Efficient Hydroelectric Generation Using Novel Balance Schemes

by

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Abstract

In order to control frequency and interchange schedules in electric power systems, a permanent balance between generation and demand is necessary. Following electric demand has traditionally been realized by control of flexible generation resources. As a consequence, conventional generation units are utilized in lower maximum output power and less efficient operating points. Transition toward increased penetration of intermittent Distributed Energy Resources (DER) requires more balancing capacity in power systems which makes frequency control a more challenging issue.

Demand Side Management (DSM) is a main ingredient of Smart Grid (SG)s to improve efficiency and reliability. Some industrial processes have inherent flexibilities making them capable of virtually storing enough energy to immediately and continuously respond to control signals of transmission system operator. These loads, when equipped with advanced metering, communication and control infrastructure, can realize participation of Demand Side Storage (DSS) in sub-hourly time steps of grid balance.

In order to fairly distribute the benefits of interconnection among all control areas, frequency control standards are defined and proposed by reliability coordinators e.g. NERC. Once new standards become effective, Balancing Authorities (BA)s modify their Automatic Generation Control (AGC) and real-time balance logic to comply with the new requirements.

This research is dedicated to finding novel balance structures in sub-hourly dispatch and real-time operation. The objectives of the proposed balance structures are to increase hydroelectric generation efficiency and reduce unit maneuvering leading to mechanical wear and tear.
Abstract

A new Demand Dispatch (DD) application for industrial flexible loads and a new sub-hourly balance structure based on use of DSS are developed in this thesis. Also in real-time operation, a novel AGC logic is proposed to maximize the benefits of a hydroelectric dominated Balancing Authority based on latest frequency control standards. It is shown through mathematical modeling, static scheduling optimization formulations and dynamic simulations that utilizing 5% of system peak demand as sub-hourly dispatched DSS saves up to 2% in generation efficiency and utilizing the proposed real-time AGC logic leads to generation efficiency saving of up to 1.3%. Both proposed methods also significantly reduce mechanical wear and tear.
Preface

The chapters of this thesis were prepared and written by the author with the help and supervision of university supervisor Dr. William G. Dunford, university co-supervisor Dr. Ebrahim Vaahedi and industry supervisor Malcolm Metcalfe. Some of the research results are already published/accepted as journal articles, conference proceedings and/or submitted for peer review.

In all chapters and paper publications, the author was responsible for developing the ideas, mathematical formulations, implementing the models, conducting the simulations, compiling the results and concluding the work. All manuscripts are prepared by the author while university supervisors Dr. William G. Dunford and Dr. Ebrahim Vaahedi have provided supervisory comments and corrections during the process of studies and writing the manuscripts.

The industrial supervisor helped the author during this research by providing real industrial load data and general information about demand side management and the potential benefits for utilities and load owners.

My contributions during the PhD has resulted in the following publications and conference presentations.

A version of Chapter 3 and part of Chapter 2 is published as a journal paper.

Preface

Two conference presentations were also based on primitive results of these chapters.


A version of Chapter 4 is submitted to a peer review journal.


Some other results of this part is accepted for presentation in a conference.

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## Glossary

**ACE** Area Control Error. 6, 81–83, 87, 89, 95, 105, 107

**AGC** Automatic Generation Control. ii, iii, vii, x, xii, 3, 5, 6, 10, 12, 17–20, 24, 27, 28, 80, 81, 86–89, 92, 93, 96, 97, 101, 105, 107, 109

**BA** Balancing Authority. ii, iii, 5, 6, 18, 19, 81, 83–85, 87, 89

**BAAL** Balancing Authority ACE Limit. 6, 84, 85, 87, 107

**BRD** Balance Resource and Demand. vii, viii, 5, 6, 16, 18–20, 81, 83, 89, 96, 99, 101, 105, 107

**CPM** Control Performance Measure. 83–85, 87, 107

**CPS** Control Performance Standards. viii, 81–85, 87, 98, 107

**DD** Demand Dispatch. iii, vii, 10, 16–20, 49, 105, 106, 108

**DER** Distributed Energy Resources. ii, 51, 52, 66

**DLC** Direct Load Control. 11, 13, 17, 50–52, 107

**DP** Dynamic Programming. vii, xi, xiii, 35–37, 40

**DR** Demand Response. xi, 7–11, 15–17, 48, 49, 51, 52, 54, 66, 108

**DSM** Demand Side Management. ii, xi, 6–8, 11, 15–17, 19, 48

Glossary

**EBO** Energy Balance Optimizer. 51, 52, 54, 59, 60, 62, 69, 75, 77–80

**ED** Economic Dispatch. vii, 3, 4, 17, 18, 21, 22, 25, 27, 28, 33, 41, 42, 45–47, 49, 50, 81, 82, 85, 87, 95, 107

**ESS** Energy Storage Systems. 9, 11, 19, 48–50, 109

**GDF** Generation Distribution Factor. 45, 46, 62

**ISO** Independent System Operator. 11, 12, 17, 54, 108, 109

**MILP** Mixed-Integer Linear Programming. 64, 65, 69, 107

**NERC** North American Electric Reliability Corporation. ii, 5, 7, 19, 20, 82, 83, 105, 107

**POP** Preferred Operating Point. xi, 28, 36, 79, 80, 106, 109

**QP** Quadratic Programming. 46, 47, 62

**SG** Smart Grid. ii, 1, 6, 16, 48

**UC** Unit Commitment. vii, xiii, 3, 4, 21, 22, 25, 27, 28, 33, 34, 36, 43, 47, 67, 76, 77, 82, 87, 88, 95, 107

**V2G** Vehicle-to-Grid. 12, 13, 15, 109

**VIU** Vertically Integrated utility. 11, 16, 17, 19, 20, 49–51, 54, 79, 81, 105, 107–109

**VPP** Virtual Power Plant. 50, 106
Nomenclature

$\beta_{i,j}$ Penstock loss constant, $s^2/m^5$.

