The Need for Faster Underfrequency Load Shedding

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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. Some underfrequency relays are set with long time delays to prevent them from incorrectly tripping for source transmission line operations where UFLS feeders have significant induction motor load. Today, the lower system inertia caused by renewable generation is increasing the potential depth of frequency excursions. This paper proposes a new rate-of-change-of-frequency scheme that allows for fast UFLS to minimize frequency excursions. The paper also presents simulations showing that the scheme is secure from misoperations for source transmission line operations.**

I. Introduction

The time of writing this paper preceded the manual load shedding events that occurred in Texas and other parts of the Midwest the week of February 14, 2021. Winter storm Uri settled over the Midwestern and deep southern states with ice, snow, and below freezing temperatures for several days, causing energy supply issues and low frequency in the Electric Reliability Council of Texas (ERCOT) region.

Automatic underfrequency load shedding (UFLS) has been used in North America as a last ditch, first line of defense to minimize the possibility of system-wide blackouts since the late 1960s. Following the 1965 northeast blackout, recommendations to prevent a similar occurrence included the use of automatic UFLS [1]. This blackout was the worst in history at the time, resulting in the loss of 20,000 MW of load, affecting 30 million people. The northeast blackout was also the catalyst for the formation of the National Electric Reliability Council (now the North American Electric Reliability Corporation [NERC]) on June 1, 1968. A year later, per the urging of the chief of the Bureau of Power for the Federal Power Commission (FPC), NERC was presented with a list of 15 study areas that the FPC believed NERC should address to ensure a reliable bulk power system. One of these study areas was load-shedding practices [2].

On August 14, 2003, another northeast blackout occurred, resulting in the loss of 62,000 MW of load, affecting 50 million people. Following this blackout, the U.S. Federal Energy Regulatory Commission (FERC) certified NERC as the Electric Reliability Organization (ERO) in the United States. NERC then filed 102 reliability standards with FERC. FERC approved these standards in March 2007 [3]. One of the standards, PRC-006 – Automatic Underfrequency Load Shedding, has 15 mandatory requirements applicable to planning coordinators, transmission owners, and distribution providers. Overall, this standard requires planning coordinators to develop a UFLS plan that transmission owners and distribution providers must follow. The planning coordinators must also perform periodic assessments of the plan to ensure it meets designed performance requirements.

While these NERC reliability standards have made cascading outages and blackouts less likely, they will, nevertheless, continue to occur, hopefully with less frequency and severity. It is impossible to anticipate all contingencies that will lead to the next cascading blackout.

The last major UFLS event that occurred in the United States was the Arizona-Southern California blackout on September 8, 2011. The sequence of events that precipitated this blackout are unfathomable. After the last transmission line tripped to form a San Diego Gas & Electric (SDG&E), Arizona Public Service (APS), and Comisión Federal de Electricidad (CFE) island, frequency in the island dropped at an initial rate of about 2.5 Hz/s, followed by a rate of about 3 Hz/s. The rapid frequency decay was caused by a severe unbalance of load over generation. All levels of UFLS tripped for this event, but not in time to arrest the frequency to a level above 57 Hz, at which point, all generation in the island tripped, causing the blackout. Overall, the Arizona-Southern California blackout resulted in the loss of 7,835 MW of load, affecting 2.7 million people [4].

Another significant recent UFLS event occurred on September 28, 2016, when the entire South Australian system blacked out. South Australia is connected to the rest of Australia via two 275 kV ac lines in Victoria. Prior to the blackout, the generation mix in South Australia was 18 percent synchronous generation (330 MW), 48 percent wind generation (883 MW), and 34 percent import over the Victoria tie lines (613 MW). The event was initiated by severe supercell thunderstorms with tornadoes, large hail, and destructive winds.

Five transmission system faults occurred within an 87-second timeframe. Six voltage dips within a 2-minute timeframe caused 456 MW of wind generation to cease producing power due to excessive low-voltage ride-through counts. This caused the imports across the Victoria tie lines to increase to almost 900 MW, which was greater than the 650 MW import limit. This excess import resulted in an unstable power swing, which initiated an out-of-step tripping scheme that tripped the two Victoria tie lines due to loss of synchronism with the rest of Australia. After the tie lines tripped, the system frequency decayed at a rate of 6 Hz/s, which was above the 3 Hz/s UFLS program design rate. All levels of UFLS tripped, but not in time to avoid a blackout. The high rate-of-change of frequency (ROCOF) was caused by the lack of sufficient synchronous generation inertia compared to the load being served [5].

The fact that it has been over nine years since the last UFLS event in the United States is good. However, the makeup of the

United States electric grid has changed immensely in nine years with the addition of significant amounts of nonsynchronous renewable generation (i.e., wind and solar), as shown in Fig. 1.

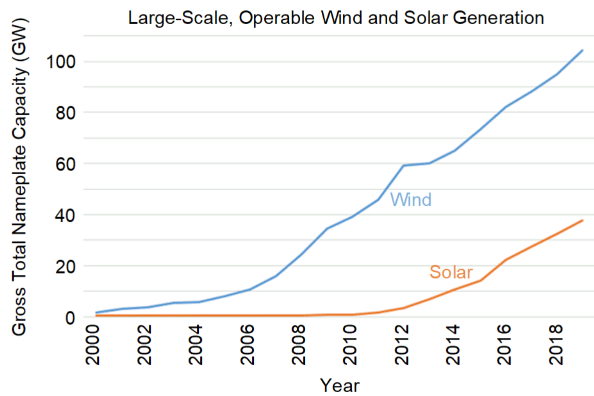

Fig. 1. Ramp-up of wind and solar generation during the 21st century

Also, the passing of almost a decade without a significant load-shed event has lulled the electric industry into a complacent false sense of security regarding existing UFLS program adequacy. Thus, it is time for the electric utility industry to reevaluate UFLS programs to ensure that they prevent blackouts and protect generators. One way of accomplishing this task is to make sure that underfrequency relays can operate as fast as possible while maintaining a good balance between dependability and security. As the United States electric grid becomes inundated with nonsynchronous renewable resources, lower system inertia and higher ROCOF will result. Ensuring UFLS relays can operate as fast as possible to arrest declining frequency during these conditions will better guarantee that this last ditch, first line of defense will prevent a blackout. This paper provides such a solution that is easy to implement in existing microprocessor-based relays with just a few settings changes.

II. Underfrequency Load-Shedding History

Prior to the 1965 northeast blackout, UFLS was not widely used in the United States for blackout prevention. Power systems were more isolated with smaller pockets of load and generation. Loss of a single generator was minimally impactful to the overall system because individual generators were smaller in size than they are today. Frequency recovery was achievable due to inertia and governor response of the remaining generation units.

In 1965, 80 percent of all generators with a nameplate rating of at least 10 MVA were in the range of 10 to 100 MVA in size. During the 1970s and 1980s, new generator additions in the United States were predominantly large coal and nuclear units, as shown in Fig. 2.

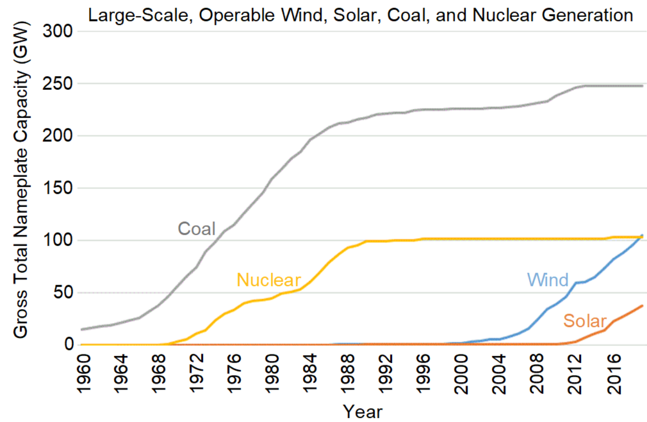

Fig. 2. Ramp-up of coal and nuclear generation during the 1970s and 1980s

These new coal and nuclear generators averaged 500 MVA and 1,000 MVA in nameplate size, respectively. Fig. 3 shows a comparison of the percentage of generation of a given size prior to 1966 and from 1966 to 1985 [6]. The rapid increase in number of large coal and nuclear generators made the likelihood of a more extreme underfrequency event possible if one of these generators suddenly tripped offline.

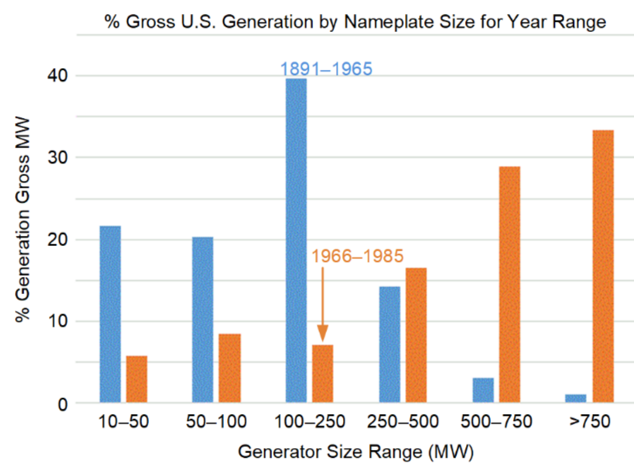

Fig. 3. Comparison of generator sizes prior to 1966 and from 1966 to 1985

From the 1970s through the 1990s, several major disturbances occurred in the United States that resulted in automatic UFLS. In 1987, NERC updated its operations criteria and guides and renamed them as operating policies [7]. One of these policies, Policy 6C, required control areas to establish plans for automatic UFLS. It was not until after the 2003 northeast blackout that NERC established mandatory reliability standard PRC-006, requiring adherence to a UFLS plan or risk fines for noncompliance.

B. Need for UFLS at Xcel Energy New Mexico/Texas (NM/TX)

The best way to understand the need for an automatic UFLS program is by use of a specific example. One such example is given in this paper based on the UFLS history of Southwestern Public Service Company (now Xcel Energy NM/TX). Xcel Energy NM/TX began like all other utilities—as an electric franchise. Over time, electric franchises throughout eastern New Mexico and the Texas Panhandle began interconnecting, forming a more contiguous system. By the early 1960s, the interconnected system covered an area of around 52,000 square miles and included four states, as shown in Fig. 4.

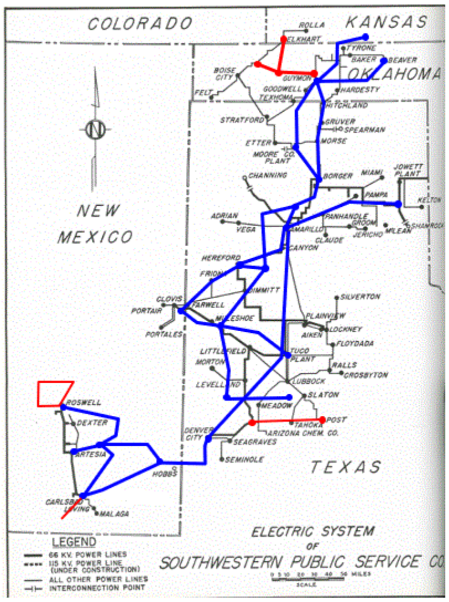

Fig. 4. Xcel Energy NM/TX in early 1960s (red lines indicate 69 kV, and blue lines indicate 115 kV)

In 1964, a major outage occurred in the Xcel Energy NM/TX system that would forever change how the transmission system was protected. A major 115 kV tie line from the southern to the northern Texas Panhandle was out of service for maintenance. A large generator in the Texas North region was also offline for maintenance. This generator alone made up 40 percent of the total generation in the Texas North region. Due to the outage of this generator, power imports from south to north were greater than normal on the remaining two 115 kV tie lines.

