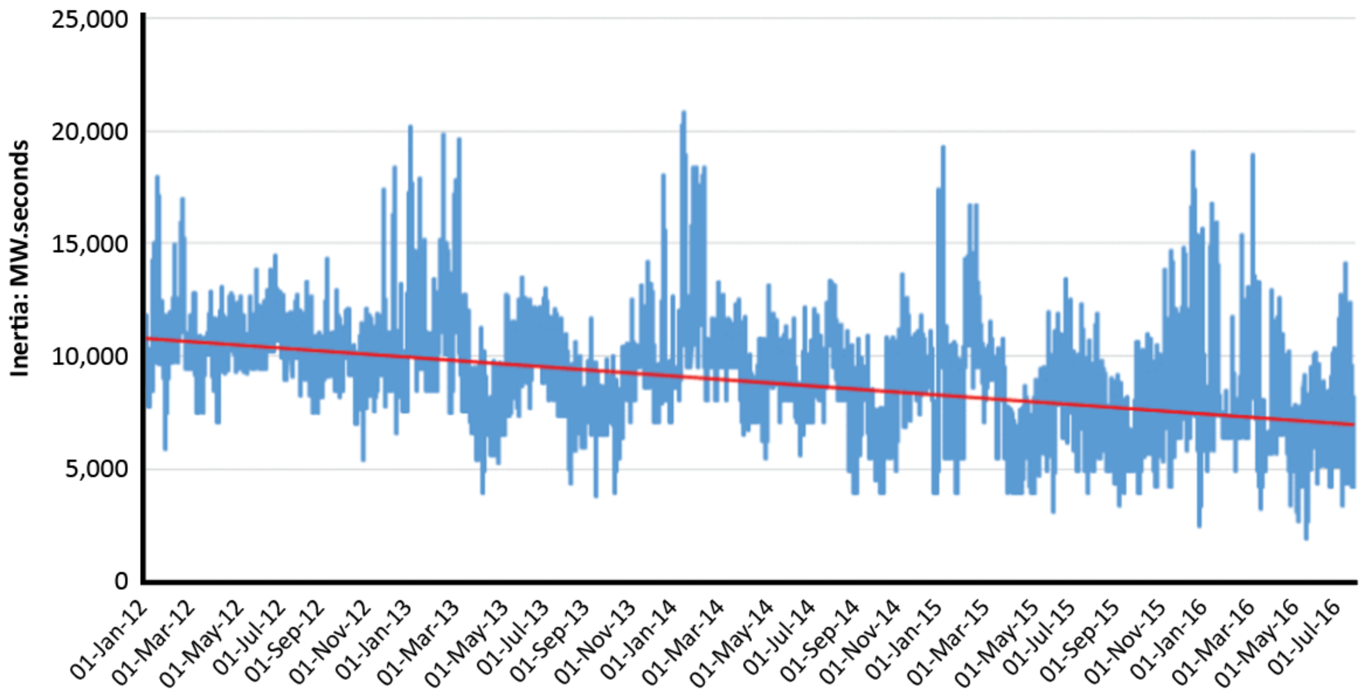

Figure B.1: System Inertia in South Australia [Source: AEMO]

A month later, on September 28, 2016, at 4:16 p.m. local time, South Australia's 1,826 MW of demand was supplied by 48% wind generation, 18% thermal generation, and 34% electricity imports (limited at 650 MW).[71] **Figure B.2** shows the resource mix at the time prior to the disturbance. According to AEMO, tornados tripped a single 275 kV transmission line and a double circuit 275 kV line. This resulted in six voltage dips over a two-minute period on the South Australia grid, causing wind farms to enter into successive fault ride-through operations and subsequent reduction output of 456 MW over a period of less than seven seconds. The generation reduction resulted in imports of nearly 900 MW, exceeding the 650 MW limit, tripping the interconnector and islanding South Australia from the rest of the system. **Figure B.3** shows the transient and sustained power reductions from the wind plants during the sequence of events.

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[67] The report is available here.

[68] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/823E457AEA5E43BE83DDD56767126BF2.ashx.

[69] https://www.aemc.gov.au/sites/default/files/content//NER-v77-Chapter-04.PDF

[70] Note that the nominal frequency in the Australian power system is 50 Hz.

[71] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf

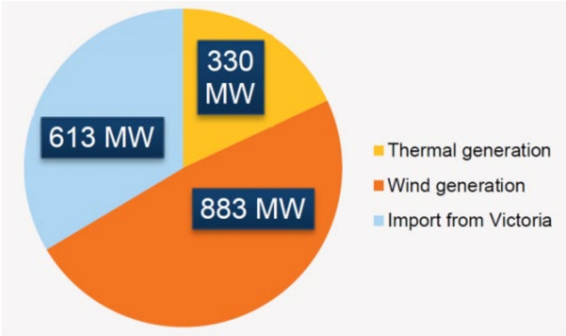

Figure B.2: South Australia Generation Mix Pre-Event [Source: AEMO]

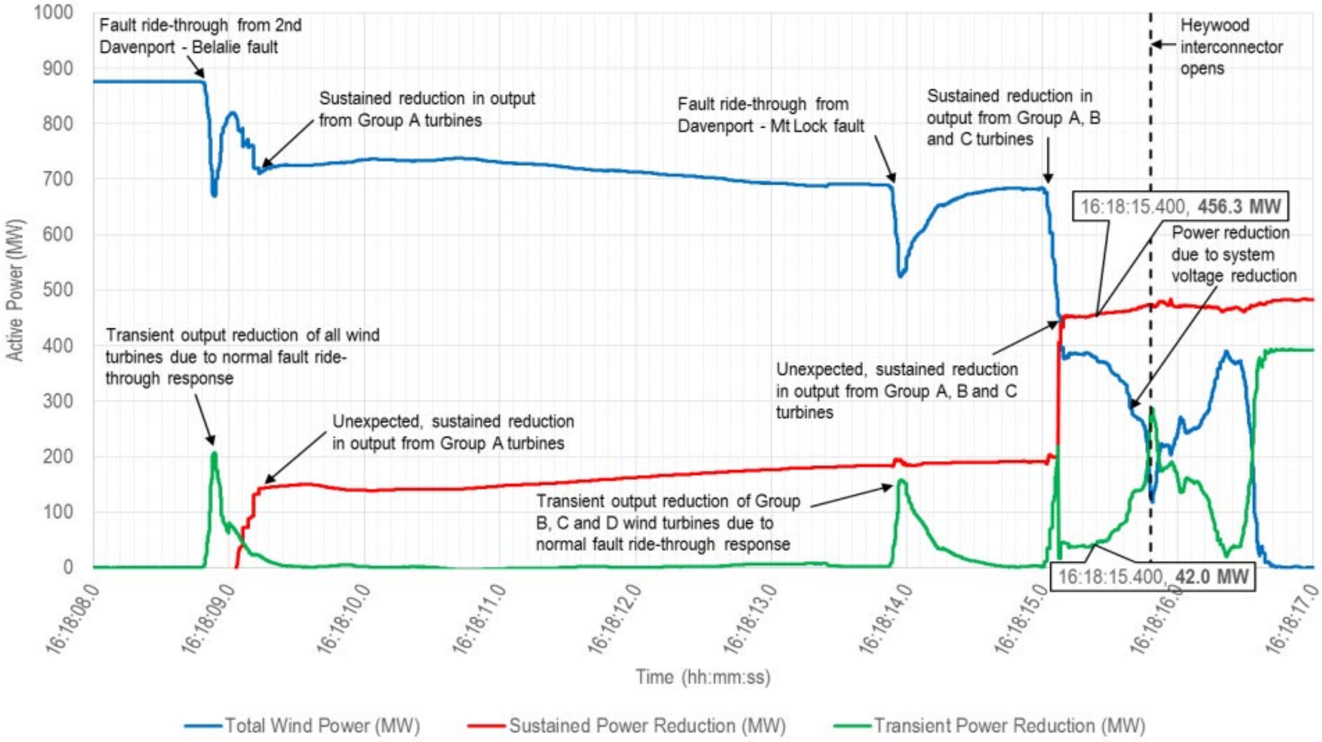

Figure B.3: Sustained vs. Transient Power Reduction of Wind Plants during September 28, 2016, AEMO Disturbance [Source: AEMO]

According to AEMO, ROCOF following separation of the South Australian system was 6.25 Hz/s (see **Figure B.4**), which was “too great for the UFLS scheme to operate effectively” as, had been identified a month earlier. AEMO explained that the primary reason for frequency instability “was that, in the absence of any substantial load shedding, the remaining synchronous generators and wind farms were unable to maintain the islanded system frequency.” The absence of inertial support and resulting high ROCOF caused by an unexpected large contingency event in South Australia caused the UFLS scheme to not operate.