$\delta_g(t)$ Vector of limits of generator ramp rates.

$\delta_t(t)$ Vector of maximum limit of pump ramp rates.

$\delta_s(t)$ Vector of limits of DSS ramp rates.

$\delta_{p,s}$ Ramp rate limit of pump $p$ in storage $s$, MW/s.

$\eta_{g,i,j}$ Generator efficiency of hydroelectric unit $i$ in plant $j$, %.

$\eta_{t,i,j}$ Turbine efficiency of unit $i$ in plant $j$, %.

$F$ Vector of active power flow limits.

$L_{\text{max}}(t)$ Vector of limit on maximum pump power.

$L_{\text{min}}(t)$ Vector of limit on minimum pump power.

$P_{\text{max}}(t)$ Vector of limits on maximum hydro generation.

$P_{\text{min}}(t)$ Vector of limits on minimum hydro generation.

$S_{\text{max}}(t)$ Vector of limits on maximum DSS consumption.

$S_{\text{min}}(t)$ Vector of limits on minimum DSS consumption.

$V_t^s$ Normalized volume of storage $s$ at time $t$.

$\rho$ Water specific weight, kg/m$^3$. 
Nomenclature

\( \hat{n}_s^t \) Ideal number of pumps to be “on at time \( t \).

\( a_{p,s} \) Coefficient of linear term of fitted discharge curve for pump \( p \) in storage \( s \).

\( b_{p,s} \) Coefficient of constant term of fitted linear discharge curve for pump \( p \) in storage \( s \).

\( D_e^t \) Effective demand at time \( t \), MW.

\( d_{i,j} \) Water discharge in unit \( i \) in plant \( j \), \( m^3/s \).

\( E_{s,T} \) Total energy consumption in storage \( s \), MWh.

\( E_{total} \) Total energy consumption of all DSSs in system-wide balance problem.

\( f_{p,s} \) Pumping rate function of pump \( p \) in storage \( s \).

\( g \) Acceleration of gravity, \( m/s^2 \).

\( h_{e;i,j} \) Effective water head of unit \( i \) in plant \( j \), m.

\( h_{f,j} \) Forebay elevation of plant \( j \), m.

\( h_{p,j} \) Penstock loss effect of plant \( j \), m.

\( h_{t,j} \) Tailrace effect of plant \( j \), m.

\( k_j \) Number of units in hydroelectric plant \( j \).

\( N \) Number of control buses.

\( n_s^t \) Real number of pumps to be “on at time \( t \).

\( N_b \) Number of storage systems in bus \( b \).

\( N_g \) Number of dispatchable power plants.
Nomenclature

$N_s$ Number of pumps in storage $s$.

$P_{j,sch}^t$ Capacity of the largest committed unit in the system at $t$, MW.

$P_{i,j}$ Generation in hydroelectric unit $i$ in plant $j$, MW.

$p_{p,s,max}$ Maximum power consumption limit of pump $p$ in storage $s$, MW.

$p_{p,s,min}$ Minimum power consumption limit of pump $p$ in storage $s$, MW.

$p_{p,s}^t$ Power consumption of pump $p$ in storage $s$ at time $t$, MW.

$Q_{p,s}$ Water inflow rate from pump $p$ to storage $s$ at highest mechanical efficiency, $m^3/s$.

$q_{p,s}^t$ Water inflow rate from pump $p$ to storage $s$ at time $t$, $m^3/s$.

$q_{s}^t$ Total water inflow rate to storage $s$ at time $t$, $m^3/s$.

$r_{s}^t$ Water outflow rate from storage $s$ at time $t$, $m^3/s$.

$RR_t^t$ Total regulation reserve requirement at time $t$.

$s_j$ Water Spillage through dam in hydroelectric plant $j$, $m^3/s$.

$SR_t^t$ Total spinning reserve requirement at time $t$.

$u_j$ Water release of hydroelectric plant $j$, $m^3/s$.

$V_{s,max}$ Maximum volume limit of storage $s$, $m^3$.

$V_{s,min}$ Minimum volume limit of storage $s$, $m^3$.

$V_s^0$ Initial volume of storage $s$, $m^3$.

$V_s^t$ Volume of storage $s$ at time $t$, $m^3$. 
Acknowledgements

I would have not been able to do this work without the help and assistance of my supportive advisor Dr. William G. Dunford and co-advisor Dr. Ebrahim Vaahedi. I would also like to thank Malcolm Metcalfe, my industry supervisor whose ideas encouraged me during this work. Great thanks to knowledgeable colleagues at Power System Group of ECE department at the University of British Columbia.

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Dedication

To my family...
Chapter 1

Introduction

1.1 Motivation

The existing electricity industry is unidirectional in nature. It converts only one-third of fuel energy into electricity and almost 8% of its output is lost along its transmission lines, while 20% of its generation capacity exists to meet peak demand only (i.e. in use only 5% of the time) [1]. Moreover, due to hierarchical topology of the equipment and their control structure, failures and effects of malfunctions penetrate to upstream and downstream regions. Advanced Metering Infrastructure necessitate realization of Smart Grid (SG) through enhanced demand side participation and bidirectional flow of power and information between supply and demand resources to overcome the growing power system challenges [2, 3]. Future grid requires high penetration of renewable energy resources, strict limits on greenhouse gas emissions and electrification of transportation systems. These factors drive transition from traditional grid to Smart Grid [4]. Smart Grid aims to increase power system efficiency, reliability and sustainability while maximizing utilization of current assets to delay investments required to meet increasing future energy needs [5, 6].

