Midwest Reliability Organization

Underfrequency Load Shedding Program

Report and Recommendations

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1. Executive Summary

The purpose of this report is to satisfy the design phase (R1.1 and R1.2) of the North American Electric Reliability Corporation (NERC) Reliability Standard PRC-006-0 requirement R1, which states "Each Regional Reliability Organization shall develop, coordinate, and document an Under Frequency Load Shedding ("UFLS") program." For 2004, the MAPP region[1] was found level 1 non-compliant of this requirement. NERC stated that the UFLS set points and values were "empirical" (refer to Attachment A). As a result of the non-compliance, MRO submitted a mitigation plan which includes this report to satisfy the Level 1 non-compliance of this voluntary, regional planning standard. In addition to resolving the 2004 Level 1 violation, the intent of this report is to provide the technical details to propose and establish an applicable Reliability Standard which will supersede both the MAIN and MAPP UFLS programs in the new mandatory standards regime recently created by legislation in the US and parts of Canada.

Since this NERC finding, the Energy Policy Act of 2005 ("EPAct 2005") and regulatory steps in Canada have resulted in mandatory standards applicable to all owners, operators, and users of the bulk power system. NERC, as the international Electric Reliability Organization ("ERO"), and MRO, as an applicant to be a Cross Border Regional Entity (for purposes of this document Regional Entity or "RE"), will be responsible for developing, proposing, and enforcing mandatory Reliability Standards. The regional standard that MRO was found Level 1 violation is not an enforceable standard under the new compliance regime (e.g. EPAct 2005) because it does not apply to an "owner, user, and operator of the bulk power system". The voluntary standard applies to "Regional Reliability Organizations" which have been superseded by Regional Entities for statutory reliability functions under the EPAct 2005. It's unclear at this time whether "Regional Reliability Organization" will exist in the future because they have no "standing" in a regulatory or legal context. Additionally, these regional standards, or so called "fill in the blank standards", have been remanded to NERC so that they can be enforced under EPAct 2005 and provincial authorities. These "standards" are included in NERC's "Reliability Standards Development Plan: 2007-2009" issued on November 30, 2006. MRO Standards Committee and staff are working on executing the RE aspects of the plan in

[1] MRO assumed the reliability responsibilities from the MAPP Reliability Council as of January 1, 2005 and therefore, this was a follow-up to a 2004 level 1 finding related to the former MAPP reliability region of NERC. In addition, MRO assumed reliability responsibilities for former MAIN Reliability Council members who joined MRO.

conjunction with other RE's and NERC (refer to the end of this report called "Key Future Aspects of the UFLS Standards and Programs").

The MRO Underfrequency Load Shedding Task Force is recommending the MRO include this report and the study results in the development of an MRO Reliability Standard in the aforementioned "Reliability Standards Development Plan: 2007-2009". Furthermore, the task force recommends that the MRO Reliability Standard adopt an UFLS program that sheds 30% of connected load according to the specifications that follow. This program includes a proposed minimum time delay for underfrequency tripping of generation to ensure overall coordination with load shedding. Subregional variations to the load shedding program are permitted as needed with a few restrictions. As part of the Standards development process, an appropriate implementation timetable is needed for transitioning to any new UFLS program requirements.

This program:

- Quickly drives frequency back towards 60 Hz without relying on governor action,
- Limits overfrequency following load shedding, and
- Minimizes additional loss of generation.

The MRO UFLS program addresses all applicable design considerations of NERC PRC-006 R1.2, which states design details shall include, but are not limited to:

R1.2.1. Frequency set points
R1.2.2. Size of corresponding load shedding blocks (% of connected loads)
R1.2.3. Intentional and total tripping time delays
R1.2.4. Generation protection
R1.2.5. Tie tripping schemes
R1.2.6. Islanding schemes
R1.2.7. Automatic load restoration schemes
R1.2.8. Any other schemes that are part of or impact the UFLS programs

In general, subregional variations to the program are acceptable provided that:

- The need for such variation is documented;
- The performance of the subregional program is adequate; and
- Such subregional variations do not impact the performance of the overall MRO UFLS program.

1.1 MRO UFLS Program Specifications

1.1.1 Underfrequency Load Shedding

The 30% load shedding requirement is covered by 5 steps of high speed underfrequency load shedding. Use of dual tripping logic allows a portion of block 5 to also serve as two delay blocks. These delay blocks prevent frequency stall out and ensure frequency recovery is quick enough to satisfy generation protection needs.

High Speed Load shedding Block number	Block size, % of initial load	Frequency setpoint (Hz)	Relay time (cy)*	Maximum breaker time (cy)
1	6	59.3	6	8
2	6	59.1	6	8
3	6	58.9	6	8
4	6	58.7	6	8
5	6	58.4	6	8
The following two delay blocks are a subset of block 5 using logic of the form: trip IF (58.4 Hz for 6 cy) OR IF (X Hz for Y cy), with the second trip times and delays defined below**				
Delayed Load Shedding Block number	Block size, % of initial load	Frequency setpoint (Hz)	Relay time + intentional delay time (cy)	Maximum breaker time (cy)
1	2	58.7	500	8
2	2	59.5	2400	8

* 6cy minimum detection time recommended for relay security purposes to prevent false trips

**As an alternative, utilities can implement the delay blocks as independent blocks, which increases the total load shedding obligation to 34%.

1.1.2 Generation Protection

Underfrequency relaying protects generation from excessive loss of life, and settings and time delays must also be coordinated with load shedding to allow the UFLS program a reasonable time to play out and to restore frequency. Companies that are unable to meet the proposed minimum time delay standard will be required to shed additional load to compensate for loss of generation. Such load must be a reasonable match to the amount of generation tripped and shed at essentially the same time and in the same general location.

Allowable Generator Automatic Underfrequency Trip Frequencies and Required Time Delays

setpoint (Hz)	minimum delay time* (sec)
>59.5 Hz	Automatic Tripping Not Permitted
≤ 59.5 to > 59.3	2700
≤ 59.3 to > 59.0	300
≤ 59.0 to > 58.4	80
≤ 58.4 to > 58.0	30
≤ 58.0 to > 57.6	7.5
≤ 57.6	0

*Subregional programs shedding more than 30% of connected load will need to increase generation protection delay times and/or change setpoints to achieve coordination with load shedding.

1.1.3 Automatic Load Restoration

Automatic load restoration is not part of the MRO UFLS program, and should not be used. Frequency should be allowed to recover to 60 Hz before load is manually restored.

1.1.4 Underfrequency Tie-Line Separation

Underfrequency tie-line separation is not part of the MRO UFLS program design.

1.1.5 Acceptable UFLS Relays

Only high speed digital or computer based relays are acceptable. To prevent false trips, the relay operating time should be set to 6 cycles. Electromechanical relays, which have operating times that are a function of rate of change of frequency are unacceptable and need to be phased out.

1.1.6 Capacitor Tripping/Overvoltage Protection

To protect against overvoltages during an underfrequency load shedding event, systems shall implement automatic measures such as capacitor tripping to maintain voltages within acceptable limits.

2. Introduction

This report documents development of an underfrequency load shedding program for the MRO region. It is intended to satisfy design requirements specified in requirement R1 of NERC standard PRC-006-0 and to address the Level 1 violation of this voluntary, reliability standard for the MRO.

MRO assumed the reliability responsibilities from the MAPP Reliability Council as of January 1, 2005 and therefore, this was a follow-up to a 2004 level 1 finding related to the former MAPP reliability region of NERC. In addition, MRO assumed reliability responsibilities for former MAIN Reliability Council members who joined MRO.

To provide context, all of the NERC UFLS requirements are summarized in Appendix 1. This includes PRC-006-0, as well as PRC-007-0, PRC-008-0, PRC-009-0, and EOP-003-0. Some of these requirements apply to the MRO, and some apply to MRO members. Most of this is beyond the scope of this report and is included as background material for those who wish to get more familiar with NERC UFLS requirements. Consider that this standard is being re-tooled to be applicable to "all owners, users, and operators of the bulk power system" (refer to Executive Summary) and therefore, enforceable.

2.1 NERC and Regional Entities

Prior to EPAct 2005, bulk electric system reliability standards were established and enforced by the North American Electric Reliability Council and the regional councils of NERC under a voluntary regime. After EPAct 2005, approved standards are mandatory and enforceable with financial penalties with regulatory backstops. MRO was one of the regional councils of North American Electric Reliability Council. The North American Electric Reliability Council has been merged into the North American Electric Reliability Corporation (the international Electric Reliability Organization) or "new" NERC. MRO is a member of the corporation and has applied to become a Cross Border Regional Entity ("Regional Entity" or "RE") under the EPAct 2005 and provincial authority. The compliance and enforcement regime is based upon delegated authority between new NERC, the corporation, and Regional Entities.

NERC's underfrequency load shedding requirements are a last resort measure, intended to prevent total system collapse and to help ensure quick load restoration.

NERC provides the broad outlines. The specific technical details are worked out at the level of NERC's members, the eight regions in the voluntary regime.

On January 1, 2005, the Midwest Reliability Organization (MRO) assumed the reliability functions of the MAPP Regional Reliability Council and other councils as needed. The MRO region extends into what had formerly been part of the northern portion of the MAIN Regional Reliability Council (excluding Wisconsin Electric Power Company) and the province of Saskatchewan. Therefore, the MRO assumed the responsibility for the MAPP and MAIN UFLS programs and will continue to maintain these programs until they are superseded by an applicable Reliability Standard. The intent of this report is to resolve the 2004 Level 1 violation. This report may also provide the technical foundation to propose and establish such an applicable MRO Reliability Standard.

2.2 The MAPP and MAIN Legacy UFLS Programs

Full descriptions of the MAPP and MAIN legacy programs can be found in Appendix 2.

The MAPP and MAIN UFLS programs both shed 3 blocks of connected load in 10% steps at 59.3 Hz, 59.0 Hz, and at 58.7 Hz.

The MAIN program includes a generation protection "minimum time delay" standard to coordinate generation protection with load shedding. In MAPP, such protection settings were chosen by individual utilities with no assurance of overall system coordination.

The MAIN program requires new relays to be of the solid state type with 6 cycle detection time.

Both programs allow electromechanical relays to be used to some extent. This is a problem as electromechanical relays are slower, voltage sensitive, and operating times are a function of rate-of-change of frequency. They cannot be effectively coordinated with the high speed solid state relays.

The MAPP program also allows delays of up to 60 cycles at any stage of load shedding. Such delays, if used, will affect the ability of a load shedding program to coordinate with generation protection.

2.3 MRO-UFLS Task Force and the RAC

The MRO Reliability Assessment Committee (RAC) formed the Underfrequency Load Shedding Task Force (MRO-UFLS Task Force) to develop an UFLS study to resolve the Level 1 violation. The MRO-UFLS Task Force roster is included as Appendix 3.

2.4 Implementation and Ongoing Management of the MRO UFLS Program

It is expected that, as a result of this study, a new MRO UFLS Reliability Standard will be developed and submitted to NERC and appropriate regulators for approval and subsequent mandatory enforcement through the compliance program.

The MRO will monitor responsibilities related to UFLS implementation, data collection, periodic assessments, and other requirements as needed to assure success. As part of the standards development process, an implementation phase must be included and should grant sufficient time to transition to any new program required by a Reliability Standard.

NERC requires periodic data collection, assessment, and documentation. These activities are not part of the design process, but are briefly discussed in the study scope to provide a complete context for UFLS responsibilities handled by MRO.

The implementation and monitoring activities must satisfy the remainder of existing PRC-006 under the voluntary regime:

PRC-006-0 R1.3. A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.

PRC-006-0 R1.4. Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically (at least every five years or as required by changes in system conditions) and shall include, but not be limited to: PRC-006-0 R1.4.1. A review of the frequency set points and timing, and PRC-006-0 R1.4.2. Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between demand (Load) and generation. *(The emphasis in this instance is effectiveness of the "as implemented" MRO program which due to practical considerations will differ to some extent from "as designed".)*

PRC-006-0 R2. The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).

PRC-006-0 R3. The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).

In addition to PRC-006, the following activity is required:
Review should be initiated following any major system disturbance where UFLS was activated and recommendations should be made as appropriate. A 5-year review process should be set up as an ongoing MRO activity.

Any modifications to the MRO UFLS program that arise from periodic review should be clearly documented. The historical perspective of how the MRO program was originally developed and how it evolves over time should be clearly documented.

Assessments should focus on the program from a total MRO system basis (or subregional basis) to see if objectives are being satisfied. In any implementation, the block sizes will only be a close approximation to the target levels. At the individual utility level, the degree of fit will vary at each stage, and vary among utilities; but errors may be off-set when all individual programs are considered as a whole.

3. Scope and Objective

The objective is to satisfy the design phase (R1.1 and R1.2) of requirement R1 of the NERC Reliability Standard PRC-006-0 which states "each Regional Reliability Organization shall develop, coordinate, and document an UFLS program".

The "MRO Underfrequency Load Shedding (UFLS) Scope and Study Process Outline" is included as Appendix 4. This document lays out a step by step process to work through the review and development of an UFLS program. It ties each step back to specific requirements found in NERC PRC-006-0 R1.

4. Basics of UFLS Program Development

4.1 Overview of the Issues

4.1.1 Design Problem

UFLS systems by design are the last line of defense against blackouts. They protect against a system breakup that falls far outside of a typical event. Therefore the analysis cannot be exactly precise and there is no assurance that load shedding will work as intended for all disturbances which may arise. However, the UFLS Task Force anticipated complications and developed a program using good engineering judgment, common sense, and reasonable assumptions. The resulting program provides reasonable coverage, is well behaved, and coordinates generation protection with load shedding.

The MRO UFLS program is intended to be a minimum requirement. The intent of the MRO program is to have a uniform UFLS program which applies to most of the MRO footprint, while also having a mechanism to allow subregional variations where needed and appropriate. It is recognized that some utilities may need to shed more than 30% of their connected load to cover internal disturbances, or to incorporate non-standard features such as tie-line separation to make a clean break. Generally such exceptions will be needed for subregions that are weakly interconnected to the rest of the system, and that may experience more than 30% loss of generation/import. Those types of areas need to satisfy internal needs first, and it is unlikely that such internal programs will adversely impact the larger MRO program. Approval of subregional variations will be contingent upon MRO's acceptance of utilities internal studies that show a subregional program is needed, effective, and that it does not impact the larger MRO regional program.

Underfrequency relaying (often with multiple settings) protects generation from excessive loss of life when operating at off-nominal frequencies and it is imperative that settings and time delays be coordinated with load shedding to allow the UFLS program a reasonable time to play out and restore frequency. If generation trips during this critical period, it will cause a further drop in frequency, and quite likely a subsequent cascading loss of additional generation that quickly leads to a blackout.

The Task Force designed the load shedding program to quickly drive frequency back towards 60 Hz to minimize the exposure to operating at low frequencies. In a sense, the load shedding program becomes the first line of defense for the generators and further reduces risk to generators.

The Task Force recognized that the dynamic nature of system loads and generation is changing. Each of these factors complicates things in different ways. The following trends are being observed throughout the industry:

More wind generation is being added which tends to lower the system inertia (older wind units may trip quickly, newer wind units do not provide any inertial effects, or more accurately, any MW·sec of stored energy to the system, and wind units do not have any governor).

The inertia of conventional generation is expected to decrease.

More combustion turbines and combined cycle units are being added (CTs are thermally limited, causing net power to drop significantly as frequency declines).

More variable speed motor drives are being used (which lowers system damping).

Many loads appear as constant power due to associated power electronics (lowers system damping).

All of these trends make the system more difficult to control should an UFLS event occur.

4.1.2 How the System Responds to an Imbalance

Load shedding is primarily needed to cover system breakups where islands form. At that point load and generation are no longer matched up. When load suddenly exceeds generation, frequency will decline until a new stable operating point is reached. Assuming turbine power remains constant (meaning that governor action is ignored), the system will reach equilibrium because generator torque increases as frequency drops and the load torque decreases. At some point these torques will again be equal.

The rate of frequency decline is a function of the energy stored in the rotating machines (inertia constant H) and the overload level. The final frequency is a function of the load damping characteristic (d) and the overload level. In this report, the term "overload" refers to the generation/load imbalance, which is typically expressed in per unit of remaining generation.

Without load shedding, even a small imbalance will result in a significant frequency deviation. By shedding load, the frequency decline can be stopped at much higher frequencies.

The ideal case would be to shed exactly the right amount of load as soon as the imbalance occurs. Unfortunately, this is not possible.

The practical application is to shed blocks of load at different frequencies with a minimum of delay to quickly arrest the frequency decline.

The final frequency will depend on the final load/generation balance after load shedding takes place. If insufficient load is shed, there is a chance that frequency may stall out well below 60 Hz.

Most power systems are designed to operate continuously within the 59.5 Hz to 60.5 Hz range. Operation below 59.5 Hz can only be tolerated for a limited time (which varies with frequency), and for most units, instant trips are required in the area of 57 Hz to 57.5 Hz (or even higher).

So far governor action has been ignored as units do not respond instantly to governor signals and little power change will occur in the first 2 seconds. Should system frequency stall out low, governor action or on additional blocks of load shed on delay will be relied upon to drive frequency back towards 60 Hz.

Slow recovery must be avoided as generation protection could pick up and trip units. Such tripping will cascade and collapse the system. To prevent this, the load shedding program needs to be designed to supplement governor action to force quick frequency recovery, not just stop the frequency decline; and the MRO region will also need a coordinated generation protection time delay criteria which allows UFLS to play out. The Automatic Generation Control (AGC) performed by control areas cannot be relied on to correct frequency as it is only intended for normal interconnected system operation and will transfer to manual mode for severe disturbances.

While some governor action is expected at power plants, an exact amount of sustained response cannot be quantified. The Task Force took the conservative approach of designing a program that works even if there is little net unit response to underfrequency.

The Task Force used the following assumptions:
Governors may respond, but the unit may fail to respond to underfrequency because it is already fully loaded or in an unresponsive operating mode.
Some units, like nuclear, often have governor response to system frequency changes blocked.
Load controllers may force units back to the original setpoints after 30 seconds or longer delay, so governor response may be momentary.
Stability models do a crude job of estimating governor response as they ignore boiler dynamics and other limiting factors – they overestimate what may really happen.
Gas turbine thermal limit controls can cause power output to decrease as frequency drops and may counteract governor action from other units.
Wind units do not have any governor response.

The Task Force adopted a policy to shed the majority of load with no delay to quickly arrest the frequency decline, and then to trip additional small blocks of load on delay if recovery is too slow. This ensures recovery towards 60 Hz without relying on governor action. It also gives a way to ensure coordination between load shedding and generator protection.

Load shedding is a drastic action and in some instances will cause a subsequent overfrequency event. This problem is more acute in programs which shed large blocks of load, or ones which have relay coordination problems (i.e. setpoints too close together).

The Task Force expects units will be responsive to overfrequency, but did not want to expose units to severe imbalances where governor action shuts off enough steam flow to cause internal plant problems like the lifting of safeties. The solution was to share the load shedding between more blocks to decrease individual block sizes.

The general concept of load shedding is easy to grasp but there are many interrelated issues wrapped up under the heading of "underfrequency load shedding". The Task Force broke the interrelated problems down and worked through various issues to arrive at the recommended program. This was an iterative process involving a number of tradeoffs and compromises.

4.2 Things to Consider

The following questions and issues were considered by the Task Force:

- What is the objective of the design?
- What is the appropriate modeling/simulation approach to use in the design work?
- What are suitable relay types and required relay response times?
- What are the possible subregions (islands)?
- What are the needs of these subregions?
- Which subregions need alternative load shedding programs?
- Canadian systems?
    - Others?
- Do any subregions need forced islanding (O/S, UF tie-line separation, transfer tripping, etc)?
- How is coordination achieved between NERC regions as well as between MRO subregions?
- How are the generation protection requirements going to affect load shedding design and performance?
- What should the basis be for regional turbine/generator underfrequency protection standards?
- How are provisions made for units which are going to trip prematurely?
- How are overfrequency problems caused by load shedding minimized or mitigated?
- How quickly should overfrequency problems be corrected?
- Are there any special requirements or unique factors to consider?
- What type of tradeoffs or compromises will be made?
- How does wind generation affect an UFLS program?

- How do industry trends towards lower inertia affect an UFLS program?
- Combustion Turbines represent a large percentage of new generation, how do they affect an UFLS program?
- How will DC transmission behave during a major frequency decline?
- What values are appropriate for load damping, “d”?
- What range of system base inertia constants, “H”, should be used?
- What are the advantages, disadvantages, and tradeoffs related to increasing the number of load shedding stages, increasing/decreasing time delays, adding automatic load restoration, etc.?

4.3 Technical References

The Task Force considered the following technical references:

IEEE C37.106-2003, “IEEE Guide for Abnormal Frequency Protection for Power Generating Plants”

IEEE PC37.117 (draft), “Guide for the Application of Protective Relays Used for Abnormal Load Shedding and Restoration”

WSCC “Underfrequency Load Shedding Relay Application Guide”, December 1974

General Electric GET-6449, “Load Shedding, Load Restoration and Generator Protection Using Solid-state and Electromechanical Underfrequency Relays”

WECC Off-Nominal Frequency Report of July 2005, containing the original WSCC UFLS program report of November 25, 1997, and subsequent technical reviews.

4.4 Guiding Principles

In the early stages of this study effort, the Task Force decided on the following guiding principles:

- The Task Force would evaluate the program using the “equivalent inertia” modeling approach recommended in the relay application guides, which allows rapid prototyping.

- The Task Force would keep the 30% load shedding levels as a minimum requirement unless review indicates more needs to be shed.
- The Task Force would work to coordinate all individual system needs into an overall coordinated program (to the extent it can be done).
- The Task Force established "soft" targets for minimum and maximum frequency excursions. The Task Force did not want minimum frequency to drop much below 58 Hz, and wanted to limit the time and extent that frequency is above 61 Hz.
- The Task Force decided that generation protection settings should be based on expected frequency recovery times from the simulations. As a reality check, the protection settings specified for the NERC regions WECC, MAIN, and NPCC were used as proxies for typical generation protection settings, and were compared to actual worst case times spent below 60 Hz.
- The Task Force decided to design the UFLS program to quickly drive frequency back towards 60 Hz. Load shedding then becomes the first line of defense for generator protection.

4.5 Steps of the Design Process

The following steps are listed in the order shown in the study scope, with commentary given as needed.

1. Determine off-nominal frequency limits for generation

   The load shedding program was designed to minimize time spent below 60 Hz by shedding some load on delay to ensure quick frequency recovery without relying on governor action. As such, the load shedding program becomes the first line of turbine/generator underfrequency protection. The recommended time delays in the generation protection criteria were chosen to coordinate with the load shedding program response times.

2. Establish relaying and performance criteria

   To be responsive and quick acting, the program needs to use high speed solid state or computer based relaying. Relays need to be able to pick up in 6 cycles.

3. Identify possible islands to study or areas with special requirements, with consideration given to historical disturbances

    The MRO region was broken into 10 subregions, which individually, or combined with neighboring subregions, define possible islands. See Appendix 5 for a detailed discussion.

4. Describe each island in terms of load, losses, station service load, inertia, damping, etc. Data was extracted from 5 seasonal power flow cases.

    See Appendix 5 for a detailed discussion.

5. Determine the required level of protection for each island (amount of load shed)

    From that raw data, some judgment was applied to determine what levels of load shedding are going to be adequate.

6. From review of above, determine the need for regional or sub-regional UFLS differences, and coordinate such variations with the MRO program

    Initial scoping work identified Saskatchewan, Manitoba and the Upper Peninsula of Michigan as subregions which may need to shed more than 30% of connected load. Utilities representing these subregions performed their own independent analysis in parallel to the MRO UFLS effort. The findings indicate Saskatchewan and Manitoba should continue to shed more than 30% of connected load, and that a 30% load shedding level is satisfactory for the Upper Peninsula area.

7. Determine the number of load shedding blocks, frequency setpoints, and block sizes that satisfy performance criteria and achieve relay coordination objective.

This was done using simple “system equivalent” models to capture the steady state and dynamic response.

8. Address overvoltage issues

This effort cannot possibly get into the specific details of what each utility will have to do to prevent high voltage problems as the system is suddenly unloaded by underfrequency load shedding. At the same time, an awareness of the problem and the implications needs to be created. Load increases in proportion to voltage squared so high voltages can easily offset the effect of load shedding. The goal is to maintain reasonable voltages during load shedding, so utilities will be required to trip capacitors along with load or take other automatic actions to maintain the voltage profile. Some of this will happen automatically as the shunt compensation may be on feeders with the load. At other times the capacitors or reactors are on the higher voltage system, and a different approach is needed to keep voltages fairly constant and reasonable. Each utility will have to work out the details of how this applies to their system and take actions they feel are appropriate.

9. Address overfrequency issues

The Task Force investigated factors which limit unit frequency responsiveness, and the ability of units to take drastic action without causing additional problems internal to the plant. Like much of this study, this is an area where there is considerable uncertainty. The Task Force concluded that units should be responsive to overfrequency and that automatic load restoration was not needed to correct the potential overfrequency conditions so long as individual plants are not required to take too drastic of action. The Task Force concluded that units could quickly reduce power by 3% of rated capacity without causing problems, but suspected that problems would occur if power is reduced by 8% of rated capacity or more. In between is a gray area where it becomes a judgment call. The recommendation to change from a program which sheds load in 3 blocks, to one which sheds load in 5 blocks, was driven by the overfrequency concerns. Automatic load restoration was evaluated as one way to minimize the time spent above 61 Hz, but in the end, the Task Force decided that governor action was sufficient and the automatic load restoration concept was dropped.