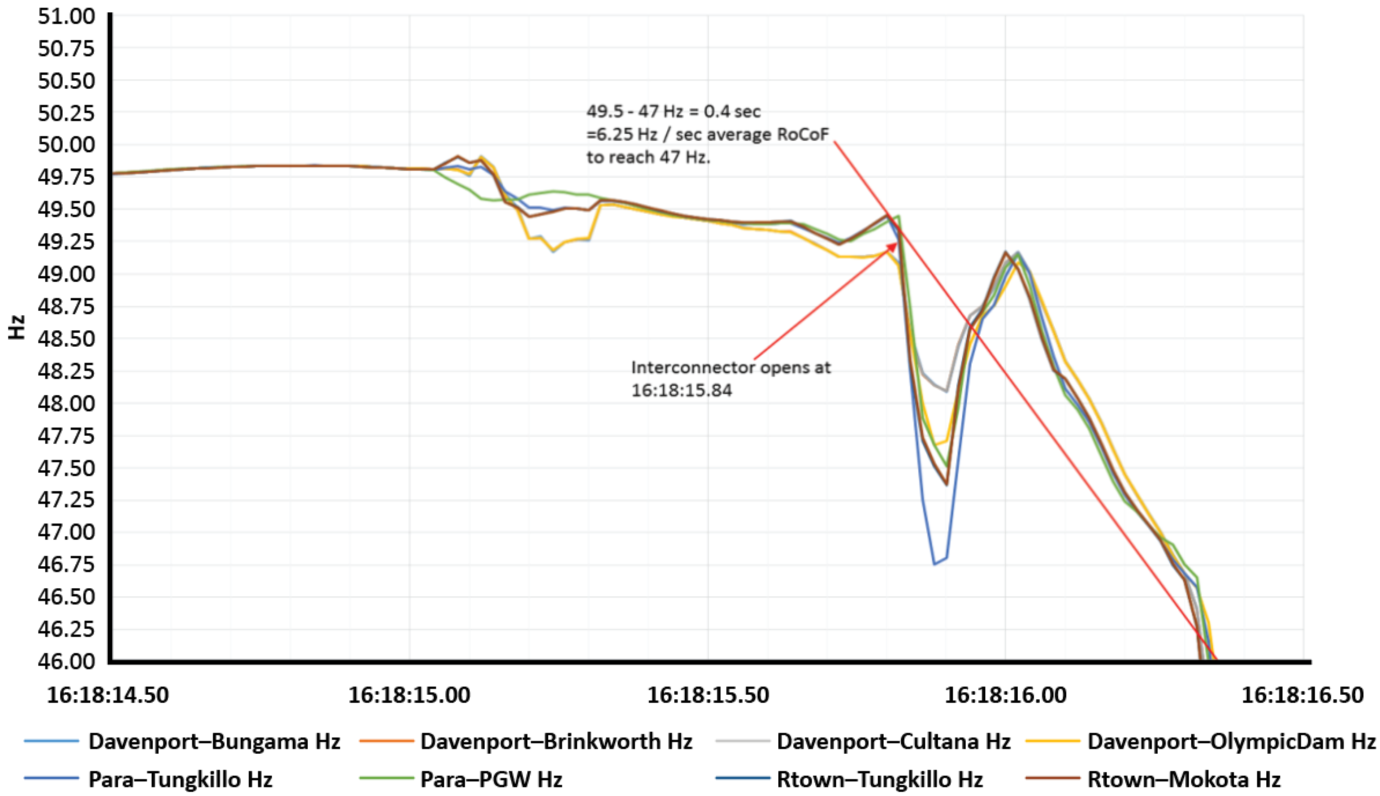

Figure B.4: Frequency and ROCOF in Various SA Nodes Immediately Before the System Separation [Source: AEMO]

After the blackout, AEMO identified a need for "sufficient inertia to slow down the ROCOF and enable automatic load shedding to stabilize the island system in the first few seconds." They have since implemented restrictions on the interconnector flow to ensure its loss (the largest expected contingency) does not result in a ROCOF that exceeds 3 Hz/s. They have also created a minimum requirement for the number of on-line synchronous generators as they face critical inertia levels to support existing fast frequency response and primary frequency response capabilities.

Since this event, AEMO has begun comprehensive work on UFLS, specifically looking into the DER impacts. **Figure B.5** demonstrates their emphasis on the importance to account for DER in underfrequency events at a high level. The net load disconnected from the system can vary depending on if the DERs disconnect during the underfrequency event, worsening frequency performance. As a result of their efforts, AEMO has implemented new network constraints to limit contingency sizes related to separation events in periods where the capabilities of UFLS to arrest system frequency are low. AEMO has also actively pursued a dynamic arming scheme to selectively disarm UFLS circuits with reverse flows in real time.[72]

[72] AEMO's work on this topic can be found here and here

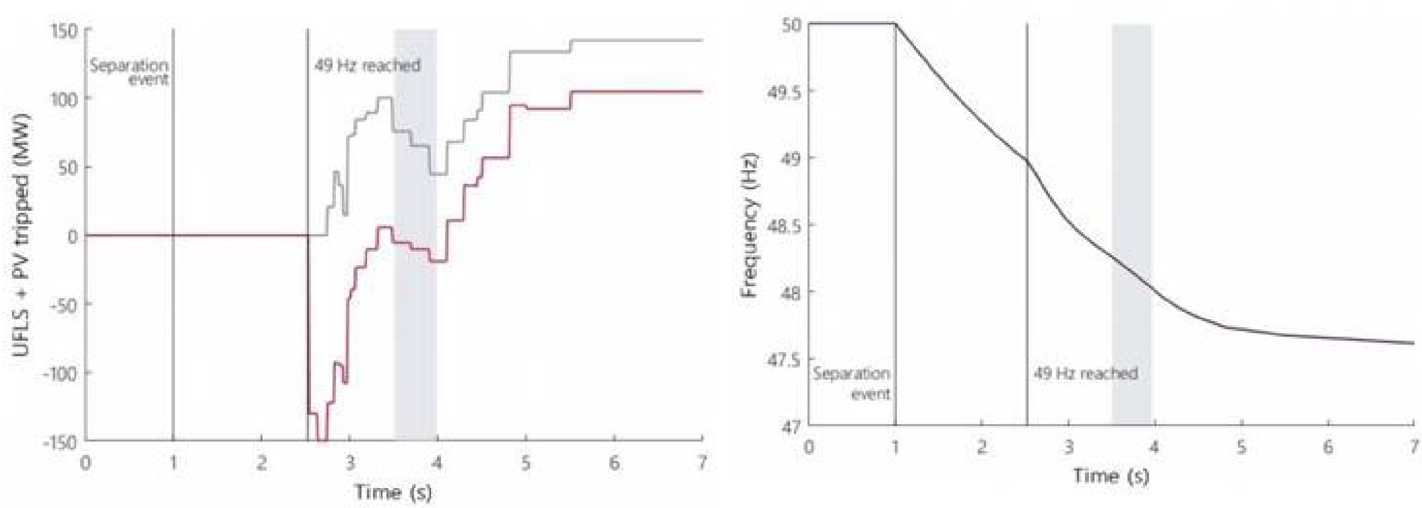

Figure B.5 Example of UFLS Operation during a Period with High Distributed PV Generation [Source: AEMO]

The South Australia experience demonstrates the importance of studying the impacts that decreasing system inertia can have on ROCOF and system frequency stability. While this example does not include DERs, DERs can and will contribute to decreasing system inertia. AEMO recently identified the importance of accounting for high levels of DERs in UFLS scheme design, suggesting the use of new "smart UFLS devices" like electric vehicles.[73]

System planning studies will need to ensure DERs are appropriately modeled such that their impact on system inertia can be appropriately captured. Inaccurate assumptions of sufficient inertial response can yield inaccurate simulation results of island-level performance during large underfrequency events. Therefore, PCs should ensure that off-peak demand conditions are also studied where local island system inertia may be at its lowest and ROCOF may be at its highest expected levels.

