A Novel Underfrequency Load-Shedding Solution to Avoid Blackouts Under Low System Inertia Conditions

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Abstract*—Underfrequency load shedding (UFLS) has been used for decades to maintain the balance of load and generation after a loss of generation. Most, if not all, of the Planning Coordinators in North America utilize the same UFLS strategy that was originally devised after the 1965 northeast blackout. This method has worked effectively, but the makeup of the electric grid that this specialized relaying protects has changed immensely in the last 20 years. Especially since the last blackout on United States soil, which was the Arizona Public Service-Southern California blackout in 2011. There has been a rapid influx of renewable generation in North America, and it is replacing and displacing synchronous generation, which is reducing electric system inertia. As system inertia continues to decrease, the rate-of-change of frequency (ROCOF) during a frequency excursion increases. This increases the likelihood that too much load will be shed, resulting in frequency overshoot and the possibility of generation tripping on overfrequency, which leads to a possible blackout. This paper presents a novel, patent-pending approach to UFLS. This approach is simple to implement and uses conventional microprocessor relays that are deployed remotely in the field. The relays are programmed utilizing ROCOF supervision to trip the right amount of load under low system inertia conditions, thus minimizing the possibility of a systemwide blackout. A unique, Integrated Protection Planning Simulation (IPPS) tool was used to perform UFLS program studies under variable system inertia conditions. The system studied was a scaled-down, realistic 2000 MW system, representative of an actual utility system. Test results for the ROCOF-supervised and conventional UFLS programs were obtained and compared. Studies proved that the ROCOF-supervised UFLS program resulted in less load shed, final frequencies within +/– 0.5 Hz of nominal, and no instances of final frequencies that could result in a blackout.

I. INTRODUCTION

Automatic underfrequency load shedding (UFLS) has been used in North America as a last ditch, first line of defense to minimize the possibility of systemwide blackouts since the late 1960s [1]. Blackouts, though uncommon, have been a part of the history of electricity in the United States (U. S.) since electrification began in the early 1900s. Notable U. S. blackouts are discussed in [1], such as the 1965 and 2003 northeast blackouts, the 2011 Arizona Public Service (APS)- Southern California blackout, and the 2016 South Australia blackout.

Both the APS-Southern California and South Australia blackouts started with a series of unfathomable events that ultimately led to massive imports of power over tie lines that were incapable of carrying the additional load. These two blackouts, though smaller and less impactful than the northeast blackouts, are significant and relevant today as explained in the following sections, especially given the changing generation resource mix of North American electric grids.

In the Southern California Edison (SCE) system, at the San Onofre Nuclear Generating Station (SONGS), load flowing south to San Diego Gas & Electric (SDG&E) was greater than the 3,200 MW limit of the SONGS separation scheme. This scheme operates to isolate SCE generation at SONGS from the five 230 kV lines South of SONGS that feed into SDG&E. When the SONGS separation scheme operated to form an SDG&E, APS, and Comisión Federal de Electricidad (CFE) island, 3,400 MWs of import power into the region was lost, resulting in a severe deficit of generation to feed the 7,300 MWs of remaining load (import power at time of trip was 47 percent of island generation). All levels of UFLS operated, tripping about 3,800 MWs of load. An additional 600 MWs of generation also tripped but left a 200 MW deficit in generation. Frequency continued to decay below 57 Hz, resulting in additional generator tripping and a system blackout [2].

In South Australia, supercell thunderstorms with severe lightning caused multiple transmission faults within a 2-minute window. These faults resulted in voltage dips that exceeded the low-voltage ride-through count capability of multiple wind farms, which caused them to cease producing power. In all, about 450 MWs of wind generation were lost. This loss of generation resulted in an increase of import power from Victoria, exceeding the maximum power transfer capability of the two 275 kV tie lines. Both tie lines correctly tripped on out-of-step, resulting in a loss of about 900 MWs of import power. The loss of 900 MWs of import power (about 49 percent of island generation) coupled with low system inertia (only 18 percent of total generation was synchronous generation) resulted in all levels of UFLS tripping, but not enough load was tripped fast enough to prevent a blackout and loss of 1,826 MWs of load [3].

The 2011 APS-Southern California blackout is significant today, because it is the *last* blackout that occurred on U. S. soil and the observed rate-of-change of frequency (ROCOF) during this event ranged from 2 to 3 Hz/s. The South Australia blackout is significant today because the percentage of renewable generation to balancing area loads in North America, especially in certain regions, is approaching or exceeding the 48 percent of wind generation that was present in South Australia during the 2016 blackout. Additionally, measured ROCOF during the South Australia blackout peaked at around 6 Hz/s! These blackouts are relevant today because both resulted in a ROCOF that was greater than the ROCOF for which the existing UFLS program is designed.

The APS-Southern California and South Australia blackouts both culminated in a massive loss of import power of almost 50 percent. This loss of generation in the form of import power alone was enough to result in a high ROCOF. The low system inertia of the South Australia system following separation from Victoria is of the most concern, because both variables that cause high ROCOF (i.e., large loss of generation and low system inertia) were critical and the ROCOF in South Australia was *double* that observed in the APS-Southern California blackout.

Blackouts are rare, occurring only about every 10 to 15 years in North America since the 1965 northeast blackout. Rare though they are, blackouts can have a significant economic, health, and welfare impact on affected communities, so preventing them or at least minimizing their impact should be a high priority for electric service providers. It is estimated that the economic cost of the APS-Southern California blackout was at least $100 million (about $35 per customer) [4]. It is estimated that the economic cost of the 2003 northeast blackout was about $6 billion ($120 per customer) [5]. In 2024 dollars, the cost of these blackouts would be about $140 million ($49 per customer) and $10.3 billion ($206 per customer), respectively. Assuming the next blackout on U. S. soil affects 1 million customers, at a cost of $100 per customer, the economic impact could top $100 million.

Since the 2011 APS-Southern California blackout, a renewable energy revolution has occurred. In fact, just a dozen short years after this blackout, wind and solar generation has quintupled in the U. S. from 50 GWs to nearly 250 GWs of nameplate capacity, as shown in Fig. 1 [6]. The massive influx of renewable generation is beginning to replace and displace fossil (synchronous) generation. Since wind and solar generation are intermittent (nondispatchable), synchronous generation is forced offline when the wind blows and when the sun shines. As more synchronous generation is forced offline, system inertia decreases and the probability of higher ROCOF during a frequency excursion increases.

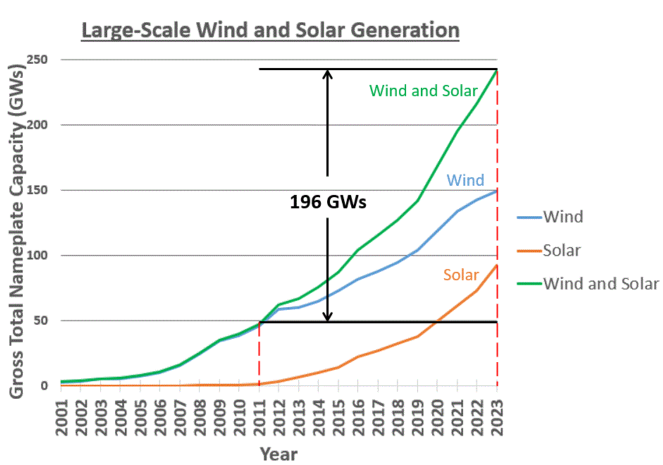

Fig. 1. Ramp-up of wind and solar generation since the last U.S. blackout.

Varying and higher ROCOF during a frequency excursion caused by loss of significant generation or import power has rendered traditional UFLS programs obsolete. Studies on a 1/3rd scale test system (2,000 MWs), representative of the Xcel Energy New Mexico/Texas system, has proven this. These studies were conducted using an Integrated Protection Planning Simulation (IPPS) tool, during which varying amounts of generation were tripped (5 to 40 percent of total system load) to create a series of underfrequency conditions. This process was conducted on four different systems with 0 percent, 25 percent, 50 percent, and 67 percent Type 4 wind farms, replacing equivalent percentages of synchronous generation. These reductions in synchronous generation resulted in comparable percentage reductions in system inertia. Study results for the 67 percent-reduced-inertia system using a conventional UFLS program led to a system blackout on severe overfrequency or underfrequency for 40 percent of the cases studied.

Maintaining the status quo regarding UFLS strategies is not viable in renewable-generation-dominated electric systems. If the status quo is maintained, blackouts, millions of dollars in economic loss, North American Electric Reliability Corporation (NERC) fines, and bad publicity will become more common. This paper presents a novel, cost-effective UFLS strategy that minimizes the possibility of blackouts.

II. Designing an Effective UFLS Program

UFLS programs are necessary to stabilize a system after a sudden loss of significant amounts of generation. Under normal power system conditions, a balance of generation and load exists, resulting in normal frequency (i.e., 60 Hz in North America). When a significant loss of generation occurs (e.g., a generation loss of 10 percent or more of the balancing area load), frequency begins to droop because the remaining generation cannot supply the existing load. If the balance of generation and load is not restored, frequency can continue to decrease, possibly to a point where damage can occur to remaining loads and generators. To remedy this situation as quickly as possible, underfrequency relays are distributed throughout the power system to trip loads at predetermined frequency set points to regain the balance of generation and load.

UFLS program design is a mostly forgotten activity from a bygone era. The 1965 northeast blackout was the catalyst for broadscale adoption of UFLS across North America in the late 1960s. The designs of these UFLS programs by electric utilities were mostly the same, consisting of a percentage of total system load, shed in multiple steps and at different frequency set points, with some intentional relay operation time delay.

Early UFLS programs were developed based on actual events and general system knowledge by the experienced engineers of the time. Beginning in the 1970s, positive-sequence load-flow programs began to emerge, allowing engineers to study the power system in more detail to validate and better fine-tune UFLS programs. Today, system planning simulation tools have advanced to the point that dynamic UFLS events can be simulated across a power system to fully vet a program's efficacy. However, having this capability does not disregard the wisdom and experience of seasoned engineers who know how a particular power system might fall apart.

UFLS events generally occur after an unforeseen, unstudied series of multiple, inconceivable contingencies occur, usually in a short period of time that precludes transmission operator intervention. The contingencies that cause UFLS are well outside the N-1 or occasional N-2 criteria that diligent transmission planners study to design a reliable, cost-effective power system. Anticipating the contingencies that might precipitate a UFLS event is nearly impossible. Therefore, UFLS programs generally work under the assumption that a system has had a series of cascading outages of transmission or generation elements that result in an islanded system with a generation deficit. From this extreme starting point, steps can be followed to develop a UFLS program for the system under study. Two excellent references [7] [8], written in the late 1960s and early 1970s, discuss the steps required to design an effective UFLS program; they are outlined in the following subsections.

A. Maximum Loss of Generation or Import Power

The initial step in developing an effective UFLS program is to determine the maximum anticipated loss of generation or import power. Usually, the maximum value is one of the following:

- Loss of the largest system generator or loss of an entire power plant that may include multiple units.
- Loss of multiple generators or power plants that are interconnected to the power system through only a few transmission lines that could all trip and isolate the generation.
- Loss of interregional tie lines importing power into a portion of the power system.

The utility system is a 6,200 MW summer-peaking electric system connected to the Southwest Power Pool (SPP) portion of the Eastern Interconnection (EI) via 10 transmission tie lines, depicted in Fig. 2. In the late 1970s and early 1980s, two coal-generating plants were added to the system. A coal plant in the Texas North part of the system consisted of three 350 MW units, and the other in the Texas South part of the system consisted of two 540 MW units. The total summed tie line import limits with all ten tie lines in service are 1,885 MWs, based on a 0.90 per-unit voltage constraint at a Texas North substation 345 kV bus. Total summed tie line operating limits account for the loss of one of the 540 MW coal units, yielding an operating limit of 1,885 – 540 = 1,345 MWs. Tie line operating limits decrease for various combinations of N-1 and N-2 tie line outages. The lowest tie line operating limit under a specific N-2 condition is 540 MWs.

The loss of the largest utility power plant at full generating capability would result in the loss of 1,080 MWs of total generation. Loss of all tie lines carrying maximum import power allowed by the tie line operating limit would result in the loss of 1,345 MWs. Historical UFLS events on the utility system have happened under weakened system conditions, at which multiple SPP tie lines have been out of service, then a sudden loss of 500–1,000 MWs of generation occurs. Based on the previous scenarios, the maximum loss of generation or import power for this system is 1,345 MWs.

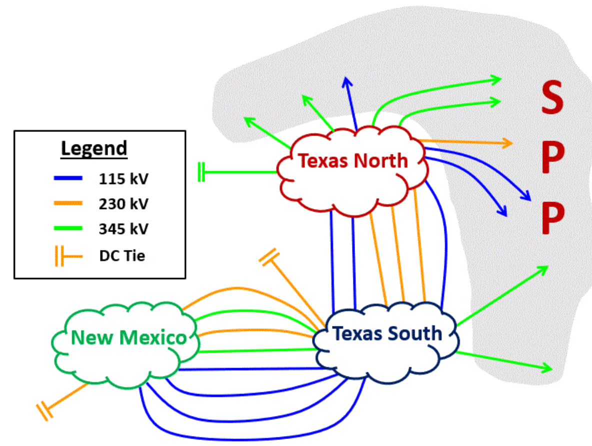

Fig. 2. Xcel Energy New Mexico/Texas EI tie lines.

B. Number and Size of Load-Shedding Steps

Once the maximum anticipated loss of generation or import power has been determined, the next step is to determine how many load-shed levels are desired and the amount of load to shed in each level. It is generally advisable to use at least two or more load-shed levels to trip at least a total amount of load equal to the maximum amount of generation or import power calculated previously. Each load-shed level should trip approximately the same percentage of load as every other level. It may also be desirable to trip more or less load in the first level to account for the tripping of the largest single generating unit of the system.

Referencing the utility system as an example, it is clear that if three levels of UFLS are desired, rounding 1,345 MWs up to 1,350 MWs equates to 450 MWs per level. Also, because the largest single unit on the system is a 540 MW coal unit, it could be beneficial to trip an amount of load in the first UFLS level closer to this value to minimize the possibility of tripping multiple UFLS levels for the trip of a single unit. For simplicity, in this example, each level could be rounded up to 500 MWs for a total of 1,500 MWs to ensure that at least the minimum amount of load will be tripped. If five levels of UFLS are desired, each level could be set to trip 300 MWs of load. The first level could also be set to 500 MWs to be closer to the largest unit. Then the other four levels could be set to 250 MWs each, for a total of 1,500 MWs.

C. Frequency Set Points

In North America, continuous operation of a power system is generally allowed if the frequency is greater than or equal to 59.5 Hz and less than or equal to 60.5 Hz. Outside of these bounds, load shedding is recommended if the frequency continues to drop below 59.5 Hz and generator tripping is recommended if the frequency continues to increase above 60.5 Hz.