While in this weakened configuration, the sister unit to the offline Texas North unit tripped on loss of excitation, resulting in a significant increase in south-to-north power flows. These power flows were more than the maximum power transfer capability of the remaining transmission lines, resulting in an unstable power swing and tripping of the transmission line phase distance relays. When the tie lines tripped, only 20 percent of the normal Texas North generation remained energized, which was inadequate to serve the load. This severe unbalance of load over generation resulted in an unrecoverable decline in the Texas North system frequency, resulting in a Texas North blackout (Fig. 5).

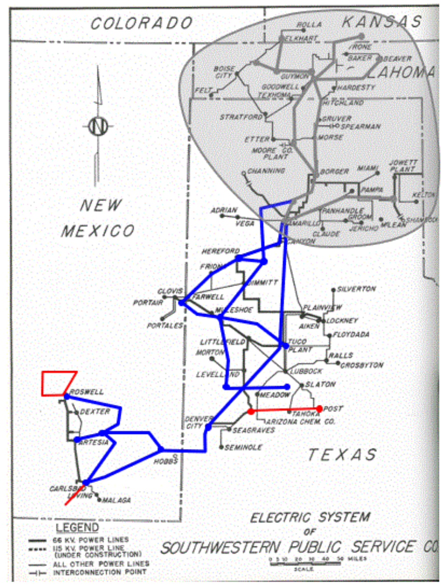

Fig. 5. 1964 Texas North blackout (red lines indicate 69 kV, and blue lines indicate 115 kV)

Following this blackout, several protective relaying changes were implemented across the entire Xcel Energy NM/TX system. First, power-swing blocking relaying was added to every looped transmission line terminal, and select tie lines were set to trip for out-of-step conditions. Second, automatic UFLS was added across the system at three frequency set points: 59.3 Hz, 59.0 Hz, and 58.7 Hz. The UFLS scheme was applied equally in each of the three load/generation islands and each underfrequency level would shed about 10 percent of the total system load. This combination of strategic islanding and underfrequency load shedding would prove to be a valuable system stability enhancement to prevent system-wide blackouts (Fig. 6).

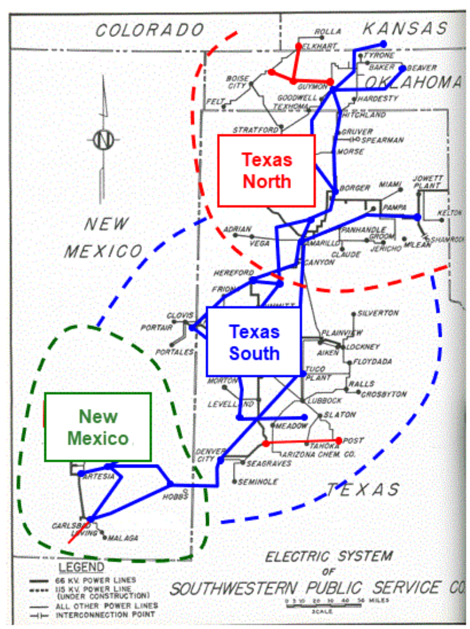

Fig. 6. Xcel Energy NM/TX natural load/generation islands

Over the course of the next several decades, this UFLS program would be put to the test. In 1972, Xcel Energy NM/TX added its first tie line to the Eastern Interconnect. This 230 kV line stretched from Amarillo, TX, to Elk City, OK. In the late 1970s and early 1980s, two coal plants were added to the generation fleet. One plant near Muleshoe, TX, consisted of two 540 MW units. The other plant in Amarillo, TX, consisted of three 350 MW units. Between 1983–1985, it was not uncommon for one of the large coal units to trip. When one did, it was common for power imports across the 230 kV tie line to exceed the maximum power transfer of the line, resulting in an unstable power swing and an out-of-step trip. This resulted in an unbalance of load over generation, and underfrequency relay tripping ensued. Over the span of these 2 years, this happened 11 times.

In the late 1980s, additional tie lines were added to the Xcel Energy NM/TX system, strengthening the connection to the Eastern Interconnect. No separation events occurred after this strengthening of the system until 1996. The 1996 separation event was caused by the tripping of two 540 MW generators and several 230 kV Texas South to Texas North tie lines. The power transfer from the Eastern Interconnect resulted in the tripping of all tie lines and the remaining tie lines tying Texas South to Texas North. All levels of underfrequency relaying tripped for this event, but not enough load was shed to prevent Texas South and New Mexico from blacking out. Only Texas North remained energized.

In 2008, Xcel Energy NM/TX experienced its most recent separation event. Half of the Eastern Interconnect tie lines were out of service due to storm damage. A lightning strike near the largest coal plant caused a ground potential rise at the plant, which resulted in the two 540 MW units running back about 400 MW each. The import of power across the Eastern Interconnect tie lines resulted in out-of-step tripping and underfrequency tripping at 59.3 Hz.

C. *Purpose of UFLS*

Besides the benefit of minimizing the possibility of a system-wide blackout, automatic UFLS has a greater purpose—protecting the generation fleet. Generators are designed to operate continuously at their nominal frequency (i.e., 60 Hz in North America). Extended operation at too low of a frequency can cause damage to generators and especially steam turbines. Hydroelectric plants are more capable of handling a drop in frequency than steam turbine plants. Hydroelectric plants are minimally impacted by drops of frequency up to 10 percent (a 6 Hz drop), whereas steam turbine plants are sensitive to frequency drops of up to 5 percent (a 3 Hz drop).

When an underfrequency event occurs, it is necessary to begin shedding load quickly to avoid reaching frequency levels that can affect online generators. As the frequency decays, motor-driven auxiliary generator processes (e.g., feedwater pumps, coal pulverizers, coal feed belts, draft fans, etc.) begin to slow down, reducing the mechanical power input to the generator. This, in turn, results in less electrical generator output and worsening frequency decay.

Adequate automatic UFLS is critical to the health of steam turbines. As shown in Table I, frequency levels below 59 Hz begin to cause cumulative damage to steam turbine blades.

TABLE I
STEAM TURBINE FREQUENCY-TIME DAMAGE

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

The time in Table I is cumulative over the life of the machine, so if a turbine is subject to 57.6 Hz for 30 seconds, it can only withstand 30 additional seconds at 57.6 Hz before damage occurs [8].

Additionally, underfrequency relaying is applied to steam turbines to protect them from accumulated damage. Prior to the northeast blackout in 2003, generator owners applied underfrequency relaying independently to ensure protection of their generation assets. After the 2003 blackout, NERC Standard PRC-024 became the North American guide for applying underfrequency tripping of generators and steam turbines [9]. The PRC-024-2-allowable low-frequency tripping levels of the major interconnections in the United States are shown in Table II.

TABLE II
PRC-024-2-ALLOWABLE LOW-FREQUENCY TRIPPING

	PRC-024-2-Allowable Low-Frequency Tripping Time Delay (s)		
Freq. (Hz)	**Eastern Interconnection***	**Western Interconnection**	**ERCOT Interconnection**
>59.5	Continuous	Continuous	Continuous
≤59.5	1,792	Continuous	Continuous
>59.4	1,201	Continuous	Continuous
≤59.4	1,201	180	540
≤59.0	242	180	540
≤58.4	22	30	30
≤58.0	4.44	30	2
≤57.8	0	7.5	2
≤57.5	0	7.5	0
≤57.3	0	0.75	0
≤57.0	0	0	0

*EI tripping times follow formula $10^{(1.7373 \cdot f - 100.116)}$ for frequency values >57.8 Hz and ≤59.5 Hz. This formula was applied to fill in EI values in Table II at the frequency shown.

Since underfrequency tripping of generators and steam turbines is applied to protect the North American generation fleet, it is critical that UFLS be applied to avoid underfrequency tripping of generation. Loss of additional generation during an underfrequency event will only make the excursion worse, possibly leading to an area blackout.

D. UFLS Technical Basics

Prior to implementation of a UFLS program, it is necessary to study and understand the system to which the program will be applied. Historical events tend to play a role in load-shedding program development, as was the case for Xcel Energy NM/TX. Historical events typically reveal where natural load/generation islands form. It is critical when implementing a load-shedding program that load/generation in anticipated islands be as balanced as possible after loss of significant generation or after a separation event. The load that is shed must offset the generation and/or imported power lost to restore a balance of load to generation.

To illustrate, consider the small, fictitious system shown in Fig. 7.

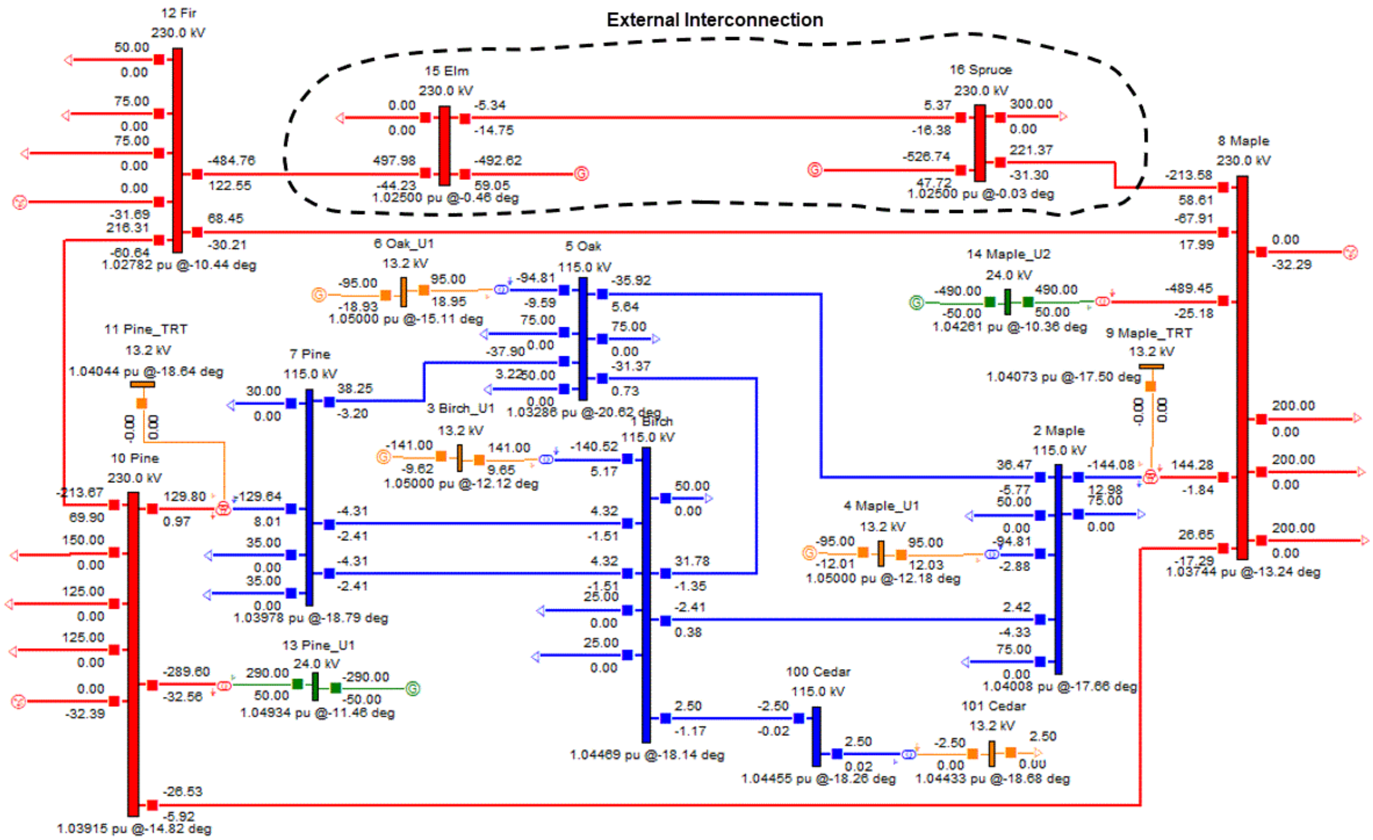

Fig. 7. UFLS test system

The UFLS test system was created using an integrated protection planning simulation (IPPS) tool. The IPPS tool links a database of detailed relay models in a short-circuit program with commercially available load flow/power system dynamic stability software. The link between these two programs allows for testing of detailed relay models when running dynamic system simulations.