Permanent balance between generation and demand in real-time is the key to stable and reliable operation of electric power systems. Electric power system demand follows seasonal to daily cycles, which are predictable using demand forecasting methods. But the very short term and real-time component of system demand has stochastic characteristics imposing mismatches between generation and demand. In order to keep these mismatches within
1.1. Motivation

permitted levels while reducing balancing costs, a hierarchy of different balancing tasks is designed in Energy Management Systems (EMS) of operation centers. Generation resources are committed and dispatched economically to meet the demand. Since electric demand is a non-controllable stochastic fluctuating quantity, flexible generation units have traditionally been used as balancing tools to follow the demand. However, there are technical and economic constraints on the generation side that reduce generation flexibility and make energy balance a challenging task. Unexpected outages of loads, generation units as well as transmission and distribution lines also aggravate the problem. As renewable energy penetration increases, the variable and uncertain characteristics of demand become even more severe to handle. According to the report on annual energy outlook in [7], by 2035 the combined intermittent and non-dispatchable non-hydroelectric energy resources are expected to deliver 14% of total generation in electric energy. The consequent outcome of increasing this percentage is the need for installing/committing more expensive operating reserves and sub-hourly load-following capacity in generation units, increased wear and tear of thermal, gas and hydroelectric generation units and carbon footprint of non-renewable units.

Each generation unit has an efficiency characteristic for generating resources showing the efficiency of produced electricity in each operating point (output power). This efficiency characteristic is the most important element used in scheduling and dispatch routines to maximize the benefits of utilized resources. Operating reserves are provided by leaving a part of plant capacity for reserve, thus reducing the total achievable output power and operating the plant at lower efficiency than that of most efficient point. Thus generation unit owners suffer from lost opportunity costs associated with reduced capacity, increased mechanical wear and tear as well as generation efficiency loss.

It is widely accepted in industry and academia that these challenges in balancing generation and demand should be addressed and new measures
must be proposed and developed to facilitate the transition toward adoption of more renewable energy resources and operating the assets near their “knee” points. In other words, any attempt to increase asset utilization and generation efficiency would contribute in following the energy and utility industry road maps. These measures include new generation control architecture, balance logics and use of demand side response in different control time scales i.e. from primary frequency response to short-term and even long-term generation and demand scheduling routines. Proposing and developing these measures must be compatible with the state-of-the art technology in terms of metering, control and communication infrastructure to be accepted and adopted in electric energy industry. In other words, ideas and methods that are not economic neither compatible with today’s utility standards will have a very low chance of being adopted in real world.

1.2 Background

1.2.1 Generation-Demand Balance

As the electric power system demand changes or a deviation happens in generation from its schedule, an imbalance occurs in the system, which leads to operating in a new frequency deviated from nominal frequency [8]. In order to keep system frequency within reliable margins, different frequency control measures in different time frames are utilized in power systems. Autonomous and manual, centralized and decentralized generation and demand adjustments are implemented both ahead of time i.e. day-ahead and hour-ahead Unit Commitment (UC) and hour-ahead or in real-time i.e. Economic Dispatch (ED) and Load Frequency Control (LFC) [9].

The function of real-time Automatic Generation Control (AGC) in power system is to realize LFC and Economic Dispatch of generation units. LFC or frequency regulation is done in 2s-4s time steps to maintain system frequency within allowable limits by tracking the deviations of real-time system
1.2. Background

demand from forecasted demand and unintended fluctuations in generator outputs and matching the tie-line flows with the schedules [10]. Economic Dispatch is performed in sub-hourly time intervals (normally 5 min) to economically load different resources to minimize the generation costs subject to static and dynamic unit constraints and system-wide constraints [11]. Depending on type and characteristics of the dispatchable generation portfolio, the Unit Commitment program schedules hourly sets of committed generation resources to be dispatched in real-time and meet the system forecasted demand, regulation and contingency reserves.

1.2.2 Frequency Control Tasks

There are three types of frequency control: *primary*, *secondary* and *tertiary* frequency control [12]. *Primary* frequency control happens right after imbalances and includes effects of droop-based automatic response of governors, sensitivity of loads and frequency responsive load control. This type of control is fast and takes place in less than 1 min. If this response is not enough to bring frequency back to the desired range, centrally coordinated *secondary* frequency control takes place which is realized through maneuvering of flexible generation and loads to respond AGC signals. AGC signal is updated in 2s-4s time steps and economically dispatched among AGC assigned units. The response time is around 1-2 min. *Tertiary* frequency control is centrally coordinated dispatch of dispatchable resources in longer time steps to follow system slower demand variations. This task is also called “load following” or “ramping” service and takes place in Economic Dispatch time frame.

In interconnected power systems, utilities are synchronized through AC tie-lines. Tie-lines realize energy exchange between utilities and possibility of interactive frequency control support [10, 13]. Therefore, in interconnected operation mode, frequency related reliability risks are less than isolated operation mode. Interconnected operation has also provided utilities with high savings in balancing costs. Besides these benefits, control areas in each inter-
connection are responsible to continually adjust their generation and responsive demand to meet their internal demand and energy exchange obligation as well as the share of interconnection frequency control support. Since obligations change much faster than flexible generation and responsive demand, only the trend of them is followed by balancing tools. Therefore, frequency and interchange power fluctuate around their schedule [8, 9]. Accumulation of mismatches in frequency and unintended interchange power must be controlled to stay within permitted levels.