UFLS frequency set points have a generally accepted upper and lower bound. The upper bound is typically just under 59.5 Hz (e.g., 59.4 Hz and 59.3 Hz). The lower bound is typically 58.0–58.5 Hz and is established based on Table I. Once frequency gets below 59.0 Hz, cumulative damage to steam turbines begins, which can diminish the useful life of a critical resource. All load shedding must be completed before system frequency decays to 57 Hz. At that level or below, generator auxiliary processes begin to shut down (reducing generator output) and generators are allowed to trip instantaneously per NERC PRC-024-3, Frequency and Voltage Protection Settings for Generating Resources [9].

TABLE I
STEAM TURBINE FREQUENCY-TIME DAMAGE [1]

Frequency at Full Load (Hz)	Minimum Time to Damage (min)
59.4	NA
58.8	90
58.2	10
57.6	1

Once the desired upper and lower frequency bounds are determined, the frequency set points can be calculated. A generally accepted approach is to set each UFLS level with the same frequency separation from each adjacent level (assuming three or more levels are used). The calculated separation is determined by taking the difference between the upper and lower frequency bounds and dividing it by one less than the desired number of UFLS levels. For the utility system, the desired upper and lower frequency bounds are 59.3 Hz and 58.7 Hz, respectively, with a calculated difference of 0.6 Hz. If three levels of UFLS are desired, the UFLS levels will be 0.3 Hz apart and set at 59.3 Hz, 59.0 Hz, and 58.7 Hz. If five levels are desired, the upper and lower bounds of 59.4 Hz and 58.6 Hz would make more sense to achieve a difference of 0.8 Hz. The calculated UFLS level separation would be 0.2 Hz, and the UFLS levels would be 59.4 Hz, 59.2 Hz, 59.0 Hz, 58.8 Hz, and 58.6 Hz.

D. *Frequency Element Intentional Time Delay*

All underfrequency relays should have some intentional time delay but only the minimum amount necessary for secure operation. Typical lower-end intentional time delays range from 3 to 6 cycles, while upper-end delays range from 20 to 30 cycles. One security challenge for short time delays arises during fault conditions in which voltage waveforms can be distorted, as shown in Fig. 3. This is especially the case if the voltage transformer connected to the underfrequency relay is a coupling capacitor voltage transformer. A 6-cycle time delay is usually sufficiently long enough to ride-through a fault event, as most faults are typically cleared within that time.

Underfrequency relays that use voltage zero crossings to calculate frequency are most susceptible to misoperation when the voltage waveform is distorted and should use an intentional short time delay in the higher end of the range. Modern-day microprocessor relays are less susceptible to misoperation due to advanced digital signal filtering and the ability to use all three phase voltages and calculated quantities, such as positive-sequence voltage for frequency calculation and negative- and zero-sequence quantities for supervised tripping.

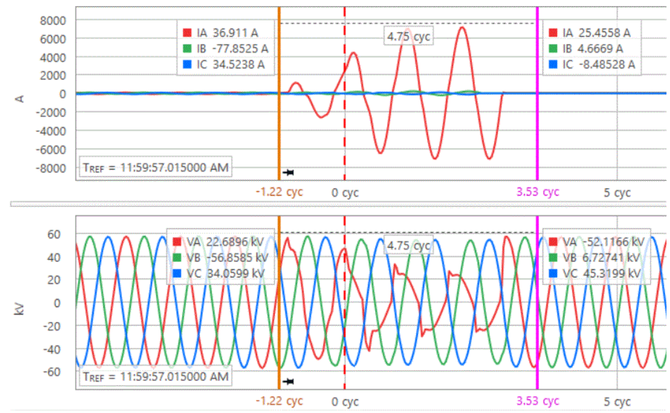

Fig. 3. Distorted voltage waveform during a fault condition.

Another security challenge for short time delays arises at transmission-tapped or transmission-radial distribution substations that utilize underfrequency relaying. If the distribution feeders serve large amounts of induction motor load, loss of the transmission source can result in misoperation of the distribution underfrequency relays if the intentional time delay is too short. Fig. 4 shows such a case, in which opening CB1 de-energizes the radial distribution substation. At the substation, the frequency collapses faster than the voltage due to the induction motor load spinning down and holding the bus voltage above the underfrequency relay undervoltage inhibit threshold. If the intentional time delay is less than about 20 cycles, the underfrequency relay can misoperate, causing an extended outage to the industrial customer. This security challenge can be minimized by adding current or ROCOF trip supervision, as discussed in [1].

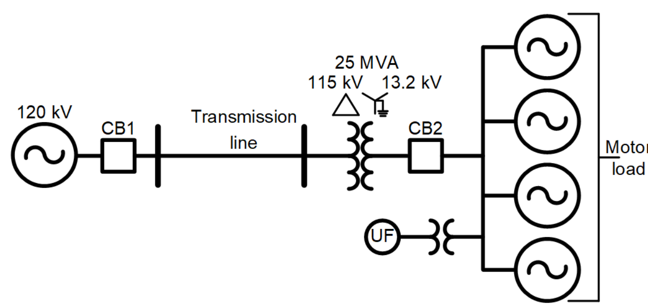

Fig. 4. Radial transmission line to distribution induction motor load.

E. *Location of Frequency Relays*

Underfrequency relays should generally be evenly scattered throughout an electric utility system, typically at distribution substations that are tripping individual feeders or the entire substation. Occasionally, it is necessary to trip transmission sources to distribution substations on underfrequency if the distribution substations are owned by the customer. This action should only be done if absolutely necessary, and care should be taken not to trip lines that are critical for maintaining system stability. Additional load should be tripped where heavy load pockets of a system exist. For example, the utility system depicted in Fig. 2 demonstrates that the New Mexico load pocket is experiencing heavy load growth and should have additional proportional load added to the UFLS program.

Tripping too much or too little load in a load pocket that is weakly interconnected to another part of the system can result in excess tie line power flows that can result in angular instability between regions, which causes out-of-step tripping and island formation. Any portion of a power system that is weakly interconnected with another system should be treated as a separate island and studied as such following all the aforementioned steps in this section.

Soon after the northeast blackout in 2003, NERC was certified by the U.S. Federal Energy Regulatory Commission (FERC) to be the Electric Reliability Organization (ERO). NERC then filed 102 reliability standards with FERC. FERC approved these standards in March 2007 [10]. One of these standards, NERC PRC-006, Automatic Underfrequency Load Shedding, requires all Planning Coordinators in North America to develop UFLS programs for the electric utilities within their jurisdiction. It was at this time that Planning Coordinators coalesced utility UFLS practices into regional NERC standards with requirements that standardized the application of UFLS.

The North American electric grid is split into three major islanded synchronous grids: The Western Interconnection (WI), the Texas Interconnection (TI), and the EI. The WI Regional Entity is the Western Electricity Coordinating Council (WECC). The TI Regional Entity is the Texas Reliability Entity (Texas RE). The EI has four Regional Entities: the Midwest Reliability Organization (MRO), the SERC Reliability Corporation, ReliabilityFirst (RF), and the Northeast Power Coordinating Council. All six of these Regional Entities are responsible for the reliability of the North American electric grid, and their geographic boundaries are shown in Fig. 5.

Within each Regional Entity footprint, multiple Planning Coordinators are responsible for developing UFLS programs pursuant to NERC PRC-006. One of those Planning Coordinators within MRO jurisdiction is the SPP. The utility must comply with the UFLS program developed by the SPP [12]. The SPP program lays out the number of UFLS levels, frequency set points, minimum and maximum amount of load to be shed at each level, the maximum underfrequency relay intentional time delay, and the maximum undervoltage inhibit threshold, as shown in Table II. While this table is specific to the SPP, it generally applies to the rest of the Planning Coordinators in the EI with a few regional differences.

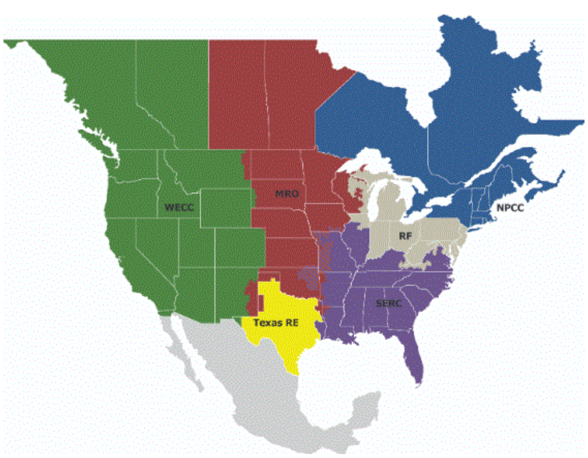

Fig. 5. Map of NERC Regional Entities [11].

TABLE II
SPP UFLS PROGRAM REQUIREMENTS

UFLS Step	Frequency (Hz)	Minimum Accumulated Load Relief as Percentage of Forecasted Peak Load (%)	Maximum Accumulated Load Relief as Percentage of Forecasted Peak Load (%)
1	59.3	10	25
2	59.0	20	35
3	58.7	30	45

- Intentional relay time delay ≤ 30 cycles.
- Undervoltage inhibit ≤ 85 percent of nominal voltage.

The Texas RE and WECC UFLS programs are similar to the SPP program, but they are also uniquely different. The Texas RE program [13] uses three levels and intentional time delays of 30 cycles or less, similar to SPP, but the underfrequency levels are separated by 0.4 Hz instead of 0.3 Hz. The WECC program [14] uses five levels separated by 0.2 Hz and a total tripping time of 14 cycles or less. The Northwest Power Pool subarea of WECC has the same number of levels but different frequency set points. Both Texas RE and WECC have additional antistall load-shed provisions to help avoid uncontrolled frequency decline. The WECC region additionally allows for automatic load restoration of Level 1 loads that have previously tripped on underfrequency to prevent severe frequency overshoot above 60 Hz. Both the Texas RE and WECC UFLS programs are illustrated in Table III and Table IV, respectively. Note that the Texas RE is the Regional Entity for the Electric Reliability Council of Texas (ERCOT). ERCOT is the grid operator within the Texas RE footprint.

TABLE III
TEXAS RE UFLS PROGRAM REQUIREMENTS

UFLS Level	Frequency (Hz)	Load Relief
1	59.3	5% of the ERCOT system load (total 5%)
2	58.9	An additional 10% of the ERCOT system load (total 15%)
3	58.5	An additional 10% of the ERCOT system load (total 25%)

- Intentional relay time delay ≤ 30 cycles.
- Antistall at 59.5 Hz: 1.5 percent load with 90-second delay, 3.0 percent load with 120-second delay, 4.5 percent load with 150-second delay.

TABLE IV
WECC UFLS PROGRAM REQUIREMENTS

Load-Shedding Block	Percent of Balancing Authority Area Load Dropped	Frequency Set Point (Hz)	Tripping Time
1	5.3	59.1	No more than 14 cycles
2	5.9	58.9	No more than 14 cycles
3	6.5	58.7	No more than 14 cycles
4	6.7	58.5	No more than 14 cycles
5	6.7	58.3	No more than 14 cycles
Additional automatic load shedding to correct underfrequency stalling			
	2.3	59.3	15 s
	1.7	59.5	30 s
	2.0	59.5	60 s
Load automatically restored from 59.1 Hz block to correct frequency overshoot			
	1.1	60.5	30 s
	1.7	60.7	5 s
	2.3	60.9	0.25 s

One of the challenges for Transmission Owners is the administration of the Planning Coordinator UFLS program. The most onerous task is proving that adequate percentages of load are being shed in each level. Within the SPP service territory, load-shed values in planning software are tallied for a requested season to calculate the UFLS percentages for NERC PRC-006 compliance. These values are typically peak (summer) or valley (spring) forecast loads that are static in nature. In reality, these load values are changing constantly, so actual load-shed percentages at any given time may be different than the planning model indicates.

A way of self-auditing a UFLS program is to query energy management system (EMS) databases to extract and analyze load data on a historical basis to evaluate program effectiveness. This has been done for the utility system. Hourly system data are collected for every UFLS load and are aggregated and analyzed to ensure proper amounts of load can be shed. Table V shows hourly data for the last day of October 2023 and the percentage of load shed to total load for each level. It also shows the overall total of all three levels. Additionally, the number of hours in the month in which percentages are less than or greater than desired are calculated. There is a deficit in Level 3 for 55/744 (7.4 percent) hours, but overall, no hours less than 30 percent or greater than 45 percent.

TABLE V
EMS LOAD QUERY AND SUMMARY OF UFLS EFFECTIVENESS

NERC PRC-006 Load-Shed Percentages (10/31/2023)				
Time	**59.3 Hz (MW)%**	**59.0 Hz (MW)%**	**58.7 Hz (MW)%**	**Total LS %**
0:00	11.58	12.05	10.46	34.09
1:00	11.81	12.28	10.62	34.72
2:00	11.79	12.27	10.71	34.77
3:00	11.84	12.19	10.59	34.63
4:00	11.64	11.92	10.62	34.18
5:00	11.53	11.97	11.09	34.60
6:00	11.83	12.27	11.11	35.21
7:00	12.35	12.04	11.20	35.59
8:00	12.21	11.70	11.11	35.02
9:00	12.55	11.76	11.11	35.42
10:00	12.73	12.07	10.97	35.76
11:00	12.96	11.72	10.81	35.49
12:00	13.27	11.72	10.44	35.43
13:00	13.11	11.59	10.18	34.89
14:00	13.07	11.13	10.04	34.24
15:00	13.22	10.94	10.13	34.30
16:00	13.25	10.81	10.04	34.09
17:00	13.09	11.08	10.01	34.18
18:00	12.91	10.73	10.13	33.77
19:00	12.91	10.54	10.06	33.51
20:00	12.67	10.48	10.22	33.37
21:00	12.14	10.54	10.77	33.45
22:00	12.05	11.19	10.91	34.14
23:00	12.09	12.07	11.15	35.32

Hour count <10%	**Hour count <10%**	**Hour count <10%**	**Hour count <30%**
0	1	55	0
Hour count >15%	**Hour count >15%**	**Hour count >15%**	**Hour count >45%**
0	0	0	0

In the APS-Southern California and South Australia blackouts, a common issue observed was high ROCOF, which peaked at 3 Hz/s and 6 Hz/s for each event, respectively. High ROCOF presents challenges to UFLS programs. If ROCOF is too high, multiple UFLS levels may trip, when only a single level needs to trip. Tripping more load than necessary impacts more customers and can result in frequency overshoot above nominal frequency, which can result in generators tripping on overfrequency, possibly leading to a systemwide blackout.