10. Unknowns/Uncertainties

There is considerable uncertainty involved in this effort. The Task Force bracketed the range of the significant variables, and then ran simulations using a "bandwidth" approach. Overloads equivalent to 0% to 30% loss of generation were considered.

Although the load damping is not known, it is expected that the damping constant will be between 1 and 2. This is the range that was covered.

The range of system based inertia (total MW•sec/Pgen) was varied from the low to high extremes (2.5 to 15). The very low end is perhaps lower than what is expected today, but may be what may be seen in the future as new low inertia base load units are added and as more wind generation is added. (Newer wind units with power electronics allowing variable slip frequency operation decouple the inertial effects from the grid, so they do not contribute any MW•sec of stored energy but they will stay on-line; the older units initially contribute MW•sec, but quickly trip off following a frequency drop.)

The Task Force was not able to quantify what types of unlikely events are going to cause islands to form. However, likely islands were identified and it was confirmed that each individual island was adequately represented by the same range of input data, such that a single set of simulations applies to all islands for loss of up to 30 % of generation (or loss of import).

11. Tradeoffs/Compromises

All of the above design steps involve tradeoffs and compromises, and the Task Force believes the recommended UFLS program was the best after all things were considered.

12. Other side issues

The Task Force investigated several side issues that affect load shedding programs including:

- A general investigation into wind generation issues such as future trends, expected dynamic response, expected underfrequency trip points, and expected inertial effects.
- Factors which cause gas turbine power to drop off as frequency drops, and generation protection issues which are unique to gas turbines.
- Factors which are preventing units from being responsive to frequency changes, how load damping is decreasing each year, etc.
- The Task Force followed related activities in other NERC regions and IEEE groups.

13. Consider out of step tripping/blocking, and under frequency tie line tripping issues, if needed

This is beyond the scope of this work, but it is quite relevant to the Canadian systems, which are weakly connected to the United States. This is not a feature of the minimum criteria proposed, but the Task Force believes that it makes good sense to consider the issues in certain situations where tie line strength to neighboring systems is just not enough to handle the high tie line flows when neighboring systems respond (or vice versa). In some instances, a quick clean break will help minimize the extent of the disturbance and make it easier to deal with. Such actions are treated as regional exceptions to the program, and utilities which need such programs will have to present work to MRO showing the need and necessity.

14. Iterate towards a best solution, and revise assumptions and protection levels as needed

    Simplified modeling approaches were used to allow rapid prototyping and to allow a generalization as to how the system will respond to a wide range of overloads. This also allowed easy evaluation of sensitivities to different inertia and load damping assumptions, and investigation of the effect of different levels of generic governor action.

5. A Closer Look at the Technical Details

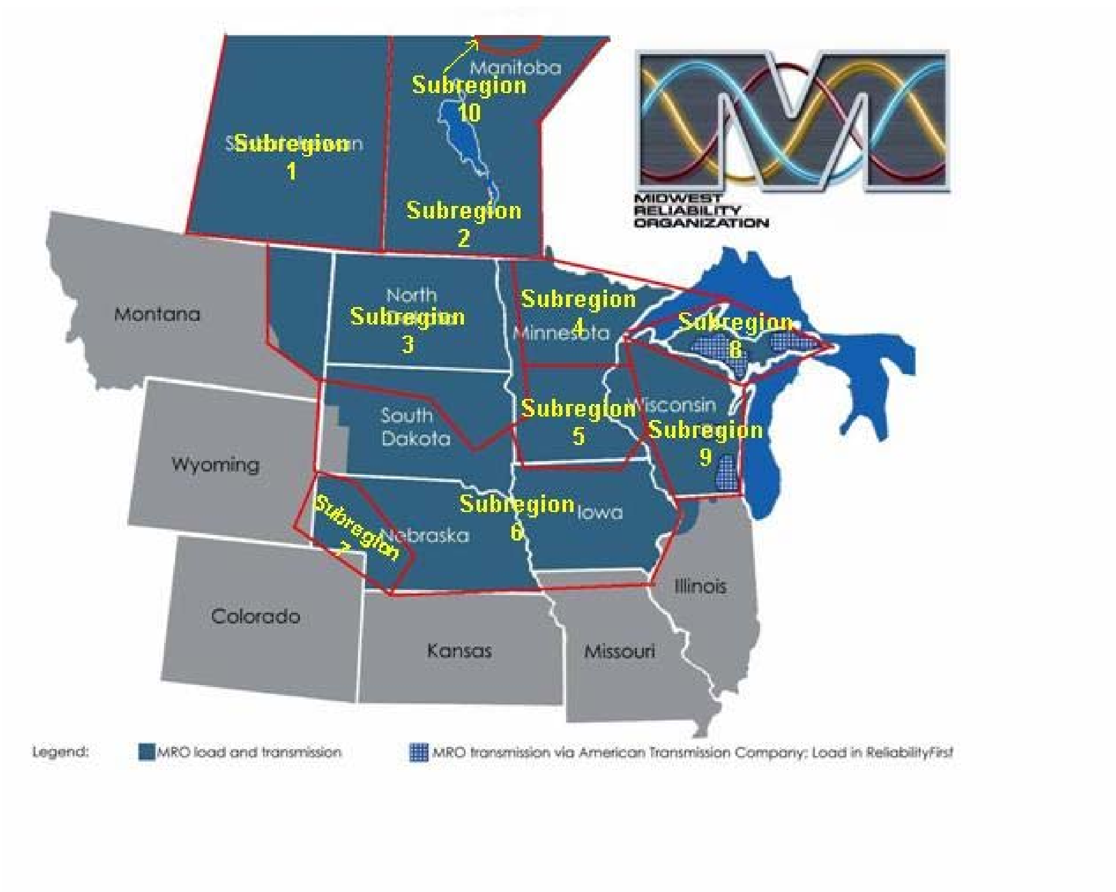
5.1 Initiating Disturbances and Possible MRO Area Subregions

It is nearly impossible to speculate what the initiating disturbances may be, but break points can be identified from historical events or predicted using engineering judgment. Using this model, the MRO footprint was broken down into several subregions. These subregions, alone, or in combinations, represent our postulated islands.

The subregions were then quantified in terms of generation, load, losses, and inertia. This information helped to assess load shedding requirements. Summer, winter, and spring conditions were considered.

These subregions are shown in Figure 1.

Figure 1



A summary of data by subregion is included in Appendix 5. This includes load, losses, generation, and AC and DC interchange.

5.1.1 What Do the Subregions Tell Us?

The MRO-UFLS Task Force took the approach that the new MRO program would retain 30% load shedding as a MRO “minimum level” unless review of subregions indicates that a higher level is warranted.

The data which was extracted from the five base cases was used as a starting point. The Task Force then considered some different initial generation dispatches, or as an equivalent, the Task Force assumed some additional loss of generation or loss of DC line import at the time the island forms. Although this was a rough approach, it gave a sense of how severe an event would have to be to require shedding 30% load. Utilities which represent each of the postulated islands drew conclusions for their own areas to ensure their needs are being met. The final conclusion is that the 30% load shedding level is adequate for the majority of the MRO.

The initial review work identified Saskatchewan, Manitoba and the Upper Peninsula of Michigan as subregions which may need to shed more than 30% of connected load. Utilities representing these subregions were asked to perform their own independent analysis in parallel to the MRO UFLS effort. Summary reports for these subregions are included in Appendix 6. The findings indicate Saskatechewan and Manitoba should continue to shed more than 30% of connected load and that a 30% load shedding level is satisfactory for the Upper Peninsula area. These regions are weakly interconnected to the rest of MRO, and what is done in these areas will have little effect on the rest of the MRO footprint.

The original intent of this effort was to provide a new minimum program for UFLS while still allowing regional exceptions which are needed and make sense. The Task Force is recommending that deviations from the proposed program be allowed as long as the requesting utilities can demonstrate the need for such programs, show the variation is effective, and show it does not affect the overall MRO program.

5.2 Simulation Approaches

5.2.1 Full Transient Stability Program

The full transient stability program is considered the most accurate dynamic modeling approach for a wide range of dynamic studies. It is an excellent tool for studying very specific conditions. However, for this effort, it is too detailed, which makes it poorly suited for generalizing and rapid prototyping. For this effort stability cases would have required some modeling enhancements to improve on governor modeling and to allow capacitor tripping in response to overvoltages. Even with such enhancements, the results may not be any better than what is obtained with a much simpler dynamic equivalent.

The Task Force wants to point out that governor action in the stability cases is quite likely to differ from what is seen in reality, and appropriate attention to detail is needed if stability cases are to be used in load shedding studies. In reality, governor action may be overridden by other plant controls or limited by boiler dynamics, etc. This is a problem recognized by the industry, and the WECC region even developed a new turbine governor model which empirically captures some of the factors which limit unit response.

5.2.2 Single Machine "Equivalent Inertia" Approach

The analysis performed in this study is based on the equivalent inertia method. This is the dynamic simulation method generally recommended by underfrequency relay application guides.

This is a simplification of the transient stability program, where the inertial effects of all units are aggregated into one simple equivalent machine. This model predicts an average frequency decline. This tool ignores voltage fluctuations and typically ignores governor response although a simplistic governor was added for the MRO effort. The equivalent inertia approach is an excellent way to capture the "big picture" and for doing rapid prototyping.

5.2.2.1 Dynamic Modeling Of Frequency Decay

The references listed in section 4.3 discuss the equivalent inertia modeling approach in some detail. The Task Force recommends the reader review the appendix of the GE document GET-6449, "Load Shedding, Load Restoration, and Generator Protection Using Solid-state and Electromechanical Underfrequency Relays". This document can be downloaded from General Electric's website.

5.2.2.2 Calculating the Equivalent Inertia

The "equivalent inertia" dynamic model is based upon a single machine which represents the total MW•sec contributed by all rotating units as an equivalent inertia constant on "Pgen base":

$H_{equivalent}$=sum (MW•sec)/sum (Pgen)

5.2.2.3 Introduced Modeling Approximations

This model introduces some approximations which the user needs to be aware of.

5.2.2.3.1 Average Frequency

By creating a single bus equivalent the machine to machine oscillations that would be seen in reality are eliminated. The result is a model which predicts the average frequency across the system. In reality, the frequency at two locations may vary by .2 Hz or more as the frequency rings down. Due to these superimposed machine to machine oscillations, the minimum transient frequencies at some locations could be lower than what are being predicted with this simple model. This has some implications for generation protection coordination.

5.2.2.3.2 Constant Voltage

The equivalent model holds voltage constant during the simulation. This is the idealized case, and is obviously not what would be seen during a system underfrequency event. The design goal is to keep voltages fairly constant as load is shed by requiring capacitors to be tripped with load, or by requiring utilities to take other measures to keep voltages reasonable. In this instance, the constant voltage assumption is reasonable.

5.2.2.3.3 Assumption of Constant Turbine Power

This model assumes that turbine power will not decrease as frequency drops. This is not the case with at least some of the Combustion Turbines (CT's), where power output drops as frequency drops (by at least a 5% drop for a 5% decrease in frequency as best case, with larger drops expected in many cases).

5.2.2.3.4 Governor

The "equivalent inertia" modeling approach typically ignores governor action as little if any governor action will occur during the initial fast frequency decline. However, a generic governor model (the IEESGO model in the PSS/e program) was added towards the end of the study to explore sensitivities. The model data is shown below:

Governor Parameters	Values
droop	0.05 to .12*
t1	0.12
t2	0
t3	0.2
t4	0.25
t5	7
t6	0.3
k2	0.71
k3	0.425
pmax	1.5**
pmin	0.5**

* adjusted as appropriate to our needs

**these limits are on the governor part of the model, and were set as needed

This data represents the median values of a screened set of stability data where very fast and very slow models were excluded. The resulting model is quite similar in response to one that was created to match up with data collected in WECC for a trip of the Colstrip unit. (Similar historical data for the MAPP region was unavailable.) The above data provides a damped response over the 2 to 15 second time frame where governor action would be expected to occur and appears to be a reasonable model to represent a "typical" response of a reasonably responsive steam unit. It models what an ideal governor is expected to do. This model helped to bracket the range of expected system responses with no governor being the worst case, and a responsive governor the best case. Actual system response is expected to be in between these extremes.

The industry is just becoming aware that frequency response is not as simple as assumed in the past. One NERC region, WECC, developed a new turbine/governor model which empirically captures some of the factors which limit the desired frequency response. There are several factors. Some units are base loaded and cannot increase output further. Some units have governors blocked. Integrated turbine/boiler controls, which are often proprietary and poorly understood, can override governor action. CT's are thermally limited, and the net response to a frequency decline is a significant decrease in power which is related to this thermal constraint. In addition, power/load controllers can return units to the original setpoint. These "return to setpoint" controls may be fast or slow.

After review, the Task Force concluded the net unit response to overfrequency is likely to be more predictable than the response to underfrequency.

6. How do the existing MAPP and MAIN UFLS programs behave?

Both MAPP and MAIN presently have programs which shed 10% of connected load at 59.3 Hz, 59.0 Hz, and 58.7 Hz. In this regard, both will behave in a similar manner.

6.1 Known problems

The obvious deficiencies of the existing MAPP program are:

- the lack of a generation protection standard which coordinates with load shedding
- the fact that the MAPP program allows excessive load shedding delays
- the MAPP program allows use of slow responding electromechanical relays (which have operating times which are a function of the rate of change of frequency).

These aspects of the existing program are easily corrected by setting appropriate requirements.

The analysis proceeded with the assumption that relaying will have to be the high speed type which operates in 6 cycles. The Task Force then focused on the total amount of load being shed, the size of the load shedding blocks, and the associated frequency setpoints.

6.2 Is 30% Load Shedding Adequate?

The Task Force concludes that shedding a total of 30% of connected load is appropriate for the majority of the MRO footprint.

6.3 Are Load Blocks the Correct Size?

The next question is whether or not the program should shed load in three blocks or with more than three blocks.

Assume the objective is to cover 30% loss of generation with 3 blocks of load shedding. In that case, the Task Force probably would have chosen the same block sizes and setpoints as used by MAIN and MAPP, as overall UFLS relay coordination is achieved and minimum frequencies are acceptable.

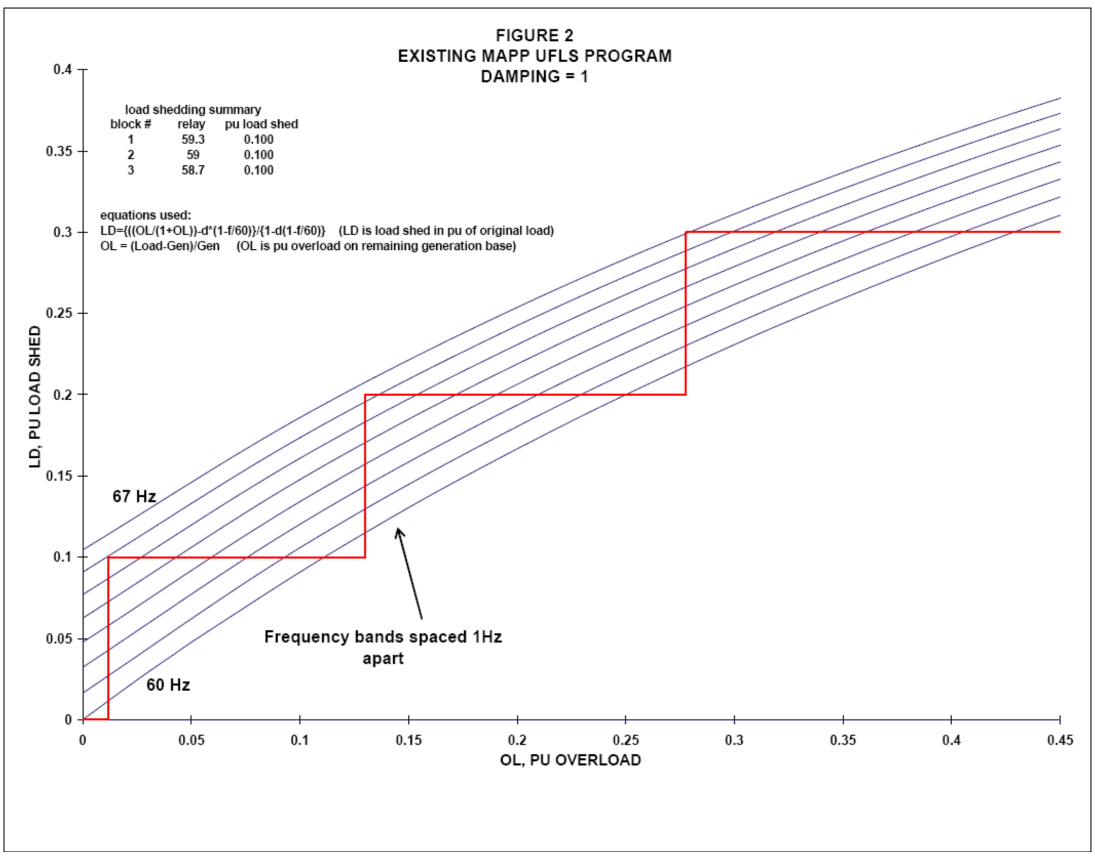
However, there are always tradeoffs involved, and the Task Force concludes it is preferable to trip load in smaller increments than 10% to minimize the exposure to overfrequency related problems, which is why the Task Force is recommending that MRO adopt a new program which covers the 30% load shedding requirement by shedding 5 blocks of 6% load.

The tradeoff is that use of smaller blocks to limit overfrequency comes at the expense of making the load shedding program slower to respond and minimum transient frequencies tend to be somewhat lower.

6.4 Overfrequency Problems

There is a subset of conditions where too much load is shed and the resulting overfrequency condition is of concern. The simple fact is that potential overspeed problems get worse as block size is increased.

To illustrate let's ignore governor action and look at the final frequencies obtained for different combinations of initial overload and actual load shed. This is shown by Figure 2.



At some overload level the frequency drops low enough to reach a setpoint where a 10% load block is shed. This block then covers the next range of overloads until another setpoint is reached and another block is tripped. By inspection, at the point where a block trips, only 2% more load would have had to be shed to get back to 60 Hz. This means about 8% too much load is shed at this point and frequency could reach approximately 66 to 67 Hz without governor action.

Figure 3 shows the same problem from the perspective of a time step simulation to approximately a .27 pu overload (the point where the 3rd block trips). This example is based on a system based inertia constant (H) of 6 MW•sec/Pgen and a load damping coefficient (d) of 1. The governor was ignored.

Figure 3

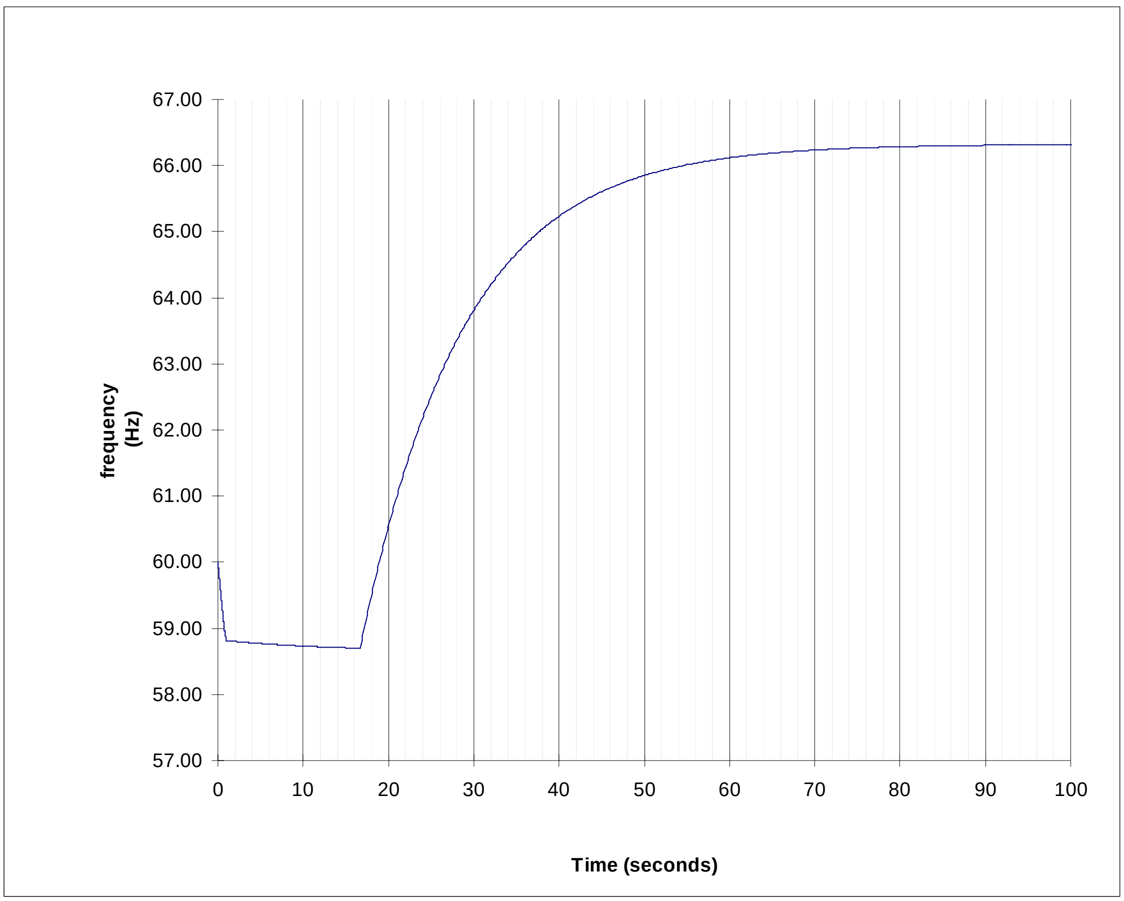
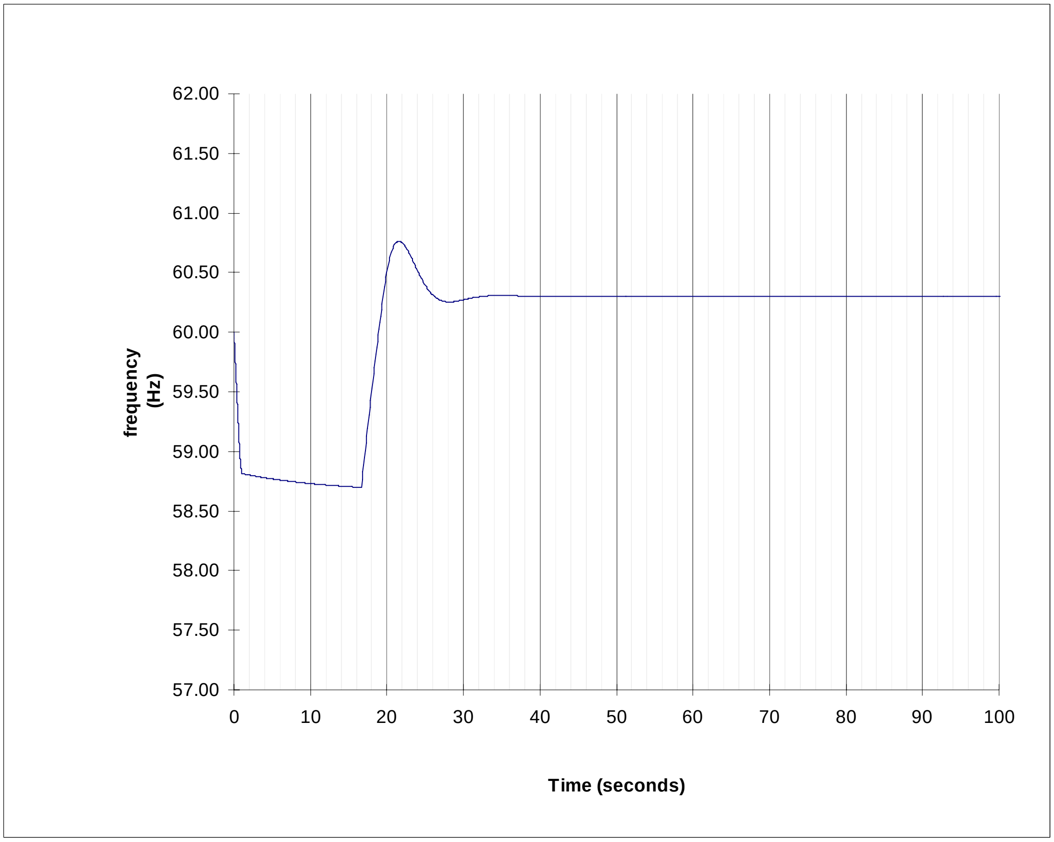


Figure 4 shows a similar time step simulation using the same overload and modeling assumptions except a responsive governor was allowed to respond to just the overfrequency event.

Figure 4



The "generic governor" results (based on 5% droop) show there is a good chance that governor action will limit overfrequency to reasonable levels, but actual results may fall between the extremes of figures 3 and 4.

Review indicates there is some uncertainty concerning the actual unit response to overfrequency. One complication is that the imbalance may be large enough to trigger load rejection controls, or to cause problems in plants due to the sudden decrease in steam flow through turbines, etc. Another complication is that load controllers may eventually override the governor action and return power to original setpoints. It is expected that such devices, if used, will engage after a 30 second or longer delay. Because of this, final conditions with and without governor action are being considered.

