REAL-TIME SECURITY ASSESSMENT FOR THE ICELANDIC ELECTRICAL POWER SYSTEM USING PHASOR MEASUREMENTS

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Abstract

This thesis investigates ways to evaluate the security level of Icelandic power system with respect to the traditional system protection, wide-area control system (WACS) schemes and level of the production units in the system.

The system security assessment is to define flexible transmission limits between areas and determine maximum transfer in case of emergency. The system security level can therefore act as an reference to the system operators of Icelandic power system. In order to assess the level of security it was necessary to implement defense systems in Landsnet PSS/E model and than it was possible to simulate different conditions in the system.

Simulation results were then used to identify important factors and to define formulas which can assess in real-time production and load balance between the main system generation areas in case of islanding. In addition computational algorithms were built to calculate the level of system security in areas including systems Landsnet 66kV system areas in the south, 132 / 66kV system areas of the East and the Westfjords.

The algorithm were programmed in Landsnet WAMS system and is being used to monitor the security level of the Icelandic power system. Part of the project was to investigate if it were possible to use Landsnet SCADA simulation system for dynamic simulations. The response of the SCADA simulator was similar to PSS/E model but SCADA system refresh rate is 2 seconds. Consequently, it was not considered desirable to use the SCADA simulator in this project.

Another part of this thesis was to find the best way of splitting the system with the optimum generation-load balance. Many ideas came up but it was not enough time to simulate and analyze all of them. Instead it is a opportunity for others to continue the research in this interesting field that adaptive islanding is.

Above all, project went fairly well and can hopefully be useful to Landsnet in future operation of the Icelandic power system.

Formáli

Þetta verkefni var unnið fyrir Kerfisstjórnarsvið Landsnets og Háskólann í Reykjavík sem hluti af námskröfum til þess að öðlast meistaragráðu í raforkuverkfræði. Verkefnið var unnið frá 1.september 2015 til 1.maí 2015.

Verkefnið snýst um það að finna leiðir til þess að meta öryggisstig íslenska raforkukerfisins með tilliti til hefðbundinna kerfisvarna, víðstýringa (WACS) og stöðu framleiðslueininga í kerfinu. Öryggisstig kerfisins er metið til þess að innleiða breytileg flutningsmörk flutningssniða á milli landsvæða og ákvarða hámarksflutning í neyðartilvikum. Öryggisstigið getur því virkað sem leiðbeinandi reglur eða viðmiðun við rekstur íslenska raforkukerfisins. Til þess að meta öryggisstigið þurfti að innleiða kerfisvarnir og víðstýringar í PSS/E módel Landsnets til þess að mögulegt væri að herma mismunandi raunskilyrði í kerfinu.

Niðurstöður hermana voru svo notaðar við smíði á aðferð sem getur metið í rauntíma jafnvægi framleiðslu og álags á milli megin-framleiðslusvæða kerfisins ef kemur til eyjareksturs. Einnig voru smíðuð reikniverk sem geta reiknað út öryggisstig/stöðugleika í svæðakerfum Landsnets þ.a.m. 66kV svæðakerfi á Suðurlandi, 132/66kV svæðakerfi á Austurlandi og Vestfjörðum.

Þessi reikniverk voru sett upp í WAMS kerfi Landsnets og eru notuð til þess að vakta öryggisstig íslenska raforkukerfisins. Hluti af verkefninu var athuga hvort það væri mögulegt að nota Orkustjórnkerfishermi Landsnets til hermana. Reyndist tíðniviðbragð hermisins vera svipað og PSS/E en erfitt var að notast við gögn því uppfærsluhraði Orkustjórnkerfa (SCADA) er 2 sekúndur. Þar af leiðandi var ekki talið æskilegt að notast við Orkustjórnkerfisherminn í þessu verkefni. Einnig var hluti af verkefninu að finna leiðir til þess að skipta upp íslenska raforkukerfinu á sem bestan máta, þá með tilliti til framleiðslu og álagsjafnvægis. Margar hugmyndir komu upp og reyndist ekki tími til þess að herma þær allar, en það gefur öðrum tækifæri til þess að halda áfram með það mikilvæga og spennandi verkefni sem valvís kerfisuppskipting er.

Vinnan við verkefnið gekk vel og getur vonandi reynst vel sem undirstaða á rauntíma mati á stöðugleika/öryggi íslenska raforkukerfisins. Þetta er upphafið að rauntíma öryggismati íslenska raforkukerfisins, en talsverð vinna er í framundan í því að uppfæra og betrumbæta reikniverk eftir því sem kerfið og tækni breytist.

Acknowledgement

First of all, I would like to thank my supervisors at Landsnet, Ragnar Guðmannsson and dr. Magni Þór Pálsson. Their advice and great discussions throughout the research has been valuable. I would like to thank my supervisor at Reykjavik University, dr. Ragnar Kristjánsson for the support and guidance during the work of this thesis. Furthermore, I would like to thank the employees of Landsnet and Ragnar Örn at Efla who supported me with informations and ideas. I want to thank Samuel Perkin for his assistance in reviewing and proofreading the thesis. My family and friends deserves my deepest gratitude for their patience and encouragement throughout my studies. Finally I would like to thank my family for their support, especially my parents who have always been very supportive and my two children Hrafnhildur Sif and Kristinn Páll who have also unknowingly supported me in a great way. At last but not least I would like to thank my fiancée Katrín Harpa for her endless support, good advices and assistance throughout all my studies.

Preface

This thesis was written at Landsnet, Department of System Operation, and Reykjavik University in partial fulfillment of the requirements for acquiring the M.Sc degree in electrical engineering. The research and thesis writing has been conducted from the 1st of September 2015 to the 30th of April 2016. Project was worked for Landsnet and Reykjavik University.

The purpose of this project was to estimate the system security level by developing power system security assessment algorithm to perform the assessment in real-time. This is possible by using Landsnet wide-area measurement system (WAMS). The WAMS system is the center of all PMU measurements which is being gathered throughout the entire Icelandic electrical system. The thesis is about the research of security limits in the Icelandic power system and development of a algorithm which works as an early warning for instability in the Icelandic power system.

Nomenclature

AGC Automatic Generation Control

AVR Automatic Voltage Regulator

DLC Dynamic Load Control

DVAR Dynamic Volt-Amp Reactive

KKS Identification Systems for Power Plants (G: Kraftwerk Kennzeichnen System)

PDC Phasor Data Concentrator

PMU Phasor Measurement Unit

PSS Power System Stabilizer

PSS/E Power System Simulator for Engineering

SCADA Supervisory control and data acquisition

SIPS System Integrity Protection Schemes

SPS Special Protection Schemes

TSO Transmission System Operators

TETRA Terrestrial Trunked Radio

WACS Wide-area Control System

WADS Wide-area Defence Schemes

WAMS Wide-area measurement systems

Contents

List of Figures

List of Tables

List of Algorithms

Chapter 1

Introduction

1.1 Background

Electrical Transmission System Operators companys (TSO) want to maintain one level of redundancy for all transmission, generation and major distribution components. One of the main challenges of the TSOs is a great increase in load and difficulties with building new power lines to satisfy the load demand. Because of this increasing load demand and lack of investment in transmission infrastructure, therefore transmission capacity is often limited by thermal limitations in many cases [1].

In Iceland, Landsnet is responsible for the Icelandic electrical power transmission system. To maximize the transfer capabilities special protection schemes and wide-area control system have been used to stabilize the system during disturbances. These protection/control schemes are not implemented into the SCADA system or the PSS/E (Power System Simulator for Engineering) model, which is inconvenient for dynamic simulation. How is then possible to determine system maximum power tranfer capabilities? what are the consequences of a fault on the ability of the system to transfer power? This is one of the problems that are the motivation for the work in this thesis.

In the year 2007, Landsnet started to implement Phasor Measurement Units (PMUs) in their system to get more precise information regarding PSS equipment installation in Krafla to the control center. That was the beginning of Landsnet's Wide-Area Measurement System (WAMS). By analyzing the WAMS measurements and using them for daily system monitoring has led to more understanding on system stability and transient behavior.

The system is often operated without one level of redundancy and at the beginning load shedding schemes triggered by underfrequency conditions were installed to reduce power swings and frequency instability during disturbances. To maximize the transmission capabilities and increase stability, Wide-Area Control Systems (WACS's) have been implemented for real-time load control or load tripping. Along with WACS both traditional and special system protection schemes, which trip circuit breakers for islanding purposes and increase the generator response during disturbances, have been installed in the system.

1.2 Problem Description

The Icelandic power system is aging and overloaded, especially the 66kV distribution systems and the 132kV ring connection around Iceland. The 132kV ring was finished in the year 1984 and since then no major upgrades has been carried out. During the winter and when water reservoir are low, the 132kV is often operated above traditional security limits, which is based on the one level redundancy. In order to make the system more secure; the before mentioned protection schemes involving wide-area measurements have been implemented to control or trip load. But the operator in the control center does not know how much load will be tripped or controlled in real-time. By using the WAMS system it is possible to make calculation or measure the system stability threshold in real-time. This information can have significant influence on the system operation and how the system is operated.

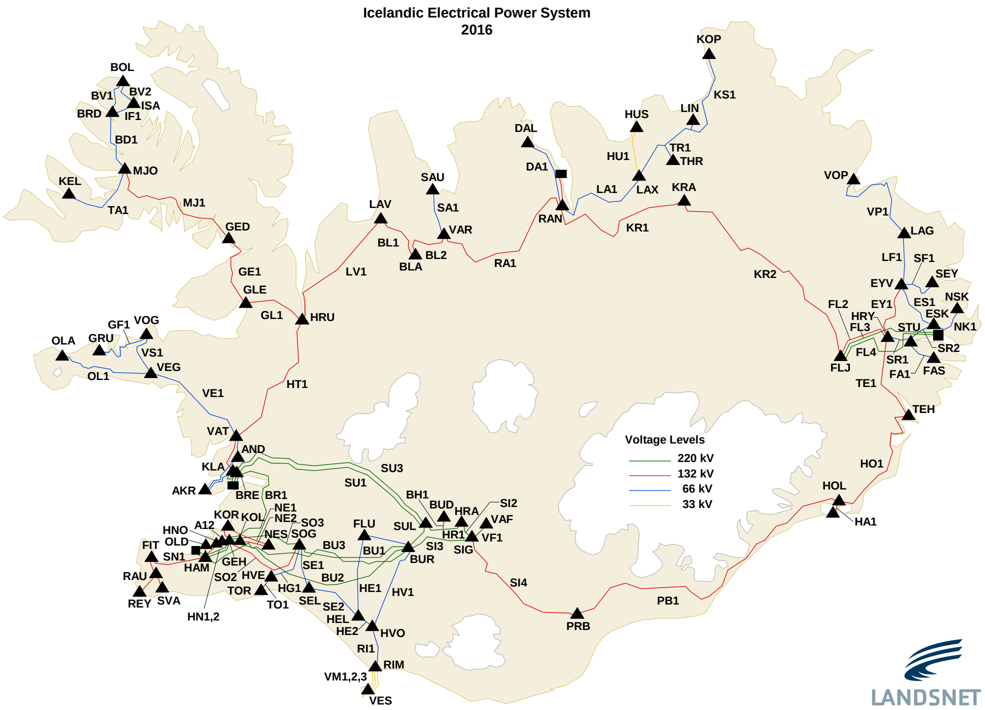


Figure 1.1 The Icelandic Electrical Transmission System [2]

Because the one level redundancy is often not fulfilled, it is necessary to obtain ways for system state estimation in real-time in case of a disturbance, with or without WACS and special system protection schemes. Load flow simulation informs the user if the system condition is good or bad with no regard to WACS og protection schemes. Therefore load-flow simulation (N-1 contingency analysis) do not show the real system response. It gives a simple idea of what will happen and works for system with no system protection schemes or WACS. In cases when the Icelandic system is heavily loaded it is not possible to use load-flow simulation with reliable results because of multiple protection schemes.

1.3 Project Aim

The general project aim is to valuate the security limits of the Icelandic power system without and with respect to WACS, traditional and special system protection and electrical production status in the system. By defining security limits, it is possible to introduce flexible transmission limits between different areas of production. Depending on the security limit it will be analyzed if it is possible to reform present system with islanding schemes.

With other words, the aim is to obtain a procedure to predict the security limits in real-time during operation of the Icelandic transmission system. The main project scope will be detecting the security limit, which refers to power transfer capacities for components, and how it should be split in case of emergency. The security limit depends partly on the power production which is often a consequence of the water reservoirs in East- and West Iceland, where the main electrical production is located. The system limitations are obtained by computer simulations, using PSS/E. By finding the system limitation with and without WACS, then it is possible to define thresholds for direct measurements or special algorithms, which will be developed and presented in this thesis.

The project aim is:

i Literature review and security assessment methods research

ii Implement WACS and Special Protection Schemes into PSS/E via Python code.

- Carry out a model validation to compare the model response to the real system response. This procedure is necessary for the knowledge of model limitations, see appendix 7.1 for more information.

iii Simulate chosen system corridors with the aim of finding security limits.

- System response is simulated in steps for particular corridors, or with other words cuts and will be discussed in chapter 2, to obtain knowledge how the system behaves during chosen events. Then this knowledge is used for defining the parameters which should be used for the security assessment in real-time using PMU data. The security assessment is done by using measurements in calculations and defining limits (thresholds) on the calculated value, either they are static or dynamic depending on generation or load conditions.
- The second task is to simulate various reasonable islanding schemes to check whether they are better or worse then the present islanding schemes.
- The third task, operation in case of emergency.

iv Defining methods and create algorithms for real-time security monitoring using Landsnet WAMS.

1.4 Thesis Structure

The thesis is categorized into five parts as follows:

- Part I - Background, Theory and State of the Art
  - Chapter 2: The Icelandic power system is described and what challenges are in the daily operation.
  - Chapter 3: This chapter introduces fundamental material regarding electrical power transmission capabilities and stability.
  - Chapter 4: Provides a theoretical discussion on how electrical power system simulations are performed.
  - Chapter 5: N-1 Criterion and Power System Security Assessent is introduced.
  - Chapter 6: Phasor Measurement, Wide-Area Measurement and Control Systems are discussed. Provides a description of special system protection schemes, system integrity protection schemes and wide area control system schemes. In this chapter are system protection schemes discussed which are used in the Icelandic power system.
- Part II - Model Discussion
  - Chapter 7: Model Validation Results are discussed
  - Chapter 8: Power System Comparison to Theory and Simulations are discussed and a real example analyzed.
- Part III - Simulation and Research
  - Chapter 9: Introduction to the simulation process and how it was organized.
  - Chapter 10: Simulation results are presented and discussed.
- Part IV - Real-Time Power System Security Assessment
  - Chapter 11: Discussion about real-time power system security assessment and how it can be used.
  - Chapter 12: Real-time power system security assessment Equations are presented, which are partly the result from the simulation results.
  - Chapter 13: Real-time power system security assessment algoritms are introduced. The algorithms use the equations presented in chapter 12.
- Part V - Conclusion and Future Work
  - Chapter 14: Conclusion and Future Work

Part I

Background, Theory and State of the Art

Chapter 2

The Icelandic Power System

This chapter is an introduction to the Icelandic electrical power system. System characteristics and challenges are described in a relevant way for the thesis material.

2.1 Introduction

The Icelandic power system has two main generation areas, one in West Iceland and other in East Iceland. These generation areas are connected by 30 year old 132kV line ring connection around Iceland. There are two 132kV radial ends, one that connects Westfjords to the main 132kV ring from Hrútatunga (HRU) and to Mjólká (MJO). The second is connected between Hamranes (HAM) to Fitjar (FIT) in Reykjanes. In South-West Iceland is a strong 220kV grid and in East-Iceland were Kárahnjúkar (KAR) hydro plant is located. Then are five 66kV distribution area based systems which are Landsnet responsibility, shown in figure 1.1

2.2 Characteristics of the Icelandic Power System

In this section characteristics of the Icelandic system will be introduced. The section is divided into two subsection. First section is about what kind of generation and load is in the system. The latter is about transmission limits and corridors (cuts).

2.2.1 System Generation and Load Characteristics

All power generation is renewable energy except for two islands (Grímsey and Flatey) that use fossil fuels for constant power generation, otherwise fossil fuel is used only during emergencies. Total power generation in the year 2010 was approximately 16 TWh and the percent share of total electricity generation can be seen in figure 2.1 [3].

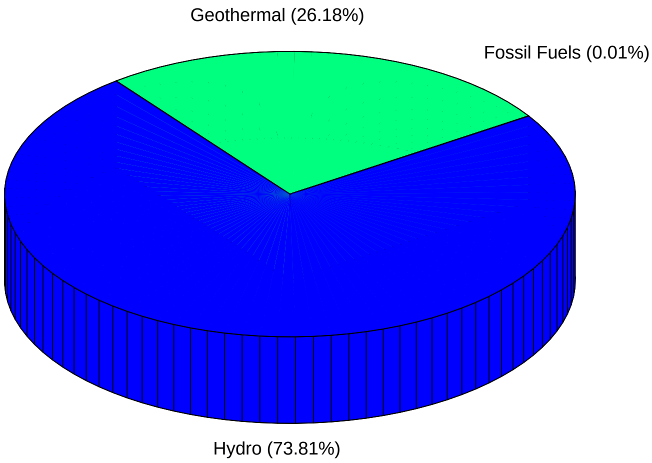


Figure 2.1 Percent Share of Total Electricity Generation [3]

Hydro power plants production depends on water reservoirs levels. Often it is necessary to transfer power from West to East Iceland (and vice versa) because of low reservoir levels. This leads to heavy transfer between areas through weak and long 132kV ring connection around Iceland. The 132kV ring is a huge bottleneck in system operation and during the winter time risk of disturbance is very high.

Geothermal power plants are power regulated. To get the best efficiency out of the resource it is necessary to keep the steam process constant as possible. Geothermal power plants are often slow in switching or do not switch to frequency regulation during disturbances. Therefore hydro power plants are the prime frequency regulators.

One of the challenges in operation of the Icelandic power system is low inertia. In South-West Iceland the inertia is more than in the East and North. High inertia systems are often described as ”stiff”, so the South-West is relatively stiff in comparison to East and North [4]. During islanding conditions the East island is weaker then the West in case of inertia. Inertia has a major influence of frequency stability and the relationship will be introduced in section 3.3.

The load consumption is mainly heavy industrial loads, three aluminum smelters (two in West Iceland and one in the East), one ferro silicon plant (West Iceland), data centers (Reykjanes) and aluminum foils factory (Akureyri). The rest is ”general” consumption, smaller industry and public consumption. The load percent share is shown graphically in figure 2.2.

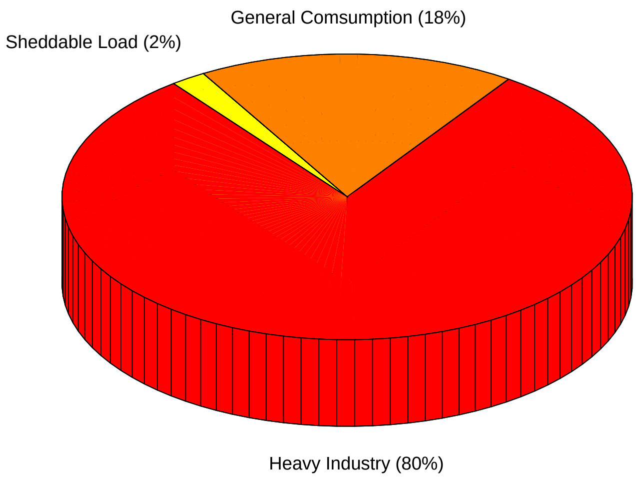


Figure 2.2 Percent Share of Total Load [3]

Because four heavy industrial smelters are such a large part of the load it causes problems if there is a disturbance in their production process, offhand tripping and sudden changes in load can cause frequency instability. Aluminum smelters are sensitive to voltage instability which often leads to load being disconnected which causes frequency instability.

In this thesis Landsnet KKS code (G: Kraftwerk Kennzeichnen System, E: Identification Systems for Power Plants) is used for simplification. Icelandic names are shown first then appropriate KKS code name is then put in parenthesis afterwards. The KKS code will be used and the reader is encouraged to either check figure 1.1 or read the system plan document [5] for more information.

2.2.2 Transmission Limits and Cuts

Factors which can limit transmission capabilities are:

- Thermal Limits
- Frequency Stability
- Rotor Angle Stability
- Voltage Stability

Frequency, Voltage and Rotor angle stability are often assessed for steady-state operation and for contingencies analysis that are relevant for security assessments. To estimate system state and simplify operation of the Icelandic system, Landsnet has defined relevant transmission corridors that are prone to congestion, or so called "cuts" to distinguish between power flows in the system. The cuts that will be under investigation in this thesis are shown in figure 2.3.

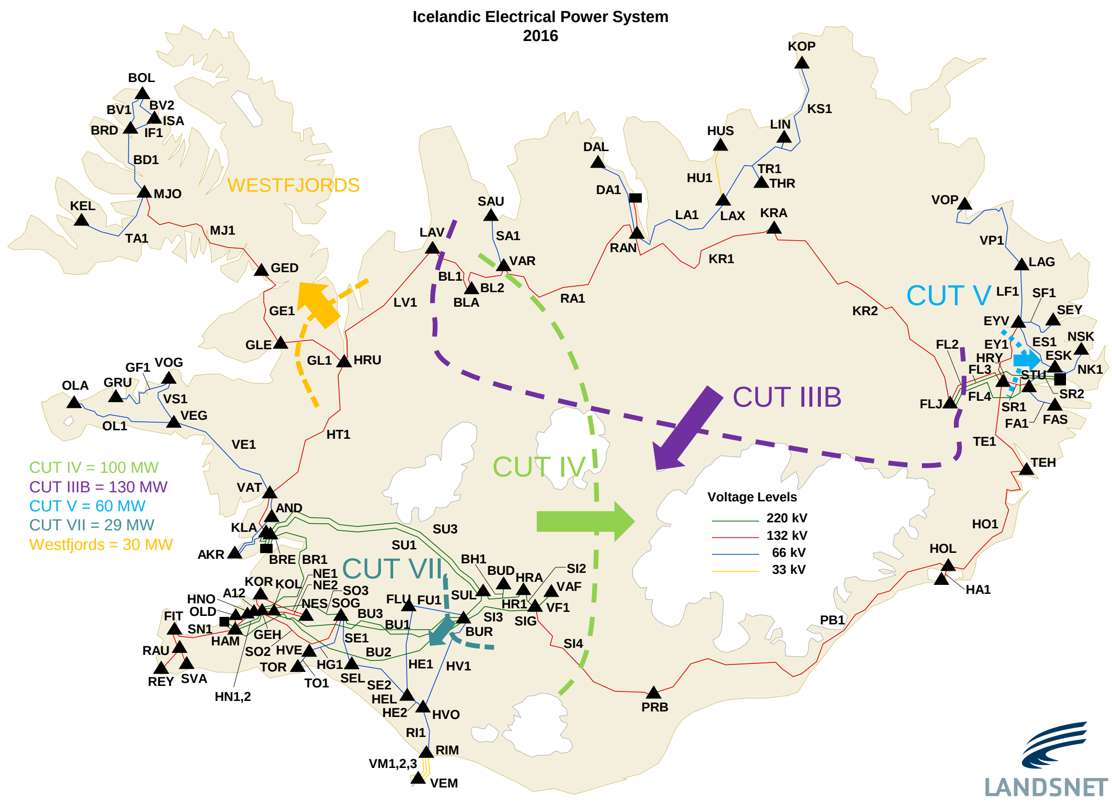


Figure 2.3 The Icelandic Transmission System [2]

Here below are the cuts listed and defined along with their transfer limits:

- Cut IIIb = BL1 + FL2 = 130MW
- Cut IV = BL2 + SI4 = 100MW
- Cut V = SR1 + EY1 = 60MW
- Cut VII = HE1 + HV1 = 29MW

At present the limits are built upon experience, thermal limits and frequency stability. If the power transfer is from the East to West and one line trips it can lead to a system separation and unbalanced islands. Then in the East island there is more than enough power which leads to overfrequency and in the West island power is needed which leads to underfrequency. The magnitude of power transfer between the East and West is what indicates how severe the frequency deviation in each island will be. Cut IV and Cut IIIb are cuts that measure this export/import between areas.

Cut VII is in the 66kV system in South Iceland and the lines are heavily loaded due to thermal limits and voltage stability. Load has increased in the South of Iceland, especially in Vestmannaeyjar (VEM) because of more fish related industries. Cut V is used to monitor power flows in East Iceland, or so called Eastfjords. The transmission line are capable of transferring the needed power but are limited by the thermal limits of cables that are used to connect transmission lines to switchgear which is located inside the substations. The thermal limits of the cables used in the 66kV area based systems is one the main problems in the operation of these system when the load is heavy.

2.2.2.1 Introduction to Interesting Cuts in the Icelandic Power System

Westfjords - 132kV Radial Line (Westline) Westfjords is a special case in the Icelandic power system. Westline (Vesturlína) consist of three 132 kV transmission line which make one radial line. The total length of the line is 162 km and is one of the longest lines in the Icelandic transmission system. It was built during the years of 1980 to 1983. Westline is one of the least reliable transmission line in the system because of the relatively high threat of icing and bad storms. Technical transmission capacity of the Westline is 100 MVA but the bottleneck of transmission is a 132 kV/66 kV transformer in Mjólká (MJO), which is only 30 MVA. Subsequently, the transmission capacity is severely under developed, only 30% of the technical transmission capacity is used during the heaviest load cases. But it should be noted that the line is very long and with more power flowing through the line the increase of loss and voltage drop increases [6].

CUT IIIb - Power Export from East to the West Cut IIIb is the active power sum of Fljótsdalslína 2 (FL2) and Blöndulína 1 (BL1). The power flow through Cut IIIb is a measurement on power transfer from East Iceland to West Iceland. The power flow through Cut IIIb is above 100MW if the water reservoirs in KAR are good. Then generators at KAR are used to produce as much as possible and export power to the West for saving water in reservoirs. Cut IIIb is then above 100MW in the beginning of summer when the snow is melting into KAR reservoirs in the highlands. FL2 thermal limit is a 178MVA line, but is limited to 91MVA by current transformer at Hryggstekkur (HRY). FL2 lies over a mountain which is called Hallormsstaðarháls and failures on the line are often because of icing conditions on that mountain. BL1 transmission capacity is 178MVA due to thermal limits and is not limited by current transformers. BL1 is rather short and there are not often faults on the line.

CUT IV - Power Export from West to the East Cut IV is the active power sum of Sigöldulína 4 (SI4) and Blöndulína 2 (BL2). Cut IV is a measurement on active power transfer from West Iceland to the East. Flow in Cut IV is dependent on mainly three factors: reservoirs at Kárahnjúkavirkjun (KAR), fish smelter load and generator maintenance in KAR. When the flow is over 100MW then one or two of these factors are the reasons for such high import to East Iceland. The load is heavy and only one large hydro power plant, KAR, along with few smaller generation station, for example geothermal plant Krafla (KRA) rated 60MVA and the hydro plant Lagarfossvirkjun (LAG) which is rated 34MVA, are located in East Iceland. To improve system stability during emergencies and disturbances there are many defense schemes, for example load shedding scheme for the fish smelters and tripping schemes for the transformer 7 and transformer 8 in FLJ. These schemes are discussed in 6.6.2.3 and 6.6.2.2. SI4 is limited by current transformers at SIG and the transfer capacity is therefore 91MVA, but thermal limits are 178MVA. Thermal limits of BL2 is 178MVA line and is not limited by current transformers. BL2 is a rather short line.

CUT V - Eastfjords Cut V is the active power sum of Stuðlalína 1 (SR1), which is 132kV cable from Hryggstekkur (HRY) to Stuðlar (STU), and Eyvindarárlína 1 (EY1), which is a 132kV overhead line from HRY to Eyvindará (EYV). Cut V is a measurement on active power being used in the Eastfjords. When Cut V is near or above its defined limits it is because of fish smelters are using electricity for its production (smeltering or freezing fish). These lines are the main power supply for the Eastfjords and therefore very important for power reliability in the area. SR1 and EY1 are both limited by current transformers and can transfer 91MVA. The 66kV system that is connected to STU and EYV can handle up to 50-60MVA.

CUT VII - South Iceland Cut VII is the sum of Hvolsvallarlína 1 (HV1) and Flúðalína 1 (FU1). Cut VII is in South Iceland and is heavily loaded during the winter time. The largest load is in Vestmannaeyjar (VEM) or 24MW, where water heating is 14-16MW. This part of the system is one of the weakest and well over the cut limit during the winter. FU1 and HV1 are the main power supply for the area. FU1 is limited by the thermal limits of an cable which is a part of line and therefore can only transfer 26MVA. But the line is thermal limits are 54MVA. HV1 has 54MVA thermal limit but is limited to 45MVA by current transformers at BUR and HVO.

Chapter 3

Electrical Power Transmission Capability

This chapter provides an overview of basic concepts and definitions related to power system stability as it is used in the following chapters. Furthermore, a general description of how a power system, like the Icelandic one, is limited by small transmission capacity between areas and has only renewable electricity generation which is mainly hydro but also geothermal which is not problematic when comes to stable generation. Here below is a summary over factors that are limiting in electrical power transmission systems. These factors are all critical and essential with respect to a save and secure power system.

- *Transformers*
- *Circuit breaker ratings*
- *Current transformers*
- *Thermal limits of lines*
- *Stability*

These factors will be discussed in this chapter theoretically and practically. The practical approach is more relevant regarding the security assessment.

3.1 Power System Stability

In [4] and in [7] stability is defined as:

> *The concept of stability is central to several disciplines, for example in electrical engineering, physics and mathematics. Control systems that do not exhibit stable performance would be almost worthless and stability theory is central to control system design and analysis.*

Power systems should be designed in way it can withstand naturally occurring disturbances and as well costumer-related disturbances. In [8, p.854] stability is defined as:

> *Stability is the ability of a power system to remain in synchronous equilibrium under steady operating conditions, and to regain a state of equilibrium after a disturbance has occurred.*

In [4, p.17] stability is described as:

> *Power system stability may be broadly defined as that property of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance.*

And according to [4, p.17-18], [9], [10] and [11], instability is described as:

> *Instability in a power system may be manifested in many different ways depending on the system configuration and operating mode. Traditionally, the stability problem has been one of maintaining synchronous operation. Since power systems rely on synchronous machines for generation of electrical power a necessary condition for satisfactory system operation is that all synchronous machines remain in synchronism or "in step". This aspect of stability is influenced by the dynamics of generator rotor angles and power-angle relationships*

Disturbances can be of any type, and have the potential of causing instability if not removed promptly. Power systems are normally not designed to withstand extremely large disturbances, but the anticipation of such events may lead to the design of appropriate controlled response schemes. Underfrequency load shedding is one example of such a scheme. Stability is also defined in a mathematical context, in which case stability under consideration is the stability of solution of the differential equations that describe the power system [8, p.854].

> *Stability refers to the behaviour of the solution of the nonlinear differential equations that are used to represent the physical power system.*

Power system stability can be classified into two main classes and subclasses in terms of categories, angle stability and voltage stability as is shown in Appendix C.1. The figure shown in the Appendix gives the overall picture of the power system stability problem and is a effect and convenient way to deal with complexities of the problem. But overall stability of the system should always be kept in mind. Solutions to stability problems of one category should not be at the expense of another. It is essential to look at all aspects of the stability phenomena and at each aspect from more than one viewpoint [4].

3.2 Power Transfer Between Active Sources

Examining factors that influencing transfer of active and reactive power between two sources connected by inductive reactance in figure 3.1. This kind of system is a representative of two sections of a power system interconnected by a transmission system with power transfer from one section to the other.

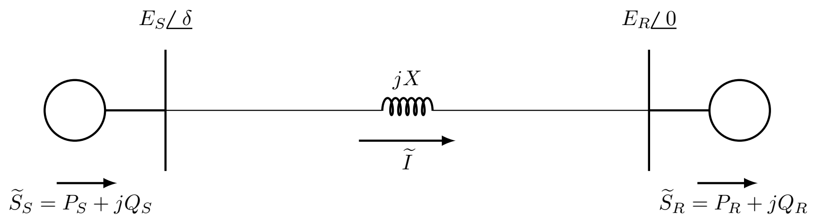


Figure 3.1 Equivalent system diagram [4]

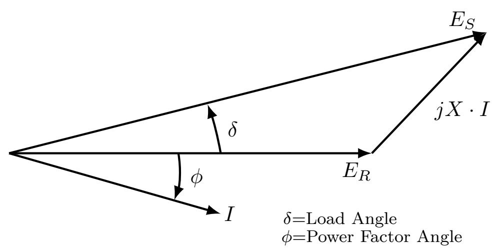


Figure 3.2 Phasor diagram [4]

The impedance representing the transmission lines, transformers and generators is by most part inductive and the resistance (real part) of the impedance neglected. When a full network is represented as a model for each of its elements and then reduced to a two-bus system, the resulting impedance will be essentially an inductive reactance. The shunt capacitances of transmission lines do not explicitly appear in the model shown in figure 3.1, their effects are implicitly represented by the net reactive power transmitted. Analysis of transmission of active and reactive power through an inductive reactance thus gives useful insight into the characteristics of transmission systems [4, p.250].

Complex power at the receiving end is defined as:

$$S_R = P_R + jQ_R = E_R \cdot I^* = E_R \cdot \left[\frac{E_S - E_R}{jX}\right]^* = E_R \cdot \left[\frac{E_S cos\delta + jE_S sin\delta - E_R}{jX}\right]^* \quad (3.1)$$

The real and imaginary part of the complex power at the receiving end is defined as:

$$P_R = \frac{E_S E_R}{X} sin\delta \quad (3.2)$$

$$Q_R = \frac{E_S E_R cos\delta - E_R^2}{X} \quad (3.3)$$

And for the sending end:

$$P_S = \frac{E_S E_R}{X} \sin \delta \tag{3.4}$$

$$Q_S = \frac{E_S^2 - E_S E_R \cos \delta}{X} \tag{3.5}$$

These equations describe how active and reactive power are transferred between the active parts of the power system. By looking at the equations here above and imagine that if $\delta = 0$ then no real power is transferred, but reactive power is transferred. The sending end voltage is larger then the receiving end $E_S > E_R$, and Q_S and Q_R are both positive and therefore reactive power is transferred from the sending end to the receiving end. If $E_S < E_R$ and and Q_S and Q_R are both negative then the reactive power flows from the receiving end to the sending end. To interpret this conclusion,

- Lagging current that flows through inductive reactance causes a drop in receiving end voltage.
- Leading current that flows through inductive reactance causes a rise in receiving end voltage.

Then for each case the reactive power can be defined as in 3.6.

$$Q_S - Q_R = \frac{(E_S - E_R)^2}{X} = XI^2 \tag{3.6}$$

Then the conclusion is that the reactive power consumed by the reactance X is XI^2

If $\delta > 0$ and $E_S = E_R$, then P_S and P_R are positive. With that conditions fulfilled then the active power flows from the sending end to the receiving end.

$$P_R = P_S = \frac{E^2}{X} \sin \delta \tag{3.7}$$

$$Q_S = -Q_R = \frac{E^2}{X}(1 - \cos \delta) = \frac{1}{2} XI^2 \tag{3.8}$$

If $\delta < 0$ then the active power flows in the reverse direction, from the receiving end to the sending end. In both of these cases no reactive power is transferred because each end supplies half of the reactive power XI^2 consumed by X. If the receiving end voltage and current are in phase, the power factor is unity, and the magnitude of E_S is only little bit higher then E_R the sending end supplies all of the XI^2 consumed by X.

The active power is function of voltage magnitudes and δ. In power systems in general the voltage magnitude has to be within a certain limit from the nominal value and therefore the active power transfer is controlled mainly by change in angle δ.

In power systems losses are always a problem. To describe the way losses occur it is necessary to define a equation for the current I.

$$I = \frac{E_S \cos\delta + jE_S \sin\delta - E_R}{jX} \tag{3.9}$$

Where the reactive power losses are defined as:

$$Q_{\text{losses}} = XI^2 = X\frac{P_R^2 + Q_R^2}{E_R^2} \tag{3.10}$$

If the series resistance R of the network is added then:

$$P_{\text{losses}} = RI^2 = R\frac{P_R^2 + Q_R^2}{E_R^2} \tag{3.11}$$

From defined losses equations the reactive power losses are always absorbed by X, XI^2. Then the concept "reactive power loss" is a companion term to "active power loss" RI^2, absorbed by R. From the same equations it can be seen that if reactive power is increased then active power losses increase as well as reactive power losses. This is the fundamental problem of power transmission efficiency and voltage regulation.

From above analysis following conclusions were made:

1. Active power transfer depends mainly on angle, which the sending end voltage leads the receiving end voltage.
2. Reactive power transfer depends mainly on voltage magnitudes. Reactive power is transmitted from the end with the higher voltage magnitude to lower voltage magnitude end.
3. Its not possible to transmit reactive power over long distances because it would require a large voltage gradient to do so.
4. An increase in reactive power transfer causes an increase in active power losses as well as reactive power losses.

These general conclusions are acceptable for practical systems. The basic characteristics of ac transmission reflected in these conclusions have a dominant effect on the way in which we operate and control power systems [4, p.250-254].

3.3 Control of Active and Reactive Power

Active- and reactive power are influenced by different control action as was discussed in section 3.2. Therefore these two different types of power can be investigated separately in a large class of problems. Active power is related to frequency control and reactive power is related to voltage control. The quality of power supply is mainly determined from these two factors, frequency and voltage, therefore the control of these types of power are vital for a satisfactory performance of power systems. In the following sections the control actions are discussed along with the main properties.

3.3.1 The Swing Equation

To determine the dynamic behavior of a generating unit in a power system during a disturbance there is a equation called *swing equation*. The equation is Newton's second law, expressed in terms of the power system quantities. The prime mover and generator can be described by the second order differential equation 3.12 [8, p.858].

$$J\frac{d^2\theta}{dt^2} = T_a \qquad \text{[Nm]} \tag{3.12}$$

where

J = moment of inertia (kg-m^2)
θ = physical angle of shaft (rad)
t = time (s)

Unbalance between the torques acting on the rotor, the net torque causing acceleration or deceleration is defined as:

$$T_a = T_m - T_e \qquad \text{[Nm]} \tag{3.13}$$

where

T_a = accelerating torque (Nm)
T_m = mechanical torque (Nm)
T_e = electromagnetic torque (Nm)

The total shaft angle can be expressed as:

$$\theta = \omega_R t + \delta_m + \alpha \qquad \text{[rad]} \tag{3.14}$$

where

ω_R = shaft rated angular velocity (rad/s)
δ_m = torque angle (rad)
α = arbitrary angle to a fixed reference (rad)

Shaft rated angular velocity give the angular position of a synchronously rotating reference. If there were no disturbance to the shaft, the total angle θ would advance linearly with time and the angle δ_m to vary, usually damped oscillatory manner for a smaller disturbance, but it may increase or decrease monotonically without oscillation for a large disturbance.