Part of developing an effective UFLS design is to ensure that each level of load trips before the next level is reached. For this to happen, the maximum ROCOF to traverse from one level to the next must be calculated. The maximum ROCOF for SPP, Texas RE, and WECC are calculated in (1), (2), and (3) to be 1.8 Hz/s, 2.4 Hz/s, and 1.2 Hz/s, respectively. For the calculations, intentional time delay is assumed to be 6 cycles and the breaker operating time to be 4 cycles, for a total operating time of 10 cycles or 0.1667 seconds.

$$SPP\ MAX = \frac{59.3\ Hz\ - 59.0\ Hz}{0.1667\ s} = 1.8\frac{Hz}{s} \tag{1}$$

$$Texas\ RE\ MAX = \frac{59.3\ Hz - 58.9\ Hz}{0.1667\ s} = 2.4\frac{Hz}{s} \tag{2}$$

$$WECC\ MAX = \frac{59.1\ Hz - 58.9\ Hz}{0.1667\ s} = 1.2\frac{Hz}{s} \tag{3}$$

It is evident from these calculations that a ROCOF of 3 Hz/s or greater will not achieve the desired goal of tripping each successive level before reaching the next level. By examining the fundamental formulae for frequency decay (loss of generation) and frequency rise (loss of load), as shown in (4) [15], the variables that affect ROCOF can be determined.

$$f = f_{sys} - \Delta L \bullet \left(1 - e^{-\frac{t}{T}}\right) \bullet K \bullet 60$$
$$T = \frac{M}{D}\ K = \frac{1}{D} \tag{4}$$

where:

f_{sys} is the base system frequency (60 Hz).

ΔL is the change in load per unit.

t is time in seconds.

H is the inertia constant of the system.

M is the mechanical starting time, which equals 2H.

D is the load-damping constant.

60 is the constant to put the values in Hz.

Rewriting the equation and substituting values for *T* and *K* yields (5).

$$f = f_{sys} - \Delta L \bullet \left(1 - e^{-\frac{D \bullet t}{2 \bullet H}}\right) \bullet \frac{1}{D} \bullet 60 \tag{5}$$

D represents the increase or decrease in system power consumption based on the changing frequency, as seen by the frequency-dependent motor load. Motor loads that are frequency-dependent operate at nominal power when the system frequency is 60 Hz. If the system frequency increases, the motor speeds up, yielding a higher electrical power level. If the system frequency decreases, the motor slows down, yielding a lower electrical power level. D is expressed as a percentage change in load for a 1 percent change in system frequency. Typical ranges of D are 1 to 2 percent [16]. An in-between value of 1.5 was chosen for use in this analysis, thus a 1 percent change in system frequency results in a 1.5 percent change in load. The equation for D is shown in (6) [1].

$$D = \frac{Load_{Sys} 1.5}{100} \tag{6}$$

where:

$Load_{Sys}$ is the remaining system load after loss of load (i.e., load shedding) or system separation.

1.5 is the percent change in load for a 1 percent change in system frequency.

100 is the system base in MVA.

Taking the first derivative of (5) yields (7), which is used to calculate the ROCOF at any point in time.

$$\frac{df}{dt} = \frac{-30 \bullet \Delta L}{H} \bullet e^{-\frac{D \bullet t}{2 \bullet H}} \tag{7}$$

Solving the first derivative at t = 0 yields (8) and results in the fastest ROCOF.

$$\frac{df}{dt} = \frac{-30 \bullet \Delta L}{H} \tag{8}$$

Examination of (8) shows that only two variables cause high ROCOF: 1) Loss of large amounts of generation or load and 2) low system inertia. The most concerning of these variables in today's power system is inertia. Prior to the dawn of the 21st century, inertia only varied as load varied, which occurred when synchronous generators were placed online or offline. Since the beginning of the 21st century, inertia is still impacted by changing loads, but it is significantly more impacted by variable wind and solar generation ramping up and down.

Correlation analysis is a way to visualize the impact of one data set on another to see if the data are related in any way. Correlations are either positive or negative. A positive correlation means that as the first data set changes in sign and magnitude, the second data set changes similarly in sign and magnitude. A negative correlation means that as the first data set changes in sign and magnitude, the second data set changes oppositely in sign and magnitude.

The impact of wind-generation ramp rates (increases or decreases in generation from 1 hour to the next) to tie line ramp rates can be correlated and analyzed using correlation analysis spreadsheet tools on the utility system EMS hourly data. Additionally, the increase in yearly peak wind is shown as a cause for the changing ramp rate correlation, as shown in Fig. 6.

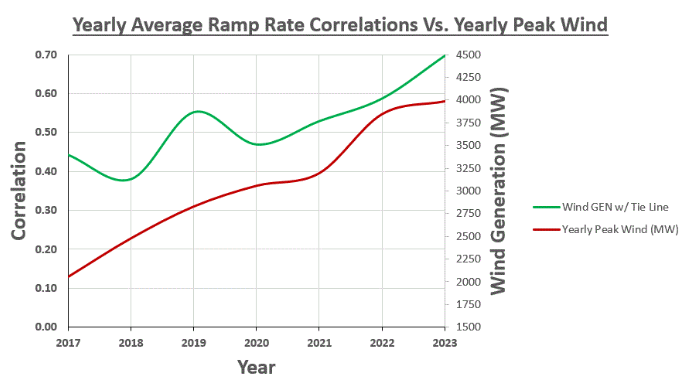

Fig. 6. Ramp rate correlations vs. yearly peak wind.

As the graph shows, there is a notable change in the wind-generation ramp rate to tie-line ramp rate as the wind generation peak increases from year to year. As wind generation in the Texas Panhandle ramps up or down, tie-line ramp rates do as well, as indicated by the increasing positive correlation over time. This is clearly demonstrated, since the buffer for the surplus or deficiency of wind generation is the 10 tie lines connecting the utility to the EI.

Given that the utility system is clearly showing a steady decrease in inertia due to both the retirement of fossil fuel generation and displacement due to wind generation, ROCOF in excess of the current UFLS program design is now a growing reality. Depending on the system configuration and generation dispatch at the time of the next system separation event, the utility system could suffer a severe frequency excursion that exceeds the existing UFLS program design, increasing the possibility of a systemwide blackout.

III. Inventing an Outside-the-Box UFLS Program

In July 2018, the Institute of Electrical and Electronics Engineers (IEEE) Power and Energy Society, in cooperation with NERC, published an award-winning technical report titled *Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance* [17]. This technical report highlights a concern that higher ROCOF may require shorter time delays on underfrequency relays to allow faster tripping during frequency excursions.

This raised a concern at the utility, because at the time about 40 percent of all UFLS relays were set with a 30-cycle time delay to prevent underfrequency relays from mis-tripping on motor spin-down when the transmission source was lost. This prompted detailed studies to consider using ROCOF supervision in conjunction with undervoltage inhibit supervision to allow shortening time delays to 6 cycles. The results of the studies are documented in detail in [1].

The conclusions of [1] are that faster UFLS tripping showed improvement over staggered tripping (a mix of short and long time-delayed tripping) of up to about 50 percent renewable penetration (i.e., 50 percent reduction of inertia). At above 50 percent reduced system inertia, overtripping of load was likely and resulted in frequency overshoot past 60 Hz and the possibility of generators tripping on overfrequency, which can result in a systemwide blackout.

After the publication of [17] and [1], a new approach to UFLS program design was conceived at the utility. Based on the knowledge that faster tripping when inertia is depleted by more than 50 percent can still lead to the possibility of a blackout, the idea of tripping loads based on monitored ROCOF was pondered. Initially, the thought was to centrally monitor ROCOF at the transmission control center, then send signals to loads to be tripped remotely. However, this approach would have been costly since it would require significant communications infrastructure buildout to remote loads. Additionally, this approach could be compromised if communications outages occurred due to storm damage or other causes.

Another approach considered was a modern-day microprocessor relay ROCOF protection element. A particular relay that was considered would constantly monitor ROCOF and have a ROCOF threshold setting (e.g., 0.5 Hz/s,). When ROCOF reaches the setting threshold, the relay issues a trip after an intentional fixed time delay plus an additional time delay that is more or less based on low or high measured ROCOF. This approach was not selected because it did not fit the SPP UFLS program requirements of being able to pick up at a specific frequency set point and ensure trip output in 30 cycles or less.

The selected approach was to utilize existing and new programmable microprocessor underfrequency relays deployed remotely in the field that could be programmed to operate based on locally measured frequency and ROCOF. One of the advantages of this approach is that the remotely deployed relays can operate autonomously. Since frequency decays at different rates and reaches different levels across the system for a common frequency excursion, only the most affected frequency pockets will shed load, thus minimizing customer impact.

The ROCOF UFLS strategy was developed following the same approach as outlined in [1] and [18] in which ROCOF is measured simply by using two frequency monitoring elements and a timer to establish a df/dt threshold. Multiple sets of timers between two frequency elements were used to establish ROCOF bandwidths that allowed tripping via multiple paths based on measured ROCOF. Frequency drop would be predetected with a frequency element set higher than the tripping frequency. This allows tripping *at* the frequency set point without additional time delay. Conventional underfrequency tripping was also allowed where a frequency set point was reached, a timer was started, and load tripping was initiated when the timer expired. Conventional undervoltage inhibit supervision was also maintained. ROCOF motor spin-down supervision, as described in [1], was also used to allow for lower conventional underfrequency relay time delays. A further enhancement was to allow some Level 1 underfrequency relays to automatically restore load based on rising ROCOF if frequency overshoot occurred. The full patent-pending logic diagram is shown in Fig. 7.

Observing the color-coded logic in Fig. 7, shown with circles, each major component of the overall logic is reviewable. The first component discussed is the conventional, built-in UFLS logic highlighted in green. When frequency drops to 59.3 Hz, frequency element Freq_2 asserts, starting Timer 5 (T5). If the frequency stays below 59.3 Hz, then T5 expires after a 6-cycle time delay, asserting OR_1 and allowing conventional UFLS tripping to occur. The second component discussed is the conventional, built-in undervoltage inhibit logic highlighted in blue. If the monitored voltage drops to 67 percent of nominal, the undervoltage inhibit element UV_1 asserts, dropping out AND_6, which disables underfrequency tripping.

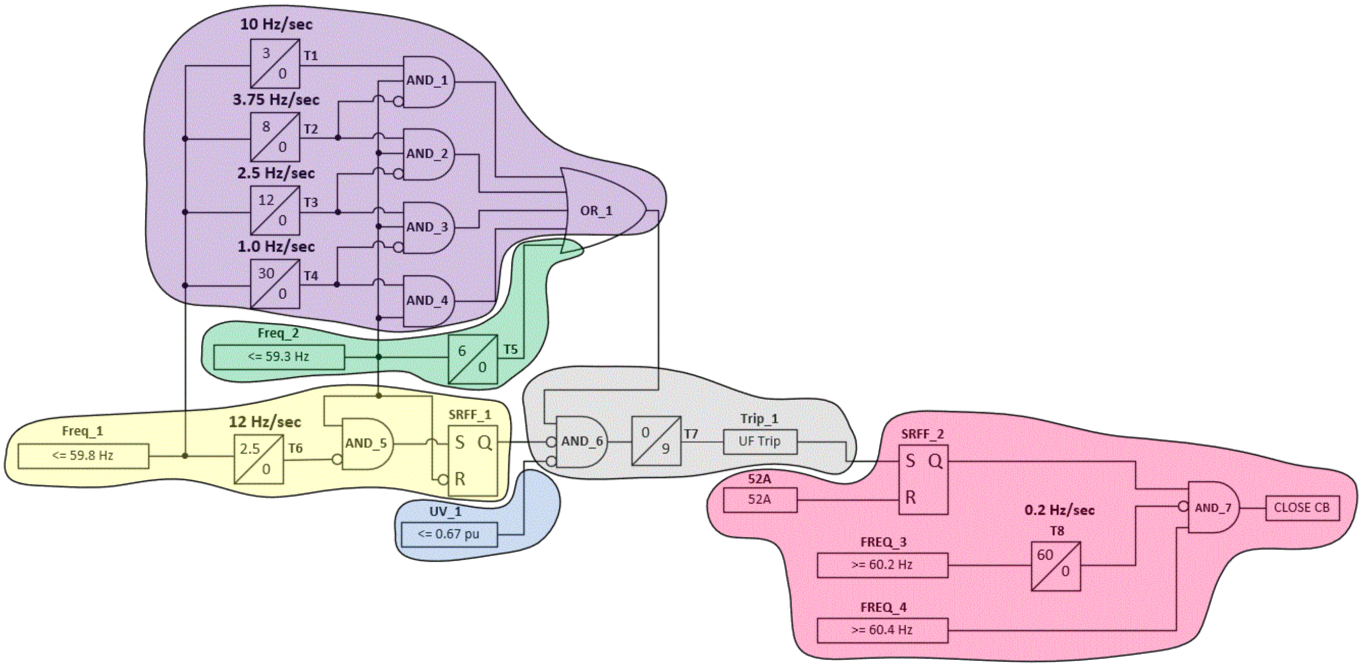

Fig. 7. Full patent-pending ROCOF UFLS color-coded logic.

The third component discussed is the custom ROCOF motor spin-down and fast transient filter logic highlighted in yellow. This logic, like the undervoltage inhibit logic, supervises underfrequency tripping to prevent mis-trips [1]. When frequency drops to 59.8 Hz, the frequency element Freq_1 asserts, which starts T6. If the frequency stays below 59.8 Hz but above 59.3 Hz for 2.5 cycles, T6 expires and blocks AND_5 from asserting, which prevents flip-flop SRFF_1 from being able to be set, thus allowing underfrequency tripping to occur via AND_6. If the frequency drops from 59.8 Hz to 59.3 Hz in less than the T6 time delay, then SRFF_1 is unreset and AND_5 asserts, setting SRFF_1, which deasserts AND_6, thus preventing underfrequency tripping.

The fourth component discussed is the custom high-speed ROCOF underfrequency trip logic highlighted in purple. When frequency drops to 59.8 Hz, frequency element Freq_1 asserts, starting a series of staggered timers (T1, T2, T3, and T4). Each timer represents a ROCOF threshold determined by the difference of Freq_1 and Freq_2 and divided by the timer settings (converted from cycles to seconds). For example, T1 represents a ROCOF calculated as shown in (9):

$$T1\ RoCoF = \frac{59.8\ Hz - 59.3\ Hz}{3\ cyc. \bullet \dfrac{1\ s}{60\ cyc.}} = \frac{0.5\ Hz}{0.05\ s} = 10\frac{Hz}{s} \qquad (9)$$

Each of the four timers (T1, T2, T3, and T4) inputs into a respective AND gate (AND_1, AND_2, AND_3, or AND_4). Each AND gate is asserted when its respective timer expires, its successive timer is not expired, and its frequency element Freq_2 has asserted. The only exception to this is AND_4 because it does not have a successive timer. Each of the AND gates (AND_1, AND_2, AND_3, and AND_4) input into OR gate OR_1, which initiates underfrequency tripping via AND_6. Each AND gate represents a bandwidth of ROCOF for which it operates. AND_4, AND_3, AND_2, and AND_1 operate when ROCOF is between 0–1.0 Hz/s, 1.0–2.5 Hz/s, 2.5–3.75 Hz/s, and 3.75–10 Hz/s, respectively.