The Task Force only evaluated a generic governor which mimics an ideal governor for a fairly responsive steam unit. The reality is that a wide range of different net governor response is likely to be achieved depending on the composition of on-line generation.

The key point is that overfrequency can jeopardize units, as loss of generation at this point will cycle the system back into underfrequency.

The magnitude of governor response obtained from the "generic model" with 5% droop is shown below. Turbine power is the Y axis and time is the X axis.

Figure 5

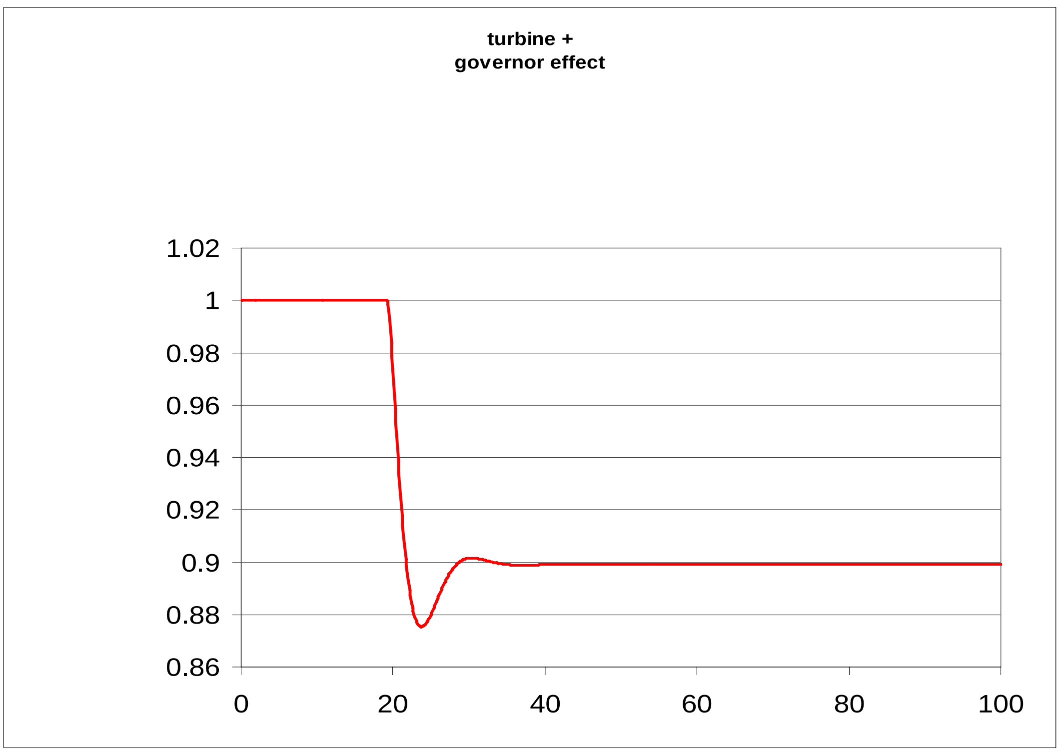


Figure 5 shows governor action causes Pgen to drop to 90% of initial values. This would be expected within about 15 seconds. The Task Force urges the reader to think in generalities and focus on basic trends. Actual governor action may be faster or slower than the above "typical" data.

Obviously, it will be hard on steam units if governor action is too drastic and closes off too much steam for too long. Safeties may lift and fail to reseat, or plants may develop other internal plant problems which may affect the ability of the unit to stay on line. It is hard to quantify what is "too much". The Task Force believes that sudden power reductions of up to 3% of rated capacity are not going to be a problem, while sudden reductions of 8% of rated capacity can lead to internal plant problems, like lifting of safeties on steam units. In between is the gray area.

To further complicate matters, the total change in Figure 5 represents a change in power referenced to the initial Pgen level. During off peak conditions many units may be spinning which are partially loaded. In that instance, the above 10% reduction of Pgen might only represent 5% reduction on a machine rating basis, assuming all units are responsive. That should be much easier on individual units. During peak load conditions, the remaining units may be fully loaded, and then the 10% reduction in Pgen would be closer to a 10% reduction on a rated capacity basis.

If some units are not responsive at all, then the remaining units will have to respond even harder.

If the governor also responds to underfrequency, then load shedding blocks tend to pick up at slightly higher overloads, similar to shifting the stair step characteristic of Figure 2 slightly to the right. It's hard to quantify this effect and in reality it may not be too noticeable. The observations are based on very optimistic conditions where the governor is only limited by the droop characteristic. This effect also moderates the overfrequency problem to some degree as the final load level will be closer to the initial (pre governor) generation output.

Higher load damping will also reduce the actual frequency deviations for a given imbalance. Using the best case damping assumption, d=2, gives a characteristic similar to Figure 2 except it shows the expected maximum frequency would be around 62.8 Hz.

6.5 Coordination of UFLS with Generation Protection Requirements

Unit trip settings within the MRO footprint vary widely as MAPP did not have a generator underfrequency tripping time delay standard. It is unlikely that there is coordination with load shedding. The MRO program addressed this by providing a proposed standard which coordinates with load shedding.

6.6 Further Examination of the Existing Program

This section further quantifies the performance of the existing program as evaluated using the “equivalent inertia” approach.

First the governor is ignored. Next, a governor which only responds to overfrequency is included, and finally an “ideal, fully responsive” governor is added. Case runs use a governor droop of 5% where the primary interest is the overfrequency response and a governor droop of 12% where the primarily interest is the underfrequency response. The higher droop is in anticipation that many units will be fully loaded and unresponsive to underfrequency. (This modeling approach explains the minor differences in the overfrequency governor response between Figures 7 and 9.)

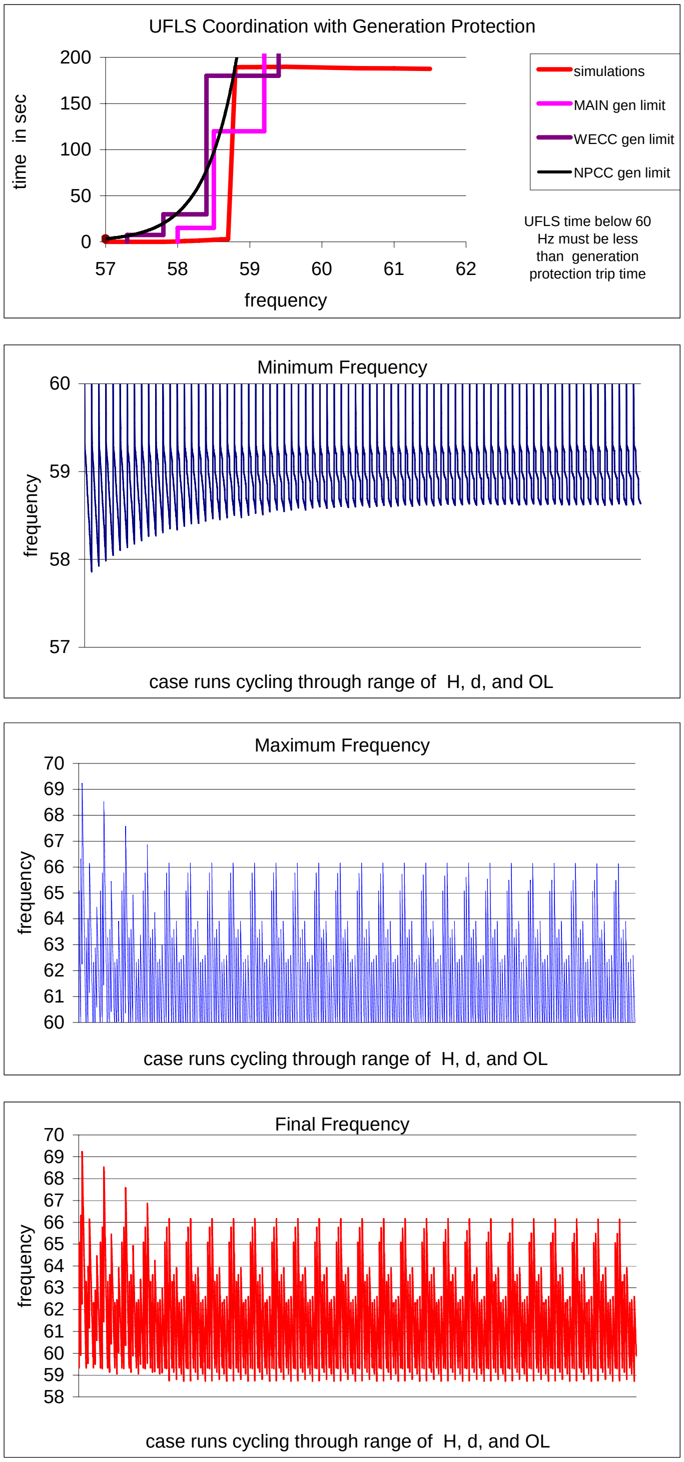
By examining the time step simulation of Figure 4, it can be seen that three data points describe the basic performance of a time step simulation: the minimum transient frequency, the maximum transient frequency, and the final frequency. With a sufficient number of runs, the envelope of expected performance under all conditions considered in the “band width” analysis can be shown on a set of simple summary plots.

The following plot sets present this type of overview information. These plots also show the extent to which generation protection can be coordinated by showing the worst case times spent at or below frequencies in the range from 57.0 Hz to 59.5 Hz (in 0.1 Hz increments). The plots also show the worst case times spent at or above frequencies in the range from 60.5 Hz to 61.5 Hz (in 0.5 Hz increments). Data was not compiled for the continuous overating range of 59.5 Hz to 60.5 Hz, and times shown in this band have no significance and are an artifact from interpolation.

The plots are based on 3041 case runs per set, which cycle through a range of overloads (0 to 30% loss of generation), a range of load damping (1, 1.5, and 2), and a range of system base inertia (2.5 to 15 in 0.5 steps). The range of system inertia considered extends beyond the calculated “typical” range. Today it is unlikely to achieve an H (inertia) value below 3 or 3.5 (this is calculated on system base and defined as total MW•sec of spinning units divided by the total Pgen). On the upper end, an inertia constant of 10 or higher could be reached, but perhaps not all the way to 15.

To interpret the minimum, maximum, and final frequency plots, note that low inertia results are to the far left, and the high inertia results are to the far right. For each discrete inertia level there are three sets of runs with different damping levels: to the left are results for damping = 1, damping of 1.5 is in the center, and damping of 2.0 is to the right. For each damping level a range of overloads is run from no loss of generation to 30% loss of generation (again left to right for increasing values).

Figure 6, existing MAPP Program of 3 blocks of 10% assuming no governor action



Load Shed

block 1: 0.1 at 59.3 Hz with 6 cy delay
block 2: 0.1 at 59 Hz with 6 cy delay
block 3: 0.1 at 58.7 Hz with 6 cy delay

Min Frequency
57.86

Maximum Frequency
69.24

Maximum Final Frequency
69.24

Minimum Final Frequency
58.72

min d
1.00

max d
2.00

d increment
0.50

min system base H
2.50

max system base H
15.00

H increment
0.50

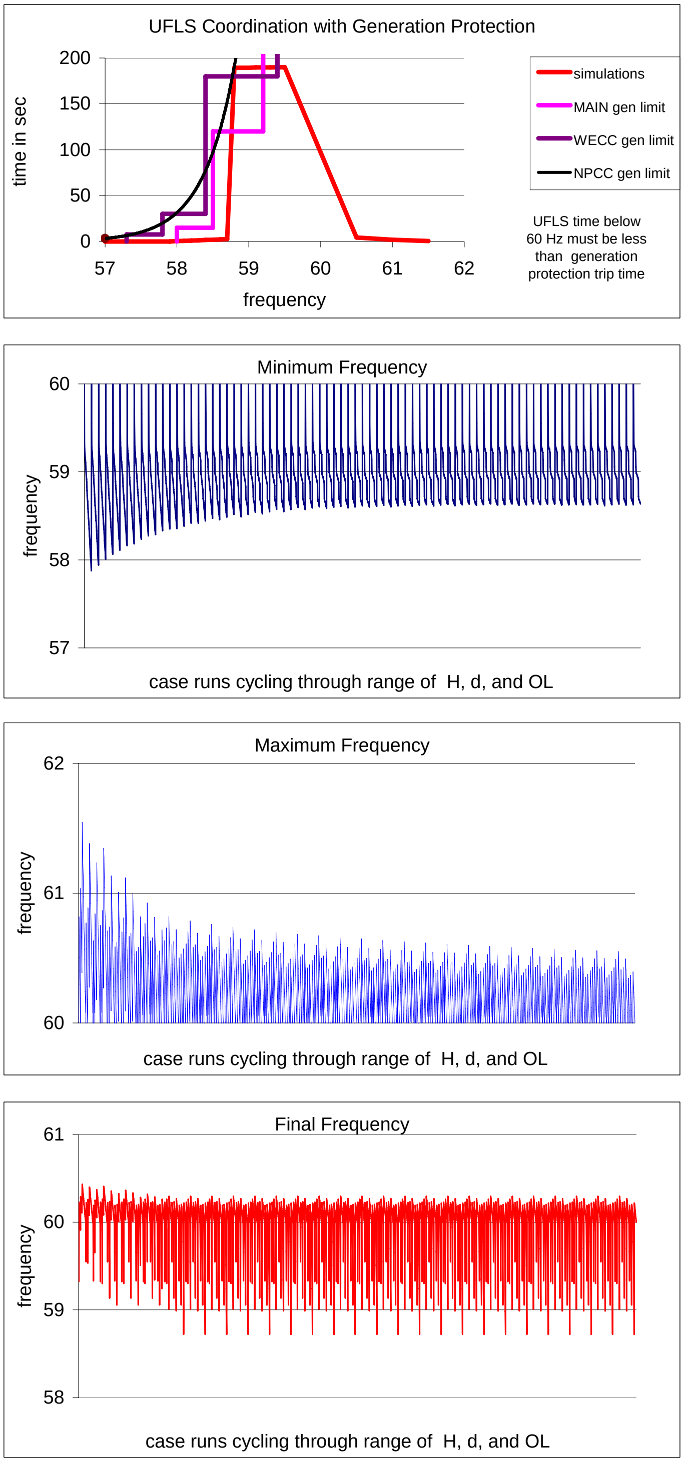
Comments

This is the performance of the existing MAPP UFLS program assuming high speed relaying is used to trip load (6 cycle detection time assumed) and assuming we do not get any governor response

As can be seen, with this condition we do not achieve any coordination with typical generation protection settings (WECC, MAIN, and NCPP used as proxies of typical settings)

The minimum transient frequency is fairly good.
The maximum transient frequency is quite high.

Figure 7, Existing MAPP program with governor only responding to overfrequency



Load Shed

block 1: 0.1 at 59.3 Hz with 6 cy delay
block 2: 0.1 at 59 Hz with 6 cy delay
block 3: 0.1 at 58.7 Hz with 6 cy delay

Min Frequency
57.88

Maximum Frequency
61.55

Maximum Final Frequency
60.43

Minimum Final Frequency
58.72

min d
1.00

max d
2.00

d increment
0.50

min system base H
2.50

max system base H
15.00

H increment
0.50

Comments

Existing MAPP program with governor responding to overfrequency only

Governor action:
in about 25% of runs, final power was reduced by at least 7%

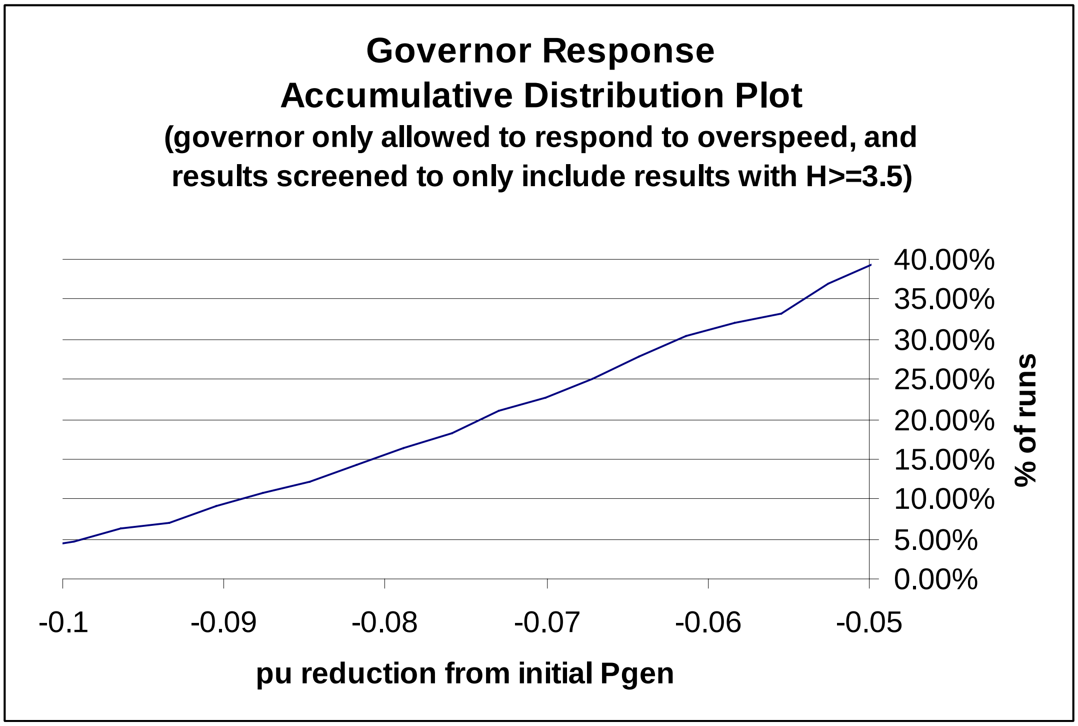
in about 15% of runs, final power was reduced by at least 8%

in about 10% of runs, final power was reduced by at least 9%

maximum reduction was about 18% (at very low H)

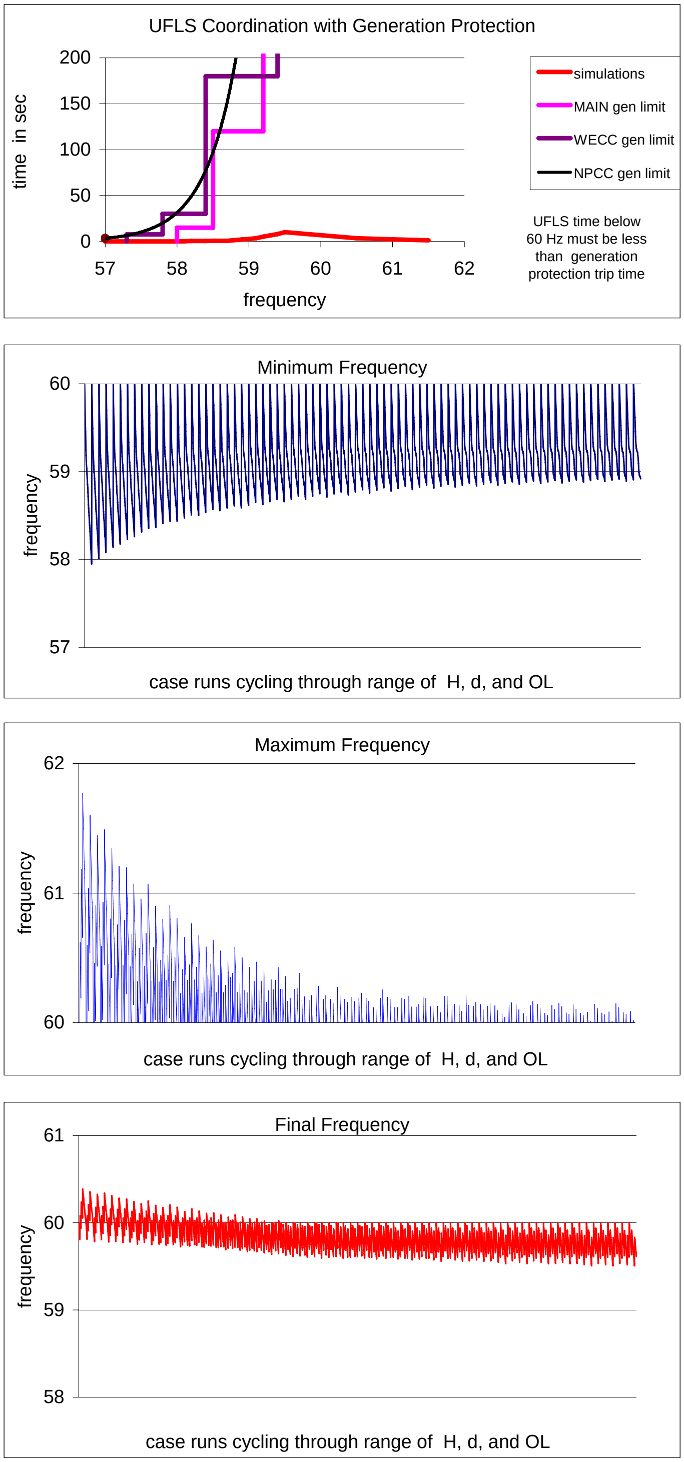
The amount of power reduction from the governor was a maximum of 18% for the very low inertia condition (H=2.5) where frequency drops so quickly that coordination is lost between load shedding stages. The Task Force only evaluated such low levels of inertia as an extrapolation of existing trends showing inertia has been decreasing. A more realistic minimum H for the existing system might be 3.5. The governor results were screened to exclude runs with inertia lower than 3.5 and obtained the following histogram.

Figure 8



The next set of runs allows the governor to be active in both directions. Limits for the final power change were left wide open (limits of 1.5 to .5 pu). Realistic factors that limit unit response, like the energy in the boiler and the boiler firing dynamics, are being ignored (although droop was increased to compensate for some units being completely unresponsive). However, these same limiting factors are also ignored in typical stability models where units are often allowed to move freely under governor control from Pgen to Pmax or Pmin. Consider this set of case work as an example of 2 things: 1) that a governor which is very responsive to frequency declines reduces the tendency to overshed, and 2) that simple models ignore some significant factors and tend to give overly optimistic results (this even applies to the full transient stability programs).

Figure 9, Existing MAPP program with fully responsive "ideal" governor



Load Shed

block 1: 0.1 at 59.3 Hz with 6 cy delay
block 2: 0.1 at 59 Hz with 6 cy delay
block 3: 0.1 at 58.7 Hz with 6 cy delay

Min Frequency
57.95

Maximum Frequency
61.77

Maximum Final Frequency
60.39

Minimum Final Frequency
59.51

min d
1.00

max d
2.00

d increment
0.50

min system base H
2.50

max system base H
15.00

H increment
0.50

Comments

Existing MAPP program
with fully responsive governor

All factors which may limit governor power increases have been ignored, so consider this as representing an idealized case, and also unrealistic. It serves as an example, and shows how strong governor response on underfrequency can also limit overfrequency, especially when the system inertia (H) is higher.

In this example, the maximum governor action increased power by about 16% and decreased power by 9% in case runs were inertia was 3.5 or higher

Figure 10

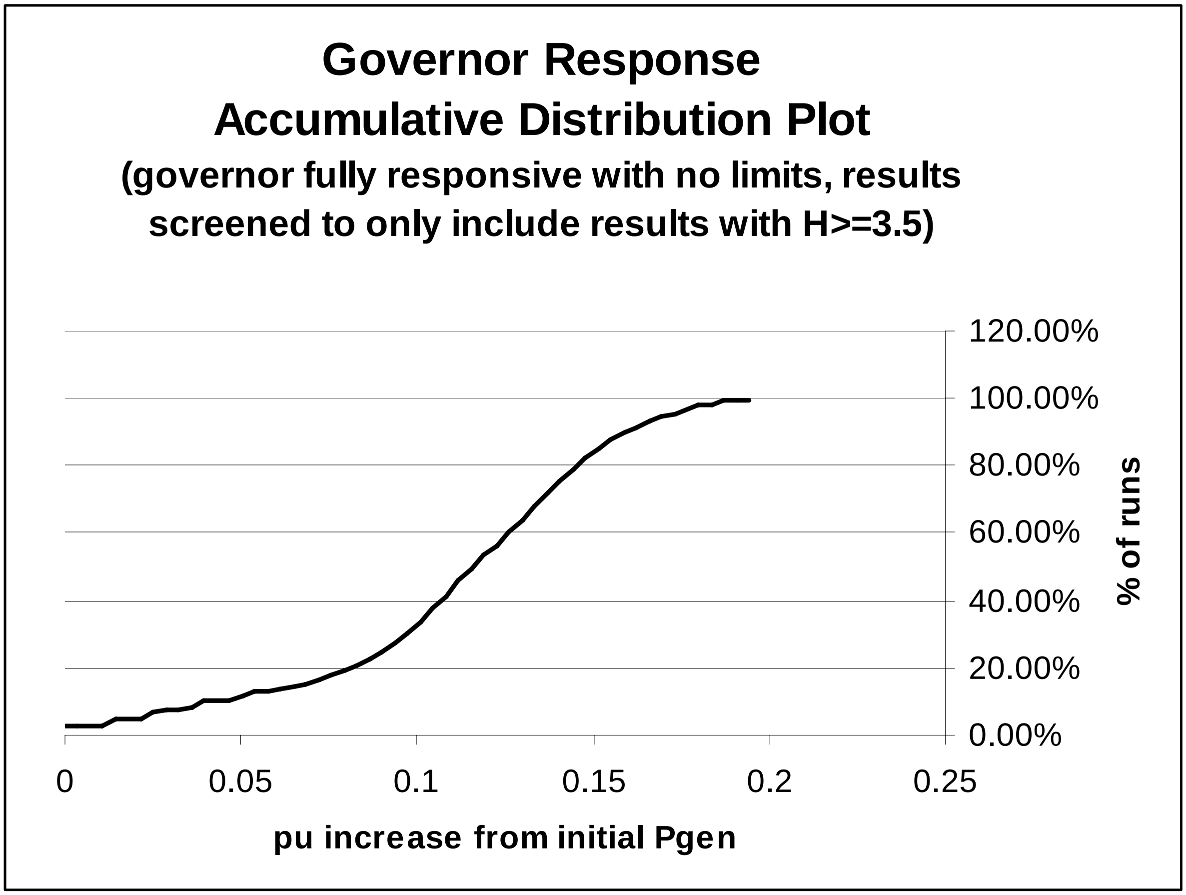


Figure 10 gives a better idea of the type of power increase that was required to give the results shown in Figure 9. About 70% of the runs show increases of 10% or more, which is quite unrealistic.