There is unique relationship between the shaft angular velocity and the electric system radian frequency that depends entirely on the number of poles in the generator. This relationship can be written in terms of angular velocities as:

$$\omega = \frac{p}{2} \cdot \omega_m \tag{3.15}$$

where

p = number of poles (rad/s)
ω = radian frequency of generated voltage (rad/s)
ω_m = mechanical shaft speed of generator (rad/s)

The base values for the angular velocities can be written from 3.15 as:

$$\omega_B = \frac{p}{2} \cdot \omega_R \tag{3.16}$$

where

ω_B = electric system base radian frequency (rad/s)
ω_R = mechanical shaft speed of generator (rad/s)

In computations involving power system it is convenient to normalize all equations with respect to a common system volt-ampere base. Normalizing the swing equation requires that we find an expression for the base torque. Torque is related to power and speed by the expression

$$\text{Torque} = \frac{\text{Power}}{\text{Speed}} \rightarrow T_B = \frac{S_B}{\omega_R} = \frac{pS_B}{2\omega_B} \tag{3.17}$$

where S_B is the system three-phase voltampere base.

$$\frac{2H\omega_u}{\omega_B}\frac{d^2\delta}{dt^2} + \frac{D\omega_u}{\omega_B}\frac{d\delta}{dt} = P_{mu} - P_{eu} \tag{3.18}$$

Equation 3.18 has convenient form since the electric generated power can be written in terms of the angle δ. The result is a differential equation that can be solved for the torque angle δ. Sometimes the equation is simplified by assuming that the mechanical power is constant, which is usually true for a short time following the initiation of a disturbance, since it takes a finite amount of time for the speed governor to respond, change the prime mover valve position, and for the prime mover power to change [4], [8].

3.3.2 Reactive Power and Voltage Control

The control of reactive power and voltage should satisfy the following objectives:

1. Voltage at the terminals of all equipment in the system are within acceptable limits.
2. System stability is enhanced to maximize utilization of the transmission system.
3. The reactive power flow is minimized to reduce RI^2 and XI^2 losses to a pratical minimum. This ensures that the transmission system operates efficiently. Mainly for active power transfer.

3.3.2.1 Reactive Power Compensation and Methods of Voltage Control

Reactive power compensation is often the most effective way to improve both power transfer capability and voltage stability. The compensation is done either by shunt or series, active or passive components. Active compensation uses feedback control to regulate the voltage or other variables. The following forms of compensation is available:

- Synchronous generators - *absorb and produce*
- Overhead lines - *depending on load current they absorb or supply*
- Underground cables - *produce*
- Transformers - *absorb*
- Loads - *absorb (some cases produce and are then capacitive compensated)*
- Compensating devices - *supply or produce depending necessity*

The control of voltage levels is accomplished by controlling the production, absorption, and flow of reactive power at all levels in the system. The generating units provide the basic means of voltage control; the automatic voltage regulators control field excitation to maintain a scheduled voltage level at the terminals of the generators. Additional means are usually required to control voltage throughout the system. The devices used for this purpose may be classified as follows:

- Sources or sinks of reactive power, such as shunt capacitors, shunt reactors, synchronous condensers, and static var compensators (SVCs).
- Line reactance compensators, such as series capacitors.
- Regulating transformers, such as tap-changing transformers and boosters.

Shunt capacitors and reactors, and series capacitors provide passive compensation. These devices are either permanently connected or switchable. The contribute to voltage control by modifying the network characteristics. Synchronous generators and SVCs provide active compensation, because the reactive power is automatically adjusted to maintain voltages at the buses in the system. Generating units and SVCs hold the voltages steady at certain points in the system. Voltages elsewhere in the system are determined by active and reactive power flows through the system circuits [4, p.627-629].

3.3.3 Active Power and Frequency Control

In a stable power system the frequency is nearly constant. A good frequency control keeps a constancy in speed for induction and synchronous machines. A constancy in speed is very important for generating units as they are highly dependent on the performance of the auxiliary equipment that controls the speed. In a power system there are many generating units and each one has its speed governor that provides the primary speed control function, while supplementary control orginating at a central control centre allocates generation. The control of generation and frequency is commonly referred to as ”load-frequency control” [4].

3.3.3.1 Generator response to load change

If there is a load change the electrical torque output T_e of the generator changes instantaneously. Then a mismatch between the mechanical torque and the electrical torque is formed which results in change of generating unit speed and is determined by equation of motion or the swing equation 3.3.1, [8].

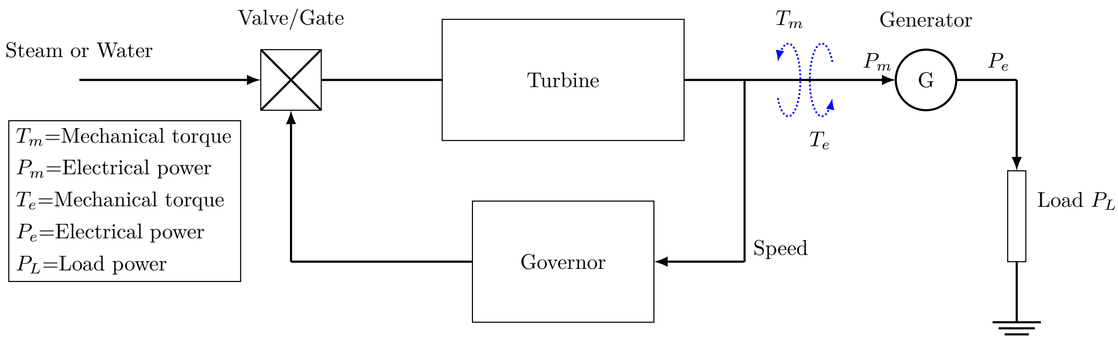


Figure 3.3 Generator supplying a load [4, p.582]

Figure 3.4 represents the relationship between rotor speed and the function of electrical and mechanical torques. When studying load and frequency is preferred to use the quantity of power.

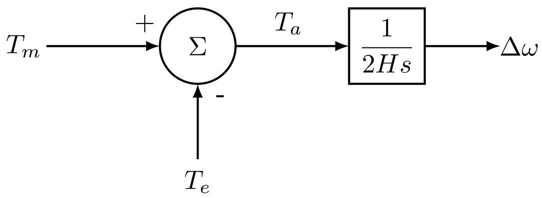


Figure 3.4 Generator transfer function speed and torque [4, p.582]

The relationship between power P and torque T is:

$$P = \omega_r T \tag{3.19}$$

If the deviation in speed is small then the prefix Δ is used and the initial value is denoted by $_0$.

$$P = P_0 + \Delta P$$

$$T = T_0 + \Delta T$$

$$\omega = \omega_0 + \Delta\omega$$

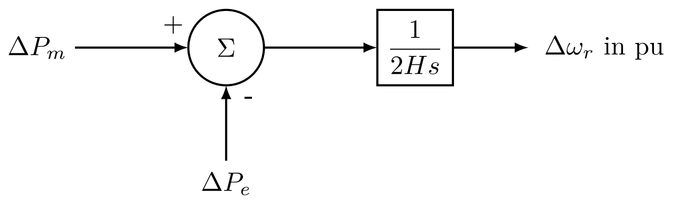


Figure 3.5 Generator transfer function speed and power [4, p.582]

In steady state the electrical and mechanical torques are equal with constant speed. Then relationship between power and torque can be expressed as:

$$\Delta P_m - \Delta P_e = \Delta T_m - \Delta T_e \tag{3.20}$$

The inertia constant H is defined as the kinetic energy in watt-seconds at rated speed divided by the VA base. Using ω_0 to denote rated angular velocity in mechanical radians per second, the inertia constant is [4, p.129,132]

$$H = \frac{\text{stored energy at rated speed in MW per second}}{\text{MVA rating}}$$

$$H = \frac{1}{2}\frac{J\omega_{0_m}^2}{VA_{base}} \tag{3.21}$$

3.3.3.2 Load response to frequency deviation

Power system loads are composite of a variety of electrical devices. The overall frequency-dependent characteristic of a composite load may be expressed as:

$$\Delta P_e = \Delta P_L + D\Delta\omega_r \tag{3.22}$$

where

ΔP_L = Non-frequency sensitive load change
$D\Delta\omega_r$ = Frequency sensitive load change
D = Load damping constant

The damping constant is a percent change in load for one percent change in frequency. The response of the system, if there is no speed governor, is determined by the inertia constant and the damping constant. The steady-state deviation is such, the change in load is exactly compensated by the variation in load due to frequency sensitivity [4, p.581-585].

3.3.3.3 Governors with speed-droop characteristics

If all the generator have the same speed setting then they will fight each other, trying to control system frequency to its own setting. For stable load division between two or more units operating in parallel, the governors are provided with a characteristic so that the speed drops as the load is increased. The speed-droop characteristic can be obtained by adding a steady-state feedback loop around the integrator as shown in figure 3.6 [4, p.589].

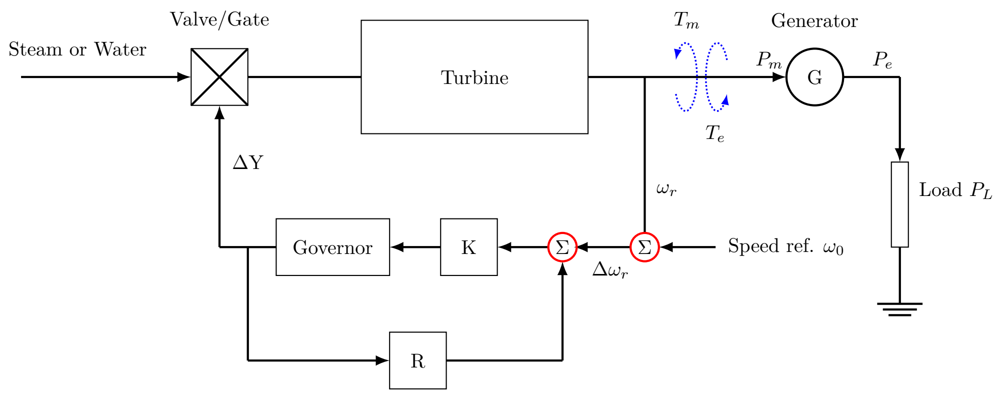


Figure 3.6 Governor with steady-state feedback [4]

The value of R determines the steady-state speed versus load characteristic of the generating unit. In more details it is the ratio of speed deviation ($\Delta\omega_r$) or frequency deviation (Δf) to change in valve/gate position ΔY or power output (ΔP) is equal to R. The parameter R is the speed regulation or so called ”droop”.

$$\%R = \frac{\text{percent speed or frequency change}}{\text{percent power output change}} = \frac{\omega_{NL} - \omega_{FL}}{\omega_0} \cdot 100 \tag{3.23}$$

where

ω_{NL} = Steady-state speed at no load
ω_{FL} = Steady-state speed at full load
ω_0 = Nominal or rated speed

This speed droop characteristic is represented as the ideal relationship. The actual speed droop characteristic is typically on the range from 2% to 12% depending on the unit type, steam or hydro, and unit output.

The composite power/frequency characteristic of a power system depends on the combined effect of the droops of all generator speed governors and the load in the system. The composite frequency response characteristic of the system is defined as:

$$\beta = \frac{-\Delta P_L}{\Delta f_{SS}} = \frac{1}{R_{eq}} + D \tag{3.24}$$

β is expressed in MW/Hz and sometime referred to as the stiffness of the system. The composite regulating characteristic of the system is equal to $1/\beta$. An increase in system load will increase the generation due to governor action and a total system load due to its frequency-sensitive characteristic.

3.4 Frequency Stability

In [12] frequency stability is defined as:

> *Frequency stability refers to the ability of a power system to maintain steady frequency following a severe system upset resulting in a significant imbalance between generation and load. It depends on the ability to maintain/restore equilibrium between system generation and load, with minimum unintentional loss of load. Instability that may result occurs in the form of sustained frequency swings leading to tripping of generating units and/or loads.*

In large interconnected system frequency instability can occur when systems are splitted into islands and the question is if the load-generation balance is acceptable [12]. In section 3.4.1 abnormal frequency conditions are introduced and their effects on system components. The classification of stability is best described by figure in Appendix C.1. The disadvantage with figure in Appendix C.1, is that frequency stability is not defined in the figure. In [12] this same figure has been updated and is shown here below in figure 3.7.

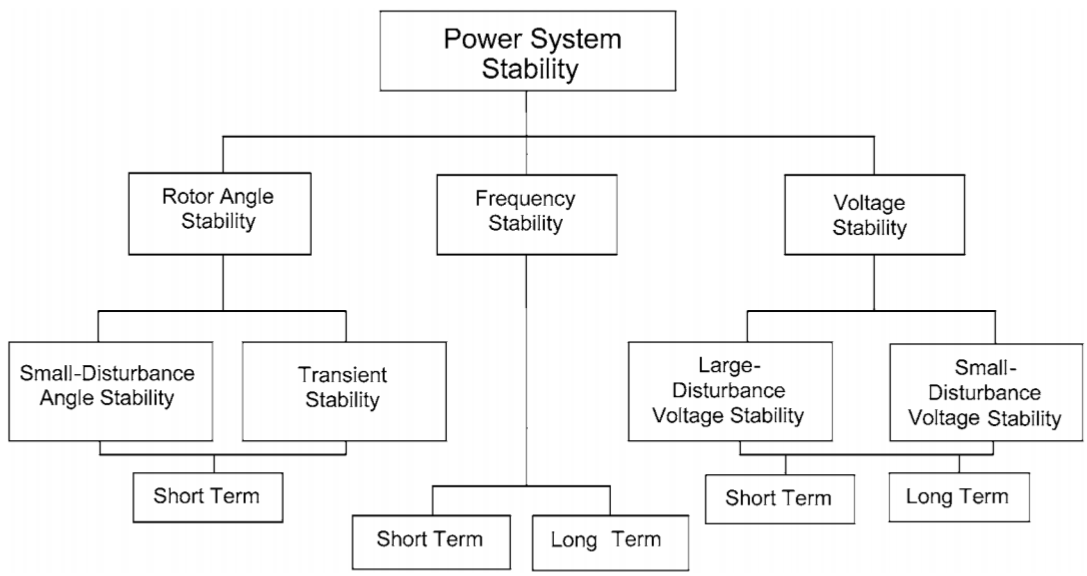


Fig. 1. Classification of power system stability.

Figure 3.7 Classification of Power System Stability [4, p.36]

In isolated island systems, frequency stability can be a problem for any disturbance causing a significant loss of load or generation [13]. In the Icelandic power system, which is an isolated islanded system, frequency stability is the most common problem. The load is 80% aluminum smelters that are sensitive for voltage variations which can lead to load tripping, if there is a large change in voltage magnitude. When the load is tripped than frequency stability is a large concern. The effects of frequency variations will be discussed in section 3.4.1.

The frequency stability issue can be attributed to low inertia of the Icelandic power system. The system has many small generators, mainly hydro but also geothermal. Geothermal plants do not participate in frequency regulation, the power output is constant. The reason for this is that geothermal plants are very sensitive to frequency instability because the speed of the generators is high (3000rpm - 2 pole generators). The speed is related to frequency which can lead to tripping because of overspeed and is best described by the following formula.

$$n_s = \frac{120 \cdot f}{P} \tag{3.25}$$

Therefore the hydro power plants in the system contribute the most in during a disturbance. There are many small generators with relatively low inertia. The importance of inertia is best shown by the swing equation, discussed in detail in section 3.3.1. When determining frequency gradient during a disturbance the total rotational energy of the system is needed. To calculate that value apparent power for the generators in the system are needed S_{rated} and the inertia constant H of each generator. Then the total rotational energy E_{rot} can be calculated by formula 3.29 in next section.

3.4.1 Abnormal Frequency Operation

Abnormal frequency conditions are when power systems influence disturbances of two kinds. First, if relatively large load is tripped then power systems are influenced by overfrequency effects. Second, if relatively large generating units tripped then power systems are influenced by underfrequency effects. These two conditions can have severe consequences and can lead to total blackout or electrical equipment to be damaged. In section 3.4.1.1 and 3.4.1.2 the effects of under- and overfrequency are discussed in detail.

3.4.1.1 Effects of Overfrequency Conditions

Overfrequency conditions occur because of generation increase or load loss, which is often termed a load rejection as far as the generating units concerned. The result is increased speed of the generating unit and should be controlled by the prime mover speed governors. Assuming that the load reference settings of the speed governors are not changed, the governor ”droop” setting will determine the final change in generator speed or frequency per unit change in load. Should the overspeed condition persist, the generator is usually not in a hazardous condition since generator loading is lower than normal and cooling is improved due to the increased speed. Moreover, since the load has been lost, voltages are likely to be high, resulting in reduced excitation. If the excitation is greatly reduced, the generator might be tripped by loss-of-excitation protection, depending on the sensitivity and settings of these relays. It is possible that a unit could be tripped due to high voltage, should voltage regulator be out of service. Generator tripping may not necessarily be a serious matter since there is already too much generation in the overfrequency island, and such a trip is likely to be an isolated event. Assuming a 5% droop characteristics in the governor, a 50% load rejection will result in a 2.5% rise in speed, to frequency of 51,25Hz. Turbine has a lifetime of tenth of minutes at this speed. Thus, even if the governor is not responding quickly, the operator has time to take manual control action to reduce the governor load reference setting before a substantial loss of life occurs. For higher frequency excursions, and overfrequency relay can be used to initiate runback of the governor load reference motor, which readjusts the desired turbine output [8].

3.4.1.2 Effects of Underfrequency Conditions

In an underfrequency island all the generators in the system are overloaded and the speed, and hence the cooling, are below normal. Because of the overload conditions, system voltages are likely to be low, causing generator excitations to be increased, perhaps to their limits. This raises the possibility of thermal overload of both the stator and the rotor. The possibility exists for unit trip due to stator overheating, rotor overheating, overexcitation and underfrequency (volt/hertz). Moreover, the entire island is short of generation and a trip of any unit could start a cascading of unit trips and a rapid deterioration of the island to a complete blackout condition. Therefore, it is very important that the protection not be overly sensitive and initiate unit trips unless absolutely necessary. Looking at underfrequency conditions with respect to the turbines it is important that the turbine is protected by underfrequency relaying to prevent lengthy excursions that expend large amounts of turbine life. Another perspective is to shed load instead of using underfrequency relays to trip the generator to avoid system blackout. A good system load shedding defense scheme is a more convenient way of making sure the island will survive the disturbance and prevent turbine damages [8].

3.4.2 Introduction to Frequency Gradient Calculations

In section 3.3 and 3.4.1 frequency control and the effects of abnormal frequency conditions are discussed. If it is a possibility to predict with little uncertainty the Icelandic system frequency response, it could be a good input for the system operators at Landsnet. In section 3.3.1 the swing equation is discussed. From the swing equation it is possible to determine the frequency gradient, if the swing equation is expressed in terms of angular velocities:

$$\frac{2H}{\omega_{0m}}\frac{d^2\delta}{dt^2} = 2H\frac{d\omega_m}{dt} = P_m - P_e = P_a \quad \text{[pu]} \tag{3.26}$$

By rearranging the formula, then the frequency gradient can be determined

$$\frac{df}{dt} = f_0\frac{d\omega_m}{dt} = \frac{P_a f_0}{2HS_{gen}} = \frac{\Delta P \cdot f_0}{2E_{rot}} \quad \text{[Hz/s]} \tag{3.27}$$

The size of a disturbance (ΔP) in respect to the total rotational energy in the system determines the frequency gradient at t=0.

$$\left(\frac{df}{dt}\right)_{t=0} = \frac{\Delta P \cdot f_0}{2E_{rot}} \quad \text{[Hz/s]} \tag{3.28}$$

The rotational energy is calculated by multiplying each generator inertia constant to the S_{max} and summed up together.

$$E_{rot} = \sum_{i=1}^{N} H_i S_{gen,i} \quad [MJ] \tag{3.29}$$

In equation 3.28, if generation decrease or load increase have the same effect on system frequency, therefore ΔP is negative $-P$ in those conditions. But if generation is increased or load decreased, then ΔP becomes positive $+P$.

Equation 3.28 output shows how fast the frequency will drop or rise if there is a disturbance. But it does not indicate how the generators will respond to the disturbance or how the frequency will be in steady-state condition after the disturbance.

To valuate the safety of the system it is necessary to know the peak value of the frequency, the first frequency swing in the disturbance, which will indicate how low or high the frequency peak will be, is it going to trigger underfrequency schemes and is sheddable load available? If the sheddable load is available, disturbances is going to have less influence on the system frequency. If not available, the frequency gradient will be worse. To valuate the gradient then it is logical to ask these question: What is the magnitude of the disturbance P, is there any sheddable load and at what value of frequency will it trip[1], where on the system frequency swing does the disturbance occur, and how many generators and what generators are online? All these question are worth asking and do matter in this estimation.

3.4.3 Steady-State Frequency after a Disturbance Assessment

The frequency after a disturbance can be calculated. If the purpose of the frequency safety estimation is to estimate the steady-state value after a disturbance then it is necessary to obtain the generators droop constants and then calculate the system regulation constant (K) for the system that is being monitored. The droop constant is defined as:

$$R\% = \frac{f_{NL} - f_{FL}}{f_0} \cdot 100 \tag{3.30}$$

Where $R\%$ is the droop constant. The droop constant was discussed in section 3.3.3.3. The droop constant is given by the generator manufacturer. The system regulation constants are obtained by using the following formula:

$$K = \frac{\Delta P}{\Delta f} = \frac{S_{rated}}{R\% \cdot f_{sys}} \quad [\text{MW/Hz}] \tag{3.31}$$

Then the system wide regulation constant is:

$$K = \frac{1}{R_{eq}} \quad [\text{MW/Hz}] \tag{3.32}$$

Where R_{eq} is the percent droop for the combined system and is defined as follows:

$$R_{eq} = \frac{1}{\frac{1}{R_1} + \frac{1}{R_2} ... + \frac{1}{R_n}} = \frac{1}{K_1 + K_2 ... + K_n} \tag{3.33}$$

The system regulation constant indicate how many MW/Hz each generator will contribute due to system frequency regulation.

As noted before the frequency gradient calculations, built on inertia, do not imply the final steady-state value of the frequency. With other words, calculating the frequency gradient does not implies how the generators response after the first seconds. The gradient approach only indicates how fast the frequency will fall and how deep at the first swing. After that the

[1] For example, underfrequency scheme for sheddable costumers range in East Iceland is: f=49,0-48,7Hz

regulation system take over and control the frequency. If system frequency is low, the generator increases it power output because of governor actions (valve/gate opens) until it trips because of overloading. It is possible to calculate the steady-state frequency after a disturbance if the droop and regulation constant are known. Then the system regulation constant can be calculated with the following formula:

$$f_{ss} = -\frac{\Delta P}{K_{sys}} \tag{3.34}$$

The above mentioned parameters are needed to make dynamic simulations in PSS/E and are therefore available for calculations. By knowing the steady-state frequency after the disturbance it could be used to inform system operators if the underfrequency scheme is enough to recover the system or if some backup plan is needed, for example tripping chosen priority load.

3.5 Transmission Characteristics and Voltage Stability

In this section transmission line performance will be discussed. Beginning on explanation on performance equations and by using them it is possible to rewrite them in different terms for calculations.

3.5.1 Performance Equations

To calculate the receiving end voltage and currents from different conditions the Performance Equations are used. With these equation it is possible to rearrange them into different equations for other known parameters [4]. The final results from the algebraic calculations is:

$$\bar{V} = \frac{\bar{V}_R + Z_C \cdot \bar{I}_R}{2} \cdot e^{\gamma \cdot x} + \frac{\bar{V}_R - Z_C \cdot \bar{I}_R}{2} \cdot e^{-\gamma \cdot x} \tag{3.35}$$

$$\bar{I} = \frac{\bar{V}_R / Z_C + \bar{I}_R}{2} \cdot e^{\gamma \cdot x} - \frac{\bar{V}_R / Z_C - \bar{I}_R}{2} \cdot e^{-\gamma \cdot x} \tag{3.36}$$

By using this equation it is possible to plot the voltage profile of any known line. Prestbakkalína 1 (PB1) is 171 km long and is one of the longest line in the Icelandic power system and is operated on 132kV. The positive sequence parameters for the overhead line PB1 are the following:

R = 0.0812 Ω/km

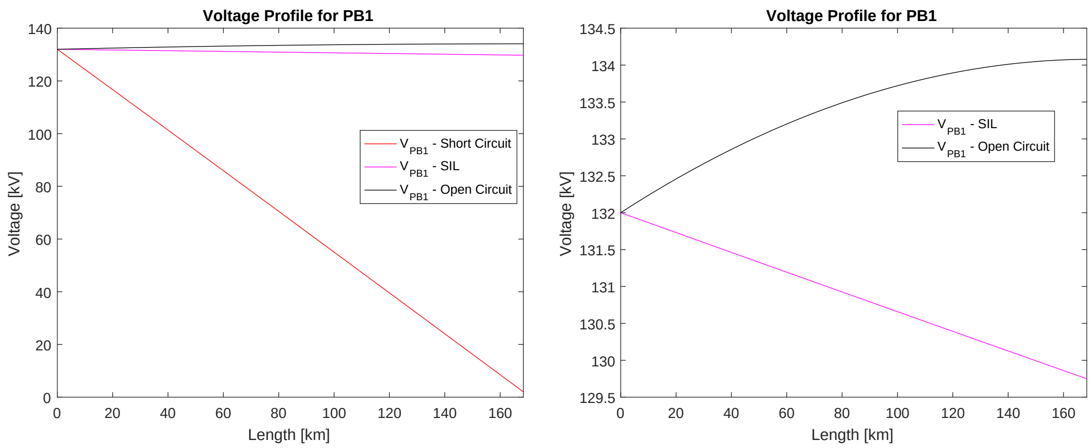
L = 0.001299 H/km

C = 8.30 $\cdot 10^{-9}$ F/km

In figures 3.8a and 3.8b and the voltage profile for PB1 is represented. In the figure are three cases were the line is **short-circuited**, **open-circuit** and when **SIL** condtions. The SIL condition is when it is terminated by it surge impedance.

$$SIL = \frac{V_0^2}{Z_C} \tag{3.37}$$

Were V_0 is the rated voltage of the line. At SIL the transmission line has V and I as constant amplitude along the line and are in phase throughout the length of the line. Then are the phase angle between the sending and receving end equal. Basically, there is no reactive power absorbed or generated at either end of the line, and the voltage and current profiles are flat.



(a) Voltage Profile for PB1 **(b)** Voltage Profile for PB1 without short circuit

Figure 3.8 Voltage Profile for PB1

By using the performance equations for transmission lines, power or communications, then it is possible to estimate the voltage and current profile of any type of line. This approach can be interesting when there is need for comparison of overhead line or underground cable for an example [4].

3.5.2 P-V Curves

Carson W. Taylor wrote the following words in his book [14, p.27] that describe the purpose, advantages and disadvantages of P-V curves.

> *P-V curves are often used in steady-state analysis, power flow simulation is the primary study method... P-V curves are useful for conceptual analysis of voltage stability and for study of radial systems. The method is also used for large meshed networks where P is the total load in an area and V is the voltage at a critical or representative bus. P can also be the power transfer across a transmission interface or interconnection. Voltage at several busses can be plotted. A disadvantage is that the power flow simulation will diverge near the nose or maximum power point on the curve. Another disadvantage is that generation must be realistically rescheduled as the area load is increased.*

From the P-V curves there is a inherent maximum limit of power that can be transmitted at any load factor. Since there is a limit, the only way to transfer more power is by lowering the load angle. By doing so, the the current will increase and therefore the losses. Up to a certain point the increase in current dominates the decrease in voltage on the receiving end, resulting in increased power. Finally the voltage decrease will end with the trend reversing. To calculate and plot a PV curve for a lossless power line equation 3.39, 3.41 and 3.42 are used. Equation 3.38 can be solved for P and then the PV curve plotting is possible [4].

$$V = \sqrt{\frac{E^2}{2} - Q \cdot X + \sqrt{\frac{E^4}{4} - X^2 \cdot P^2 - X \cdot E^2 \cdot Q}} \tag{3.38}$$

When solving for P_{max} gives two possible answers but only one can work, because one of the equation returns a negative value. This negative values is not permitted because it is under square root. Equation 3.39 is the positive under square root.

$$P_{max} = \frac{-E^2 \cdot tan\phi - E \cdot X \cdot \sqrt{tan\phi + E^2}}{2 \cdot X} \tag{3.39}$$

To calculate the voltage part of the P-V curve plot, the following equations are used. There are two equations for the voltage, because the diverge near the "nose" or "knee" of the curve. Therefore the power flow analysis does cover it when voltage unstability occurs during a disturbance.

$$V_{sqrt} = \sqrt{\frac{E^4}{4} - X^2 \cdot P_i^2 - X \cdot E^2 \cdot P_i \cdot tan\phi} \tag{3.40}$$

$$V_{LOW} = \sqrt{\frac{E^2}{2} - P_i \cdot tan\phi \cdot X - V_{sqrt}} \tag{3.41}$$

$$V_{HIGH} = \sqrt{\frac{E^2}{2} - P_i \cdot tan\phi \cdot X + V_{sqrt}} \tag{3.42}$$

Equation 3.42 is for the "higher" part of the curves an the "lower" part is found by equation 3.41. Then it is possible to plot the voltage vs. active power calculated by the before mentioned equations. To make these calculations the resistance are neglected and only the reactance is used of the line parameters. By writing a function in for example MATLAB, the reactance, receiving end voltage and the power factor are the factors needed. The power factor has a significant influence on the receiving end voltage and the maximum power being transmitted. This means by adding a shunt capacitive compensation on the receiving end, then the voltage can be regulated for more active power transfer [4].

For an example, if the resistance of PB1 is neglected (lossless line), then the reactance of PB1 and voltage magnitude is only needed. By plotting four curves with different load angles or power factors, it can be demonstrated how important it is to compensate reactive power for more active power transmission. Were, E=132 kV, X=68.6 Ω and $\phi = [20°, 10°, 0°, -5°, -10°]$

Figure 3.9 demonstrates two matters

- As the power factor decreases, the ratio of active power to apparent power also decreases, as the angle θ increases and reactive power increases.
- As the power factor increases, the ratio of active power to apparent power increases and approaches unity, while the angle θ decreases and the reactive power decreases.

The following discussion and figure representation has no taken into account the losses. The line resistance would cause less active power transmission and is most often insignificant. At more leading power factors the maximum power is higher (leading power is obtained by shunt

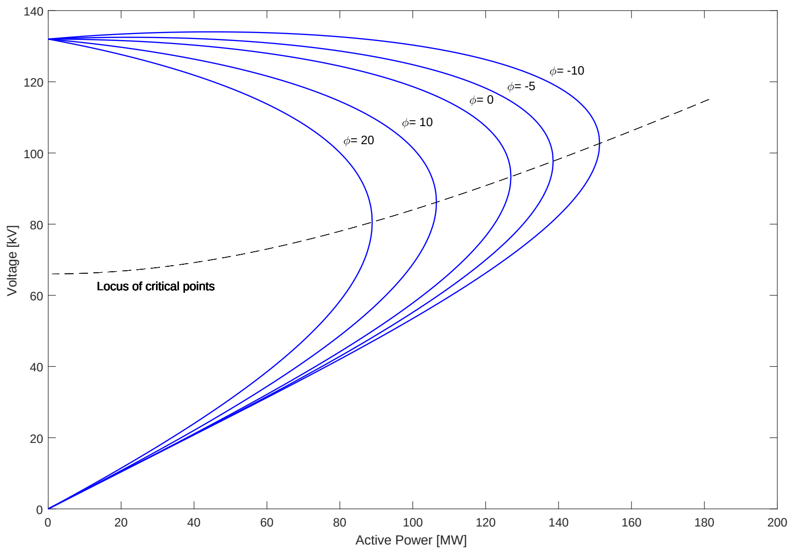


Figure 3.9 PV curves with different load angles for PB1

compensation). The critical voltage is also higher, which is a very important aspect of voltage stability [14, p.30-31].

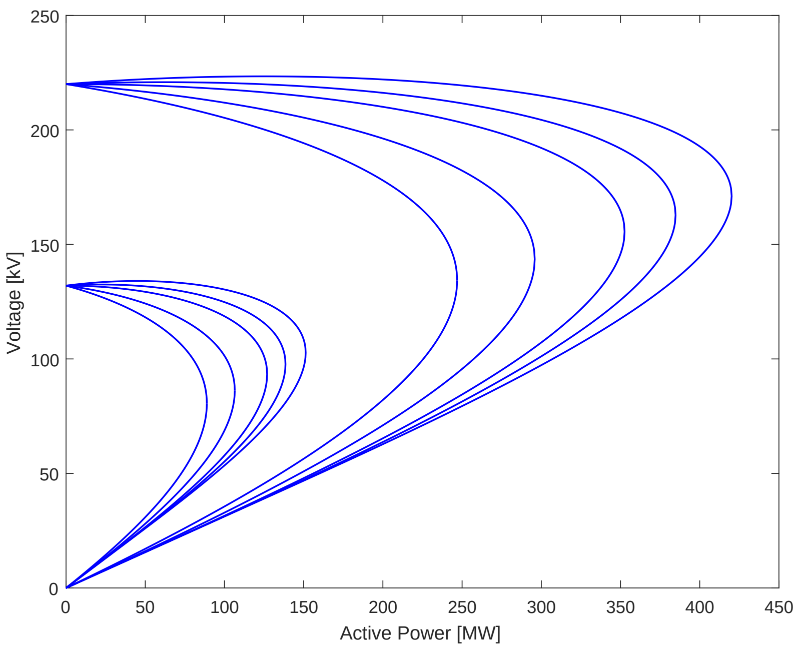


Figure 3.10 PV curves with different load angles for PB1 and various voltage levels

In figure 3.10 is the PV curve for voltage magnitudes, 132kV vs. 220kV, with constant reactants (X=68.64 Ω). As the voltage gets higher with less current, more power can be transferred. It should also be mentioned that with increasing reactance the transfer capabilities decreases. P-V curves are useful in deriving how much load shedding should be done to establish prefault network conditions even with the maximum increase of reactive power supply from various automatic switching of capacitors or condensers.

3.5.3 Q-V Curves

Voltage stability dependents on variations in reactive power (Q) as well active power (P). One way to analyze voltage stability is to investigate the Q-V relationship, which shows the sensitivity and variation of bus voltages with respect to reactive power injections or absorptions [4]. The effect of voltage sensitivity loads, or of tap changing reaching limit can be shown on Q-V curves. Q-V curves with voltage sensitive loads, prior to tap-changing, will have much greater reactive power margins and much lower critical voltages. When the tap changer hit limits, the curve tend to flatten out rather then turn up on the left side [14]. *Q-V curves are presently the workhorse method of voltage stability analysis at many utilities. Since the method artificially stresses a single bus, conclusion should be confirmed by more realistic methods* [14, p.34].

3.6 Out of Step - Loss of Synchronism

When a disturbances occur the generation sources may start swinging, it starts with a slow oscillation of the voltage angles between the two sources. For stable swings, these voltages will vary in rather poorly damped oscillations with a frequency that depends on the inertia of the two sources and the impedance between them. Most often the oscilliation will be less then 1 Hz, with oscillation of 0.5-0.7 Hz being common. This gives a period of oscillation greater than 1 second, which is rather long time for observation of the phenomenon. If the disturbance is large enough there will be no oscillation, but monotonic increase in angle until the voltage collapses at some point [4], [8].

In subsection 6.6.1.2 a tripping scheme is represented that was partly invented to tackle this kind of problem. The scheme is used split the system into two islands, especially in the south where PB1 is a very long line and voltage stability issues were known at HOL, and to prevent SIG to be out-of-step with East Iceland when one or more lines in the North Iceland trip. Often do impedance protection pick up the loss of synchronism because the voltage tends to fall. Special Out-of-Step protection is a very delicate protection method and is not used unless analysis and system research has shown the need and purpose of the protection method, because the a certain kind of disturbance may lead to instability. There is no Out-of-Step protection, because it is tackled by splitting the system.

But there are situations where it is desirable to block Out-of-Step protection tripping. For example, it is necessary to block at locations where tripping will separate the system into greatly unbalanced islands with large difference between load and generation. This is true regarding the Icelandic power system. Blocking is also required when there is no fault on the protected line, but only transients penetration of the trip zone due to the oscillatory conditions, for example when a aluminum smelter trips in the Icelandic system [8].

3.7 Thermal limits

Thermal limits on overhead lines are intended to limit the temperature of energized conductors and the resulting sag, which causes decreased clearance to ground, and loss of tensile strenght which occurs when the aluminum conductor is continued exposure to temperature extremes. The maximum currents depends on wind velocity and outside temperature. Therefore there a distinction between continuous rating and limited rating. Depending on pre-contingency current, temperature and wind velocity limited rating can be used during emergencies [4, p.226].

There are ways to possible to increase MVA thermal capacity of an existing line. Some of these methods are technically plain such as reinforcing the structures and restringing the line with larger conductor. Other methods of thermal uprating is using weather dependent dynamic thermal ratings or voltage uprating by reduction from normal phase spacing. The price here lies in the greater degree of technical sophistication required to ensure safe and reliable operation at higher loadings [15].

3.8 Transient Stability

Transient stability is the ability of the power system to maintain synchronism after a severe disturbance, such as loss of load, generation or fault on transmission lines. System response during severe disturbance involves large excursions of generator rotor angles, power flows, voltages and other system parameters. Stability is influenced by the nonlinear characteristics of the power system. If the generator angles remain within a certain boundary the system will survive, if outside this boundary there will be loss of synchronism because of transient instability. If this occurs the system protection should operate in a way that a new equilibrium point is reached [4],[8].

3.8.1 Influencing Factor of Transient Stability

Factor that contribute to transient stability are listed in this book [4, p.835]. Transient stability of the generator is dependent on the following:

- How heavily the generator is loaded.
- The generator output during the fault, depends on fault location and type.
- The fault-clearing time.
- The postfault transmission system reactance.
- The generator reactance, lower reactance increases peak power and reduces initial rotor angle.
- The generator inertia. The higher inertia, the slower the rate of change in angle. This reduces the kinetic energy gained during fault.
- The generator internal voltage magnitude ($E^{'}$). This depends on the field excitation.
- The infinite bus voltage magnitude E_B.

In this thesis relevant fundamental concepts will be covered. In those concept the actually rotor angle is shown as a function of time, but the time scale has not been defined. Accurate analysis of transient stability is done by time-domain simulation in which the nonlinear differential equations are solved by using step-by-step numerical integration techniques as Euler Method or Runge-Kutta Methods [4]. For further reading [4, p.836-872].

3.8.2 Stability Considerations and Power Transfer

In section 3.2 a power tranfer between active sources was discussed. The complex power being transferred has real and imaginary part. The real part is 3.2 and this formula is crucial for power transfer capability estimations. The mathematical proof of ther formula, assuming having a lossless line, is in [4, p.221]. The proof ends on the following formula:

$$P_R = \frac{E_S E_R}{Z_C \sin\theta} \sin\delta \tag{3.43}$$

Where Z_C is defined for **short lines** as:

$$Z_C = Z_C\theta = \sqrt{L/C}\omega\sqrt{LC}l = \omega Ll = X_L \tag{3.44}$$

X_L is the series inductive reactance and therefore the expression for power transferred is 3.2 or

$$P_R = \frac{E_S E_R}{X_L} \sin\delta \tag{3.45}$$

Formula 3.45 states that if the voltage is fixed, the power transmitted is a function of only the transmission angle δ. When P_R is equal to the natural load, $\delta = 0$ and therefore is no power transfer. The fundamentals in transient stability are the above equations, 3.2 or 3.45 and the theoretical background, being transferred power between active sources. By using a simple analytical methods a basic understanding on the transient stability phenomenon can be obtained. The power-angle relationship is graphical approach and a graph is shown in figure 3.11.