The fifth component discussed is the custom supervised underfrequency trip logic highlighted in gray. This logic combines all the aforementioned logic into an underfrequency trip decision if all supervising elements allow for a trip. If any of the inputs to OR_1 assert, SRFF_1 is not asserted, and UV_1 is not asserted, then AND_6 will assert T7, which will issue an underfrequency trip (Trip_1). T7 will maintain assertion of Trip_1 with its 9-cycle dropout timer.

The sixth component discussed is the custom supervised automatic load restoration logic highlighted in light red. If used, a trip output from Trip_1 will assert flip-flop SRFF_2, if the Breaker Contact 52A is open, which prevents reset of SRFF_2. Load restoration will occur via AND gate AND_7 if SRFF_2 is set and the frequency has risen to 60.2 Hz asserting the frequency element FREQ_3 for less than T8 pickup time (60 cycles), and frequency has risen to 60.4 Hz before T8 expires. All the aforementioned logic, time delays, and frequency set points are changeable. All frequency thresholds and timer settings can be adjusted. The number of ROCOF bandwidths can be adjusted based on the amount of load to be shed in a given ROCOF bandwidth. All these settings are adjustable and must be determined and tested by system studies.

Development of the ROCOF UFLS program requires a more detailed, nonconventional approach than the typical Planning Coordinator approach. A typical approach is to generically run studies for a summer-peak season and drop a predetermined amount of load once the study island has been formed. For instance, with a formed island, 25 percent of the generation in the island may be taken offline all at once, so the frequency response with active load-shed relay operations may be observed. If frequency recovers to within +/– 0.5 Hz of nominal (60 Hz), the study is successful. This approach of using the summer-peak season ensures high system inertia, low ROCOF, and better UFLS program response.

A more appropriate approach with today's ever-changing power grid, which contains more and more renewable, nondispatchable generation, is to run more detailed, exhaustive studies to fully evaluate system UFLS performance. Multiple seasons should be studied, including high-inertia summer-peak and low-inertia shoulder season (i.e., spring or fall). Additionally, each season studied should include high- and low-inertia scenarios with variable loss of generation (i.e., loss of 5 to 50 percent of system generation in 5 percent increments). This approach allows full vetting of the UFLS program performance for a multitude of ROCOF conditions under multiple combinations of inertia and loss-of-generation scenarios.

Performing UFLS assessments using this method is necessary to develop the ROCOF UFLS program. Once all the data are compiled, the necessary data components can be calculated:

- Maximum amount of load to be shed
- Frequency element thresholds
- Minimum and maximum disturbance ROCOF
- ROCOF thresholds and timer delays
- ROCOF bandwidths
- Amount of ROCOF bandwidth load to be shed
- Amount of load to be shed in subsequent levels

A generic simple example for a 2000 MW system was evaluated. The minimum amount of generation tripped was shown to be 100 MWs (5 percent of system load) and the maximum amount of generation tripped was shown to be 800 MWs (40 percent of system load). Frequency element thresholds for Freq_1 and Freq_2 are 59.8 Hz and 59.3 Hz, respectively. Observed ROCOF for all studies ranged from 0.25 Hz/s to 4 Hz/s following the inertia and loss-of-generation guidelines mentioned previously. The maximum amount of load to be shed is 900 MWs. The ROCOF thresholds are determined to be 1.0 Hz/s, 2.0 Hz/s, 3.0 Hz/s, and 7.5 Hz/s, for T4, T3, T2, and T1, respectively. The upper-bound ROCOF was set to just under twice the maximum observed. Required timer delays to achieve ROCOF thresholds are 30 cycles, 15 cycles, 10 cycles, and 4 cycles for T4, T3, T2, and T1, respectively.

A maximum of 25 percent of system load (500 MWs) is desired to be shed in Level 1, and only all of Level 1 load will be tripped with ROCOF. The remaining two levels (59.0 Hz and 58.7 Hz) will each trip 200 MWs of load with 6-cycle time delays and ROCOF motor spin-down supervision. Ten percent (200 MWs) of system load in Level 1 will be tripped when ROCOF is between 0 and 1.0 Hz/s. Fifteen percent (300 MWs) of system load in Level 1 will be tripped when ROCOF is between 1.0 and 2.0 Hz/s. Twenty percent (400 MWs) of system load in Level 1 will be tripped when ROCOF is between 2.0 and 3.0 Hz/s. Finally, twenty-five percent (500 MWs) of system load in Level 1 will be tripped when ROCOF is between 3.0 and 7.5 Hz/s. No automatic load restoration is used for this example.

Individual Level 1 UFLS relays in the field will be programmed to trip an appropriate amount of load based on locally measured ROCOF. This is accomplished by removing inputs to OR_1 that emanate from the AND gates that represent a bandwidth of ROCOF. Ten percent of the system loads will trip via AND_4, an additional 5 percent of the system loads will trip via AND_3, an additional 5 percent of the system loads will trip via AND_2, and an additional 5 percent of the system loads will trip via AND_1. The total amounts tripped by each AND gate are shown in Fig. 8.

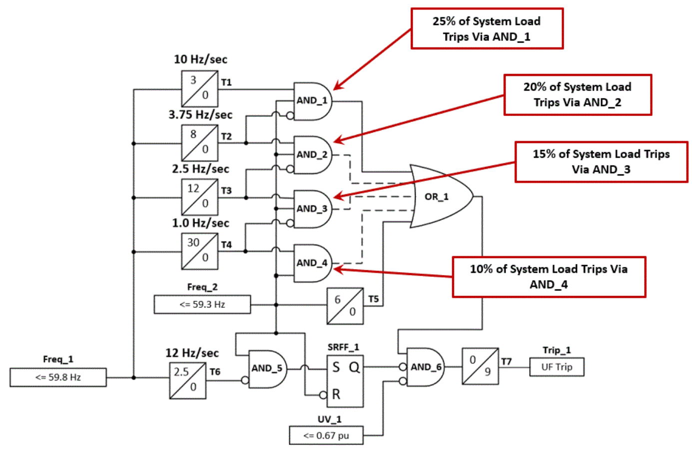

Fig. 8. Level 1 patent-pending ROCOF logic with percentage of load breakdown.

The generic example ROCOF UFLS program has been developed, but it must be tested to validate and optimize program performance. To test the program, a unique, advanced, off-the-shelf IPPS tool was used.

The IPPS tool is an emerging technology that captures the interdependence of system dynamics and relay actions [19]. As shown in Fig. 9, this next-generation program integrates a detailed protection modeling and simulation environment with the conventional transient stability simulation environment. The main features of IPPS include [20]:

- Protection system model with thousands of relay models that protection engineers utilize to develop settings and perform protective relay coordination studies.
- Transient stability model that planning engineers utilize to perform dynamic system stability studies.
- Tool that simulates the planning and protection models simultaneously so that the effect of protective relay operations on the dynamic behavior of the system and cascading failures can be studied. Relay operation times are determined by simulation and not assumed.
- Tool that provides a platform for developing and testing special protection schemes and their associated wide-area protection and control algorithms.

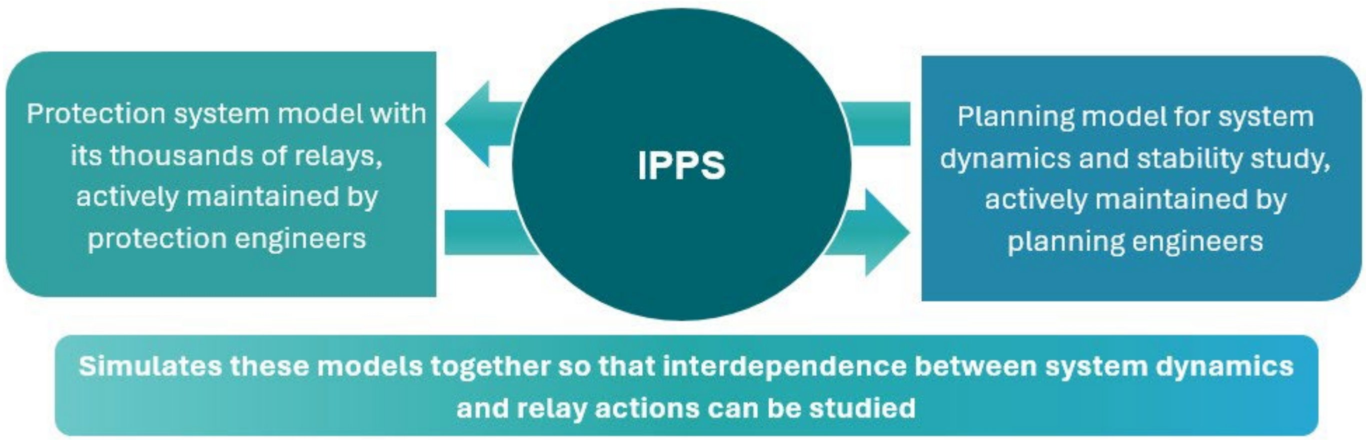

Fig. 9. IPPS tool.

Integrating protection and planning studies in a single environment provides many benefits [20]:

- The ability to perform conventional planning studies with full consideration of protective relay behavior. The relay settings used are the ones calculated and verified by protection engineers.
- Postmortem analysis of events in which protective relay operations played a part in a blackout.
- The ability to reveal and help prevent hidden stability problems created by relay operations.
- Planning and protection network models that are better aligned with each other, allowing for easier exchange of data between protection and planning departments. Regulatory bodies should appreciate this convergence.

The success of, and the validity of the results produced by the IPPS tool depends, to a large extent, on the level of detail built into the protective device models. The IPPS relay library consists of over 7,400 relay styles and is the world's largest library of protective relay models. Protective relay modeling in the IPPS tool sets itself apart from other tools in the following ways [20]:

- The entire relay is modeled as a single object, with all the protective elements that the actual relay contains.
- Manufacturer-specific setting names are used.
- Accurate mathematical relay models are used to implement manufacturer-specific comparator equations and supervision logic.
- Advanced protection schemes are fully supported, such as teleprotection, single-pole tripping, breaker failure, automatic reclosure, power-swing blocking, and out-of-step tripping.
- Generic auxiliary relay elements (e.g., overfrequency, underfrequency, timers, latches, and AND and OR gates) are available to build custom logic, which was done initially for the ROCOF logic described in Fig. 7.

The maximum number of buses the IPPS tool can handle is 150,000. This capability, together with its fast simulation speed will suffice the needs for most real-world systemwide studies. Several industry applications of the IPPS tool are described in [19] [21] [22].

A scaled-down 1/3rd scale test system was created using the IPPS tool that is representative of the 6,200 MW peaking utility, as depicted in Fig. 10.

The base-case 2,000 MW system contains 100 percent synchronous generation. The base-case UFLS system was set to trip 10 percent of system load (200 MWs each) in three levels (59.3 Hz, 59.0 Hz, and 58.7 Hz) using conventional 6-cycle intentional time delays. Three additional test systems were created that contain 25 percent, 50 percent, and 67 percent inverter-based resource (IBR) penetration that was made up of Type 4 wind farms. Each of these IBR cases reduced system inertia by about the same percentages. This was accomplished by replacing an equivalent amount of synchronous generation with wind generation. These four cases are used throughout the rest of the paper to test various UFLS algorithms.

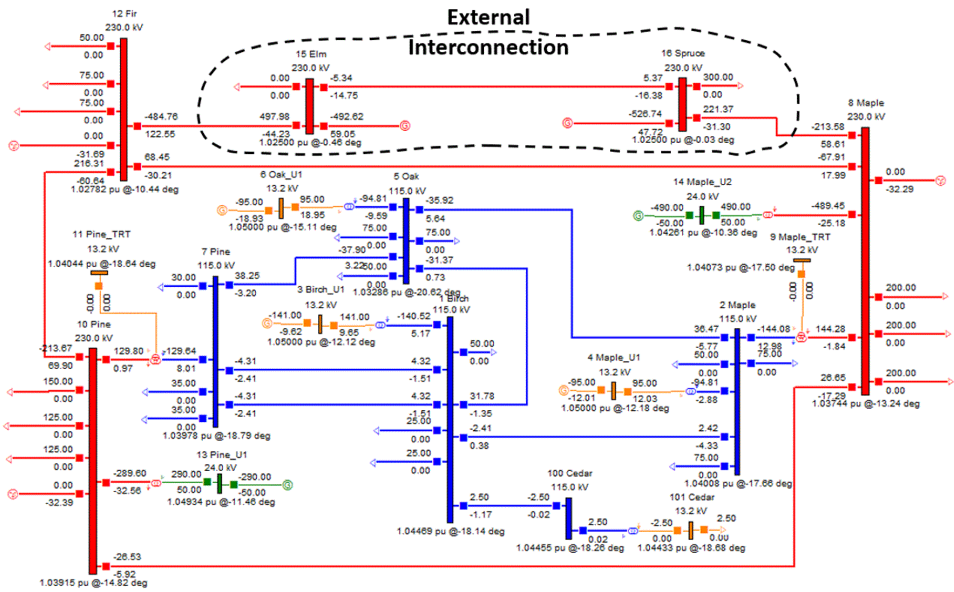

Fig. 10 1/3rd 2,000 MW test system.

IV. Other Frequency Excursion Mitigation Strategies

As previously stated, UFLS is the last ditch, first line of defense to avoid blackouts. Once UFLS has occurred and all levels have operated, no other system protection strategies are available to prevent system blackout except synchronous generator governor action. If high penetrations of IBR are present during a frequency excursion, there may not be enough synchronous generator headroom for governor response to increase generator MW output enough to regain the balance of load and generation.

What if UFLS *wasn't* the first line of defense to prevent blackouts during frequency excursions? Two pre-emptive mitigation strategies exist that can minimize the possibility and impact of UFLS operation: 1) synchronous condenser deployment across the system and 2) Battery Energy Storage Systems (BESSs) deployment across the system.

Deployment of high-inertia synchronous condensers can allow for inertia to be switched online or offline as needed to ensure a minimum amount is maintained to keep ROCOF within UFLS program design limits. Synchronous condensers also provide other benefits, such as short-circuit current and voltage regulation. Adding synchronous condensers to a system can be expensive, costing around $25 million per 100 MVAR.

Deployments of both grid-forming (GFM) and grid-following (GFL) inverters coupled to BESSs can provide power (MW) injection and absorption for underfrequency or overfrequency excursions. Most modern BESSs have the capability of providing a fast frequency response or an inertial frequency response to quickly (as fast as a few cycles) support frequency. Adding a BESS to a system can be expensive, costing around $115 million per 100 MWs.