The test system was designed to mimic the Xcel Energy NM/TX system. Names of generators and substations were scrubbed and made generic. Internal system generators in the test system are actual units from the Xcel Energy NM/TX system. The load flow/stability models in the IPPS tool are the same as actual models used by the Xcel Energy NM/TX Transmission Planning department.

Table III shows pertinent load and generation facts about the UFLS test system used for the studies in Sections III and IV of this paper. The system is loaded within 200 MW of the peak load with heavy imports across the two tie lines. Import limits are determined for each tie line independently and collectively. Limits are based on voltage (0.95 pu) or stability constraints (nonconvergent load flow).

TABLE III
UFLS TEST SYSTEM LOAD, GENERATION, AND IMPORT DATA

	Case Study Actual (MW)	System Peak/Limit (MW)
Internal System Load	1,803	2,000
Internal System Generation	1,111	1,150
External System Load	300	NA
External System Generation	1,019	2,000
Internal System Import	698	1,200
Fir-Elm Import Limit	NA	900
Maple-Spruce Import Limit	NA	425

Table IV shows details about the system generation. The nameplate capacity of all the internal generation is 1,150 MW. The external generation represents the equivalent source of the outside world and consists of two 1,000 MVA generators. These generators are represented in the IPPS tool by a generator model. The internal generation is represented by a generator, exciter, and governor model. The inertia constant of each generator is converted to the system base of 100 MVA and is summed to represent the equivalent inertia of the system. These inertia values will be used in the calculations that follow.

TABLE IV
UFLS TEST SYSTEM GENERATION NAMEPLATE AND INERTIA DATA

Generator Name	Nameplate MVA	Generator Inertia Constant (H)	Generator Inertia 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	1,000	3.959	39.59
Spruce	1,000	3.959	39.59
		Total	**125.64**

While more accurate, complex electromagnetic transient or positive-sequence root-mean-square load flow and stability software is not necessary to calculate how the system frequency will change in response to a change in load or generation. The fundamental formulae for frequency decay (loss of generation) and frequency rise (loss of load) is shown in (1) [10].

$$f = f_{sys} - \Delta L \bullet (1 - e^{-\frac{t}{T}}) \bullet K \bullet 60 \quad (1)$$

$$T = \frac{M}{D} \qquad K = \frac{1}{D}$$

where:

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

ΔL is the change in load in per unit.

t is time in seconds.

M is the inertia constant of the system, 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 (2).

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

The load-damping constant, 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 will operate at nominal power when the system frequency is 60 Hz. If the system frequency increases, the motor will speed up, yielding a higher electrical power level. If the system frequency decreases, the motor will slow down, yielding a lower electrical power level. The load-damping constant, D, is expressed as a percent change in load for a 1 percent change in system frequency. Typical ranges of D are 1 to 2 percent [11]. An in-between value of 1.5 was chosen for use in this analysis, thus a 1 percent change in system frequency will result in a 1.5 percent change in load. The equation for D is shown in (3).

$$D = \frac{Load_{sys} \bullet 1.5}{100} \quad (3)$$

where:

$Load_{sys}$ is the remaining system load after 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.

Fig. 8 shows an example of the loss of the Maple Unit 2 generator (ΔL = 4.9 pu). The graph shows the decay and eventual bottoming-out of the frequency if it declines without a governor response.

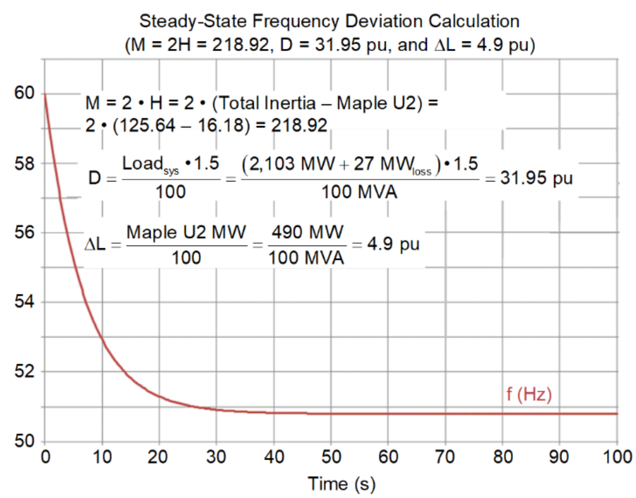

Fig. 8. Frequency decay without governor response when Maple Unit 2 tripped

Taking the first derivative of (2) yields (4) to calculate the ROCOF at any point in time.

$$\frac{df}{dt} = \frac{-30 \bullet \Delta L}{H} \bullet e^{-\frac{D \bullet t}{2 \bullet H}} \quad (4)$$

Solving the first derivative at t = 0 yields (5) and results in the fastest ROCOF.

$$\frac{df}{dt} = \frac{-30 \bullet \Delta L}{H} \quad (5)$$

After examining Fig. 8 more granularly at the beginning of the frequency decay, the ROCOF can be calculated using (4) and the straight line slope equation, as shown in Fig. 9. Calculating the ROCOF for a given system study is a quick way to determine the severity of an underfrequency event. As was done for the South Australia system prior to the 2016 blackout, studies determined the worst-case ROCOF for system recovery was 3 Hz/s. This same type of analysis is recommended for UFLS program development, especially with changing resource mixes and varying levels of system inertia.

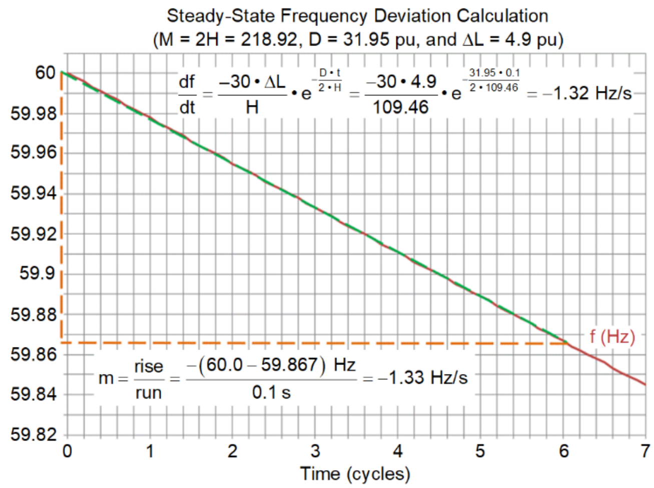

Fig. 9. ROCOF calculation when Maple Unit 2 tripped

Other useful calculations can be performed by solving (2) for t, as shown in (6).

$$t = -\frac{2 \bullet H}{D} \bullet \ln\left[1 + \frac{D \bullet \left(f - f_{sys}\right)}{60 \bullet \Delta L}\right] \quad (6)$$

Equation (7) offers an example of how (6) can be used to calculate the time it takes to get to 59.3 Hz, as shown in Fig. 8.

$$t = \frac{-2 \bullet 109.46}{31.95} \bullet \ln\left[1 + \frac{31.95 \bullet (59.3 - 60)}{60 \bullet 4.9}\right] \quad (7)$$
$$= -6.852 \bullet \ln(0.924) = 0.542 \text{ s}$$

Using (2) and (6) repetitively, it is possible to simulate UFLS scenarios. The time to each underfrequency level can be calculated, and then the time and frequency at which the breakers open to shed UFLS Level 1 can be calculated. At this point, new ΔL and D values are calculated to account for load shed, and then the process continues for each remaining UFLS level. The process ends if enough load has been shed before t = 3 s to result in a negative ΔL when frequency will begin to increase, or the frequency is less than 57.0 Hz, at which point system collapse can be assumed. Ending the process at t = 3 s is chosen because that is the point at which generator governor response can be assumed to assist in increasing generator output to correct the frequency.

Xcel Energy NM/TX created a spreadsheet to perform hourly calculations for a month's worth of energy management system (EMS) data. Hourly EMS generation, load, UFLS, and system inertia are summed and tabulated. Then, system separation what-if scenarios are calculated, per the process mentioned previously, for each hour with ΔL representing lost import power (generation) or export power (load). Performing these calculations can help assess the potential effectiveness of a UFLS program and can pinpoint areas for improvement.

An additional tool developed allows for detailed spreadsheet simulations (with behind-the-scenes programming) for any hour in a monthly spreadsheet. The detailed simulation takes underfrequency relay intentional time delay and breaker operating time into consideration during the calculation. For best-case UFLS simulations, all load can be shed at the time the frequency set point is reached, as depicted in Fig. 10.

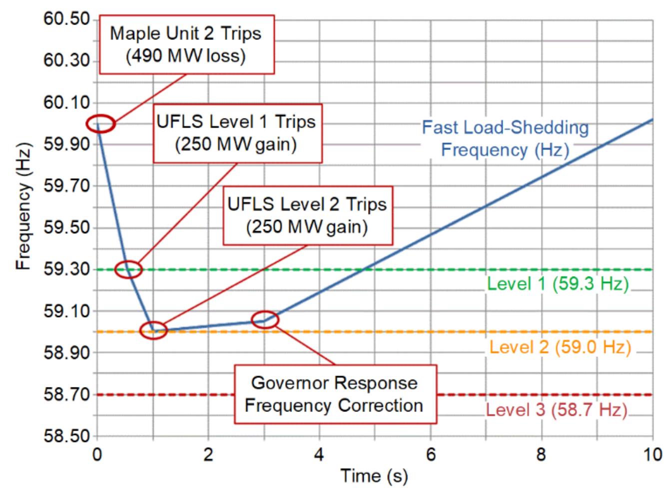

Fig. 10. Fast load-shedding spreadsheet simulation response when Maple Unit 2 tripped

E. UFLS Relaying in Use at Xcel Energy NM/TX

Most underfrequency relays in use today at Xcel Energy NM/TX are either solid-state electronics or microprocessor-based technology. Solid-state relays use a crystal oscillator in megahertz range to generate a nominal frequency reference that is compared to the sensed system frequency. The comparison begins at the sensed voltage zero crossing. Usually, just a single-phase voltage is used. If the sensed frequency differs by the desired underfrequency set point, the relay issues a trip output after a settable timer expires, if the voltage is healthy.

Microprocessor-based relays use internal proprietary algorithms to track the measured system frequency. Either a single voltage or all three voltages can be used to track the frequency. Once the frequency set point is reached, the relay will issue a trip after a settable timer expires, if the voltage is healthy.

Both technologies use voltage inhibit logic that prevents tripping on underfrequency if the sensed voltage drops below the settings threshold. Typically, the undervoltage set point is in the range of 50 to 80 percent of nominal voltage. This supervision is desirable to prevent underfrequency element mis-trips during fault conditions or when the transmission source is de-energized.

F. Xcel Energy NM/TX Regional UFLS Practices

The 2003 northeast blackout ushered in dozens of NERC reliability standards that are effective today. NERC PRC-006 is the reliability standard specifying how automatic UFLS programs are to be studied, designed, administered, and documented by regional planning coordinators. The regional standard that Xcel Energy NM/TX must comply with is the Southwest Power Pool (SPP) PC UFLS Plan [12]. This plan specifies the specific load-shedding frequency, amounts of load shed, time delays for UFLS elements, and the allowable undervoltage inhibit settings.

Table V shows the details for each of the three UFLS levels required by SPP for entities with greater than 100 MW forecast peak load. Additionally, the intentional time delay of the underfrequency relay must be 30 cycles or less, with no requirement for total clearing time, and the undervoltage inhibit setting must be ≤85 percent of nominal voltage.