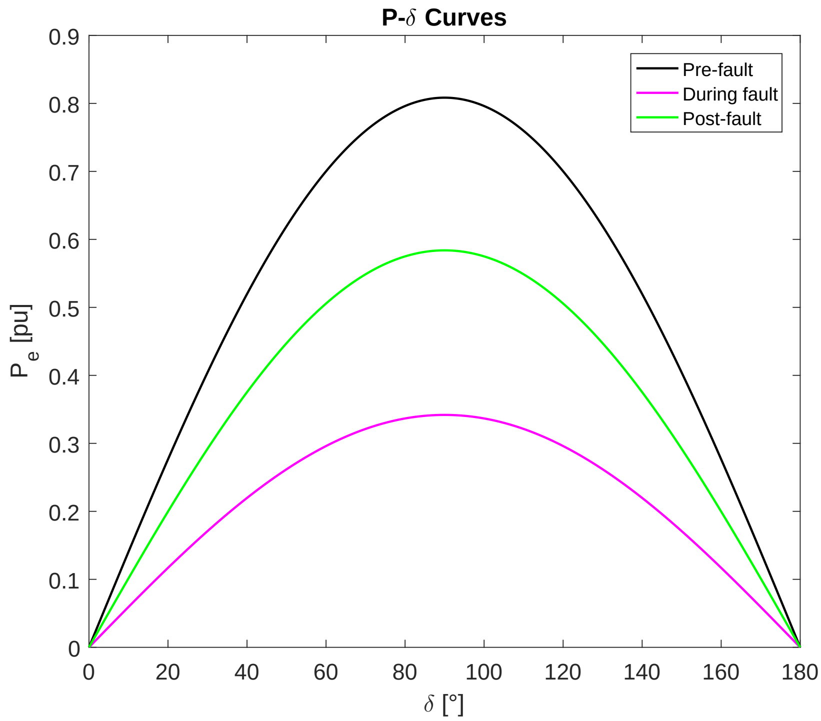


Figure 3.11 P-δ curves in

In figure 3.11 shows the behavior of a similar system as is shown in figure 5.1 which gets into a faulted condition (Pre-fault, During fault and Post-fault). The system reactance controls the shape of the curves, if one line is out-of-service then the effective reactance is higher and therefore the maximum power transferable is less then if both lines are in service. To transfer the same amount of power in steady-state, the rotor angle has to be higher, and therefore near the stability limit which is $\delta = 90°$ [4]. When there is a disturbance, oscillation of δ is superimposed on the synchronous speed ω_0. The speed deviation ($\Delta\delta_r = d\delta/dt$) is very much smaller than ω_0. Therefore the generator speed is practically equal to ω_0. Then it is possible to use torque and power interchangeably when referring to the swing equation (discussed in 3.3.1) [4, p.829].

3.8.3 Equal-Area Criterion

For single machine infinite bus system it is not necessary to solve the swing equation to determine whether the rotor angle increases indefinitely or oscillates about the equilibrium position. Information regarding the maximum angle excursion δ_m and the stability limit may be obtained graphically by using the power angle diagram in figure 3.12. The lower diagram shows the rotor angle time response and the upper diagram is the power-angle variation [4].

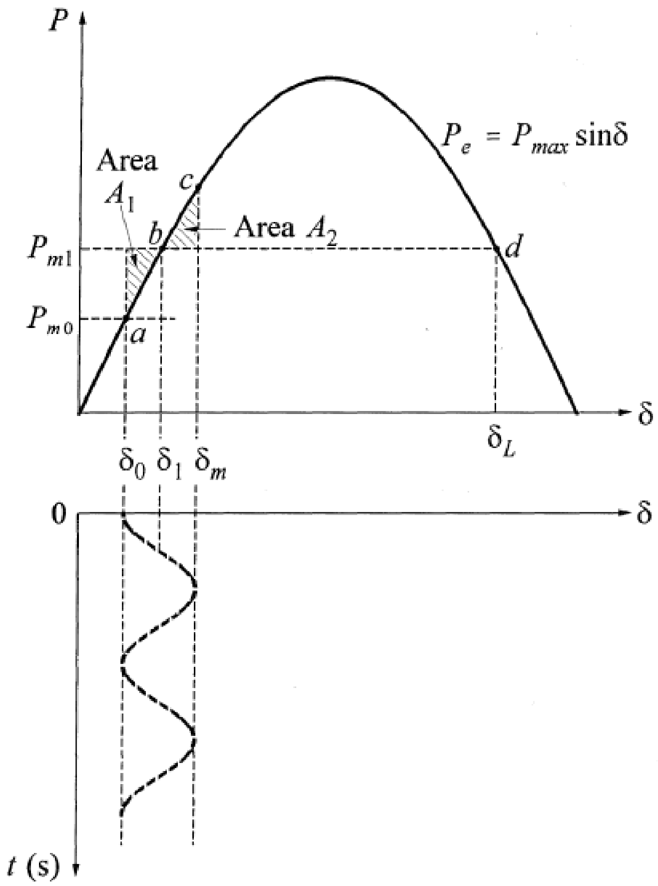


Figure 3.12 Step change in mechanical power input and the response [4]

Equation 3.46 describes the relationship between the rotor angle and the accelerating power.

$$\frac{d^2\delta}{dt^2} = \frac{\omega_0}{2H}(P_m - P_e) \tag{3.46}$$

Now P_e is nonlinear function of δ and therefore the equation cannot be solved directly. If both sides are multiplied by $2d\delta/dt$, then:

$$2\frac{d\delta}{dt}\frac{d^2\delta}{dt^2} = \frac{\omega_0(P_m - P_e)}{H}\frac{d\delta}{dt} \tag{3.47}$$

Integrating gives

$$\left[\frac{d\delta}{dt}\right]^2 = \int \frac{\omega(P_m - P_e)}{H} d\delta \tag{3.48}$$

The speed deviation $d\delta/dt$ is initially zero but will change as a result of a disturbance. For stable operation, the deviation of angle δ must be bounded, reaching a maximum value and then changing direction. This requires $d\delta/dt$ to become zero at some time after a disturbance. Therefore from last equation, the criterion for stability may be written as:

$$\int_{\delta_0}^{\delta_m} \frac{\omega_0}{H}(P_m - P_e)d\delta = 0 \tag{3.49}$$

where δ_0 is the initial rotor angle and δ_m is the maximum rotor angle. The area under the function $P_m - P_e$ against δ must be zero if the system is stable. This is satisfied when area A_1 is equal to A_2. Kinetic energy is gained by the rotor acceleration when δ changes from δ_0 to δ_{cr}. The gained energy is:

$$E_1 = \int_{\delta_0}^{\delta_{cr}} P_m - P_e d\delta \tag{3.50}$$

and the energy lost during deceleration when δ changes from δ_1 to δ_0 is:

$$E_2 = \int_{\delta_{cr}}^{\delta_m} P_m - P_e d\delta \tag{3.51}$$

If the system is stable, then $E_1 = E_2$ and if $E_1 > E_2$ then the system is unstable. This is the basic of equal-area criterion. It indicates if the maximum swing of δ and hence the stability of the system without computing the time response through formal solution of the swing equation. The criterion can be readily used to determine the maximum permissible increase in P_m for the system. The stability is maintained only if an area E_2 at least equal to E_1. If E_1 is greater than E_2, then the net torque is accelerating rather than decelerating [4], [8].

Chapter 4

Electrical Power System Theory and Simulations

This chapter will introduce electrical power system simulation theory and models. The power system model used in this thesis will be introduced and explained in a broad manner.

4.1 Electrical Power System Simulation Theory

This section is a introduction to the power system simulation theory. It is explained how power systems are simulated mathematically and the fundamental theory is introduced for load-flow and dynamic simulations.

4.1.1 Load Flow Simulations

Load flow simulation is a analytical technique for detailed analysis of power flow in large complex networks. Load flow analysis involves the calculation of power flows and voltages in a power system for specified terminal og bus conditions. Such calculations are required for analysis of steady-state and also dynamic performance of power systems.

In power flow analysis four real quantities are associated with each bus.

- Active power P
- Reactive power Q
- Voltage magnitude V
- Voltage angle θ

The buses in the system are categorized in three different types dependent on which two of the four values are known at each bus.

1. PV bus - Active power and voltage magnitude are specified. These buses represent voltage controlled buses such as buses with generators, synchronous condensers and static var compensators.

2. PQ bus - Active power and reactive power are specified. These buses are often referred to as load buses.
3. Reference bus, slack bus often referred as swing bus - where voltage magnitude and angle are specified. Only one bus in the system can be defined as the slack bus.

It is desirable to keep the Q associated with the slack bus within reasonable limits, otherwise the load flow solution could be unrealistic. Transmission lines are represented by equivalent π circuits with lumped parameters. Shunt capacitors and reactors are represented as simple admittance elements connected to ground. Transformers with off-nominal turns ratio are represented by equivalent π circuits. Any phase shifts introduced due to transformer connections, for example (Δ-Y connections) are not usually represented. Phase-shifting transformers, which are provided specifically for controlling power flow, are represented but the phase angle is fixed. As the purpose is to consider only balanced operation of the power system, each element modelled in terms of its single-phase equivalent (positive sequence) [4].

There are two ways of represent the relationship between voltages and currents, either by loop equations or node equations. The node equation approach is usually preferred because the number of independent node equations is smaller then than the number of independent loop equations. The node admittance matrix is written as [4, p.257]:

$$\begin{bmatrix} \widetilde{I}_1 \\ \widetilde{I}_2 \\ \dots \\ \widetilde{I}_n \end{bmatrix} = \begin{bmatrix} Y_{11} & Y_{12} & Y_{13} & \dots & Y_{1n} \\ Y_{21} & Y_{22} & Y_{23} & \dots & Y_{2n} \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ Y_{n1} & Y_{n2} & Y_{n3} & \dots & Y_{nn} \end{bmatrix} \begin{bmatrix} \widetilde{V}_1 \\ \widetilde{V}_2 \\ \dots \\ \widetilde{V}_n \end{bmatrix} \tag{4.1}$$

where

- n is the total number of nodes
- Y_{ii} is the self addmittance of node i) sum of all the admittances terminating at node i
- Y_{ij} is mutual admittance between nodes i and j = negative of the sum of all admittances between nodes i and j.
- $\widetilde{V}_i$ is the phasor voltage to ground at node i
- $\widetilde{I}_i$ is the phasor current flowing into the network at node i

Effects of generators, nonlinear loads and other devices connected to the network nodes are reflected in the node current. Constant impedance, linear loads are included in the node admittance matrix.

Equation 4.1 is linear if the current injections $\widetilde{I}$ were known. However, in practice current injection is unknown for most nodes. The current at any node k is related to P, Q and $\widetilde{V}$ as:

$$\widetilde{I}_k = \frac{P_k - jQ_k}{\widetilde{V}_k^*} \tag{4.2}$$

For PQ nodes, P and Q are known. For PV nodes, P and V are known. For other types of nodes, the relationship between P, Q, $\widetilde{V}$ and $\widetilde{I}$ are defined by characteristics of the device connected to the nodes. Because of boundary conditions imposed by different types of nodes makes the problem nonlinear and because of that the power-flow equations are solved iteratively using teqniques as Gauss-Seidel or Newtown-Raphson methods. For further reading and more detailed discussion regarding load-flow computing and the Gauss-Seidel or Newton-Raphson methods references , [16], [17] and [4, 257-269] are recommended.

4.1.2 Dynamic Simulations

Electrical power system is a continuous system which can be represented by mathematical methods such as differential and algebraic equations. A convenient form is the state variable formulation, which is a system of n first order linear differential equations that results from a nth order system.

Dynamic simulation process of a physical system has three steps:

1. Construction of a set of differential equations describing the behavior of the physical system in general
2. Determination of a set of values of constant and variable parameters describing, in detail, the condition of the physical system at some point.
3. Integration of the differential equations with the values determined in step 2 as initial conditions

The differential equations to be solved in power system stability analysis are nonlinear ordinary differential equations with known initial values as equation 4.3:

$$\frac{d\mathbf{x}}{d\mathrm{t}} = f(\mathbf{x}, \mathrm{t}) \tag{4.3}$$

where $\mathbf{x}$ is the state vector of n dependent variables and $\mathbf{t}$ is the independent variable (time). The objective is to solve $\mathbf{x}$ as a function of $\mathbf{t}$. The intial values of $\mathbf{x}$ and t are equal to the $\mathbf{x}_0$ and t_0 [4, p.836].

To solve this equation there are many advanced numerical methods, for example Runge-Kutta Methods. For further reading about different numerical integration methods [4, p.836-848]. To observe knowlegde regarding the structure of power system models and dynamic simulations the author recommends [4, p.848-872].

PSS/E uses the second order Euler or ”Modified Euler Method” scheme to perform numerical integration. By using Modified Euler Method, numerical instability problems will be avoided and the accuracy will be sufficient if the time step is kept 0.25 to 0.2 times smaller than the shortest time constant being used in the simulation [18], [4, p.838].

4.2 Power System Models

To simulate a power system dynamics in great detail so the results are believable it is necessary to have access to as much information about the system as possible. The informations regarding power lines and cables, generators, loads and all compensated (series-, shunt compensation and SVC's) equipment connected to the system. These informations are crucial and have to be as precise as possible. In PSS/E there is a model for each component and for example for the generators there are governor-, excitation- and turbine models. For large loads are often special load models which focus on describing combination of the load (resistive, capacitive or inductive) and therefore the main characteristics of the load behavior is possible to simulate. There are no special line models because the parameters are way different for overhead lines and cables [4],[8]. Most of the parameters can be measured, some can be obtained by testing and others can be calculated by using theory. The bottom-line is, the dynamic simulations have to follow the theory to be trustworthy.

4.2.1 Importance and Accuracy of Power System Models

A model of complicated power system show seldom the exactly same response as the real power system. When starting to work with a model it is necessary to compare it to the reality. By comparing the response of the model and the real system then the limitations of the model are known. By knowing the limitation of the model then it is possible to estimate and distinguish problems and the behavior of the system in reality. This comparison can be done in many ways and in this thesis it is called "Model Validation". One way of doing the model validation is to chose one disturbance that occurred in reality and simulated in the model and then compare the results to see the accuracy. In this thesis it was done and is represented in section 7.1. WAMS measurements were used for the comparison of real measurements versus the simulated response.

If the model is not behaving as the real system, is then the model behavior in accordance to the theory? In some cases the model has a better performance then the real system and vice versa. For example, in this thesis the behavior of generator in Hrauneyjarfossvirkjun (HRA) was more relevant in the model than in reality, 7.5a. The first response of the generators in HRA, due to the disturbance in the model validation, is the inertia response then the power output decreases which is normal, but then the regulation process starts and the power output increases. It would be expected that a generator would not increase its generation during a heavy load loss as was in the case of model validation.

Figure 4.1 Model structure in PSS/E

Dynamic power system simulations are complex and to make the model of the system there are many different models to represent many various components. For example, one generator in SIG is represented by 3 models in PSS/E,

- Generator model - GENSAE
- Exciter model - BBSEX1
- Turbine-Governor model - VOTGOV

The model structure is shown in figure 4.1. The other models are not used in Landsnet PSS/E model. In chapter 14.4 is the need of getting PSS models of several generation station noted for more model accuracy. Each generator model has special properties and are described in the API manual for PSS/E. The most common generator PSS/e models in the Icelandic power system are:

- GENSAL - Hydro Generation
- GENSAE - Hydro Generation
- GENROU - Geothermal Generation

In subsection 3.3.3 the transfer function for a generator is discussed. In figure 3.3 the a diagram of the transfer function diagram is shown. For each box in the transfer function diagram is a special model in PSS/E which simulates different characteristics of the generator.

The generator model has the synchronous generator standard parameters that influence the subtransient-, transient- and synchronous parameters. In the book "Power System Stability and Control" is a table over the standard parameters [4, p.153]. Also is the inertia constant (H) defined in the generator model.

Exciter models involve the excitation system and the Automatic Voltage Regulator (AVR) function. The field voltage E_{fd} is defined in the model (minimal and maximum values), the gain K of the exciter system and the feedback parameters [4, p.334-335]. The fundamental function of the exciter system is to control the stator voltage, provide the power system with reactive power and control the generator output during disturbances. PSS devices are part of the excitation system in reality but in PSS/E there is a special model for such devices.

> *Mathematical models of excitations systems are essential for the assessment of desired performance requirements, for the design and coordination of supplementary control and protective circuits..[4, p.334-335]*

The turbine and governor are in one model in PSS/E. The governor controls the input into the turbine and therefore the generator output. Lets begin with a short turbine discussion and then the governor. P. Kundur describes hydro turbine charactertistics in his book [4, p.378] as:

> *The performance of a hydraulic turbine is influenced by the characteristics of the water column feeding the turbine; these include the effects of water inertia, water compressability, and pipe wall elasticity in the penstock. The effect of water inertia is to cause changes in turbine flow to lag behind changes in turbine gate opening...*

Governors controls the speed of a generator, also discussed in subsection 3.3.3.3. If a generator is power regulated the active power is constant or if the generator is frequency regulating then the governor uses system frequency as a input and controls the power output of the generator as frequency changes. According to [4, p.394]:

> *The basic function of a governor is to control speed and/or load... The primary speed/load control function involves feeding back speed error to control the gate position. In order to ensure staisfactory and stable parallel operation purpose of the droop is to ensure quitable load sharing between generating units. Typically, the steady-state droop is set at about 5%, such that a speed deviation about 5% causes 100% changes in gate position or power output; this corresponds to a gain of 20.*

The most common load model is CLODBL, which is used to model aluminum smelters. Which is 80% of the load in the Icelandic power system. Other loads are simulated as standard load model given by PSS/E. Switched shut model are two and are for the SVC at KLA (CKLFST) and HRY (CSSCST).

All before mentioned models are very complex and the configuration/tuning of them can be difficult. Changing one parameter can have a major influence on the system response.

4.2.2 Discussion about Second Newton's Law and Simulation

In section the second Newton's law was discussed, 3.3.1 theoretically. The intention by this section is to discuss the meaning of this equation and how it is used in electrical power analysis studies.

To be able to use a power system, it needs to be stable. The power flows from the generators to the loads through complex systems of transmission lines, circuit breakers and transformers. The power flow between generators is dependent on the angle between them. The stable point of power system is when the generation and consumption is in a balance. Generator is moved by his prime mover, the turbine. If there is a mismatch between the electrical output of the generator and the generated mechanical shaft power, the generator will accelerate. The rate of the acceleration is determined by the mismatch of power and the generator inertia.

As noted before, all power system need to be in stable conditions and maintain synchronism. But when there is a disturbance in a power system, it reacts to it and that is referred to as transient stability. In general practice studies related to transient stability in power system the swing equation is used.

More often than not, the power generation systems are subjected to faults of all kinds, and hence it is extremely important for power engineers to be well-versed with the stability conditions of the system. In general practice studies related to transient stability in power system are done over a very small period of time equal to the time required for one swing, which approximates to around 1 sec or even less. If the system is found to be stable during this first swing, it is assumed that the disturbance will reduce in the subsequent swings, and the system will be stable thereafter as is generally the case. Now in order to mathematically determine whether a system is stable or not we need to derive the swing equation for power systems as was done previously.

Chapter 5

N-1 Criteria and Power System Security Assessment

N-1 Criteria has been used for long period of time for power system security assessment. This chapter is an introduction to the N-1 criteria, security assessment methods and challenges for modern power systems. The main challenge is lack of new transmission infrastructure, it is necessary to find ways to increase the security limits of the system without greatly reducing the security of supply.

5.1 N-1 Criteria

The Nordic Grid Code [19], N-1 Criterion is defined as:

> N-1 Criteria are a way of expressing a level of system security entailing that a power system can withstand the loss of an individual principal component (production unit, line, transformer, bus bar, consumption etc.). Correspondingly, n-2 entails two individual principal components being lost.

The Icelandic power system was originally built as N-1 or one level of redundancy. When one transmission line undergoes a fault and is tripped by system protection, the system impedance increases and then loading on rest of other lines in the system increases. The purpose of the transmission cuts is either to indicate potential, following a fault or instability issues if power transfer exceeds certain limits. For example cut IV, the cut limits indicates if N-1 criteria is not fulfilled due to line BL2 thermal limits or SI4 transmission limit due to current transformers. System operation is not only limited by thermal limits but also by stability consideration. The security constraints, the maximum power transfer in that particular cut is a indicator for the system security. In Appendix A, the theory of power transfer through impedance is discussed. Then transient theory is used in section 3.8 for stability consideration and power transfer. An example is in Appendix A.1.

What happens if a line fault occurs in power systems ? The line protection detects the fault and removes the line from service normally in 100 milliseconds. Then the major part of the power that was flowing through the line is redistributed between the remaining line/lines. If the system is operated on the edge of thermal limits, then the other lines could eventually trip because of overload which could lead to a blackout. The same argument can be used for stability consideration, if system stability is threatened then consequences may be severe, worst case scenario being a blackout [19]. For instance the Italian blackout in 2003 described in [20] and [21]. In [20] the course of events is described as:

> *On September 28th, 2003, at 3:01 a.m., a fault on the Swiss power system caused the overloading of two Swiss internal lines close to the Italian border. The interconnection lines were heavily loaded by the large power import and the coordination between the system operators was not sufficient to mitigate the overload. The consequent loss of those important branches caused cascading outages of the lines interconnecting the Italian system and the remaining part of the UCTE (Union for the Coordination of the Transmission of Electricity) system. This resulted in a very sudden loss of synchronism between the Italian system and the UCTE grids, causing the loss of the whole import. The consequent power unbalance caused the frequency in Italy to decline; the automatic load shedding procedure was not able to shed load enough to balance the generation and the load, and this resulted in the blackout.*

This event emphasizes that if power system are heavily loaded and N-1 Criterion is not fulfilled the consequences may be severe. In Appendix A.1 is a theoretical example that emphasizes the need of line upgrades as the load increases, if N-1 criteria conditions should be fulfilled.

5.2 Stability Limits

Each power system has its special characteristics (various combinations of lines, generators and load) and the stability limit depends on these characteristics. Transient stability analysis is used to carry out dynamic security assessment and to determine if a power system can withstand a set of major, yet credible, contingencies. The aim is to evaluate the risk of instability when a system approaches a certain state. This state can be a sudden load increase or decrease, line or generation tripping which may trigger instability conditions [22]. In [22, p.26] the "Icelandic Problem" fits the general description of finding stability limits very well, so well that is best to quote the book it self:

> *Instability in a multiarea power system may also be triggered when attempting to transfer a large MW block between weakly interconnected areas, for example, when compensating for load increase and/or generation outages in a system area by raising the generation elsewhere. In order to ensure that the grid would not get too close to its stability limit, prior to clearing such a transaction, one would first have to evaluate the maximum transfer capability across the "links," or transmission corridors, that interconnect the areas involved in such transaction. This is typically the case in longitudinal (radial) systems that span distinct system areas with significant load-generation imbalances, but may also happen in meshed transmission networks.*

To overcome this problem, it is possible to use approximations that fulfill the time constraints, without a significant loss of accuracy.

5.2.1 Dynamic Stability Limits

The stability limit concept can be seen as a function of the system state vector. For each system situation there is a new system state and therefore a new stability limit [22]. By adding dynamic to the stability limit concept is making the stability limit flexible. In the Icelandic power system dynamic stability limits could be dependable on sheddable load or generation plant power output. All cuts in itself are all dynamic, if one line of two lines in a cut is taken out of service than the limit of the cut is lowered.

5.2.2 Security Margin - Steady-State Stability Reserve

The security margin is: safe amount of stability reserve [22]. For example, if a tie line stability limits are 100MW then the security margin could be 0-100MW. By dynamic simulation it was discovered that is possible in case of emergency, to transfer 120MW because thermal limits. That it is if the line trips then the consequence is frequency instability and underfrequency protection scheme will be activated. If the line trips when power flow is below 100MW then there is no frequency instability and the underfrequency scheme is not activated. If one generator is out of service at end of the tie line, then the limit is not 100MW, but could be only 60MW because the system inertia is smaller and therefore the frequency stability decreases with increased power flow through the tie line [4],[22],[8].

5.3 Power System Security Assessment

In this section power system security assessment will introduced in two subsections. First section is the definition of power system security assessment. The latter section contains discussion about security assessment in power system.

5.3.1 Definitions of Power System Security Assessment

Security refers to the degree of resistance to, or protection from, harm or instability. It applies to any vulnerable and valuable component. In case of power systems, stability is most valuable. Any system without stability can be considered worthless. When combining security and assessment the aim is to sense how far the system is from harm [4], [22], [8].

> *Security refers to the degree of risk in a power system's ability to survive imminent disturbances (contingencies) without interruption to customer service. It relates to robustness of the system to imminent disturbances and, hence, depends on the system operating condition as well as the contingent probability of disturbances* [23]

Power system security is normally assessed on the basis of security standards [24]. Security assessment is the quantification of risk of a power system in a live operational context. Real-time security assessment is to set secure limits and informing operators of present system threats. Real-time power system security assessment uses information from SCADA or WAMS to calculate and display results to the system operators in real-time.

5.3.2 Extended N-1 Criterion and Real-time Security Assessment

Extended N-1 Criterion is discussed here with respect to Real-time Security Assessment. In figure 5.1 is the system that will be used for the explanation.

In chapter 2 the Icelandic system properties and characteristics are described. Bear in mind, the Icelandic power system has two main hydro generation areas which are connected together by 132kV ring connection. This raises the question, how much power is possible to transfer between areas through these weak lines without severe consequences if either Line 1 or 2 is tripped? For example, each line can deliver 100MW of active power. For those reasons it is possible to transfer 200MW active power between areas if the electrical output of the generators in the West allows it and there is reserve power available to take on increased demand for generation in the West. By transferring 200MW from West to the East does not fulfill the requirements for N-1 Criterion because if both lines are operated at their fullest capacity, and Line 1 trips then Line 2 cannot transfer 200MW, but only 100MW. Transferring 200MW and if there is a fault on either Line 1 or Line 2, the consequences may be severe and could lead to a blackout in the East system.

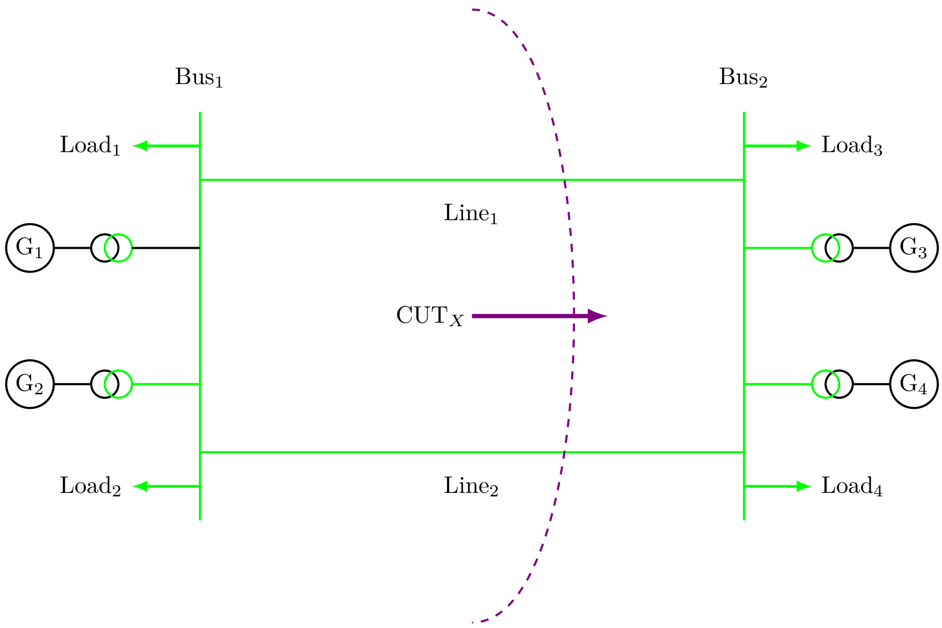


Figure 5.1 Simple Explanation Model

According to the N-1 requirements it is not possible to transfer 200MW between the areas, the limit is 100MW. If it is absolutely necessary on constantly to transfer 200MW between areas then there are at least two options:

1. Building a new line that could transfer at least 100MW.
2. Obtain control over the load in the East.

Building a new line is a large investment and takes time. If it is necessary to transfer 200MW in a short term then taking control over the load is a possibility. In this case, a proportion of the load could become sheddable for a load shedding scheme. These factors depend on communications and available data to take that large decision. If there are no good communications or any quality data as PMU data, then underfrequency protection scheme would be the best option with rather narrow settings.

If the communication and PMU data is available then it is not necessary to use underfrequency protection as primary protection. Then it is possible to trip the load nearly simultaneously when either Line 1 or 2 trips by using a PDC unit which is introduced in next chapter. Underfrequency conditions should be avoided because it is not good for turbines or generators [8], see section 3.4.1. Taking control of load or generation to fulfill N-1 Criteria could be called "**Extended N-1 Criteria**".

For Extended N-1 Criteria, the security assessment could be built on the proportion of load available in the tripping scheme - dynamic stability limit. As the proportion of sheddable load involved in the tripping scheme increases, then the power transfer can be increased. If sheddable load proportion is under a certain limit, then there is a risk of serious disturbance that could have severe consequences in the East system (bus 2).

If and only if the active power through CUT_x is above 100MW ($P_{CUT_x} > 100MW$) then the load tripping scheme should be active and all the load above 100MW should be in the load tripping scheme for maximum security.

The security assessment could be automatic or be switchable by the system operator. Then the system operator has to be aware of the situation at each moment in the system operation. Security assessment and informing system operators about the situation by using PMU data and multi special system protection schemes is a way to deal with this problem if line upgrades are not allowed or delayed. Assessment methods are explained and discussed later in this thesis.

N-1 limits are not applicable to a system with two distinct areas, given that dynamic stability issues depend upon the present of reserve generation in both areas, as well as the transfer between areas. Given that the issue is dynamic and dependent on the system state, the N-1 criterion needs to be augmented with more sophisticated approaches. Using PMU data and WACS is one approach, and will be discussed later in this paper.

Chapter 6

Wide-Area Measurement and Control Systems

In this chapter phasor measurements and wide-area measurement system will be discussed. A historical review of PMU will not be provided but for further reading about PMUs these references are recommended [25], [26].

6.1 Phasor Measurement Units (PMUs)

The phasor measurement unit (PMU) is a device that measures voltage and current phasors in real time. Synchronization of PMUs is achieved by using a common synchronizing signal from the global positioning satellite (GPS). The synchronization of different waveforms at various locations makes it possible to gather the measurements for example, at a control center and display the information in real time on a screen. The primary power system voltages and current are transformed by voltage and current transformers, filtered by analog anti-aliasing filters, and converted by A/D converters at a sampling instant defined by a sampling clock. The sampling rates are 50 samples per second, f_0 is the nominal power system frequency [26].

Figure 6.1 shows an example of angle condition monitoring in the Iceland power system by using PMU measurements. The green dots with the phasors are PMU locations in the Icelandic system.

The precision of phasor measurements is defined in terms of Total Vector Error (TVE) which is defined as:

$$TVE = \sqrt{\frac{(X_r(n) - X_r)^2 - (X_i(n) - X_i)^2}{X_r^2} + X_i^2} \tag{6.1}$$

Where $X_r(i)$ and $X_i(n)$ are the real and imaginary part of the phasor given by the measuring device, X_r and X_i are the theoretical real and imaginary phasor values of the input signal at the time of measurement. Accuracy limits of PMUs, expressed as TVE should be within 1%. This implies a phase error within ± 0.01 rad ($\pm 0.57°$) or a maximum time error of 26.5μs at 60Hz and 31.8μs at 50Hz [27], [28]. Stability and accuracy of clocks are very important as the

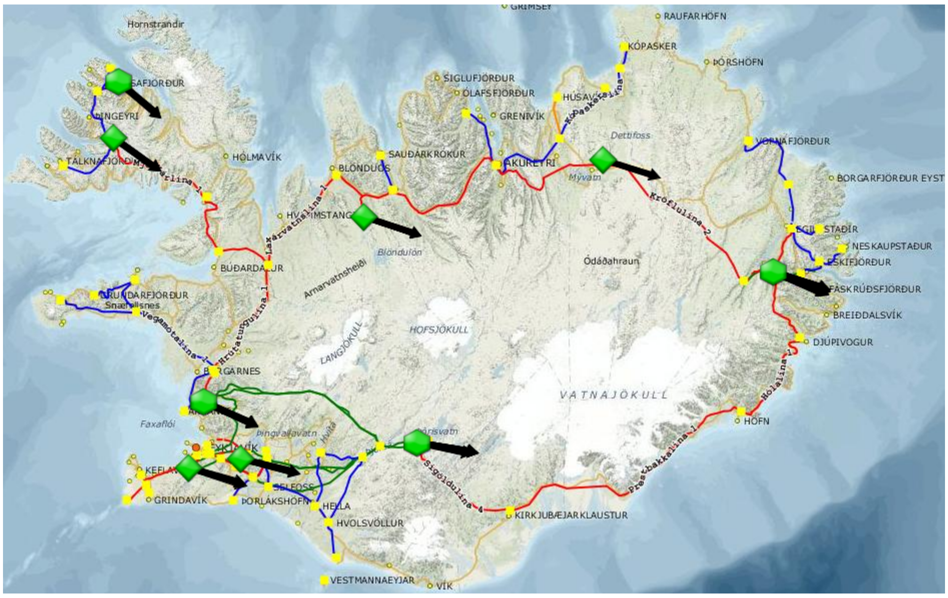


Figure 6.1 WAMS: Angle Condition Monitoring using PMUs

reference wave form is generated from the clocks, as time error of 1µ sec can induct 0.018 Hz in 50Hz system [29]

6.2 Wide Area Measurements System (WAMS)

A wide area measurements system is a system of many PMUs connected to a Phasor Data Concentrator (PDC). The PMUs transfer the synchronized measurements of voltages and currents to a first-level PDC, and several such PDCs transfer their collected data to the PDC at next level of the hierarchy. This PDC is often termed as the main PDC [30].

6.3 Wide Area Control System (WACS)

Wide area control system is a system that uses information from the wide area measurement system to determine if a certain action is required. If predefined limits are fulfilled then a PDC unit triggers the scheme. It is easy to get confused when investigating protection schemes which use wide area measurements. There is RAS, SPS, SIPS and WACS. In book [30] there is a discussion regarding what systems that use wide-area measurements should be called.

> *Remedial Action Schemes (RAS) or Special Protection Systems (SPSs) have been in use in power systems for many years in order to take corrective actions in anticipation of a catastrophic event from occurring. Recently, IEEE Power System Relaying Committee recommended that a more descriptive name to used to describe such systems: SIPS (System Integrity Protection System). The basic concept behind such systems is to determine through simulations of the power network for various contingencies if a certain sequence of events are likely to lead to major disturbances and possible cascading failures. Its also verified through simulation that such conditions can be detected by taking real-time measurements of critical power flows, circuit breaker status on key transmission lines, level of generation and load,*

and so on. These critical measurements are brought to a control center and each of these variables is compared with predetermined limits in order to determine if a catastrophic event is imminent. A set of pre-calculated corrective measures - such as tripping of loads and generation, modifying settings of controllable devices - are then initiated [30, p.333].

In a final project report [31] the difference between RAS, SPS, SIPS is defined as:

System protection schemes (SPS) (also called remedial action schemes, RAS) are designed to detect abnormal system conditions, typically contingency-related, and initiate pre-planned, corrective action to mitigate the consequence of the abnormal condition and provide acceptable system performance. SPS actions include, among others, changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. SPS is also used as the acronym for special protection scheme, with has the same meaning as system protection scheme. However, it was recommended in that word special be replaced by the word system, since it can be argued that all protection is special in some fashion. IEEE uses the System Integrity Protection System (SIPS), RAS is used by (BPA, WECC) others use the term SPS.

The conclusion is: SIPS use wide area measurement to find a initial steady-state condition to simulate a system and then return the simulation results to the system operator or trigger SPS schemes. SPS are not necessarily counting on any simulation on daily basis, but are configured in a way that protects the system for known bad-conditions found out by experience or past simulation [32]. The SIPS encompasses SPS, RAS, as well as additional schemes such as, but not limited to, underfrequency, undervoltage, out-of-step,etc..[33].

6.4 Special Integrity Protection System Schemes - SIPS

In certain power system, studies of system performance may show that large disturbances on important lines or facilities can cause violent and often disastrous effects. This may occur in systems that are interconnected by long or weak tie lines, which may be heavily loaded. When this occurs, the system may not be able to survive, resulting in total blackout. One way to prevent this disastrous result is to separate the interconnected system in a controlled fashion, such that the resulting islands can be assured of having a reasonable balance between load and generation. This increases the probability of survival of the islands. Another condition that requires special treatment is the occurrence of a disturbance by one utility that, because of it is nature or size, causes serious consequences to the transmission system of neighboring utility. In the interconnected systems of all over worldwide, interconnections are designed and operated such that this type of condition should not occur. In other words, it is a design requirement, either expressed or implied, that one should not design a system that creates a serious problem for a neighboring utility. This requires measures to be taken during the design process that will assure neighboring utilities that new facility will not cause them operating difficulties, even during unusual events such as faults or other disturbances [8], [30].

6.4.1 Special Protection System Characteristics

The material in this section is from [30] and [8]. The type of control scheme described above is known by various names, in addition to SPS, depending on the originator, for example:

- Special Stability Controls
- Dynamic Security Controls
- Contingency Arming Schemes
- Remedial Action Schemes
- Adaptive Protection Schemes
- Corrective Action Schemes
- Security Enhancement Schemes

These schemes provide different types of control actions, depending on the problem created when the disturbance occurs. Some schemes trip generators, other intentionally open transmission lines, and some create islanded system at predetermined locations. The schemes have several traits in common:

1. All are dynamic security control systems and are designed to control power system stability in cases where the uncontrolled response is likely to be more damaging than the controlled response.
2. All are devised by off-line analysis, as opposed to on-line real-time control. The reason for this is that the power system response is too fast to allow time for the usual sequential control system logic, which might be summarized as:
   (a) make the observation in real time,
   (b) determine the scope of the disturbance,
   (c) decide what action is required, and then
   (d) take the needed action.

   In particular, item (c) may take a relatively long time, even if it is possible to create a logic that will always make the correct decision.
3. Many of these schemes are armed or disarmed, as required, in order to meet the needs of the system at a particular time. In other words, the special control logic may not be required under certain operating conditions, in which case the SPS is disarmed.
4. All of the schemes provide a particular type of remedial action that is designed to alleviate a certain observed system condition, or to take a predetermined action when a certain event occurs whose resulting effects are calculated to be too serious to ignore.