[73] http://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf

Appendix C: Hawaii Electric Light Case Study—Adaptive UFLS

HELCO has seen rapid adoption of DERs across its service territory on the Hawaii Island.[74] From 2011 to September 2019, the aggregate gross nameplate capacity of solar PV DERs in HELCO's service territory surged from 10 MW to 101 MW (see **Figure C.1**). The total nameplate capacity of DERs on the Hawaii Island is now twice as large as any other single generator on the island and nearly 50% of HELCO's historical peak load of 191 MW. The highest instantaneous penetration of DERs serving end-use load experienced by HELCO to-date is estimated to be in the excess of 80 MW. **Figure C.2** shows the widening range (greater variability) of average February net loads on the Hawaii Islands from 2011 to 2018.

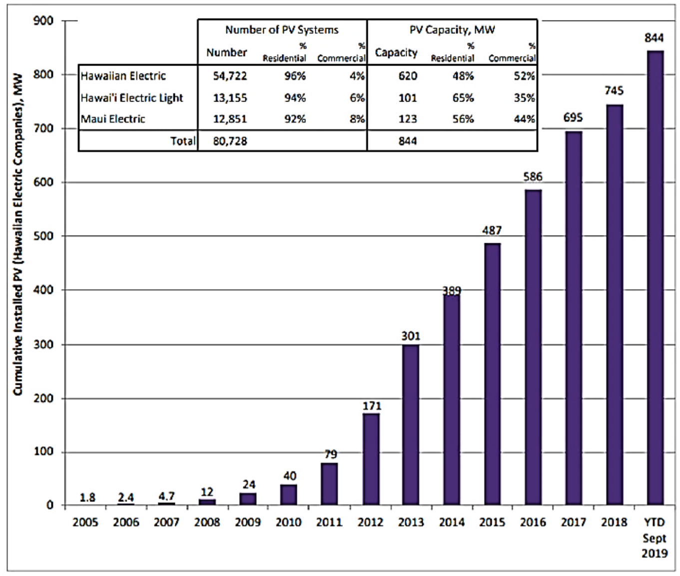

Figure C.1: Solar PV DER Growth across HELCO [Source: HELCO]

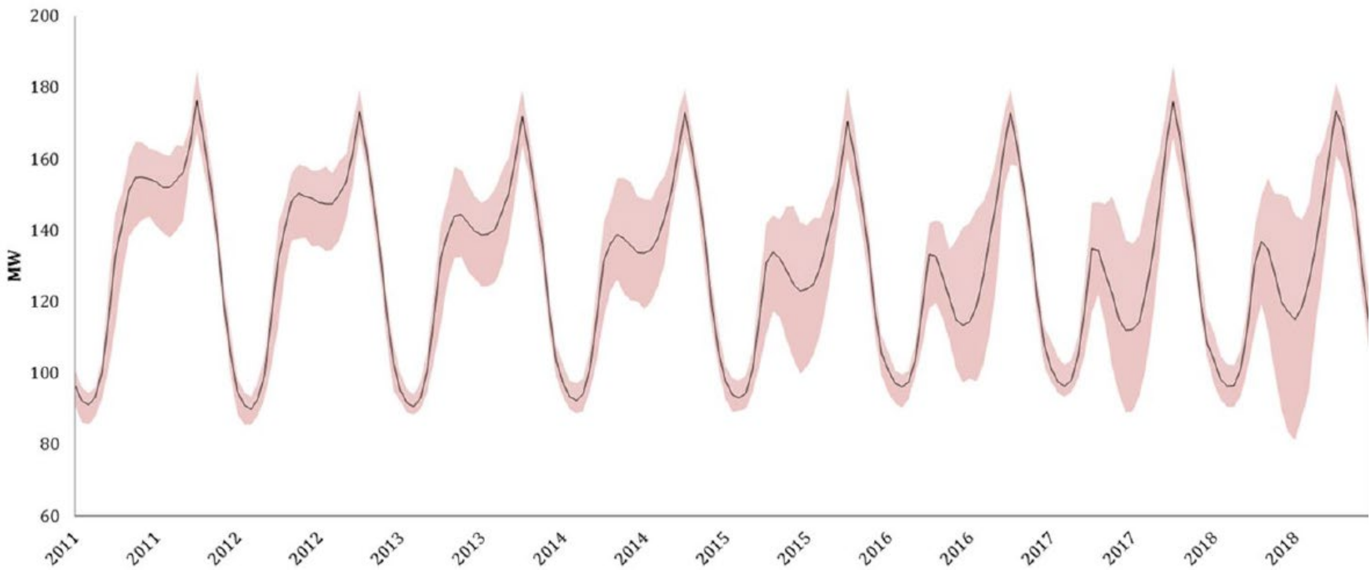

Figure C.2: Impact of DER on Hawaii Island's February Average Daily (Net) Load [Source: HELCO]

As an islanded network, balancing supply and demand on Hawaii Island has proven challenging, and HELCO currently relies on UFLS for a portion of its contingency reserves. Under high levels of DER penetration, reliable operation of its UFLS to maintain operation of the overall network during large power imbalances has been compromised. In 2014, HELCO conducted an initial study that determined its UFLS scheme was at risk of over-shedding load relative to the necessary amount per the specified requirements, leading to potential overfrequency conditions. The static UFLS

[74] R. Quint, et al., *Transformation of the Grid: The Impact of Distributed Energy Resources on Bulk Power Systems*, IEEE Power and Energy Magazine, vol. 16, iss. 6, pp. 35–45, October 2019. Available here

scheme in use at the time was set to shed blocks of predetermined net load at the feeder-level based on the historical amount of load on the circuit. The assumption in the static scheme was that the amount of load on the circuits in the blocks generally matched the total system demand. However, this is no longer the case with increasing penetrations of DERs.

Net loading on each feeder is influenced by the amount of DER production, and feeders may even be exporting power to the system for many hours of the day. Tripping these feeders would result in additional loss of net energy. Furthermore, the behavior of legacy DERs installed prior to current interconnection requirements places additional considerations on UFLS program design. The loss of aggregate DERs at legacy frequency trip settings of 59.3 Hz adds to the net energy loss during underfrequency events and exacerbates the loss of generation contingencies. On the other hand, a larger portion of legacy DERs may also trip for high frequency conditions at 60.5 Hz. This could pose risks of DER tripping exceeding the largest single generator contingency. Due to the increased risks of overfrequency, a critical aspect of the UFLS design is now avoiding over-shedding of load and reaching the 60.5 Hz trip point for the larger portion of legacy DERs.

Recognizing that the development and installation of the new UFLS scheme would take time, the static UFLS scheme was modified to reduce the possibility of over-shedding load by creating an additional load shed block and reducing the load in each block. In addition, circuits that had been included in a both an instantaneous stage and a delayed “kicker” stage were assigned to only one stage to ensure that the load in the delayed stages would still be retained if needed to return the frequency to 60 Hz even if the instantaneous stages operated to stabilize frequency for the initial disturbance.

Due to the rapid growth of solar PV DERs, HELCO identified a need for dynamic assignment of circuits to the UFLS scheme in real-time operations. The widespread variation of net load due to DER output variability across the distribution system caused HELCO to re-evaluate the ability of a static UFLS program. In 2015, HELCO studied how an “adaptive” UFLS scheme might serve both to target load shed from distribution circuits with variable net load throughout the day as well as to rapidly detect whether load shed is required on its system. Study results pointed to necessary changes to the static scheme to avoid over-shedding and under-shedding during different operating conditions. It was determined that HELCO would need to develop a custom application for an adaptive UFLS scheme to reflect both the amount of load shedding required and then dynamically assign circuits to the scheme stages. The application calculates the required amount of net demand required to be shed in real-time based on telemetered values from each distribution feeder circuit. Then, distribution circuits are automatically assigned to the underfrequency trip settings through communication to distribution circuit underfrequency relays. Furthermore, HELCO determined that UFLS operations based on ROCOF may be required in addition to the frequency trip settings and has planned to implement this feature in the future based on system needs. In all, over 40 substations required relay upgrades and real-time automatic controller installations. Around 78% of the distribution circuits, accounting for 70% of peak load, needed to be included in the scheme for its effective operation. Based on the urgency of the problem at hand, HELCO implemented the adaptive UFLS scheme in December 2017.

Settings for HELCO’s adaptive UFLS program are shown in **Table C.1**, including the frequency and ROCOF trip settings, the percentage of net system demand to be tripped at each stage, and the expected time of operation after the frequency threshold is passed.