TABLE V
SPP AUTOMATIC UFLS LEVELS AND PERCENTAGE OF LOAD SHEDDING

UFLS Level	Freq. (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

G. *Xcel Energy NM/TX UFLS Practices*

Xcel Energy NM/TX's adaptation to the SPP UFLS plan was an easy transition since the number of frequency levels and tripping points matched existing company practices. Xcel Energy NM/TX sets all underfrequency relays to trip with an intentional time delay of 6 cycles. The exception to this rule is to use a time delay of 30 cycles (maximum allowed) if a load-shedding feeder serves significant motor load. The reason for this exception is discussed in greater detail in the following sections. Undervoltage inhibit settings are typically set to 66.67 percent of the nominal voltage. This value allows for dependable tripping of underfrequency relays for an underfrequency event when voltage may be collapsing, but also provides adequate security from misoperation during source transmission line fault conditions.

III. MODERN DAY POWER SYSTEM UFLS CHALLENGES

Implementation of a UFLS program is not a trivial task, even with guiding NERC standards and long-living individual utility practices. This is especially true today with increasing penetration of renewable generation replacing and displacing synchronous generation. Less synchronous generation equates to less system inertia. Less system inertia equates to higher ROCOF for a sudden loss of generation or load. Higher ROCOF equates to deeper frequency excursions, resulting in excessive load shedding and the possibility of total system collapse.

Frequency tripping points, intentional time delays, and undervoltage inhibit settings are established per the planning coordinator's NERC PRC-006 standard. Ranges of settings are allowed for an intentional time delay and undervoltage inhibit. Most utilities establish standard set points for these two settings; however, certain circumstances occasionally require deviation from the standard.

Transmission line faults must be cleared by the transmission line relays. If a distribution substation is tapped off a faulted transmission line, it will be de-energized when breakers open at the transmission sources. If the distribution substation has feeders equipped with underfrequency relays, it is possible that the underfrequency relay could misoperate upon line de-energization due to the rapid decrease in frequency at the distribution bus. Although the loads will be de-energized for either relay operation, the load restoration procedure is different for a UFLS relay operation and for transmission line relay operation. At Xcel Energy NM/TX, UFLS relays are designed to trip a lockout relay to disconnect the loads. These lockout relays can be reset only by transmission operators and not by the distribution operators. After a UFLS relay trip, the distribution operators must discuss load restoration with the transmission operations group. Once the transmission operations group has deemed that the system is stable, UFLS lockouts are reset and distribution operations can systematically restore load with guidance from transmission operations.

However, after a normal transmission line operation to clear a fault, de-energized loads would remain connected to the bus and automatically restart once the transmission source is restored. It is important to ensure that UFLS relaying is secure from misoperation during transmission fault conditions and line de-energization to avoid prolonged, unnecessary outages to affected loads.

A. *Higher ROCOF*

As the 2016 South Australia blackout proved, UFLS is not effective if the ROCOF is too high. According to Fig. 1, low-inertia wind and solar generation resources have tripled to nearly 150 GW since the last major UFLS event in the United States (2011 Arizona-Southern California blackout). Given the electric industry's push to a more carbon-free generation fleet, it is likely that the next UFLS event in the United States will be more severe due to higher ROCOF.

Analysis of Xcel Energy NM/TX EMS data has shown that there is an inverse correlation between higher penetrations of wind generation to the amount of system inertia. In other words, as wind penetration increases, system inertia decreases. Minimum hourly inertia values continued to trend down, reaching values of around 25 percent of the maximum available inertia. Analysis of theoretical ROCOF values for simulated Eastern Interconnect separation events show that the declining system inertia can result in ROCOF values approaching 3 Hz/s.

Recently, on December 2, 2020, a new hourly and daily wind penetration record was set for the Xcel Energy NM/TX balancing area. The instantaneous hourly peak was 88 percent (hourly peak wind output divided by the same hourly peak load) and the 24-hour peak was 77 percent (24-hour MWh wind generation divided by 24-hour MWh load)! These data show that for the Xcel Energy NM/TX system, higher ROCOF is more likely for the next UFLS event.

Using the UFLS test system depicted in Fig. 7, it is possible to illustrate the effect of lower system inertia on a UFLS program. The IPPS tool underfrequency relay models are used at various substations in the test system and are set to shed 12.5 percent of the system load in three frequency levels. Undervoltage inhibit settings are set at 67 percent of nominal voltage. Intentional underfrequency time delays are set at 6 cycles for 60 percent of the loads and 30 cycles for 40 percent of the loads (Table VI). This split represents the actual Xcel Energy NM/TX UFLS program due to large amounts of industrial motor load.

TABLE VI
UFLS TEST SYSTEM LEVELS AND PERCENTAGE OF LOAD SHEDDING

UFLS Level	Freq. (Hz)	Peak Load Shed -ding (%)	Load Shedding With 6-Cycle Delay (MW)	Load Shedding With 30-Cycle Delay (MW)	Total Load Shedding (MW)
1	59.3	12.5	150	100	250
2	59.0	12.5	150	100	250
3	58.7	12.5	150	100	250

Four cases were run to show the effect of varying system inertia (Table VII). Inertia was reduced for each case by replacing synchronous generation with Type IV wind farms throughout the system. For each case, the 500 MVA generator Maple Unit 2 was tripped to cause an underfrequency event (490 MW of lost generation). Each simulation ran for 10 seconds.

TABLE VII
UFLS TEST SYSTEM CASE STUDIES

Case	Total Synchronous Generation (MVA)	Total Wind Generation (MVA)	Wind Penetration (%)
1	3,150	0	0
2	2,350	800	25
3	1,550	1,600	50
4	1,050	2,100	67

1) Case 1: 100 Percent Synchronous Generation

Fig. 11 shows the frequency plot of the sudden loss of Maple Unit 2. Table VIII shows the time and frequency that each UFLS level is tripped. The ROCOF for this case just prior to load shedding is –0.95 Hz/s. For this event, UFLS Levels 1 and 2 trip with all the 59.3 Hz load being shed first, followed by the 59.0 Hz load. A total of 500 MW of system load is shed. The frequency nadir occurs at t = 1.788 s at a value of 58.921 Hz. The frequency continues to improve and settles out at a value of about 60.2 Hz at t = 10 s. Note that the hand calculations match the dynamic simulation fairly closely. These hand calculations will be shown in all four case studies for comparison. Hand calculations in general will be more conservative than the actual results, because system voltages, generator controls, and system impedances between the generators are not considered. Also, the governor response is assumed to be three seconds after event initiation. The actual governor response will vary.

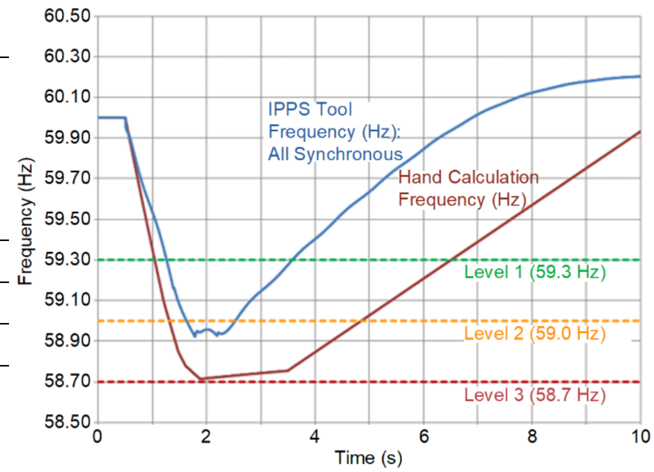

Fig. 11. Case 1 simulation response when Maple Unit 2 tripped

TABLE VIII
CASE 1 UFLS TEST SYSTEM RESULTS

UFLS Level	Load (MW)	Shunt	Substation	Time (s)	Freq. (Hz)
59.3_6_CYC	150	10-1	Pine	1.388	59.159
59.3_30_CYC	75	5-1	Oak	1.788	58.921
59.3_30_CYC	25	1-2	Birch	1.788	58.921
59.0_6_CYC	75	12-1	Fir	1.808	58.940
59.0_6_CYC	75	12-2	Fir	1.808	58.940
59.0_30_CYC	50	5-3	Oak	2.192	58.927
59.0_30_CYC	50	2-3	Maple	2.200	58.934
Total	**500**				

2) Case 2: 25 Percent Wind Generation

Fig. 12 shows the frequency plot of the sudden loss of Maple Unit 2 for the 25 percent wind generation case. Table IX shows the time and frequency that each UFLS level is tripped. The ROCOF for this case just prior to load shedding is –1.53 Hz/s. For this event, UFLS Levels 1 and 2 trip with all the 59.3 Hz and 59.0 Hz 6-cycle-delayed load being shed first, followed by the 30-cycle-delayed load. A total of 500 MW of system load is shed, like in Case 1. The frequency nadir occurs at t = 1.5 s at a value of 58.713 Hz. The frequency continues to improve and settles out at a value just over 60.1 Hz at t = 10 s. Again, the hand calculations match fairly closely but indicate that the 6-cycle-delayed 58.7 Hz load is shed as well.

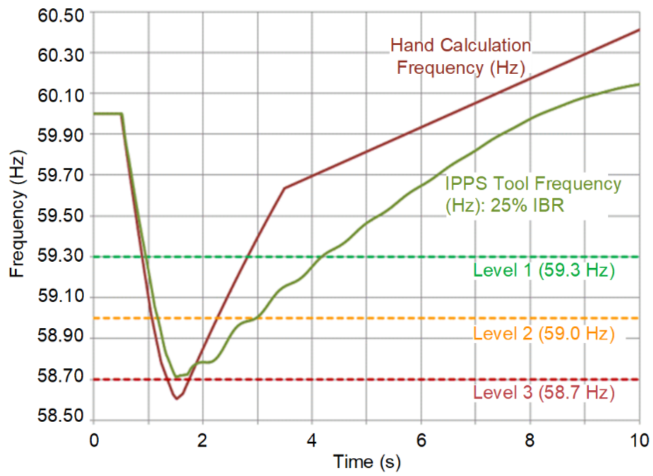

Fig. 12. Case 2 simulation response when Maple Unit 2 tripped

TABLE IX
CASE 2 UFLS TEST SYSTEM RESULTS

UFLS Level	Load (MW)	Shunt	Substation	Time (s)	Freq. (Hz)
59.3_6_CYC	150	10-1	Pine	1.100	59.082
59.0_6_CYC	75	12-1	Fir	1.304	58.844
59.0_6_CYC	75	12-2	Fir	1.304	58.844
59.3_30_CYC	75	5-1	Oak	1.500	58.713
59.3_30_CYC	25	1-2	Birch	1.500	58.713
59.0_30_CYC	50	2-3	Maple	1.708	58.723
59.0_30_CYC	50	5-3	Oak	1.717	58.724
Total	**500**				

3) Case 3: 50 Percent Wind Generation

Fig. 13 shows the frequency plot of the sudden loss of Maple Unit 2 for the 50 percent wind generation case. Table X shows the time and frequency that each UFLS level is tripped. The ROCOF for this case just prior to load shedding is –2.58 Hz/s. For this event, all three 6-cycle-delayed UFLS levels trip, followed by the 30-cycle-delayed Levels 1 and 2. A total of 650 MW of system load is shed. The frequency nadir occurs at t = 1.2 s at a value of 58.503 Hz. The frequency continues to improve and settles out at a value of 61.8 Hz at t = 10 s. Hand calculations match fairly closely for this case but indicate that the 30-cycle-delayed 58.7 Hz load is shed as well. Of special interest (and concern) is the frequency reaching a value of 61.8 Hz at the end of the event. This frequency is at the allowable instantaneous overfrequency tripping value for the Eastern Interconnect, according to NERC PRC-024 [9].