The challenges with these solutions are that both are expensive and take five or more years to implement. However, both solutions have merit and purpose in reducing the severity of frequency excursions by damping out both variables that can result in high ROCOF. Synchronous condensers add inertia back to the system, thus increasing the value of H in the denominator of (5). A BESS providing MW injection and absorption during frequency excursions decreases the magnitude of ΔL in the numerator of (5). Both solutions working independently or in tandem will have the effect of decreasing ROCOF and minimizing UFLS. The tests of both solutions are tested and compared in the next section.

V. Testing Frequency Excursion Mitigation Strategies

UFLS studies were performed using the IPPS tool and employing the base system model depicted in Fig. 10. Four test systems were developed and studied that consisted of 0 percent, 25 percent, 50 percent, and 67 percent IBR generation, made up of Type 4 wind turbines. For each test system, variable amounts of generation were tripped, ranging from approximately 100 MWs (5 percent of total system load) to 800 MWs (40 percent of total system load), in roughly 50 MW increments. A total of 13 tests were run for each test system. As a benchmark, each test system was studied with conventional UFLS using the SPP PRC-006 program (3 levels at 59.3 Hz, 59.0 Hz, and 58.7 Hz) to trip 10 percent of system load (200 MWs) per level using a 6-cycle intentional time delay. Breaker operating times were set to 3 cycles. Following the benchmark UFLS studies for each test system, the 67 percent IBR system was studied with conventional UFLS for the following two cases: 1) Replacement of lost inertia with synchronous condensers and 2) The addition of 200 MWs (10 percent of system peak load) of fast-acting BESSs for frequency excursions. Finally, each test system was studied by applying the patent-pending ROCOF UFLS program.

A. *Microprocessor Relay Model Development*

Initial underfrequency relay model development consisted of multiple generic auxiliary relays available in the IPPS tool. Each relay local zone of protection (LZOP) for a simple underfrequency relay consisted of two relays: 1) An underfrequency relay and 2) a timer relay. Motor spin-down protection wasn't studied, so undervoltage and ROCOF supervision were not modeled. Modeling the ROCOF UFLS logic became even more complicated because each LZOP consisted of 12 relays. This approach made setting up the underfrequency relays more difficult and time consuming, but having the ability to build a custom relay was very convenient for testing new concepts.

Within the IPPS tool, a manufacturer-specific relay model was customized to implement the UFLS logic, as shown in Fig. 7. Four timers with different delay settings are utilized to identify various ROCOF modes and initiate the corresponding ROCOF supervisor.

Another important component of the overall UFLS logic is a set-reset (SR) flip-flop latch. The SR latch has been modeled in the IPPS tool to produce outputs such as set, reset, or maintain the previous state. Based on the SR latch output, the underfrequency tripping will be enabled or disabled accordingly. Having one relay per LZOP is much more convenient, easy to set up, and flexible when changing settings.

B. Testing the Conventional UFLS Program

As mentioned at the beginning of this section, four test systems were studied and 13 tests were performed on each test system. Starting with the 0 percent IBR case, a baseline was established to compare to the other test system studies. The 0 percent IBR case had 5 synchronous generators that were tripped either individually or in combination at t = 0.5 seconds to start the underfrequency event. All studies were run out to 30 seconds to get the final frequency. The time and frequency of each load trip was tabulated, and several key data points were documented and calculated. Documented quantities were frequency nadir (frequency valley), time to nadir, and final frequency. Calculated quantities were total load shed and decreasing and increasing ROCOF. Decreasing ROCOF was calculated from the time the generator(s) tripped to the first load that tripped. Increasing ROCOF was generally calculated from the frequency nadir to the peak frequency.

The study process is illustrated for one of the tests on the 0 percent IBR system (Fig. 10), in which 490 MW Maple Unit 2 and 141 MW Birch Unit 1 are tripped simultaneously, resulting in a total loss of ~630 MWs of generation (32 percent of total system generation). Both generators are tripped at t = 0.5 seconds. Fig. 11 shows the first 3 seconds of the event, including all UFLS. ROCOF for this event is 1.14 Hz/s, which is within the design parameters of 1.8 Hz/s. Each level trips before its subsequent level trips.

Frequency nadir occurs at the time of Level 3 load tripping. At t = 30 seconds, the final frequency recovers to 59.94 Hz, within the +/– 0.5 Hz of the nominal desired range, as shown in Fig. 12.

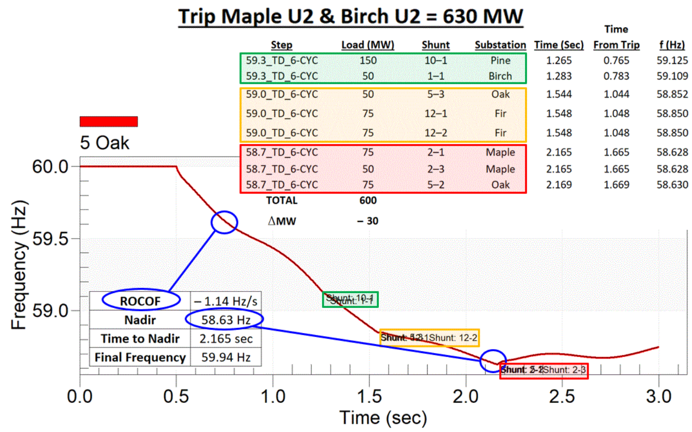

Fig. 11. Load shed for trip of 630 MWs of system generation (0 percent IBR system).

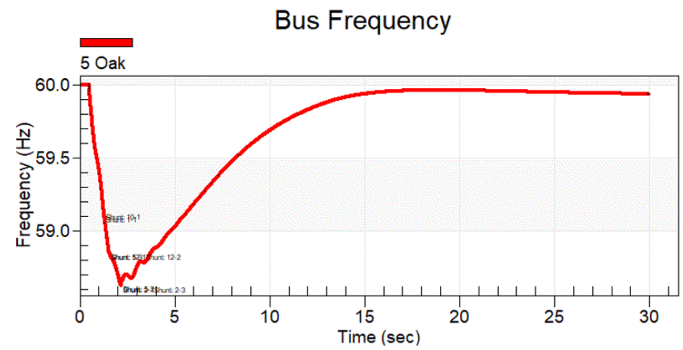

Fig. 12. Final frequency for trip of 630 MWs of system generation.

Twelve additional loss-of-generation studies were performed with more and less amounts of generation tripped. The results of these studies are detailed in Table VI. The highest and lowest frequency nadir are highlighted in orange and red, respectively. The highest frequency overshoot is highlighted in yellow. Final frequencies outside of +/– 0.5 Hz of nominal frequency are highlighted in light orange and red. Red-highlighted final frequencies indicate frequencies that will result in instantaneous tripping of generation and system blackout. These color codes apply to all the following UFLS summary tables. As the table shows, the highest ROCOF occurred for the trip of the most generation. The highest frequency overshoot was 60.85 Hz. Three final frequencies were outside the desired +/– 0.5 Hz bandwidth, with the worst being the same as the lowest frequency nadir of 56.98 Hz for the trip of 780 MWs of generation. The UFLS program design did not trip enough load for this test case, resulting in system blackout. The average of the absolute value of excess load shed was 60 MWs.

TABLE VI
0% IBR CONVENTIONAL UFLS SUMMARY

		Conventional UFLS				
Generation Tripped (MWs)	**ROCOF (Hz/s)**	**Total Load Shed (MWs)**	**Excess Amount of Load Shed (MWs)**	**Frequency Nadir (Hz)**	**Overshoot Frequency (Hz)**	**Final Frequency (Hz)**
95	–0.16	0	–95	59.40	59.57	59.57
140	–0.24	200	60	59.27	60.40	60.26
190	–0.35	200	10	59.26	60.18	60.09
235	–0.49	200	–35	59.22	59.90	59.86
330	–0.63	400	70	58.99	60.83	60.49
385	–0.74	400	15	58.96	60.22	60.15
430	–0.84	400	–30	58.91	59.94	59.90
490	–0.97	400	–90	58.91	59.47	59.47
525	–0.84	600	75	58.69	60.85	60.64
585	–1.08	600	15	58.68	60.28	60.23
630	–1.14	600	–30	58.63	59.97	59.94
680	–1.11	600	–80	58.64	59.60	59.60
780	–1.24	600	–180	56.98	NA	56.98
			Total: –295			
			Ave. ABS Diff.: 60.38			

Table VII, Table VIII, and, Table IX show the UFLS results for the 25 percent, 50 percent, and 67 percent IBR (reduced inertia) cases. The results show increasing ROCOF for decreasing inertia. 37 percent (19/52) of the case studies show initial ROCOF greater than the conventional program design of 1.8 Hz/s. As inertia is reduced, increasing counts of final frequencies outside the range of 59.5 Hz to 60.5 Hz occurs (for each of the 0 percent, 25 percent, 50 percent, and 67 percent cases, the counts are 3, 7, 7, and 9, respectively).

The 67 percent case shows 38 percent (5/13) of the tests resulted in frequencies that reached 61.8 Hz or 57.8 Hz, which is the allowable instantaneous tripping threshold for generators in the EI [9]. Also of note is that for each successive case study, the average of the absolute value of excess load shed continues to increase. A final observation is that for each successive case study, the total amount of load shed increases (for each of the 0 percent, 25 percent, 50 percent, and 67 percent IBR cases, total load shed was 5,200 MWs, 5,600 MWs, 5,600 MWs, and 6,000 MWs, respectively).

TABLE VII
25% IBR CONVENTIONAL UFLS SUMMARY

		Conventional UFLS				
Generation Tripped (MWs)	**ROCOF (Hz/s)**	**Total Load Shed (MWs)**	**Excess Amount of Load Shed MWs**	**Frequency Nadir (Hz)**	**Overshoot Frequency (Hz)**	**Final Frequency (Hz)**
95	–0.19	200	105	59.28	60.93	60.70
140	–0.38	200	60	59.26	60.60	60.44
190	–0.51	200	10	59.23	60.15	60.08
235	–0.69	200	–35	59.16	59.74	59.71
330	–0.97	400	70	58.95	61.07	60.71
375	–1.06	400	25	58.94	60.17	60.10
435	–1.26	400	–35	58.89	59.87	59.81
490	–1.54	600	110	58.69	61.22	61.22
540	–1.72	600	60	58.65	60.72	60.72
590	–1.75	600	10	58.61	60.27	60.27
640	–1.93	600	–40	58.57	59.43	59.43
690	–2.18	600	–90	57.10	NA	57.10
740	–2.35	600	–140	55.11	NA	55.11
			Total: 110			
			Ave. ABS Diff.: 60.77			

TABLE VIII
50% IBR CONVENTIONAL UFLS SUMMARY

		Conventional UFLS				
Generation Tripped (MWs)	**ROCOF (Hz/s)**	**Total Load Shed (MWs)**	**Excess Amount of Load Shed (MWs)**	**Frequency Nadir (Hz)**	**Overshoot Frequency (Hz)**	**Final Frequency (Hz)**
95	–0.32	200	105	59.26	61.05	60.74
140	–0.62	200	60	59.22	60.69	60.46
190	–0.81	200	10	59.17	60.17	60.08
235	–1.11	200	–35	59.10	59.73	59.69
330	–1.56	400	70	58.89	61.34	60.79
375	–1.64	400	25	58.91	60.26	60.16
435	–2.1	400	–35	58.76	59.89	59.80
490	–2.63	600	110	58.63	61.34	61.34
540	–2.91	600	60	58.53	60.79	60.79
600	–2.65	600	0	58.52	59.99	59.92
640	–3.46	600	–40	58.38	NA	58.88
700	–3.08	600	–100	57.68	NA	58.01
750	–3.27	600	–150	55.92	NA	55.93
			Total: 80			
			Ave. ABS Diff.: 61.54			

TABLE IX
67% IBR CONVENTIONAL UFLS SUMMARY

		Conventional UFLS				
Generation Tripped (MWs)	**ROCOF (Hz/s)**	**Total Load Shed (MWs)**	**Excess Amount of Load Shed (MWs)**	**Frequency Nadir (Hz)**	**Overshoot Frequency (Hz)**	**Final Frequency (Hz)**
95	–0.54	200	105	59.23	61.26	60.78
140	–1.02	200	60	59.14	60.86	60.49
190	–1.25	200	10	59.10	60.22	60.13
235	–1.73	400	165	58.96	62.20	61.31
330	–2.6	400	70	58.70	61.81	60.88
375	–2.33	400	25	58.78	60.32	60.17
435	–3.47	600	165	58.44	64.23	61.91
490	–4.37	600	110	58.31	61.50	61.46
540	–4.82	600	60	58.17	60.89	60.86
600	–3.72	600	0	58.29	60.04	59.93
640	–5.72	600	–40	56.93	NA	57.79
700	–4.26	600	–100	56.77	NA	57.16
750	–4.51	600	–150	53.82	NA	53.86
			Total: 480			
			Ave. ABS Diff.: 81.54			

C. Testing Synchronous Condenser Additions

Synchronous condensers are essentially synchronous generators, but without a prime mover (e.g., coal, natural gas) to produce power (MWs = 0). Synchronous condensers consist of a generator and exciter and are typically brought online with a starter motor to get them up to synchronous speed so they can be connected to the power system. Synchronous condensers typically range in size from about 20 to 200 MVARs and are connected to the transmission system via a step-up transformer. Benefits of synchronous condensers are system inertia (H constants ranging from 1 to 6 MW•s/MVA), short-circuit current, up or down voltage support, and overall grid stability. They are especially beneficial for weak grids (i.e., grids with low inertia or low short-circuit strength).

The viability of synchronous condenser usage in low inertia systems was tested using the 67 percent IBR (reduced inertia) test system. All the replaced or displaced inertia was added back to the system by modeling high-inertia synchronous condensers. Each synchronous condenser was rated 150 MVAR and had an H constant of 6 MW•s/MVA at 100 MVA base. The same UFLS program was used as in the previous case studies in this section. In all, 10 synchronous condensers were added to replace all the lost inertia, as shown in Fig. 13. Table X shows the percentage of depleted inertia for the 67 percent IBR system. Table XI shows the percentage of inertia added back to the system with high-inertia synchronous condensers.