Table C.1: HELCO Adaptive UFLS Load Shedding Scheme [Source: HELCO]

Stage	Setting [Hz]	% of Net System Demand [MW]	Time
df/dt*	0.5/sec	15%	9 cycle relay plus breaker time
1	59.1	5%	8 cycle relay plus breaker time
2	58.8	10%	8 cycle relay plus breaker time
3	58.5	10%	8 cycle relay plus breaker time

Table C.1: HELCO Adaptive UFLS Load Shedding Scheme [Source: HELCO]

Stage	Setting [Hz]	% of Net System Demand [MW]	Time
4	58.2	15%	8 cycle relay plus breaker time
5	57.9	10%	8 cycle relay plus breaker time
6	57.6	20%	8 cycle relay plus breaker time
Kicker 1a	59.3	5%	10 seconds
Kicker 1b	59.5		30 seconds
Kicker 2	59.5	5%	20 seconds

Stage 1 and stage 2 should sum to 15% of total system net load (maximum allowed load shedding for N-1 unit trips).
Stage 1 through stage 4 should sum to 40% of total system net load (maximum allowed load shedding for N-1-1 unit contingencies).
*Not currently active.

The program settings are static; however, they are based on the total net system demand that is continuously fluctuating. The allocation of distribution circuits to arm at any given time is dynamic and adapts to changing system conditions. The adaptive UFLS scheme selects which distribution circuits by using a priority order that consists of four categories:

1. Normal circuit (no tripping restrictions)
2. Restricted circuit (avoid tripping if possible)
3. Highly restricted circuit (last resort for tripping)
4. Not participating (do not trip)

Each distribution circuit is then assigned to blocks based on a participation factor of one through nine (see **Table C.2**) that is determined by using additional factors like whether a circuit has a "hot line tag"[75] and how many times it has previously been tripped as part of UFLS operations.

Table C.2: Customer Participation Prioritization [Source: HELCO]

Customer Priority	Priority Description	Participation
1	Normal circuit (no tripping restrictions)	1
		2
		3
2	Restricted circuit (avoid tripping if possible)	4
		5
		6
3	Highly restricted circuit (last resort for tripping)	7
		8
		9
4	Does not participate (do not trip)	10

After calculating MW targets for each UFLS stage based on the calculated total system net load in real-time, the energy management system assigns distribution circuits to UFLS stages to achieve the required MW load shed targets. **Figure C.3** shows a summary display used in the HELCO EMS adaptive UFLS scheme.

[75] Which blocks remote reclosing, should the circuit be tripped.

UFLS STAGE DATA

System Load: 141.853
Total Target: 112.185
Total Available: 114.292

Stage	Frequency	Percent	Target MW	Avail MW	Tol %	Tolerance	Delta MW
STAGE1	59.100	5.00	7.01154	6.82032	5.000	0.351	0.191
STAGE2	58.800	10.00	14.02308	13.83560	5.000	0.701	0.187
STAGE3	58.500	10.00	14.02308	13.34422	5.000	0.701	0.679
STAGE4	58.200	15.00	21.03462	22.24468	8.000	1.683	-1.210
STAGE5	57.900	10.00	14.02308	14.21575	8.000	1.122	-0.193
STAGE6	57.600	20.00	28.04617	25.46988	25.000	7.012	2.576
KICKER1	59.500	5.00	7.01154	6.79824	8.000	0.561	0.213
KICKER2	59.300	5.00	7.01154	6.54598	8.000	0.561	0.466

Figure C.3: Summary Display of HELCO Adaptive UFLS Scheme EMS [Source: HELCO]

While the adaptive UFLS scheme has performed well against multiple events over the past few years, it has limitations including the extent of the contingencies that it is planned for. In July 2019, an over-shedding of load occurred when a storm caused a quickly occurring n-1-1 event that disconnected a power plant while it was generating 40 MW. The sudden loss of 40 MW (28% of load) was outside of the planning criteria applied in designing the UFLS scheme and resulted in the highest ROCOF experienced on the system to date (in excess of 2Hz/Second); the resulting load shed of nearly all the instantaneous stages caused frequency to reach 61.0 Hz (see Figure C.4). While the storm conditions did limit the solar generation at the time, a still measurable and significant loss of solar generation in certain areas of the Island was observed due to the high frequency. This event demonstrates that even a fairly robust UFLS design will not always prevent significantly abnormal frequencies. This highlights the essential importance of grid-supportive interconnection requirements for DER with DER production becoming a potentially significant portion of on-line generation, including expanded ride-through capabilities and control.

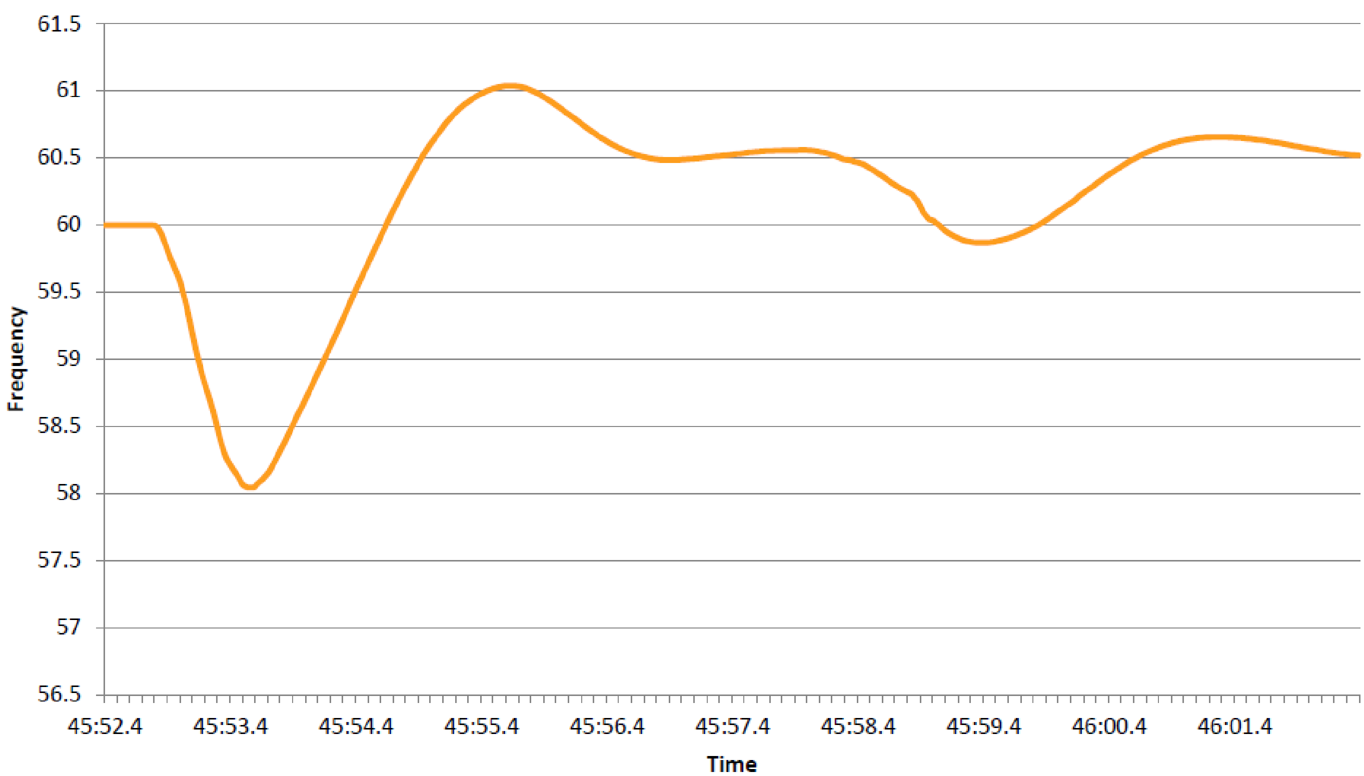

Figure C.4: July 8, 2019 UFLS Event on Hawaii Island [Source: HELCO]

As a result of this event, HELCO identified additional improvements to the UFLS program, including changes to UFLS block sizes, UFLS frequency thresholds, and enabling the ROCOF trip setting. The recommendation was for this to be implemented by the first quarter of 2020. In actual field implementation, it was found that the dynamic system behavior makes the ROCOF settings challenging and the initial implementation resulted in a small load shed during normally cleared faults.

Given that the loss of aggregate DERs with legacy frequency and voltage settings remains HELCO's largest contingency, HELCO has also identified a need for FFR from energy storage resources to reduce the incidence and impact of UFLS load shed. This FFR is procured through competitive bid.[76] The FFR storage resource is sized according to HELCO's resource plans and the level of aggregate DERs with legacy trip settings. The resource providing this service is required to have configurable parameters, a proportional response to changes in frequency outside a pre-defined deadband, have capability to respond to over and underfrequency events, and be able to maintain established state of charge. HELCO is presently managing the increasing amounts of variable and IBRs (particularly DERs) by procuring sufficient amounts of operating reserves and grid flexibility.