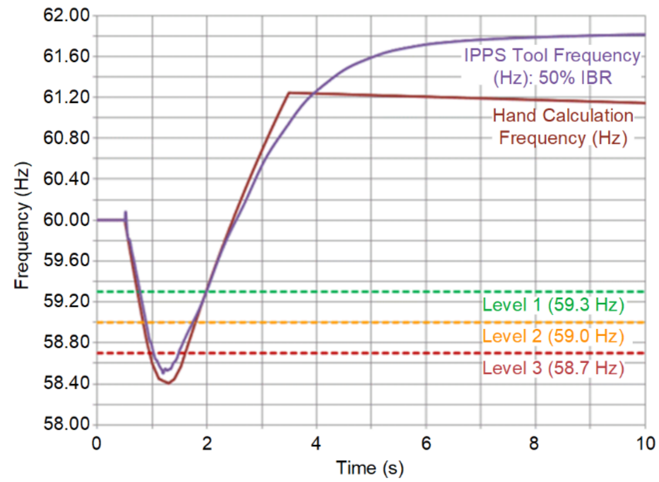

Fig. 13. Case 3 simulation response when Maple Unit 2 tripped

TABLE X
CASE 3 UFLS TEST SYSTEM RESULTS

UFLS Level	Load (MW)	Shunt	Substation	Time (s)	Freq. (Hz)
59.3_6_CYC	150	10-1	Pine	0.929	58.892
59.0_6_CYC	75	12-1	Fir	1.038	58.678
59.0_6_CYC	75	12-2	Fir	1.038	58.678
58.7_6_CYC	75	2-1	Maple	1.179	58.532
58.7_6_CYC	75	2-2	Maple	1.179	58.532
59.3_30_CYC	75	5-1	Oak	1.329	58.543
59.3_30_CYC	25	1-2	Birch	1.329	58.543
59.0_30_CYC	50	5-3	Oak	1.442	58.636
59.0_30_CYC	50	2-3	Maple	1.442	58.636
Total	**650**				

4) Case 4: 67 Percent Wind Generation

Fig. 14 shows the frequency plot of the sudden loss of Maple Unit 2 for the 67 percent wind generation case. Table XI shows the time and frequency that each UFLS level is tripped. The ROCOF for this case just prior to load shedding is –4.34 Hz/s. For this event, all three 6-cycle-delayed UFLS levels trip, followed by all three 30-cycle-delayed levels. A total of 750 MW of system load is shed. The frequency nadir occurs at t = 1.071 s at a value of 58.143 Hz. The frequency continues to rise to a value of about 65.5 Hz at t = 10 s. Hand calculations match fairly closely for this case as well. The high final frequency is of concern and indicates that generation tripping on overfrequency is possible.

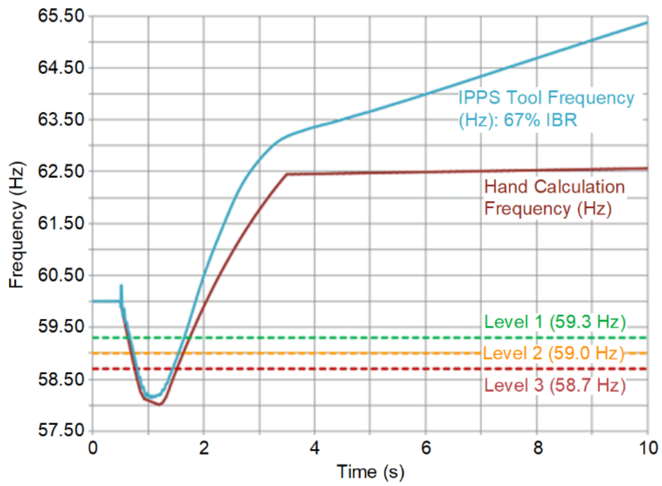

Fig. 14. Case 4 simulation response when Maple Unit 2 tripped

TABLE XI
CASE 4 UFLS TEST SYSTEM RESULTS

UFLS Level	Load (MW)	Shunt	Substation	Time (s)	Freq. (Hz)
59.3_6_CYC	150	10-1	Pine	0.813	58.641
59.0_6_CYC	75	12-1	Fir	0.875	58.393
59.0_6_CYC	75	12-2	Fir	0.875	58.393
58.7_6_CYC	75	2-1	Maple	0.946	58.215
58.7_6_CYC	75	2-2	Maple	0.946	58.215
59.3_30_CYC	75	5-1	Oak	1.213	58.205
59.3_30_CYC	25	1-2	Birch	1.213	58.205
59.0_30_CYC	50	2-3	Maple	1.279	58.285
59.0_30_CYC	50	5-3	Oak	1.279	58.285
58.7_30_CYC	75	5-2	Oak	1.350	58.429
58.7_30_CYC	25	1-3	Birch	1.354	58.445
Total	**750**				

Graphing the four cases together, Fig. 15 shows how increased penetrations of wind generation results in faster frequency decay and lower frequency nadirs, due to lower system inertia. The UFLS program established for the UFLS test system is adequate for wind penetration levels up to 50 percent. Augmentations need to be made to the program in order to perform adequately for wind penetrations greater than 50 percent.

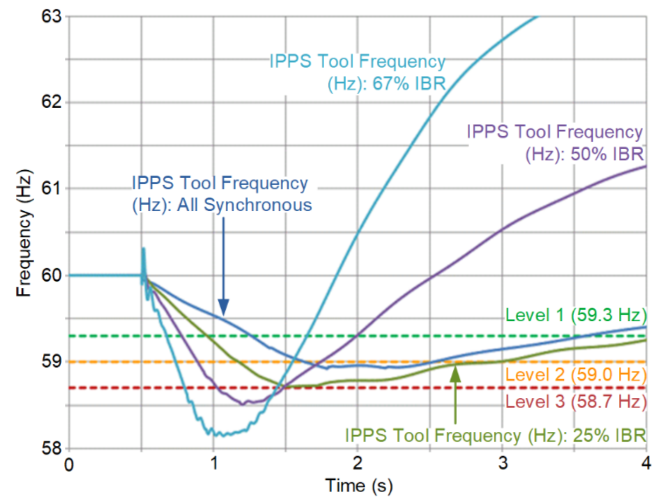

Fig. 15. Cases 1–4 simulation response when Maple Unit 2 tripped

B. Fixed UFLS Time Delays

UFLS relays are set to trip a predefined percentage of load when the measured frequency decreases below the underfrequency set point. These relays are commonly installed at substations where they monitor the voltage and frequency of the load bus. The frequency measured at the load bus will decrease for a system-wide underfrequency event. However, it may also decrease during the following cases, which are not related to a true UFLS condition [13]:

1. Fault on the transmission line or step-down transformer
2. Fault on the PT circuit
3. Motor spin down after the source breaker opens

The UFLS relay should not operate for the cases listed above. Fig. 16 shows an electromagnetic transient software (EMTS) model of four 3 MVA induction motors connected to a power system through a step-down transformer. In addition to the motors, resistor, inductor, and capacitor (RLC) loads are connected to the bus. The model parameters are given in the appendix. During the simulation, the motor bus voltage and frequency are recorded, as well as the current flowing from the transformer secondary windings into the motor bus. The load on the bus was varied to simulate different conditions that could cause the UFLS relay to misoperate.

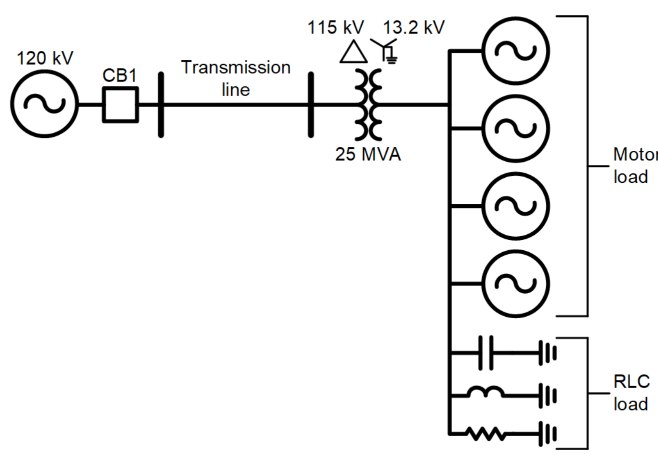

Fig. 16. EMTS model

A detailed analysis of the two power system conditions that could result in UFLS misoperation is provided in the following subsections.

1) Case 1: Three-Phase Fault on the Transmission Line

In this simulation case, all four motors are connected to the bus and the RLC load is offline. A three-phase fault (3LG) is simulated at the end of the transmission line, on the high-side bus of the transformer. Fig. 17 shows the frequency measured at the motor bus during the fault. The frequency decayed from 60 Hz to 53 Hz within 115 ms (7 cycles) of the fault occurring.

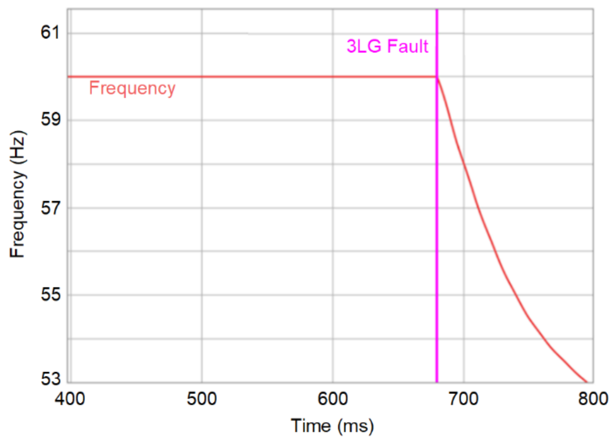

Fig. 17. Frequency decay during a fault (EMTS)

If the UFLS relay on the motor bus makes a trip decision based on the frequency, without any additional supervision, it would misoperate during this fault. Fig. 18 shows the voltage profile before and after the fault occurs. The voltage on the bus decays and nears zero around 115 ms (7 cycles) after the fault.

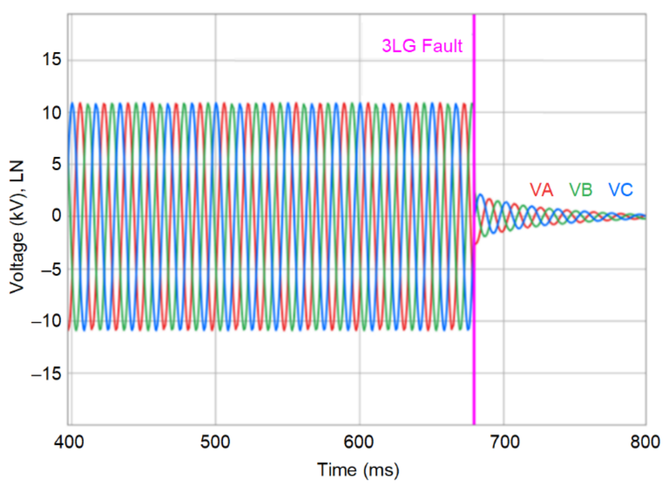

Fig. 18. Voltage decay during a fault (EMTS)

Most UFLS relays are supervised with an undervoltage block element and a short time delay to prevent underfrequency tripping for fault and transient conditions. The typical undervoltage block setting range is 50 to 80 percent of the rated bus voltage, and the short time delay is 3 to 6 cycles [13]. During this fault simulation, the undervoltage block asserts due to low bus voltage and prevents the UFLS misoperation.

The logic diagram of a fixed time frequency element with voltage supervision is shown in Fig. 19. The frequency element is blocked if the voltage measured by the relay decreases below the supervision threshold (27B81). Additionally, a time delay (81D1D) is provided so that the underfrequency element can ride through transient conditions. It also provides time for relay processing.