Figure 11

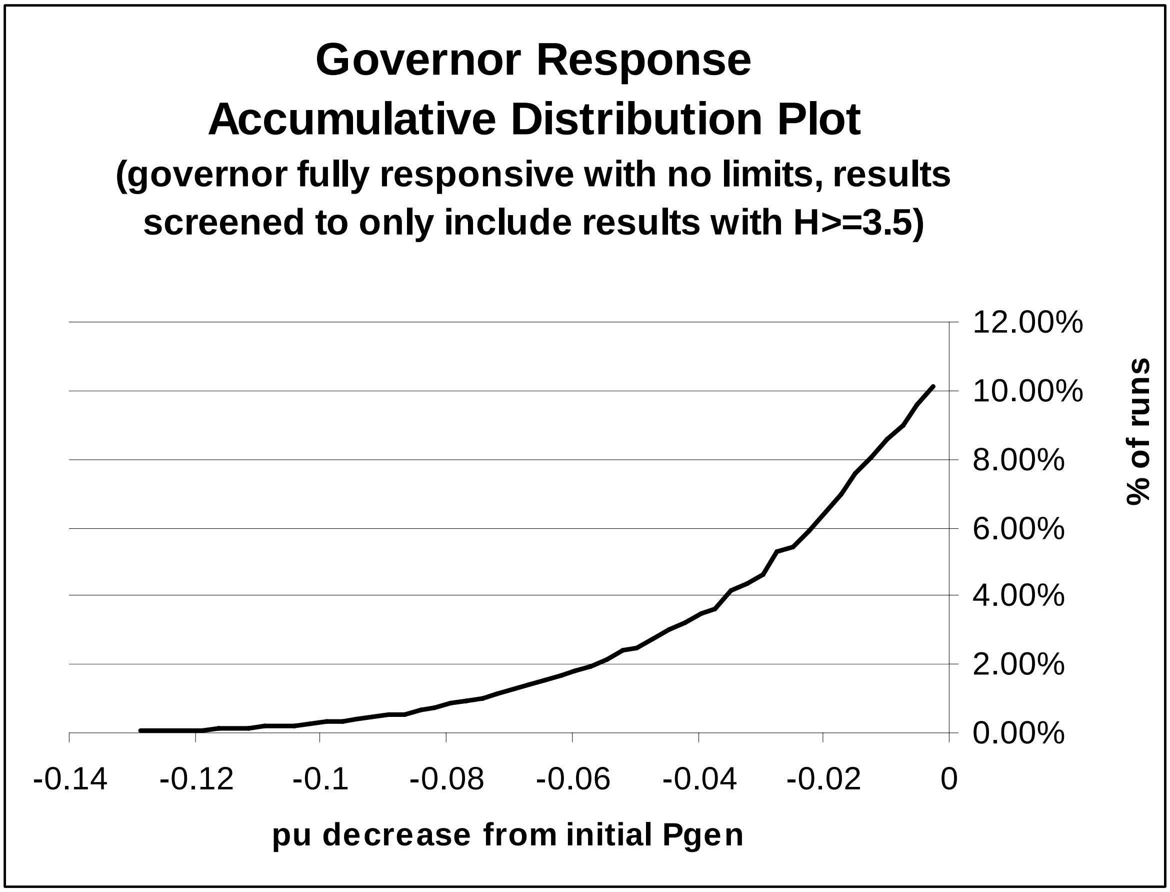


Figure 11 shows overfrequency related power decreases caused by the governor. Compared to Figure 8, governor response to underfrequency also moderated the overfrequency problems. This work indicates a trend, but is an exaggerated example due to the large and quick increase in power that was observed in response to underfrequency.

Several other runs were made with various arbitrary governor limits imposed. The results were between the extremes presented, and once limits were hit the overall turbine/governor model suddenly became quite slow to respond.

7. The Proposed MRO UFLS Program

The consensus of the Task Force is that governor action can be counted on to limit overspeed, as long as extreme action is not required which may place units at risk.

The Task Force also concludes that the net system governor/unit response to underfrequency cannot always be counted on (or predicted) for the reasons discussed in Section 4.1.2.

In consideration of these factors, The Task Force adopted the following strategy to develop this program:

1. To minimize potential overfrequency problems, the number of high speed load shedding blocks was increased, and the size of each block was decreased accordingly to meet the target load shedding level of 30%.

2. Two small blocks of load shed on delay were added to force frequency recovery even when governor response to underfrequency is minor or nonexistent.

3. The analysis assumed no governor action and at this point the setpoints of both the high speed blocks and the delay blocks were tuned to get the quickest frequency recovery possible subject to relay coordination constraints and issues.

4. A range of inertia was considered which extends beyond what is presently expected to assess the implications. (H was considered as low as 2.5, but a realistic minimum would be 3.5.)

5. The proposed generation underfrequency tripping minimum time delay standard was developed by reviewing the amount of time spent below 59.5 Hz in the no governor simulations.

6. Governor response to overfrequency was added to show how much governor action would be expected. This was quantified as a % change from initial Pgen to give a level of comfort that it is not going to require drastic action to limit overfrequency.

7. Governors were allowed to respond in both directions to see how this affects final results. In this instance, droop was changed from 5% to 12%, since it was a more appropriate value for modeling the underfrequency response, even though 5% droop might be more appropriate for the overfrequency response. (12% is what WECC presently sees.)

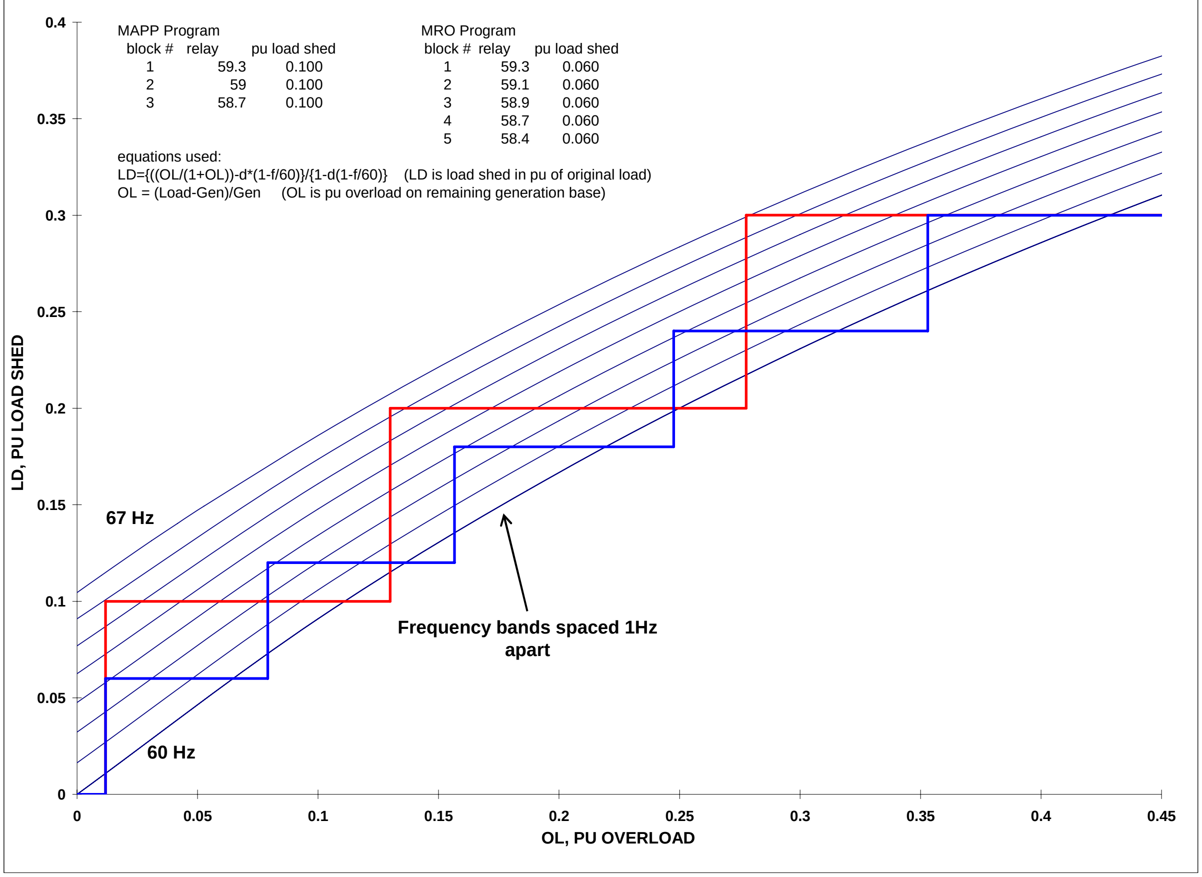
The following summaries present the Task Force's findings in the above sequence.

7.1 Choice of Block Sizes

7.1.1 High Speed Load Shedding Blocks

Figure 12 provides one form of comparison between the proposed MRO program and the existing MAPP program. The proposed MRO program covers the same range of loss of generation, but uses 5 blocks of 6% load, which dramatically decreases the potential for overfrequency problems.

FIGURE 12
COMPARISON OF EXISTING MAPP PROGRAM TO PROPOSED MRO PROGRAM
DAMPING = 1



7.1.2 Load Blocks Shed on Delay

In addition to the high speed load shedding blocks shown above, the Task Force is proposing two blocks of load shed on delay which trip 2% load each. These load blocks can be treated as separate blocks, or included as subsets of block 5 by implementing the appropriate dual tripping logic.

The 2% size was a best fit to what is needed to force final frequency to 59.5 Hz or higher in the runs with no governor action. One block covers frequencies below 59.5 Hz, and the other covers frequencies below the trip setting of the fourth load shedding block, which is 58.7 Hz.

The delay blocks ensure frequency is promptly driven back towards 60 Hz even if there is only a minor net generation increase in response to the frequency decline.

These delay blocks represent an extra measure being taken to ensure the proposed generation protection time delay can be met.

7.2 Performance of Proposed Program

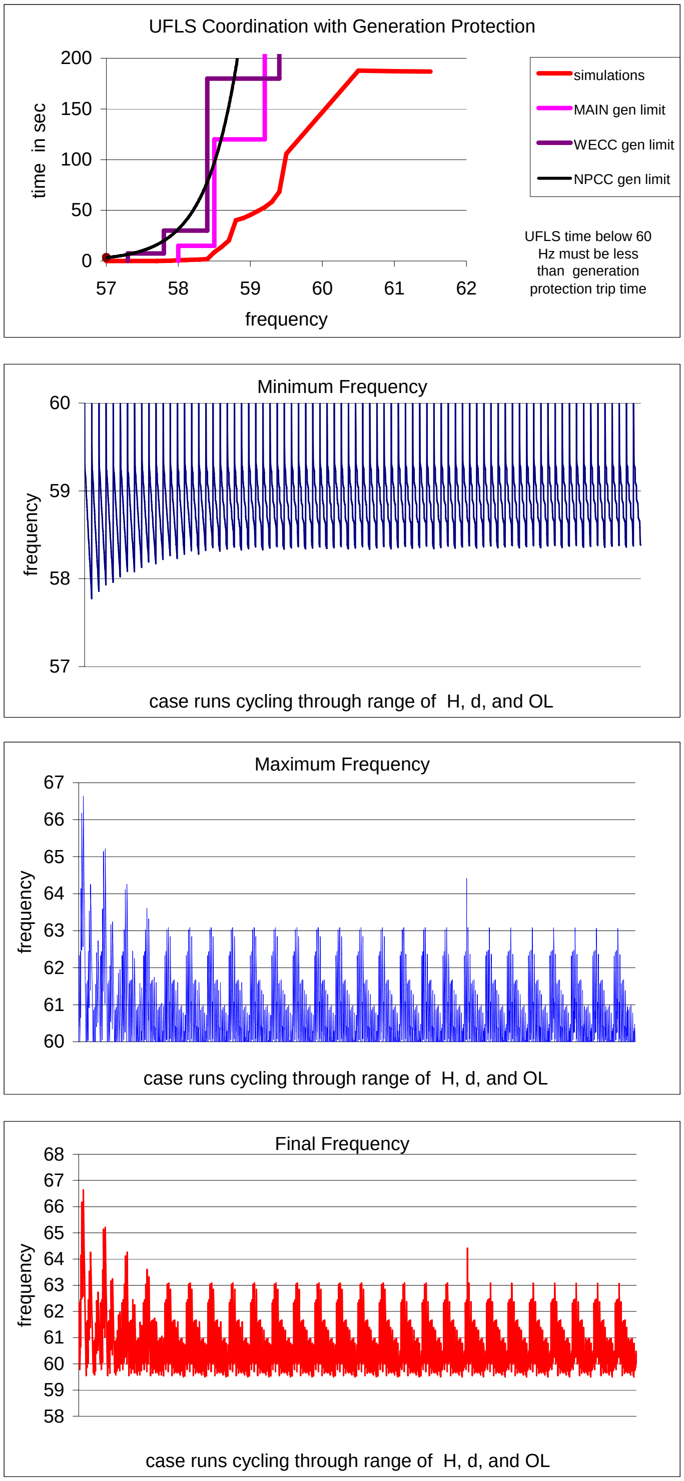
The Task Force recommends that delay blocks be implemented as a subset of block 5 by use of the appropriate dual logic (the newer computer based relaying packages include underfrequency load shedding with multiple setpoints and delays).

This enhances overall coordination, minimizes the occurrence of overshedding and requires less load to be included in the UFLS program.

If desired, utilities can implement these delay blocks as separate load blocks. By doing so, some relay coordination is lost but this was judged to be a minor issue as the amount of extra load tripped is small. To demonstrate, the remaining results are presented with the delay blocks first treated as a subset of block 5, and then as separate discrete load blocks.

7.3 Dynamic Response, No Governor

Figure 13, MRO program, no governor (with delay blocks as subset of block 5)



Load Shed

block 1: 0.06 at 59.3 Hz with 6 cy delay
block 2: 0.06 at 59.1 Hz with 6 cy delay
block 3: 0.06 at 58.9 Hz with 6 cy delay
block 4: 0.06 at 58.7 Hz with 6 cy delay
block 5: 0.06 at 58.4 Hz with 6 cy delay
delay block 1: 0.02 at 58.7 Hz with 500 cy delay
delay block 2: 0.02 at 59.5 Hz with 2400 cy delay

Min Frequency
57.77

Maximum Frequency
66.63

Maximum Final Frequency
66.63

Minimum Final Frequency
59.51

min d
1.00

max d
2.00

d increment
0.50

min system base H
2.50

max system base H
15.00

H increment
0.50

Comments

the two delay blocks are subsets of block 5 and if tripped before block 5 will reduce the size of block 5

If block 5 trips first, then the delay blocks were also removed

The delay block tripping delays were set as short as possible to get the quickest frequency recovery possible, subject to overall relay coordination. Coordination is fairly good, with one minor "spike" where overshedding occurs. This is considered an acceptable compromise.

Times spent at or below 58.5 Hz are uncomfortably close to tripping times allowed by the MAIN generation tripping time delay standard. The minimum transient frequency drops below 58.0 Hz, the point where the MAIN program allows actions such as instant tripping. The conclusions are the MRO generation tripping time delay proposed standard needs more time delay below 58.5 Hz than provided by the MAIN standard and the instant trip threshold should be lowered below the expected minimum frequency.

Figure 14, MRO program, no governor (separate delay blocks)

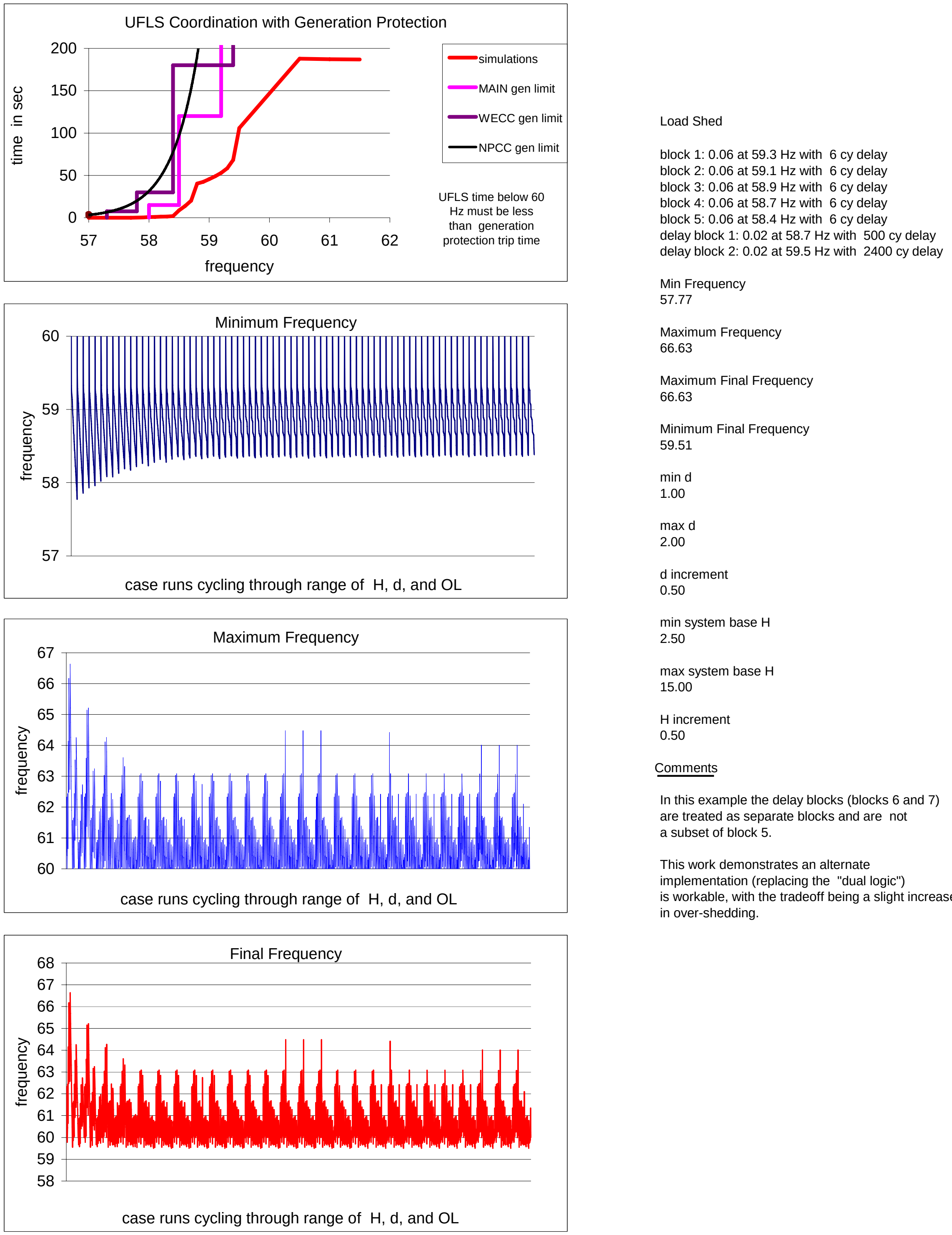
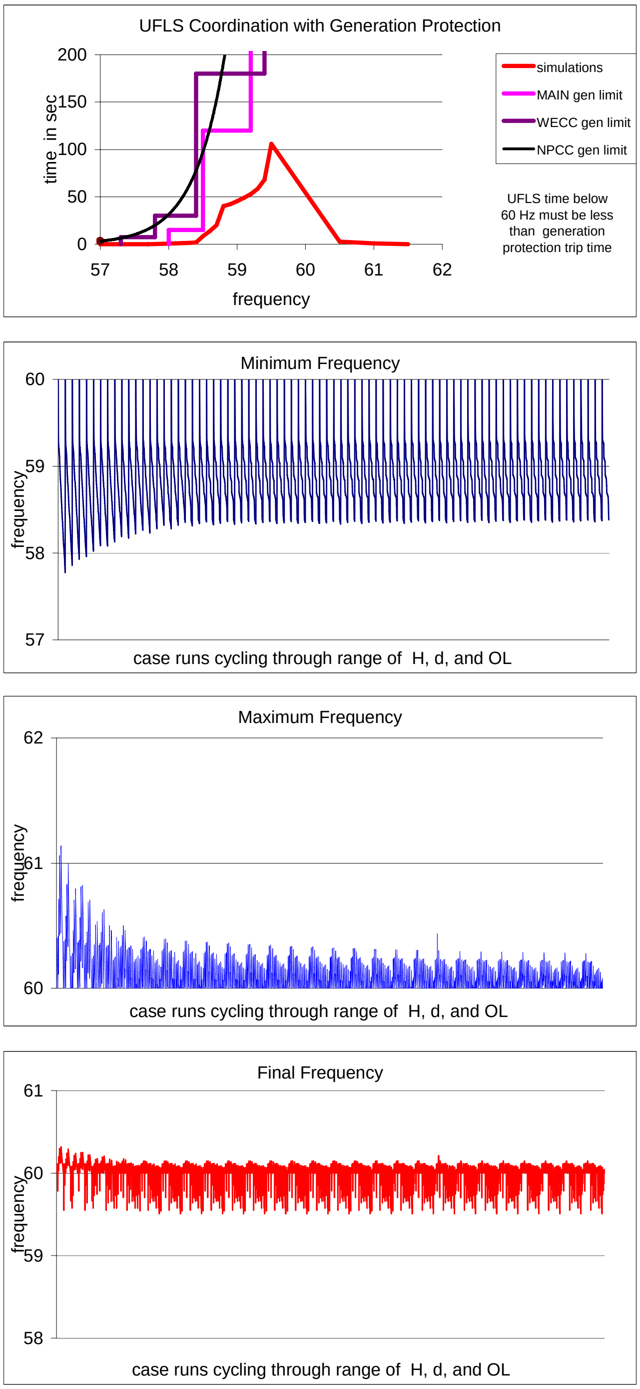


Figure 14 illustrates that relay coordination gets worse when the delay blocks are separate discrete blocks, but this is minor and quite manageable. Frequency recovery is as quick as in Figure 13.