HELCO's experience with studying and implementing an adaptive UFLS scheme will prove invaluable to entities across North America as the BPS is faced with higher levels of aggregate DERs in the future.

76 https://www.hawaiielectriclight.com/documents/clean_energy_hawaii/selling_power_to_the_utility/competitive_bidding/20190822_final_stage_2_hawaii_variable_rfp.pdf

Appendix D: Impacts of DERs on ISO-NE UFLS Islanding Study

Driven by state policies and private investments, DERs have steadily grown in the ISO New England (ISO-NE) area. As of December 2018, there were over 157,000 solar PV DERs in ISO-NE that were under 5 MW with the vast majority of installations under 25 kW installations representing a total of 2,884 MW (see **Figure D.1**).[77] State-level distribution of solar PV DERs in ISO-NE for 2018 is shown in **Table D.1**. Massachusetts constitutes about 65% of the total installed solar PV capacity in the New England area. The 2019 ISO-NE solar PV DER forecast indicates a much faster growth of solar PV installations across the New England area in the coming years. **Figure D.2** illustrates ISO-NE's solar PV forecasts and how existing integration of DERs has far exceeded forecasts over the past five years.

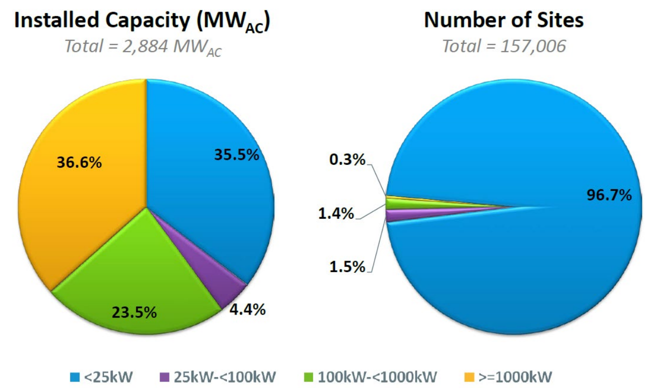

Figure D.1: Installed Solar PV Capacity as of December 2018 in ISO-NE [Source: ISO-NE]

Table D.1: 2018 Solar PV DERs in ISO-NE, by State [Source: ISO-NE]

State	Installed Capacity (MW)	Number of Installations
Massachusetts	1,871	90,720
Connecticut	464	35,889
Vermont	306	11,864
New Hampshire	84	8,231
Rhode Island	117	5,993
Maine	42	4,309
New England	**2,884**	**157,006**

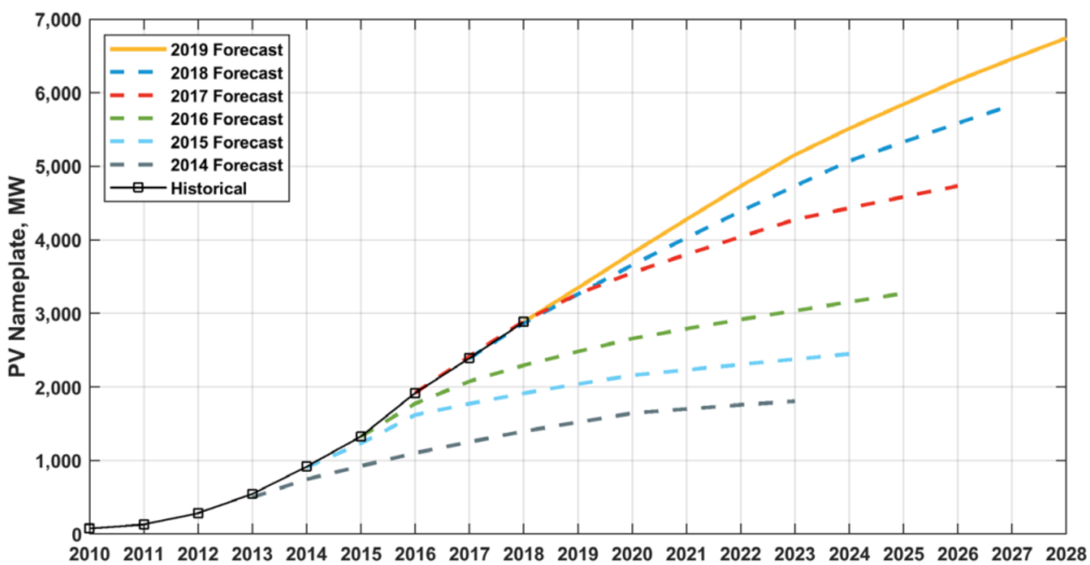

Figure D.2: Reported vs. Forecasted Solar PV DER Growth [Source: ISO-NE]

[77] ISO New England Final 2019 PV Forecast: https://www.iso-ne.com/static-assets/documents/2019/04/final-2019-pv-forecast.pdf

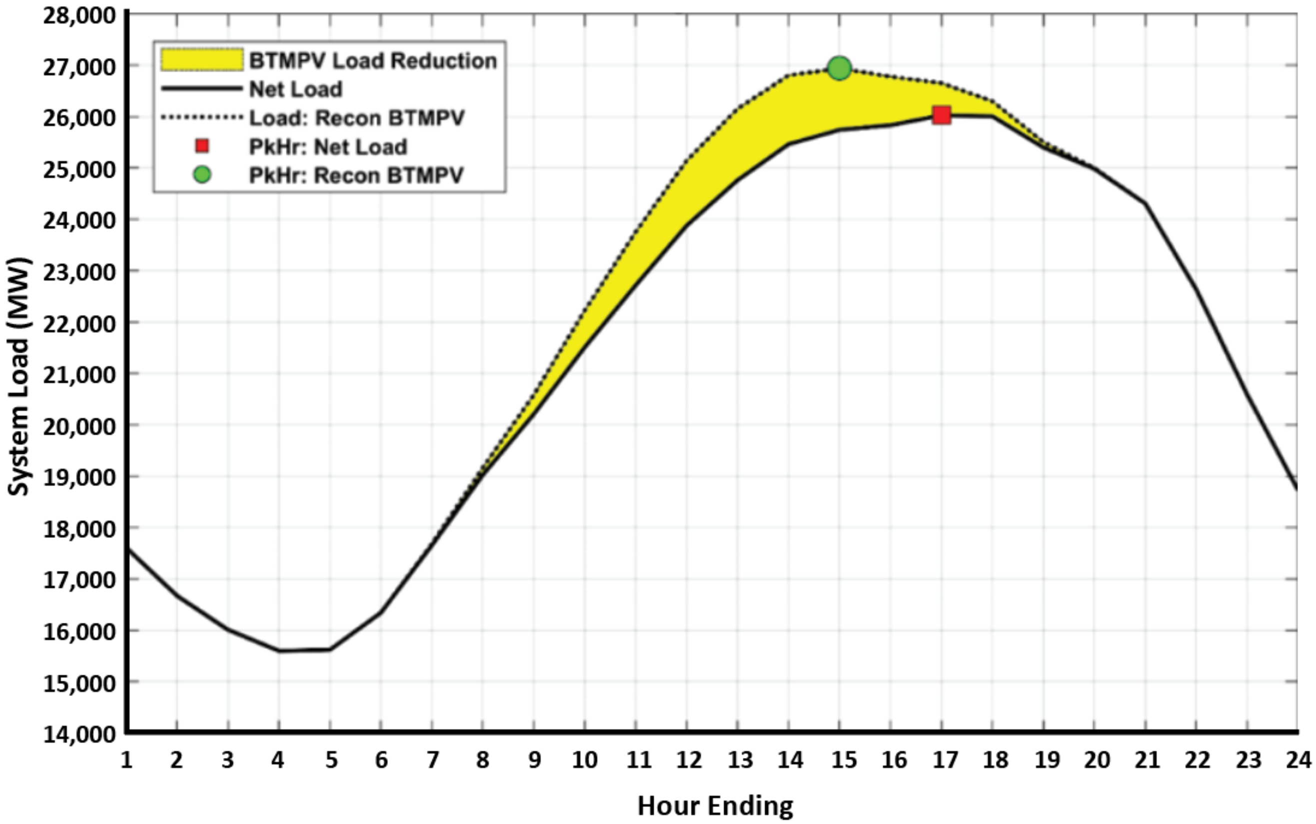

Figure D.3: Solar PV DER Offsetting Net System Load during Summer Peak—August 29, 2018 [Source: ISO-NE]