1.2.3 Frequency Control Standards

In order to fairly distribute the benefits of interconnection among all control areas, frequency control standards are defined by reliability coordinators [14, 12, 15]. Reliability coordinators continually monitor compliance of control areas and aim to develop new balance standards to increase the economic benefits of the interconnected operation while keeping reliability of interconnection in acceptable level. North American Electric Reliability Council (NERC) enforces reliability standards and regulations for all interconnections in North America under which each control area should be operated. These standards affect real-time frequency control measure of areas i.e. AGC. Once the new standards become effective, areas modify their AGC logic and balancing strategies to comply with the new requirements [16, 17]. Researchers also study the effects of new standards on dynamic and long-term statistical performance of generation control and evaluate benefits associated with the new limits and targets [18, 19, 20, 21].

Based on North American Electric Reliability Corporation’s latest frequency control draft known as Balance Resource and Demand (BRD) (BAL 007-01-1), each Balancing Authority is responsible “to maintain interconnection frequency within predefined limits under all conditions (i.e., normal and abnormal)”. As of Feb. 2013, 13 Balancing Authorities in the Eastern Interconnection, 26 in the Western Interconnection, the Electric Reliabi-
ity Council of Texas (ERCOT) and Quebec were under field trial for this standard and reliability coordinators continue to monitor the performance of participating Balancing Authorities [22]. This standard mandates Balancing Authorities to maintain clock-minute average of their Area Control Error (ACE) within frequency-dependent Balancing Authority ACE Limit (BAAL).

Wider ACE bounds allow system operator to make less costly generation maneuvering in real-time. In other words, less regulation capacity is needed to stay within new ACE limits. This leads to operation in more efficient points and less deviations in AGC assigned generation units. Doing so, a Balancing Authority could benefit from rotational energy storage in synchronous generators of interconnection.

Implementation of new AGC logics based on BRD standards, could accelerate adoption of more renewable energy resources and reduce overall system balance costs.

1.2.4 Demand Side Management

The relatively low average plant utilization and advances in communication, control and network infrastructures necessitate realization of a significant scope of Smart Grid i.e. Demand Side Management (DSM). DSM as a tool to shift system demand from peak periods to off-peak periods includes everything that is done on the demand side of energy system. Shaping the system demand would reduce the need for installing new generation capacity and as mentioned in part 1.1 new generation-based operating reserves. DSM also increases the utilization and efficiency of existing generation capacity [23][24]. The target of DSM as an alternative to conventional generation adjustment practices is to maximize economic benefits of power system while fulfilling reliability concerns in terms of maintaining frequency error within tolerable limits [4][25][26].

Electric energy infrastructure is very expensive and power system plan-
1.2. Background

ners tend to reduce and/or defer huge capital investments to meet the growing electric demand. So the new philosophy of power system operation is to keep demand fluctuations as small as possible to decrease the needed flexibility and increase system efficiency. Adding communication infrastructure and intelligent decision making tools to current power systems to achieve responsive demand does not require huge investments compared to conventional alternatives i.e. making new generation, transmission and distribution infrastructures, so demand manipulation is believed to be economic and reliable resource in power system operation. Historically, under frequency, under voltage and fast manual load shedding have been used by operators in emergencies, but the utility-level nature of these acts make them disruptive for customers, so operators hesitate to implement them frequently.

NERC defines DSM as an important element among all required resources to meet the increasing demands for electricity in North America [27]. As seen in Figure 1.1, based on [27] DSM includes two components: Energy Efficiency (EE) and Demand Response (DR). Energy Efficiency programs aim to reduce overall energy consumption in all hours of a day by putting stress on end-user energy solutions in order to solve long-term problems e.g. environmental effects of burning fossil fuels. In addition to energy savings, Energy Efficiency can reduce peak demand and avoid/defer new investments. Short-term problems, on the other hand, can be handled by demand management programs which are referred to as Demand Response. Demand Response is defined as responsiveness of customers to price or control signals from utility to change the timing, level of demand or total energy consumption. Demand Response can be exercised in different time intervals from seconds to several hours or an entire day to serve utility as well as consumers. Demand Response programs aim to influence system reliability through peak demand reduction in periods of high market prices or low-reserve conditions rather than reduction in overall energy consumption [6, 28, 29].

Figure 1.2 demonstrates classification of Demand Response. NERC clas-
1.2. Background

Figure 1.1: Classification of Demand Side Management

Figure 1.2: Classification of Demand Response
sifies Demand Response programs as Dispatchable and Non-Dispatchable [27]. Non-Dispatchable Demand Response programs motivate end users to reduce their total energy consumption or shift their consumption to low risk time intervals to reduce costs or increase reliability. Dispatchable Demand Response programs are implemented through customer response to direct control signals from utility for better asset utilization and running in better operating points to enhance reliability and efficiency. The Federal Energy Regulatory Commission (FERC) order 719 [30] and order 745 [31] promote participation in Demand Response programs and discuss compensation rules and initiatives. Current Demand Response programs in electricity markets are based on voluntary or directly controlled load curtailments or load reductions to support the power grid while providing a revenue stream for participating customers and aggregators [6, 28]. Demand Response provides excellent opportunities to avoid/defer investments required to meet the current fluctuating demand and reduce the overall energy price. However, load curtailments or load reductions cause temporary discomfort for the participants. This inconvenience limits their deployment frequency and duration.

1.2.5 Demand Side Energy Storage - Demand Dispatch

Since demand manipulations of Demand Response programs are not able to serve power system continuously, there always have been efforts to find solutions to fix demand fluctuations problem. One solution could be adding storage capacity to power grid. Energy Storage Systems (ESS) such as batteries, super capacitors, flywheels and Superconducting Magnetic Energy Storage (SMES), etc. have been suggested for facilitating intermittent generation integration, improving grid reliability and power quality, enabling energy arbitrage, transmission distribution investment deference and providing ancillary services in [32, 33, 34, 35]. The main drawback of using these storage systems with a power electronics interface is their high capital cost,
low energy density, low cycle efficiency and potential adverse environmental effects [34].