7.4 Results with Governor Responsive to Overfrequency and 5% droop

Figure 15, MRO program, governor acts on overfrequency (delay blocks subset of block 5)



Load Shed

block 1: 0.06 at 59.3 Hz with 6 cy delay
block 2: 0.06 at 59.1 Hz with 6 cy delay
block 3: 0.06 at 58.9 Hz with 6 cy delay
block 4: 0.06 at 58.7 Hz with 6 cy delay
block 5: 0.06 at 58.4 Hz with 6 cy delay
delay block 1: 0.02 at 58.7 Hz with 500 cy delay
delay block 2: 0.02 at 59.5 Hz with 2400 cy delay

Min Frequency
57.77

Maximum Frequency
61.14

Maximum Final Frequency
60.32

Minimum Final Frequency
59.51

min d
1.00

max d
2.00

d increment
0.50

min system base H
2.50

max system base H
15.00

H increment
0.50

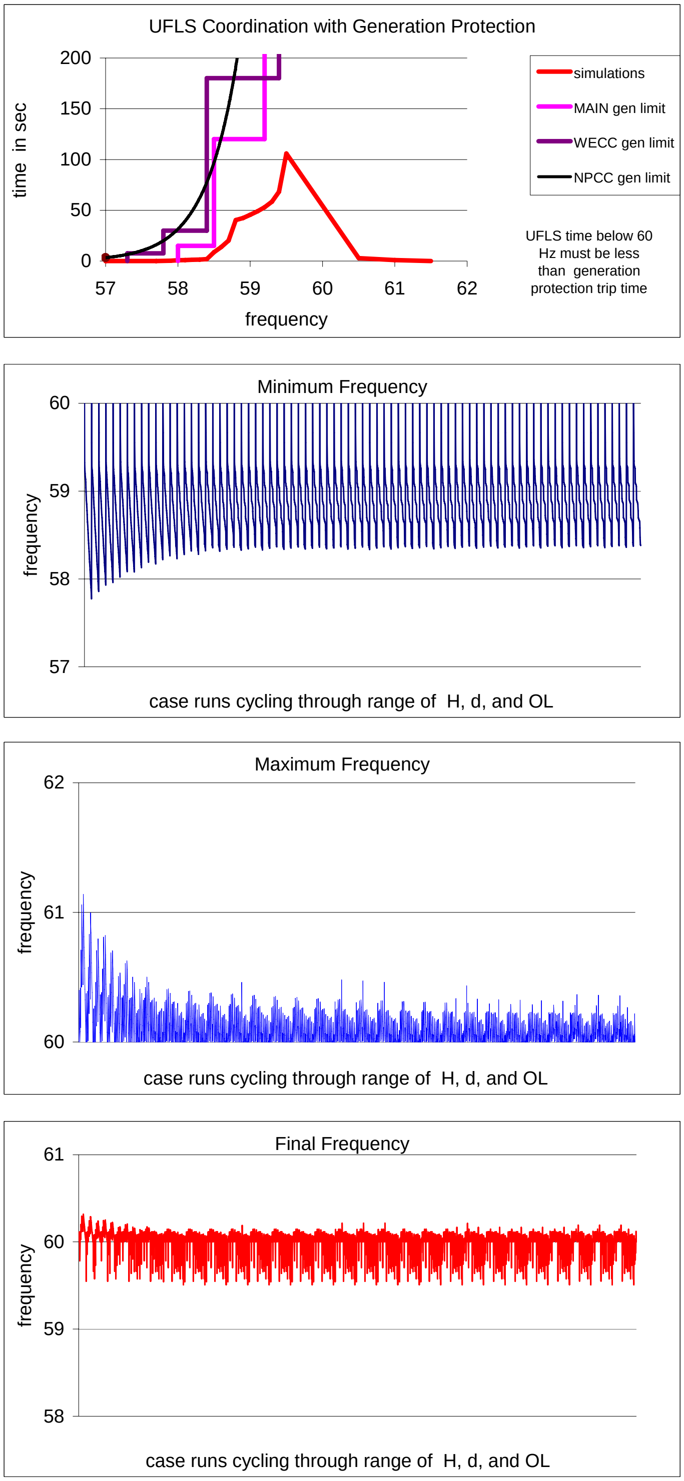
Comments

In this set of runs the governor is responsive to overfrequency, but unresponsive to underfrequency.

the two delay blocks are subsets of block 5 and if tripped before block 5 will reduce the size of block 5

If block 5 trips first, then the delay blocks were also removed

Figure 16, MRO program, governor acts on overfrequency (separate delay blocks)



Load Shed

block 1: 0.06 at 59.3 Hz with 6 cy delay
block 2: 0.06 at 59.1 Hz with 6 cy delay
block 3: 0.06 at 58.9 Hz with 6 cy delay
block 4: 0.06 at 58.7 Hz with 6 cy delay
block 5: 0.06 at 58.4 Hz with 6 cy delay
delay block 1: 0.02 at 58.7 Hz with 500 cy delay
delay block 2: 0.02 at 59.5 Hz with 2400 cy delay

Min Frequency
57.77

Maximum Frequency
61.14

Maximum Final Frequency
60.32

Minimum Final Frequency
59.51

min d
1.00

max d
2.00

d increment
0.50

min system base H
2.50

max system base H
15.00

H increment
0.50

Comments

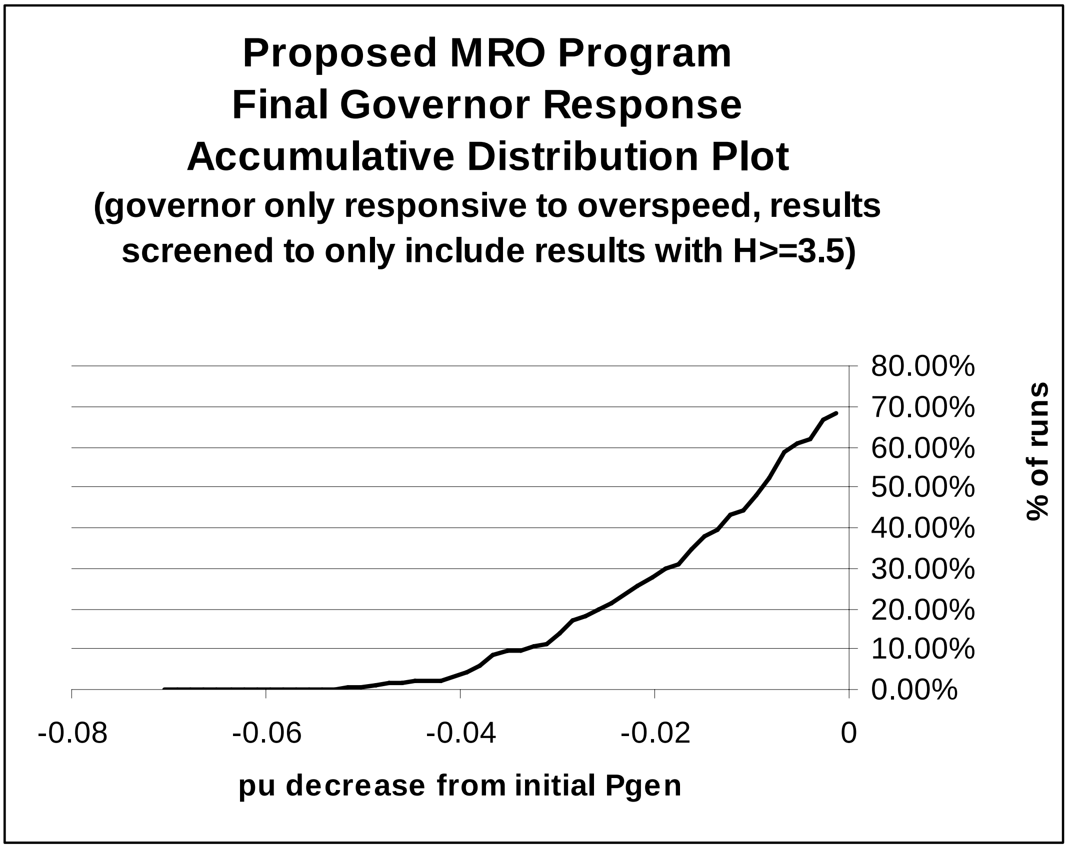
In this set of runs the governor is responsive to overfrequency, but unresponsive to underfrequency.

In this example the delay blocks (blocks 6 and 7) are treated as separate blocks and are not a subset of block 5.

This work demonstrates an alternate implementation (replacing the "dual logic") is workable, with the tradeoff being a slight increase in over-shedding, but this is not a problem.

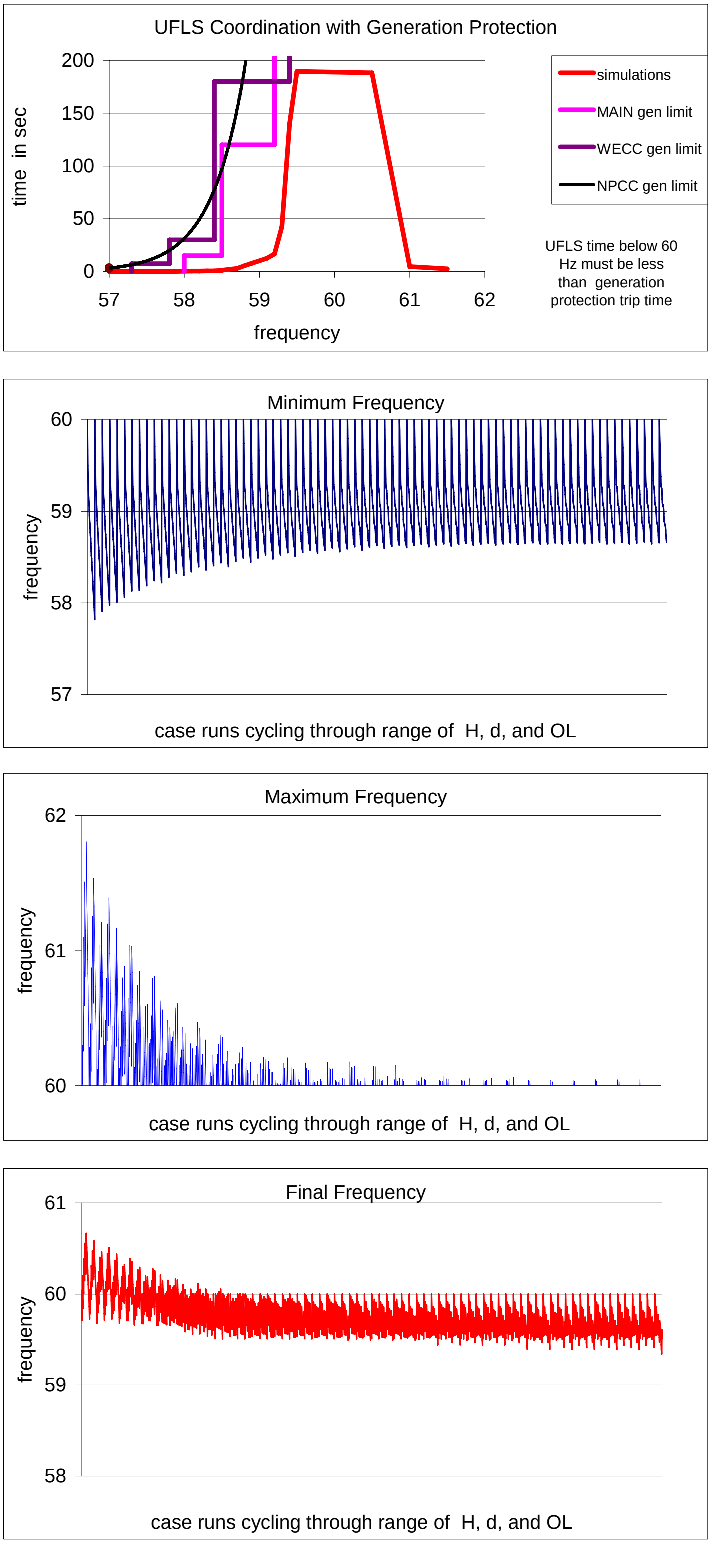
The maximum frequency and final frequency are sufficient and meet the desired targets (maximum frequency remains less than approximately 61.2-61.4 Hz and final frequencies remain in the range of 59.5 Hz to 60.5 Hz). Overall this works very well in both variations of the proposed plan and as shown in Figure 17, the required amount of governor action is reasonable.

Figure 17, Governor Response Accumulative Distribution Plot



7.5 Results with Fully Responsive Governor and 12% droop

Figure 18, MRO program, responsive "ideal" governor (delay blocks subset of block 5)



Load Shed

block 1: 0.06 at 59.3 Hz with 6 cy delay
block 2: 0.06 at 59.1 Hz with 6 cy delay
block 3: 0.06 at 58.9 Hz with 6 cy delay
block 4: 0.06 at 58.7 Hz with 6 cy delay
block 5: 0.06 at 58.4 Hz with 6 cy delay
delay block 1: 0.02 at 58.7 Hz with 500 cy delay
delay block 2: 0.02 at 59.5 Hz with 2400 cy delay

Min Frequency
57.82

Maximum Frequency
61.81

Maximum Final Frequency
60.67

Minimum Final Frequency
59.34

min d
1.00

max d
2.00

d increment
0.50

min system base H
2.50

max system base H
15.00

H increment
0.50

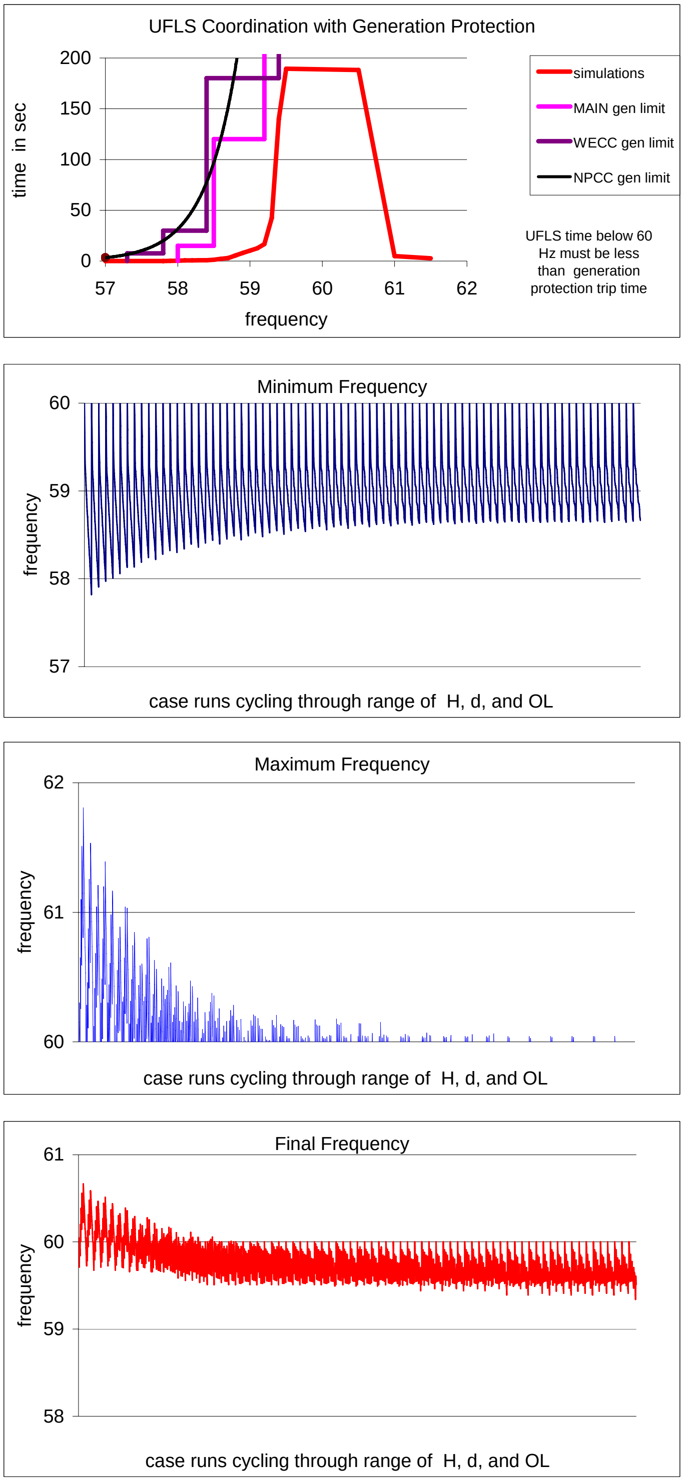
Comments

In this set of runs the governor is fully responsive to frequency changes. Limits were set at .5 to 1.2 pu and we used 12% droop. This gives an idealized governor which may be more responsive than what we would actually expect.

the two delay blocks are subsets of block 5 and if tripped before block 5 will reduce the size of block 5

If block 5 trips first, then the delay blocks were also removed

Figure 19, MRO program, responsive "ideal" governor (separate delay blocks)



Load Shed

block 1: 0.06 at 59.3 Hz with 6 cy delay
block 2: 0.06 at 59.1 Hz with 6 cy delay
block 3: 0.06 at 58.9 Hz with 6 cy delay
block 4: 0.06 at 58.7 Hz with 6 cy delay
block 5: 0.06 at 58.4 Hz with 6 cy delay
delay block 1: 0.02 at 58.7 Hz with 500 cy delay
delay block 2: 0.02 at 59.5 Hz with 2400 cy delay

Min Frequency
57.82

Maximum Frequency
61.81

Maximum Final Frequency
60.67

Minimum Final Frequency
59.34

min d
1.00

max d
2.00

d increment
0.50

min system base H
2.50

max system base H
15.00

H increment
0.50

Comments

In this set of runs the governor is fully responsive to frequency changes. Limits were set at .5 to 1.2 pu and we used 12% droop. This gives an idealized governor which may be more responsive than what we would actually expect.

In this example the delay blocks are treated as separate blocks and are not a subset of block 5.

This work demonstrates an alternate implementation (replacing the "dual logic") where delay blocks 1 and 2 are separate blocks shed on delay and are not a subset of block 5.

Figure 20

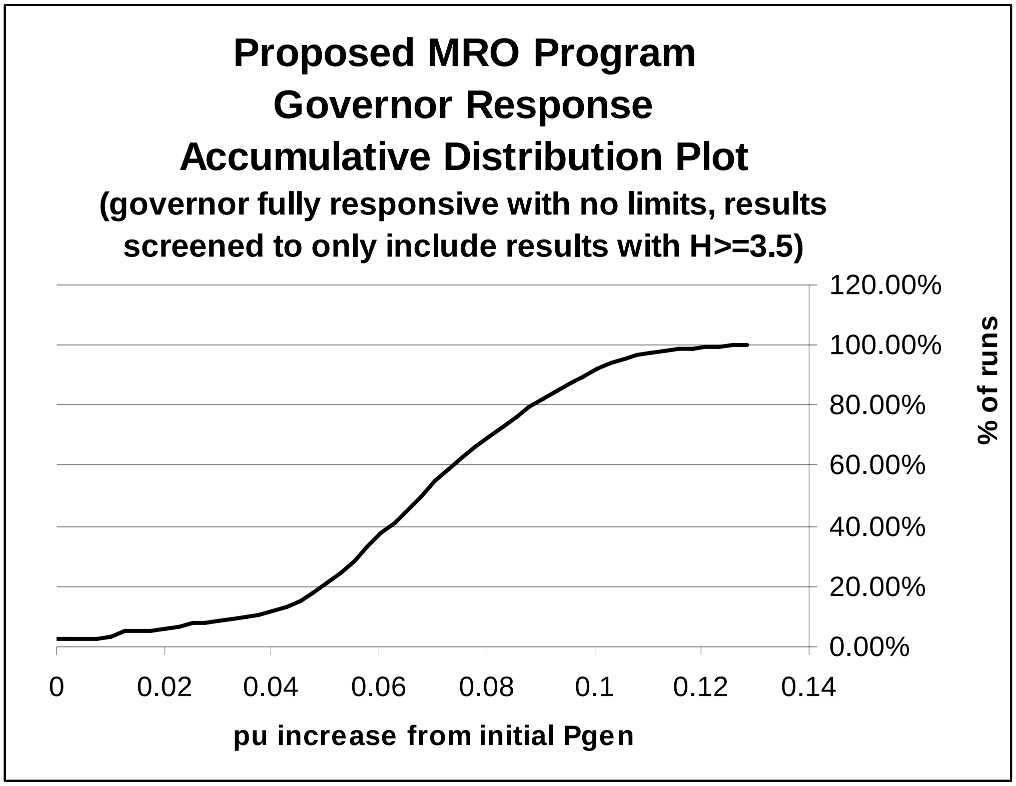
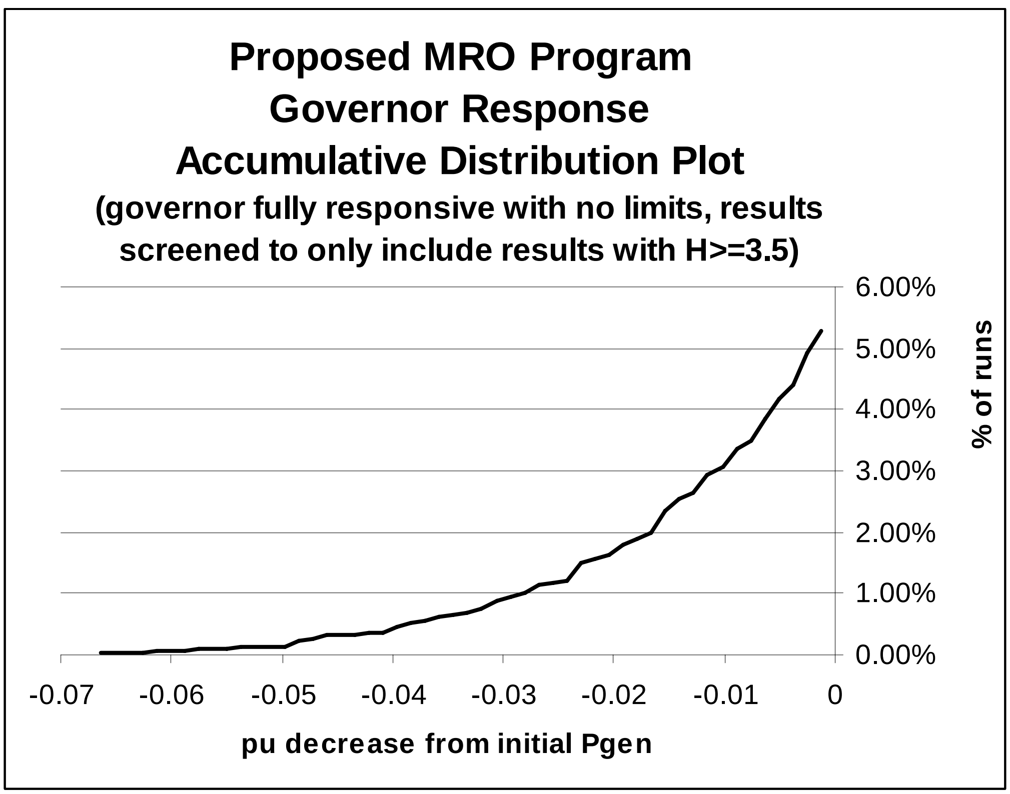


Figure 21



This "fully responsive governor" work brackets one end of a range of possible responses to underfrequency, and the actual governor response is expected to be somewhere between this response and no response. Although the observed effect is perhaps an exaggerated one, the Task Force felt this casework provides insight and is worth presenting. In these runs, the final frequencies drop as low as 59.34 Hz, and the target minimum is 59.5 Hz. This is close enough to the desired final frequency range that operators will have sufficient time to respond. Further, the frequencies below 59.5 Hz may be a consequence of modeling limitations. The histograms indicate this "best case", "responsive", governor model is responding to a greater extent than may occur. In this instance, governor response is occurring rapidly and strong enough to track the initial frequency decline. This effect is most noticeable in the higher inertia cases where the rate of change of frequency is lower. Due to the quick, strong response, minimum transient frequencies improve to the point where some blocks may not pick up. This causes the load shedding simulations to "under-shed", and the final frequencies to settle out lower. With all factors considered, these results were judged to be close enough to the desired final frequency target range of 59.5 Hz to 60.5 Hz.

7.6 Proposed Generation Protection Standard

It is critical that generator underfrequency trip settings and time delays are coordinated with the expected performance of the load shedding program. The whole point of such a standard is to keep generation protection from tripping units while load shedding is still occurring. Failure to do so can lead to a cascading collapse of the system.

The Task Force is proposing a generation protection time delay standard which considers actual times spent below 60 Hz from the simulations with some additional margin added to ensure good coordination.

The Task Force believes the proposed generation protection time delay standard is reasonable and prudent for areas of MRO which are shedding 30% load.

Sub-regions which need to shed more than 30% of connected load will probably need to add additional time delay to units in their sub-region to ensure coordination with load shedding. They will have to finalize the details as part of their sub-regional plans.

Generation owners need to consider that the load shedding program was designed to act as the first line of defense to protect generation from sustained low frequencies. The goal was to provide a program which minimizes underfrequency exposure.

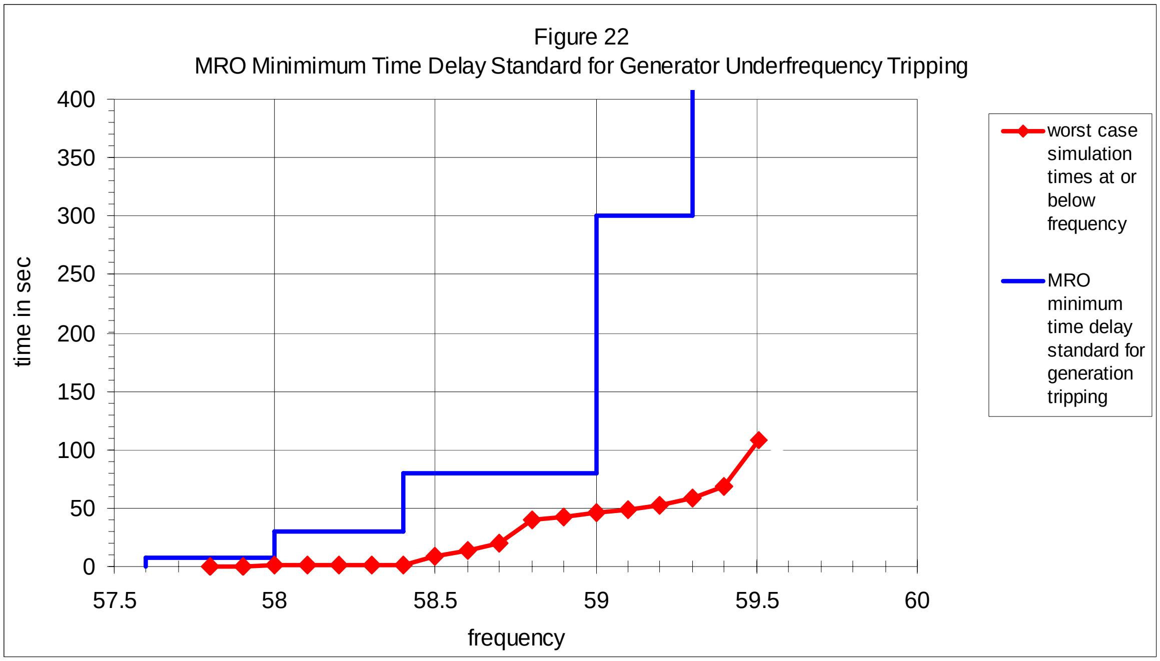
If generation owners cannot comply with this criteria, provisions will need to be made to trip an identical amount of load simultaneously as their unit trips. Such additional load shedding should ideally be in the same general area. However, it is strongly recommended that all generation have tripping time delays set to comply with this proposed standard to the extent it is possible to do so, and virtually all generation is expected to be able to comply.