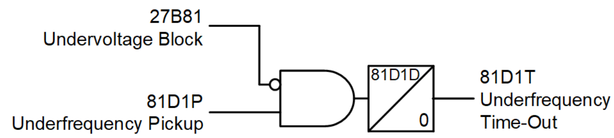

Fig. 19. UFLS relay logic with voltage supervision

2) Case 2: Motor Spin Down After the Source Breaker Opens

In this simulation case, the load on the bus remains the same: all four motors are connected to the bus, and the RLC load is offline. The circuit breaker (CB1) at the source of the transmission line is opened. This represents a normal breaker operation to de-energize the transmission line. There is no fault on the system. Fig. 20 shows that when the source to a motor load is disconnected, the voltage on the motor terminals does not go to zero immediately upon the opening of the source breaker. Rather, the motor voltage exhibits a decay in magnitude and in frequency [15].

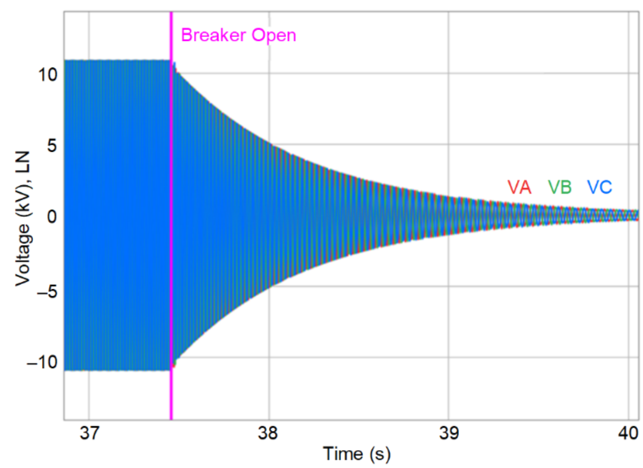

Fig. 20. Voltage decay with motor load (EMTS)

The frequency decay after CB1 opens is shown in Fig. 21. The frequency decay, caused by motor deceleration after the breaker opened, and the rate of the motor bus voltage decay are both determined by the type of motors in use and the type of loads being driven [14]. Additionally, the transmission line capacitance also keeps the motors excited and can extend the voltage decay [8].

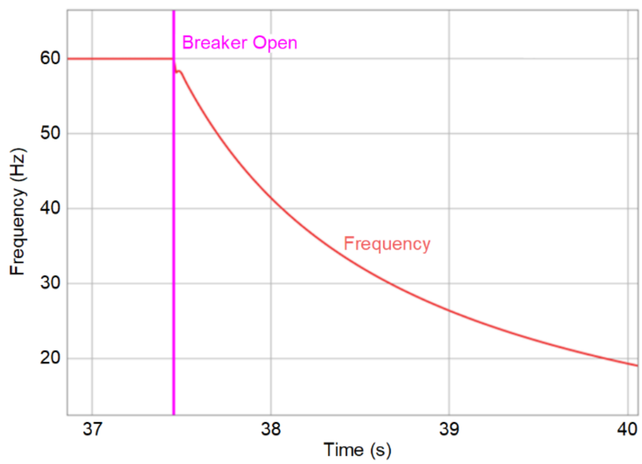

Fig. 21. Frequency decay with motor load (EMTS)

The currents and voltages from the EMTS simulation were saved in a COMTRADE file format and replayed in a UFLS relay using a test set. The settings programmed in the UFLS relay are shown in Table XII.

TABLE XII
UNDERFREQUENCY RELAY SETTINGS

Protection Setting	**Set Point**
UFLS Pickup 1 (81D1P)	59.3 Hz
UFLS Delay 1 (81D1D)	6 cycles
UFLS Pickup 2 (81D2P)	59 Hz
UFLS Delay 2 (81D2D)	6 cycles
UFLS Pickup 3 (81D3P)	58.7 Hz
UFLS Delay 3 (81D3D)	6 cycles
Undervoltage block setting (27B81)	5.1 kV LN, primary

The undervoltage block setting is 67 percent of the rated bus voltage (13.2 kV, LL). During the test, the UFLS relay was programmed to record an event report. Fig. 22, Fig. 23, and Fig. 24 show the event report for this case. Fig. 22 shows that the motor loads hold the bus voltage up after CB1 is opened.

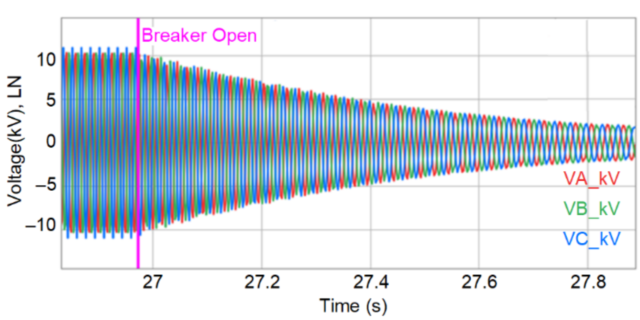

Fig. 22. Voltage decay with four motors (event report)

Shortly after CB1 opens, the frequency decays below the lowest underfrequency setting (81D3P), as shown in Fig. 23.

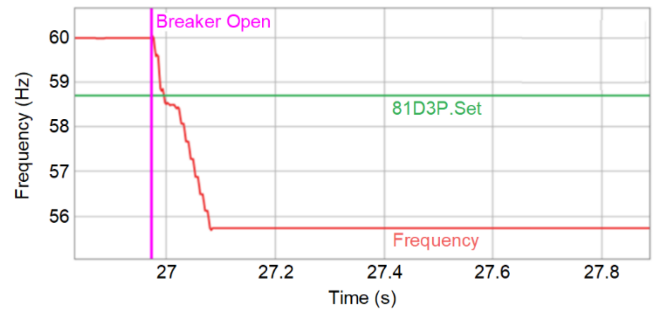

Fig. 23. Frequency decay with four motors (event report)

When the voltage decays below the undervoltage block threshold, the 27B81 bit is asserted, as shown in Fig. 24. All three levels of UFLS (81D1P, 81D2P, and 81D3P) pick up during the test and then time out and trip after 6 cycles. The 81D1P element picks up 16.7 ms (1 cycle) after the breaker is opened. The undervoltage block asserts 153 ms (9 cycles) after the 81D1P element picks up. The Relay Word bits that indicate the UFLS element trip are 81D1T, 81D2T, and 81D3T. The TRIP bit asserts and trips the UFLS lockout relay.

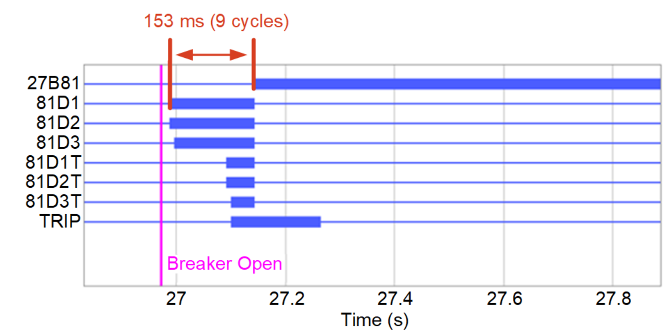

Fig. 24. Digital signals with four motors (event report)

The special case of UFLS relay applications on a motor bus is a known issue that has been described in [13] and [8]. The prevailing solution to this problem is to increase the time delay to about 20 cycles or greater. In most cases, extending the time delay allows the voltage to decay below the undervoltage block setting before the underfrequency element times out. The UFLS relay performance was studied for different loading conditions using the model shown in Fig. 16. The loading conditions are listed as follows:

- Motor load (varying from one to four motors) along with a resistor connected to the bus
- Motor load (varying from one to four motors) along with a capacitor connected to the bus
- Motor load (varying from one to four motors) along with an inductor connected to the bus
- Only motor load (varying from one to four motors) connected to the bus; RLC components were not connected to the bus

The responses of the UFLS relay with a 6-cycle and 30-cycle delay for all the loading conditions are shown in Table XIII. Extending the time delay works for most loading conditions and prevents a misoperation. The only loading condition when this fails to provide the required supervision is Test 8, when a single motor and a capacitor are connected to the bus. In this case, a time delay of 33 cycles would have prevented the UFLS operation.

TABLE XIII
TEST RESULTS FOR 6-CYCLE AND 30-CYCLE DELAYS WITH VOLTAGE SUPERVISION

Test	RLC Load Connection	Connected Motors	UFLS Levels 1, 2, 3 6-Cycle Delay	UFLS Levels 1, 2, 3 30-Cycle Delay
1	Resistor	4	Trip	No Op
2	Resistor	3	Trip	No Op
3	Resistor	2	Trip	No Op
4	Resistor	1	Trip	No Op
5	Capacitor	4	Trip	No Op
6	Capacitor	3	Trip	No Op
7	Capacitor	2	Trip	No Op
8	Capacitor	1	Trip	No Op
9	Inductor	4	Trip	Trip
10	Inductor	3	Trip	No Op
11	Inductor	2	Trip	No Op
12	Inductor	1	Trip	No Op
13	None	4	Trip	No Op
14	None	3	Trip	No Op
15	None	2	Trip	No Op
16	None	1	Trip	No Op

IV. MODERN DAY POWER SYSTEM UFLS SOLUTION

Cases 1 and 2 in Section III (B) prove the need for the UFLS relay to be supervised to prevent misoperations. The following three main supervision methods are used to differentiate between a system-wide underfrequency event and a fault or transient switching condition:

- Voltage supervision
- Current supervision
- ROCOF supervision

The UFLS relay test results for each supervision method are presented in this section along with a summary of all the methods.

A. Voltage Supervision

As shown in Fig. 17, the frequency decays at a load bus during a transmission line fault and could result in the UFLS relay misoperating. To prevent this, the underfrequency element is supervised with an undervoltage block. The undervoltage block is typically set to 50 to 80 percent of the rated bus voltage. A high-undervoltage block setting makes the element secure from misoperations due to motor loads and transmission line faults. A low-undervoltage block setting makes the element dependable and ensures that the UFLS relay operates for a system underfrequency event where voltage could sag at the bus.

Table XIV shows a comparison of the UFLS relay operation for two undervoltage pickup settings: 67 percent and 80 percent of the rated bus voltage. The time-delay setting is 6 cycles. The higher voltage setting of 80 percent increases security because it takes less time for the voltage to decay to 80 percent of the rated voltage and to block the UFLS relay from tripping with the undervoltage block element. It takes a longer time for the voltage to decay below the 67 percent voltage threshold and to block the UFLS relay. Reducing the voltage setting increases the number of misoperations. However, to ensure dependable operation in case of a true underfrequency event when bus voltages could also decrease, Xcel Energy NM/TX uses an undervoltage block setting of 67 percent. Note that with the lower undervoltage block setting of 67 percent, the UFLS relay misoperates for all the tests, as shown in Table XIV.

Increasing the undervoltage block pickup improves security for some loading conditions. However, to secure the UFLS relay completely, additional supervision or a longer time delay is required.

B. Current Supervision

Current supervision can be used to differentiate between a system-wide underfrequency event and a loss of source condition on a motor bus. If sufficient current is flowing into the motor bus, it indicates that loads are connected and the underfrequency is due to a system-wide event. The UFLS relay should operate for this case. On the other hand, if the current measured is much lower than the normal load current of the bus, the UFLS relay can be blocked because this indicates a loss of source. To test current supervision for motor bus applications, an overcurrent element (50P2) was set to 50 percent of a single motor's full load current. The UFLS relay logic is shown in Fig. 25.

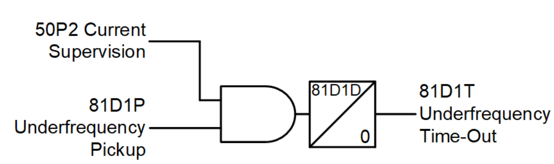

Fig. 25. UFLS relay with current supervision

The current decay when the source breaker is opened is shown for two cases.