6.4.2 Special Integrity System Protection Design Procedure

The design of an SPS follows a logical procedure. It is necessary first to understand the system response to disturbances. Some disturbances are more serious than others, depending on the type, location, complexity, and duration of the disturbance. Some may be found to be very serious, and may be such that the protective devices normally used for system protection are inadequate. This may dictate the installation of several devices, some of which may be of special design [8],[34]. The following design procedure definitions are from [8, p.904].

1. Definition of Critical Conditions. The critical disturbances are those expected to have a devastating effect on the power system under a particular operating condition. Their identification will probably require many stability studies, for different operating conditions and different disturbance scenarios. In some cases, the engineer seeks guidance in this search from actual disturbance that have occured and resulted in serious consequences such as loss of stability, islanding, loss of load, or blackout. This procedure should result in a clear definition as to the disturbances can be detected, and their effect. It is also possible to devise corrective measures using computer simulation as a tool, including the action to be taken, the required speed of that action, and the results of the control action.

2. Definition of Recognition Triggers. Recognition triggers are devices that are used to identify the need for SPS response. Usually the triggers are relays of various types and may be used in combinations. For example, line relays on different lines, perhaps at different locations, can be used as input triggers in an ”and” or ”or” logic to take a particular action. In some schemes that have been designed, there are dozens of such input triggers that are possible to use. For example, line fault, low voltage of a given magnitude at a certain location, apparatus faults, such as transformer faults.

   In some cases, these input triggers are combined in hardwired or digital logic to form super triggers, each of which may dictate different controlled responses, such as

   - Generation tripping
   - Line tripping
   - Load shedding
   - Load increase or decrease

   In a few cases, transferred trip signals are sent hundreds of kilometers to remote facilities to order the desired control action.

6.5 Islanding in Power Systems

Islanding is when interconnected system is separated in way that two or more islands are formed. The island ability to survive depends on the generation and load balance in each island.

In some cases it could be better to split a system into islands before disturbance, if and only if it is possible to restore or preserve balance between load and generation in the island [30]. In [30] islanding is discussed as follows:

> *In recent years much emphasis has been placed on system integrity protection schemes (SIPS), also known as remedial action schemes or system protection schemes. These schemes take into account the prevailing power system conditions by obtaining measurements of key parameters in real time. The most promising technique is to use wide-area measurements (such as synchronized phasor measurements) and determine appropriate islanding and restoration strategies based upon these measurements. However, this whole field is in it is infancy, and much theoretical work needs to be*

done (and is being done) before practical solutions based on real-time measurements can be found.

What is being proposed in this thesis is relevant to this text. Landsnet can use their WAMS system to split the system with the best load-generation balance. The present islanding schemes which are discussed in section 6.6 are local protection units that split the system depending on power flows on BL1, BL2, FL2 and SI4. This method is valid and can be evolved further to split the system with most balance. By using real-time security assessment which is being proposed in this thesis it is possible to determine the best split automatically if a disturbance occurs.

In the operation of the Icelandic power system it was decided that islanding is preferable to on-load generation rejection [35]. In general islanding is considered the last line of defense, designed for severe events beyond the capability of standard protection (for N-1 events). Beyond standard protection, there are proposed mechanism to contain the extent of the event and enable faster restoration:

- System Integrity Protection System (SIPS)
- Wide-area Control System (WACS)
- Adaptive Islanding,

Adaptive islanding is automatic control of the islanding process with respect to the power flow and stability in the system. The purpose is to minimize the impact of islanding and the islands can continue to operate with good load-generation balance. The use of adaptive islanding is thought to improve system security and reduce time that the system is exposed to a high risk [35].

6.6 Protection Schemes in the Icelandic Power System

In this section wide area control system protection schemes in the Icelandic power system are explained in detail along with local protection schemes. No SIPS are in use the Iceland power system. One of the project aims was to implement system protection into the PSS/E model and was done by using Python programming language, explained in Appendix B. By implementing the WACS and protection schemes it was possible to valuate their influence on the system stability.

6.6.1 Special System Protection Schemes

In this subsection protection schemes will be presented. These protection schemes are built into traditional local protection devices. Therefore they are not using measurements elsewhere in the system (WAMS measurements).

By knowning the configurations of the local protection it is possible to use WACS schemes to prevent protection schemes from operating or move trip signals to other locations for islanding purposes. The protection schemes described in the following subsections are often the last line of defense with regards to overall system stability.

6.6.1.1 System Protection at Blanda

Blanda (BLA) is in North Iceland and there is a hydro power plant connected to the 132kV main ring. BLA has three generators, 60MVA each. Bus A is connected to BL1, which is the line between BLA and Laxárvatn (LAV) and bus B to BL2, which is the line between BLA and Varmahlíð (VAR). Between the buses is a circuit breaker (bus-tie breaker) which is used to split the system in the North during disturbances. The setup is shown in figure 6.2 . Each generator can be switched between buses and therefore it is possible to balance generation in the islands before split occurs.

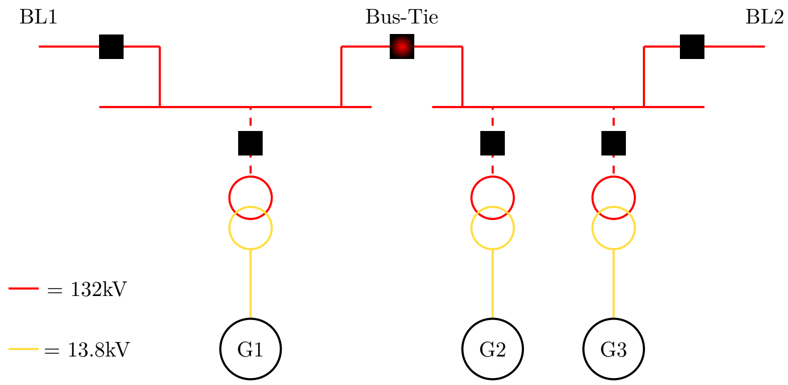


Figure 6.2 Blanda: Substation Circuit Diagram

The line protection is configured as follows:

- $P_{BL1} > 130MW$
- $P_{BL2} > 120MW$

If the generators are connected as figure 6.2 shows and if BL2 trips in heavy transmission, then the power generated by generators 2 and 3 will flow through the bus-tie and along BL1. Which will lead to bus-tie tripping, then there are two unused generators in the system. This is the disadvantage of using the bus-tie breaker, if either line trips then you lose important generation. In certain cases it would be more convenient to transfer the trip to another circuit breaker in the system to decrease load demand and stop power swings. Another way is using power-swing blocker with a time delay and keep the current setting. In some cases this setting is convenient (Cut IV) but in other cases it is not (Cut IIIb). The pros and cons will be discussed and some cases simulated later in the thesis regarding Cut IIIb.

6.6.1.2 System Protection at Sigalda/Hólar

There are two ways of splitting the system in South Iceland. First it is by transferring the trip signal from Sigalda (SIG) to a circuit breaker at Hólar (HOL) for PB1 which lies between Prestbakki (PRB) and Hólar (HOL). As is shown in figure 6.3 the circuit breaker for PB1 at HOL is tripped. If the following conditions are fulfilled: $P_{SI4} > 120MW$ then a trip signal is sent via fiber to HOL and the circuit breaker for the line is tripped. This is done because SI4 and PB1 are connected together via no load breaker (disconnector) at PRB (Prestbakki). Tripping the circuit breaker at SIG would cause voltage problems at PRB if connected to HOL because of light load at PRB and very long line from HOL to PRB, $l_{PB1} = 171$ km.

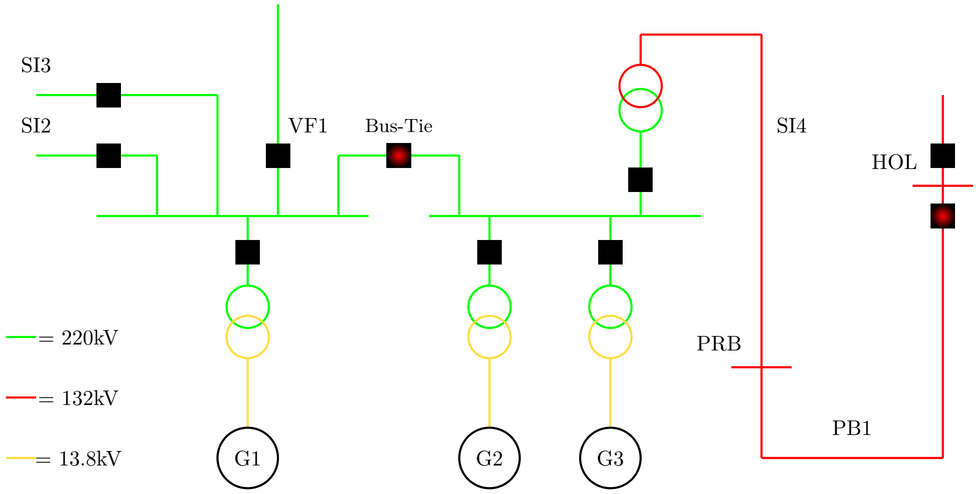


Figure 6.3 Sigalda: Substation Circuit Diagram

Other way of splitting is doing it at SIG by tripping a newly installed bus-tie breaker. That means there are two generators connected to the East in SIG and one to the West. The bus-tie breaker was installed in fall 2015. It should be mentioned that the bus-tie circuit breaker makes it possible to split the system into two islands and leaving two generators at SIG along with the East Island to preserve load-generation balance in the island. The tripping scheme for this breaker is introduced later in this thesis and described in great detail. Before the installation the limit was $P_{cutiv} = 120MW$ and then a transferred trip signal would trip the circuit breaker at HOL for PB1.

6.6.1.3 System Protection at Fljótsdalur

In Fljótsdalur (FLJ) power can be imported and exported to the system through transformer 7 (TR7) and transformer 8 (TR8). These transformers connect FLJ to the 132kV ring system. When the transformers get overloaded then there are special protection schemes depending if the power is being exported or imported. When the transformers are tripped then FLJ and the aluminum smelter at Reyðarfjörður - Alcoa (ARE) comes a mini island. Figure 6.4 is a connection diagram for FLJ and ARE.

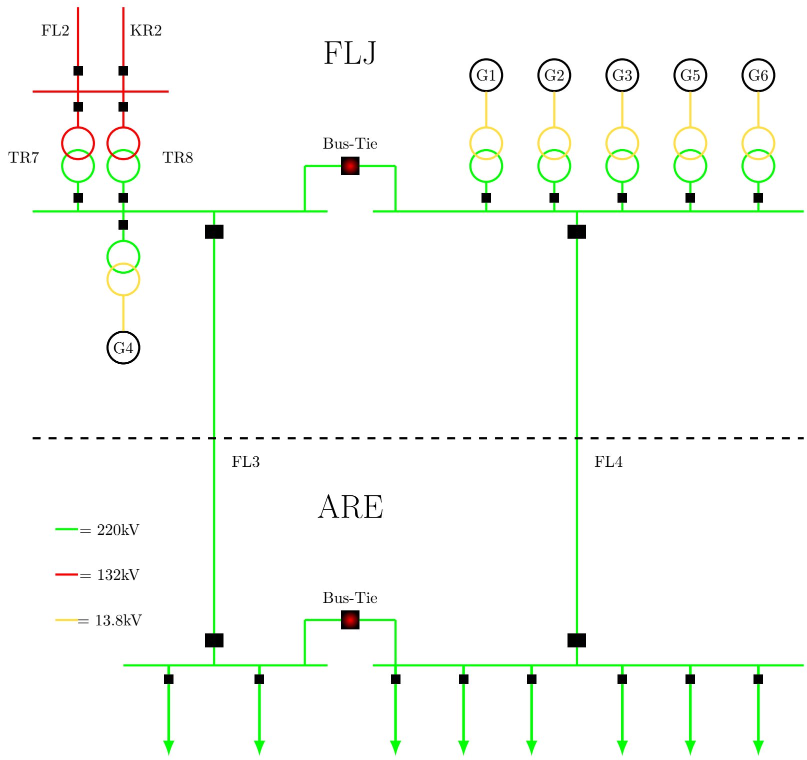


Figure 6.4 Fljótsdalur: Substation Circuit Diagram

FLJ TR7 and TR8 tripping scheme is different depending on power flow through the transformers, importing means the power is coming from the 132kV ring connection and export vice versa. For importing from the 132kV ring then the protection scheme is described in steps:

- Step 1 - $P_{FLJTR7\&8} > 150$MW, t $> 0{,}1$s $\Longrightarrow$ 90MW load reduction at ARE (ALCOA)
- Step 2 - $P_{FLJTR7\&8} > 150$MW, t $> 3{,}0$s $\Longrightarrow$ FLJ Transformers 7 & 8 trip on 132kV side
- Step 3 - $P_{FLJTR7\&8} > 180$MW, t $> 0{,}4$s $\Longrightarrow$ FLJ Transformers 7 & 8 trip on 132kV side

If exporting to the 132kV ring then there are two steps:

- Step 1 - $P_{FLJTR7\&8} > 150$MW, t $> 3{,}0$s $\Longrightarrow$ FLJ Transformers 7 & 8 trip on 132kV side
- Step 2 - $P_{FLJTR7\&8} > 180$MW, t $> 0{,}4$s $\Longrightarrow$ FLJ Transformers 7 & 8 trip on 132kV side

Last but no least is the system protection for FL2.

- If $P_{FL2} > 140MW$, t $> 0{,}2$s then FLJ transformer 7 & 8 are tripped on 132kV side.

6.6.2 Wide-Area Control System (WACS) Schemes

In this subsection WACS functions in the Icelandic power system are presented. These functions are in operation on daily basis and one of the intentions of this thesis is to simulate the system response with and without them. The East Iceland Protection Scheme and Westfjords schemes are not used in the dynamic simulations.

6.6.2.1 Norðurál - Dynamic Load Control Scheme

Norðurál (NAL), is an aluminum smelter in West Iceland with a 535 MW load on daily basis. The dynamic load control system is an automatic system that operates if predefined frequency deviation values are fulfilled. If the frequency goes up then NAL increases the load in steps. If the frequency goes down then NAL decreases the load in steps. The frequency reference for the dynamic load control is at BRE. Settings for upward regulation are:

- $f_{BRE} > 50,5Hz \rightarrow P_{NAL} = +10MW$
- $f_{BRE} > 50,7Hz \rightarrow P_{NAL} = +20MW$

If the $f_{BRE} > 50,7Hz$ then 10+20=30MW increase in NAL load. The load is increased for 5 seconds and then the load is driven down by 60MW/min until rated load value before the disturbance is reached. Settings for downward regulation are:

- $f_{BRE} < 49,2Hz \rightarrow P_{NAL} = -18MW$
- $f_{BRE} < 48,8Hz \rightarrow P_{NAL} = -30MW$

If the $f_{BRE} < 48,8Hz$ then 18+30=48MW decrease in NAL load. The load is held down for one minute and then increased again at the rate of approximately 20MW/min.

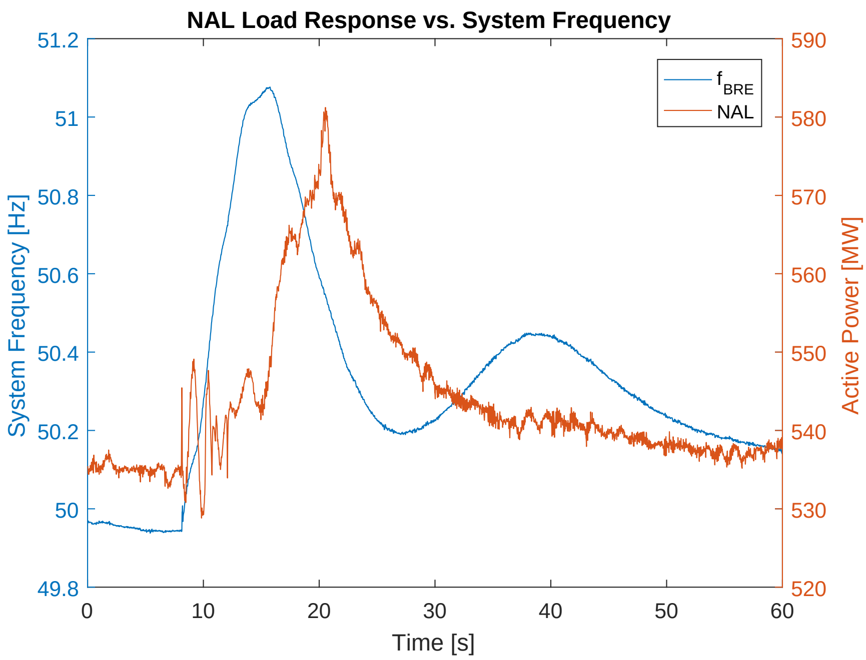


Figure 6.5 NAL Dynamic Load Control vs. System Frequency

6.6.2.2 ARE - Down Regulation Load Control Scheme

ARE is the largest in Iceland with 560MW load on daily basis. It is located in East Iceland and is connected to a substation in Fljótsdalur (FLJ). In FLJ there are two transformers (TR7 and TR8) connected to the main 132kV ring by FL2 and KR2. Sometimes the water reservoir is adverse at Kárahnjúkavirkjun (KAR) and then power has to be imported from other hydro and geothermal plants in the system to fed Alcoa load.These conditions call for heavy power import through before mentioned transformers in FLJ.The down regulation load control at Alcoa is triggered by the power flow through the transformers. The conditions for active power import are:

- $P_{FLJTR7-8} > 120MW \rightarrow P_{ARE} = -10\text{MW}$
- $P_{FLJTR7-8} > 140MW \rightarrow P_{ARE} = -20\text{MW}$

6.6.2.3 East Iceland Load Shedding (EILS) - Fishsmelter Tripping Scheme

In East Iceland are six fish smelters which are connected to the electrical system at distributional level (11kV).

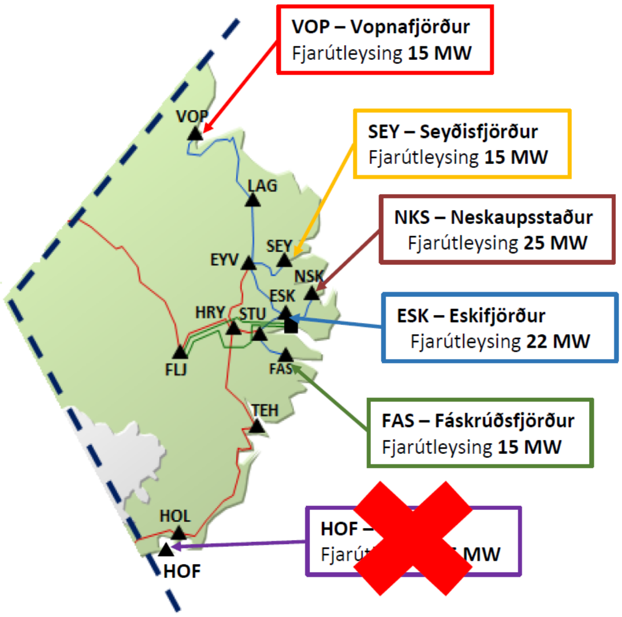


Figure 6.6 Fishsmelter tripping scheme in East Iceland [Kerfisvarnarskjal,p.11]

The fish smelters load is categorized as sheddable load. These fish smelters have their own diesel generators for their equipment, which can used if the smelters get tripped from the system. Load capacity of all these smelters combined are 92 MW and therefore in emergencies it may be necessary to trip these smelters. If the following system conditions are fulfilled then a trip signal is sent to **all** the smelters:

- $P_{SI4}+P_{BL2} > 180$ MW
- $P_{SI4} > 115$ MW

- $P_{BL2} > 115$ MW

If either line of Cut V exceed the predefined limit a trip signal is only sent to fish smelters in Fá Fáskrúðsfjörður (FAS), Neskaupsstaður (NKS), Eskifjörður (ESK) and Seyðisfjörður (SEY).

- $P_{SR1} > 60$ MW
- $P_{EY1} > 40$ MW

If either line of Cut Vb exceeds the predefined limit a trip signal is only sent to fish smelters in ESK and NKS.

- $P_{SR2} > 40$ MW
- $P_{ES1} > 40$ MW

In Reykjavik there is a PDC unit monitoring these values, when any of the above conditions are fulfilled then a signal is sent to a TETRA modem and this TETRA modem sends a signal to other TETRA modems located at VOP, SEY, NKS, ESK and FAS. Then the tetra modem at the substation sends a trip signal to the 11kV circuit breaker for the sheddable load.

6.6.2.4 South Iceland Protection Scheme

Selfosslína 2 (SE2) are based in the 66kV area system in South Iceland. The purpose of SE2 protection is to trip the line if there is too much power transfer through the line $P_{SE2} > \pm 16$MW. SE2 is the connection between the South-West and South-East system. Were the South-West system is supplied by Sogsvirkjanir (SOG) to Selfoss (SEL). The South-East system is supplied by Búrfellsvirkjun (BUR). If SOG trips, then SE2 will be overloaded and if BUR trips then SE2 will be overloaded. In BUR are two 13.8/66kV transformers, that are combined 80MVA and are the protected by overload protection which is 130% for 2.5 seconds.

6.6.2.5 Westfjords Protection Scheme

Breiðadalslína 1 (BD1) is based in the 66kV area system in the Westfjords, during the winter if the Westline trips than BD1 is always tripped and all the load at North Westfjords. Then MJO is still connected to KEL. After 60-90 seconds a back-up diesel generation station at BOL is online and the load is connected in steps. During the summer time settings at MJO are changed so MJO tries to handle all the load if the Westline trips.

In this thesis a logic is proposed to keep the Westfjords connected by tripping load immediately if the Westline is disconnected (if $P_{Westline}$<23MW) or load shedding by underfrequency protection. Most of the load is for heating water (house heating and etc.) for general public, and it is sheddable. This is discussed in more detail later in section 13.4. This was not simulated dynamically and therefore not implemented in the PSS/E python script used for this thesis.

Part II

Model Discussion

Chapter 7

Model Validation and Simulations Analysis

In this chapter model and simulation analysis will be introduced. In the beginning a model validation was conducted. Subsequently, test simulations were carried out which had to evaluated in a apposite way. The method that was used to evaluate the simulations will be presented along with an working example.

7.1 Model Validation

In this section model validation results are presented. Model validation is carried out by choosing one or two events and simulating them in great detail. This approach is used to get the limitation and accuracy of the model. For example, generators response to massive load loss and frequency response, or even voltage response and time factors of the responses. The event is a massive disturbance that lead to system split into two islands. Event timeline and explanations are discussed in following sections.

7.1.1 Disturbance on 8th August 2015

At 05:52:05 in morning of 8.August 2015 there was a fault at aluminum smelter in West Iceland that lead to a 320 MW load loss. The system was not heavily loaded at the time but there was a 102MW export from West Iceland to the East part. There were a few generators out of service and when the smelter tripped the following things happened, the event time line is shown in figure 7.1. Local system protection at BLA and SIG operated because of overloading on BL2 and SI4 nearly immediately after the aluminum load loss in the West. Therefore the system was splitted into two islands. In those cases when there is heavy export, which is around and over 100 MW, there will be a underfrequency condition in the East island and over-frequency conditions in the West island. At the time of the event power-flow from West to the East was around 102MW. After the system split, a Ferro silicon plant in West island lost 45 MW load and around same time Svartsengi (SVA), a geothermal power-plant at Reykjanes tripped in the West island. Because the frequency fall in the East Island underfrequency protection tripped one rectifier at ARE leading to 90 MW load reduction which stabilized the East island frequency rather quickly. The frequency eventually reached 52,55 Hz in the West island after the split and 48.57 Hz in the East island. ARE underfrequency scheme triggered the load shedding at 49.1 Hz.

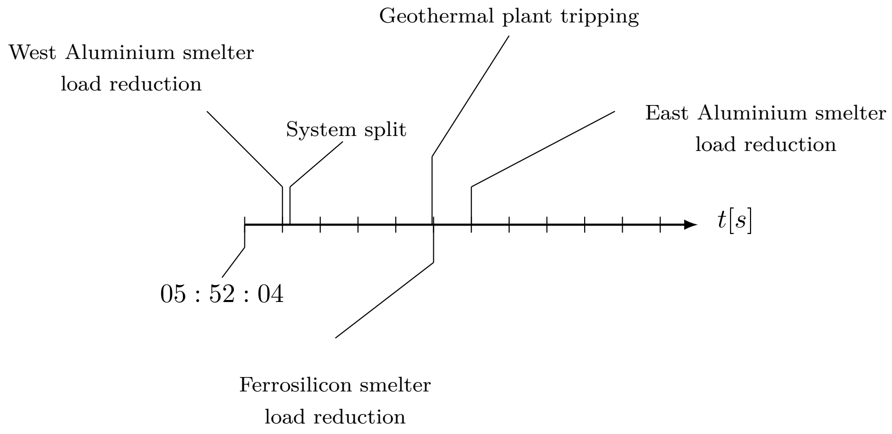


Figure 7.1 Disturbance timeline - 8.August 2015

7.1.2 Simulation Versus WAMS Measurements

In this section the model validation results are presented. To get the right timeline of the disturbance it was necessary to analyze the events in great detail. Getting the event order right and the magnitude of load shedding for each load accurate. Because the frequency response is influenced by number of generators and the proportion of load loss. Figure 7.2 shows the industrial load response.

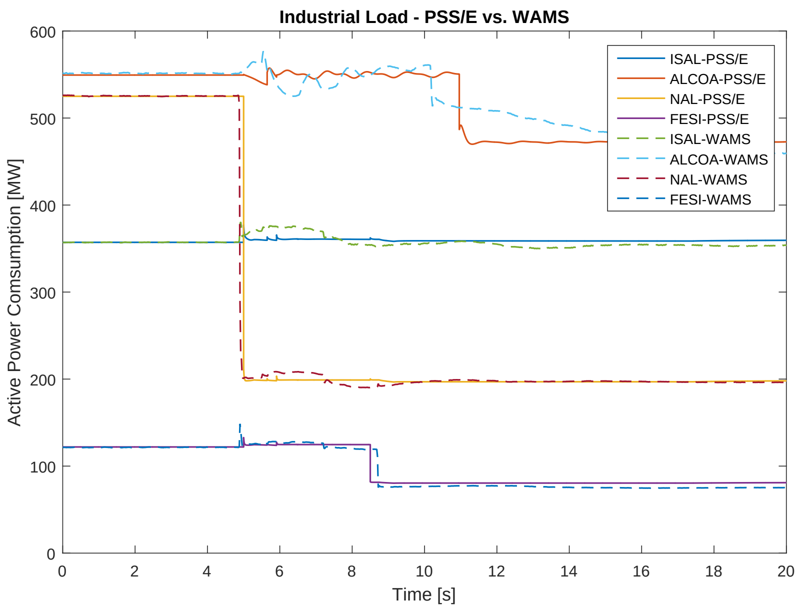
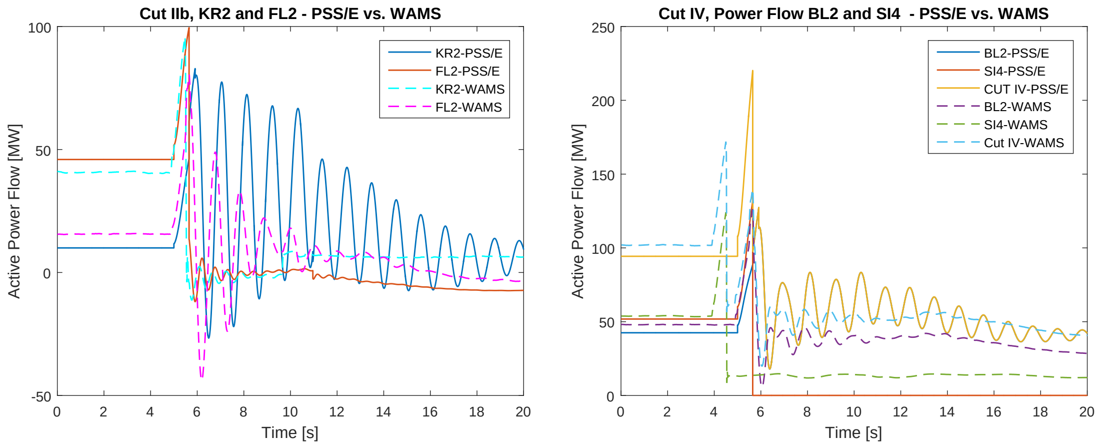


Figure 7.2 Industrial Load before and during the fault

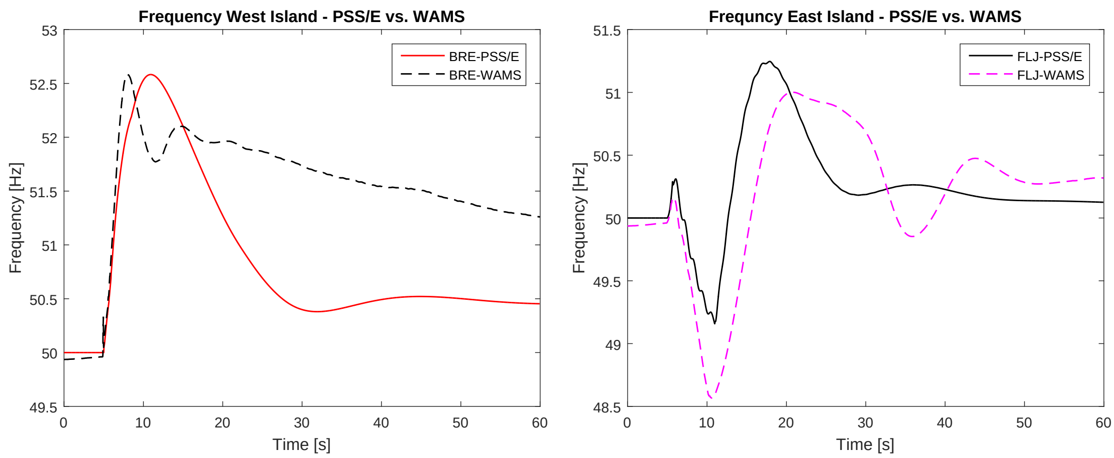
In 7.3b shows the system response to the disturbance before system split and after. The active power value on SI4 becomes zero in the model but is around 10MW in the real event. This is because the old islanding scheme kept HOL along with the West Island, then SIG had to supply HOL. But then it was changed so HOL was kept with the East island in case of islanding. There were two generators at BLA connected to the East island, so Cut IV after the disturbance is around 50MW.

Figure 7.3a shows the active power import to FLJ, before the split FL2 is delivering around ≈ 45 MW then SI4 is tripped and the power flow changes signs, then FLJ is exporting power to the system instead of the smelter load at ARE absorbing the power. This is correct behavior because around t=10s underfrequency protection trips 90 MW load at ARE, which is approximately one rectifier unit out of six. The pink graph is KR2 and it is connected to the geothermal power plant KRA and two units at BLA further in the West.



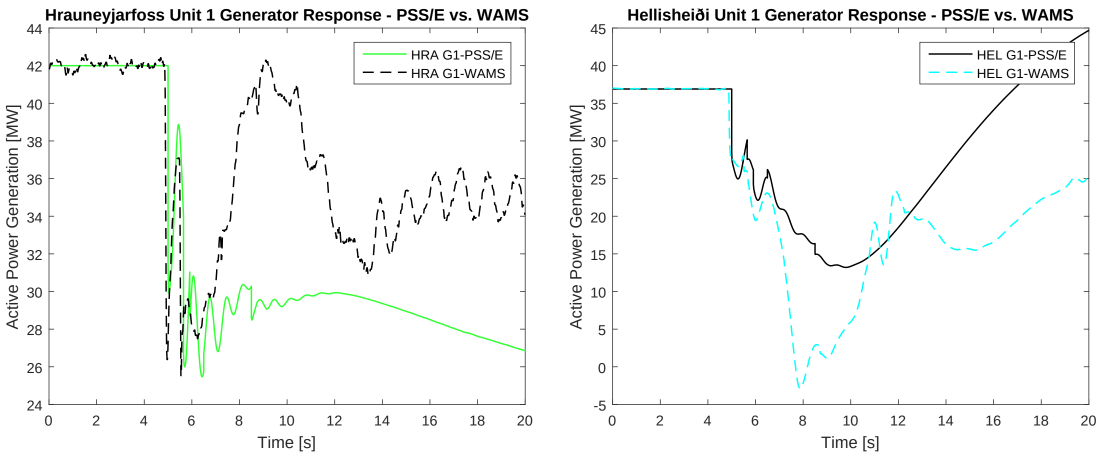
(a) KR2 and FL2 power flow **(b)** Cut IV power flow

Figure 7.3 Critical Power Flows Response



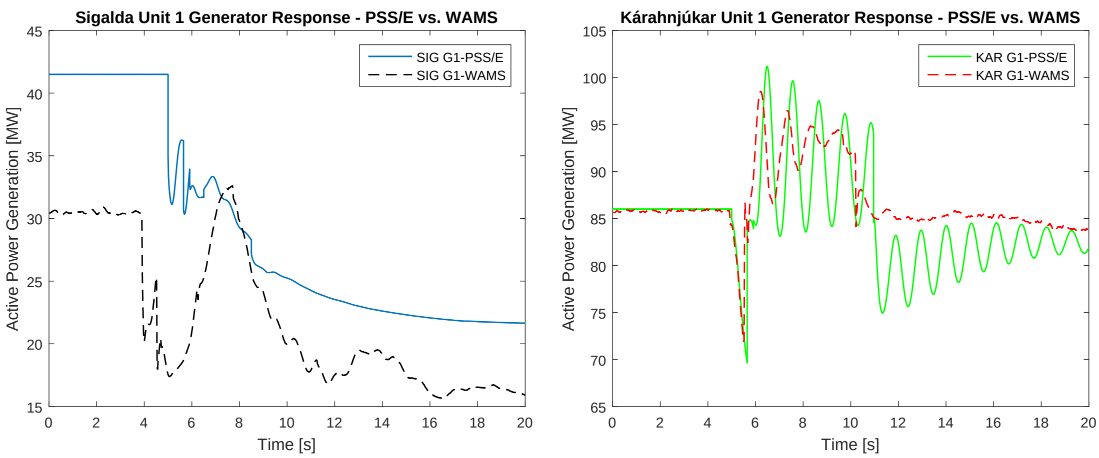
(a) Frequency in the West island **(b)** Frequency in the East island

Figure 7.4 System Frequency Response During Islanding



(a) Hydro Generation Unit 1 at HRA **(b)** Geothermal Unit 1 at HEL

Figure 7.5 Geothermal and Hydro Generation Response



(a) Hydro Generation Unit 1 at SIG **(b)** Hydro Generation Unit 1 at SIG

Figure 7.6 Hydro Generation Units Response

The generation response at KAR is very interesting, the amplitude of the response is more but if the mean value would be taken it would be very similar to the real response. It is a confirmation for a precise model of the governor.

7.1.3 Model Validation Conclusion

The model validation conclusion is that the PSS/E model is acceptable. In this process of model validating there was a few adjustment done regarding generator models and it made the frequency response more accurate. The frequency response was not as accurate as was expected but the model validation indicates that the damping is more in the model then in the reality. The frequency response was more accurate in the West island when the system was splitted into two islands than interconnected. Before any model adjustments it was tested to compare the frequency response to another event, where all generation in the East island was tripped, except KAR. Generation before the event was approximately 40MW and the frequency dropped to 49,0Hz, but in the real event the frequency dropped to 48,6Hz.

7.2 Simulation Analysis Method

This section contains an explanation of the method used to evaluate the simulations performed at the study of this thesis. In order to evaluate the consequences of individual disturbance it was necessary to define a standard procedure. The procedure is built on circuit breaker movements, protection scheme operation and frequency stability. Reasons for this type of instability was explained in section 3.4.

7.2.1 Simulation Result Standard (Consequence Factor)

To describe different situation to each disturbance a consequence table 7.1 was created. In next part of the thesis simulations will be valuated by a consequence factor. The consequence factor is explained further in 7.2. Each simulation will be given color from table 7.1 that describes the consequences and the system response in each simulation.

Table 7.1 Consequence Factor Table

Consequence Factor	Description
●	System is stable.
●	System is stable but stressed
●	System is in island condition and stable
●	System is in island condition but stressed
●	Very severe disturbance

The frequency is dominating in this consequence factor grading. The rule of thumb is: two conditions of three must be fulfilled for grading. As always there are some exceptions. All exceptions in grading are marked (for example, *) and explained at the bottom of the tables if it is thought to be relevant.

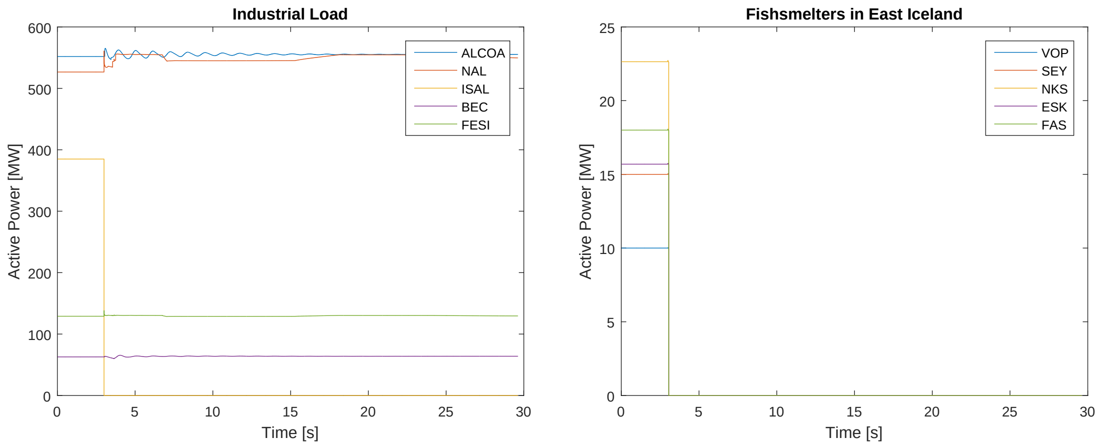
Table 7.2 Consequence Factor Explanation Table

●	Frequency is within limits | $f_{sys} = 50 \pm 0.5$Hz No local protection or WACS operated No circuit breaker movement except the fault clearance $\rightarrow X_{cbm} \geq 2$
●	Frequency is within limits | $f_{sys} = 50 \pm 0.5 - 0.7$Hz Local protection and WACS operated Circuit breaker movement $= X_{cbm} \rightarrow X_{cbm} \geq 3$
●	Frequency is out of traditional limits| $f_{sys} = 50 \pm 0.7 - 1.2$Hz Local protection and WACS operated Circuit breaker movement $= X_{cbm} \rightarrow X_{cbm} \geq 7$
●	Frequency is out of traditional limits | $f_{sys} = 50 \pm 1.2 - 1.7$Hz Local protection and WACS operated Circuit breaker movement $= X_{cbm} \rightarrow 7 \leq X_{cbm} \leq 8$
●	Frequency is out of bound | $f_{sys} = 50 \pm 1.7$Hz) Priority load and generator tripping Local and WACS protection operated Circuit breaker movement $= X_{cbm} \rightarrow X_{cbm} \geq 8$

7.3 Simulation Analysis Example

This section will discuss how consequence factor will be used to analyze the consequences and the frequency stability of the Icelandic power system for one chosen event. The reader is encouraged to check with section 6.6 while reading for system proctection and WACS configurations.