There is one caveat to this “trip additional load” concept that applies only to older wind generation units. The units referred to are the induction generator type of wind units that do not include the sophisticated power electronics which give newer units the capability of variable slip operation. This older type of induction generation can only operate over a narrow range of slip frequencies, making them much less stable than conventional generation. They are expected to trip off at fairly high frequencies. This is an inherent characteristic of the uncontrolled induction generator and is not the result of generator trip settings. As these units do not have specific underfrequency trip settings, an argument can be made that this proposed standard really does not apply to those units. The Task Force believes this is a reasonable approach. The practical considerations are:

- These types of units represent a small fraction of the existing generation base.
- There is no way to easily size additional load shedding blocks to compensate for loss of this generation as the initial generation levels are unpredictable.
- It is reasonable to consider loss of this generation as part of the hazard covered with the 30% load shedding requirement.

Newer wind units should not have this problem as they are generally of the variable slip type and are expected to stay on-line down to 57 Hz.

The proposed standard for MRO is shown below. For reference, the time versus frequency data from the runs where only the governor was allowed to respond to overfrequency (from Figure 15) is shown. This is what is considered to be the worst case for time spent below 59.5 Hz, and what is referenced when discussing coordination and margin.



Allowable Generator Automatic Underfrequency Trip Frequencies and Required Time Delays

setpoint (Hz)	minimum delay time* (sec)
>59.5 Hz	Automatic Tripping Not Permitted
≤ 59.5 to > 59.3	2700
≤ 59.3 to > 59.0	300
≤ 59.0 to > 58.4	80
≤ 58.4 to > 58.0	30
≤ 58.0 to > 57.6	7.5
≤ 57.6	0

*Subregional programs shedding more than 30% of connected load will need to increase generation protection delay times and/or change setpoints to achieve coordination with load shedding.

8. Conclusions and Recommendations

The proposed MRO underfrequency load shedding program represents a minimum requirement for underfrequency load shedding and generator underfrequency protection to replace the legacy programs developed by MAPP and MAIN.

The Task Force started by identifying potential islanding scenarios within the MRO region, to estimate how the system may break up. By examination, it was concluded that a 30% load shedding requirement is sufficient for the majority of MRO. This is also the total load shedding requirement of the legacy load shedding programs.

The Task Force identified a few subregions that may need to shed more load. Utilities in those subregions have to determine how to best satisfy their internal needs. The MRO effort focused on the remainder of the MRO area and left the subregional details to the affected utilities. These utilities provided additional discussion of these subregions in Appendix 6.

Work then focused on this core portion of MRO and on providing 30% load shedding coverage. Performance objectives were established and options were evaluated to meet these performance goals. Considering the various tradeoffs and inherent uncertainties, the Task Force's believes the recommended program represents the best compromise. The goal was to create a program that can force quick frequency recovery while also minimizing potential overfrequency problems.

The Task Force concludes that the proposed program improves upon the legacy programs by:

- Requiring the slow electromechanical relays be replaced with high speed solid state or computer based underfrequency relays
- Eliminating the arbitrary delays allowed in the MAPP program
- Providing a generation protection standard which coordinates with the new load shedding program for all overloads up to the design level
- Addressing load shedding related overfrequency issues by reducing the size of individual load blocks
- Forcing quick frequency recovery by shedding some load on delay to ensure good coordination with generation protection even when assuming minimal net frequency response from generation

Utilities will need sufficient time to make the transition to the new program. The Task Force recommends MRO consult with member utilities to get a better idea of what constitutes a realistic time frame for completion.

The Task Force believes this analysis satisfies all NERC requirements relating to the development and expected performance of an UFLS program for MRO.

Design requirements are summarized in NERC PRC-006 R1.2., which states design details shall include, but are not limited to:

R1.2.1. Frequency set points
R1.2.2. Size of corresponding load shedding blocks (% of connected loads)
R1.2.3. Intentional and total tripping time delays
R1.2.4. Generation protection
R1.2.5. Tie tripping schemes
R1.2.6. Islanding schemes
R1.2.7. Automatic load restoration schemes
R1.2.8. Any other schemes that are part of or impact the UFLS programs

The Task Force considered all of these factors and made recommendations as required. The program does not include tie line tripping, islanding schemes, or automatic load restoration. Some limited automatic load restoration was originally considered to deal with possible high frequencies, but it was concluded that this was not needed. Concerning load restoration in general, the system operators should restore load manually in small increments once frequency has recovered to 60 Hz.

The Task Force did not find any other schemes that impact the UFLS programs. DC lines would be included in this category. The review indicates DC lines will be able to ride through the frequency disturbance.

The Task Force found that 30% load shedding works fairly well. There are practical limits to what UFLS can do. The requirement to shed more than 30% is not mandatory, but utilities are being given the option provided they do not impact the larger MRO program.

> Initial scoping work identified Saskatchewan, Manitoba and the Upper Peninsula of Michigan as subregions which may need to shed more than 30%

of connected load. Utilities representing these subregions performed their own independent analysis in parallel to the MRO UFLS effort. The findings indicate Saskatchewan and Manitoba should continue to shed more than 30% of connected load, and that a 30% load shedding level is satisfactory for the Upper Peninsula area.

One helpful development is that computerized relaying packages are becoming quite common. The standard packages provide multiple protection functions including a sophisticated set of underfrequency load shedding functions. This includes tripping load using multiple underfrequency setpoints/delays. The extent to which utilities have already migrated to these types of relays is not known, but utilities that already have these relays should find it straightforward to implement the new program.

The load shedding and generation protection specifications follow:

High Speed Load shedding Block number	Block size, % of initial load	Frequency setpoint (Hz)	Relay time (cy)*	Maximum breaker time (cy)
1	6	59.3	6	8
2	6	59.1	6	8
3	6	58.9	6	8
4	6	58.7	6	8
5	6	58.4	6	8
The following two delay blocks are a subset of block 5 using logic of the form: trip IF (58.4 Hz for 6 cy) OR IF (X Hz for Y cy), with the second trip times and delays defined below**				
Delayed Load Shedding Block number	Block size, % of initial load	Frequency setpoint (Hz)	Relay time + intentional delay time (cy)	Maximum breaker time (cy)
1	2	58.7	500	8
2	2	59.5	2400	8

* 6cy minimum detection time recommended for relay security purposes to prevent false trips

**As an alternative, utilities can implement the delay blocks as independent blocks, which increases the total load shedding obligation to 34%.

Allowable Generator Automatic Underfrequency Trip Frequencies
and Required Time Delays

setpoint (Hz)	minimum delay time* (sec)
>59.5 Hz	Automatic Tripping Not Permitted
≤ 59.5 to > 59.3	2700
≤ 59.3 to > 59.0	300
≤ 59.0 to > 58.4	80
≤ 58.4 to > 58.0	30
≤ 58.0 to > 57.6	7.5
≤ 57.6	0

*Subregional programs shedding more than 30% of connected load will need to increase generation protection delay times and/or change setpoints to achieve coordination with load shedding.

Companies unable to meet the proposed generation protection standard must be prepared to trip additional load to compensate for undesirable generator tripping.

9. Key Future Aspects of the UFLS Program

The existing program within the MRO region (former MAPP and former MAIN) of 3 steps of 10% load shed per step has been successfully implemented by the MRO region as well as bordering reliability regions (Reliability*First*, for the former MAIN portion of the footprint; and SPP) and has been deemed to be adequate by NERC for decades. In fact, the majority of the Eastern Interconnection regions use 3 steps of 10%. However, the MRO UFLS Task Force believes that the results of the study should be carefully considered in the development of any future UFLS standard under the new, mandatory enforcement regime for Reliability Standards. Furthermore, the Task Force recommends that the MRO RAC submit a MRO SAR using the study's recommendations in the evaluation of an Eastern Interconnection-wide or broader (MRO-SPP-RFC) UFLS standard which would consider reliability impacts across a larger geography to assure both reliability and consistency, where possible. Using the MRO's standards process, the relative costs, benefits, and implementation of any future changes to the existing UFLS programs can be carefully considered by the constituencies within the region.

In addition, the NERC Standards Committee has formed a NERC SAR drafting team to address UFLS standards PRC-006, PRC-007, PRC-008, and PRC-009 (NERC Project 2007-01). A continent-wide UFLS standard is very doubtful and an Eastern Interconnection-wide standard may be possible, but not timely to meet the FERC requirement for an enforceable standard on UFLS. The existing UFLS standard is considered a "fill in the blank" standard to be refined on a regional-basis to meet the requirements to be enforceable on owners, users, and operators of the bulk power system. The SAR drafting team will determine which requirements of PRC-006 should be continent-wide and which requirements should be defined by the regional Reliability Standards.

Appendix 1 – Related NERC V0 Standards

Related NERC V0 Standards

Below are the NERC V0 standards associated with UFLS. It should be noted that the MRO must be compliant with PRC-006-0 whereas the MRO members must be compliant with EOP-003-0, PRC-007-0, PRC-008-0, and PRC-009-0.

Standard EOP-003-0 — Load Shedding Plans

Purpose: A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.

R8. Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

Standard PRC-006-0 — Development and Documentation of Regional UFLS

Purpose: Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.

Requirements

R1. Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program, which shall include the following:

R1.1. Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations.

R1.2. Design details shall include, but are not limited to:

R1.2.1. Frequency set points.

R1.2.2. Size of corresponding load shedding blocks (% of connected loads.)

R1.2.3. Intentional and total tripping time delays.

R1.2.4. Generation protection.

R1.2.5. Tie tripping schemes.

R1.2.6. Islanding schemes.

R1.2.7. Automatic load restoration schemes.

R1.2.8. Any other schemes that are part of or impact the UFLS programs.

R1.3. A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.

R1.4. Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include,

but not be limited to:

R1.4.1. A review of the frequency set points and timing, and

R1.4.2. Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation.

R2. The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).

R3. The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).

Measures

M1. The Regional Reliability Organization shall have documentation of the UFLS program and current UFLS database.

M2. The Regional Reliability Organization shall have evidence it provided documentation of its UFLS program and its database information to NERC as specified in Reliability Standard PRC-006-0_R2.

M3. The Regional Reliability Organization shall have evidence it provided documentation of its assessment of its UFLS program to NERC as specified in Reliability Standard PRC-006-0_R3. UFLS program was not provided, or an assessment was not completed in the last five years.

Standard PRC-007-0 —Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organization's Underfrequency Load Shedding Program Requirements

Requirements

R1. The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.

R2. The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.

R3. The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).

Measures

M1. Each Transmission Owner's and Distribution Provider's UFLS program shall be consistent with its associated Regional Reliability Organization's UFLS program requirements.

M2. Each Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program shall have evidence that it provided its associated Regional Reliability Organization and NERC with documentation of the UFLS program on request (30 calendar days).

Standard PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

Requirements

R1. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).

Measures

M1. Each Transmission Owner's and Distribution Provider's UFLS equipment maintenance and testing program contains the elements specified in Reliability Standard PRC-008-0_R1.

M2. Each Transmission Owner and Distribution Provider shall have evidence that it provided the results of its UFLS equipment maintenance and testing program's implementation to its Regional Reliability Organization and NERC on request (within 30 calendar days).

Standard PRC-009-0 — Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event

Requirements

R1. The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:

R1.1. A description of the event including initiating conditions.

R1.2. A review of the UFLS set points and tripping times.

R1.3. A simulation of the event.

R1.4. A summary of the findings.

R2. The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.

Measures

M1. Each Transmission Owner's, Transmission Operator's, Load-Serving Entity's and Distribution Provider's documentation of the UFLS program performance following an underfrequency event includes all elements identified in Reliability Standard PRC-009-0_R1.

M2. Each Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operate a UFLS program, shall have evidence it provided documentation of the analysis of the UFLS program performance following an underfrequency event as specified in Reliability Standard PRC-009-0_R1.

Appendix 2 – MAPP and MAIN UFLS Descriptions

MAIN GUIDE NO. 1B

supersedes

(Revision No. 3)

Approved May 9, 2003

Operating Procedures During
Generating Capacity Deficiencies Causing
Declining System Frequency Or Separation

Coordination and monitoring within MAIN are done to assure the reliability of electric power supply. However, in spite of these efforts conditions may occur in one or more systems which will result in a capacity deficiency. In the event of a capacity deficiency, the deficient systems have the primary responsibility to balance load and capacity. When the deficient systems have taken all possible corrective steps and still are unable to correct the capacity deficiency, all systems in MAIN shall take actions to aid in correcting the deficiency.

Generating capacity deficiencies result in declining system frequency. This Operating Guide establishes coordinated procedures for arresting declining frequency and restoring frequency to stable levels.

The Guide addresses two conditions.

I. System Emergency Condition
II. System Restoration Condition

All systems shall keep the MAIN Coordination Center advised of their capacity situation and of actions taken or contemplated to supplement capacity. The Center will monitor the bulk power system in the Midwest so as to aid in evaluating operating conditions and will assist in coordination of actions among MAIN systems as well as with other regional centers. All systems shall continue to monitor important system values giving particular attention to safe loading limits of transmission circuits and interchange capability limits. Good communication with neighboring systems and the MAIN Coordination Center shall be maintained.

I. **System Emergency Condition**

A **System Emergency Condition** will be declared by the MAIN Coordination Center if the system frequency is **59.95** Hz and declining.

A significant decline in frequency may require the shedding of load in order to avoid widespread system outages and to minimize the risk of damage to equipment.

The actions taken in an emergency will depend upon the condition that precipitated the frequency decline. If an islanding condition were to occur suddenly, the frequency decline may be rapid depending upon the size of the island and the relative imbalance between generation and load. The operation of underfrequency relays may occur (depending on the frequency level) although manual load shedding, if timing permits, also may be appropriate. On the other hand, manual procedures may be able to arrest a gradual frequency decline, caused by an imbalance with the eastern interconnection essentially intact, before the frequency declines to the first step settings of the underfrequency relays.

In either event, both manual load shedding, including voltage reduction, and the operation of automatic underfrequency load shedding relays comprise the operating tools of the entities in MAIN to correct the generating capacity deficiencies that result in declining system frequency.

The following general actions are recommended during a **System Emergency Condition:**

A. Frequency Declining: 59.95 to 59.9 Hz

Utilize all Operating Reserves to the extent practical. Available Operating Reserves shall be shared as much as possible to provide regulating margin for all systems.

Deficient systems and other systems if appropriate, shall exercise all practical load reduction measures such as the curtailing of interruptible load and voltage reduction.

B. Frequency Declining: **59.9** to **59.3** Hz

If there is time for manual corrective action, the deficient systems and other systems as appropriate, shall manually shed firm load in amounts sufficient to balance load and generation, and to provide regulating margin. Such action shall continue until the frequency decline is arrested.

C. Frequency Declining: **59.3** to **58.7** Hz

All MAIN systems shall utilize automatic load shedding devices to arrest declining frequency. The frequency settings shall be as follows:

Step 1 At **59.3** Hz, shed not less than 10% of system load.

Step 2 At **59.0** Hz, shed additional load so that the total amount shed from Steps 1 and 2 is not less than 20% of system load prior to Step 1.

Step 3 At **58.7** Hz, shed additional load so that the total amount shed from Steps 1, 2 and 3 is not less than 30% of system load prior to Step 1.

To enhance the effectiveness of automatic load shedding, all MAIN systems shall comply with the following:

Use solid state underfrequency relays for all new installations and relay replacements. These relays should be applied on the first step of load shedding, where practical, to take advantage of their improved stability over electromechanical relays and their constant response time which is not significantly affected by voltage magnitude or frequency decay rate.

Set time delays for each of the three automatic load-shedding steps at 6 cycles. For large motor loads that may be isolated, the time delay may be increased to 15 cycles. If this is not adequate to avoid operation on isolation, a high-dropout overcurrent relay should be applied to supervise underfrequency relay tripping having a 6 cycle time delay.

Trip bulk power capacitor banks along with loads, unless specific studies show this to be a problem or of negligible benefit.

Set the voltage setting on automatic load shedding relays which are equipped with undervoltage inhibit as low as possible within the security constraints of the relay.

D. Frequency Declining: Below **58.7** Hz

Between 58.7 and 58.0 Hz, if frequency continues to decline, all systems shall take any action necessary to arrest the frequency decline except the opening of major transmission lines. Generating unit underfrequency tripping shall not be implemented except as provided in Table 1.

At 58.0 Hz, or below, systems shall take independent actions as they deem necessary to arrest frequency decline and facilitate the restoration of interconnected system operation to normal and minimize the duration of customer electric service interruption. It should be noted that if these actions do not restore system frequency within a period of a few seconds to a few minutes, all nuclear units and some fossil steam units within the affected area can be expected to trip automatically.

Application of the frequencies and time delays shown in Table 1 for allowable automatic isolation of generating units should provide sufficient time delay to permit system recovery from temporary frequency excursions below the isolation frequency with due concern for avoiding turbine damage. It is vitally important that automatic load shedding be allowed to function before generator underfrequency relaying causes tripping of generators. In those cases where generators must be tripped for their own protection outside the specifications of Table 1, additional load shedding must be installed within the immediately adjacent load entity, to compensate for the generators that trip outside the specifications of Table 1. The amount of load shall be in addition to that shed in accordance with Part I.C, Steps 1, 2 and 3, of this Guide. It is beyond the scope of this document to define any physical or contractual arrangements for implementing this additional load shedding.

Table 1.
Allowable Generator Automatic Underfrequency Trip Frequencies
And Required Time Delays

Generator UF Setting (Hz)	Minimum Time Delay (Sec)
≥ 59.5	Automatic tripping not permitted
< 59.5 to > 59.2	2700
≤ 59.2 to > 58.5	120
≤ 58.5 to > 58.0	15.0
≤ 58.0	Owner’s discretion

II. **System Restoration Condition**

A. Low Frequency - Frequency Decline Arrested:

After the decline of system frequency has been arrested, the following action shall be taken:

All generating capacity of systems in the low frequency area shall be fully utilized, including maintaining operation of the turbine-generators at fully open valve positions, until frequency is restored to normal.

If the frequency is below 59.5 Hz, all systems in the low frequency area shall manually shed an additional 10% of the remaining load that is not a part of the third step (58.7 Hz) of the automatic underfrequency loadshedding relay program, within 15 minutes of the frequency arrest.

If completing the action in Step II-A-1 has not returned the frequency to 59.5 Hz, or above, all systems in the low frequency area shall manually shed an additional 10% of the remaining load that is not part of the third step (58.7 Hz) of the automatic underfrequency load shedding relay program, within 10 minutes. Repeat such action until frequency is restored to at least 59.5 Hz.

When frequency has been established at 59.5 Hz or above, the deficient systems shall continue to shed load until no longer deficient.

If after ten minutes the action taken in Steps II-A-1&2 has not returned system frequency to that of the neighboring systems, all systems within the low frequency area shall shed additional load, until frequency is restored to that of the neighboring systems. When frequency has been restored to that of the neighboring systems, the isolated area shall be synchronized with the interconnected systems as generation and transmission facilities permit.

Load restoration and resumption of normal voltage levels and power schedules between systems shall be coordinated and directed by the system operators.

B. Total System Collapse

In the event of the total collapse of an area, affected systems shall take appropriate action necessary to resynchronize with the interconnected system as soon as their facilities will allow. Affected systems shall ascertain that they will not impose a burden on other interconnected systems by a mismatch of generation and load when they resynchronize.

Load restoration and resumption of normal voltage levels and power schedules between systems shall be coordinated and directed by the system operators.

Member control areas shall keep the MAIN Coordination Center informed of activities within their jurisdiction. The MAIN Coordination Center shall facilitate the restoration process as appropriate.

Note: In accordance with MAIN bylaws, the appropriate MAIN Committees shall review this Guide at least once every five years, and recommend any necessary changes to the MAIN Board for approval.

MAPP

Coordinated Underfrequency Load Shedding Program

April 28, 2000

MAPP ORS Approval	April 28, 2000
Next Annual Review	April 28, 2001
Last Technical Assessment________	_________

for MAPP Compliance

With NERC Planning Standard

IIID.S1 -S2.M1

MAPP Regional Underfrequency Load Shedding Program

1.0 INTRODUCTION

A coordinated automatic underfrequency load shedding (UFLS) program is required to help preserve the security of the generation and interconnected transmission systems during major declining system frequency events.

The purpose of this document is to identify the requirements of the MAPP Coordinated Underfrequency Load Shedding Program to ensure appropriate coordination with MAPP subregional UFLS programs and neighboring Regional UFLS programs. It is also to ensure appropriate coordination within the MAPP Reliability Region with generation control and protection systems, undervoltage load shedding programs, load restoration programs, and transmission protection and control systems. The intent is that the MAPP coordinated UFLS program and MAPP subregional UFLS programs shall be in compliance NERC and MAPP
Planning Standards.

The MAPP Operating Review Subcommittee has the responsibility for compliance of the MAPP Coordinated UFLS Program with NERC and MAPP Planning Standards and to assess compliance of subregional UFLS programs to the MAPP UFLS Program.

References to applicable NERC Standards and Measurements are indicated in
bold type within parentheses.

2.0 MAPP UFLS PROGRAM OBJECTIVES AND PRINCIPLES

The MAPP UFLS Program shall be planned and implemented in coordination with other UFLS programs within the MAPP Region and, where appropriate, with neighboring Regions **(IIID.Sl).**

The MAPP UFLS Program shall be coordinated with generation control and protection systems, undervoltage load shedding programs, Regional load restoration programs, and transmission protection and control systems **(lllD.S2).**

The intent of the MAPP UFLS Program is also to:

a) minimize the risk of total or partial system collapse as a result of severe disturbances causing significant generation/load unbalance,
b) prevent damage to generation and transmission facilities,
c) provide for equitable load shedding (interruption of electric supply to customers), and,
d) improve overall reliability of the interconnected systems.

Load shedding resulting from an underfrequency event should be controlled so as to balance generation and customer demand (load), permit rapid restoration of electric service to customer demand that has been interrupted, and when necessary re-establish transmission interconnection ties.

Subregional UFLS programs may have additional requirements to the MAPP UFLS Program requirements provided it can be demonstrated that the MAPP UFLS Program is not adversely affected.

3.0 MAPP UFLS REQUIREMENTS

3.1 General

Those entities owning or operating UFLS programs in the MAPP Region shall ensure that their programs are consistent with the MAPP UFLS Program requirements including automatically shedding load in the amounts and at the locations, frequencies, rates, and times consistent with the MAPP UFLS Program requirements **(IIID.S1 .M2).**

Those entities owning or operating UFLS equipment in the MAPP Region shall have a maintenance program to test and calibrate their UFLS relays to ensure accuracy and reliable operation. Documentation of the implementation of the maintenance program shall be provided to MAPP on request (within 30 days) **(IIID.S1 .M5).**

3.2 Underfrequency Load Shedding

Underfrequency load shedding relays shall be installed to help balance the load with available generation should a separation occur in the interconnected system. Each load serving entity in the MAPP Reliability Region shall shed about thirty percent of its load in ten-percent steps at 59.3, 59.0 and 58.7 Hz.

Total tripping time (relay + breaker time) at each load shed point shall be set to meet the objectives of the MAPP UFLS Program but shall not exceed 60 cycles at the indicated frequency set points.

Subregional UFLS programs are permitted to and may be designed in response to local islanding conditions provided it can be demonstrated that the MAPP UFLS Program is not adversely affected.

4.0 COORDINATION WITH PROTECTION AND CONTROL

The MAPP UFLS Program shall be coordinated with generation control and protection systems, undervoltage load shedding programs, Regional load restoration programs, and transmission protection and control systems **(lllD.S2).**

Coordination must include consideration of tie tripping schemes, islanding schemes automatic load restoration schemes, or any other schemes that are part of or impact UFLS schemes in the MAPP Region **(IIID.SI-S2.Ml).**

5.0 MAPP UFLS PROGRAM DATABASE

A database of the MAPP UFLS Program shall be maintained and annually updated. This database shall include sufficient information to model the MAPP UFLS Program in dynamic simulations of the interconnected transmission systems **(IID-S1 .M3).**

6.0 COORDINATION OF REGIONAL UFLS PROGRAMS

The MAPP UFLS Program shall be coordinated, where appropriate, with the UFLS programs of neighboring Reliability Regions. The MAPP UFLS Program and the UFLS programs of the neighboring Reliability Regions shall be reviewed jointly with the neighboring Reliability Regions, at least every five years or as required by changes in system conditions, to ensure appropriate coordination.

7.0 PERIODIC ASSESSMENT OF THE MAPP UFLS PROGRAM

A technical assessment of the effectiveness of the design and implementation of the MAPP UFLS Program in achieving its stated objectives shall be conducted and documented at least every five years or as required by changes in system conditions **(IIID.SI .M4).**

This technical assessment shall include but not be limited to:

A review of the frequency set points and trip timing, and

Dynamic simulations of the system frequency response up to the UFLS design level.

8.0 REGIONAL PLAN ADMINISTRATION

The MAPP Regional UFLS Plan shall be prepared, maintained, annually reviewed, revised as necessary and approved by the MAPP Operating Review Subcommittee. A copy of the documentation plan shall be retained on file at the MAPP Center. Additionally, the plan will be posted on the MAPP web site, providing public access, as part of Section 5 of the MAPP Reliability Handbook.