ISO-NE does not have direct visibility of the location or output of DERs since the majority of these resources do not participate in ISO-NE wholesale markets. Nevertheless, ISO-NE has observed how DERs (in aggregate) have reduced system net load and even shifted the system peak load in some cases. As an illustrative example, see **Figure D.3**. ISO-NE reconstituted the total expected gross load on its system by adding the expected level of DER output to the measured net load for a peak summer day in 2018. On this day, the peak net load (red square) of approximately 26,000 MW was not only lower than the peak gross load (green circle) of approximately 27,000 MW, but the hour of net peak load also shifted from 3:00 p.m. to 5:00 p.m.[78] Given the projected growth of aggregate DER projected in the ISO-NE 2019 solar PV forecast, it is important to understand the increasing penetration of DERs in the ISO-NE footprint and the potential impacts this can have on BPS performance (particularly during underfrequency disturbances).[79]

NPCC Regional Entity UFLS Program

NPCC Directory 12[80] describes the implementation plan for UFLS programs in the NPCC Regional Entity. With the adoption of PRC-006-NPCC-02, NPCC intends to retire Reliability Direction 12 in accordance with the NERC Rules of Procedure; nevertheless, these values were in effect to determine system performance requirements at the time of the study. **Table D.2** shows the stages of UFLS operation, the percentage size of each UFLS tripping block, and the operating times for load shedding actions. The NPCC UFLS program consists of five stages with four stages having about 7% of load shed at each stage. The fifth stage is an anti-stall stage that sheds an additional 2% load if the island frequency is below 59.5 Hz for more than 10 seconds.

[78] https://www.iso-ne.com/static-assets/documents/2019/03/a4_draft_2019_isone_annual_energy_and_summer_peak_forecast.pdf

[79] The results shown in this section do not represent the official results of ISO-NE as studies similar to this are being performed by SS-38 NPCC working group. However, the results do highlight some of the concerns that may need to be addressed with increasing DER penetration.

[80] Available here

Table D.2: NPCC Region UFLS Program PRC-006-NPCC [Source: NPCC]				
Stage	Threshold Setting [Hz]	Tripping Block Size [%]	Cumulative Load Shed [% of TO or DP Load]	Total Operating Time [s]
1	59.5	6.5–7.5%	6.5–7.5%	0.3
2	59.3	6.5–7.5%	13.5–14.5%	0.3
3	59.1	6.5–7.5%	20.5–21.5%	0.3
4	58.9	6.5–7.5%	27.5–28.5%	0.3
5*	59.5	2–3%	29.5–31.5%	10

Note: Total operating time is the load-weighted average for all load within a BA area with maximum deviation for any load limited to ± 50 ms.
* Anti-stall

UFLS Program Design Studies Incorporating DERs

ISO-NE used a 2023 summer peak base case with ISO-NE gross load of 28,176 MW and 5,200 MW of DERs. Following DER modeling guidelines,[81] DERs were modeled as either R-DERs or U-DERs in the power flow base case. A total of 2,200 MW were represented as R-DERs and 3,000 MW were represented as U-DERs. The load bus in the power flow base case was converted to six feeders, five feeders with R-DER resources and one feeder with U-DER resources (see **Figure D.4**). Key modeling assumptions were made, listed below:

- R-DERs are installed throughout the distribution system near the end-use loads and are located on feeders that may have UFLS relays. During underfrequency conditions, UFLS relays will trip feeders that include end-use load and R-DERs. End-use load and any co-located R-DERs are modeled to trip in a way that is consistent with NPCC Directory 12 frequency set points and load shed requirements (per **Table D.2**).
- R-DERs are evenly split among the feeders, a reasonable assumption since the objective of the study is to understand the impact of DERs on an islanded ISO-NE system. Therefore, the distribution of DERs among feeders is not of concern.
- U-DERs are modeled separately from the R-DERs so that they can be differentiated from any DERs that may be tripped by the UFLS relays. U-DERs are not located on the distribution feeders; therefore, they would not trip during operation of the UFLS relays.
- DERs are assumed to be compliant with IEEE 1547-2018 and assumed to meet the ISO-NE Source Requirements Document[82] establishing DER settings requirements within the ISO-NE footprint (see **Figure D.5**).
- DER models are implemented as follows:
    - R-DERs are modeled by using REGC_A and REEC_A dynamic models, voltage control is not used, constant real and reactive power mode (unity power factor) is assumed, and voltage and frequency tripping are modeled (see **Figure D.5**). Note that R-DERs trip along with the UFLS. The frequency settings are the same as the UFLS set points. This is to simulate the tripping of load and a DER at the same time. In PSS/E version 33.12.1, the load and the DER cannot be modeled as a single composite load as in Version 34 and above; hence, the two components were split.
    - U-DERs are modeled by using REGC_A, REEC_A, and REPC_A dynamic models, voltage control is included, plant controls are included, and voltage tripping is modeled (see **Figure D.5**).
        - Frequency trip settings for U-DERs are much lower than the NPCC UFLS set points shown in **Table D.2** and have longer trip times; therefore, frequency tripping of U-DERs is not included. Note that R-DER are part of the load; hence, they would trip with the load. The U-DERs are

[81] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[82] https://www9.nationalgridus.com/non_html/ISO%20New%20England%20Source%20Requirement%20Document-2018-02-06.pdf

separate and their frequency timer settings are more than the UFLS set points. For example, at 58.5 Hz, the trip setting is 300 seconds. The simulation is run for 60 seconds only before which the frequency has to go above 59.5 Hz. So U-DER frequency tripping has not been included.

- Second generation renewable models were used at the time of study due to an implementation issue in the DER_A model, which has been resolved. Previous SPIDERWG reliability guidance on the choice of dynamic models representing aggregate DERs should still be used when performing such studies.

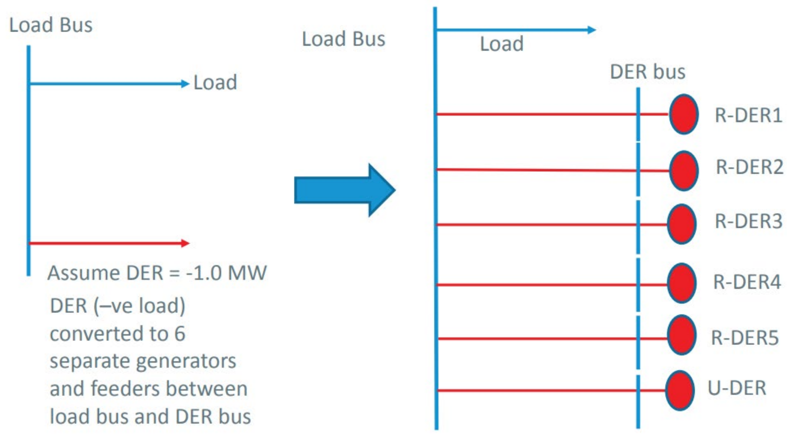

Figure D.4: DER Modeling in Power Flow [Source: ISO-NE]

Shall Trip – IEEE Std 1547-2018 (2nd ed.) Category II					
Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category II		
	Voltage (p.u. of nominal voltage)	Clearing Time(s)	Voltage	Clearing Time(s)	Within ranges of allowable settings?
OV2	1.20	0.16	Identical	Identical	Yes
OV1	1.10	2.0	Identical	Identical	Yes
UV1	0.88	2.0	Higher (default is 0.70 p.u.)	Much shorter (default is 10 s)	Yes
UV2	0.50	1.1	Slightly higher (default is 0.45 p.u.)	Much longer (default is 0.16 s)	Yes

Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category I, Category II, and Category III		
	Frequency (Hz)	Clearing Time(s)	Frequency	Clearing Time(s)	Within ranges of allowable settings?
OF2	62.0	0.16	Identical	Identical	Yes
OF1	61.2	300.0	Identical	Identical	Yes
UF1	58.5	300.0	Identical	Identical	Yes
UF2	56.5	0.16	Identical	Identical	Yes

Figure D.5: Voltage and Frequency Trip Settings for DERs—ISO-NE SRD Requirements [Source: ISO-NE]

Figure D.6 below shows the percentage of R-DERs tripped and the associated frequency trip points. These percentages have been applied to all R-DERs in the load flow case. The frequency trip settings for an R-DER correspond with the UFLS program settings. This has been done to simulate the tripping of load as well as an R-DER at the set points as dictated by the UFLS program.