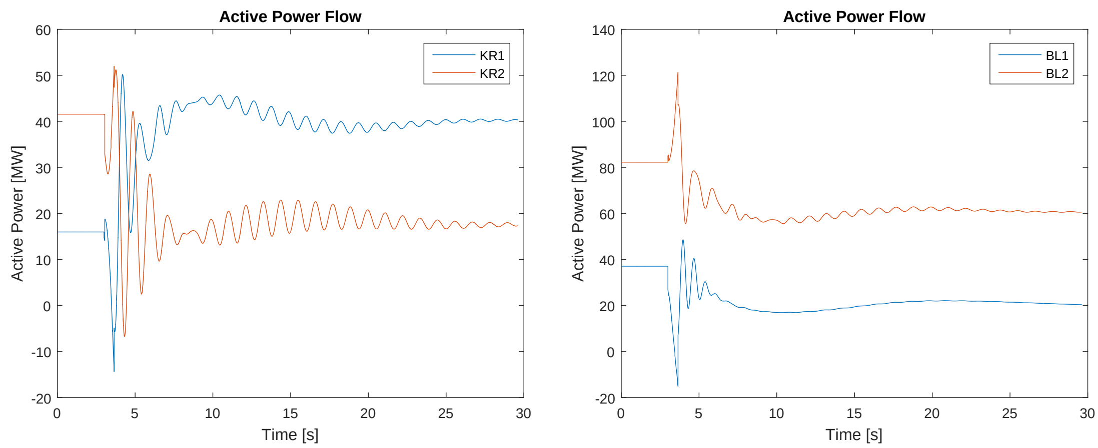
The disturbance event trigger is when a aluminum plant (ISAL) in West Iceland trips. Active power flow through Cut IV is 170MW and the tripping scheme is set to trip the bus tie breaker at SIG if active power reaches the limit of SI4 (P_{SI4}>120MW), introduced in section 6.6.1.2.



(a) Active Power Industrial Load **(b)** Active Power Fish Smelter Load

Figure 7.7 Example of Active Power Load Response

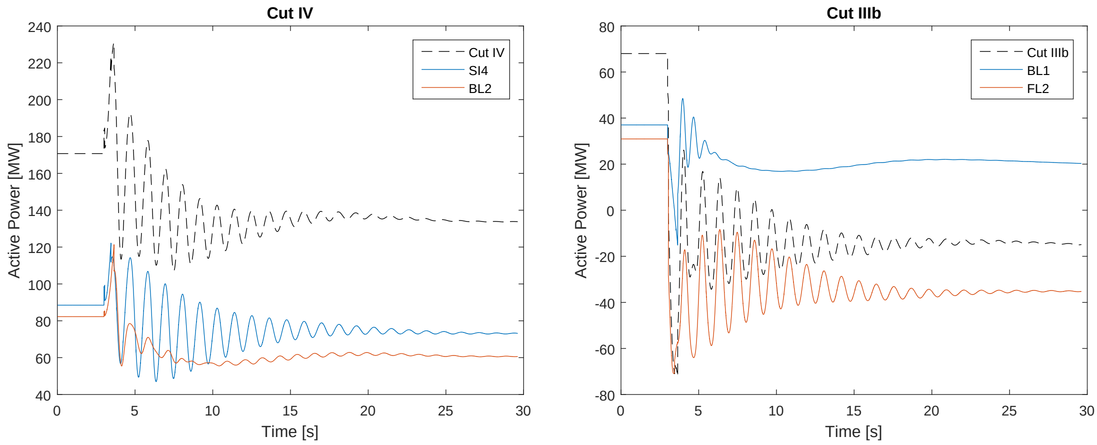
In figure 7.7a all heavy industrial active power load is shown. ISAL disconnects from the power system with nearly 400MW. It is noted that the DLC at NAL is triggered and their load is increased due to WACS. In figure 7.7b fish smelter load in East Iceland is shown. The WACS trips 81MW of fish smelters load.



(a) Active Power Flow - KR1 & KR2 **(b)** Active Power Flow - BL1 & BL2

Figure 7.8 Example of Power Flows Response

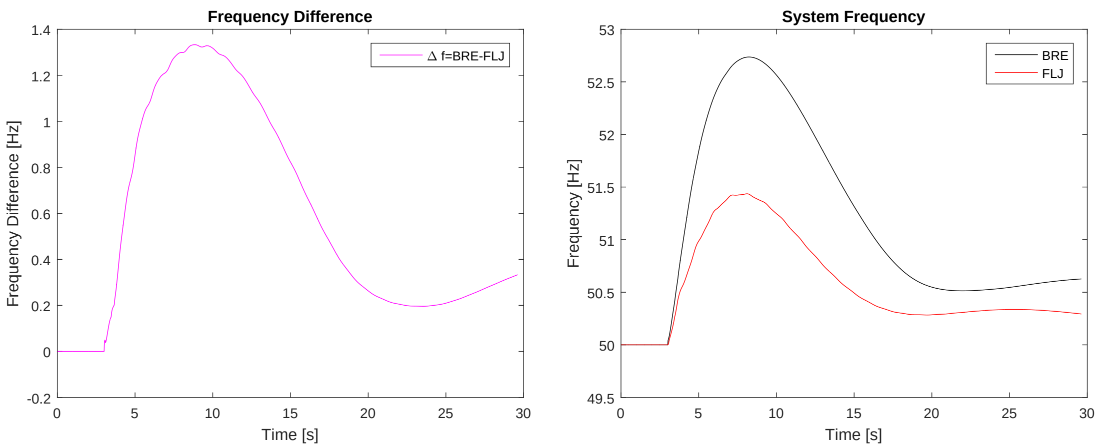
Figures 7.8a and 7.8b show the power flow through BL1, BL2, Kröflulína 1 (KR1) and Kröflulínu 2 (KR2). In figure 7.8b it is noted that active power flow on BL2 reaches 120MW, then the bus-tie at BLA is tripped. Figure 7.9a shows the power flow through Cut IV and SI4 had reached its limits just milliseconds before BL2, than the system is splitted into two islands.



(a) Active Power Flow in Cut IV **(b)** Active Power Flow in Cut IIIb

Figure 7.9 Example of Active Power Load Response

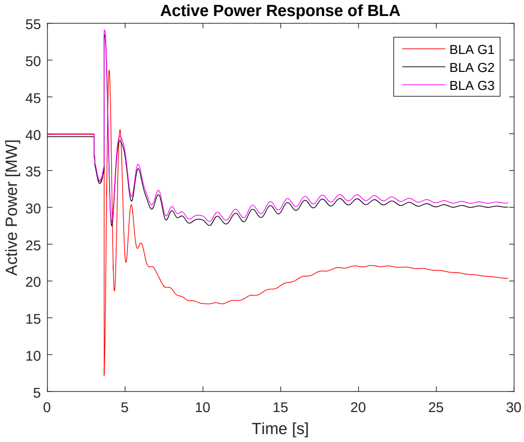
Islanding conditions can also be identified by examining figure 7.10b that shows the frequency in the West island (BRE) and in the East island (FLJ). The frequency response in the East island is not as aggressive as it is in the West island because of the split, according to the theory the generation-load balance is better in the East island after the split.



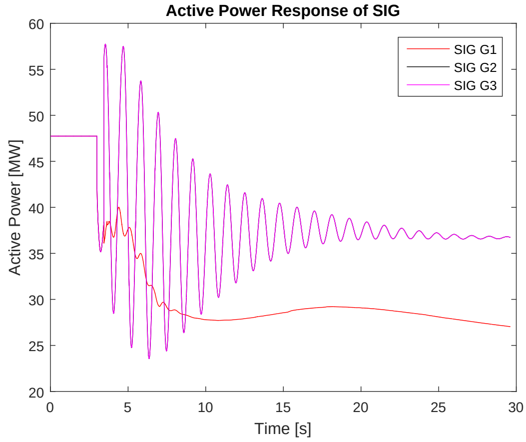
(a) Frequency Difference between the Islands **(b)** Frequency Response in West and East Islands

Figure 7.10 Example of Frequency Response

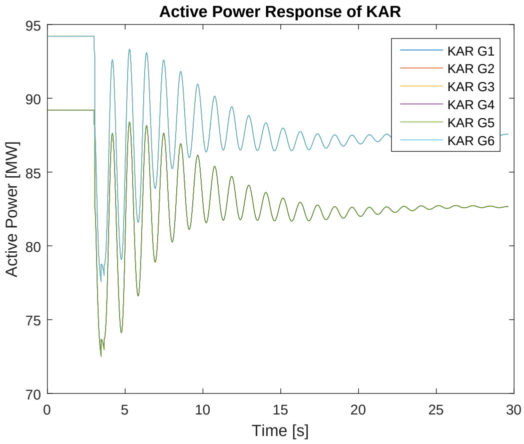
In figure 7.11 chosen generation responses are shown. All the generators participate in the regulation process and become stable soon after the system split. Figure 7.8a is reflecting the generation response at Krafla (KRA) shown in figure 7.11d. In this case it is clear that it would be feasible that KRA would participate in frequency regulation but KRA generation goes back up to rated value soon after the system split instead of lowering its active power output. The generators response in SIG and BLA is different depending on what island each generator is connected to. Generator 1 at BLA and SIG are connected to the West island and the responses are very similar because of frequency is higher than in the East. Generators 2 and 3 at BLA and SIG are all connected to the East system.



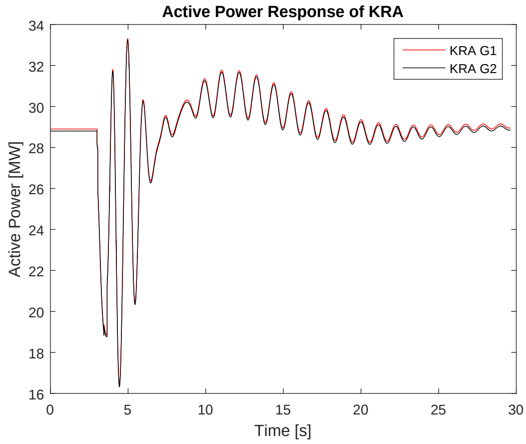
(a) Active Power Generation Response at BLA



(b) Active Power Generation Response at SIG



(c) Active Power Generation Response at KAR



(d) Active Power Generation Response at KRA

Figure 7.11 Active Power Generation Response

From this simulation is clear that the overall system stability in both islands is good. WACS schemes at Norðurál and for the fish smelters operated along with system protections that splitted up the system. In this particular case it maybe not the best decision to trigger the fish smelter scheme when a aluminum smelter in West Iceland trips, given that SIG tripping scheme is set to the bus tie breaker at SIG. The consequence of this event were seven circuit breaker movements and according to the consequence factor this simulation will get the grade: (●).

Chapter 8

Power Systems Comparison to Theory and Simulations

In this chapter simulation results, theory and real system response will be discussed. Potential methods to make the security assessment will be discussed and validated.

8.1 SIG Model Instability Issues

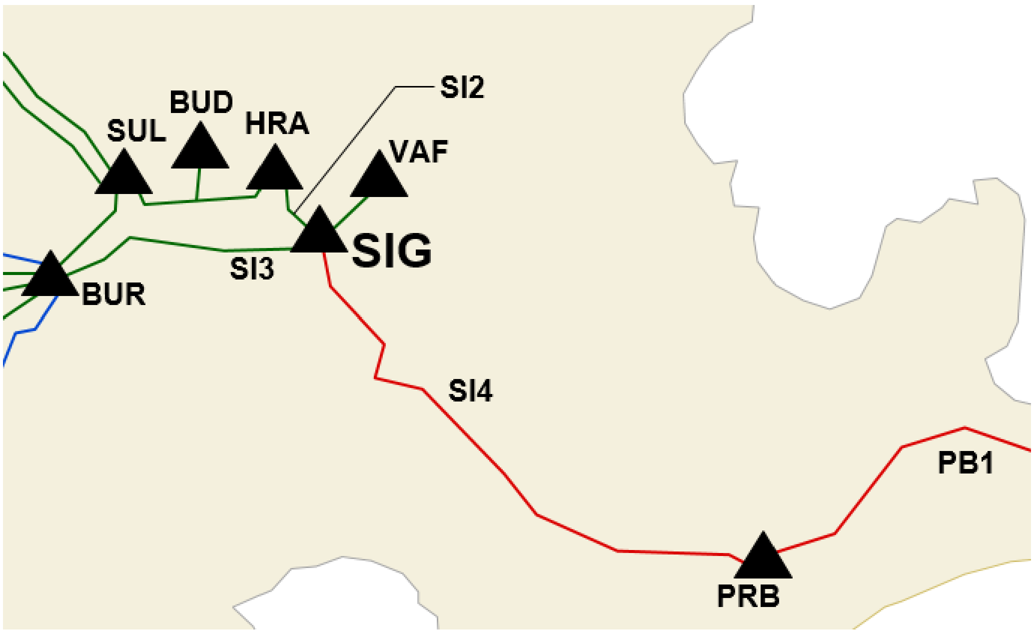


Figure 8.1 Sigalda - Geographical Connection Diagram

Sigalda (SIG) is a 189MVA hydro power plant in the Icelandic power system. SIG is connected to VAF, HRA, BUR by 220kV and to PRB by 132kV. SIG has been a critical point in the system because of it is connection to the 132kV main ring system. In SIG is a 220/132kV transformer (120MVA) which is connected to SI4. The importance of SI4 has been noted before for power transfer from the generation area in the West to East and vice versa. SI4 and PB1 are often considered as one line, because there is no circuit breaker at PRB for the line. There are two isolating line switch breakers at PRB and one circuit breaker for the 132/19/11kV transformer to feed the surrounding area. If there is a fault on the SI4 or PB1, the line is tripped at HOL and in SIG. SI4+PB1 is the longest line in the Icelandic power system and it is series capacitive compensated at HOL. The instability can be related to the length of SI4+PB1 and due to there is no PSS model for the generators at SIG.

Related to this is the before mentioned D-VAR model at HRY. The model response should also be investigated in relations to this before noted instability issue.

When simulating BL2 trip in Cut IV when splitting at SIG TT1 the generators at SIG often came unstable with no WACS, see figure 8.2. In reality the same case would probably not be unstable. The reason for this is that in reality there is a PSS equipment for all the generators at SIG but not in Landsnet PSS/E model. Which is likely the reason for instability. The following time line is in the model:

1. BL2 trips
2. SIG TT1 trips due to over flow P_{SI4}>120MW
3. Generators 2 and 3 at SIG begin to react and become unstable
4. Simulation is invalid because of instability

See the SIG generators 2 and 3 response in figure 8.2 for the unstable case.

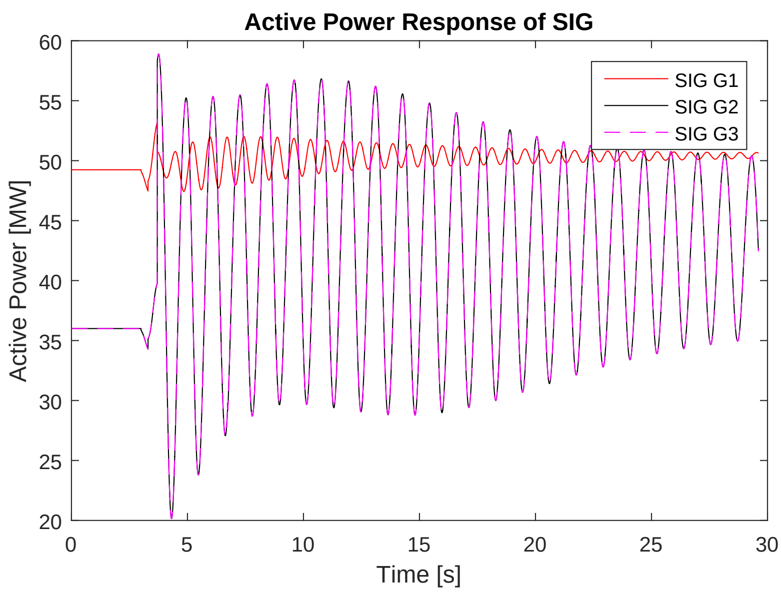


Figure 8.2 SIG response, Cut IV = 130 MW - NO WACS

In reality the PSS equipment would make the generators calmer and the frequency would drop. When that would happen then valves for the generators would open because of governor actions. As the frequency would drop then the PSS equipment, which is a part of the exciter system, would start to affect the power output.

PSS system uses additional inputs to damp system oscillations. Most common is to use rotor speed deviation, accelerating power or frequency deviation. By using PSS on the generators at

SIG, their dynamic performance is way better and the generators are more capable of damping system oscillations. PSS are often used to tackle small-signal stability issues [4].

Figure 8.3 shows real PSS testing and the author was at SIG at the time. The testing was conduct in late 2015 and was to reconfigure the PSS system so the generators would handle to be splitted with East Iceland during disturbances (SIG bus-tie split). To configure the PSS it was necessary to increase the power output of the generator until it started to oscillate. From the behavior of the generator it was possible to define the gain of the chosen inputs which influence the generator power output.

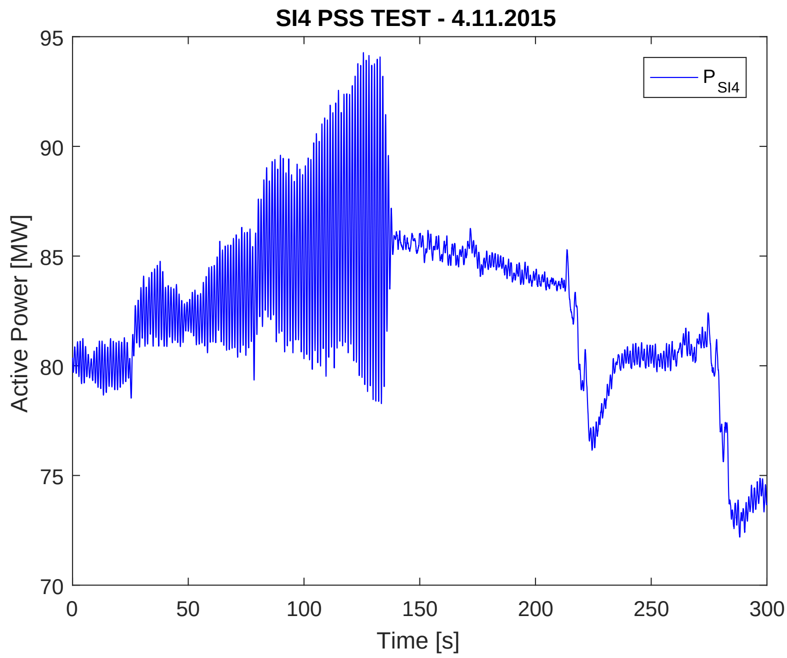


Figure 8.3 Generators 2 and 3 at SIG during PSS testing

This is intended to show the importance of having PSS installed in modern power system and also that PSS models have to be implemented into the Icelandic dynamic power model.

In case of BL2 tripping and tripping scheme is selected at SIG, underfrequency protection scheme in East Iceland would trip load and a new steady-state point would be created. So the time line with PSS model would probably look as:

1. BL2 trips
2. SIG TT1 is tripped due to over flow P_{SI4}>120MW
3. Generators 2 and 3 at SIG begin to react and become unstable
4. PSS calms the generator 2 and 3 at SIG
5. Underfrequency protection trips the load or WACS 6.6.
6. A new steady-state point would be created for restoration.

If the WACS is available then the load shedding scheme is activated when SI4>115MW, then load is shed at the same time as the bus-tie breaker at SIG is opened. The response is in figure 8.4. Then the generators at SIG do not have to transfer as much power it would if the load would not have been shedded.

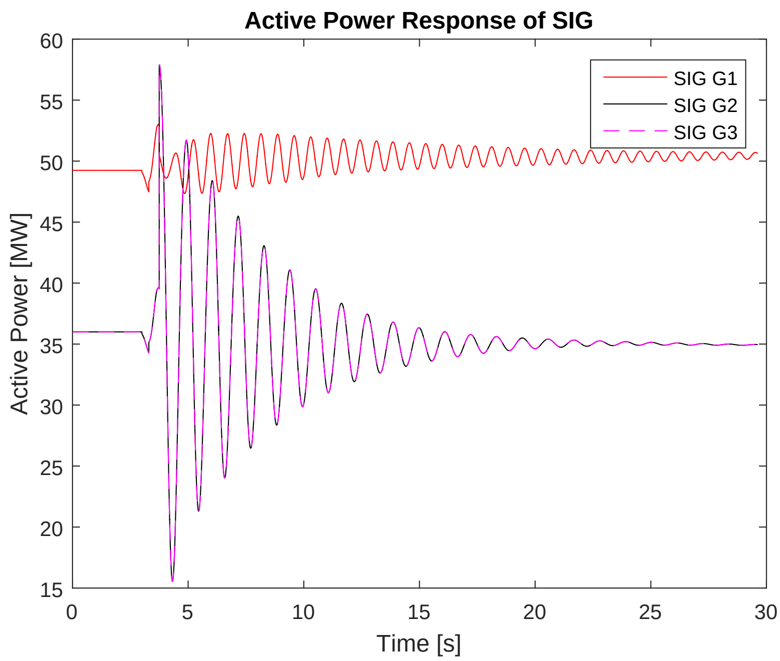


Figure 8.4 SIG response, Cut IV = 130 MW - WACS

It is difficult to estimate the security limit of the system when BL2 trips. It can be estimate from the generation in SIG, but the two generator which are connected to the system are 126MVA and the 132/220kV transformer is 120MVA. The max power transfer of SI4 is 91MVA because of current transformers for the line (400A). Therefore, if there is sheddable load and the probability of BL2 trip then the power flow through Cut IV can be estimated by formula:

$$S_{SIG_2} + S_{SIG_3} - S_{LS} < 91MVA \tag{8.1}$$

It should be mentioned, if S_{SI4}>100MVA, P_{CUTIV}>120MW before the tripping of BL2, then the transformer 4 in SIG will eventually trip because of overload. That would propably cause a frequency drop to 48.6Hz which would trigger the underfrequency protection at ARE smelter that sheds 90MW. The ARE underfrequency protection would save the East island system from blackout.

8.2 Frequency Gradient Assessment

The frequency gradient estimation is based on power increase or decrease, frequency at the given time when the disturbance occurs, the MVA value of the generator and the inertia. The most pronounced effect of high values of inertia is to reduce the initial rate of frequency decline, and to delay and reduce in the maximum deviation. Generators with high inertia are stiffer. Note that the inertia does not affect the final steady-state value of frequency [8, p.823]. It is possible to calculate the frequency gradient and the steady-state frequency after a disturbance in real-time in the Icelandic power system by using Landsnet WAMS system. All variables are known or can be calculated and therefore it is possible.

In the Icelandic power system there are two main production areas, as have been noted before in chapter 2. If water reservoirs are low in one part then it may be necessary to transfer power from one part of the system to the other part. As the power transfer magnitude increases the magnitude of underfrequency in the low water reservoirs part increases also. If there occurs a system disturbance that leads to a system split, the islanding scheme cuts off the power supply for the low water reservoirs island.

If the power transfer is from West Iceland to East Iceland through Cut IV, it is risky. The West production area has much more inertia and therefore is more capable to take on disturbances then the East production area. The total rotational energy is more in West- then in the East Iceland. Therefore if the power flow through Cut IV and there is sheddable load online then impact of the disturbance can be reduced, depending on magnitude of the sheddable load.

By using the frequency gradient it is possible to estimate the consequences of a system split. Then the active power flowing through the bus-tie breakers at BLA and SIG (if P_{CUTIV} =150MW) will become ΔP in equation 3.28. Which will indicate that the underfrequency gradient will be steep and fall below f=49,0Hz. Than it is known that P_{shed} =43MW will be disconnected from the system. The size of the disturbance is then reduced significantly.

$$\Delta P = P_{distb} - P_{shed} = 150 - 43 = 107MW \tag{8.2}$$

$$\left(\frac{df}{dt}\right)_{t=0} = \frac{\Delta P \cdot f_0}{2E_{rot}} = \frac{-150 \cdot 50}{2 \cdot 3690.2} = -1.01519\text{Hz/s} \tag{8.3}$$

In table 8.1 the frequency gradient is calculated for certain range of values. According to calculated values the frequency would drop:

$$f_{dist} = f_0 + \Delta f = 50 - 1.01519 = 48.98Hz \tag{8.4}$$

at the time t=0. Which indicates if all generators in the East island are online then the system is stiff. But usually when the export between areas is that high, one or more generators are offline. Which leads to the conclusion it is necessary to have a stream of breaker information from the SCADA system into the algorithm. Breaker status would indicate if generators are online or offline to determine the total rotational energy at any given moment in the system. In table 8.1 all generators are considered to be online (E_{rot}=3690.2MJ)

Table 8.1 ΔP and df/dt calculations for Cut IV

P_{CUTIV} [MW]	df/dt [Hz/s]		P_{CUTIV} [MW]	df/dt [Hz/s]
-150	-1.01519		-150+43	-0.72416
-140	-0.94751		-140+43	-0.65648
-130	-0.87983		-130+43	-0.58881
-120	-0.81215		-120+43	-0.52113
-110	-0.74447		-110+43	-0.45345
-100	-0.67679		-100+43	-0.38577
-90	-0.60911		-90+43	-0.31809

Table 8.1 informs that underfrequency load shedding schemes are very useful when dealing with disturbances when there is a lack of generation. Then a threshold can be defined, for example if the frequency gradient is df/dt $\leq$ -0.75 Hz/s then the underfrequency scheme operates, else not.

In East Iceland is a special load shedding scheme which is not triggered on underfrequency but by using power flow from West Iceland to East Iceland and is explained in detail in section 6.6.2.3. This is also relevant to 5.3.2. Because if SI4 trips in high power transfer through Cut IV for example, then BL2 has to transfer BL2+SI4 which leads to tripping of the bus-tie (if BL2>120) in BLA and therefore is the system islanded. EILS scheme would be triggered just before the islanding mode, then sheddable load would be tripped approximately at the same time as the split occurs.

8.2.1 Frequency Gradient Assessment Validation

In this subsection figure 8.5 is analyzed to check whether if it is possible to used theoretical calculations to estimate the real system frequency response.

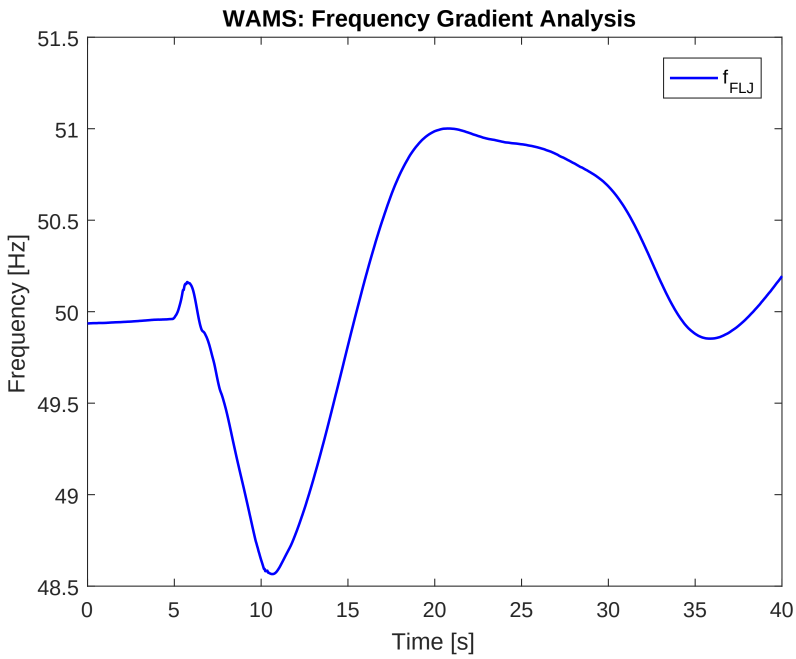


Figure 8.5 WAMS Frequency Response

By analyzing figure 8.5 it was possible to calculate the real frequency gradient (WAMS measurement) for comparison. The results are in table 8.2.

Table 8.2 Calculations from WAMS measurements

Coordinates		$\Delta x = x_2 - x_1$	$\Delta y = y_2 - y_1$	$\Delta y/\Delta x$
$t_1 = x_1$	5.9	4.2 s		
$t_2 = x_2$	10.1			
$f_1 = y_1$	50.15		-1.54 Hz	
$f_2 = y_2$	48.61			
$\Delta f/\Delta t$				**-0.3667 Hz/s**

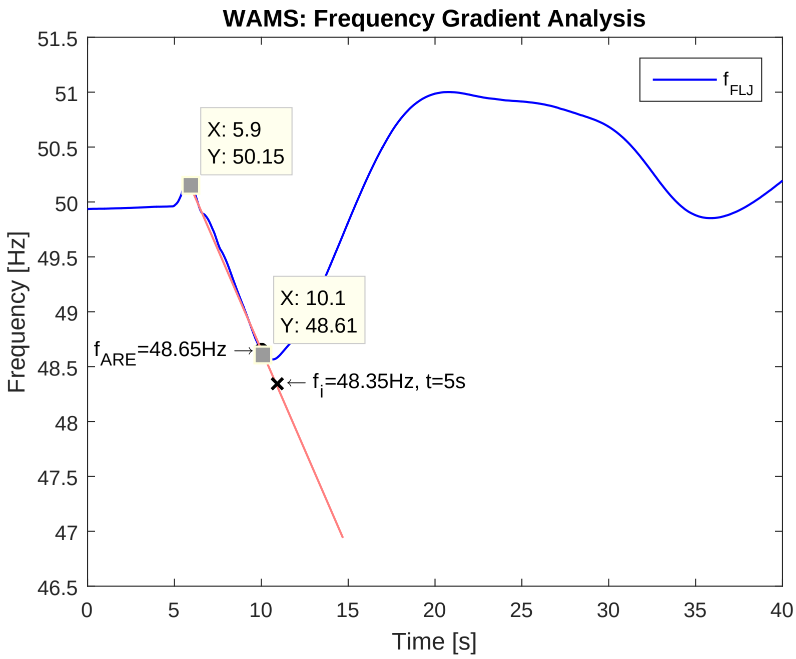


Figure 8.6 WAMS Frequency Analysis

When the disturbance occurred then P_{CUTIV} = 102MW and all generators were in service in the East island. But the islanding scheme was BLA-HOL. That means two generators at BLA were connected to the East. So power losses from West to East were not P_{CUTIV} = 102MW. In figure 8.7 the active power flow for P$_{SI4}$ is plotted with the frequency at FLJ. The active power flow before the disturbance was approximately P$_{SI4}$ ≈ 54MW. It can be checked with calculating the ΔP by rearranging equation 3.28, the active power value can be obtained:

$$\Delta P = \frac{2 \cdot df/dt \cdot E_{rot}}{f} = \frac{2 \cdot (-0.3667) \cdot 3690.2}{50} = -54.13MW \tag{8.5}$$

The ΔP is approximately the same as active power flow through SI4 before the disturbance and is shown in figure 8.8.

Then the system frequency gradient is proofed to be right by calculations:

$$\frac{df}{dt} = \frac{-P_{SI4} \cdot f_s}{2 \cdot E_{rot}} = \frac{-54.13 \cdot 50}{2 \cdot 3690.2} = -0.3667Hz/s \tag{8.6}$$

$\Delta P = P_{SI4}$ is connected two generating units at BLA and is in the East island during the

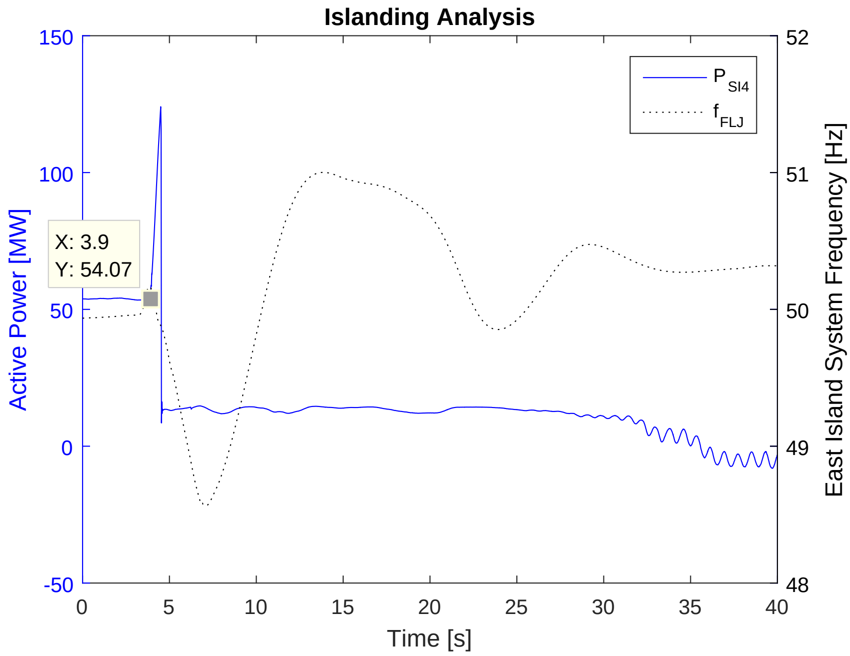


Figure 8.7 P_{SI4} v f_{FLJ}

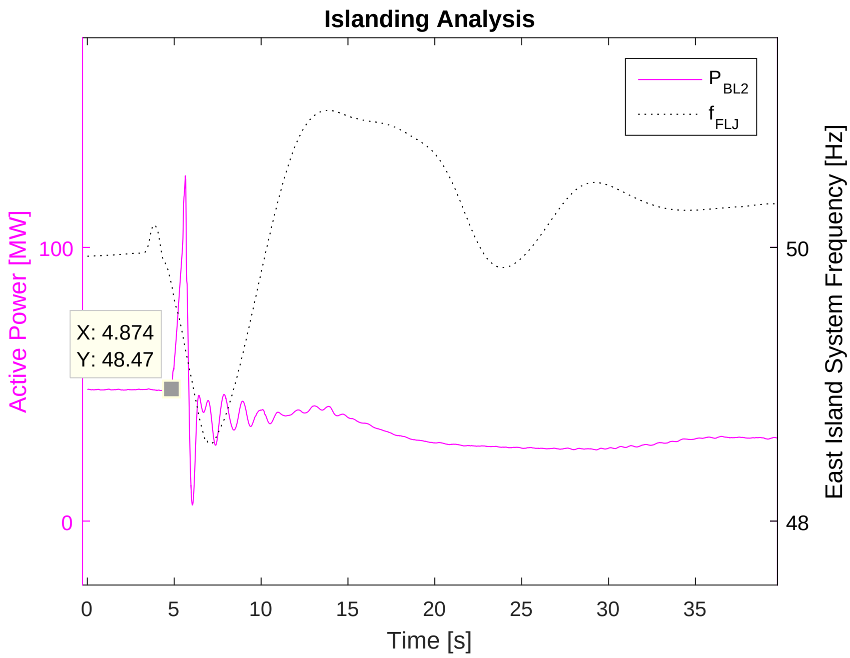


Figure 8.8 P_{BL2} v f_{FLJ}

islanding, see figure 8.9. With that magnitude of frequency gradient it takes the frequency $\Delta t \approx 4s$ seconds to hit the limit at ARE, $f_{ARElim} = 48.65Hz$.

$$f_i = \frac{df/dt}{t} \rightarrow f_i = df/dt \cdot t = -0.3667 \cdot 4.1 = -1.54Hz \tag{8.7}$$

$$f_{sys} = f - f_i = 50.15 - 1.54 = 48.61Hz \tag{8.8}$$

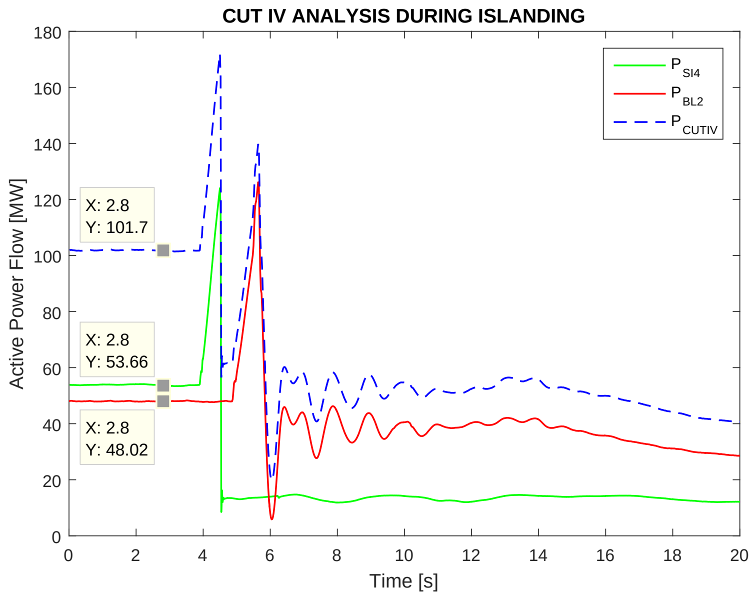


Figure 8.9 WAMS Measurements for 8.8.2015 Islanding Event

The underfrequency protection takes time to operate and trip the circuit breaker, therefore the frequency drops a little more than 48.65Hz. Its recognized that if the underfrequency protection at ARE would not work, the frequency would fall to a undesirable value. The inertia response is on the scale of t=0-5 seconds. As the inertia is higher, the frequency response is slower and therefore governors have more time respond [8, p.823]. It would be advised to use $\Delta x \approx 5s$ multiplied by the gradient to see how far system frequency will drop/rise in case of disturbance. If 5 seconds would be used in real-time security assessment for frequency stability, then the results would be:

$$f_i = \frac{df/dt}{t} \rightarrow f_i = df/dt \cdot t = -0.3292 \cdot 5 = -1.646Hz \tag{8.9}$$

$$f_{sys} = f - f_i = 50.15 - 1.646 = \mathbf{48.35Hz} \tag{8.10}$$

This is also illustrated in figure 8.6. If the calculated frequency is below $f < 48.65Hz$, then it would tell system operators the consequences of current situation is priority load tripping at ARE. To calculate the theoretical response, the generators that participate the most are taken into the calculations, BLA, LAX, KRA, LAG and FLJ. There are more smaller private owned generation plants that are not being taken into account because the data is difficult to reach and also are these plants often in ”spin-no-load” mode during disturbances. Its not known which plants do participate. The inertia constants and the apparent power base values are used for the calculations of the total rotational energy are considered to be correct. Because of before mentioned uncertainty there are some small deviations in total rotational energy.

8.2.2 Frequency Stability Assessment Implementation

Its possible to obtain real-time frequency stability assessment methods by using the calculation methods described here above. To make this possible at Landsnet control center it is necessary to configure the SCADA system and the WAMS system to communicate and exchange information. The SCADA system has to deliver generator circuit breaker positions and the power generation to the WAMS system (it would be possible to get the information in WAMS with PMU installation in LAX and LAG with generator measurements, other generating units are presently measured in the WAMS system). The WAMS system could deliver the calculated value back to SCADA but is more convenient display the results in real-time in the system operators computer using WAMS. The reason why it may be more convenient is because of slow refresh rate in SCADA system, 2-4 seconds, while WAMS samples the measurements 50 times per second and displays the results on a screen in the control room with little as no delay.

This method of frequency stability assessment could be very useful for Landsnet in daily system operation, especially during difficult or emergency system conditions.