Appendix 3 – MRO Underfrequency Load Shedding Task Force

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Appendix 4 – MRO UFLS Scope and Study Process Outline

MRO Underfrequency Load Shedding (UFLS)

Scope and Study Process Outline

April 6, 2006

The objective is to develop and document an UFLS program for the MRO region which satisfies NERC requirements outlined in:

Standard PRC-006-0

Development and Documentation of Regional UFLS Program

Development Phase:

PRC-006-0 R1. *Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program.*

1. Collect and review relevant technical materials and use as supporting documents for the study.
2. Determine off-nominal frequency limits for generation:
    a) Typical generation protection schemes use solid-state multi-setpoint relays.
    b) Protection needs define UFLS performance requirements (min/max frequency and time at frequency type of limits).
    c) Also consider off-nominal frequency capabilities of new technologies such as wind generation, the new types of CT's, etc.
    d) Consider use of ANSI/IEEE C37.106-2003 as a source of information concerning typical generation off-nominal frequency limits.
3. Establish relaying standards and performance criteria:
    a) Minimum (target) frequency for design phase.
    b) Maximum (target) frequency for design phase.
    c) Maximum total clearing times (relay + breaker clearing times) for the UFLS program. Additional delay times only allowed when specified to meet program objectives.

PRC-006-0 R1.2.3. *Intentional and total tripping time delays.*

d) Establish a MRO wide generation protection standard to allow load shedding coordination. Base it upon a reasonable loss of life per event (5% to 10%) to get sufficient time to allow UFLS to respond. Any areas which need to shed more load than the minimum amount specified for the MRO may need to set generation protection to accept higher loss of life per event to achieve coordination with load shedding.

PRC-006-0 R1.2.4. *Design details shall include generation protection.*

e) Where applicable, specify the types of relays allowed.

4. Identify possible islands to study or areas with special requirements, with consideration given to historical disturbances.

PRC-006-0 R1.2.6. *Islanding schemes.*

a) Identify import versus export areas.
b) Canada/US
c) By postulated island (see figure):
    - (island A) Saskatchewan
    - (island B) Manitoba
    - (island C) ND coalfields
    - (island D) Northern Minnesota
    - (island E) Southern Minnesota
    - (island F) Eastern Nebraska and Iowa
    - (island G) Western Nebraska
    - (island H) Central and southern Wisconsin
    - (island J) Northeastern Wisconsin & Upper Peninsula Michigan
    - Combinations of above islands (TBD)

5. Describe each island in terms of load, losses, station service load, inertia, damping, etc.
6. Determine the required level of protection for each island (amount of load shed).

   Minimum imbalance

   Maximum imbalance

7. From review of above, determine the need for regional or sub-regional UFLS differences, and coordinate such variations with the standard MRO program.

   PRC-006-0 R1.1. *Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations.*

8. Determine # of load shedding blocks, frequency setpoints, and block sizes which satisfy performance criteria and achieve relay coordination objectives.

   PRC-006-0 R1.2.1. *Frequency set points.*

   PRC-006-0 R1.2.2. *Size of corresponding load shedding blocks (% of connected loads).*

9. Address overvoltage issues.
10. Address overspeed issues.
11. Unknowns/uncertainties:
    a) Load Damping
    b) Initiating disturbances that may form islands in MRO area
    c) Plant survival following overspeed events
    d) The degree to which any "as implemented" load shedding program can meet the specified load target levels. Take this uncertainty into account in the design phase.
12. Tradeoffs/Compromises
13. Other side issues:

PRC-006-0 R1.2.7. *Automatic load restoration schemes.*

PRC-006-0 R1.2.8. *Any other schemes that are part of or impact the UFLS programs.*

14. Consider out of step tripping/blocking, and under frequency tie line tripping issues, if needed.

PRC-006-0 R1.2.5. *Tie tripping schemes.*

PRC-006-0 R1.2.6. *Islanding schemes.*

15. Iterate towards a best solution, and revise assumptions and protection levels as needed.

Implementation Phase:

1. Define allowable transition time to adjust to new program requirements.

Assessment and Documentation Phase:

1. UFLS Database Requirements:
   - Review details of existing data collection effort, and modify as needed.
   - Determine extent that electro-mechanical UFLS relays are being used

   PRC-006-0 R1.3. *A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.*

2. Periodic Assessment:
   - Review should be initiated following any major system disturbance where UFLS was activated and recommendations should be made when appropriate.
   - A 5 year review process should be set up as an ongoing MRO activity.
   - Any modifications to the MRO UFLS program that arise from periodic review should be clearly documented. The historical perspective of how the MRO program was originally developed and how it evolves over time should be clearly documented.
   - Assessments should focus on the program from a total MRO system basis (or subregional basis) to see if objectives are being satisfied. In any implementation, the block sizes will only be a close approximation to the target levels. At the individual utility level, the degree of fit will vary at each stage, and vary between utilities; but errors may be off-set when all individual programs are considered as a whole. The primary objective is that the UFLS program in total is a reasonable fit to the program specifications for the given geographic area.

   PRC-006-0 R1.4. *Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted* *periodically (at least every five years or as required by changes in system conditions) and shall include, but not be limited to:*

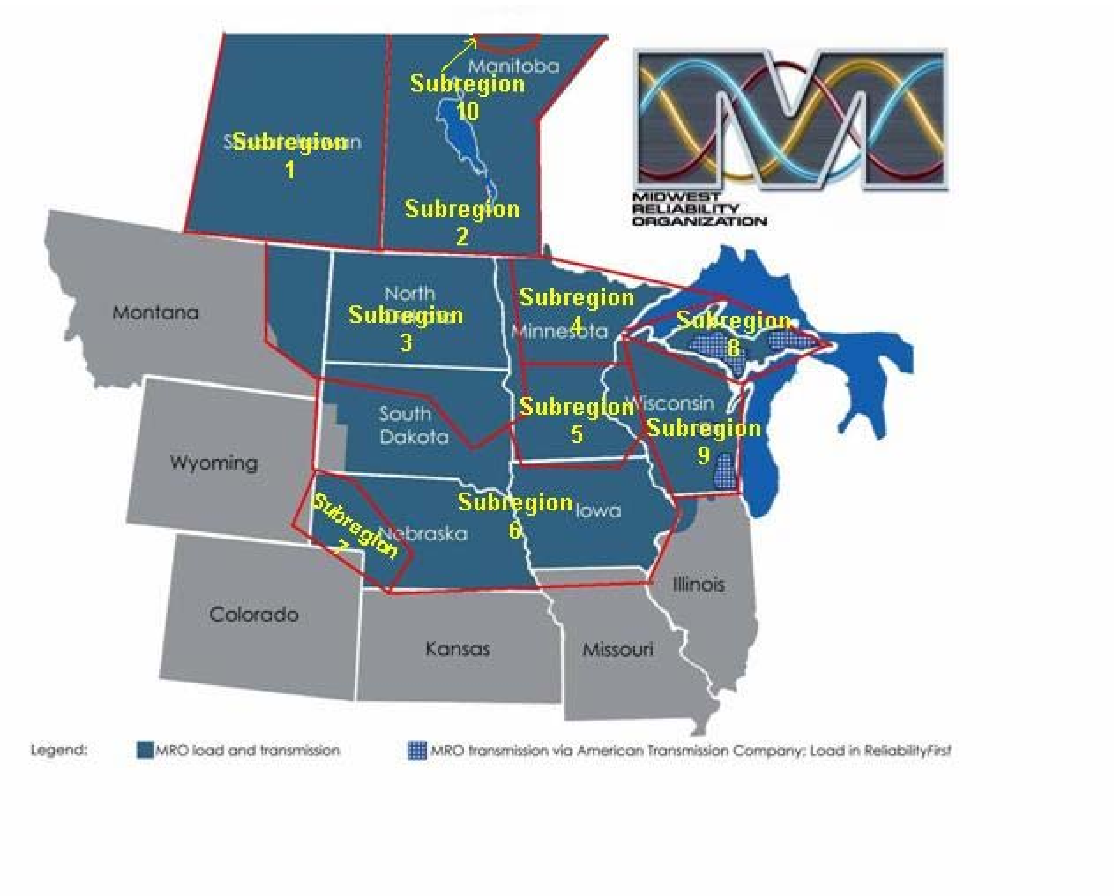
PRC-006-0 R1.4.1. *A review of the frequency set points and timing, and*

PRC-006-0 R1.4.2. *Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between demand (Load) and generation.*

Appendix 5 – Subregional Modeling Data

Analysis for Potential Islanding

The Task Force attempted to identify potential islanding scenarios by first identifying the "weak links" where the system may break up. By opening these boundary ties, the Task Force separated the MRO footprint into 10 subregions. These subregions, either alone or aggregated together when appropriate, were the basis for our postulated islands. The following diagram illustrates these potential islanding scenarios:



Saskatchewan Subregion 1

Subregion 1 is the southern SaskPower system. The southern SaskPower system has three 230 kV AC ties with Manitoba Hydro and a single 230 kV AC tie to North Dakota. Subregion 1 is also connected to the Western Interconnection through an asynchronous AC-DC-AC link. The ties were designed only for local reinforcement and economy transactions, not for large power transfers.

To prevent cascading outages, the ties with Manitoba Hydro are set to trip on under-frequency, while the tie with North Dakota will trip on out-of-step conditions. Therefore, the southern SaskPower system will become isolated from the rest of the Eastern Interconnection during major under-frequency events.

The generation for Subregion 1 is approximately 45% lignite coal fired, 30% natural gas fired/combined cycle steam, 20% hydroelectric, and 5% wind-generation.

There is the potential for a loss of generation and import greater than 30% in the SaskPower system. Therefore, SaskPower requires a UFLS program that provides more load-shed than the proposed MRO UFLS program.

Manitoba Subregions 2 & 10

Manitoba Hydro's (MH) system is unique in that more than 50% of its generation is transmitted through a HVDC system. It will coordinate with the MRO region wide footprint, but will need its own independent scheme. The MH system has approximately 5500 MW of total generation. The system is characterized by approximately 3600 MW of remote hydraulic generation located in northern Manitoba and connected to the concentration of load in southern Manitoba via two 900 km HVDC links designated as Bipole 1 and Bipole 2. MH also has about 1450 MW of hydraulic generation and 480 MW of thermal generation distributed throughout the Province. The first wind farm near St. Leon (southern Manitoba), capable of 99 MW, was connected to the Manitoba Hydro system in 2006 and potential new wind farms are presently being evaluated. The Manitoba system is synchronously interconnected to the Sask Power system to the west via three 230 kV and two 115 kV lines and to the Ontario Hydro Networks Company (OHNC) system to the east with two phase-shifted 230 kV lines. To the south, it is tied with the US part of the MRO system through a 500 kV line and three 230 kV lines.

North Dakota Subregion 3

The North Dakota subregion is defined as the area bounded by the North Dakota Export (NDEX) interface, which includes the transmission lines where separation is expected to occur in the event of an islanding event. Geographically it includes North Dakota, western Montana, parts of South Dakota, and western Minnesota.

The subregion has a 230 kV interconnection to Saskatchewan and a 230 kV interconnection to Manitoba Hydro, both of which would be expected to trip on out of step protection for a severe disturbance. The subregion also has two HVDC lines (Square Butte and CU) which always export power from North Dakota to Minnesota and a back to back HVDC link in Montana which changes from exporting to importing depending on market conditions.

This subregion normally exports power on the AC ties, although exports may be low or even slightly negative during peak winter load conditions. Most of the generation in the subregion is lignite coal fired. There is one major (450 MW) hydro plant (Garrison) and some small peaking combustion turbines. There is significant wind power potential, but less than 200 MW are currently operational.

Under nearly all scenarios, the subregion will have an excess of generation if an island forms. Underfrequency load shedding would be required for the case where frequency in the island rose to the point where units tripped on overfrequency protection or if the North Dakota subregion formed an island with one or more subregions that were deficient in generation.

Northern Minnesota Subregion 4

The northern Minnesota subregion is bounded by the North Dakota subregion on the west, Manitoba Hydro to the north, Wisconsin to the east, and southern Minnesota. The subregion has a phase shifter interconnection to Ontario Hydro at International Falls and a phase shifter transformer interconnection to Wisconsin (Stinson). There is an HVDC line (Square Butte) from North Dakota which provides an importing capability of about 500 MW. This subregion is expected to generally stay connected with southern Minnesota if islanding occurs. However, there is a major 500 kV interconnection to Manitoba with the line continuing to southern Minnesota. It is possible during high transfers that a disturbance involving loss of the 500 kV interconnections could create a separate northern Minnesota island. Thus the boundary between the northern and southern Minnesota subregions is defined by where the parallel AC ties might open on out of step for loss of the 500 kV tie to the Twin Cities.

Most of the generation in this subregion is coal fired, with some hydro. Generation from wind and combustion turbines is minimal. Exports from the region are usually low compared to the load level.

Southern Minnesota Subregion 5

The southern Minnesota subregion is bounded by the northern Minnesota, North Dakota, and Wisconsin subregions as well as Iowa to the south. This subregion could form a single island if separation occurs at what is termed the Minnesota-Wisconsin Stability Interface (MWSI) and then North Dakota separates from South Dakota. Should this large island form, it could stay together or eventually break up into various subregional islands.

This is the largest subregion in the MRO in terms of load and generation since it includes the Minneapolis/St Paul metro area. The southern Minnesota subregion has primarily coal fired and nuclear generation as well as some peaking combustion turbines and a few small hydro units. It relies heavily on imported generation, both from the CU HVDC line from North Dakota and the 500 kV interconnection from Manitoba Hydro. The subregion has increasing wind generation, also. However the subregion is also a significant energy exporter over the 345 kV ties to the south and east. The high imports from Manitoba Hydro generally coincide with high exports east. If islanding occurred, the generation/load imbalance would probably not be too severe if the two Minnesota subregions stayed connected to North Dakota. Should northern and southern Minnesota separate from the other subregions, there might be a significant generation deficiency in the southern Minnesota island.

Iowa & Eastern Nebraska Subregion 6

This subregion is covers the southeastern portion of the MRO system including portions of South Dakota, eastern Nebraska, and all of Iowa; and is basically what is left over within the MRO footprint after the other subregions are carved out according to likely break points. This subregion would potentially remain intact with portions of the eastern interconnection outside of the MRO region.

This is the largest subregion in terms of area with several interconnections. Most of the generation in this subregion is coal fired. This subregion also has a rapidly developing wind resource which will need to be monitored. At times, this region can import moderate amounts of energy.

Western Nebraska Subregion 7

This is a fairly small subregion which centers on western Nebraska. This area has little load and considerable generation, including the Laramie River Station and the Gerald Gentlemen Station. This area is stability limited, and the most likely cause of islanding would be due to internal contingencies causing loss of synchronism with the rest of MRO. Such events will lead to quick tripping of all internal generation and there will be nothing to support load or to support operation of the Stegall and Sidney DC ties to WECC. This subregion is unique in this regard. The implication is that utilities with load in this subregion may want to consider if it makes sense to apply any load shedding to this area. Presently most of Nebraska load shedding occurs outside of this subregion for the stated reason.

Upper Peninsula of Michigan Subregion 8

Subregion 8 covers the Upper Peninsula of Michigan and Northeast Wisconsin**.** This is a relatively small and weak subregion. The most significant generation is medium-size coal fired units. There are small, scattered hydro units and combustion turbine units, and no wind generation. Subregion 8 is defined by the loss of the two Straits-McGulpin 138 kV lines on the east boundary and the Morgan-White Clay 138 kV line and the two Stiles-Pulliam 138 kV lines on the south boundary.

American Transmission Company Subregions 8 and 9 Together

Together, subregions 8 and 9 cover the ATC footprint and can be considered as the "ATC subregion". This subregion is primarily the eastern half of Wisconsin and the Upper Peninsula of Michigan. It is a moderate size and strength subregion with a mix of coal fired units, nuclear units, and combustion turbines. The percentage of hydro and wind generation is small. The "ATC subregion" is defined by the loss of the two Straits-McGulpin 138 kV lines on the east boundary and several transmission lines (five 345 kV lines, two 161 kV lines, two 138 kV lines, one 115 kV line and four 69 kV lines) on the south and west boundaries. Like subregion 6, this subregion may remain interconnected with systems to the south of the MRO footprint.

Data Sources

Five seasonal power flow cases were modified to place load and generation into the identified geographical subregions. This allowed data to be easily extracted and conditions to be tabulated in each subregion. The required power flow and stability data was then tabulated on a spreadsheet and adjusted and/or updated as needed. This included adding in new generation such as wind units and separating out motor load from generation. The data collected included: load, generation, losses, AC and DC import/export, unit MVA base, unit status, and unit H constant.

Data Interpretation

The base cases used represent standard unstressed MAPP cases which do not include any additional forced generation outages or transfers. From the starting point of loss of AC ties into the area, the group considered various additional scenarios before arriving at a determination of the load shedding needs of each subregion. Specifically, the group considered:

a) Loss, or prior outage, of addition generation
b) Loss, or prior outage, of DC transmission

> The tables at the end of this appendix show data from the powerflow cases for the various subregions. In these tables, the term "% load shed" is the percent load shed required to maintain a balance of generation and load. Where generation exceeds load, default values of 0 are given. To avoid confusion, please note the per unit overload in the tables follows the convention of OL = (gen – load)/gen, which gives negative values for a generation deficit. This is the form required by the dynamic simulation program used. Elsewhere in the report such overloads are stated as OL = (load – gen)/gen which is the form required by the load shed versus overload plots (figures 2 and 12).

The intent was to keep the existing 30% load shedding requirement as a minimum for MRO, unless utilities within a given subregion indicated they need a higher level of protection. In cases where a subregion may be a subset of more than one island, the Task Force intended to coordinate the needs of the subregion with the overall needs of the larger island(s) or the MRO in general. Subregions which need to shed more than 30% of connected load are also more likely to form islands by themselves. Typically, their weak tie line capacity can limit their ability to stay connected with the rest of the MRO.

The Task Force did not dictate how load shedding needs by subregion were to be determined. The data collected was only a tool to be used with good judgment, and affected utilities were expected to look into details of what was and was not modeled in the various seasonal cases before drawing a conclusion. The expertise and judgment of those on the Task Force who represented the various subregions was used to assess each subregion and its needs.

All utilities within MRO will be expected to follow the standard MRO program unless they obtain a subregional exception/variation to the standard program. In these instances, subregional programs need to be presented to MRO for approval. They shall explain the need for the subregional program, demonstrate that it meets identified needs, and demonstrate that the program does not appreciably affect the overall MRO program.

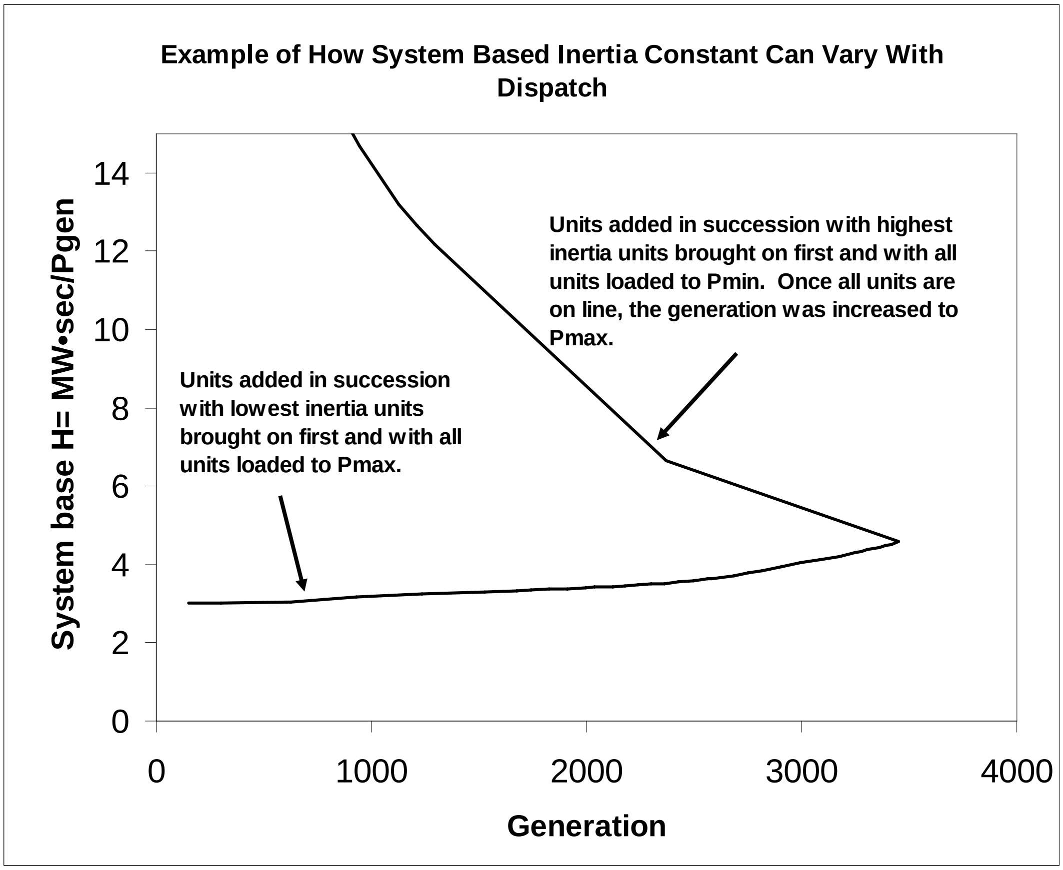
The Canadian provinces of MRO and the Upper Peninsula of Michigan were identified as regions that are weakly connected to the rest of the MRO and which may need subregional exceptions to the standard MRO program. The affected utilities were expected to provide the required analysis for these areas to ensure their needs are being met, and the MRO UFLS Task Force then focused on the remaining portions of the MRO footprint.

Range of System Based Inertia Constant (H)

The Task Force considered high and low H types of dispatch scenarios to bracket the range of system based inertia (defined as total MW•sec / Pgen, including any DC import and/or wind generation as Pgen). In our simulations, the high and low end of H was extended beyond what is expected as one measure of sensitivity.

Typical system inertias (MW•sec/Pgen) are expected to range from approximately 3.5 to about 10.0. The MRO Task Force considered inertia ranges from 2.5 to 15.0 which covered both an expected and extreme range of system inertias.

Since the MRO generation consists of approximately 51% steam generation with an approximate inertia average of 3.5 and 18% combined cycle generation with an approximate inertia average of 5.0, MRO generation should keep the MRO footprint and subregional inertias at 3.5 or higher.



Conclusions:

DC transmission is expected to stay in-service during a breakup and subsequent frequency decline.

30% load shedding is adequate for the MRO as a whole and for all subregions with the exception of the two Canadian provinces.

Inertia (H) is expected to range from 3.5 to about 10.0 or more.

By doing simulations which cover a wide range of inertia and damping assumptions, the responses of all of the postulated islands are inherently captured for up to 30% loss of generation+import with a single set of simulations.