In contrast, inherent storage and flexibility of some residential, commercial and industrial loads make them capable of immediately and continuously responding to control signals of the system operator significantly faster and more accurately than conventional generation resources [36]. These loads can be called Demand Side Storage (DSS) and used as Demand Response products in control hierarchy of power generation to enhance generation efficiency and system reliability. The capability to permanently aggregate and control loads rather than just at peak times is called Demand Dispatch (DD). Demand Dispatch is an important enabling technology to increase penetration of intermittent renewable generation through providing grid balance service [26, 37, 38, 39, 40]. Industrial processes such as water pumping in drinking water storage systems, aeration in wastewater treatment plants, industrial heating and refrigeration have an inherent flexibility within their existing assets [41]. This flexibility provides required storage to be used in active power manipulation tasks such as AGC. These processes have enough power capacity, energy storage and no adverse reactive effect on the grid that make them suitable resources for grid balance applications. Their cycle efficiency is also very close to 100%. These loads can be used to provide real-time services to power system while fulfilling their primary obligation.

Some electricity markets have accepted loads to provide regulation as a regular indefinite response service [6]. Midwest Independent System Operator (MISO) [42] and Southwest Power Pool (SPP) [43] have also accepted behind the meter generation or controllable load among energy, reserve and regulation resources as long as the loads comply with telemetry standards and can follow dispatch commands. In this thesis, fast, continuous and indefinite response of the loads is called Demand Dispatch.
1.3 State-of-the-Art Research

Applications of DSM or Demand Response in Generation-Demand balance in Independent System Operator (ISO) and Vertically Integrated utility (VIU) environments have drawn considerable attention in the literature in recent years. Some researchers have focused on the concepts and general aspects of DSM and Demand Response while others have seen the problem from wholesale markets or retailers point of views.

DSM can be implemented by scheduling charging Electric Vehicles (EV)s and ESSs, consumption of home appliances, Heating, Ventilation and Air-Conditioning (HVAC) loads in office areas and flexible industrial processes with inherent storage. Direct Load Control (DLC) and Smart Pricing (SP) are two main approaches used to affect system demand profile to follow intermittent energy feed-ins, reduce peak demand and limit the imported power from main grid connections. These approaches aim to flatten system demand by shifting consumption from peak times to off-peak times. Inefficient loading and committing extra local fossil-based generation units could also be avoided by demand manipulations.

1.3.1 Frequency Control

Benefits of Demand Response in grid balance have been studied in different frequency control levels and time frames.

Primary Frequency Response

An adaptive frequency restoration plan based on Demand Response designed in [44] to affect primary frequency response in contingency events. Authors in [45] proposed a method to directly control domestic loads by smart meters to improve primary frequency response of the power system. The effect of dynamic demand control on system frequency stability is studied in [46] and it is concluded that incorporating controllable frequency-dependant loads
1.3. State-of-the-Art Research

could result in a delay in frequency fall and reduction in backup rapid generation capacity in contingency events. Pourmousavi et al. proposed real-time central demand response scheme to improve primary frequency response in smart Microgrids [47].

**secondary frequency response**

Keyhani presented a new AGC structure based on response times of different assets in power system to overcome the drawback of intermittency in smart power grid [25]. Cheng et al. proposed a dynamic model to distribute AGC signal among utility level energy storage systems to increase their performance [48].

1.3.2 Aggregator Design

There are many papers in the literature on optimal scheduling and charging strategies of EVs in Vehicle-to-Grid (V2G) connections and design of aggregation schemes to provide ancillary services e.g. regulation reserve or spinning reserve in ISO environment and improve power quality. The objectives are maximizing the benefits of aggregators and reducing the discomfort for load owners.

**Ancillary Services**

Optimal charging of grid connected EVs to maximize the benefits of aggregators is considered in several recent publications. Sortomme et al. proposed unidirectional [49, 50] and bidirectional [51] charging strategies by dedicating capacities of Vehicle-to-Grid connections to spinning reserve and regulation reserve services to be sold in electricity markets. Han et al. also proposed a dynamic programming based aggregation design for frequency regulation providers [52]. A two-level optimization is proposed in [53] to minimize the total cost of electric vehicles charging and discharging in stations. Han et al.
1.3. State-of-the-Art Research

proposed a method of estimating the available power capacity from Vehicle-to-Grid to be used in aggregation design for regulation reserve providers [54]. Dallinger et al. designed a regulation reserve aggregation scheme for Vehicle-to-Grid based on dynamic simulation of mobility behavior [55].

Power Quality

Once the adoption of EVs and Vehicle-to-Grid connections become considerable, the effects of charging and discharging on distribution feeders are critical. Shahidinejad et al. studied profile of charging Vehicle-to-Grid loads on the grid using a large database of field-recorded driving cycles, parking times and locations [56]. A realistic driving habit pattern is estimated based on this information and effects on hourly load pattern is modeled. Authors in [56] proposed a coordinated charging algorithm for EVs to minimize power losses and voltage deviations on distribution feeders.

1.3.3 Residential Load Control

Direct Load Control

DLC approach is based on a central Energy Management System which schedules and remotely controls the operation and energy consumption of each controllable asset. This can be implemented via smart meters enabled with two-way digital communication with EMS [2, 3]. Depending on the utility or market type, different optimization problems are formulated and solved. In residential DLC schemes, system operator controls operation and energy consumption of appliances e.g. residential air-conditioning [57, 58], space heating [58, 59], electric water heating [60] and EVs [61].