8.3 Increased Active Power Transfer using SVC

In section 4.2.1 the models were discussed. PSS/E uses models built on theory to estimate the response of the generator and his output. The active power balance controls the frequency and the voltage is controlled by the reactive power. For example are SVC's used to generate reactive power at critical locations which are far away from the generation area. Then reactive power doesn't have to be transferred through the transmission lines, which increases the efficiency and more active power can be transferred [4].

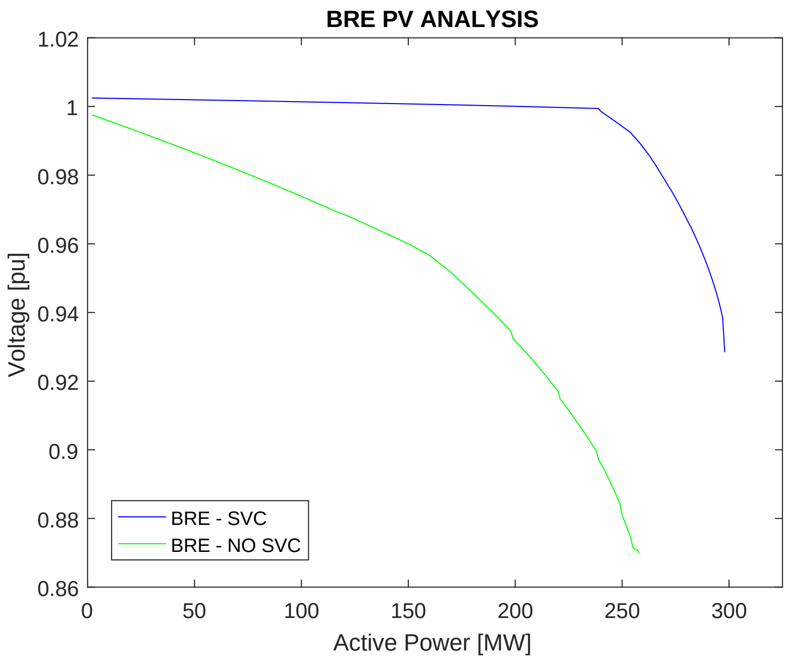


Figure 8.10 BRE PV Curve Analysis

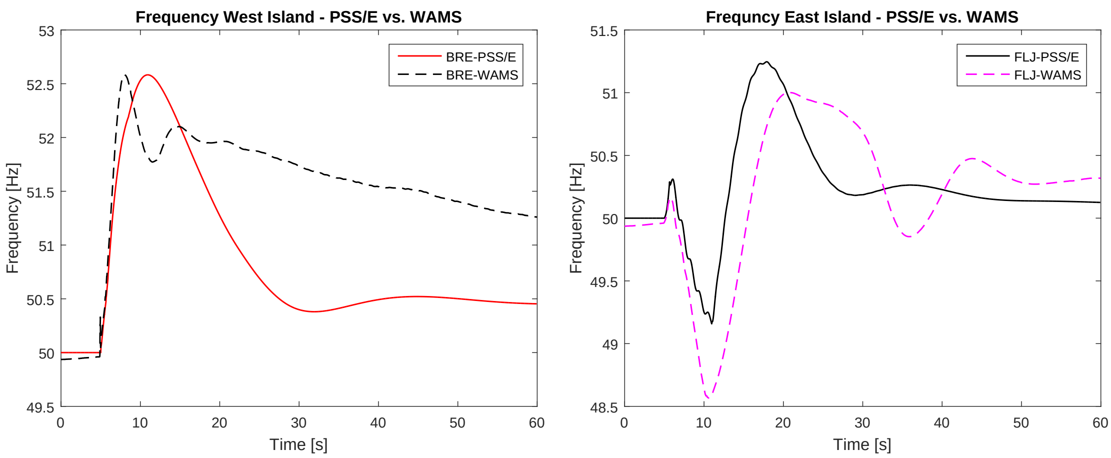
Real example of this is in the Icelandic power system, see figure 1.1. There are three lines connected to Brennimelur (BRE), two 220kV lines from Sultartangi (SUL) and one from Geithál s (GEH). BRE substation supplies one aluminum smelter, ferro-silicon plant and the whole industrial area ($P_{all} \approx$ 685MW). Near BRE is a new SVC called Klafastaðir (KLA). At KLA, TCR- and TSC reactive components was installed to decrease reactive power transfer in the 220kV system and decrease power losses, XI^2 and RI^2. The SVC produces reactive power needed and provides more voltage stability.

Figure 8.10 shows how the voltage will drop if the load is increased more than it is today, with and without SVC at KLA. The reason for installation is demonstrated clearly in this figure. By installing the SVC at KLA it is possible to increase active power transfer up 150MW with relatively good reliability. But if the SVC trips, then there could be some kind of load rejection scheme to safe the system from voltage collapse.

The voltage should always be within a certain limit, Nordic Grid Code order is 0.9pu - 1.1pu [19]. As the same goes for the frequency, it should be as constant as possible. These two parameters depend fairly on each other but rely on different control actions. The governor controls speed of the generator and therefore the frequency, exciter controls the reactive power generation. These two main devices have different models for each generator in the PSS/E model and if the parameters are not configured right in the model then it doesn't react with the same response.

8.4 Frequency Effects on Load

In models it is difficult to simulate the frequency due to complex control equipment, the generation response and due to load models which provide often damping. If the load model is not very detailed it can influence simulation results. In this thesis model validation the results were similar regarding the magnitude in overfrequency conditions in the West island but the East island had underfrequency conditions. The magnitude were not the same but response was similar. See better discussion about model validation results in section 7.1.



(a) Frequency in the West island **(b)** Frequency in the East island

Figure 8.11 System Frequency Response After Disturbance - Islanding Conditions

The theory of control of active- and reactive power was discussed in section 3.3. The simulations, figures 8.11a and 8.11b show that the model is precise with magnitude and the inertia response in the West island. The East island response is quite similar but the magnitude is not the same. This could possibly be explained by too much damping by the load model for ARE, the aluminum smelter connected to FLJ.

As was noted in 4.2.1, the importance of good modeling is important. Transmission line parameters rely on frequency as is shown in following formulas 8.11, 8.12, 8.13 and 8.14. Inductive reactance is frequency dependent because of the inductance L. Capacitive reactance is also frequency dependent because of capacitance C. The fundamental explanation is because these parameters are time dependent. Voltage and current are frequency dependent therefore also are inductance and capacitance [4].

$$v = L\frac{di}{dt} \tag{8.11}$$

$$i = C\frac{dv}{dt} \tag{8.12}$$

The capacitance changes because of change in voltage and inductance changes because of current. Both current and voltage are frequency dependent. Which leads to the reactance equations .

$$X_L = \omega \cdot L \cdot l \tag{8.13}$$

$$B_c = \omega \cdot C \cdot l \tag{8.14}$$

Were $\omega = 2\pi \cdot f = 2\pi 50 = 100\pi$ rad/s.

These equations show how much influence the frequency has on all impedances in electrical power systems. The voltage relies on reactive power. Reactive power can be generated by using capacitors or inductors, depending on the system conditions. If there is a long cable, then it is recommended to used shunted reactors because the voltage tend to be high at the receiving end and generate reactive power during light load. If there are long high voltage lines, then it is recommended to use series capacitors to boost up the voltage, the line absorbs reactive power. Reactive power is defined from the above mentioned parameters, C and L [4].

Part III

Simulations and Research

Chapter 9

Simulation Process

This chapter is a introduction to the simulation process with simple explanation. The intention is to explain how the process was designed, programmed and organized.

9.1 Introduction to the Simulation Process

This simulation process was planned in the following way: In the beginning for each cut were created 10 load cases in PSS/E, from 80MW to 180MW. Than the PSS/E files were simulated by using a Python script that activates PSS/E, runs the simulation and saves the results in a Excel document. After that the Python script runs a MATLAB script that plots predefined graphs for analysis. The Python script is the master, MATLAB and Excel are the slaves. The simulation process is described by a flow chart in figure 9.1.

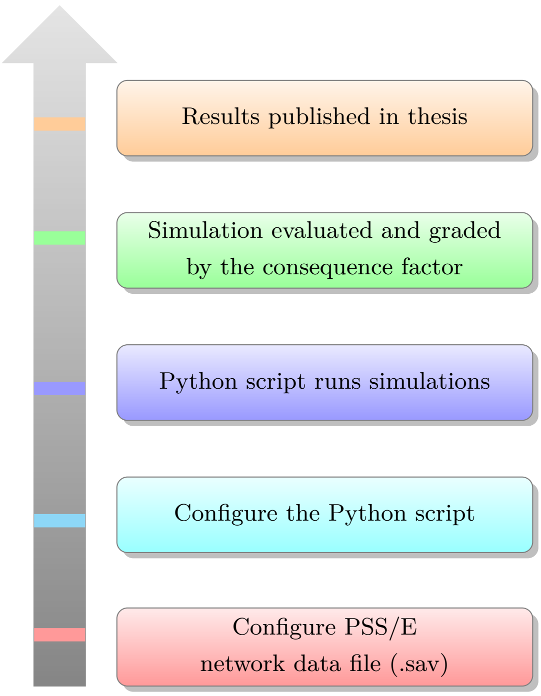


Figure 9.1 Simulation Process

The Python script foundation was written by a few system operator engineers at Landsnet. The author made changes to the script to make it usable in the project and the simulation were made more reliable by adding the wide-area control schemes, introduced in section 6.6.2, and other important protection schemes introduced in section 6.6. A small implementation report is presented in Appendix B. A MATLAB engine for Python was used and programmed in to the Python script. The script work flow is explained graphically in figure 9.2 and described as:

1. Opens PSS/E, solves the load case using Newton-Raphson (Load-Flow) to check for errors. Simulates the course of events defined in the Python script.
2. PSS/E returns data to the Python script.
3. Python script saves data in a Excel file.
4. Python script then creates a log file containing a simulation overview, all circuit breaker movements and standard PSS/E violations are kept in the log file.
5. Python script excutes a MATLAB script.
6. MATLAB script fetches data from the excel file and creates predefined data plots.
7. MATLAB script sends a command to the Python script stating the simulation process is over.

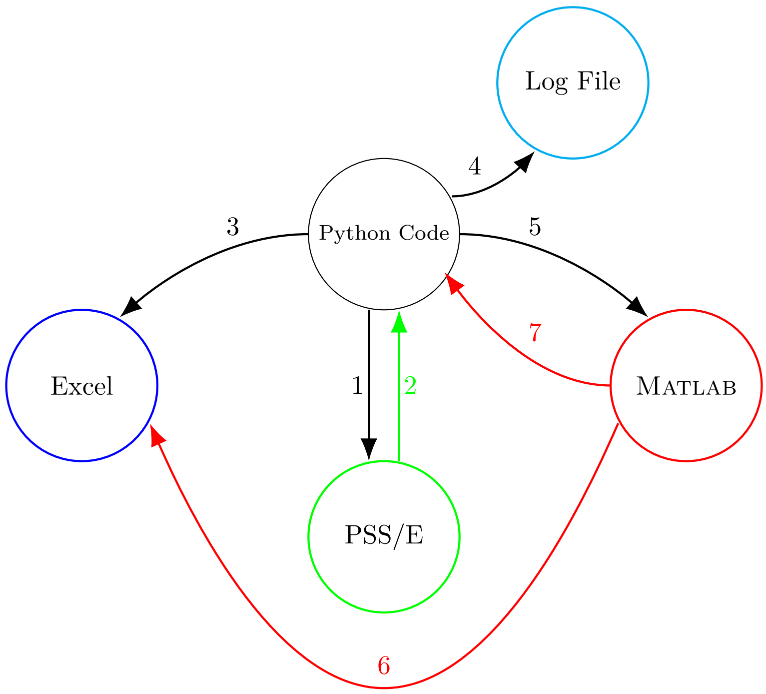


Figure 9.2 Simulation Program Flow Diagram

Total time simulation process time for one simulation is approximately one minute. If Excel was used to plot than total time was more than two minutes and the graphs had to be manipulated before being analyzed or inserted into the report.

Chapter 10

Simulation Results

In this chapter simulation results are presented. The number of simulations are approximately 742 only for cut IV and cut IIIb. Therefore it was necessary to make a of standard for the simulation results. The standard was introduced in section 7.2.1 and is called ***Consequence Factor*** *in this thesis. This chapter contains comments about the simulations and every simulation is given a grade from the "Consequence Factor". Cut IV and cut IIIb were simulated dynamically but other cuts were simulated by load flow simulation.*

10.1 Introduction to The Simulation Method

In this chapter simulation results will be presented. System cuts, cut IV and cut IIIb were simulated dynamically with and without WACS with various islanding schemes. The WACS functions were presented in subsection 6.6.2. The reason is to see by simulation if the stability limits of the cuts can be increased with the use of WACS schemes and splitting the system differently (Adaptive islanding). The reader is encouraged to check section 6.6 while reading this part of thesis for information about difference of the system with and without WACS.

10.2 CUT IV Simulations

Cut IV was introduced in section 2.2.2.1. Power transfer through cut IV has been a major problem in the Iceland power system in recent years. To ensure stability during disturbances there have been developed a islanding scheme. In recent years the islanding scheme has been in splitting at BLA and HOL. But now there is a new bus-tie breaker in SIG. But when should it be used? during what conditions? That is a part of this research to find out. BLA has a bus-tie breaker that is presented in subsection 6.6.1.1 and a graphically in figure 6.2. SIG also has a bus-tie breaker but it is possible to transfer the trip signal to HOL, introduced in subsection 6.6.1.2 and graphically in figure 6.3. The split in Northern Iceland is always conducted in BLA bus-tie breaker. But splitting in Iceland is either done in SIG or HOL. Both options are simulated and the results are presented in following subsections. The simulation results are shown in tables 10.2, 10.1, 10.4 and 10.3. Each dot is a simulation in the table. Each simulation is given a "grade" by the consequence factor in table 7.1 and for further explanations, see table

7.2. Standard PSS/E cases were made with 10MW step, from 80MW to 180MW for cut IV, by changing the generation at KAR and adding sheddable load at the Eastfjords fish smelters.

10.2.1 Split at HOL - Simulation Results

Table 10.1 Cut IV HOL Split - No WACS

Event / Unit Tripped \ P_{CUTIV}	90MW	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW
BL2	yellow	yellow	red	red	red	red	red	red	red
KAR G6	green	red	red	red	red	red	red	red	red
KR2	green	green	green	green	red	red	red	red	red
SI4	green	yellow	yellow	orange	orange	orange	orange	orange	orange
SUL	green	green	green	green	green	green	green	green	green

Table 10.2 Cut IV HOL Split - WACS

Event / Unit Tripped \ P_{CUTIV}	90MW	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW
BL2	green	yellow	yellow	red	yellow	red	red	red	red
KAR G6	green	yellow	orange	orange	orange	orange	orange	orange	orange
KR2	green	green	green	green	green	yellow	yellow	yellow	yellow
SI4	green	yellow	yellow	yellow	yellow	yellow	yellow	yellow	yellow
SUL	green	green	green	green	green	green	green	green	green

The simulation results show that WACS is very valuable if the splitting is carried out at HOL. The power transfer limits increased to (P_{CUTIV}=130MW) from (P_{CUTIV}=100MW) if WACS is in operation.

It should be noted the ring connection can handle up to (P_{CUTIV}=170-180MW) power transfer through cut IV. But if there is a line failure then the consequences are very severe. That kind of power transfer should only be considered in case of emergency.

The worst possible fault would be if BL2 trips. When BL2 is tripped, the limits at (P_{CUTIV}=120MW). The 130MW case is different because there is more sheddable load available, therefore the EILS (presented in subsection 6.6.2.3), saves the system. One of the conclusions is that if BL2 trips and there is (P_{fs}>66MW) to shed then it is a enough to save the stability in East Iceland. But in the other cases above 130MW there is not enough sheddable load to trip to save the system. Therefore underfrequency protection at ARE ($P_{loadreduction}$=-90MW) saves the system and it becomes stable.

If the splitting should be carried out at HOL, all load above the stability limit (P_{CUTIV}=100MW) should be sheddable by EILS to reserve the stability in East Iceland if there is a disturbance. If WACS is not active, then the stability limit should not be crossed, except if weather conditions are excellent and in cases of emergency.

10.2.2 Split at SIG - Simulation Results

Table 10.3 Cut IV SIG TT1 Split - No WACS

P_{CUTIV} / Event Unit Tripped	90MW	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW
BL2	🟡	🟡	🟡	🟡	🟠*	🟠*	🟠*	🟠*	🟠*
ISAL	🟡	🟡	🟡	🟡	🟡	🟡	🟡	🟡	🟡
KAR G6	🟡	🟡	🟡	🟡	🟠	🟠	🟠	🔴	🔴
KR2	🟢	🟢	🟢	🟢	🟢	🟡	🟡	🟡	🟡
SI4	🟡	🟡	🟡	🟡	🟡	🟡	🟡	🟡	🟡
SUL	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢

* Generators at SIG unstable - in 130MW

Table 10.4 Cut IV SIG TT1 Split - WACS

P_{CUTIV} / Event Unit Tripped	90MW	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW
BL2	🟢	🟡	🟡	🟡	🟡	🟡	🟡	🟡	🟡
ISAL	🟢	🟡	🟡	🟡	🟡	🟡	🟡	🟡	🟡
KAR G6	🟢	🟡	🟡	🟡	🟡	🟡	🟠	🔴	🔴
KR2	🟢	🟢	🟢	🟢	🟢	🟡	🟡	🟡	🟡
SI4	🟢	🟡	🟡	🟡	🟡	🟡	🟡	🟡	🟡
SUL	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢

In the case of BL2, when above P_{CUTIV}=140MW and NO WACS, the generators at SIG become unstable, discussed in 8.1. As the power flow through the cut gets higher, then underfrequency protection scheme for the fish smelters is triggered. The unstability in SIG generators decreases and the system becomes more stable.

In emergency conditions, if (P_{CUTIV}=140MW) and no WACS, then the tripping scheme could be; the circuit breaker for PB1 at HOL is tripped and using ARE underfrequency protection scheme, f=48,6Hz. Then one rectifier is tripped at ARE (-90MW) and the system becomes stable.

Previous results show the proportion of sheddable load is important for the stability in East Iceland during islanding. It does matter if the import from the West island is for the fish smelters or to compensate for unused capacity of generators in KAR. If it is possible to shed load at nearly the same time as system split occurs, it makes generator power response in the East island better. If the main proportion of the power flow in cut IV is for power compensation at KAR then it takes more time to respond to the disturbance. Which leads to more frequency collapse, which triggers underfrequency protection at the fish smelters and increases the risk of priority load tripping. Even though there is a enough reserve power to use, it is not enough if the sheddable load is well over 50MW. Then the frequency fall is to steep and the generators are not quick enough to regulate the frequency before it hits the underfrequency limits for the fishsmelter and in some cases the ARE load reduction. From these simulated results it was thought interesting to make a detailed analysis on the difference on power compensation at KAR and sheddable load consumption.

10.2.3 Analysis of Sheddable Load versus Power Compensating at KAR

To analyze further the difference between importing power for sheddable load or power compensating at KAR there were two cases made (.sav files). These files were simulated for five fault events and the results are shown in tables 10.5 and 10.6.

In both .sav files the $P_{CUTIV} = 160MW$.

1. Power Compensation at KAR
   - $P_{KAR} = 475MW$
   - $P_{Fishsmelters} = 0MW$
   - $P_{FLJTR7\&8} = 83.0MW$ (Export from FLJ)
2. Load Shedding Available
   - $P_{KAR} = 564MW$
   - $P_{Fishsmelters} = 83MW$
   - $P_{FLJTR7\&8} = -5.6MW$ (Import from 132kV ring)

Table 10.5 Power Compensation at KAR

	HO1 SPLIT WACS	HO1 SPLIT	SIG TT1 SPLIT WACS	SIG TT1 SPLIT
BL2	🔴	⚫	🔴	⚫
ISAL	🟠	🔴	🟠	🟠
KARG6	🔴	🔴	🔴	🔴
KR2	🔴	🔴	🔴	🔴
SI4	🟠	🔴	🟠	🔴

Table 10.6 Load Shedding Available

	HO1 SPLIT WACS	HO1 SPLIT	SIG TT1 SPLIT WACS	SIG TT1 SPLIT
BL2	🔴	🔴	🟠	🔴
ISAL	🟠	🟠	🟠	🟠
KARG6	🟠	🔴	🟠	🟠
KR2	🟡	🔴	🟡	🔴
SI4	🟡	🔴	🟡	🔴

The results show it is not possible to justify a 160MW import through cut IV only to compensate for production at KAR. Some proportion of the load should be sheddable, within the stability security margin, else the consequences are severe if there is a disturbance.

10.2.4 Simulation Notes for Cut IV

The result are demonstrating from N-1 extended contingencies. The need of load control is necessary if transfer links between areas are weak and the power generation at the load consumption place is weak in proportion to power consumption. The results are way worse if the transferred power is for compensation and one unit trips (or important line trip) at the station being compensated, because there is no thing to do except wait for the other generators to respond to the fault with severe underfrequency conditions in most cases. Then adaptive islanding comes in handy to isolate the unstable area to keep others stable.

10.3 CUT IIIb Simulations

Cut IIIb was introduced in section 2.2.2.1. When exporting from the East to West, cut IV is most often relatively low $P_{cutiv} < 80MW$. The conditions in cut IIIb are similar to cut IV, compensation or heavy load at Eastfjords. Either the generated power at FLJ is for Eastfjords, through cut V, and the rest flows towards SIG. Therefore it dependents on cut V if cut IIIb is high for power compensation or supply of fish smelters. These two different conditions are simulated in great detail with two different tripping schemes. The tripping schemes are:

1. $P_{FL2} >$ 140MW, then 132kV transformers at FLJ are tripped
2. $P_{FL2} >$ 140MW, then bus-ties at FLJ and ARE are tripped, leaving one generator at KAR connected to the 132kV ring. Supplying the auxiliary load at ARE ($P_{ARE_{AUX}} \approx$ 25 MW) and the rest is available for the load connected to the ring. One generator at KAR is 137,5 MVA.
3. $P_{BL1} >$ 130MW, then trip signal is transferred and the 132kV line VA1 is tripped at BRE instead of tripping the bus-tie at BLA.

The simulation results are shown in tables and the table setup is shown here below. Each dot is a simulation and is graded by the consequence factor in table 7.1, see table 7.2. Each item is simulated for a fish smelter case and a compensation case with and without WACS.

If $P_{FL2} >$ 140MW then:

- Trip FLJ 220/132kV transformers split
- Trip FLJ and ARE bus-tie split

If $P_{BL1} >$ 130MW then:

- Trip VA1 at BRE with FLJ 220/132kV transformers split
- Trip VA1 at BRE with FLJ and ARE bus-tie split

In section 6.6.1.3 the FLJ Special Protection Scheme was introduced. This scheme trips the 220/132kV transformers at FLJ but the 132kV ring is still connected. Then FLJ and ARE are isolated from rest of the system. The consequences of specially chosen events are listed in tables 10.7, 10.8, 10.11 and 10.12.

The idea is to check whether it is better to trip the bus-ties at FLJ/ARE shown in figure 6.4. Leaving one generator with the 132kV ring system. The results for those simulations are in tables 10.9, 10.10, 10.13 and 10.14.

In the simulation process for cut IV it was noted that power compensation and fishsmelter load are two different cases which has to be investigated separately. In the simulation process for cut IIIb it will be done right away and the difference should then be clearer.

10.3.1 FLJ TR7 & TR8 - Fish smelters

Table 10.7 Cut IIIB with Fish Smelters, FLJ Transformer Trip - No WACS

Event / Unit Tripped \ $P_{CUTIIIb}$	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
BL1	yellow	yellow	yellow	orange	orange	orange	orange	orange	orange
FL2	green	green	orange	orange	orange	orange	orange	orange	orange
KAR G_6	green	green	green	green	green	green	green	yellow	yellow
SUL G_{1+2}	green	green	green	green	green	red	red	red˙	red˙
SI4	green	green	green	green	green	green	green	green	green

˙SUL: Underfrequency protection at BRE (Ferrosilicon Plant (-87MW))

Table 10.8 Cut IIIB with Fish Smelters, FLJ Transformer Trip - WACS

Event / Unit Tripped \ $P_{CUTIIIb}$	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
BL1	green	green	green	green	orange	orange	orange	orange	orange
FL2	green	green	orange	orange	orange	orange	orange˙	orange˙	orange˙
KAR G_6	green	green	green	green	green	green	green	green	green
SUL G_{1+2}	green	green	green	green	green	orange	orange	red˙	red˙
SI4	green	green	green	green	green	green	green	green	green

˙FL2: System is stable after WACS operated
˙SUL: Frequency below f=49.0Hz

The tripping of BL1 when cut IIIb is above 100MW triggers BL2 to cross its limits, P_{BL2}>120MW. Which triggers EILS if WACS is in operation, if WACS is not in operation it leads to P_{FL2}>140MW which trips the transformers at FLJ. Then SI4 is tripped because it exceeds its limits P_{SI4}>120MW. If WACS is service, the last two SPS schemes are not operated.

If FL2 trips, then P_{BL1}>130MW and splits the system. The generation-load balance is relatively good. Generation loss in the West island is simulated by taking out SUL hydro power plant. The event has severe consequences when the power flow through cut IIIb is $P_{CUTIIIb}$>150MW. With no WACS, it leads to underfrequency tripping at the Ferro Silicon plant (JAR) connected to BRE ($P_{CUTIIIb}$=150-160MW triggers one step down (-35MW) at JAR, but $P_{CUTIIIb}$=170-180MW triggers two steps down which is -87MW). With WACS the DLC at NAL goes down for one step (-180MW) for $P_{CUTIIIb}$=150-160MW. Above 160MW in the cut NAL decreases the load for -48MW and step one of the underfrequency protection at JAR is activated (-35MW). The DLC helps alot with the frequency stability.

Regarding SI4, no mature power transfer is through SI4, because the load in Eastfjords is relatively heavy.

10.3.2 FLJ/ARE Bus-Ties - Fishsmelters

Table 10.9 Cut IIIB with Fish Smelters, FLJ/ARE Bus-tie Trip - No WACS

$P_{CUTIIIb}$ Event Unit Tripped	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
BL1	🟡	🟡	🟡	🟡	🟠	🟠	🟠	🟠	🟠
FL2	🟢	🟢	🟡	🟡	🟡	🟡	🟡	🟡	🟡
KAR G_6	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
SI4	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢

Table 10.10 Cut IIIB with Fish Smelters, FLJ/ARE Bus-tie Trip - WACS

$P_{CUTIIIb}$ Event Unit Tripped	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
BL1	🟡	🟡	🟡	🟡	🟠	🟠	🟠	🟠	🟠
FL2	🟢	🟢	🟡	🟡	🟡	🟡	🟡	🟡	🟡
KAR G_6	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
SI4	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢

The results are very similar as before because the fishsmelter load is often tripped by EILS (P_{BL2}>120MW).

10.3.3 FLJ TR7 & TR8 - Power Compensation

Table 10.11 Cut IIIB Power Compensation, FLJ Transformer Trip - No WACS

$P_{CUTIIIb}$ Event Unit Tripped	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
BL1	🟡	🟡	🟠	🟠	🟠	🟠	🔴	🔴	🔴
FL2	🟢	🟢	🟠	🟠	🟠	🟠	🟠	🟠	🟠
KAR G_6	🟢	🟢	🟡	🟡	🟡	🟡	🟡	🟡	🟡
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🔴	🔴	🔴˙	🔴˙
SI4	🟢	🟢	🟢	🟢	🟠	🟠	🟠	🟠	🟠

˙SUL: Underfrequency protection at BRE (Ferrosilicon Plant (-87MW))

Table 10.12 Cut IIIB Power Compensation, FLJ Transformer Trip - WACS

$P_{CUTIIIb}$ Event Unit Tripped	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
BL1	🟡	🟡	🟠	🟠	🟠	🟠	🔴	🔴	🔴
FL2	🟢	🟢	🟢	🟡	🟡	🟡	🟡	🟡	🟡
KAR G_6	🟢	🟢	🟢	🟢	🟢	🟢	🟡	🟡	🟡
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🟠˙	🟠˙	🟠˙	🟠˙
SI4	🟡	🟡	🟡	🟡	🟠	🟠	🟠	🟠	🟠

˙SUL: Downregulation at NAL (-48MW, two steps down)

The tripping of BL1 is the worst case scenario as the consequence factor indicates. High power transfer between areas for power compensation is difficult in the Icelandic power system. The 132kV ring connection is not strong enough if there is a disturbance. The bright sides are, cut IIIb is much more qualified for power transfers because the South-West system contains more generation units (more inertia) and it is well internally connected. Therefore it is stronger than the East Iceland system. Calculations highlight this statement that West Iceland has stronger inertia than the East in the MATLAB code in Appendix D.

10.3.4 FLJ/ARE Bus-Ties - Power Compensation

Table 10.13 Cut IIIB Power Compensation, FLJ/ARE Bus-tie Trip - No WACS

$P_{CUTIIIb}$ Event / Unit Tripped	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
BL1	🟡	🟡	🟠	🟠	🟠	🟠	🟠	🟠	🟠
FL2	🟢	🟢	🟠	🟠	🟠	🟠	🟠	🟠	🟠
KAR G_6	🟢	🟢	🟡	🟡	🟡	🟡	🟡	🟡	🟡
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🔴	🔴	🔴	🔴
SI4	🟢	🟢	🟢	🟢	🟠	🟠	🟠	🟠	🟠

The results are very similar to for splitting the 220/132kV transformer at FLJ. Except in cases when BL1 (P_{BL1} ≥120MW) and KR1 (P_{KR1} ≥150MW) trip, then it is better to trip the bus-tie. Keeping one generator for the axillary load at ARE and feeding into the 132kV ring system is better in those cases. It is also the only cases that trigger the bus-tie split at FLJ/ARE.

Table 10.14 Cut IIIB Power Compensation, FLJ/ARE Bus-tie Trip - WACS

$P_{CUTIIIb}$ Event / Unit Tripped	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
BL1	🟡	🟡	🟠	🟠	🟠	🟠	🔴	🔴	🔴
FL2	🟢	🟢	🟢	🟠	🟠	🟠	🟠	🟠	🟠
KAR G_6	🟢	🟢	🟢	🟢	🟢	🟢	🟡	🟡	🟡
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🟠˙	🟠˙	🟠˙	🟠˙
SI4	🟡	🟡	🟡	🟡	🟠	🟠	🟠	🟠	🟠

˙NAL - Load reduction

If BL1 trips, then the bus-tie at BLA trips. The simulations indicate that it could be good to trip at SIG/HOL and FLJ/ARE simultaneously and let the generator at KAR be connected to the 132kV ring system. Otherwise simulation results are very similar to previous simulations which indicate that changing the scheme from tripping the transformer to tripping bus-ties at FLJ/ARE is not feasible for the chosen cases.

10.3.5 VA1 Split - Simulation

Vatnshamralína 1 (VA1) lies from BRE to a substation in West Iceland called Vatnshamrar (VAT), see figure 10.1. In this section simulations for tripping the circuit breaker for VA1 at BRE is presented. This approach could be carried out if cut IIIb is above 100MW and a disturbance occurs which leads to overloading of BL1. In subsection 6.6.1.1 the BLA protection scheme was introduced. If P_{BL1}>130MW then BLA bus-tie is tripped. Instead it is simulated to move the trip signal to BRE and trip VA1. The advantage of transferring the trip signal is to damp system oscillations and gain better generation-load balance in the East island.

When VA1 is tripped at BRE instead of the bus-tie at BLA it means that BLA is supplying Snæfellsnes peninsula and Westfjords. The East island is made bigger. The advantage is that all the sheddable load at Westfjords is tripped if the frequency falls below f=49,0Hz, which could be helpful if the generation-load balance is not quite good. This option is simulated with a bus-tie split at FLJ and 220/132kV transformer trip at FLJ. The results are presented in next section.

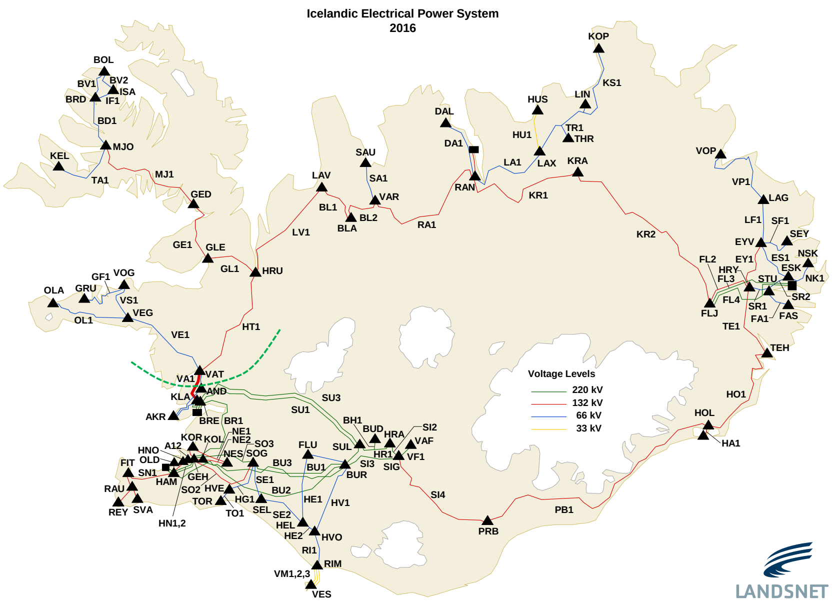


Figure 10.1 VA1 Geographical Location [2]

10.3.6 VA1 Simulation Simulation Prelude

Simulations with fish smelters load in Eastfjords were nearly identical for the FLJ/ARE bus-tie and FLJ 220/132kV transformer tripping schemes. The results changed when the power compensated cases were simulated. There was a difference when cut IIIb was above $P_{CUTIIIb}$>150MW. If P_{FL2}>140MW was fulfilled, simulations showed better system response if the bus-tie were tripped with one generator connected to the 132kV ring in FLJ. When the transformers at FLJ are tripped, then FLJ is not participating in 132kV power regulation.

Because the simulation results were identical for the fish smelter load the FLJ transformer tripping results are only shown. This does not undermine previous results because selected cases were only three, FL2, SUL and SI4.

10.3.7 VA1 and FLJ TR7 & TR8 - Simulation results

10.3.7.1 Fish smelters

The marked simulation for FL2 case in the tables can be traced to status of generation at BLA. When $P_{CUTIIIb}$=150MW, BLA generators output is around 50MW. In other cases the generation is on the scale 40-45MW. It can be learned from this if the generation of two generators connected to either bus at BLA are approaching 100MW, then in case of a disturbance the bus-tie trip scheme at BLA will be more likely to operate. Other simulations results were that if FL2 tripped then active power limit on BL1 was reached, P_{BL1}>130MW. Then two islands were created. In the East island was a little overfrequency and underfrequency in the West island (49.6-49.5Hz).

In case of generation loss in the West (tripping at SUL), the power from FLJ is transferred by FL2 and through cut V (to the Eastfjords). Then the power flow on SI4 is low, 0-20MW towards East. This means that cut IIIb is not compensating for power generation in the West. Then the West system is more prepared to take the hit of generation loss in its area. Therefore simulations are shown as green.

When SI4 trips, the power flow is low and system overall generation-load balance is not disturbed by the tripping.

Table 10.15 Cut IIIB - Fish smelter Load and No WACS

$P_{CUTIIIb}$ / Event Unit Tripped	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
FL2	🟢	🟠	🟠	🟠	🟠	🟠*	🟠	🟠	🟠
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
SI4	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢

*Three island mode, no underfrequency. BL2>120MW

Table 10.16 Cut IIIB - Fish smelter Load and WACS

$P_{CUTIIIb}$ / Event Unit Tripped	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
FL2	🟢	🟠	🟠	🟠	🟠	🟠*	🟠	🟠	🟠
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
SI4	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢

*Three island mode, no underfrequency. BL2>120MW and EILS operated

10.3.7.2 Power Compensation

Results for FL2 are the same as in previous section, the generation-load balance was good.

The influence on generation loss in West Iceland (SUL) starts to be a problem in $P_{CUTIIIb}$>150MW. The $P_{CUTIIIb}$=150MW case is special as discussed before because of power output in BLA. When cut IIIb is high because generation is low in the South-West (power compensation), then simulation results show that it is hazardous to transfer power between areas over 150MW with no WACS. If WACS is in operation the risk of severe disturbance is less, because of the DLC at NAL. It prevents or/and reduces underfrequency tripping schemes to be activated at industrial loads.

In cases $P_{CUTIIIb}$=160-180MW the system splitted into four islands. It has been mentioned before that $P_{CUTIIIb}$=150MW was special, in this (with and without WACS) case the system splitted into five islands, North-West (BRE and BLA bus-tie, P_{BL1}>130MW), North-East (BLA bus-tie and FLJ, P_{BL2}>120MW), East mini island (FLJ and ARE, P_{FL2}>140MW), South-East island (FLJ - SI4, P_{SI4}>120MW) and the South-West island (BRE and SIG, isolated by BL1 and SI4). But all islands had relatively good generation-load balance except the biggest island, the South-West one. There was underfrequency which triggered underfrequency protection at BRE to trip load (P_{JA1}=-35.8MW) at the Ferro-Silicon plant (JA1). Cases $P_{CUTIIIb}$>160MW survived with four islands, BL2 did not trip the bus-tie in those cases (traced to generation status at BLA). The load-generation balance in the Eastfjords was saved by LAG and two small hydro stations at SEY (Gúls- og Bjólfsvirkjun). When the power from FLJ is used for compensation in the West there is no fish smelters in service at Eastfjords. The priority load in the Eastfjords is not heavy, it fulfills N-1 requirements easily. Therefore the power generation in the area was enough.

SI4 cases were good but at $P_{CUTIIIb}$>150MW then BL1 hit its limits (P_{BL1}>130MW) and tripped VA1 at BRE. Therefore two islands were created with a good generation-load balance.

Table 10.17 Cut IIIB - Power Compensation and No WACS

Event / Unit Tripped \ $P_{CUTIIIb}$	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
FL2	🟢	🟠	🟠	🟠	🟠	🟠*	🟠	🟠	🟠
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🔴	🔴	🔴	🔴
SI4	🟢	🟢	🟢	🟢	🟢	🟠	🟠	🟠	🟠

*Three island mode, no underfrequency. BL2>120MW

Table 10.18 Cut IIIB - Power Compensation and WACS

Event / Unit Tripped \ $P_{CUTIIIb}$	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
FL2	🟢	🟠	🟠	🟠*	🟠	🟠*	🟠	🟠	🟠
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🟠	🟠	🔴	🔴
SI4	🟢	🟢	🟢	🟢	🟢⋆	🟠	🟠	🟠	🟠

*Three island mode, no underfrequency. BL2>120MW and EILS operated
⋆EILS operated (BL2>120MW), generation high in BLA

10.3.8 VA1 and FLJ/ARE Bus-Tie - Simulation results

10.3.8.1 Power Compensation

When FL2 is tripped, it is not crucial to have one generator at FLJ connected to the 132kV ring. It is assumed that KRA, as a geothermal plant, is close to its generation maximum (60MVA). Then nearly 60MW are flowing from KRA to Rangárvellir (RAN) in North Iceland (Akureyri). KR1 can transfer 91MVA because the line is limited by a current transformer. Then one generator at FLJ can deliver 20-30MW in addition to KRA generation through KR1. If VA1 trips with FL2, the power from FLJ cannot be transferred to BRE, were it is needed. Therefore the need for this tripping scheme is not crucial, but of course it increases reliability if there is a generation trip elsewhere in the "North Island" (which starts at BRE and ends in FLJ (FL2)).