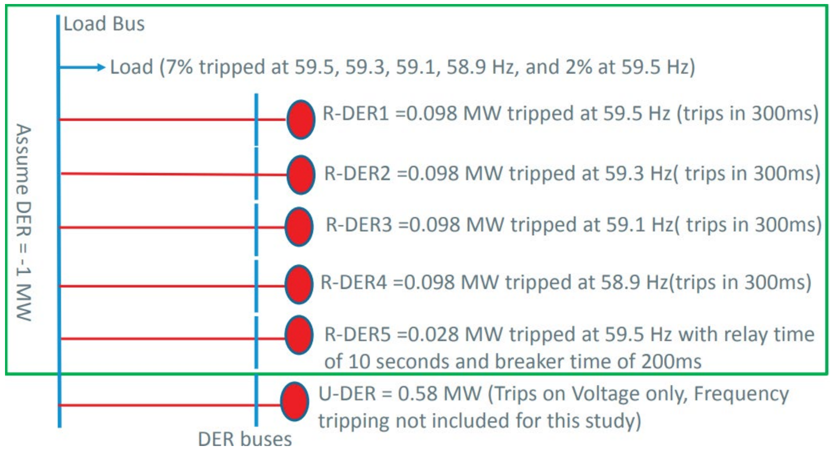

Figure D.6: Load Shed and Assumed Split of R-DER and U-DER with trip settings

Impact of R-DERs on Deficiency Calculations per PRC-006

ISO-NE assumes that DERs are evenly distributed across its system, a practical modeling assumption for R-DERs and U-DERs since PRC-006 focuses on an electrical island-level impact. The UFLS program must meet specific underfrequency performance requirements caused by an imbalance defined as follows:

$$Imbalance = \frac{Load - Actual\ Generation\ Output}{Load}, of\ up\ to\ 25\%\ within\ the\ identified\ island(s)$$

As described in **Chapter 2**, if “load” is assumed as net demand, then the deficiency for analyzing the 2023 Summer Peak Scenario would be 25% of 25,976 MW (28,176 MW of gross load minus 2,200 MW of R-DER), or 6,494 MW. If “load” is assumed as gross demand, then the deficiency would be 25% of 28,176 MW, or 7,044 MW. **Figure D.7** shows the electrical island frequency response for a simulated deficiency of each scenario. The simulation clearly shows that using gross load results in a deeper frequency nadir and a slower recovery in frequency (due to a larger deficiency). Furthermore, the simulations here show that it would be compliant with the UFLS program requirements if ISO-NE used the 25% imbalance based on net demand; however, assuming a 25% deficiency based on gross demand would result in simulations that do not meet the performance calculations (and additional load shedding would be required).

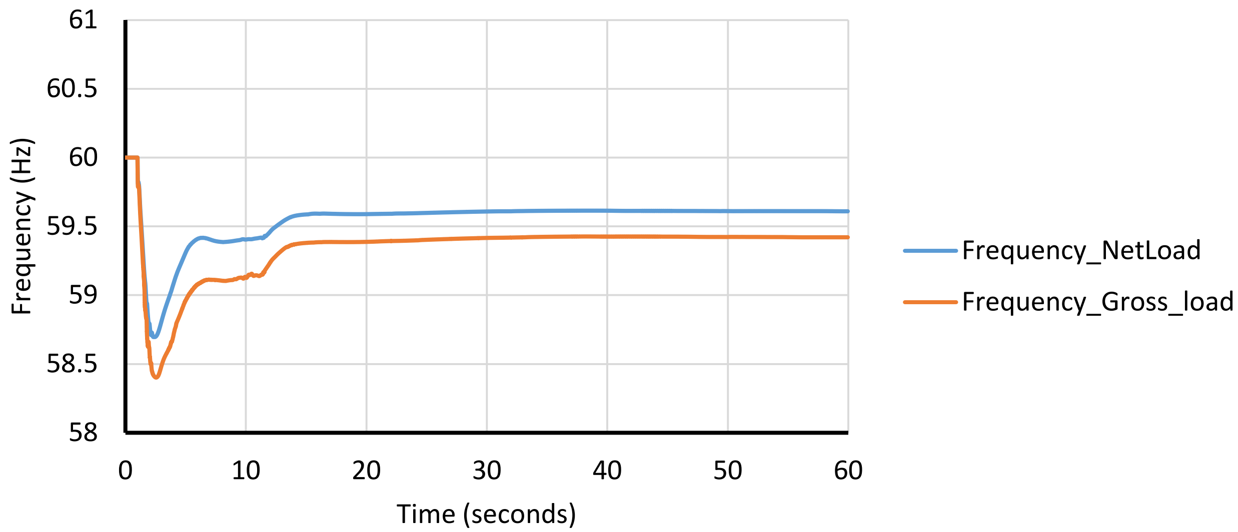

Figure D.7: Net Load versus Gross Load

Tripping of U-DER Due to Voltage Fluctuations

Subsequent to frequency recovering above 59.5 Hz, the loss of load due to UFLS action causes the bus voltages to rise to a level and for a duration that may exceed the trip settings of U-DERs, causing U-DERs to trip. Figure D.8 below shows the bus voltages at a U-DER location, causing it to trip on voltage trip settings. The bus voltage exceeded 1.1 pu for more than two seconds and, based on *Inverter Source Requirement Document of ISO New England (ISO-NE)*[83] Table-1 settings, U-DERs tripped.

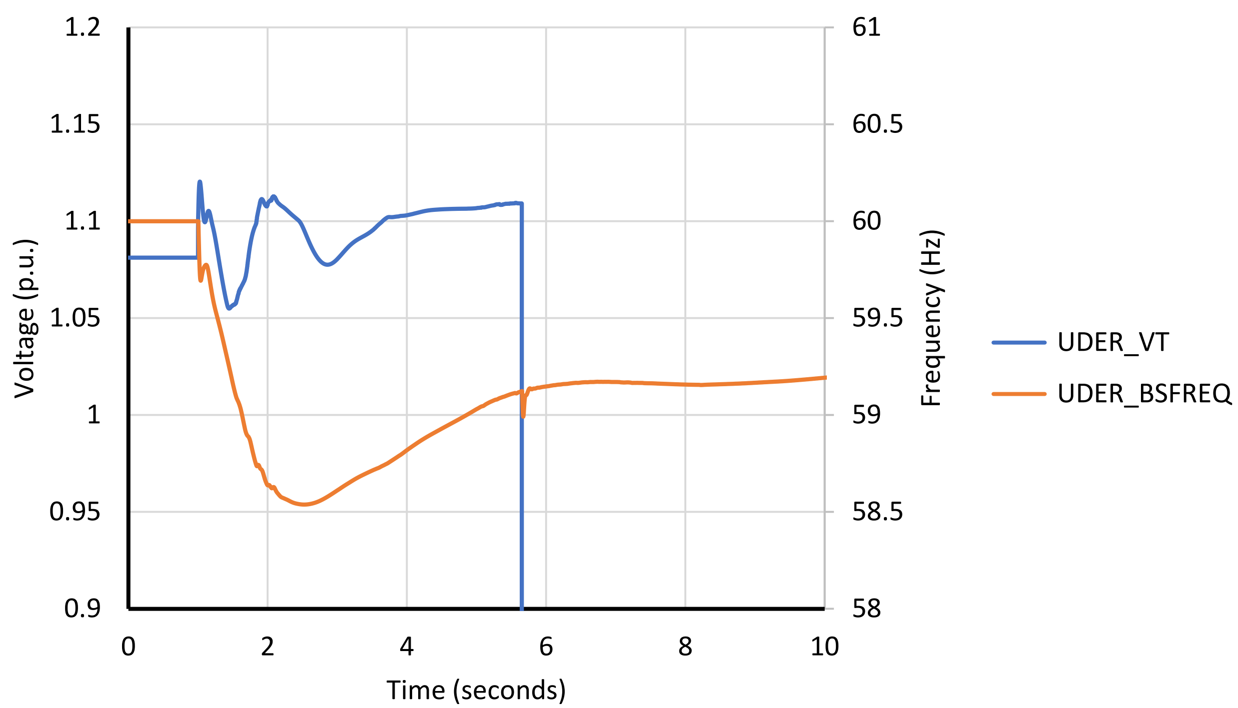

Figure D.8: U-DER Tripping on Voltage Due to UFLS

[83] https://www9.nationalgridus.com/non_html/ISO%20New%20England%20Source%20Requirement%20Document-2018-02-06.pdf

The loss of U-DERs due to voltage trip settings further adds to the island generation deficiency. It is quite possible that, due to this additional generation deficiency, the island frequency may not recover above 59.5 Hz and hence may violate the requirements as shown in **Figure D.9** below.