References [62, 63, 64] proposed models for loads participating in DLC and solved optimization problems to find the savings in generation costs. Ng et al. in [65] introduced a method to determine the number of groups of power customers to maximize the profits of utility. Chu et al. [66] presented
an objective function to minimize the amount of load reductions to reduce inconvenience of customers while taking advantage of load reduction in utilities. Scheduling the interruptible and curtailable loads from aggregators point of view is considered in [67]. However, all these contributions are in load reduction framework.

**Smart Pricing**

SP as another approach motivates end-users to shift their consumption from peak times to off-peak times. Following this scheme, consumers change their consumption pattern voluntarily without losing their privacy. Doing so, residential consumers tend to reduce their energy bills while enabling utilities and retailers to benefit from reduced peak demand and wholesale energy costs. Decentralized approaches in SP schemes are based on individual decision makings which may be optimal based on amount of information used in coordination algorithms. Lack of knowledge to properly schedule residential energy consumption and Advanced Metering Infrastructure are main challenges to fully utilize SP measures [68].

Conejo et al. in [69] presented an optimization model to adjust hourly consumption of a customer in response to hourly prices of energy. The objective of the model is to maximize the utility of the consumer subject to a minimum daily energy-consumption level, maximum and minimum hourly load levels, and ramping limits on such load levels. A power consumption scheduling module is proposed in [70] to provide economic benefits for customers. In this work, price of electricity is assumed to be time-varying. The scheduler has access to past and current prices, but only statistical knowledge about future prices, which it uses to make an optimal decision in each time period. Mohsenian Rad in [68] proposed an optimal energy scheduling unit and a price predictor unit for a residential customer in retail market environment. This design is based on a two-way communication capability between individual end-users and utility which enables receiving updated price in-
1.3. State-of-the-Art Research

formation [3, 2]. It is shown that in a general SP environment, not only Peak-to-Average Ratio of aggregate response is decreased, but also user’s payments are significantly reduced which consequently provide incentives for residential consumers to follow prescriptions of energy scheduling system. In [71] same author argues that DSM based on individual interactions between utility and each user does not necessarily lead to best solution in energy consumption problem. Alternatively, an energy scheduling design based on desired aggregate load response is designed and it is assumed that interactions among all users are enabled via two-way digital communication.

1.3.4 Power System Support

Once the volume of Demand Response in the power system reaches to a considerable level, effects of Demand Response on distribution and transmission network will be a contributing factor in Demand Response scheduling. Medina et al. in [72] modeled the distribution network in DR scheduling problem. They proposed changing the business process of Demand Response scheduling and implementation by integrating Demand Response with distribution grid topology. An event-driven load reduction scheme is proposed in [73] to enhance system security. Coordinated Vehicle-to-Grid charging is proposed in [74, 75] to minimize distribution system losses.

1.3.5 Market Operation

A summary of Demand Response implementation in electricity markets is reported in [6] and [28]. Nguyen et al. in [76] proposed a concept of Demand Response exchange to optimize the overall benefit of Demand Response by enabling the participants to deal with other DR-involved players in the market. Authors in [77] proposed a market-clearing tool which offers consumers the opportunity to reduce their energy costs by submitting shifting bids. Parvania et al. in [78] proposed a stochastic Security Constrained Unit
1.4. Research Objectives and Anticipated Impacts

The main research goal in this thesis is to reach alternative approaches in Generation-Demand balance task of a VIU e.g. BC Hydro. The main objectives in reaching alternative approaches are increasing hydroelectric generation efficiency and reducing mechanical wear and tear on conventional generation units. These approaches are based on existing and future balance standards. In order to achieve these goals, two criteria are considered:

- Generation-Demand balance using DSM as an important ingredient of Smart Grid paradigm
- Generation-Demand balance with generation units under new limits imposed by BRD draft standard

Objectives
The detailed research objectives and contributions of this PhD thesis are as follows:

1.4.1 Objective 1: Modeling Industrial Flexible Loads as Demand Side Storage (DSS)

There are some publications that introduce Demand Dispatch as a valuable alternative to traditional balancing resources [38, 79, 37, 26]. The continuous, repeated and non-interrupted service characteristic of flexible loads that does not lead to discomfort for the owners is highlighted in these publications.
1.4. Research Objectives and Anticipated Impacts

However, the exact modeling of Demand Dispatch resources in different balancing time frames i.e. Economic Dispatch and AGC is not reported in the literature. In other words, all published works are based on the “possibility” of using the inherent flexibility of some industrial loads as Demand Dispatch balancing tools. The focus in this research has been exact modeling of this flexibility.

The communication infrastructure, metering and control technology of making a network of flexible industrial loads under remote control is available and the sponsor of this research is one example. One economic load which is under operation for providing regulation reserve in ISO environment is water pumping in drinking water storage systems. Using this kind of flexible load as balancing tool in DLC formulation and VIU environment is one main contribution of this thesis. In order to use this load as a Demand Dispatch balancing tool, the inherent storage is modeled based on characteristic curve, efficiency model, physical and operational limits. Real physical and operational data of this load was given by the sponsor of the research.

1.4.2 Objective 2: Demand Side Storage as a Sub-hourly Demand Dispatch Product

Although Generation-Demand balance with DSM is topic of many research projects in recent years, to the best of our knowledge, there is no work reported in area of grid balance structure based on Demand Dispatch in VIUs. In other words, all of the published works have focused on curtailable Demand Response programs and load-based operating reserve capacity aggregation formulations to find the benefits for the customers and/or the aggregators. In VIU framework however, application of industrial load based Demand Dispatch has not been considered in published research works.