TABLE XIV
TEST RESULTS WITH VOLTAGE, CURRENT, AND ROCOF SUPERVISION

Test	RLC Load Connection	Number of Motors Connected	UFLS With Undervoltage Block = 67%	UFLS With Undervoltage Block = 80%	UFLS With Current Supervision	UFLS With ROCOF Supervision
1	Resistor	4	Trip	No Op	No Op	No Op
2	Resistor	3	Trip	No Op	No Op	No Op
3	Resistor	2	Trip	No Op	No Op	No Op
4	Resistor	1	Trip	No Op	No Op	No Op
5	Capacitor	4	Trip	No Op	No Op	No Op
6	Capacitor	3	Trip	Trip	No Op	No Op
7	Capacitor	2	Trip	Trip	Trip	No Op
8	Capacitor	1	Trip	Trip	Trip	No Op
9	Inductor	4	Trip	No Op	No Op	No Op
10	Inductor	3	Trip	No Op	No Op	No Op
11	Inductor	2	Trip	No Op	No Op	No Op
12	Inductor	1	Trip	No Op	No Op	No Op
13	None	4	Trip	No Op	No Op	No Op
14	None	3	Trip	No Op	No Op	No Op
15	None	2	Trip	Trip	No Op	No Op
16	None	1	Trip	Trip	Trip	No Op

1) Case 1: Only Motor Loads

In this simulation case, all four motors are connected to the bus and the RLC load is offline. Fig. 26 shows the decay of current after CB1 is opened.

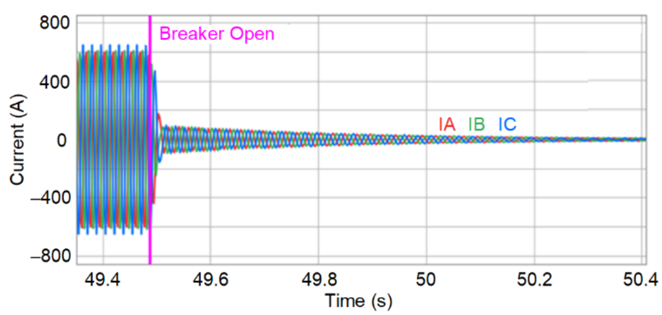

Fig. 26. Current decay with four motors (event report)

The digital signals in Fig. 27 show that two levels of underfrequency (81D1 and 81D2) pick up 16.7 ms (1 cycle) after CB1 is opened. The third level (81D3) picks up 25.2 ms (1.5 cycles) after CB1 is opened. The current supervision (50P2) drops out 59.45 ms (3.5 cycles) after CB1 opens. The 50P2 bit drops out and blocks the underfrequency elements from timing out. This prevents the UFLS misoperation. Fig. 27 shows the digital signals for the same case with only voltage supervision when the UFLS relay misoperated.

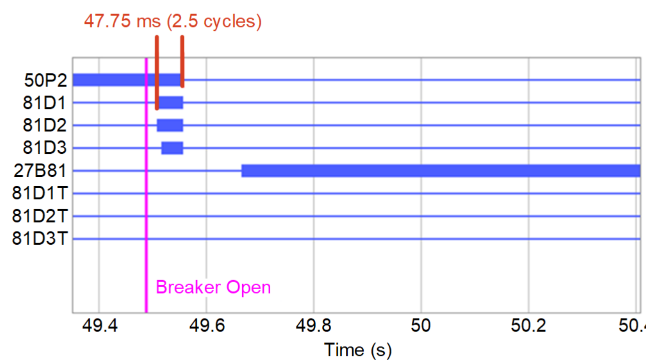

Fig. 27. Digital signals with four motors (event report)

2) Case 2: One Motor and Capacitor Connected to the Bus

In this simulation case, one motor and a capacitor load are connected to the bus. The decay in current after CB1 is opened is shown in Fig. 28. The current takes a longer time to decay as compared to Fig. 26.

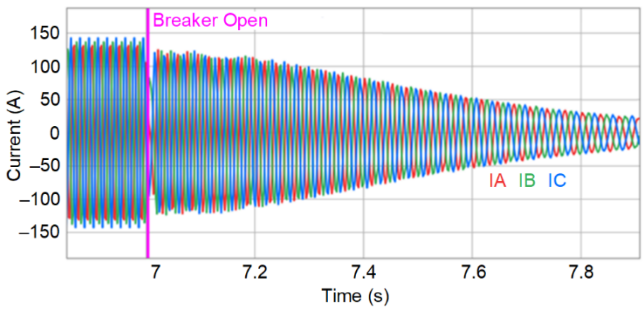

Fig. 28. Current decay with one motor and one capacitor (event report)

The digital signals in Fig. 29 show that the frequency elements (81D1, 81D2, and 81D3) pick up and then time out. The current supervision (50P2) does not drop out fast enough to prevent the UFLS operation. The undervoltage block (27B81) picks up after the UFLS has tripped. Both current and voltage supervision could not have prevented the misoperation for this case.

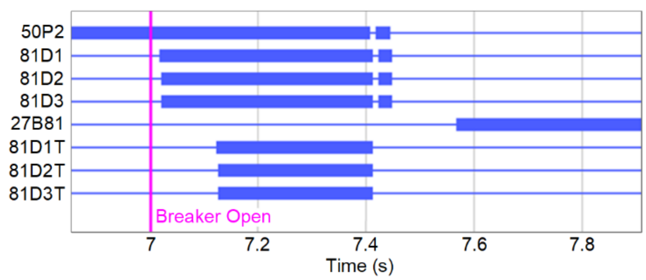

Fig. 29. Current decay with one motor and one capacitor (event report)

As compared to voltage supervision results shown in Table XIV, there are fewer misoperations with current supervision for a motor bus.

C. ROCOF Supervision

The ROCOF during a system-wide underfrequency event is much lower than the ROCOF during a source opening to de-energize a motor bus. The UFLS relay logic with ROCOF supervision is shown in Fig. 30, where ROCOF pickup = UFLS pickup +0.4 Hz. This logic uses two definite-time frequency elements with a difference of 0.4 Hz in the pickup settings and 2-cycle time delay to create a ROCOF element. This is different from the built-in ROCOF elements that are available in some microprocessor-based relays.

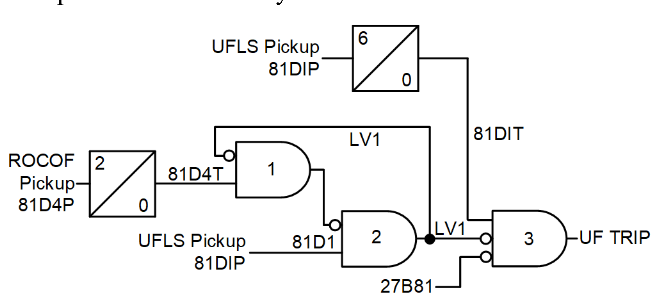

Fig. 30. ROCOF supervision

The settings used in the relay for ROCOF supervision are shown in Table XV.

TABLE XV
UFLS RELAY SETTINGS WITH ROCOF SUPERVISION

Protection/Logic setting	Set Point/Logic
UFLS Pickup 1 (81D1P)	59.3 Hz
UFLS Delay 1 (81D1D)	6 cycles
UFLS Pickup 2 (81D2P)	59 Hz
UFLS Delay 2 (81D2D)	6 cycles
UFLS Pickup 3 (81D3P)	58.7 Hz
UFLS Delay 3 (81D3D)	6 cycles
ROCOF Pickup 1 (81D4P)	59.7 Hz
ROCOF Delay 1 (81D4D)	2 cycles
ROCOF Pickup 2 (81D5P)	59.4 Hz
ROCOF Delay 2 (81D5D)	2 cycles
ROCOF Pickup 3 (81D6P)	59.1 Hz
ROCOF Delay 3 (81D6D)	2 cycles
Undervoltage block setting (27B81)	5.1 kV LN, primary
Logic Variable 1 (LV1)	81D1 * !(81D4T * !LV1)
Logic Variable 2 (LV2)	81D2 * !(81D5T * !LV2)
Logic Variable 3 (LV3)	81D3 * !(81D6T * !LV3)
Logic Variable 4 (LV4)	81D1T * !LV1
Logic Variable 5 (LV5)	81D2T * !LV2
Logic Variable 6 (LV6)	81D3T * !LV3
Trip logic	LV4 or LV5 or LV6

Each fixed-time underfrequency trip bit (81D1T, 81D2T, or 81D3T) is supervised with an ROCOF element (LV1, LV2, or LV3). The desired ROCOF supervision rate is 12 Hz/s, as shown in (8).

$$\begin{aligned} \text{ROCOF supervision} &= \frac{\text{81D4P} - \text{81D1P}}{\text{81D4D} / 60} \\ &= \frac{59.7 - 59.3\ \text{Hz}}{2/60\ \text{s}} = 12\ \text{Hz/s} \end{aligned} \tag{8}$$

The worst-case (lowest) ROCOF for the system shown in Fig. 16 was 34 Hz/s. In this worst-case simulation, all four motors and the capacitor load are connected to the bus. The ROCOF setting of 12 Hz/s is twice the frequency decay experienced in South Australia during the 2016 blackout and at least half of the worst-case ROCOF recorded in the simulation (34 Hz/s).

The frequency decay at some high-inertia motor buses after source disconnection could be lower than 12 Hz/s. The ROCOF setting would have to be decreased to below 12 Hz/s for these systems [14]. Current supervision can also be used in addition to ROCOF to improve security for such a system.

The UFLS relay operation with ROCOF supervision is shown in Table XIV. The relay correctly restrains for all cases and provides adequate security.

The results for the three supervision methods (voltage, current, and ROCOF, shown in Table XIV) can be summarized as follows:

UFLS relays are typically set with voltage supervision. Voltage supervision can be set at a certain percentage of rated voltage (50 to 80 percent) and applied to every bus. This threshold does not have to be calculated for an individual bus and is easy to set. However, as shown in Table XIV, this is not sufficient to prevent misoperations at a motor bus.

- Extending the time delay to 30 cycles will prevent misoperations at a motor bus. However, with increased penetration of renewables, there may be a need to reduce the 30-cycle time delay due to lower system inertia and faster ROCOF.
- Current supervision also improves the security of the UFLS relay but does not prevent misoperation for all cases. The current thresholds are not universal and have to be calculated based on the individual bus load. Additionally, UFLS relays may not be connected to current transformers, thus requiring additional wiring in the relay panel.

The ROCOF element provides correct supervision for every test, as shown in Table XIV. The ROCOF supervision can be applied to any bus with capable microprocessor-based relays. This threshold must be set below the worst-case (lowest) ROCOF of the motor bus during source disconnection.

D. *Faster UFLS Implementation*

Using the ROCOF supervision scheme allows a change in the test system UFLS program. All intentional time delays can now be securely set to 6 cycles to allow faster load tripping for underfrequency events. The four test cases from Section III are now revisited, and results of faster ROCOF-supervised UFLS are compared to the original results.

1) *Case 1: 100 Percent Synchronous Generation*

Fig. 31 shows the frequency response comparing staggered tripping versus tripping all loads in a UFLS level at the same time. The ROCOF is the same as the original case. Both cases shed the same amount of load (500 MW). The frequency nadir is about the same for both cases, but faster load shedding allows the frequency to recover to 60 Hz faster than staggered load shedding. The frequency settles out at about the same value for both cases.