Results show when SI4 is tripped the event does not trigger any SPS or WACS schemes. Which indicates relatively low power flow (Selected cases are for winter load conditions and are quite heavy seen from a loading perspective. HRY, Teigarhorn (TEI), HOL and PRB are taking its share).

When SUL trips, the effects are not as severe if the bus-ties at FLJ/ARE is tripped when P_{FL2}>140MW. The limits on cut IIIb can be pushed from $P_{CUTIIIb}$=150MW up to $P_{CUTIIIb}$=170MW with out and with WACS. The simulation results are promising. But it is necessary to simulate this further for different generation outputs at BLA, KRA, LAG and SIG. Otherwise the simulation results above $P_{CUTIIIb} \geq$170MW are similar to previous results.

Table 10.19 Cut IIIB - Power Compensation and No WACS

$P_{CUTIIIb}$ / Event Unit Tripped	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
FL2	🟢	🟠	🟠	🟠*	🟠	🟠*	🟠	🟠	🟠
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟠	🟠	🟠	🔴	🔴
SI4	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢

*Three island mode, no underfrequency. BL2>120MW

Table 10.20 Cut IIIB - Power Compensation and WACS

$P_{CUTIIIb}$ / Event Unit Tripped	100MW	110MW	120MW	130MW	140MW	150MW	160MW	170MW	180MW
FL2	🟢	🟠	🟠	🟠*	🟠	🟠*	🟠	🟠	🟠
SUL G_{1+2}	🟢	🟢	🟢	🟢	🟢	🟠	🟠	🔴	🔴
SI4	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢

*Three island mode, no underfrequency. BL2>120MW and EILS operated
⋆EILS operated (BL2>120MW), generation high in BLA

10.3.9 Short Simulation Notes - Cut IIIb

It is clear from the simulation results that it is easier to transfer power from East- to West Iceland. The main reason is more generating units in the West than in the East, if there is a disturbance generators in the West are more capable of taking the shock then generators in the East. If part of the export through cut IIIb is for supplying East Iceland fish smelters makes the system operation better because the load can be shedded which doesn't have overloading influences on the generators. It is noted that tripping of generation in Sultartangavirkjun (SUL), in the West during heavy importing from the East can be risky as can be seen in the tables. The DLC at NAL helped the West Iceland generators to respond to the power shortage. One of DLC purpose is to help the generator governors when the frequency drops and to help improve system response during disturbances. In addition, there were some issues with the voltage in East Iceland if FL2 tripped and if the fish smelters load was heavy, it could be related to the D-VAR[1] device at HRY or PSS equipment at SIG, discussed earlier in subsection 8.1.

10.4 Cut V and Cut VII Summary

The cuts for Eastfjords and South Iceland was simulated dynamically. The simulations were not very interesting because there was no interesting dynamics in the simulations. There were only step responses in power flows, therefore the graphs were pretty predictable. It was decided to use load flow simulations. The limits for the cuts are defined from thermal limits of the lines. In the Icelandic 66kV system it is common practice to have the switchgear inside. Because of the house structure there are cables from the last mast and inside the house. These cables are most often the limiting factor to transfer capabilities in the 66kV systems.

For cut V and cut VII line/cable thermal limits will be used as stability thresholds for the power system security assessment. The algorithm for the security assessment is introduced in chapter 11. Then the dynamic simulations results presented in this chapter are used in the assessment along with thermal limit informations from Landsnet's PSS/E model.

The gain of tripping the bus-ties at FLJ/ARE instead of tripping the transformers at FLJ is not significant when the fishsmelter load is online.

[1] http://www.amsc.com/documents/d-var-data-sheet/

Part IV

Real-Time Power System Security Assessment

Chapter 11

Introduction to Real-Time Security Assessment

In this chapter the real-time security assessment concept for the Icelandic power system is presented.

11.1 Introduction to Real Time Power System Security Assessment

In Chapter 5, N-1 Criterion and Power System Security Assessment was defined. The risk in daily operation of power systems is not always obvious and specially in systems with weak and/or heavily loaded lines between areas. The lines may handle the heavy load transfer but one fault may have hazardous consequences.

The purpose of the security assessment is to inform the system operators what will happen if certain faults occur. The security assessment is implemented into Landsnet WAMS, the system is from GE-Grid and is called PhasorPoint. The security assessment is a algorithm which is programmed in PhasorPoint (Ruby programming language) with formulas that use measurements as inputs to calculate desired quantities.

In section 5.3 power system security assessment was defined. An example of a similar assessment is presented in [23]. The difference on what is being proposed in this thesis and in the assessment method in [23] is that in the assessment method in this thesis does not use simulation made in real-time for the security assessment.

PhasorPoint offers real-time calculations and definition of security limits. The proposed assessment uses these properties, straight forward calculations and predefined limits, which can be fixed or dynamic, introduced in section 5.2.1 and will be expanded and discussed further in section 11.3. The making of a real-time power system security assessment with no ”online” simulation has its advantages and disadvantages. Advantage is a quick way of valuating the security of the system and it is possible to use a pre-owned software for the purpose of security measures. Disadvantage is the limits and calculation methods has to be obtained by many ”offline” simulations and data analysis.

11.1.1 Icelandic Real Time Power System Security Assessment

The Icelandic system has small inertia in comparison to the systems in Europe and North-America, therefore the dynamic is very fast during disturbances and there is not always a much time for operators reactions to the events happening. Then tools like [23] may not be very helpful during disturbances because of latency. The use of WAMS measurements and calculating the security of the system in real-time could be more meaningful.

As been pointed out before, frequency- and transient stability are a huge concern in operation of the Iceland power system. Therefore the aim has been on these two subjects in the development of the security assessment. In the Icelandic power system operation the limit of security is not always obvious. One part of solving that problem is to use WAMS measurements to calculate specific data which informs the operators regarding system security in real-time.

One of the main security features depends on load-generation balance, or frequency stability. Unstable power systems are not very secure or useful, therefore the frequency stability is often a fundamental point in the assessment.

11.2 Formulas and Security Limits

The formulas being used in the algorithms was developed by simulations and system analysis, by recognizing what components (line and generators) are important. Fixed security limits defined from transmission equipment thermal or current transformers limits. Dynamic security limits are defined for the main transmission system with a stability perspective.

11.3 Dynamic Load-ability Limits

The load-ability depends if transferred power is for compensation or load. It has been noted before that the magnitude of sheddable load controls how much power can be delivered between areas. The idea is to use limits on a graph which are dynamic on the y-axis and indicate how much sheddable power is connected to the grid, in real-time. Then it is possible to avoid insecure situations in the operation by increasing generation in the area, which would decrease power transfer between areas.

Lets take cut IV as an example. The dynamic axis a real measurement and could be calculated by estimating the priority load and subtracting it from the whole flow through cut V. Then sheddable load is the result as is defined in this equation:

$$P_{SHED} = P_{CUTV} - P_{PRI} \tag{11.1}$$

Then it is possible to calculate the new security limit which is defined as:

$$P_{SEC} = P_{CUTIV} - P_{SHED} \tag{11.2}$$

were

P_{SHED} = Sheddable load in the Eastfjords

P_{PRI} = Priority load in the Eastfjords

P_{SEC} = Dynamic Security Limit

The dynamic load-ability limit takes into account the sheddable load in East Iceland that would be disconnected in case of a disturbance. Using dynamic load-ability Limits could be very useful in the operation of cut IV during high export from West- to East Iceland. The limit range for P_{SEC} in cut IV could to be 110-130MW for secure operation.

Chapter 12

Real-Time Security Assessment Equations

In this chapter equations for the real-time power system security assessment is introduced. The reader is encouraged to check section 6.6 were the protection schemes were presented and explained for full understanding of this chapter concepts.

12.1 Equations Introduction

Most of the equations presented in this chapter were implemented into Landsnet WAMS and are being used in the real-time security assessment for the Icelandic power system. The equations are prestented and the purpose of them is explained. The presented value on the right of the equation (comparator) to the equation output is the limit. If equations satisfy this precondition (within the value on the comparator), the system is considered balanced and should be capable of handling a disturbance without severe consequences. If it does not satisfy the predefined condition, than the system is not secure. The consequences are imbalance in load and generation. The comparators values are very strict and WACS/underfrequency schemes are not taken into account, then dynamic ability approach can be used. Comparators values can be developed more with regards to WACS, underfrequency protection schemes and when the system is islanded.

12.2 Equations for Cut IV

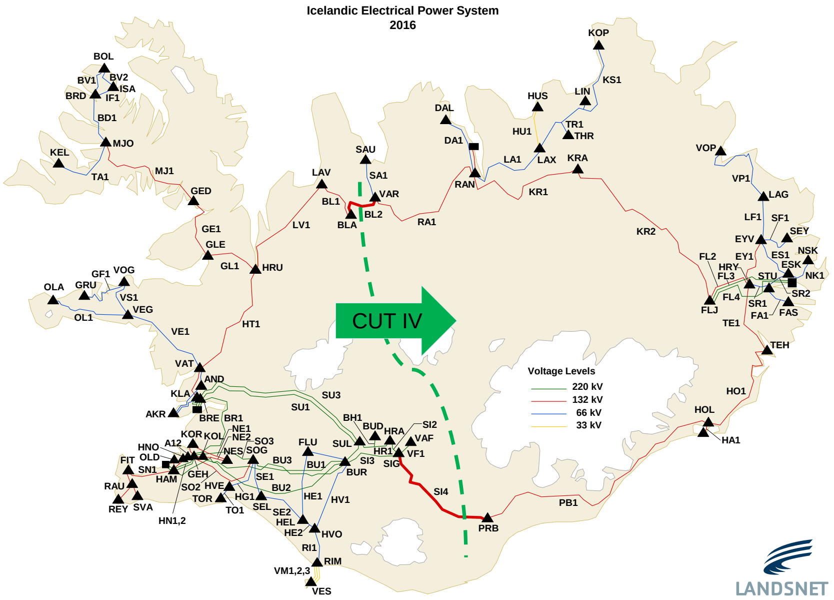


Figure 12.1 Cut IV [2]

In section 2.2.2.1 cut IV was introduced. It is suggested to implement a predefined strategy or operation rules to maintain the best load-generation balance in case of a split. The operation rules with suggested splitting schemes are defined in three stages:

1. P_{CUTIV} = 0 - 80 MW (System split at BLA and HOL)
2. P_{CUTIV} = 80 - 120 MW (System split at BLA and SIG)
3. P_{CUTIV} = 120 - 160 MW (System split at BLA and SIG)

In stages two and three it is required to move a generator between buses in BLA depending on the power flow to maintain the best load-generation balance in case of system split. Some situations like low reservoir levels at BLA and/or SIG requires low generation but the generators can react in case of a disturbance. The generators at BLA are 60 MVA each and 63 MVA in SIG. The scheme is design aims for generators at BLA and SIG can maintain load-generation balance.

12.2.1 P_{CUTIV} = 0 - 80MW

If cut IV active power flow is in the range of 0-80MW than two generators at BLA are connected to BL2 (East island). The equation 12.1 calculates how much active power is needed if SI4, PB1, HO1 or TE1 trips (132kV transmission line in South Iceland). The following three statements describes the equation results:

$$(P_{BLAG_2} + P_{BLAG_3}) - P_{CUTIV} < -35 \; [MW] \tag{12.1}$$

1. If the value is zero, the system is well balanced.

2. If the value is negative = Active power needed in the East island if the system splits - Underfrequency in the East island.
3. If the value is positive = Extra active power is in the East island if the system splits - Overfrequency in the East island.

The second equation calculates the balance between East and West islands. If the value is positive then there is enough active power in the West island and if it is negative then vice versa. Equation 12.2 shows the imbalance in load-generation if there is a system split.

$$P_{SI4} - P_{BLATT1} < X_1 \ [MW] \tag{12.2}$$

12.2.2 P_{CUTIV} = 80 - 120MW

If cut IV active power flow is in the range of 80-120MW then the splitting scheme is changed. Instead of tripping at HOL PB1, the SIG bus-tie circuit breaker is tripped if $P_{SI4} > 120$ MW. Generator 1 at BLA is connected to the bus B (East - BL2) and the other two are connected to the A bus (West - BL1). If BL2 trips, equation 12.3 calculates how much active power is needed for the East island if the system splits.

$$(P_{SIG_{G2}} + P_{SIG_{G3}}) - P_{CUTIV} < -20 \ [MW] \tag{12.3}$$

In case of emergency -40MW could be allowed if all generation station in East island are in service and have +40MW in reserve power. If SI4 trips, equation 12.4 calculates how much active power is needed for the East island if the system splits.

$$P_{BLA_{G1}} - P_{CUTIV} < -20 \ [MW] \tag{12.4}$$

In case of emergency -60MW could be allowed. Equation 12.5 valuates the transfer between areas and indicates if the system stability is threaten.

$$P_{SIG_{TT1}} - P_{BLA_{TT1}} < \pm 10 \ [MW] \tag{12.5}$$

The power transfer between areas should not be all through the bus ties. Instead the generators connected to that island should generate the power needed, so if system split occurs the balance is kept and the stability of the system is not in danger. But there are instances were these rules are broken, for example if a generator is out of service because of maintenance. Then the power transfer through the bus-ties is increased which means if the system splits it causes underfrequency in the East island.

12.2.3 P_{CUTIV} = 120 - 160MW

If cut IV is within 120-160MW the tripping scheme is the same as in the stage below, bus-tie breaker at SIG is tripped. In BLA generator 3 is added to bus B (East) along with generator 1 that is already connected to the East.

As before if BL2 trips, equation 12.6 calculates how much active power is needed for the East island if the system splits.

$$(P_{SIG_{G2}} + P_{SIG_{G3}}) - P_{CUTIV} < -40\ [MW] \tag{12.6}$$

If SI4 trips, equation 12.7 calculates how much active power is needed for the East island if the system splits.

$$(P_{BLA_{G1}} + P_{BLA_{G3}}) - P_{CUTIV} < -40\ [MW] \tag{12.7}$$

Also equation 12.5 is used in this scheme to predict the balance between areas.

12.3 Equations for Cut IIIb

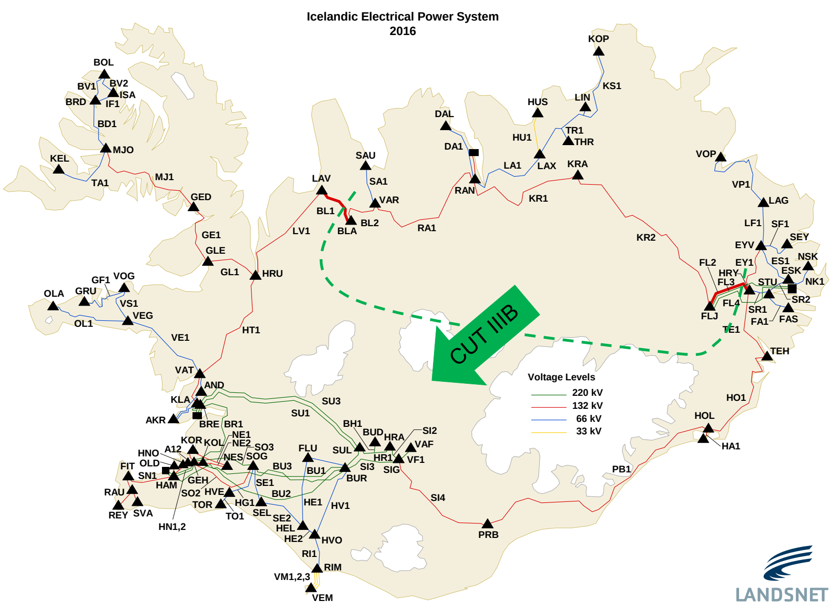


Figure 12.2 Cut IIIb [2]

In section 2.2.2.1 cut IIIb was introduced. As was done in previous section, it is suggested to implement operation rules to maintain the best load-generation balance in case of a split. The operation rules with suggested splitting schemes are defined in two stages:

1. $P_{CUTIIIb}$ = 0 - 80 MW (System split at BLA if P_{BL1}>130MW)
2. $P_{CUTIIIb}$ = 130 - 160 MW (System split at BRE (VA1) if P_{BL1}>130MW)

Tripping the circuit breaker for VA1 at BRE when the power transfer in the cut is above 130MW, and fish smelter load is under 20MW, creates a larger island. A larger island - therefore more load in this case, should have good influences on the load-generation balance. In case were the load is heavy and the splitting occurs with unacceptable balance, underfrequency protection at Westfjords would contribute to the work of gaining good balance between load and generation in the East-North island.

12.3.1 P_{CUTIIB} = 0 - 130MW

If cut IIIb active power flow is in the range of 0-130MW it is suggested that splitting schemes are not changed. If FL2 trips, then equation 12.8 calculates how much power is needed into the Eastfjord system. Lagarfosslína 1 (LF1), lies from a hydro power plant in East Iceland and is connected to Eyvindará by 66kV line. LAG (34MVA) is also connected to VOP where a fish smelter (16MW) is located and is sheddable by Landsnet. By calculating how much power is flowing from LAG indicates three things:

1. LAG generation is all transported to EYV.
2. LAG generation is supply the fishsmelter at VOP and the rest is transported to EYV.
3. LAG is out of service.

The same topology can be used for SF1 (Seyðisfjarðarlína 1), which lies from EYV (Eyvindará) to SEY (Seyðisfjörður). In SEY are two small hydro power plants, called Gúlsvirkjun (3.8MVA) and Bjólfsvirkjun (7.5MVA). Most often the generation is exported to EYV and into the Eastfjord system. If the fish smelter at SEY is operating then the power flow is inverse. The formula to calculate how much power is needed into the Eastfjord system if FL2 trips is:

$$(P_{SI4} + P_{LF1} + P_{SF1}) - P_{FL2} < -30\ [MW] \tag{12.8}$$

When cut IIIB is close to 130MW and FL2 trips, then the bus-tie in BLA trips also because of swings. P_{BL1}>130MW, therefore it is necessary to take the bus-tie power flow into the formula, to valuate how much power is needed to the West.

$$P_{CUTIIIb} - P_{FL2} - P_{BLATT1} < 80\ [MW] \tag{12.9}$$

Formula 12.10 is a little bit more advanced, it takes the participation of LAG and SEY into account.

$$P_{CUTIIIb} + P_{SI4} + P_{LF1} + P_{SF1} - P_{FL2} - P_{BLATT1} < 50\ [MW] \tag{12.10}$$

A fault on BL1 which leads to a trip of the line has serious consequences. Especially when cut IIIb is around 130 MW, has can be seen in tables in section 10.3. The simulation results indicate that the stability of the system is threaten during these conditions. In subsection 6.6.1.1 the local protection scheme at BLA is discussed.

If BL1 is heavily loaded and BLA generation is 135MW during a fault on BL1, all the generated power on the generator at bus A will flow through the bus-tie and eventually reach $P_{BL2} > 120$ MW limit, which will lead to a trip of the bus-tie breaker. To evaluate the conditions it is possible to calculate the power loss with equation 12.11

$$P_{CUTIIIb} - P_{BLA_{G1}} < 80 - 85\ [MW] \tag{12.11}$$

The comparator value is 80-85MW because the the current transformer limit on SI4 is only 91MVA. If WACS is operating when the $P_{BL2} \geq 120MW$ all sheddable load in East Island is shedded and therefore the system is safe from underfrequency conditions. If WACS is not operating then the tripping of BL1 will trigger the overloading on FL2 because of power swings and then trip the 132kV transformers at FLJ. This could result in serious underfrequency and increased power swings between areas. Therefore the tripping of the bus-tie in FLJ and ARE was simulated to check if it would contribute in reserving load-generation balance. The results are discussed in before covered section 10.3.

12.3.2 P_{CUTIIB} = 130 - 160MW

If cut IIIb active power flow is in the range of 130-160MW it is suggested instead of splitting at BLA to move the bus-tie trip signal to BRE and the circuit breaker for VA1. If FL2 trips, then the overload protection on BL1 will be triggered, sending a trip signal to BRE and tripping VA1. To estimate the power needed in the West island, then subtracting the active power of FL2 and VA1 from cut IIIb is used as shown in equation 12.12.

$$P_{CUTIIIb} - P_{FL2} - P_{VA1} < 80MW \tag{12.12}$$

Formula 12.13 is a little bit more advanced, it takes the participation of LAG and SEY into account.

$$P_{CUTIIIb} + P_{SI4} + P_{LF1} + P_{SF1} - P_{FL2} - P_{VA1} < 50MW \tag{12.13}$$

These equations are the same as before except the active power through the bus-tie in BLA is taken out of the equation and replaced by active power of VA1.

12.4 Equations for Cut V

The Eastfjord Iceland transmission system is a 66kV area based system in East Iceland. The priority load is relative small in comparison to the sheddable load which is for the fishsmelters. The system can be seen in figure 12.3.

This system has been discussed for cut IV and cut IIIb, related to fish smelter load. As noted before the load capacity of these fishsmelters can be approximately 100MW, if all online at the same time, which is improbable. Most common is 40-80MW. The system is supplied by the 132kV ring system at HRY with one 132kV cable to Stuðlar (STU), named Stuðlalína 1 (SR1) and one 132kV line to EYV, Eyvindarárlína 1 (EY1). STU and EYV are the substations that supply the Eastfjord system. From the substations EYV and STU are radial ends that lead to the fjords. Equation 12.14 is to evaluate how much power EY1 will transfer to the Eastfjord if SR1 trips. The limit (76MW) is built upon EY1 thermal limits.

$$P_{CUTV} - P_{SR1} < 76MW \tag{12.14}$$

Equation 12.15 is to evaluate how much power SR1 will transfer to the Eastfjord if EY1 trips. The limit (54MW) is built upon SR1 thermal limits.

$$P_{CUTV} - P_{EY1} < 54MW \tag{12.15}$$

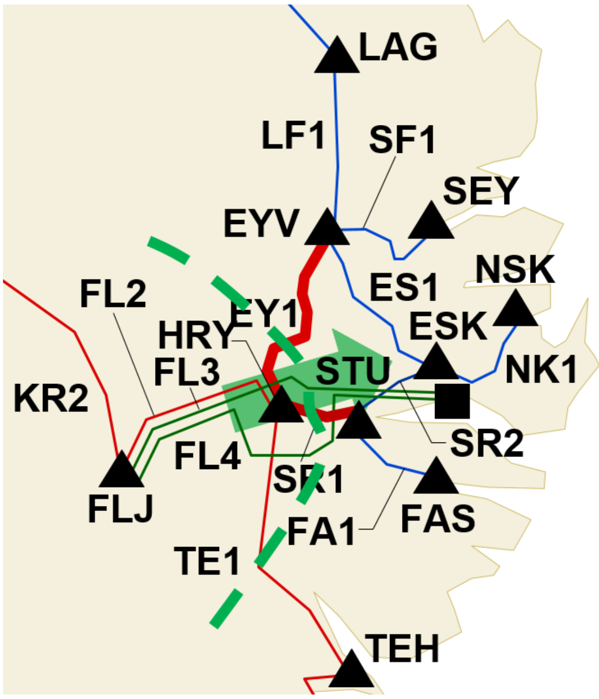


Figure 12.3 CUT V [2]

It is than possible to estimate the security of cut Vb, cut V subcut. Cut Vb and is defined as $P_{CUTVB} = P_{SR2} + P_{ES1}$. Equation 12.16 is to evaluate how much power EY1 will transfer to the Eastfjord if SR2 trips. The limit (30MW) is built upon EY1 thermal limits.

$$P_{CUTVB} - P_{ES1} < 30MW \tag{12.16}$$

Equation 12.15 is to evaluate how much power ES1 will transfer to the Eastfjord if SR1 trips. The limit (29MW) is built upon ES1 thermal limits.

$$P_{CUTVB} - P_{SR2} < 29MW \tag{12.17}$$

The following equations are for the Eastfjord area based 132/66kV system. The security margin definition is based on components thermal limits. This assessment is closely related to cut IIIb assessment.

12.5 Equations for Cut VII

In South Iceland is a 66kV transmission system. It is supplied by Búrfell (BUR), a hydro power plant, through two transformers (40MVA+40MVA=80MVA). The system can be seen in figure 12.4. The biggest loads (P_{FLU}=15MW) are at Flúðir (FLU) for cultivation and in Vestmannaeyjar (VEM) (P_{VEM}=20-24MW). In VEM a large part (16-18MW) of the load is sheddable.

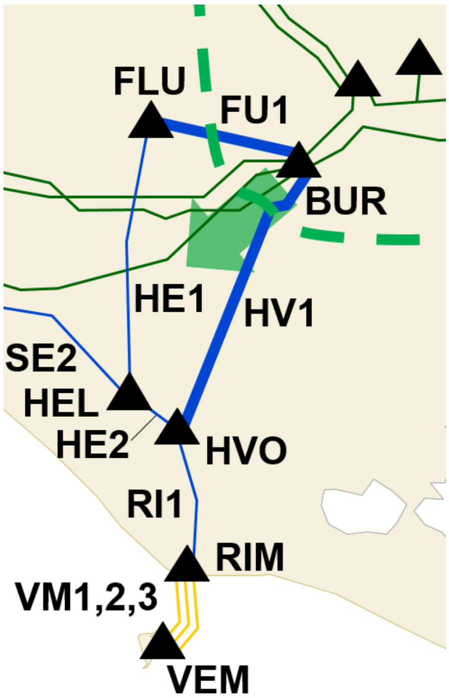


Figure 12.4 CUT VII [2]

BUR is connected to the grid by two 66kV lines, one from FLU and one from Hvolsvöllur (HVO). When the load peak is at maximum there is no N-1 criteria. If Hvolsvallarlína 1 (HV1) trips, then Flúðarlína 1 (FU1) overloads and trips. Selfoss (SEL) is supplied by Ljósafossvirkjun (LJO) by 66kV line/cable. From SEL are two lines but one of them is connected to the Hella (HEL). That is Selfosslína 2 (SE2)

The main challenge in the operation in this system is the overloading of every component when the system is heavily loaded, especially in the winter time. Some of the lines could carry more but are limited by current transformers, other are not built for heavy active power transfer. As in previous schemes the principal is estimating how much active power is needed if particular line trips. If HV1 trips, FU1 and SE2 has to supply the system for it is active power need. If SE2 is in service, then the import through SE2 has to be taken into account and the limits is therefore a little higher.

If HV1 trips, FU1 and SE2 transfer the power needed in the system and for secure operation the the security equation is:

$$P_{CUTVII} + P_{SE2} - P_{HV1} < 41MW \tag{12.18}$$

If FU1 trips, the HV1 have to be able to transfer the active power to FLU (15MW) beyond what the line was transferring before the trip.

$$P_{CUTVII} + P_{SE2} - P_{FU1} < 40 - 45MW \tag{12.19}$$

If SE2 is not in service or faulted, then the new limits are used and SE2 taken out of the equation.

If HV1 trips, then the equation is:

$$P_{CUTVII} - P_{HV1} < 23MW \tag{12.20}$$

If FU1 trips, then the equation is:

$$P_{CUTVII} - P_{FU1} < 20 - 25MW \tag{12.21}$$

If load is 15MW at FLU and FU1 trips, power has to be transferred the other way around (HV1 and SE2) then voltage collapse will be at FLU. Therefore it is only possible to transfer limited power to FLU. This is the only security assessment that can not been monitored in the WAMS. Because there are no PMUs in the area. Security assessment calculations could be done in the SCADA system with warning signs but the graphical solutions is not available with the same quality as in the WAMS system.

Chapter 13

Real-time Security Assessment Algorithm

In section 12.2 the security assessment equations were introduced. This chapter the real-time security assessment algorithm is introduced and how the equations were used in the security assessment. The algorithm was programmed in Ruby programming language in Landsnet WAMS, PhasorPoint. Real-time power system security assessment is used in daily operation of the Icelandic power system.

13.1 Security Assessment Algorithm Introduction

The topic of this chapter is real-time security assessment algorithms. The algorithms for the cuts are basically the equations presented in last chapter. The equations were code in the PhasorPoint calculation mechanism and there are nothing really to show except the output, example is presented in section 13.2.

In this chapter algorithms are presented that use the frequency gradient assessment method which was presented in section 8.2 and theoretically discussed in section 3.4. Last but not least the Westfjords security assessment algorithm is presented, based on the same theory.

13.2 Algorithm for Cuts

The algorithms for cuts use equations introduced in the previous chapter. All equations are calculated separately and then added to a graph. Equations which are defined on the same ”stage” are plotted together in one plot and the security limits are set as horizontal lines on the graph. It could be implemented in that way if the equation outcome goes over the horizontal line with the same color as the plot it self then there is security failure. For example, cut IV has three stages, which means that each stage has it own graph. The number of plots in one graph depends on the number of equations. Figure 13.1 is an example of this security assessment described here above and shows the graph for cut IV on stage 1 ($P_{CUTIV} \leq 80$MW)

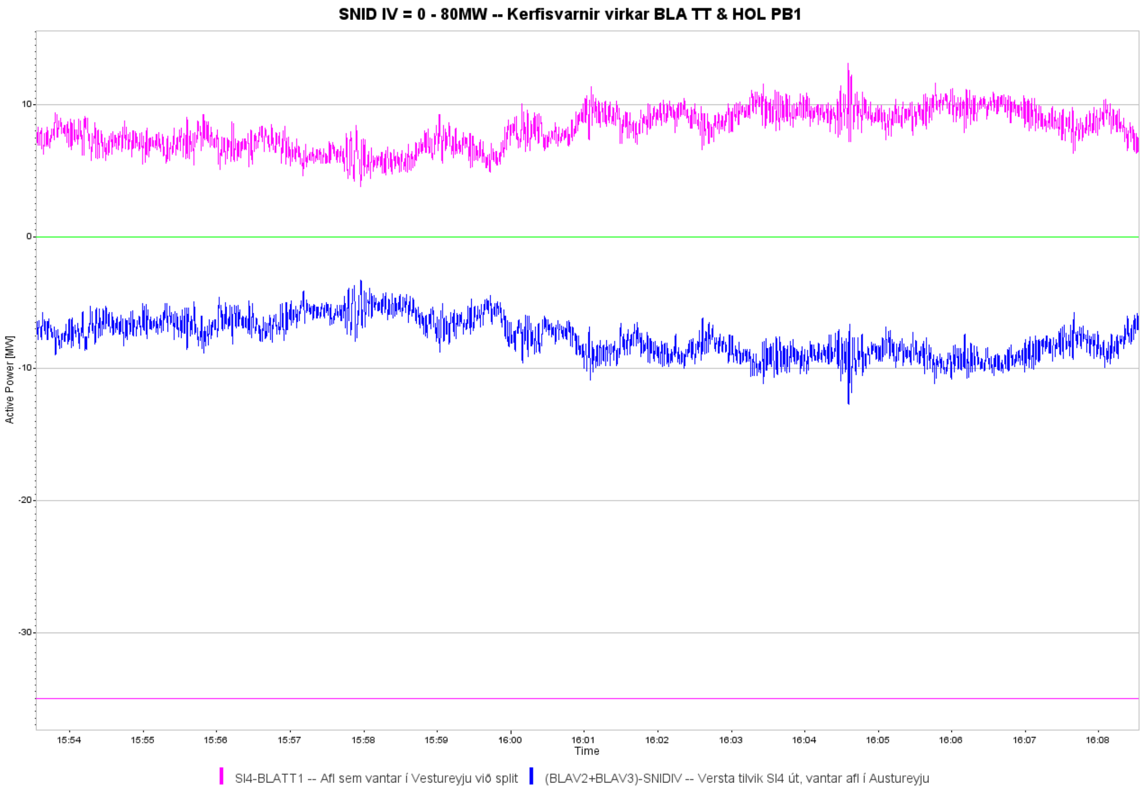


Figure 13.1 Cut IV Real-time Power System Security Assessment

The green line in the middle indicates stable operation and clean separation if the system is splitted. If the pink plot (magenta) is near or crosses the pink line in 35MW, then the split is not balanced and could have bad consequences on the frequency stability in the East island.

13.3 System Islanding Frequency Assessment

The system islanding frequency assessment method is based on the frequency gradient assessment method, presented and checked to be accurate in section 8.2.1. Two algorithms were written in Landsnet WAMS system for West and East island. The purpose is to calculate in real-time how the frequency response will be if the system becomes islanded. In next two subsection the code is shown and commented for explanations. In Appendix E.3 and E.5 algorithms are presented that take into account WACS schemes. In the East island the fish smelter load is estimate from line power flows in the 66kV area based system and then the load is taken into account when calculating the frequency response. In the West island the frequency drop is calculated and if it is below 49.2Hz then NAL DLC response is added into the equation and used for frequency response calculations.

13.3.1 West Island Frequency Assessment Algorithm

The algorithm, in Appendix E.2, takes in measurements from SIG, BLA and BRE. Then it calculates the flow in cut IV. The inertia is considered to be a constant because it is not possible to import circuit breaker status into the calculations. The system inertia is than changed in the frequency gradient calculations depending on the splitting scheme presented 12.2. The outcome of this algorithm is the frequency response if the system is splitted. This is not the steady state frequency after a disturbance, the output shows how low or high the first inertia frequency response will be. In demo-algorithm 1 the real algorithm is explained.

Data: PMU measurements for SI4, BL2 and frequency at BRE
Result: Security Assessment for West Island in case of Islanding

Calculate Cut IV - SI4+BL2;
Define West island inertia constant - if cut IV is 80MW;
Define West island inertia constant - if cut IV is 120MW;
Define West island inertia constant - if cut IV is 160MW;

if $P_{CUTIV} < 80MW$ **then**
    Calculate df/dt;
    Calculate f;
    Output = Lowest point of frequency in case of islanding;
end

if $80MW < P_{CUTIV} < 120MW$ **then**
    Calculate df/dt;
    Calculate f;
    Output = Lowest point of frequency in case of islanding;
end

if $P_{CUTIV} < 120MW$ **then**
    Calculate df/dt;
    Calculate f;
    Output = Lowest point of frequency in case of islanding;
end

Algorithm 1: Demo Algorithm - WAMS Algorithm for West Island Frequency Assessment

13.3.2 East Island Frequency Assessment Program

The algorithm, in Appendix E.4, takes in measurements from SIG, BLA and FLJ. Then it calculates the flow in Cut IV. It built on the same fundamental idea as the algorithm for West island frequency assessment. In the demo-algorithm 2 the real algorithm is explained.

Data: PMU measurements for SI4, BL2 and frequency at BRE
Result: Security Assessment for East Island in case of Islanding

Calculate Cut IV - SI4+BL2;
Define East island inertia constant - if cut IV is 80MW;
Define East island inertia constant - if cut IV is 120MW;
Define East island inertia constant - if cut IV is 160MW;

if $P_{CUTIV} < 80MW$ **then**
  Calculate df/dt;
  Calculate f;
  Output = Lowest point of frequency in case of islanding;
end

if $80MW < P_{CUTIV} < 120MW$ **then**
  Calculate df/dt;
  Calculate f;
  Output = Lowest point of frequency in case of islanding;
end

if $P_{CUTIV} < 120MW$ **then**
  Calculate df/dt;
  Calculate f;
  Display the lowest point of frequency in case of islanding;
end

Algorithm 2: Demo Algorithm - WAMS Algorithm for East Island Frequency Assessment

13.4 Algorithm Explanations for Westfjords Security Assessment

In subsection 2.2.2.1 the Westfjord system was discussed. In recent years has Landsnet put a lot of effort into making the power lines stronger and the reliability better in the area. To make the Westfjord more reliable a diesel generating station was build in Bolungarvík (BOL). If Westline trips and MJO cannot handle the load then Breiðadalslína 1 (BD1) is tripped and in the Northern Westfjords without power in approximately 90 seconds. In this 90 seconds all the breakers at Ísafjörður (ISA) and BOL are tripped, then the diesel generators are started and the 66kV buses are energized. Then the breakers at ISA and BOL are put into service one after another until all priority load is back in service.

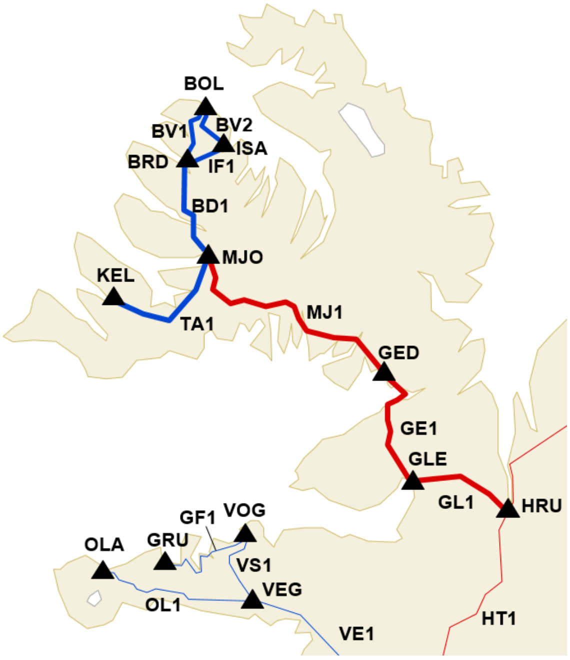


Figure 13.2 Westfjords 132kV and 66kV Transmission System [2]

If total load is not heavy, then there is no need to start the diesel engines because Mjólká (MJO) can supply the load in all Westfjords. By monitoring the import from Hrútatunga (HRU) to MJO it is possible to predict what consequences disturbance has if the Westline trips. It could be possible to predict the frequency stability using the frequency assessment method when the Westfjords get disconnected from the 132kV ring system in HRU (islanding mode). The use of the frequency gradient assessment method would calculate if sheddable load will be shedded or not in case of a split. If the sheddable load is enough to save the island, diesel power plant in BOL does not have to be activated. Sheddable load is approximately 13MW, which is tripped by underfrequency protection at f=49.0Hz. Transformer 1 (132/66kV) in MJO is 30MVA and is a limiting factor in the import from HRU. Therefore, 43% of the import is sheddable. But MJO can only supply 10MVA. If the import is P_{WL}<23MW then there is a good chance that all of the Westfjords can survive without blackout. If P_{WL}>23MW then BD1 will trip, leaving MJO with the Southern Westfjord energized but a blackout for 90 seconds in Northern Westfjords. In equation 13.1 the power left in the Westfjords is calculated if the Westline is tripped:

$$P_{LS} - P_{MJO} \lesseqgtr P_{WL} \tag{13.1}$$

were

P_{LS} = Sheddable Load
P_{MJO} = MJO Generation [MW]
P_{WL} = Import through the Westline from the 132kV ring system [MW]

If P_{WL}»10MW, BD1 will be disconnected at MJO. But if P_{WL}>10MW, then underfrequency protection will trip priority load until the generators at MJO can handle the load. It is possible to use frequency gradient calculations to estimate if the frequency in the Westfjord will drop below 49,0Hz or not. If the frequency drops below 49,0Hz and P_{MJOTR1}<23MW then sheddable load will be shedded and the island could survive if the sheddable load is 13MW. If not, then BD1 will trip. The algorithm that predicts and checks multiple conditions that are:

1. What is the load in North and South Westfjords?
2. What is the generation at MJO ?
3. Is the system is interconnected and importing power?
    - If yes, then the df/dt conditions are checked. (df/dt > 48.5 or df/dt < 48.5)
        - If df/dt > 48.5Hz - $P = P_{Load} - P_{Shed} + P_{Gen}$, where $P_{Shed} = 13MW$
        - If df/dt < 48.5Hz - $P = P_{Load} - P_{Shed} + P_{Gen}$, where $P_{Shed} = 6.5MW$

Is the frequency gradient below or above 48.5Hz and is the power flow through transformer 1 in MJO below or above 23MW? If the frequency gradient is above 48.5Hz and power flow transformer 1 below 23MW then the island will survive if sheddable load is tripped by underfrequency protection. If either of the conditions are fulfilled then the island will not survive and back-up power plant in BOL will be energized. The algorithm could also carry out system security assessment in islanded mode, the stability can be estimated the following way:

1. Is the island interconnected (BD1 in service)?
    - If yes, $P = P_{LoadNW} - P_{BOLGen}$ - checking if the power balance is good or not.
    - If no, is TA1 or BD1 out of service ?
2. Not efficient: If BD1 is out of service then are two islands, north and south island. MJO supplying the South and BOL supplying the North.
3. Not efficient: If TA1 is out of service then it is checked if BD1 trips and if BOL can handle the load.