This flexibility of industrial loads provides required storage to be used in active power manipulation tasks such as Economic Dispatch. These processes have enough power capacity, energy storage and no adverse reactive effect.
1.4. Research Objectives and Anticipated Impacts

on the grid that make them suitable resources for grid balance applications. Their cycle efficiency is also very close to 100%. These loads can be used to provide ongoing services to power system while fulfilling their primary obligation. This flexibility however, is limited to different operational and physical constraints. The most important one is “limited energy” that could be absorbed or released in Economic Dispatch time frame. In traditional practices of power system operation, there is no constraint on produced energy in generation units. Designing a balance logic which includes “energy constraints” for responsive loads is necessary to add Demand Dispatch resources to dispatchable assets in Economic Dispatch time frame. Formulation of a system-wide balance structure is another contribution of this thesis.

1.4.3 Objective 3: An AGC Logic Based on Maximum Benefits From BRD Draft Standards

Frequency control standards have evolved during decades of interconnected operation to fairly distribute the benefits among all tied Balancing Authorities. These benefits include increasing the frequency reliability and reducing the balancing costs in a fairly manner. Adoption of each new standard is reported to realize millions of dollars of savings in balancing costs for Balancing Authorities [12, 14].

Once a standard becomes accepted, researchers in academia and industry focus on evaluating the existing AGC logics under new standards. Their goal is to ensure compliance with new standards and find the amount of resources required to be dedicated to frequency control. The other goal is to increase Balancing Authorities benefits in terms of less generation maneuvering and more generation efficiency. Although reliability coordinators tend to decrease balancing costs for all utilities in a fairly manner, it is the responsibility of each Balancing Authority to asses the existing AGC logics under new standards and improve their benefits by developing new AGC logics while meeting the requirements of the new standards.
Although lots of Balancing Authorities in all North American interconnections are under field trial of NERC’s draft standard BRD, to the best of our knowledge there is no published work in this area in the literature. No evaluation study is reported and no new AGC logic is proposed based on BRD standards. Since Balancing Authorities could consider new wide limits of BRD standards as an alternative to investments on utilizing different balancing resources e.g. DSM and ESSs, the second part of this thesis is focused on this topic. One main contribution of this thesis is to propose an AGC logic to gain new limits and maximize the benefits of a hydroelectric dominated Balancing Authority e.g. BC Hydro. A heuristic AGC logic is proposed to maximize the hydroelectric generation efficiency and decrease the mechanical wear and tear.

Anticipated Impacts
The outcome of this thesis regarding objective 1 is introducing another application for a State-of-the-Art technology of using a network of water pumping loads in drinking water storage systems. Regarding objective 2, the outcome is introducing a sub-hourly balance logic formulation which maximizes the hydroelectric generation while not compromising the operation of flexible loads as Demand Dispatch resources. Proposing a new AGC logic based on BRD which is elaborated as objective 3, would impact the existing AGC logics and be implemented to reduce the balancing costs. All these applications could be implemented in a hydroelectric dominated VIU e.g. BC Hydro.

1.5 Thesis Outline
This thesis consists of 5 chapters. The current chapter introduces the motivation and objectives of this work as well as a brief background on the topics. A literature review is also included in this chapter which introduces the main related works in this area. Chapter 2 provides a detailed description of the models used as prerequisites to the proposed generation control schemes in
this work. In other words, materials of chapter 2 are used to implement the balance schemes which are tied to the proposed balance schemes. In chapter 3, a sub-hourly Generation-Demand balance control structure based on Demand Dispatch is proposed. The balance logic is formulated to increase hydroelectric generation efficiency and not to compromise the main operation of the loads. Moreover, an industrial flexible load is modeled for this application. Chapter 4 describes a real-time generation control method based on NERC’s BRD standards. In this chapter, an AGC logic is developed to maximize the benefits of a hydroelectric dominated VIU. Finally, chapter 5 presents a summary of the contributions of the work and comments briefly on the future directions.
Chapter 2

Generation-Demand Balance

2.1 Introduction

Due to the randomness of the demand in power systems and different operative characteristics of different generating resources, there is a consistent mismatch between total generation and total demand in electric power system. Any imbalance between generation and demand will induce a deviation in system frequency from the nominal frequency value (60 Hz in North America). The dynamic and magnitude of this deviation depends on the characteristics of constantly fluctuating loads and intermittent generation resources and dynamic of rotating masses in the power systems i.e. rotors of generators. Permanent balance between generation and demand in real time is the key to reliable operation of the electric power system. In order to keep these variations within permitted levels, three different operation planning processes are used: Unit Commitment, Economic Dispatch and Frequency Regulation. Each process has different time scale and must consider adequate reserve \[80, 81, 82\].

Operating reserve is the generating capacity available to the system operator within a short interval of time to meet the demand in case a generator goes down or there is another disruption to the supply. Regulation reserve is defined as a generation capacity within which output power of some generators can swing to compensate for the error between total demand plus interchange power and generation in a specific multi-area interconnection\[1\].

\[1\] Multi-area interconnection is comprised of regions, or areas, that are interconnected by tie-lines.
2.1. Introduction

Figures 2.1 and 2.2 illustrate the concept of spinning reserve and regulation reserve in a generation unit. Each generation unit has a maximum and a minimum operating point. Depending on the current generation level and ramping capability of the unit, part of the generation capacity is available as spinning reserve. As shown in Figure 2.1 in each operating interval the unit is loaded in a base point. The green area in each operating interval shows the amount of feasible increment in output power from the base point in cases of emergencies i.e. spinning reserve. Since the base point is near maximum unit capacity in interval 1, there is less room for increment in output power. Therefore, the spinning reserve is less than intervals 2 and 3. Figure 2.2 illustrates the same concept for regulation reserve capacity of units where dark and light orange areas show the room for regulation down and regulation up in each sub-hourly interval, respectively.