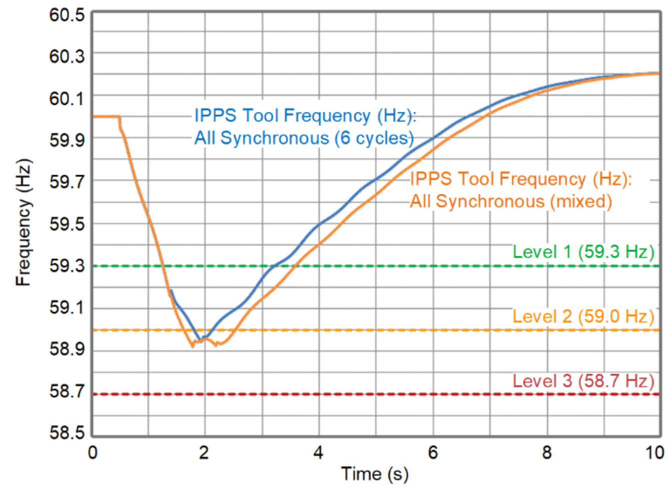

Fig. 31. Case 1 comparison of faster load shedding to staggered load shedding

2) *Case 2: 25 Percent Wind Generation*

Fig. 32 shows the frequency response for the 25 percent wind generation case. The ROCOF is the same as the original case, and the same amount of load is shed (500 MW). Faster load shedding results in a 0.2 Hz improvement of the frequency nadir, and frequency recovers to 60 Hz about a second faster.

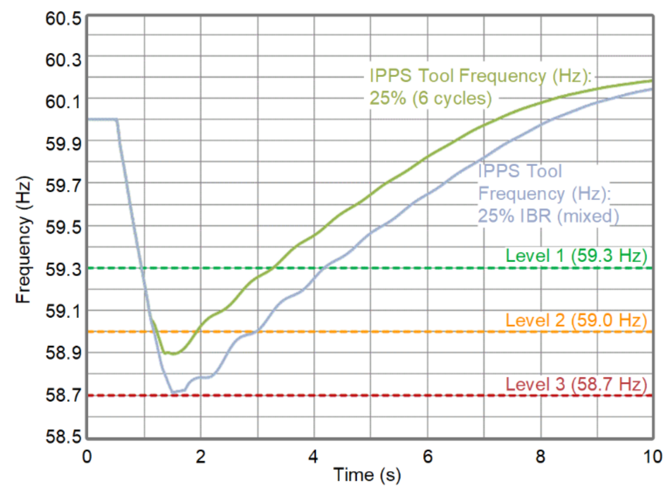

Fig. 32. Case 2 comparison of faster load shedding to staggered load shedding

3) *Case 3: 50 Percent Wind Generation*

Fig. 33 shows the frequency response for the 50 percent wind generation case. The ROCOF is the same as the original case; however, only 500 MW of load is shed with faster load shedding instead of 650 MW using staggered time delays. As Fig. 33 shows, the frequency nadir stays above 58.7 Hz, avoiding unnecessary load shedding. Faster load shedding results in a 0.2 Hz improvement of the frequency nadir. More importantly, the frequency settles out at about 60.3 Hz instead of 61.8 Hz, thus avoiding the potential for overfrequency generator tripping.

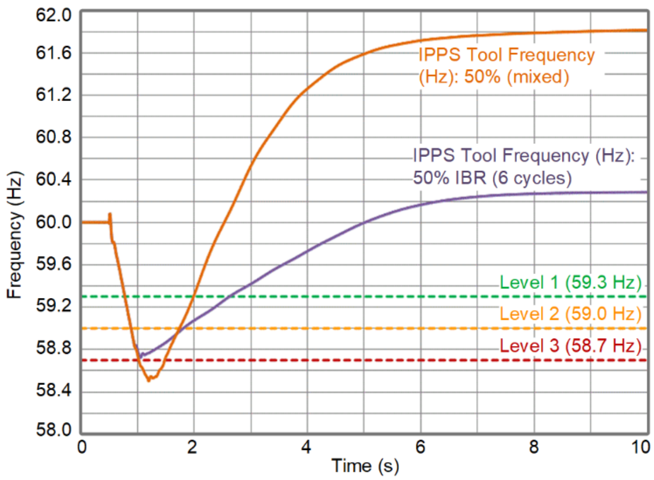

Fig. 33. Case 3 comparison of faster load shedding to staggered load shedding

4) *Case 4: 67 Percent Wind Generation*

Fig. 34 shows the frequency response for the 67 percent wind generation case. The ROCOF is the same as the original case, and all levels of UFLS trip, shedding 750 MW of load. Faster load shedding results in a 0.2 Hz improvement of the nadir and a faster return to 60 Hz. However, the frequency at the end of the event is still critically high, likely resulting in additional generation tripping.

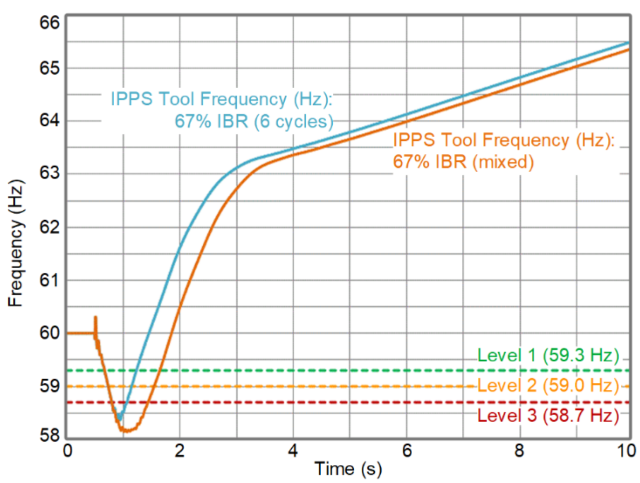

Fig. 34. Case 4 comparison of faster load shedding to staggered load shedding

V. Conclusion

UFLS relays that have been set the same way since the late 1960s must be re-evaluated due to changing generation resource mixes. This paper shows that increases in wind and solar generation can cause lower system inertia, which can cause system frequency to decrease faster during a system-wide UFLS event.

UFLS relays on feeders with heavy motor loads are typically set with a longer time delay. This provides security when the source is de-energized. However, the time delay needs to be reduced to ensure that load is tripped fast enough for the system to recover in a true system-wide UFLS event with more wind generation.

The paper described the different UFLS supervision methods that are used to provide security from mis-trips. The effectiveness of these supervision methods was tested for the motor bus application and showed that ROCOF supervision provides sufficient security to reliably trip with a 6-cycle time delay instead of a 30-cycle time delay. Additional testing and simulation are needed to evaluate if the time delay can be reduced to below six cycles.

Implementation of faster UFLS tripping in the test system showed performance improvements with wind penetration up to 67 percent. Frequency nadir was reduced, and recovery to nominal frequency was faster. Shedding load faster can also avoid shedding additional UFLS levels, thus reducing the total amount of load shedding for an underfrequency event. When wind penetrations exceed 50 percent, frequency overshoot above nominal frequency is more severe, possibly leading to generation tripping on overfrequency.

Additional studies are necessary to improve UFLS programs for systems with wind penetrations above 50 percent. Solutions to be studied include additional Level 1 load shedding, additional load-shedding levels, reduced UFLS intentional time delays (3 to 4 cycles), addition of synchronous condensers to replace lost system inertia, and addition of battery energy storage systems to provide over/underfrequency power absorption and injection.

The dynamically changing electric grid has challenging problems to overcome in order to ensure the stability, reliability, and affordability of the bulk power system. Implementing faster UFLS is a first step to meet this challenge. Other engineering solutions, once studied, validated, and implemented, will help ensure the industry's UFLS programs will perform as desired in an ever increasing carbon-free generation world.

VI. Appendix

The model shown in Fig. 16 was simulated in two different EMTS programs. The details of the transmission line model and the loads connected to the bus are described in this section. The results from the two different EMTS programs are compared in this appendix. The parameters of the induction motor model are shown in Table XVI. The load on the machine is 80 percent of the per-unit speed squared.

Table XVI
Motor Model Parameters

Rated MVA	3 MVA
Rated Frequency	60 Hz
Stator Resistance	0.005 pu
Stator Leakage Reactance	0.08 pu
Magnetizing Reactance	3.92 pu
Outer Cage Rotor Resistance	0.012 pu
Outer Cage Rotor Reactance	0.119 pu
Inner Cage Rotor Resistance	0.112 pu
Inner Cage Rotor Reactance	0.070 pu

The transmission line is modeled using the frequency-dependent phase model, which is a traveling-wave model. The parameters of the transmission line model are shown in Table XVII.

TABLE XVII
TRANSMISSION LINE PARAMETERS

Model Type	Frequency-dependent phase
Line Length	25 mi
Ground Resistivity	100 Ω ft
Shunt Conductance	3.048e-12 mho/ft
Conductor Type	Ibis
Conductor Height	48.5 ft
Horizontal Conductor Spacing	12.5 ft

The motor load on the bus is varied from one to four motors, and additionally, RLC components are connected to the bus. The RLC load values are shown in Table XVIII.

TABLE XVIII
RLC LOAD PARAMETERS

Resistor Load	1.74 MVA (100 Ω)
Inductor Load	1 MVA (0.462 H)
Capacitor Load	1 MVA (15.24 µF)

The percentage difference for each test case is calculated using the results from the two EMTS programs. The test number corresponds to a specific loading condition and is listed in Table XIX.

TABLE XIX
TEST NUMBER AND CORRESPONDING LOAD ON THE BUS

Test	RLC Load Connection	Connected Motors
1	Resistor	4
2	Resistor	3
3	Resistor	2
4	Resistor	1
5	Capacitor	4
6	Capacitor	3
7	Capacitor	2
8	Capacitor	1
9	Inductor	4
10	Inductor	3
11	Inductor	2
12	Inductor	1
13	None	4
14	None	3
15	None	2
16	None	1

The percentage difference is shown in Fig. 35 and was checked for the following results:

- Time taken for voltage to decay below 10 kV
- ROCOF value at 0.1 seconds after the breaker is opened
- ROCOF value at 0.25 seconds after the breaker is opened
- ROCOF value at 0.5 seconds after the breaker is opened

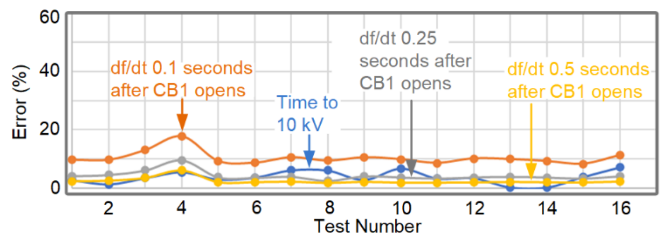

Fig. 35. Error for EMTS results

The percentage difference for most tests is below 10 percent and the highest difference is 18 percent. This confirms that both EMTS programs give similar results for the test cases.

The length of the transmission line also determines the time taken for the voltage to decay due to the line capacitance. Fig. 36 shows the voltage decay when the transmission line is 15 miles and 50 miles in length. All four motors are connected to the bus, and the RLC load is offline. As the length of the transmission line is increased, the voltage takes a longer time to decay.

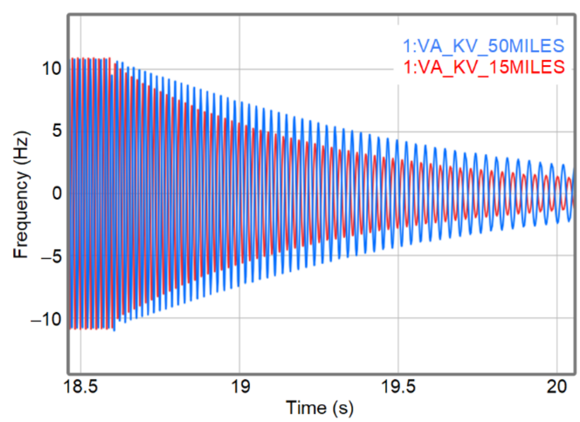

Fig. 36. Voltage decay for four motors on the bus

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VIII. 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 32 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 CTF34. 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.

Katriana J. Webber graduated from Tascosa High School in 2019. She attended Amarillo Area Center for advanced learning, participating in the engineering program, and she received her AutoCAD software inventor and OSHA certification before graduating. She is currently attending Amarillo College and is working toward her AS in Engineering, which she will earn in 2021. Katriana then plans to transfer to Texas Tech University to pursue a BS in electrical engineering where she will graduate in 2023.

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.