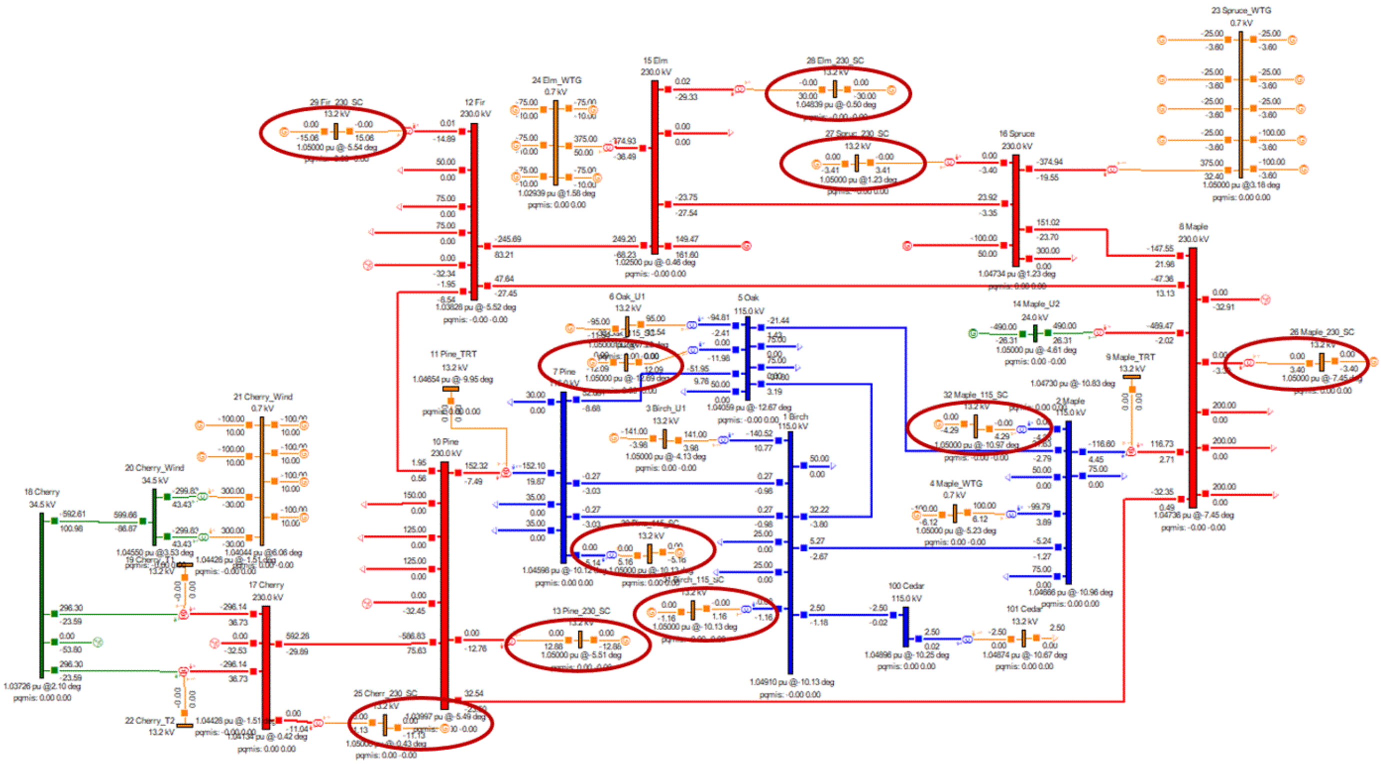

Fig. 13. 67 percent IBR test system with synchronous condensers.

TABLE X
PERCENT INERTIA DEPLETED BY 67% IBR

Generator Name	Nameplate MVA	Generator Inertia Constant (H)	All Synchro H at 100 MVA Base
Birch U1	150	6.22	9.33
Oak U1	100	5.48	5.48
Pine U1	300	3.33	9.99
Maple U1	100	5.48	5.48
Maple U2	500	3.236	16.18
Elm	1000	3.959	39.59
Spruce	1000	3.959	39.59
Total	**3150**		**125.64**

Generator Name	Nameplate MVA	Generator Inertia Constant (H)	67% Wind H at 100 MVA Base
Birch U1	150	6.22	9.33
Oak U1	100	5.48	5.48
Cherry WTG	600	0	0
Maple WTG	100	0	0
Maple U2	500	3.236	16.18
Elm	200	3.959	7.918
Elm WTG	500	0	0
Spruce	100	3.959	3.959
Spruce WTG	900	0	0
Total	**3150**		**42.867**

Inertia depleted by Type IV wind:
(125.64 – 42.867) / 125.64 • 100 = 65.88%

As can be seen in Table XI, slightly more inertia was added back to the system than the original 0 percent IBR system. Thirteen studies equivalent to the 0 percent IBR case were run with the synchronous condenser case. The results of the synchronous condenser studies are shown in Table XII. Comparing results to the 0 percent IBR case, results are mostly similar, but slightly worse, when replacing inertia with synchronous condensers. The highest and lowest frequency nadirs are worse for the synchronous condenser case, as is the frequency overshoot and the count of final frequencies outside the range of 59.5 Hz to 60.5 Hz (7 cases versus only 3 for the 0 percent IBR system). ROCOF is also slightly worse, but still within the design parameters for the UFLS program. The average of the absolute value of excess load shed is also slightly worse. The total amount of load shed for the synchronous condenser system is 5,600 MWs, compared to 5,200 MWs for the 0 percent IBR system.

TABLE XI
SYNCHRONOUS CONDENSER INERTIA ADDED BACK TO 67% IBR SYSTEM

SYNC CON Name	Nameplate MVA	SYNC CON Inertia Constant (H)	67% Wind H at 100 MVA Base
Birch 115 SC	150	6.00	9.00
Cherry 230 SC	150	6.00	9.00
Elm 230 SC	150	6.00	9.00
Fir 230 SC	150	6.00	9.00
Maple 230 SC	150	6.00	9.00
Maple 115 SC	150	6.00	9.00
Oak 115 SC	150	6.00	9.00
Pine 230 SC	150	6.00	9.00
Pine 115 SC	150	6.00	9.00
Spruce 230 SC	150	6.00	9.00
Total	**1500**		**90.00**

Inertia added back by SYNC CON:
(42.867 + 90.00) / 125.64 • 100=105.75%

TABLE XII
67% IBR CONVENTIONAL UFLS SUMMARY
WITH SYNCHRONOUS CONDENSERS ADDING INERTIA BACK TO SYSTEM

		Synchronous Condenser UFLS				
Generation Tripped (MWs)	**ROCOF (Hz/s)**	**Total Load Shed (MWs)**	**Excess Amount of Load Shed (MWs)**	**Frequency Nadir (Hz)**	**Overshoot Frequency (Hz)**	**Final Frequency (Hz)**
95	–0.17	200	105	59.28	60.93	60.74
140	–0.30	200	60	59.26	60.61	60.46
190	–0.41	200	10	59.24	60.08	60.02
235	–0.54	200	–35	59.19	59.64	59.63
330	–0.82	400	70	58.96	60.94	60.71
375	–0.78	400	25	58.97	60.22	60.14
435	–1.06	400	–35	58.92	59.67	59.66
490	–1.19	600	110	58.68	61.33	61.33
540	–1.32	600	60	58.66	60.75	60.75
600	–1.33	600	0	58.66	60.08	60.01
640	–1.59	600	–40	57.81	60.00	57.81
700	–1.56	600	–100	58.16	60.00	58.24
750	–1.68	600	–150	56.16	60.00	56.16
			Total: 80			
			Ave. ABS Diff.: 61.54			

The synchronous condenser system results are slightly worse than the 0 percent IBR system results because synchronous condensers cannot inject MWs back into the system to support frequency with governor response. But it can be concluded that adding inertia back to the system using synchronous condensers is a viable, albeit expensive solution. For this test system, the cost figures from Section IV demonstrate that the total investment to replace inertia with synchronous condensers would be about $375 million.

D. *Testing BESS Additions*

BESSs are becoming a necessary element of today's renewable energy portfolio. Used predominantly for peak-shaving during high load conditions, BESSs are an important component of the modern electrical grid for overall grid stability. In addition to peak-shaving, BESSs can provide voltage support when deployed near electrical loads that are far removed from other generation. They can also supply near instantaneous voltage and frequency support during system voltage and frequency excursions. BESSs can range in size from just a couple of MWs to several hundred MWs. Typical discharge durations range from 1 to 4 hours.

The viability of BESS usage in low inertia systems was tested using the 67 percent IBR test system. Various amounts of BESSs were tested ranging from 200 to 400 MWs. It was concluded that 200 MWs (10 percent of test system peak load) was an optimum balance of cost and performance. In all, two 200 MW BESSs were modeled, each operating at 100 MW capacity, as shown in Fig. 14.

Thirteen studies equivalent to the 0 percent IBR case were run with the BESS case. BESS power injection predisturbance was 0 MWs. The BESS was programmed to inject MWs when frequency was below 59.5 Hz and remove MW injection when frequency was above 60.5 Hz. This allowed the BESS to respond before UFLS to minimize the amount of load shed for each study. BESS MW injection and absorption were delayed by 3 cycles. The results of the BESS studies are shown in Table XIII.

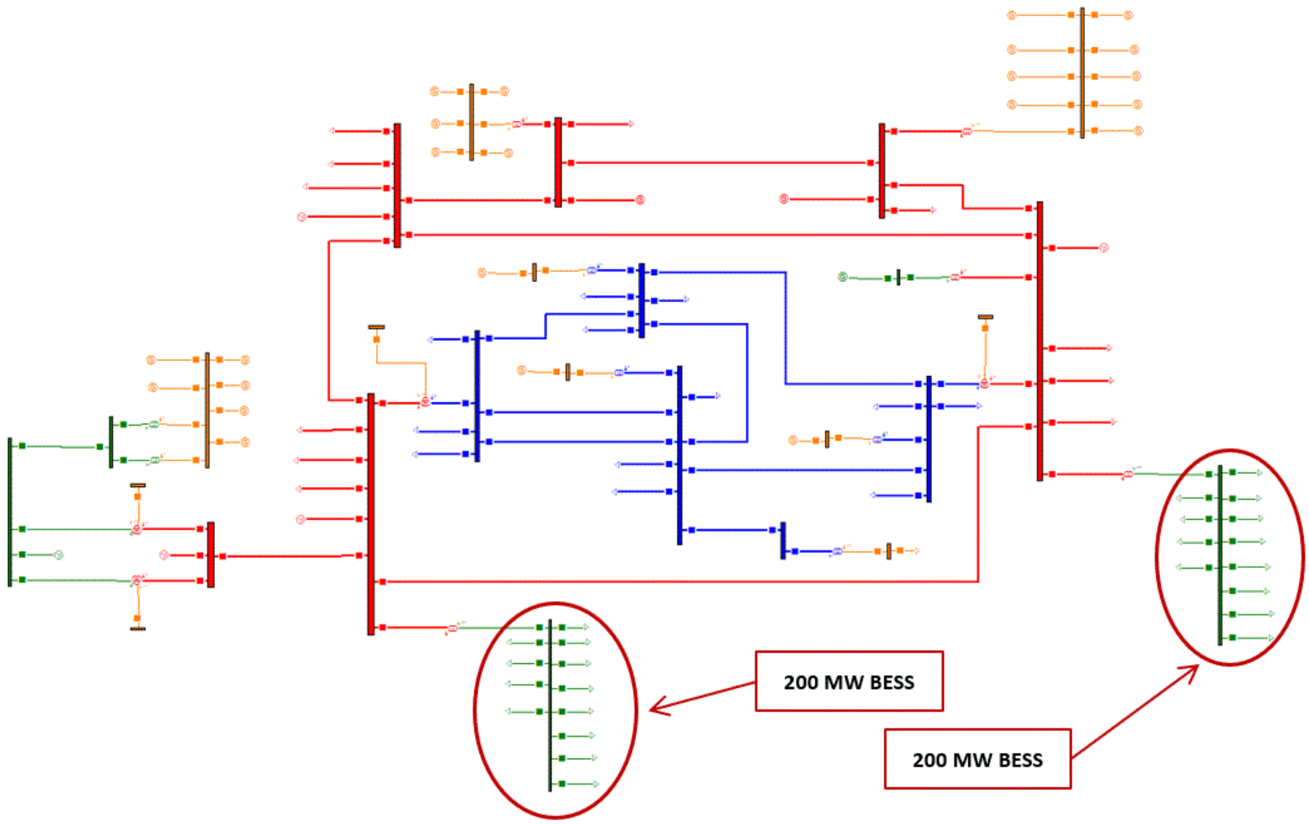

Fig. 14. 67 percent IBR test system with BESSs.

TABLE XIII
67% IBR CONVENTIONAL UFLS SUMMARY
WITH BESS PROVIDING FAST FREQUENCY RESPONSE

		200 MW BESS UFLS				
Generation Tripped (MWs)	**ROCOF (Hz/s)**	**Total Load Shed (MWs)**	**Excess Amount of Load Shed (MWs)**	**Frequency Nadir (Hz)**	**Overshoot Frequency (Hz)**	**Final Frequency (Hz)**
95	–0.57	0	5	59.47	60.24	60.08
140	–1.02	0	10	59.45	60.22	60.12
190	–1.23	0	–15	59.43	59.93	59.93
235	–1.69	0	–35	59.32	59.73	59.71
330	–2.47	200	–30	59.09	59.89	59.83
375	–2.16	200	0	59.11	60.10	60.03
435	–3.28	400	–10	58.91	60.51	59.97
490	–4.02	400	–15	58.73	60.22	60.04
540	–4.42	400	–15	58.65	60.04	60.04
600	–2.95	400	–75	58.84	60.20	60.08
640	–5.28	600	10	58.39	60.34	60.26
700	–3.42	600	–50	58.66	60.44	60.23
750	–3.65	600	–100	58.54	60.23	59.94
			Total: –320			
			Ave. ABS Diff.: 28.46			

When comparing these results to the 0 percent IBR case, a significant improvement is observed, even in light of the fact that ROCOF was near the extreme levels shown for the 67 percent IBR case. Frequency nadir is improved for most cases as is frequency overshoot. The average of the absolute value of excess load shed is about half of the 0 percent IBR case. The most significant improvements are final frequency (within +/– 0.3 Hz of nominal for each case) and total load shed of 3,800 MWs, which is 27 percent less than total load shed for the 0 percent IBR case.

Based on these study results, it is evident that BESSs should be considered as an option to provide fast frequency responses in low inertia systems. The challenges will be developing market mechanisms to incentivize BESS owners to provide this ancillary service and developing grid-interconnection codes that require it. A BESS is also expensive to implement. For this test system, the cost figures from Section IV demonstrate the total investment for 200 MWs of a BESS would be about $230 million.

E. Testing the ROCOF UFLS Program

The logic shown in Fig. 7 was deployed across the four different test systems. A couple of iterations of studying different ROCOF bandwidths and amounts of load to trip in each bandwidth were undertaken until an optimum program was developed, as shown in Table XIV. Following the guidelines for the generic ROCOF UFLS program example in Section III, the actual program was developed.