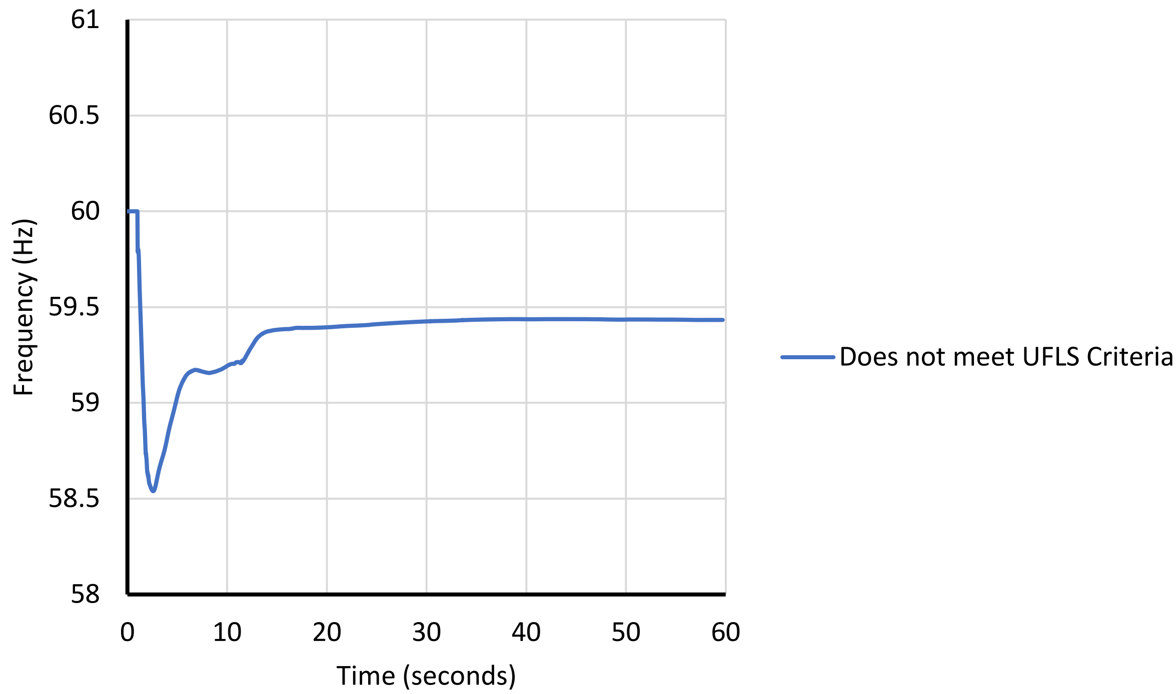

Figure D.9: ISO New England Island Frequency Performance

UFLS Program Design with DER Impacts

High penetration of DERs in the system may require compensatory load shedding to make up for the loss of DERs during underfrequency conditions. Under NPCC Directory 12 requirements (now replaced by the regional Reliability Standard PRC-006-NPCC requirements), generating units shall not trip for underfrequency conditions in the area above the curve as shown in **Figure D.10** below.

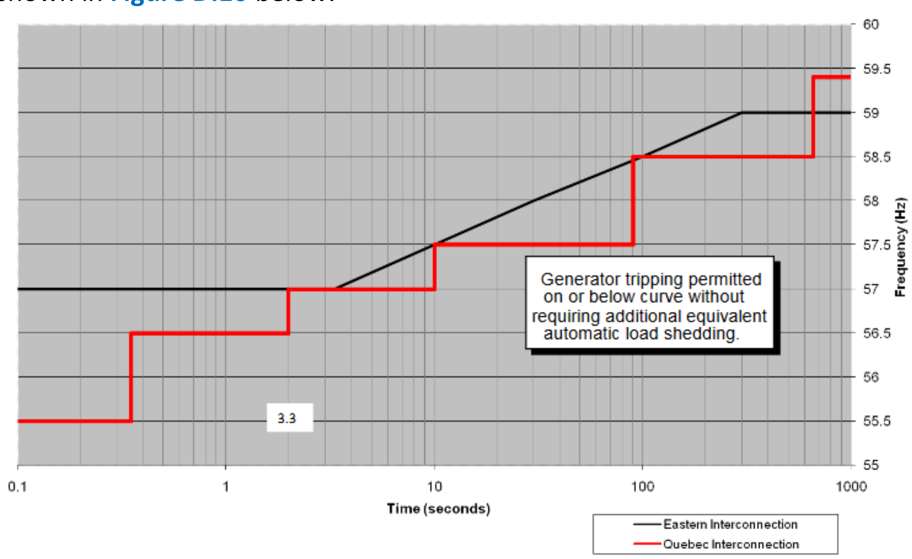

Figure D.10: Standards for Setting Underfrequency Trip Protection for Generators

If one considers the total R-DER that trips above the black curve in **Figure D.10** as a single aggregated unit, then additional compensatory load shedding may be needed to cover for the loss of the R-DERs. Including an additional compensatory load shedding percentage to cover for the loss of the R-DERs helps the island frequency to recover above 59.5 Hz and makes the UFLS program compliant. **Figure D.11** below shows the island frequency with compensatory load shedding.

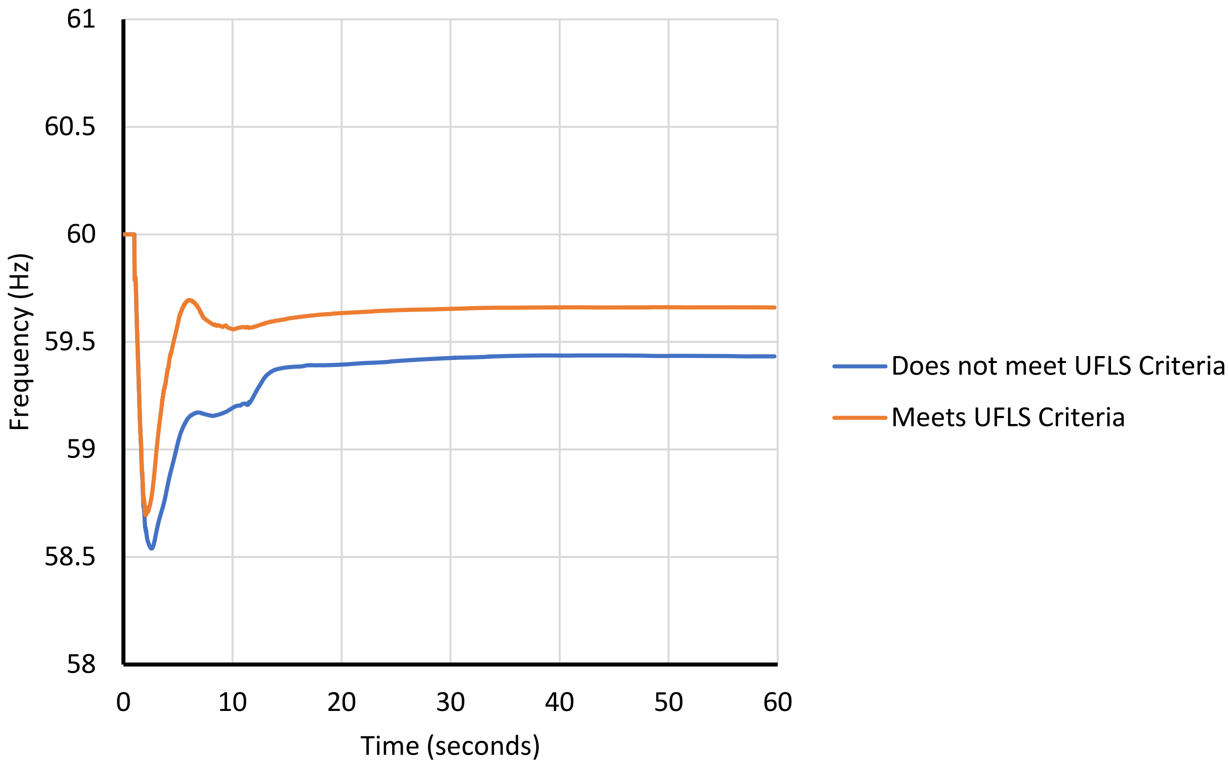

Figure D.11: ISO New England Island Frequency with Compensatory Load Shedding

Guideline Information and Revision History

Guideline Information	
Category/Topic: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs	**Reliability Guideline/Security Guideline/Hybrid:** Reliability Guideline
Identification Number: RG-MOD-0721-1	**Subgroup:** SPIDERWG

Revision History		
Version	**Comments**	**Approval Date**

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Errata

3/8/2022 – The word “SER” was changed to “DER” in the Executive Summary.