The algorithm is presented in Appendix E.1. This assessment is different than others because the state estimation changes the calculation methods on the graph. So operators could rely on the information being display in the same graph for different states of the system. The disadvantage is that operators has to trust what is being calculated and displayed for each system state. This can be confusing and could make it unusable. The other way is splitting up the algorithm for two different cases, interconnected and islanding mode conditions. In demo algorithm 3 the real algorithm is explained in a simple manner.

Data: PMU measurements for BOL, ISA, MJO
Result: Security Assessment for the Westfjords in case of Islanding
Import measurements;
Calculate all load in the Westfjords;
Calculate generation;
Calculate load;
Algorithm checks if the Westfjords are islanded or not;
Inertia defined for BOL and MJO;

if *If the Westfjord system is interconnected and importing from HRU - Heavy import* **then**
    Calculate df/dt;
    Calculate f;
    if *If* $f_{MJO} > 48.5Hz$ **then**
        Sheddable load is approximately 13MW;
        How power needed is calculated and displayed;
        if *If* $f_{MJO} < 48.5Hz$ **then**
            Sheddable load is approximately 5.5MW;
            How power needed is calculated and displayed;
        end
    end
end

if *If the Westfjord system is interconnected and importing from HRU - Light import* **then**
    Calculate df/dt;
    Calculate f;
    if *If* $f_{MJO} > 48.5Hz$ **then**
        Sheddable load is approximately 7.5MW;
        Power needed is calculated and displayed;
        if *If* $f_{MJO} < 48.5Hz$ **then**
            Sheddable load is approximately 3.5MW;
            Power needed is calculated and displayed;
        end
    end
end

if *If the Westfjord system is islanded* **then**
    if *If all lines are in service within the system* **then**
        Power needed in North Westfjords if BD1 trips;
        if *If TA1 is out of service* **then**
            Power needed in North Westfjords if BD1 trips;
        end
    end
end

Algorithm 3: Demo Algorithm - WAMS Algorithm for Westfjords

Part V

Conclusion and Future Work

Chapter 14

Conclusion and Future Work

This chapter is divided in four sections, first three are conclusions for various parts of this thesis and the fourth section contains proposals for future work.

14.1 General Conclusion

The purpose of this master thesis was to estimate the security level of the Icelandic power system with respect to special protection schemes (SPS), wide-area control system (WACS) schemes and level of the production units in the system. The project evolved into making power system security assessment methods for the most delicate corridors (cuts) in the system. The methods were designed with the Icelandic SPS and WACS schemes in mind.

In this thesis the possibilities of using wide-area measurements for power system security assessment was explored. The focus was mainly on two alternatives, N-1 extended criteria assessment and frequency stability assessment. These security assessment methods could be very useful for future operation of the Icelandic power system.

The methods were not simulated in PSS/E but tested on the real system by using Landsnet wide-area measurement system (WAMS), PhasorPoint. The algorithm was coded in *Calculated Data* option in the program. By using the Calculated Data option it is possible to get measurements and use them for all kinds of calculations. For example, angle difference, frequency difference and -gradient calculations, industrial load summation and generation-load balance equations. The imagination is the limit.

The disadvantage of using these methods is that requires a good system characteristics knowledge and deep analysis work. Dynamic and load-flow simulations were used to simulate the system response for various system conditions. The advantage for TSOs of making this kind of power security assessment is that this approach yield good knowledge to the company employees and a way of obtaining power system security assessment. The results of this project is a power system security assessment tool which was implemented into the wide-area measurement system at Landsnet. The WAMS work can be summarized as:

- Cut IIIb - Generation-Load Balance Assessment and Frequency Stability Assessment
- Cut IV - Generation-Load Balance- and Frequency Stability Assessment

- Cut V - Generation-Load Balance Assessment
- Cut VII - Generation-Load Balance Assessment
- Westfjords - Generation-Load Balance- and Frequency Stability Assessment

14.2 PSS/E Model Conclusion

Landsnet PSS/E model is pretty good and gave sensible results most often. There were unstable cases and they need more attention than was time for in this project. SPS schemes, some times in this thesis called "traditional protection", and WACS schemes were implemented into the PSS/E model by Python code, see implementation report in Appendix B. The Python code was then used to carry out the simulations, saved simulated data into excel sheets and MATLAB figures for further analysis. Proposed work to make the model better is discussed in the Future Work section.

14.2.1 PSS/E Simulation Conclusion

Overall results were acceptable. The difference between FLJ transformer tripping and FLJ bus-tie tripping was not as good as expected, it would be very interesting to simulate it again when PSS equipment has been added to the model. Transferring trip signal from BLA to BRE when P_{BL1}>130MW was very promising and was often better than tripping the bus-tie at BLA. In retrospect, the consequence factor was not the best way to express the simulation results. There are so many things happening and it is difficult to express all of them with one dot. The consequence factor shows in a good way how much is possible to deliver between areas and the consequences with respect to frequency and circuit breaker movement.

14.3 Power System Security Assessment Conclusion

14.3.1 Frequency Gradient Assessment Method

It was shown in the project that this method can work and could be valuable for system operators. In cases of emergencies it is possible to operate the system on the edge of frequency stability and underfrequency protection limit is can be avoided in system operation during critical conditions. By updating the ΔP value with respect to sheddable load and potential/most likely line losses it is possible to operate the system with more confidence and security.

The edge of stability could be for example be the underfrequency limit at ARE f_{ARElim}=48,65Hz in East Iceland if the system becomes islanded. The ARE underfrequency protection trips one rectifier at the pot line in ARE ($P = -90$MW). This saves the overall stability of the system and prevents generation tripping and transformer tripping in FLJ because of overload. This method could also be used to determine the best way of splitting the system by monitoring the frequency gradient in few possible islanding conditions. The best split would than be carried out based on the frequency gradient assessment.

14.3.1.1 Steady-State Frequency

It is recognized that steady-state frequency response could be useful. But for East Iceland during a split, if sheddable load is heavy then it is enough to trip that load so the frequency bounces back to 50Hz, depending on power flow through Cut IV before the disturbance and the splitting scheme. If there is no sheddable load, the underfrequency protection at ARE fixes the problem. It was thought to be more valuable to know how low the frequency will drop in the first seconds during a disturbance instead of calculating something that will be stable, eventually. Besides the project time was running out.

14.3.2 N-1 Extended Contingency Assessment Method Conclusion

This approach was designed by defining equations that use critical measurements for system stability. Critical measurements are for example: active power generation at BLA, SIG and FLJ, power flows on BL1, BL2, SI4 and FL2, and frequency in East Iceland during heavy import from West- to East Iceland. By using this cut assessment it is possible to estimate generation-load balance if islanding schemes operate. Then could severe disturbances be avoided by changing generation plans, for example if bad storm is coming or during natural catastrophic events.

14.4 Future Work

During the research, simulation and writing of this thesis many interesting things came up involving various parts. The identified future research projects are related to the material of this thesis but also other things related the future Icelandic system operation. These projects are listed here below:

- **Construction of Dynamic Simulation Assessment Tool for Landsnet.**

  This could be established by writing a code (Python, C++) that can communicate with the SCADA system, WAMS and PSS/E. The information from WAMS and SCADA are used to set up a simulation case in PSS/E, which simulates and then delivers graphs (or a Excel file with plotted simulation data) and comments if instability is detected. Could be a good thesis project for collaboration of two master students, in electrical engineering and computer science.

- **Frequency Stability Assessment Improvements**

  To make the Frequency Stability Assessment more reliable the algorithm needs to be updated in real-time with information from SCADA/WAMS about what generators are online. Enquiry was sent to the SCADA manifacturer and was in progress when these words were written. Real-Time Steady-State Frequency Stability Assessment could be a interesting project.

- **PSS/E Model Improvements**

  To make the model better it is suggested to analyze load models for the aluminum smelters and for the DVAR at HRY. The load is a large proportion of the total load so they do contribute to system damping and maybe explain the frequency response. The DVAR at HRY contributes to the voltage stability if FL2 trips.

Then it is suggested to add model for Power System Stabilizer (PSS) models at KRA, SIG, BLA, BUD and FLJ/KAR. It is clear from the simulations in this project that they do matter during simulations of cases that are on the edge of stability.

- **PSS/E Simulation Projects**

  When the model has been updated it would be interesting to simulate what happens if KR1 when cut IIIb is above 130MW. It was simulated during the work for this thesis but it was unstable. It would also be very interesting to investigate further transferring trip signal from BLA to BRE for tripping of VA1 when P_{BL1}>130MW. Analyze if P_{FL2}>140MW if it is feasible to trigger EILS to trip fishsmelter load in the Eastfjords. Preliminary results indicate that it could be useful when Cut IIIb is high and fishsmelter is online when KR1 or KR2 trips. Then it would also be interesting to make a Q-V analysis for HRY and the D-VAR. Checking the performance of the DVAR and what if it is tripped (or FL2 while heavily loaded (P_{FL2}>60MW)), what influences do that have on the voltage stability in the area?

- **New Parameters for Power System Security Assessment**

  It is possible to use angle difference to estimate system stability in algorithms. It is very fast indicator and gives information about transferred power between areas. It could be very useful for the security/stability assessment. For example, islanding detection for the DLC at NAL uses the angle difference between BRE and FLJ. Besides frequency difference could be used in some cases.

- **Islanding Schemes**

  Check the pros and cons of splitting the system simultaneously at BLA and SIG. Where is the limit of splitting VA1 (at BRE) and HT1 (at VAT) instead of tripping the bus-tie in BLA? It could be an interesting project for students to investigate ways to co-ordinate real-time islanding scheme which determines the optimum islanding conditions.

- **Power System Security Assessment System Upgrades**

  As been noted before, this project is not done. Whenever the system changes, for example if new lines are build or new generation plants, then limits, parameters and equations might need to be updated. This is a disadvantage and advantage. The disadvantage is that it is time-consuming to review and approximate the assessment. The advantage is the gain of system operation and characteristics knowledge. It is recognized that all systems have to be upgraded when new components are added to the system (property database, PSS/E models and etc.).

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Appendices

Appendix A

Power Flow Through an Impedance

The basic equation for power flow through an impedance is central to the concept of stability, since it illustrates the importance of impedance or transfer admittance in limiting the power flow through a network. Consider the simple system shown in figure A.1,

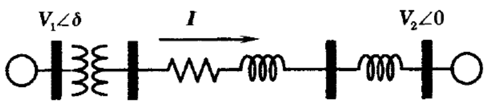

Figure A.1 Power flow through an impedance [8, p.854]

where the equation is written in terms of power flow in the direction of defined current flow.

$$\mathbf{I} = \frac{\mathbf{V}_1 - \mathbf{V}_2}{\mathbf{Z}} = \frac{V_1\underline{/\delta} - V_2\underline{/0}}{Z} \tag{A.1}$$

where

$$\mathbf{Z} = R + jX \tag{A.2}$$

Z is the series impedance between the two voltage sources, and may include several lines, transformers, or other series impedances. Then the complex power leaving the voltage source on the left in figure A.1 is defined as:

$$P_1 + jQ_1 = \mathbf{V}_1\mathbf{I}_1^* \tag{A.3}$$

or

$$P_1 + jQ_1 = \frac{V_1^2}{Z^2}(R + jX) - \frac{V_1V_2}{Z}[(R\cos\delta - X\sin\delta) + j(X\cos\delta + R\sin\delta)] \tag{A.4}$$

The most interesting is the active power injected at node 1, which can be written as:

$$P_1 = \frac{V_1^2 R}{Z^2} - \frac{V_1V_2}{Z^2}(R\cos\delta - X\sin\delta) \tag{A.5}$$

In most power systems at higher voltages, the resistance is much smaller than the reactance, so often equation A.5 is written without the resistance and is then written as:

$$P_1 = \frac{V_1 V_2}{X} \sin\delta = P_{\max} \sin\delta \tag{A.6}$$

Equation A.6 is well known in electrical engineering in stability studies and often used to estimate system stability by plotting up a curve of power (pu) versus torque angle (degrees).

A.1 Stability Example

Example of N-1 Criteria - Thermal- and Stability Limitation

Lets analyze N-1 criteria in a very simple way by using the theory of power flow through impedance. There are two adjacent lines, with the same reactance $X_1 = 0.5$pu. When both in service the overall reactance of the system is $X = 0.25$pu. The voltage is..

$V_1 = 1.0\underline{/90.0^\circ}, V_2 = 0.95\underline{/0^\circ}$ and $X_{all} = 0.25$pu

The lines are both at the same voltage level and can transfer the same amount of power. If the line are both transferring near their maximum capability ($\delta_s = 90^\circ$ and $\delta_s = 0^\circ$) then the power transferable is:

$$P_1 = \frac{V_1 V_2}{X_{all}} \cdot \sin\delta = \frac{1.0 \cdot 0.95}{0.25} \sin 90.0^\circ = \frac{1.0 \cdot 0.95}{0.25} = 3.8 \text{ pu} \tag{A.7}$$

Now one of the line is tripped by line protection and then there is only one line.

$$P_2 = \frac{V_1 V_2}{X_1} \cdot \sin\delta = \frac{1.0 \cdot 0.95}{0.5} \sin 90.0^\circ = \frac{1.0 \cdot 0.95}{0.5} = 1.9 \text{ pu} \tag{A.8}$$

Transferable power decreased by half, $P = \frac{3.8}{2} = 1.9$pu and the maximum transferable power through the line is only 1.9pu. If one line is transferring 3.8pu, it could lead to immediately tripping because of overload or thermal limits are reached.

What if, both lines can transfer 3.8 pu? Then N-1 is fulfilled and the lines can handle load. But what if there is a angular instability ? We have the same situation as before but the rotor angle between the generators creases ? $\delta_s = 90.0^\circ$ and $\delta_r = 35.0^\circ$.

$$P_2 = \frac{V_1 V_2}{X_1} \cdot \sin\delta_s - \delta_r = \frac{V_1 V_2}{X_1} \cdot \sin 90^\circ - 35^\circ = \frac{1.0 \cdot 0.95}{0.5} \sin 55.0^\circ = 1.56 \text{ pu} \tag{A.9}$$

One line is still connected after the disturbance but the rotor angle between the generators is increasing which leads to more power flow from Bus 1 to Bus 2, the power through the line is now more then it is capable of transferring. This is a stability issue. To tackle stability issues there are many ways. On next page are three typical ways of dealing with this kind of problems.

- **Power Swing Blocker**
  If it is known that there are power swing between areas during the clearing of a fault and after it, then it is possible to use a power swing blocker because it is known that the system stabilizes, the rotor angle between the two generator finds a new equilibrium point. The generators at Bus 2 will increase they're generation and therefore the power transfer decreases [8].

- **Load Shedding**
  To stabilize the condition then it is possible to shed load if $P_{L2} \geq 1.1$ pu. To be able to carry this out there have to be good communications between areas.

- **Islanding Schemes**
  Last but not least is tripping the line in service also if $P_{L2} \geq 1.1$ and having the system in islanding mode instead of trying to keep it together during the disturbance. Then one island is saved instead of risking of total blackout. The consequences in the other island depends on many things, how much total rotational energy is online? is there a underfrequency protection scheme or other load shedding schemes? It is always considered better to shed load then risk total blackout [8].

Appendix B

PSS/E WACS and Local Protection Implementation

One of the objectives in this project was to implement local protection- and wide area control system schemes (WACS) into the PSS/E configuration. That was done by using Python code to run the dynamic simulations through PSS/E. Landsnet had a python program before but that code was adjusted to the protection schemes that are used today. After these adjustments and testing, a model validation was carried out and the results are analyzed and explained in Appendix B.

The protection schemes that were implemented:

- Dynamic Load Control at Nordural
- Load Reduction Control at Alcoa
- East Island Load Shedding - Fishsmelter Load Shedding Scheme.
- FLJ Transformer 7 and 8 Tripping Schemes
- SIG and BLA tripping schemes.

- Local protection for FL2 was implemented.
- Local protection for SE2 was implemented.
- Underfrequency schemes were checked, adjusted and some missing loads were added to the schemes.

Appendix C

Classification of Power System Stability

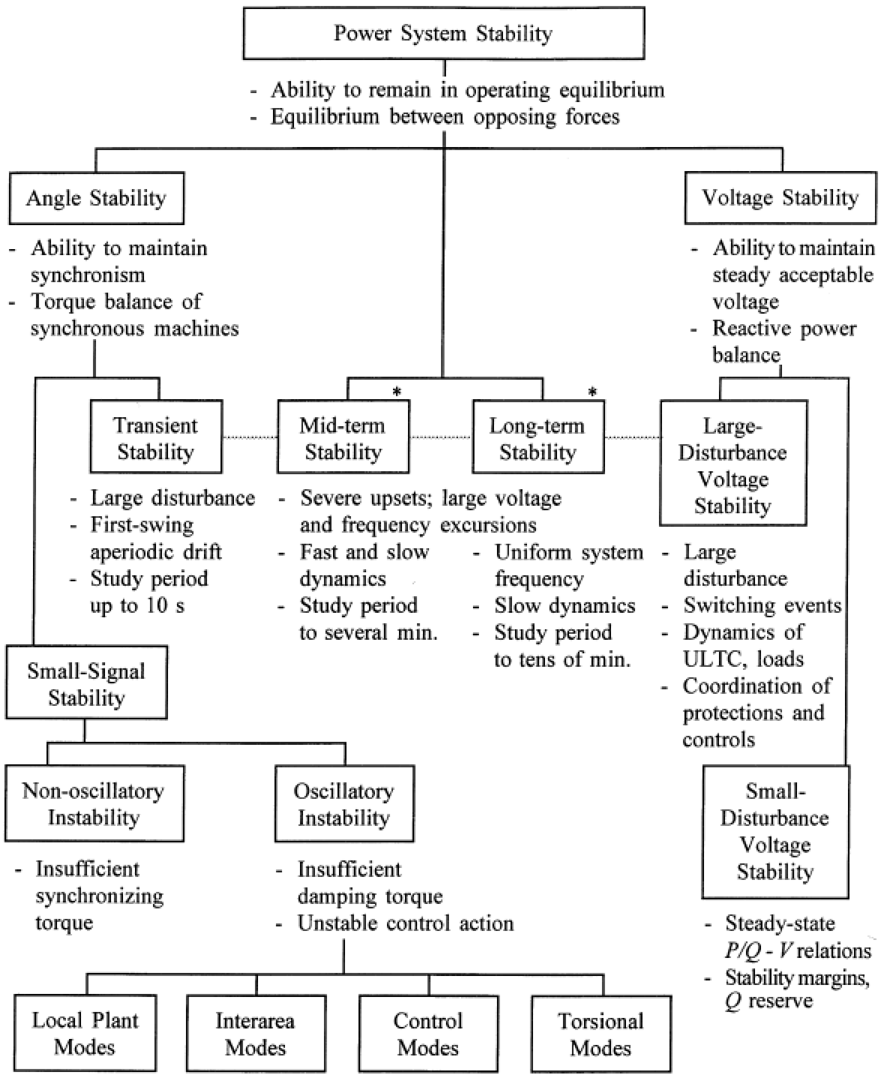

Figure C.1 Classification of Power System Stability [4, p.36]

Appendix D

Matlab Inertia Calculations for Iceland

```
%Landsnet & Reykjavik University - T900MEIS
%Inertia Calculations for the Icelandic Power System
%Written by: Gunnar Ingi Valdimarsson
%Date: 2.4.2016

%Purpose of this code is calculating the inertia in the Icelandic System.
%The formula is: xGEN=(H*MVA)+(H*MVA)+...

%Calculating E rotational energy in East Iceland.
xFLJVA=(3.4950*127.8*10^6)+(3.4950*127.8*10^6)+(3.4950*127.8*10^6)...
+(3.4950*127.8*10^6)+(3.4950*127.8*10^6)+(3.4950*127.8*10^6);
xLAG=(1.57*10*10^6)+(2.14*24*10^6);
xLAX=(3.15*10*10^6)+(3.15*28*10^6);
xKRA=(6.58*37.5*10^6)+(6.58*37.5*10^6);

%Calculating E rotational energy in West Iceland.
xBUR=(2.75*53.3*10^6)+(2.75*53.3*10^6)+(2.75*53.3*10^6)...
+(2.75*53.3*10^6)+(2.75*53.3*10^6)+(2.75*53.3*10^6);
xHRA=(3.51*81.5*10^6)+(3.51*81.5*10^6)+(3.51*81.5*10^6);
xVAF=(4.0*53.3*10^6)+(4.0*53.3*10^6);
xSUL=(3.5*72*10^6)+(3.5*72*10^6);
xBUD=(2.5*60*10^6)+(2.5*60*10^6);
xIRA=(2.78*19.4*10^6)+(2.78*19.4*10^6)+(2.06*21.0*10^6);
xSTE=(2.3*16.5*10^6)+(2.3*16.5*10^6);
xLJO=(2.8*5.5*10^6)+(2.8*5.5*10^6)+(2.6*7.2*10^6);
xHEL=(5.91*55*10^6)+(5.91*55*10^6)+(5.91*55*10^6)+(5.91*55*10^6)...
+(5.91*55*10^6)+(5.91*55*10^6);
xNES=(6.58*40*10^6)+(6.58*40*10^6)+(6.58*40*10^6)+(6.58*40*10^6);
xSVA=(3.04*50*10^6)+(5.10*50*10^6);
```

```
xREY=(4.38*55*10^6)+(4.38*55*10^6);

%BLA
xBLAV1=2.75*60*10^6;
xBLAV2=2.75*60*10^6;
xBLAV3=2.75*60*10^6;
xBLA=xBLAV1+xBLAV2+xBLAV3;

%SIG
xSIGV1=4*63*10^6;
xSIGV2=4*63*10^6;
xSIGV3=4*63*10^6;
xSIG=xSIGV1+xSIGV2+xSIGV3;

%West Iceland Inertia in islanding mode
%If Cut IV is below 80MW
W_Erot1=xBUR+xHRA+xVAF+xSUL+xBUD+xIRA+xSTE+xLJO+xHEL+xNES+xSVA+xREY...
+xSIG+xBLAV1+xBLAV2;

%If Cut IV is below 80MW and only two generators at BLA in service
W_Erot2=xBUR+xHRA+xVAF+xSUL+xBUD+xIRA+xSTE+xLJO+xHEL+xNES+xSVA+xREY...
+xSIG+xBLAV2;

%If Cut IV is over 80MW
W_Erot3=xBUR+xHRA+xVAF+xSUL+xBUD+xIRA+xSTE+xLJO+xHEL+xNES+xSVA+xREY...
+xSIGV1+xBLAV1;


%East Iceland Inertia in islanding mode
%If Cut IV is below 80MW
E_Erot1=xFLJVA+xLAG+xLAX+xKRA+xBLAV2+xBLAV3;

%If Cut IV is below 80MW and only two generators at BLA in service
E_Erot2=xFLJVA+xLAG+xLAX+xKRA+xBLAV2;

%If Cut IV is over 80MW
E_Erot3=xFLJVA+xLAG+xLAX+xKRA+xBLAV2+...
xBLAV3+xSIGV2+xSIGV3;

%Command window output
W_Erot1 =8.2225e+09\\
W_Erot2 =8.0575e+09\\
W_Erot3 =7.5535e+09\\
E_Erot1 =3.6902e+09\\
E_Erot2=3.5252e+09\\
E_Erot3=4.1942e+09\\
```

Successes: Landsnet, Iceland

Successes: Landsnet, Iceland

The Icelandic transmission system consists of two major clusters of both loads and generators: one in the east and another in the south-west. Under normal operation these two clusters are connected through a 132 kV ring.

Landsnet was concerned that the introduction of new generators planned for the east of Iceland would lead to severe system instability unless the 132kV ring network was reinforced. This would have required significant additional capital expenditure.

The Icelandic transmission system also had historical problems with low frequency oscillations and ineffective Power System Stabilisers (PSS).

To tackle these problems Landsnet decided to install a Wide Area Management System (WAMS). Due to Alstom's past experience in power system dynamics, PSS tuning and WAMS deployment we were the perfect choice to address these challenges.

Alstom installed an e-terraphasorpoint WAMS to collect, analyse and visualise real-time synchrophasor data from across the Icelandic transmission system. Alstom then baselined the dynamic performance of the system. Using this information we started the process of testing and re-tuning the PSS under a variety of power flow conditions.

This project was extremely successful. The oscillatory stability improvements as a result of our services were clearly visible to Landsnet. Network configurations that previously showed poor damping were now stable and the continuous monitoring and analysis that e-terraphasorpoint provides now enables Landsnet to avoid these sorts of issues in the future.

Alstom is now using the synchrophasor data from Landsnet's PhasorPoint WAMS to deploy a Wide Area Defense System, which aims to prevent network separation by avoiding the voltage angle difference between the two regions exceeding the tripping threshold. To achieve this, if a large load loss is detected, selected generators are tripped sequentially to slow down the growth of the angle difference.

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Appendix E

Algorithms for Icelandic Power System Security Assessment using WAMS

E.1 Westfjord Stability Estimation Algorithm

The algorithm was programmed in Ruby which is the programming language that PhasorPoint uses for data calculations. The algorithm is designed to estimate the load-generation balance in the island in real-time. The balance indicates whether the island can survive or not, if not BD1 is tripped and the BOL backup power plant is energized.

There are PMUs at ISA, MJO and BOL and the data streams from these PMUs are used for the estimation. At first the algorithm calculates necessary parameters for the algorithm.

```
#Landsnet & Reykjavik University - T900MEIS
#Real-time Power System Security Assessment for the Westfjords
#Written by: Gunnar Ingi Valdimarsson
#Date: 14.2.2016
 if ( (BOLf!=null) && (MJOf!=null) && (PBV1!=null)...
  && (PIF1!=null) && (PISASP1!=null) && (PISASP2!=null)...
  && (PMJOSP2!=null) && (PMJOSP1!=null) && (PTA1!=null)...
  && (PBD1!=null) && (PHL1!=null) && (PBOLG1!=null)...
  && (PBOLG2!=null) && (PBOLG3!=null) && (PBOLG4!=null)...
  && (PBOLG5!=null) && (PBOLG6!=null) && (PBOLSP1!=null)  ) {

#Calculate the load in all Westfjords
PWL=PBD1+PTA1+PHL1;

#Calculate the generation at MJO
PMJOGSUM=PMJOSP2+PHL1;
```

```
#Calculate the generation at BOL
PBOLGSUM=PBOLG1+PBOLG2+PBOLG3+PBOLG4+PBOLG5+PBOLG6;

#Calculate the sum of generation in Westfjords
PGSUM=PMJOGSUM+PBOLGSUM;

#Calculate the load in North Westfjords
PBOLALAG=PBOLGSUM-PBOLSP1; #Load in BOL
PISAALAG=PISASP1+PISASP2; #Load in ISA
PBRDALAG=PBD1+PIF1+(-PBV1); #Load - smaller towns
PNW=PBOLALAG+PISAALAG+PBRDALAG; #Sum of loads

#Calculate the load in South Westfjords
PSW=PHL1+PTA1;

#All Westfjords load
PWALL=PNW+PSW;
```

Then the algorithm checks if the Westfjords are connected to the system or not.

```
#BOL
ErotBOL=3.2292; #Erot=H*S=H_1*S_1...+H_6*S_6=(0.299*1.80)*6=3.2292 [MJ]]

#MJO
ErotMJO=39.68; #Erot=H*S=H_1*S_1+H_*S_2=3,61*9,1694+3,61*8,45=39,68 [MJ]]

#PLS is the sheddable load, tripped at f=49,0Hz

#If the system is interconnected and importing from HRU - heavy load
if ( (PBD1>=15) && (PTA1>=4) && (-PMJOSP1>0.099) ){

#Calculating the frequency gradient
dfdtmjo=(-PMJOSP1*MJOf)/(2*ErotMJO);
fmjo=MJOf-dfdtmjo;

if ( fmjo > 48.5 ){
PLS=13; #Roughly approximation on the sheddable load
Pmiss=PWALL-PLS+PMJOGSUM; #Load-Sheddable-Load+Generation
}

else if ( fmjo < 48.5 ){
PLS=5.5 #Roughly approximation on the sheddable load
Pmiss=PWALL-PLS+PMJOGSUM
}
}
#If the system is interconnected and importing from HRU - light load
```

```
if ( (PBD1<=15) && (PTA1<=4) && (-PMJOSP1>0.099) ){

if ( fmjo > 48.5 ){
PLS=7.5; #Roughly approximation on the sheddable load
Pmiss=(PWALL-PLS)+PMJOGSUM

else if ( fmjo < 48.5 ){
PLS=3.5 #Roughly approximation on the sheddable load
Pmiss=(PWALL-PLS)+PMJOGSUM
}

}
```

If the system is in islanding mode, the algorithm valuates what conditions are in the system (if power lines TA1 or BD1 is out of serice while MJO TR1 is also out of serive) at any current time and displays data for that conditions.

```
#Islanding mode - No sheddable load is allowed (PLS=0).

#If the system is in island mode and BD1 and TA1 is in service.
if ( (-PMJOSP1<0.099) && (PBD1>0.1) && (PTA1>0.1) ){

Pmiss=PNW-PBOLGSUM; #Load-Generation at BOL

}

#If the system is in islanded mode and TA1 out of service.
if ( (PTA1<0.099) && (PMJOSP1<0.099) && (PBD1>0.099) ){

Pmiss=PNW-PMJOGSUM; #Load in the North - Generation in BOL and MJO

}

return Pmiss; #Pmiss = displayed in the graph for monitoring.

}
```

If BD1 is tripped, then there are two islands and MJO will supply the Southern Westfjords and BOL will supply the North Westfjord. It was estimated by the author that was not necessary to valuate the balance between the load and generation in two island mode.

E.2 West Island Frequency

```
#Reykjavik University and Landsnet
#T900MEIS - Gunnar Ingi Valdimarsson
#Frequency Calculations for West Iceland if islanding

#Get measurement input for calculations
if ( (PSI4!=null)&& (PBL2!=null) && (fBRE!=null) ) {

#Calculate Cut IV
Pcutiv=PSI4+PBL2;

#West Inertia (MJ) depending on flow in Cut IV
WErot80=8222.5;
WErot120=8057.5;
WErot120=7553.5;

#If P_CutIV < 80MW - Stage 1
if ( (Pcutiv<80) ){
dfdt=(+Pcutiv*fBRE)/(2*WErot80);
f=fBRE-dfdt;
}

#If 80MW< P_CutIV > 120MW - Stage 2
if ( (Pcutiv>80) && (Pcutiv<120) ){
dfdt=(+Pcutiv*fBRE)/(2*WErot120);
f=fBRE-dfdt;
}

#If P_CutIV > 120MW - Stage 3
if ( (Pcutiv>160) ){
dfdt=(+Pcutiv*fBRE)/(2*WErot160);
f=fBRE-dfdt;
}

return f;
}
```

E.3 West Island Frequency if NAL DLC is Active

The algorithm was programmed in Ruby which is the programming language that PhasorPoint uses for data calculations. The algorithm is designed to evaluate the frequency stability of the West Iceland when the system is in islanding mode and the DLC at NAL is active. There are PMUs at SIG, BRE and BLA and the data streams from these PMU's are used for the estimation.

```
#Landsnet & Reykjavik University - T900MEIS
#Real-time Power System Security Assessment for the Westfjords
#Written by: Gunnar Ingi Valdimarsson
#Date: 20.4.2016
if ( (PSI4!=null) && (PBLATT1!=null)...
 && (PBL2!=null) && (fBRE!=null) && (NALENABLE!=null) ) {

#Calculate Cut IV
Pcutiv=PBL2+PSI4;
Pdister=PBLATT1+PSI4

#West Inertia (MJ) depending on flow in Cut IV
WErot80=8222.5;
WErot120=8057.5;
WErot120=7553.5;

#If P_CutIV < 80MW - Stage 1
if ( (Pcutiv<80) ){
dfdt=(+Pdister*fBRE)/(2*WErot80);
f=fBRE-dfdt;
}

#If 80MW < P_CutIV > 120MW - Stage 2
if ( (Pcutiv>80) && (Pcutiv<120) ){
dfdt=(+Pdister*fBRE)/(2*WErot120);
f=fBRE-dfdt;
}

#If P_CutIV > 120MW - Stage 3
if ( (Pcutiv>160) ){
dfdt=(+Pdister*fBRE)/(2*WErot160);
f=fBRE-dfdt;
}

#NAL + Imported power to the West island
PNAL1=18; #First step down at NAL DLC (MW)
PNAL2=30; #Second step down at NAL DLC (MW)
Pdist1=Pdister+PNAL1; #Lost imported power if split + PNAL1
```

```
Pdist2=Pdister+PNAL1+PNAL2; #Lost imported power if split + PNAL2

#If Dynamic Load Control Available at NAL.
#NALENABLE is a signal from NAL rectifier control which
#..indicates if the control is available (1) or not (0).

if ( (NALENABLE==1) ){
if ( (f <= 49.2) && (Pcutiv <= 80) ){
dfdt=(+dist1*fBRE)/(2*WErot160);
f=fBRE-dfdt;
}

if (  (f <= 49.2) && (Pcutiv >= 80) && (Pcutiv <= 120)  ){
dfdt=(+Pdist1*fBRE)/(2*WErot160);
f=fBRE-dfdt;
}

if ( (f <= 49.2) && (Pcutiv >= 160) ){
dfdt=(+Pdist1*fBRE)/(2*WErot160);
f=fBRE-dfdt;
}
if ((f <= 48.8) && ((Pcutiv <= 80)) ){
dfdt=(+Pdist2*fBRE)/(2*WErot160);
f=fBRE-dfdt;
}

if ( (f <= 48.8) && (Pcutiv >= 80) && (Pcutiv <= 120)  ){
dfdt=(+Pdist2*fBRE)/(2*WErot160);
f=fBRE-dfdt;
}

if ( (f <= 48.8) && (Pcutiv >= 160) ){
dfdt=(+Pdist2*fBRE)/(2*WErot160);
f=fBRE-dfdt;
}
}
return f;
}
```

E.4 East Island Frequency

```
#Reykjavik University and Landsnet
#T900MEIS - Gunnar Ingi Valdimarsson
#Frequency Calculations for West Iceland if islanding

#Get measurement input for calculations
if ( (PSI4!=null)&& (PBL2!=null) && (fFLJ!=null) ) {

#Calculate Cut IV
Pcutiv=PSI4+PBL2;

#West Inertia (MJ) depending on flow in Cut IV
EErot80=3690.2;
EErot120=3525.2;
EErot120=4194.2;

#If P_CutIV < 80MW - Stage 1
if ( (Pcutiv<80) ){
dfdt=(-Pcutiv*fFLJ)/(2*EErot80);
f=fFLJ-dfdt;
}

#If 80MW< P_CutIV > 120MW - Stage 2
if ( (Pcutiv>80) && (Pcutiv<120) ){
dfdt=(-Pcutiv*fFLJ)/(2*EErot120);
f=fFLJ-dfdt;
}

#If P_CutIV > 120MW - Stage 3
if ( (Pcutiv>160) ){
dfdt=(-Pcutiv*fFLJ)/(2*EErot160);
f=fFLJ-dfdt;
}

return f;

}
```

E.5 East Island Frequency if Fish Smelter Load Online

The algorithm was programmed in Ruby which is the programming language that PhasorPoint uses for data calculations. The algorithm is designed to evaluate the frequency stability of the East Iceland when the system is in islanding mode and fish smelters are tripped by WACS. There are PMUs at SIG, BRE and BLA and the data streams from these PMU's are used for the estimation.

```
#Landsnet & Reykjavik University - T900MEIS
#Real-time Power System Security Assessment for the Westfjords
#Written by: Gunnar Ingi Valdimarsson
#Date: 14.4.2016
 if ( (PSI4!=null) && (PBL2!=null) && (fFLJ!=null) && (PSR1!=null)...
  && (PEY1!=null) && (PFA1!=null) && (PES1!=null) && (PSR2!=null) ) {

#Cut V Summation
CutV=-PSR1+PEY1;

#Load Shed Checker
 if ( ( CutV >= 10) ){ #If Cut V is above 10MW then sheddable load is online.

#If SR2>=5 MW - Sheddable load
 if ( (PSR2 >= 5) ){
SR2=PSR2-5;
}

#If SR2<=5 MW - No sheddable load
 else {
SR2=PSR2*0.01;
}

#If FA1>=3 MW - Sheddable load
 if ( (PFA1 >= 3) ){
FA1=PFA1-3;
}

#If FA1<=3 MW - No sheddable load
 else {
FA1=PFA1*0.01;
}

#If ES1>=8 MW - Sheddable load
 if ( (PES1>=8) ){
ES1=PES1-8;
}
```

```
#If ES1<=8 MW - No sheddable load
else {
ES1=PES1*0.01;
}
}

#Cut IV Summation
Pcutiv=PSI4+PBL2;
#Sheddable Load Summation
Pshed=FA1+SR2+ES1;
#Total summation
Ptotal=Pshed+Pcutiv;

#East Inertia (MJ) depending on flow in Cut IV
EErot80=3690.2;
EErot120=3525.2;
EErot120=4194.2;

#If P_CutIV < 80MW - Stage 1
if ( (Pcutiv<80) ){
dfdt=(-Ptotal*fFLJ)/(2*EErot80);
f=fFLJ-dfdt;
}

#If 80MW < P_CutIV > 120MW - Stage 2
if ( (Pcutiv>80) && (Pcutiv<120) ){
dfdt=(-Ptotal*fFLJ)/(2*EErot120);
f=fFLJ-dfdt;
}

#If P_CutIV > 120MW - Stage 3
if ( (Pcutiv>160) ){
dfdt=(-Ptotal*fFLJ)/(2*EErot160);
f=fFLJ-dfdt;
}
return f;
}
```