TABLE XIV
ROCOF UFLS PROGRAM LOAD-TRIPPING AND RESTORING DETAILS

		Total Level 1 (MWs)		**460**	**410**	**260**	**205**						
		Total Level 1%		23.00%	20.50%	13.00%	10.25%						
		Total ROCOF Level 1 (MWs)		460	360	260	100						
		Total ROCOF Level 1%		23.00%	18.00%	13.00%	5.00%						
				3 cyc.	8 cyc.	12 cyc.	30 cyc.						
				AND_1	**AND_2**	**AND_3**	**AND_4**						
Sub	**Load Label**	**Load (MWs)**	**UFLS Level**	**ROCOF 3.75–10 Hz?**	**ROCOF 2.5–3.75 Hz?**	**ROCOF 1.00–2.5 Hz?**	**ROCOF 0–1.00 Hz?**	**Time Delay**	**Load Restore**	**Load Restore ROCOF**		**f start**	**f restore**
Birch	1-1	50	3	Y	Y	Y	Y	6	N				
Birch	1-2	25	1	Y	Y	Y	Y	6	1	>0.15 Hz/s	80 cyc.	60.1	60.3
Birch	1-3	25	1	Y	Y	Y	N	12	1	>0.25 Hz/s	48 cyc.	60.1	60.3
Fir	12-2	75	2	N	N	N	N	6	N				
Fir	12-3	50	1	Y	N	Y	N	30	N				
Maple	2-1	75	3	N	N	N	N	20	N				
Maple	2-2	75	3	N	N	N	N	20	N				
Maple	2-3	50	2	Y	Y	N	N	30	N				
Oak	5-1	75	1	Y	Y	Y	Y	6	N				
Oak	5-2	75	2	N	N	N	N	20	N	Was 15 cyc.			
Oak	5-3	50	1	Y	N	N	N	599940	N				
Oak	5-3	50	3	N	N	N	N	10	N				
Pine	7-1	35	1	Y	Y	Y	N	599940	N				
Pine	7-1	35	3	N	N	N	N	20	N				
Pine	7-2	20	1	Y	Y	Y	N	599940	1	>0.5 Hz/s	24 cyc.	60.1	60.3
Pine	7-2	20	3	N	N	N	N	20	1				
Pine	7-3	30	1	Y	Y	Y	N	20	1	>0.10 Hz/s	120 cyc.	60.3	60.5
Pine	10-1	150	1	Y	Y	N	N	599940	N				
Pine	10-1	150	3	N	N	N	N	30	N				
Total		**2055**											
Level 1 Total	460	**MWs**	23.00%	%									
Level 2 Total	200	**MWs**	10.00%	%									
Level 3 Total	200	**MWs**	10.00%	%									
Not Used Total	940	**MWs**	47.00%	%									

For ROCOF between 0–1 Hz/s, 1–2.5 Hz/s, 2.5–3.75 Hz/s, and 3.75–10 Hz/s, corresponding amounts and percentages of system load applied to Level 1 are tripped as follows: 100 MWs (5 percent), 260 MWs (13 percent), 360 MWs (18 percent), and 460 MWs (23 percent), respectively. Additional Level 1 load in the amounts of 105 MWs and 50 MWs is tripped with conventional time-delayed tripping for the 0–1 Hz/s and 2.5–3.75 Hz/s ROCOF bandwidths, respectively. Level 2 and Level 3 UFLS will trip 200 MWs (10 percent), each with varying time delays, some programmed to trip on ROCOF. Four ROCOF tripping only Level 1 loads (5-3, 7-1, 7-2, and 10-1) are also armed to trip in Level 3 with staggered time delays (gray highlighted rows) for higher inertia conditions with loss of large amounts of generation. A total of 255 MWs of extra load are made available for Level 3 tripping (455 MWs total or 22.75 percent of system load) *if* it doesn't ROCOF trip in Level 1. Four loads (100 MWs total or 5 percent of total system load) are made available for automatic load restoration if frequency overshoot occurs. Loads 1-2, 1-3, and 7-2 will restore at 60.3 Hz if ROCOF is above 0.15 Hz/s, 0.25 Hz/s, and 0.5 Hz/s, respectively. Load 7-3 will restore at 60.5 Hz if ROCOF is above 0.1 Hz/s.

The study process for the ROCOF UFLS program is illustrated for one of the tests on the 67 percent IBR system in which 490 MW Maple Unit 2, 75 MW Elm Unit 1, and 75 MW Elm Unit 2 are tripped simultaneously, resulting in a total loss of 640 MWs of generation (32 percent of total system generation). All three generators are tripped at t = 0.5 seconds. Fig. 15 shows the first 2 seconds of the event, including all UFLS. ROCOF for this event is 5.45 Hz/s, which is the highest observed ROCOF for any of the 52 studies. All 460 MWs of Level 1 loads trip, because the ROCOF is greater than 3.75 Hz/s. One Level 2 load trips on ROCOF greater than 3.75 Hz/s, and two time-delayed Level 2 loads trip (total of 200 MWs of Level 2 load tripped). One 50 MW Level 3 load trips on ROCOF between 1 and 2.5 Hz/s. Total load tripped for this event was 710 MWs with 70 MWs of load restoration for a net of 640 MWs of load tripped. Frequency nadir occurs about 5 cycles after the Level 3 load trips. Fig. 16 shows the point of 70 MWs of load restoration at just above 60.3 Hz. Frequency overshoot peaks at 60.35 Hz and settles out to a final frequency of 60.16 Hz.

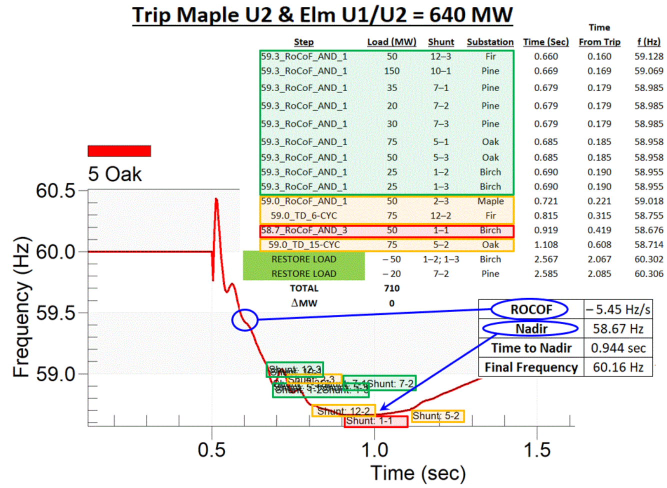

Fig. 15. ROCOF load shed for trip of 640 MWs of system generation (67 percent IBR system).

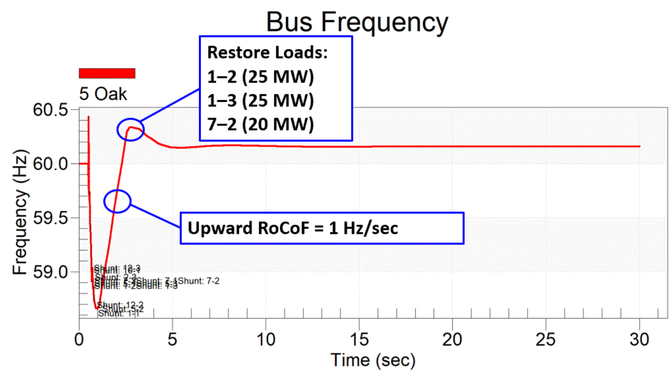

Fig. 16. Final frequency and load restoration for trip of 640 MWs of system generation.

Table XV, Table XVI, Table XVII, and Table XVIII show the UFLS results for the 0 percent, 25 percent, 50 percent, and 67 percent IBR cases. Only two out of the 52 cases resulted in final frequency outside of the 59.5 Hz to 60.5 Hz range, and both were within a tenth of a Hz of the desired bandwidth. Frequency overshoot for all cases was below 60.7 Hz. The average of the absolute value of excess load shed is significantly improved over the conventional UFLS case studies with all four systems showing an average difference of less than 40 MWs, contrary to the conventional average differences, which were all greater than 60 MWs. Finally, for each of the 0 percent, 25 percent, 50 percent, and 67 percent IBR cases, total load shed was 5,240 MWs, 5,640 MWs, 5,770 MWs, and 5,550 MWs, respectively. The sum of these totals yields a 200 MW reduction in load shed compared to the conventional UFLS results. This is not a significant improvement, but having more load available in Level 3 for low ROCOF scenarios when there is a large ΔL resulted in significantly improved final frequencies for the last three studies in each of the 0 percent and 25 percent IBR cases.

TABLE XV
0% IBR ROCOF UFLS SUMMARY

		ROCOF UFLS				
Generation Tripped (MWs)	**ROCOF (Hz/s)**	**Total Load Shed (MW)s***	**Excess Amount of Load Shed (MWs)**	**Frequency Nadir (Hz)**	**Overshoot Frequency (Hz)**	**Final Frequency (Hz)**
95	–0.16	0	–95	59.36	59.54	59.94
140	–0.24	100	–40	59.29	59.84	59.80
190	–0.35	205	15	59.25	60.18	60.09
235	–0.49	205	–30	59.19	59.92	59.87
330	–0.63	355	25	58.98	60.37	60.17
385	–0.74	405	20	58.93	60.31	60.24
430	–0.84	405	–25	58.85	59.99	59.93
490	–0.97	405	–85	58.79	59.42	59.42
525	–0.84	505	–20	58.69	60.05	59.97
585	–1.08	575	–10	58.63	60.60	60.49
630	–1.14	660	30	58.61	60.49	60.39
680	–1.11	710	30	58.64	60.52	60.45
780	–1.24	710	–70	58.63	59.95	59.95
			Total: –255			
			Ave. ABS Diff.: 38.08			

* Includes auto load restoration

TABLE XVI
25% IBR ROCOF UFLS SUMMARY

		ROCOF UFLS				
Generation Tripped (MWs)	**ROCOF (Hz/s)**	**Total Load Shed (MWs)***	**Excess Amount of Load Shed (MWs)**	**Frequency Nadir (Hz)**	**Overshoot Frequency (Hz)**	**Final Frequency (Hz)**
95	–0.19	100	5	59.29	60.12	60.05
140	–0.38	155	15	59.29	60.19	60.10
190	–0.51	205	15	59.21	60.14	60.07
235	–0.69	205	–30	59.10	59.75	59.72
330	–0.97	335	25	58.91	60.43	60.21
375	–1.06	410	35	58.97	60.21	60.18
435	–1.26	460	25	58.88	60.40	60.22
490	–1.54	460	–30	58.78	59.87	59.87
540	–1.72	510	–30	58.68	59.83	59.93
590	–1.75	630	40	58.63	60.54	60.54
640	–1.93	660	20	58.54	60.33	60.33
690	–2.18	710	20	58.64	60.33	60.33
740	–2.35	780	40	58.54	60.51	60.49
			Total: 150			
			Ave. ABS Diff.: 25.38			

* Includes auto load restoration

TABLE XVII
50% IBR ROCOF UFLS SUMMARY

		ROCOF UFLS				
Generation Tripped (MWs)	**ROCOF (Hz/s)**	**Total Load Shed (MWs)***	**Excess Amount of Load Shed (MWs)**	**Frequency Nadir (Hz)**	**Overshoot Frequency (Hz)**	**Final Frequency (Hz)**
95	–0.32	100	5	59.28	60.14	60.06
140	–0.62	155	15	59.26	60.34	60.13
190	–0.81	205	15	59.17	60.18	60.08
235	–1.11	260	25	59.23	60.26	60.14
330	–1.56	335	5	58.97	60.24	60.06
375	–1.64	410	35	58.95	60.33	60.21
435	–2.10	435	0	58.74	60.32	60.03
490	–2.63	490	0	58.64	60.31	60.18
540	–2.91	540	0	58.87	60.31	60.17
600	–2.65	610	10	58.72	60.05	59.98
640	–3.46	660	20	58.68	60.36	60.36
700	–3.08	780	80	58.62	60.52	60.26
750	–3.27	790	40	58.53	60.37	60.15
			Total: 250			
			Ave. ABS Diff.: 19.23			

* Includes auto load restoration

TABLE XVIII
67% IBR ROCOF UFLS SUMMARY

		ROCOF UFLS				
Generation Tripped (MWs)	**ROCOF (Hz/s)**	**Total Load Shed (MWs)***	**Excess Amount of Load Shed (MWs)**	**Frequency Nadir (Hz)**	**Overshoot Frequency (Hz)**	**Final Frequency (Hz)**
95	–0.54	100	5	59.27	60.16	60.06
140	–1.02	160	20	59.23	60.53	60.17
190	–1.25	190	0	59.22	60.31	59.99
235	–1.73	235	0	59.18	60.30	59.97
330	–2.60	310	–20	59.03	60.51	59.88
375	–2.33	390	15	58.91	60.37	60.12
435	–3.47	410	–25	58.96	60.32	59.83
490	–4.37	460	–30	59.00	60.30	59.84
540	–4.82	505	–35	58.85	60.31	59.90
600	–3.72	610	10	58.69	60.31	60.00
640	–5.72	630	–10	58.67	60.34	60.16
700	–4.26	760	60	58.58	60.62	60.30
750	–4.51	790	40	58.44	60.45	60.19
			Total: 30			
			Ave. ABS Diff.: 20.77			

* Includes auto load restoration

The previous ROCOF UFLS results show that the program worked well for the four system case studies (i.e., 0 percent, 25 percent, 50 percent, and 67 percent IBR test systems). Next, an attempt was made to stress test the various IBR test systems by applying faults at all the substation buses to ensure that the ROCOF UFLS scheme is secure from misoperation. The fault that was applied to each of the substation buses was a three-phase fault with a duration of 6 cycles to represent normal high-speed transmission fault clearing. During these tests, generator rotor angles were monitored to ensure they damped out and did not become unstable. Frequency was also monitored to ensure no unexpected deviations occurred. It was identified that during the 67 percent IBR case, a fault on a 230 kV bus caused rotor angle instability and network load-flow convergence issues. This case specifically resulted in severe numerical load-flow nonconvergence during the fault, as shown in Fig. 17.

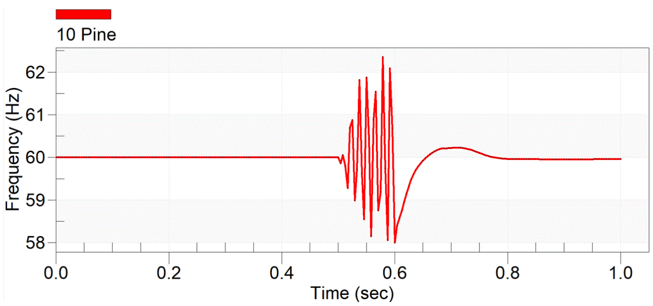

Fig. 17. 3-phase fault with load-flow nonconvergence.

It is shown that severe frequency spikes of +/– 2 Hz occurred from sample to sample during the fault condition. In fact, all the IBR cases showed some degree of nonconvergence during the fault, but for cases above 50 percent, the data indicated severe nonconvergence *after* the fault as well, which meant the data could not be trusted for cases above 50 percent. Further investigation into the cause of the nonconvergence issue for the IBR cases needs to be performed. None of the cases below 50 percent resulted in the operation of UFLS relays for a 6-cycle three-phase fault. In future studies, stress testing of the system will include faults with longer durations and different types of faults, such as single line-to-ground, double line-to-ground, and phase-to-phase faults, to see if they will have any detrimental impact to the ROCOF UFLS program.