Sub-Region 1, Saskatchewan

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	2740	2354	1539	2741	3037
sum on-line Pmax	2933	2533	1801	2849	3243
sum on-line Mach Base	3289	2841	2045	3203	3652
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	2705	2320	1552	2697	2987
LOSSES	101	101	55	97	103
TOTAL LOAD	2806	2421	1607	2794	3090
DC #	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	0	0	0	0	0
TOTAL INTERCHANGE	-66	-67	-68	-53	-53
AC INTERCHANGE	-66	-67	-68	-53	-53
PU overload for loss of AC ties	-0.024	-0.028	-0.044	-0.020	-0.017
% loadshed for loss of AC ties	2.4%	2.8%	4.2%	1.9%	1.7%

Sub-Region 2, Manitoba South

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	1395	1184	1030	1312	1696
sum on-line Pmax	1569	1451	1325	1675	1820
sum on-line Mach Base	1742	1627	1512	1860	2001
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	2782	2368	1555	3414	3790
LOSSES	276	232	127	289	312
TOTAL LOAD	3058	2600	1681	3703	4102
DC # 7	-897	-825	-564	-881	-920
DC # 8	-897	-825	-564	-881	-920
DC # 5	-823	-756	-501	-806	-812
DC # 6	-823	-756	-501	-806	-812
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	-3440	-3162	-2129	-3374	-3463
TOTAL INTERCHANGE	-1662	-1416	-652	-2391	-2407
AC INTERCHANGE	1778	1747	1478	983	1056
PU overload for loss of AC ties	0.368	0.402	0.468	0.210	0.205
% loadshed for loss of AC ties	0	0	0	0	0

Sub-Region 3, North Dakota

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	5740	5081	2899	4767	5244
sum on-line Pmax	5923	5559	3795	5194	5516
sum on-line Mach Base	6480	6057	4117	5635	6000
MOTOR LOAD	69	69	69	69	69
OTHER LOAD	3695	3208	1862	3710	4074
LOSSES	250	213	77	215	244
TOTAL LOAD	4014	3490	2009	3994	4386
DC # 1	527	527	237	527	527
DC # 2	527	527	237	527	527
DC # 3	205	205	140	205	205
DC # 4	205	205	140	205	205
DC # 11	24	23	-26	87	124
	0	0	0	0	0
DC INTERCHANGE	1488	1487	728	1551	1588
TOTAL INTERCHANGE	1726	1591	890	773	858
AC INTERCHANGE	238	103	162	-778	-731
PU overload for loss of AC ties	0.056	0.029	0.075	-0.242	-0.200
% loadshed for loss of AC ties	0.0%	0.0%	0.0%	19.5%	16.7%

Sub-Region 4, Northern Minnesota

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	1355	1261	1130	1376	1121
sum on-line Pmax	1719	1644	1407	1719	1407
sum on-line Mach Base	1932	1843	1574	1932	1574
MOTOR LOAD	214	214	214	214	214
OTHER LOAD	1522	1410	1118	1549	1653
LOSSES	100	93	58	75	79
TOTAL LOAD	1836	1717	1390	1838	1947
DC # 3	-205	-205	-140	-205	-205
DC # 4	-205	-205	-140	-205	-205
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	-410	-410	-280	-410	-410
TOTAL INTERCHANGE	-482	-456	-259	-462	-826
AC INTERCHANGE	-72	-46	21	-52	-416
PU overload for loss of AC ties	-0.041	-0.028	0.015	-0.029	-0.272
% loadshed for loss of AC ties	3.9%	2.7%	0.0%	2.8%	21.4%

Sub-Region 5, Southern Minnesota

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	7380	6139	3688	4379	6794
sum on-line Pmax	7533	6226	4508	4511	6932
sum on-line Mach Base	8585	7017	5141	5141	7872
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	10419	8871	5476	7609	8439
LOSSES	266	232	105	207	230
TOTAL LOAD	10684	9103	5580	7816	8669
DC # 1	-527	-527	-237	-527	-527
DC # 2	-527	-527	-237	-527	-527
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	-1054	-1054	-474	-1054	-1054
TOTAL INTERCHANGE	-3305	-2964	-1893	-3437	-1875
AC INTERCHANGE	-2251	-1910	-1418	-2383	-821
PU overload for loss of AC ties	-0.267	-0.265	-0.341	-0.439	-0.105
% loadshed for loss of AC ties	21.1%	21.0%	25.4%	30.5%	9.5%

Sub-Region 6, Southern MRO

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	16222	14392	7332	11499	12491
sum on-line Pmax	17870	15853	11599	13575	14013
sum on-line Mach Base	20285	17806	12813	15041	15534
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	17669	15537	8811	12992	14018
LOSSES	433	385	151	356	402
TOTAL LOAD	18102	15922	8962	13348	14420
DC #	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	0	0	0	0	0
TOTAL INTERCHANGE	-1880	-1530	-1630	-1850	-1929
AC INTERCHANGE	-1880	-1530	-1630	-1850	-1929
PU overload for loss of AC ties	-0.116	-0.106	-0.222	-0.161	-0.154
% loadshed for loss of AC ties	10.4%	9.6%	18.2%	13.9%	13.4%

Sub-Region 7, Western Nebraska

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	2040	2034	1004	2047	2020
sum on-line Pmax	2362	2362	1643	2362	2312
sum on-line Mach Base	2357	2357	1600	2357	2304
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	560	490	231	260	279
LOSSES	35	35	9	35	35
TOTAL LOAD	595	525	240	295	314
DC # 10	0	0	0	0	0
DC # 12	-20	-20	-20	-20	-20
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	-20	-20	-20	-20	-20
TOTAL INTERCHANGE	1446	1509	763	1752	1706
AC INTERCHANGE	1466	1529	783	1772	1726
PU overload for loss of AC ties	0.711	0.744	0.765	0.857	0.846
% loadshed for loss of AC ties	0.0%	0.0%	0.0%	0.0%	0.0%

Sub-Region 8, Upper Michigan

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	1066	1066	1066	775	776
sum on-line Pmax	1207	1207	1207	1032	1032
sum on-line Mach Base	1476	1476	1476	1227	1227
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	1139	1139	1139	1075	1075
LOSSES	33	32	32	40	40
TOTAL LOAD	1172	1171	1172	1115	1115
DC #	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	0	0	0	0	0
TOTAL INTERCHANGE	-105	-105	-105	-339	-339
AC INTERCHANGE	-105	-105	-105	-339	-339
PU overload for loss of AC ties	-0.099	-0.098	-0.099	-0.438	-0.437
% loadshed for loss of AC ties	9.0%	9.0%	9.0%	30.4%	30.4%

Sub-Region 9, Wisconsin

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	10861	10857	10845	9479	9484
sum on-line Pmax	11106	11106	11106	10209	10209
sum on-line Mach Base	13395	13395	13395	12314	12314
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	11610	11603	11581	9324	9330
LOSSES	285	284	282	204	206
TOTAL LOAD	11894	11887	11863	9528	9536
DC #	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	0	0	0	0	0
TOTAL INTERCHANGE	-1033	-1029	-1018	-49	-52
AC INTERCHANGE	-1033	-1029	-1018	-49	-52
PU overload for loss of AC ties	-0.095	-0.095	-0.094	-0.005	-0.006
% loadshed for loss of AC ties	8.7%	8.7%	8.6%	0.5%	0.5%

Sub-Region 10, Northern Manitoba

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	3459	3178	2135	3392	3483
sum on-line Pmax	3612	3612	3612	3612	3612
sum on-line Mach Base	4150	4150	4150	4150	4150
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	0	0	0	1	1
LOSSES	18	15	6	17	18
TOTAL LOAD	18	15	6	19	20
DC # 7	897	825	564	881	920
DC # 8	897	825	564	881	920
DC # 5	823	756	501	806	812
DC # 6	823	756	501	806	812
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	3440	3162	2129	3374	3463
TOTAL INTERCHANGE	3441	3163	2129	3374	3463
AC INTERCHANGE	0	0	0	0	0
PU overload for loss of AC ties	0.005	0.007	-0.017	-0.005	0.010
% loadshed for loss of AC ties	0.0%	0.0%	1.6%	0.5%	0.0%

Combined Sub-regions: SPC and Southern MH

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	4135	3538	2569	4052	4733
sum on-line Pmax	4502	3984	3126	4524	5063
sum on-line Mach Base	5031	4468	3557	5063	5653
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	5487	4688	3107	6111	6777
LOSSES	377	333	181	386	415
TOTAL LOAD	5864	5021	3288	6497	7192
DC # 7	-897	-825	-564	-881	-920
DC # 8	-897	-825	-564	-881	-920
DC # 5	-823	-756	-501	-806	-812
DC # 6	-823	-756	-501	-806	-812
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	-3440	-3162	-2129	-3374	-3463
TOTAL INTERCHANGE	-1728	-1483	-719	-2445	-2459
AC INTERCHANGE	1712	1680	1410	929	1003
PU overload for loss of AC ties	0.226	0.251	0.300	0.125	0.122
% loadshed for loss of AC ties	0.0%	0.0%	0.0%	0.0%	0.0%

Combined Sub-regions: SPC and all MH

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	7594	6716	4704	7444	8215
sum on-line Pmax	8114	7596	6739	8136	8676
sum on-line Mach Base	9181	8618	7707	9213	9803
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	5487	4688	3107	6112	6779
LOSSES	395	348	187	404	433
TOTAL LOAD	5882	5036	3294	6515	7212
DC #	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	0	0	0	0	0
TOTAL INTERCHANGE	1712	1680	1410	929	1004
AC INTERCHANGE	1712	1680	1410	929	1004
PU overload for loss of AC ties	0.225	0.250	0.300	0.125	0.122
% loadshed for loss of AC ties	0.0%	0.0%	0.0%	0.0%	0.0%

Combined Sub-regions: Northern and Southern MH

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	4854	4362	3165	4704	5178
sum on-line Pmax	5181	5063	4938	5287	5432
sum on-line Mach Base	5892	5777	5662	6010	6151
MOTOR LOAD	0	0	0	0	0
OTHER LOAD	2782	2368	1555	3415	3792
LOSSES	294	247	133	306	331
TOTAL LOAD	3076	2615	1687	3721	4122
DC #	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	0	0	0	0	0
TOTAL INTERCHANGE	1778	1747	1477	983	1056
AC INTERCHANGE	1778	1747	1477	983	1056
PU overload for loss of AC ties	0.366	0.400	0.467	0.209	0.204
% loadshed for loss of AC ties	0.0%	0.0%	0.0%	0.0%	0.0%

Combined Sub-regions: Northern and Southern Minnesota

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	8734	7400	4818	5755	7915
sum on-line Pmax	9252	7870	5915	6230	8339
sum on-line Mach Base	10516	8860	6715	7073	9445
MOTOR LOAD	214	214	214	214	214
OTHER LOAD	11941	10281	6593	9157	10093
LOSSES	365	325	162	282	309
TOTAL LOAD	12521	10820	6970	9654	10616
DC # 1	-527	-527	-237	-527	-527
DC # 2	-527	-527	-237	-527	-527
DC # 3	-205	-205	-140	-205	-205
DC # 4	-205	-205	-140	-205	-205
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	-1464	-1464	-754	-1464	-1464
TOTAL INTERCHANGE	-3787	-3420	-2152	-3899	-2701
AC INTERCHANGE	-2322	-1956	-1398	-2435	-1237
PU overload for loss of AC ties	-0.228	-0.221	-0.251	-0.337	-0.132
% loadshed for loss of AC ties	18.5%	18.1%	20.1%	25.2%	11.7%

Combined Sub-regions: North Dakota, all Minnesota

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	14474	12481	7717	10521	13158
sum on-line Pmax	15175	13429	9710	11423	13855
sum on-line Mach Base	16996	14917	10831	12707	15445
MOTOR LOAD	284	284	284	284	284
OTHER LOAD	15636	13489	8456	12867	14166
LOSSES	615	537	239	497	553
TOTAL LOAD	16535	14310	8978	13647	15002
DC #	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	0	0	0	0	0
TOTAL INTERCHANGE	-2061	-1829	-1262	-3126	-1844
AC INTERCHANGE	-2061	-1829	-1262	-3126	-1844
PU overload for loss of AC ties	-0.142	-0.147	-0.163	-0.297	-0.140
% loadshed for loss of AC ties	12.5%	12.8%	14.1%	22.9%	12.3%

Combined Sub-regions: Southern MH, North Dakota, all Minnesota

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	15870	13665	8746	11833	14854
sum on-line Pmax	16744	14879	11036	13098	15675
sum on-line Mach Base	18738	16544	12343	14567	17446
MOTOR LOAD	284	284	284	284	284
OTHER LOAD	18418	15857	10011	16281	17956
LOSSES	891	770	366	786	865
TOTAL LOAD	19592	16911	10660	17350	19104
DC # 7	-897	-825	-564	-881	-920
DC # 8	-897	-825	-564	-881	-920
DC # 5	-823	-756	-501	-806	-812
DC # 6	-823	-756	-501	-806	-812
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	-3440	-3162	-2129	-3374	-3463
TOTAL INTERCHANGE	-3723	-3245	-1913	-5517	-4251
AC INTERCHANGE	-283	-83	216	-2144	-788
PU overload for loss of AC ties	-0.015	-0.005	0.020	-0.141	-0.043
% loadshed for loss of AC ties	1.4%	0.5%	0.0%	12.4%	4.1%

Combined Sub-regions: All MRO US (excluding Canada)

	2004SUPK	2004SUOP	2004SPLL	2004WIOP	2004WIPK
GEN	44664	40831	27963	34321	37929
sum on-line Pmax	47720	43957	35265	38602	41422
sum on-line Mach Base	54508	49950	40114	43646	46824
MOTOR LOAD	284	284	284	284	284
OTHER LOAD	46613	42258	30218	36518	38869
LOSSES	1401	1274	713	1132	1235
TOTAL LOAD	48297	43815	31215	37933	40387
DC #	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
	0	0	0	0	0
DC INTERCHANGE	0	0	0	0	0
TOTAL INTERCHANGE	-3633	-2984	-3251	-3612	-2458
AC INTERCHANGE	-3633	-2984	-3251	-3612	-2458
PU overload for loss of AC ties	-0.081	-0.073	-0.116	-0.105	-0.065
% loadshed for loss of AC ties	7.5%	6.8%	10.4%	9.5%	6.1%

Appendix 6 – Subregional Variations

Manitoba Hydro

Manitoba Hydro's (MH) system is unique, more than 50% of it's generation is transmitted through a HVdc system, consequently it requires it's own independent scheme which sheds (6 major blocks, see table 1) up to 72% load to ensure that for loss of our largest generation (the D.C. system (3350 MW)) can be recovered. For loss of this major generation and because Manitoba Hydro is weakly connected to the MRO region it will island separately due to its Out of Step relays on the tielines to the US, also from Ontario and Sask Power (at 58 Hz to prevent damage to their thermal generating units) and therefore, will not have any influence/affect on the proposed MRO program.

MH Load shedding needs to be more aggressive so that after underfrequency load shed tripping the MH frequency will be sufficient to maintain synchronism within the MH system and to prevent complete system shutdown/blackout.

Block 1	59.3 Hz	~20.6% Load shed
Block 2	59.0 Hz	~12.2% Load shed
Block 3	58.7 Hz	~16.6% Load shed
Block 4	58.5 Hz	~7.2% Load shed
Block 5	58.3 Hz	~7.5% Load shed
Block 6	58.0 Hz	~8.9% Load shed

Table 1 – MH Load Shed Program

The MH system is operated to limit the largest single contingency to the maximum of the MAPP available MAPP reserves.

MH criteria is to operate resources so that the steady-state post contingent flow into MH from the USA, after operating adjustments will not exceed the following:
(*criteria* – prevent manual load shedding for single contingency losses – NERC standard)
550 MW – winter months – November 01 through April 30
830 MW – summer months – May –1 through October 31

For multiple contingency losses MH tolerates manual load shedding until operating actions can be taken.

System posturing for potential system contingencies is based upon three strategies. These are;

Prevention: Posture the system to prevent the event from occurring.

Minimizing: If the event cannot be prevented, then minimize the system's exposure to the event.

Containing: If the impact of the event cannot be minimized, then contain the impact of a disturbance to as small an area as possible.

Summary of the UFLS Program in the Northeast Wisconsin and Upper Peninsula of Michigan (UP) Area

The northeast Wisconsin and UP area (referred to as "the area" in the following) can be defined by the five (5) tie lines that interconnect the area to the rest of the transmission system. These are Morgan – White Clay 138kV line, Stiles – Pulliam 138kV double circuits and Straits – McGulpin 138kV double circuits. This area is a subset of the ATC transmission system and of the Balancing Authority areas within the ATC footprint. Each Balancing Authority within ATC footprint is required to meet the UFLS requirements in the MAIN Guide 1B. The current UFLS program in the area includes additional load shedding beyond what is required for the ATC customers according to the MAIN guide. The current UFLS program is part of an integrated approach that addresses the area's specific reliability concerns of potential system separation and subsequent blackout.

Due to geographic limitations, economic pressure to import power and limited ties to the rest of the system, the area is vulnerable to system separation under the impact of multiple transmission line outages. ATC believes that the UFLS program should be part of an integrated approach that addresses this separation concern. In 2006, ATC and its customers finalized an enhancement to the UFLS program that existed in the area previously. The current program facilitates a total amount of load shedding of 27.8% referencing 2006 summer peak condition, which represents an extension and enhancement over the previous UFLS program that had a total amount of load shedding of 15.8%. The current program also implements the UFLS in five steps compared to the previous 3-step program. Details of the current UFLS program in the area are listed in the following.

Total UFLS at 59.3 Hz	9.4%
Total UFLS at 59.0 Hz	4.7%
Total UFLS at 58.7 Hz	6.0%
Total UFLS at 58.5 Hz	3.6%
Total UFLS at 58.3 Hz	4.0%
Total UFLS of all steps	27.8%

Also as part of the integrated approach, ATC System Operations and Midwest ISO (MISO) jointly follow the procedures specified in the Operating Guide, "WhiteClay-Morgan138kV_Stiles-Pulliam138kV", which addresses the reliability concerns of the area's critical southern tie lines, employing measures such as fast start of generators, manual load shedding, TLR and LMP real time binding constraints, etc. Also, the Flow South Operating Guide helps manage power flow into the area. It should be noted that there is negligible cascading risk to the rest of the interconnection with respect to this area. For longer term, ATC has planned projects that will strengthen the area's critical southern tie significantly. ATC has also planned to add another 115/138 kV tie to the area in the west. These transmission projects are expected to be in service by 2009 and they will greatly reduce the likelihood of the entire area separation from the rest of the system.

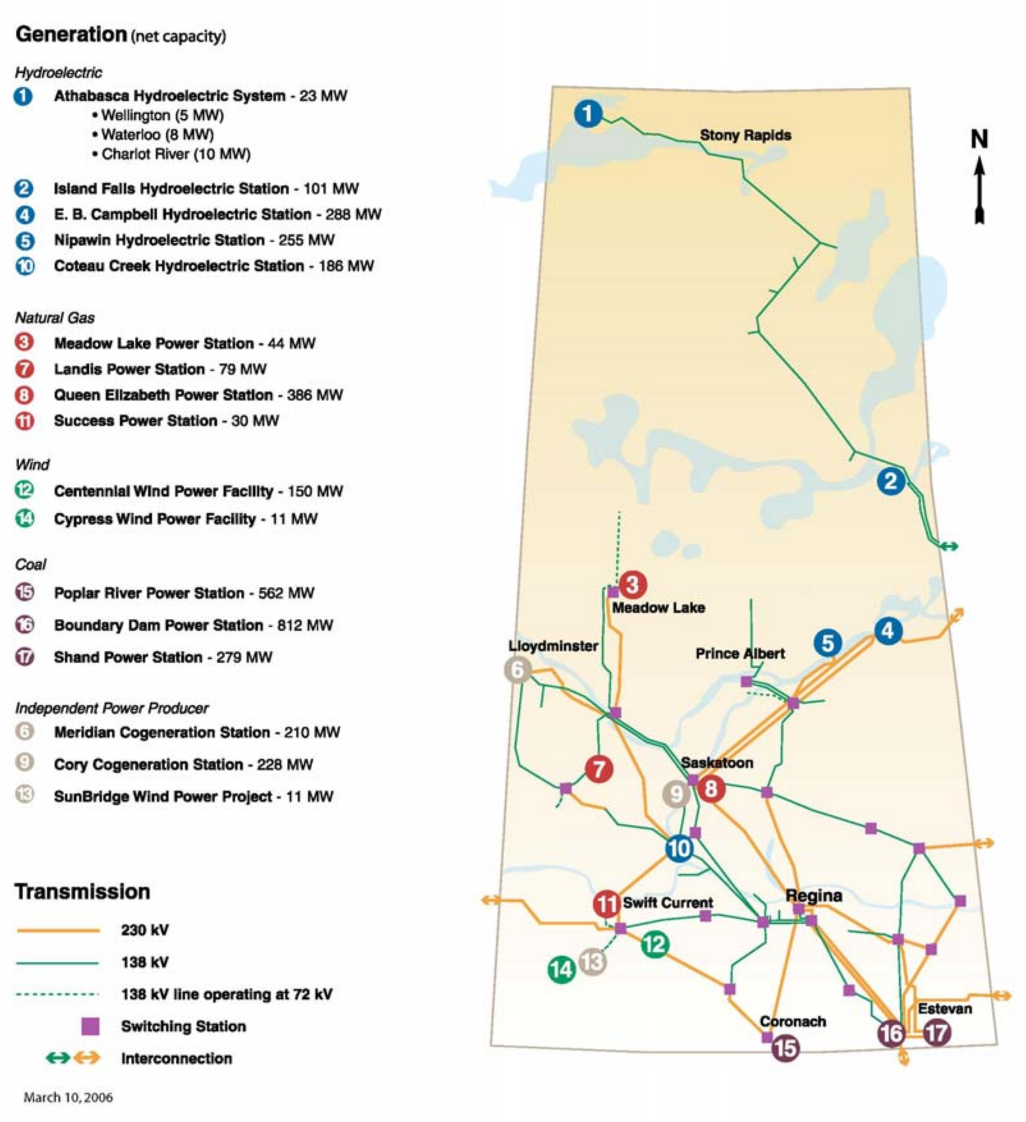
In summary, the current UFLS program in the area is considered adequate as part of the overall measures addressing one of the most significant reliability concerns of the area and should be reviewed periodically as required by the NERC standards and changing system load, generation and transmission system topology.

SaskPower / Saskatchewan

Area Description

SaskPower is located on the northwest corner of the MRO footprint, bordering the Western Interconnection, and is responsible for the bulk electric system for the province of Saskatchewan. The SaskPower system is divided into two systems, a northern system and a southern system. The two systems are not directly tied together within the boundaries of Saskatchewan.

Figure 1: SaskPower Bulk Electric System



The northern SaskPower system consists of several small hydroelectric generating facilities serving load through a 110 kV / 138 kV radial line network. It is connected to the Manitoba Hydro system through a 110 kV double-circuit tie. The SaskPower northern system, because of its radial configuration, frequently isolates (in part or in whole) from the Manitoba Hydro system. Due to the high potential for isolating and its limited generation capacity, the SaskPower northern system has it own specialized UFLS program that will not be changed at this time.

The southern SaskPower system has three 230 kV AC ties to Manitoba and a single 230 kV AC tie (through a phase-shifting transformer) to North Dakota. SaskPower is also connected to the Western Interconnection through an asynchronous AC-DC-AC link. The SaskPower ties were designed for local reinforcement and economy transactions only, not for large power transfers.

Existing SaskPower UFLS Program

The existing UFLS program for the southern SaskPower system consists of five blocks of load-shed. The total load-shed by all five stages is approximately 33-36% (dependent on seasonal load changes). The frequency set-points for the first three stages of the existing SaskPower UFLS program coordinate with the three stages of the existing MRO UFLS program. Historically, SaskPower has designed its UFLS scheme to meet the needs of the Saskatchewan bulk electric system, while coordinating with Manitoba Hydro as much as possible.

The existing SaskPower UFLS program is shown in Table 1.

Table 1: Existing SaskPower UFLS Program

Block Size, % of Initial Load	Frequency Setpoint (Hz)
~6	59.3
~9	59.0
~7	58.7
~7	58.5
~5	58.3

To provide anti-cascading protection, the 230 kV ties with Manitoba are set to trip for an under-frequency of 58.0 Hz (6-9 cycle delay), or for an over-frequency of 61.2 Hz (6-9 cycle delay). The 230 kV tie with North Dakota is set to trip on out-of-step conditions (likely to occur during an under-frequency event).

Manitoba Hydro also utilizes a secondary anti-cascading protection scheme (Northern Island Tripping Scheme) that separates the northern Manitoba Hydro AC system and SaskPower from the rest of Manitoba Hydro when system frequency drops to 59.0 Hz. However, if the frequency continues to drop following the formation of the island, the ties between SaskPower and the northern Manitoba system will trip at 58.0 Hz.

Due to the weak ties with neighboring utilities, shedding load outside of the SaskPower system would provide little benefit for a major loss of generation within SaskPower. Likewise, load-shed action within SaskPower would provide little benefit for a major loss of generation outside of the SaskPower area. The power that could be supplied over the ties between SaskPower and the rest of the Eastern Interconnection would not be enough to support the affected zone.

To accommodate the weak ties, the SaskPower-Manitoba Hydro under-frequency tie-line tripping, the Manitoba Hydro Northern Island Tripping Scheme, and the out-of-step tripping scheme on the SaskPower-North Dakota tie were designed to isolate the SaskPower system from the rest of the Eastern Interconnection during a major under-frequency event. Following isolation, the SaskPower UFLS program will attempt to correct any generation-load imbalance within the isolated SaskPower system.

Proposed SaskPower UFLS Program

There is the potential for a loss of generation and import greater than 30% (of total connected load) in the SaskPower system. Therefore the newly proposed MRO UFLS program (with 30% total load-shed) would not provide enough load-shed under certain SaskPower system contingencies.

Using the single machine equivalent-inertia methodology, the proposed MRO UFLS program was modified to provide 40% total load-shed. This was accomplished by increasing the size of the high-speed blocks, and by adding an additional sixth high-speed block. The frequency set-points for the proposed SaskPower UFLS program and the proposed MRO UFLS program are identical, therefore maintaining coordination between the two UFLS programs as much as possible. The load-shed on delay blocks for the proposed SaskPower UFLS program are also identical to the proposed MRO UFLS program. The proposed SaskPower UFLS program is shown in Table 2.

Table 2: Proposed SaskPower UFLS Program

Block Size, % of Initial Load	Frequency Setpoint (Hz)	Maximum Relay Time + Intentional Delay Time (cycles)	Maximum Breaker Time (cycles)
6.67	59.3	6	8
6.67	59.1	6	8
6.67	58.9	6	8
6.67	58.7	6	8
6.67	58.4	6	8
6.67	58.1	6	8
2	58.7	500	8
2	59.5	2400	8

A 40% total load-shed UFLS program for SaskPower would provide acceptable protection for extreme contingencies resulting in the following losses of SaskPower generation and import:

- Loss of two largest lignite units during minimum system load levels.
- Loss of three largest lignite units + 100 MW import during summer off-peak load levels.
- Loss of four largest lignite units during winter off-peak or summer peak load levels.
- Loss of four largest lignite units + 120 MW import during winter peak load levels.

Design of a SaskPower UFLS program with more than 40% total load-shed was evaluated. However, under certain scenarios a program with greater than 40% total load-shed would produce minimum transient frequencies that reach unacceptable levels, resulting in the potential tripping of generation on under-frequency. To improve performance, the size of the high-speed load-shed blocks could be made larger to correct the minimum transient frequencies. However, this would result in greater potential for over-shedding and a greater reliance on governor action to correct the over-speed conditions. For this reason, a SaskPower UFLS program with greater than 40% total load-shed was not considered further.

In conjunction with modifying the SaskPower UFLS program, an under-frequency relay shall be added to the 230 kV tie between SaskPower and North Dakota (frequency set-point to be determined). This relay will ensure isolation of the SaskPower system during major under-frequency events, and removes the reliance on operation of the out-of-step protection on the SaskPower-North Dakota tie to isolate SaskPower.

With revision of the SaskPower UFLS program, the under-frequency protection set-points for the SaskPower generating units will also be reviewed. Modifications to the SaskPower generation protection settings may be required to coordinate with the new SaskPower UFLS program.