VI. Hardware Testing the ROCOF UFLS Program

The UFLS logic described in Section III was tested using the base 2000 MW system shown in Fig. 10 with only synchronous generation, and IBR penetrations of 25 percent, 50 percent, and 67 percent. The IPPS tool was used to simulate a drop in generation for all four cases. The total MW dropped for each simulation varied from 95 MW to 740 MW, as shown in Table XIX.

Table XIX
Summary of Relay Test Cases

IBR Penetration %	Total MW Dropped	ROCOF Bandwidth (Hz/s)
0	330	0–1.0
0	490	0–1.0
0	585	0–1.0
25	95	0–1.0
25	590	1.0–2.50
25	740	2.50–3.75
50	490	1.0–2.50
50	750	2.50–3.75
67	600	2.50–3.75
67	700	3.75–10.0
67	640	3.75–10.0

The UFLS logic was programmed in the IPPS tool using logic gates and tested exhaustively through simulations. The IPPS tool has a built-in frequency measurement model that can calculate frequency from the bus voltage. This frequency is then used as an input to test the underfrequency logic simulated in the tool. These types of frequency measurement models may include filters to smooth the calculated frequency value. The smoothing filter coefficients need to be adjusted to ensure that the simulation provides realistic results. Additionally, the method used to calculate frequency in the relay can vary depending on the manufacturer and relay type. Even though the logic had been tested in the IPPS tool, it was also programmed and tested in a microprocessor-based underfrequency relay to verify that the relay operates as observed in the simulations. A total of 52 simulations were run using the IPPS tool with varying percentages of IBR penetration and loss of synchronous generation. Out of these simulations, 11 cases were carefully selected for hardware testing. The cases chosen had ROCOF values that were very close to the limits of the ROCOF bandwidths and were most likely to give a different result in the relay compared to the simulation results.

The voltage and current values at the Oak bus were recorded in a COMTRADE file for each of the 11 cases. These COMTRADE files were played back in the underfrequency relay, which was programmed with the Level 1 UFLS settings, shown in Fig. 7. The reclose logic shown in light red was disabled to focus on testing the tripping scheme. All four load-shed percentages of Level 1 were tested simultaneously.

The COMTRADE test files for one of these cases is shown following. This test file was created using the system with 25 percent IBR penetration. A total of 740 MW of generation was dropped. The IPPS tool results showed that the AND_2 bit asserted to trip part of the Level 1 load. The COMTRADE test file was then played back in the relay, and the event report triggered by the relay is shown in Fig. 18.

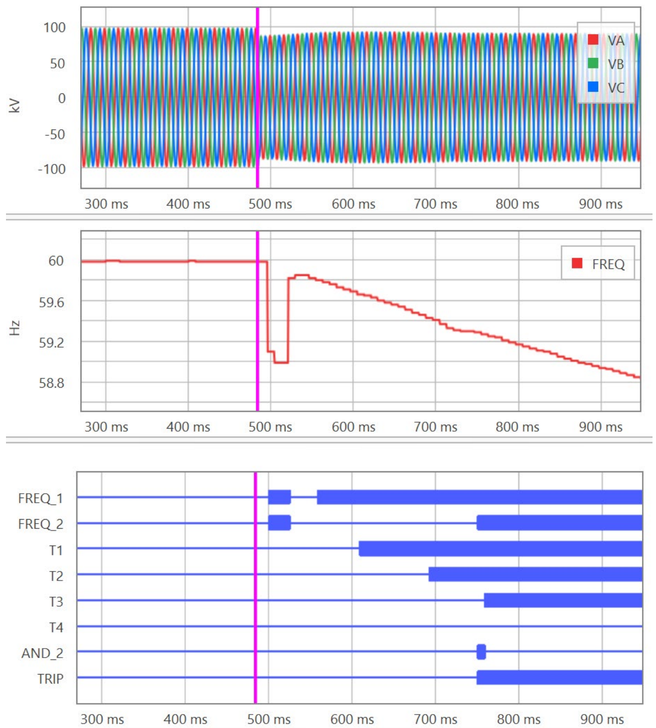

Fig. 18. Level 1 UFLS trip.

When the breaker is opened in the IPPS tool, a sudden shift in the voltage waveform causes a transient decrease in the frequency. When these voltage waveforms were played back in the relay, a similar transient was observed when the breaker was opened (shown by the vertical magenta line in Fig. 18) and lasted for a maximum time of 1.5 cycles. This causes the FREQ_1 and FREQ_2 bits to assert momentarily. After this transient has passed, the frequency decays gradually as expected during a load-generation unbalance. The frequency drops below FREQ_1 setting (59.8 Hz) and starts T1 through T4. The frequency drops below FREQ_2 setting (59.3 Hz) after 192.14 ms or 11.5 cycles. This fulfills the three conditions required to assert the AND_2 bit followed by the OR_1 bit: T2 has timed out, T3 has not yet timed out (12-cycle pickup), and the frequency has dropped below the FREQ_2 setting. The assertion of the AND_2 bit indicates that the ROCOF is between 2.5 and 3.75 Hz/s. After this, the two additional conditions required to assert the AND_6 bit are fulfilled because the motor spin-down check does not pickup and the voltage is still above the UV_1 threshold. Finally, the Trip_1 bit asserts. This logic path is highlighted in Fig. 19.

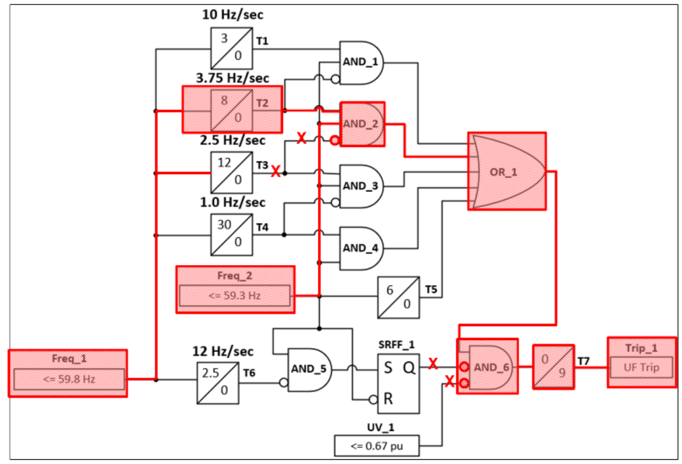

Fig. 19. UFLS trip path. (patent-pending)

The IPPS tool simulation results were compared to the relay test results to determine if the relay operated correctly. The expected percentage of Level 1 load was shed correctly for all the cases that were played back in the relay except one. The case with 67 percent IBR penetration and loss of 700 MW of generation, resulted in a ROCOF value of approximately 4 Hz/s. This caused a trip through the AND_1 bit (ROCOF between 3.75 Hz/s and 10Hz/s) in the IPPS tool but caused a trip through the AND_2 bit (2.5 Hz/s–3.75 Hz/s) in the relay test.

Due to the transient frequency drop at the beginning of the simulation, the frequency calculated by the relay was below the Freq_1 setting right from the instant when 700 MW of generation was dropped. The transient lasted 1.5 cycles. This caused T2 to time out before frequency dropped below the Freq_2 setting, as shown in Fig. 20. The output of T2 blocked the AND_1 bit from asserting. The frequency took 7.76 cycles to decrease below the Freq_2 setting after generation was dropped.

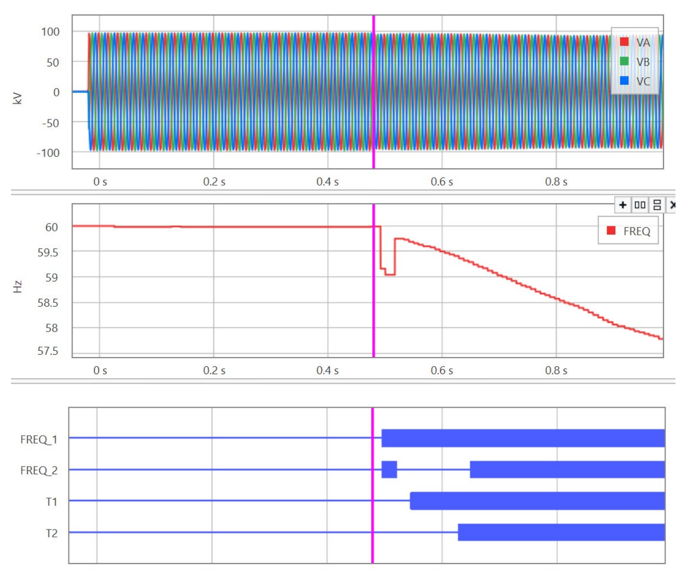

Fig. 20. Level 1 UFLS trip (67 percent IBR, 700 MW drop).

The IPPS tool uses filters to smooth the frequency calculated from the bus voltage, which would have removed or damped the transient and resulted in the AND_1 bit asserting. Even if the AND_2 bit asserted instead of AND_1, the final system frequency would be within the required range of 59.5 Hz to 60.5 Hz. This was confirmed by rerunning the IPPS tool simulation for this case study, in which loads were prevented from tripping via AND_1. With only AND_2 ROCOF tripping available, results were virtually the same. The exact same amount of load was tripped and restored, nadir was 0.15 Hz lower, and the final frequency was exactly the same at 60.3 Hz.

VII. Frequency Excursion Mitigation Strategies Comparison

The previous two sections describe UFLS strategies to ensure adequate load shed for frequency excursions, especially for systems with low inertia and the potential for high ROCOF. The following lays out the independent strategies in order of deployment cost with discussion on merits and issues.

Synchronous Condenser Deployment—Synchronous condensers can play a vital role in low inertia systems. Besides adding inertia back to the system, they can provide short-circuit strength as well. Low inertia systems are typically low short-circuit strength systems, too. Having low short-circuit strength can cause multiple system issues, such as transmission line protective relay sensitivity, voltage stability, generator stability, and control stability issues of power electronic equipment associated with IBR, SVCs, HVDCs, and STATCOMS. The study results stated previously were almost as good as the 0 percent IBR system, so replacing inertia with synchronous condensers works, but at a high cost. The turnkey installation cost for the test system studied was estimated at $375 million. To replicate this on the utility system, the cost would be triple or $1.125 billion. This is not only an expensive solution, but one that would take about 5 years or more to fully implement.

BESS Deployment—BESSs have a growing role in the modern, renewable energy-dominated electrical systems. While the primary function of BESSs is to charge during load valleys and discharge during load peaks, they can provide ancillary frequency support in either GFL or GFM mode. The tests performed on the 67 percent IBR system using only 200 MWs for fast frequency response showed great promise as an effective solution. Frequency response was much better than the 0 percent IBR and synchronous condenser case studies. This solution, however, was shown to cost about $230 million for the test system studied. Implementation on the utility system would be about triple that cost at $690 million. It would also take about 5 years or more to fully implement this solution and may require a market mechanism to provide the ancillary service.

ROCOF UFLS Deployment—ROCOF UFLS program deployment has great potential, as the study results showed. Performance was as good as BESSs, except for more load needing to be tripped. Implementation on the utility system would require reprogramming of existing UFLS relays and possible replacement of the rest. Currently, about 200 UFLS relays are deployed, of which about half are reprogrammable microprocessor relays. Reprograming 100 UFLS relays would cost approximately $200,000. Replacement of the other 100 UFLS relays would cost approximately $15 million. It is possible to implement this program by only reprogramming the existing fleet of microprocessor relays, since only about 25 percent of UFLS needs to trip in Level 1. This is a very cost-effective solution that can be implemented within about a 2-year time frame. Implementation of this program will require Planning Coordinator endorsement and may require changes to a region’s NERC PRC-006 standard to allow implementation.

VIII. Conclusion

It is a fact that the electric grid is changing rapidly, with no slowing down in sight. Retirement of synchronous fossil generation will continue to accelerate over the coming years and replacement generation will likely be more renewable resources. The combined effect of this is an electric grid with less inertia and the potential for high ROCOF during frequency excursions. Existing UFLS programs have a fixed ROCOF for which they will operate effectively. Higher ROCOF levels can render existing UFLS programs obsolete and ineffective.

While multiple strategies exist that can improve a UFLS program’s performance, in a world that is becoming IBR-dominant, implementation of a ROCOF UFLS program rises to the top as a viable solution. This solution can be implemented inexpensively and quickly, in as few as a couple of years. It can also be implemented as a standalone solution that can allow time for more capital-intensive solutions to be planned, procured, and executed to achieve a blended strategy solution. Implementation of a blend of the strategies above for frequency excursion mitigation could be the best overall solution, resulting in less load shed and even better frequency performance.

The electric grid continues to change with more wind and solar renewable resources being added every year. As the electric grid changes, so must the approach to UFLS programs. The status quo has been maintained regarding UFLS strategies in North America for over 50 years. A continuation of this approach will inevitably result in another blackout, perhaps the worst one in U. S. or world history.

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X. Biographies

Kevin W. Jones received his BS degrees in electrical engineering and computer engineering from the University of Missouri in 1989. He has broad experience in the field of power system protection, operations, and maintenance. Upon graduating, he has served nearly 36 years at Southwestern Public Service Company (now Xcel Energy), where he worked in various departments, including Distribution Design, Substation Commissioning, Transmission Operations, and System Protection Engineering. Kevin specializes in high-voltage transmission line relaying, event analysis, and system stability relaying. He is the chairman of IEEE Power System Relaying and Control Committee Working Groups C29, D29, and C51. He was the vice chairman of the NERC PRC-026-1 Standard Drafting Team titled: Relay Performance During Stable Power Swings. Kevin is a registered professional engineer in the state of Texas and a senior member of IEEE.

Solomon H. Sibhat received a Bachelor of Science in electrical engineering from Texas Tech University in Lubbock, Texas, in 2021. He began his career at Xcel Energy in 2019 as an intern in the System Protection Engineering department and transitioned to a full-time engineer upon graduation. Currently, Solomon works on projects related to underfrequency load shedding (UFLS), CAPE modeling, NERC PRC-023, NERC PRC-025, event analysis, and various aspects of power relay settings related to capital projects.

Ce Zheng received his BS and MS in electrical engineering from North China Electric Power University, and PhD in electrical engineering from Texas A&M University. He is currently working at Siemens as a senior staff power system R&D engineer. He is the technical lead for the APA-TS Link module, and for the NERC PRC standard compliance tools.

Krithika Bhuvaneshwaran received her BS in electrical engineering from Sardar Patel College of Engineering in Mumbai, India, in 2012 and her MS from Georgia Institute of Technology in Atlanta, GA, in 2016. She currently works for Schweitzer Engineering Laboratories, Inc., (SEL), as an application engineer in Plano, Texas.

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