In this chapter, hierarchy of balance tasks in power systems is introduced. Different tasks and their objectives are described in section 2.2. Sub-hourly and real-time generation control schemes proposed in this thesis are tied to the classic tasks of hydro Unit Commitment and hydro Economic Dispatch, respectively. In order to model and implement the proposed generation control schemes in a simulation environment, Unit Commitment and Economic Dispatch modules in a hydroelectric dominated utility should also be implemented. Section 2.3 describes exact modeling of generation loss function in hydroelectric generation units. This loss function as the main driving factor, is used in hydro Unit Commitment and hydro Economic Dispatch models used in this thesis. Hydro Unit Commitment model of section 2.4 is used in both sub-hourly and real-time generation control schemes of chapters 3 and 4. In other words, the output of Unit Commitment model of section 2.4 is fed to the input of the proposed sub-hourly and real-time models. The output of hydro Economic Dispatch model of section 2.5 is fed to input of the proposed real-time model of chapter 3. Therefore, this chapter is dedicated to elaboration of the concepts and mathematical models of Generation-Demand
2.1. Introduction

Figure 2.1: Spinning reserve capacity compared to generation capacity in sub-hourly control time steps

Figure 2.2: Regulation reserve capacity compared to generation capacity in sub-hourly control time steps
balance tasks and generation loss functions used in this thesis.

2.2 Balance Hierarchy

Each utility uses different generating resources to meet the total demand of the power system. For example, BC Hydro operates 31 hydroelectric facilities and three thermal generating plants, totaling 12,000 MW of installed generating capacity. Over 95% of the total generated electricity is from hydroelectric facilities which are located throughout the Peace, Columbia and Coastal regions of Advanced Metering Infrastructure and three thermal generating plants provide the remaining [83].

As the competition in power industry increases, each utility realizes to maximize the value of their resources at different levels of planning. The hierarchical approach for maximizing the benefits of resources is divided to several operation planning models with different time steps and computational burden. Advanced Metering Infrastructure Hydro uses three levels of operation planning to maximize its benefits [84]:

- Strategic long-term operation planning which covers 1 to 4 years with a monthly time step
- Medium-term optimization over a daily or weekly time step for up to a year
- Short-term optimization with an hourly or sub-hourly time step with two components. Short Term Optimization Model (STOM), which produces an optimal plant schedule for up to a week [85]; and the Dynamic Unit commitment and Loading model (DUCL) [84], which takes STOMs optimal plant generation schedule and produces an optimal DUCL schedule covering every time step

On top of this operation planning tasks, real-time frequency regulation is implemented in 2s-4s time steps through AGC.
2.2. Balance Hierarchy

Figure [2.3] illustrates the hierarchy of control tasks and their execution frequency and time steps in a typical power system generation-demand balance scheme.

2.2.1 Unit Commitment (UC)

Unit Commitment is a day-ahead (or hour-ahead) decision making tool which has complex computational models, technical and operational constraints to optimize generating units to be scheduled for next day to meet the hourly forecasted demand at minimum cost. This process also schedules the additional required units for operating reserve while considering enough regulation reserve capacity for frequency control which are required for reliable and secure operation of power system. Therefore, depending on the costs of generation and reserve resources, Unit Commitment model can select the most economic solution among all available and possible states to supply total forecasted demand and required reserve capacity.

For example, Advanced Metering Infrastructure Hydro uses STOM to maximize the benefits of its resources. This is subject to meeting the domestic load demand and making optimal trade-off between present benefits and the potential expected long-term value of resources [85]. The output of this model is hourly plant schedules, which are passed to DUCL model that minimizes the use of water in hydroelectric facilities based on water usage and start-up/shut-down costs and the value of energy and reserves in sub-hourly time steps [84]. This model selects the most economic commitment and loading in each time step and leaves enough space for regulation and operating reserves [86, 87, 88, 89, 90].

2.2.2 Economic Dispatch (ED)

Economic Dispatch is the process of allocating loads among committed generation units in an economic way subject to static and dynamic constraints
2.2. Balance Hierarchy

Figure 2.3: Control hierarchy in power system operation
of units and transmission system [11, 91, 92]. Although Economic Dispatch can be a separate program in real-time Energy Management System of power systems, some utilities have Unit Commitment programs including Economic Dispatch program that dispatches the load economically among committed units. Another target of real-time Economic Dispatch program is to compensate the load forecast error, which is not available in day-ahead or real-time load forecast models. The output of this program is the operating points of generating units in sub-hourly time steps e.g. 5 min. Depending on the constraints considered in Economic Dispatch process, different terminologies are used in literature e.g. Dynamic Economic Dispatch (DED) [93], Reserve Constrained Economic Dispatch (RCED) [94] and Security Constrained Economic Dispatch (SCED) [95]. Also mathematical modeling and optimization algorithms highly depend on characteristics of cost curves and types of constraints. Since load forecast modules can be run in sub-hourly time steps, some papers suggest implementing a real-time Dynamic Economic Dispatch (DED) based on the most updated load forecast [96]. As the communication infrastructure and computation speed of optimization routines improve, the balancing tasks can be done in smaller time steps. For example, Real-time Unit Commitment (RTUC) and Real-time Dispatch (RTD) processes take place in 15 min and 5 min time steps in California Independent System Operator to handle the 5 min to 5 min energy imbalances.

2.2.3 Frequency Regulation

Regulation is the function used to track the minute-to-minute fluctuations in system load and unintended fluctuations in generator output, in conjunction with ramp-up and ramp-down load-following process to comply with reliability standards. AGC is the system that each interconnection in power system should be equipped with to implement regulation [10]. Regulation demand of the system is usually met by leaving some generation capacity for AGC assigned units and running generation units in operating points lower than
2.3. Hydroelectric Generation Efficiency

most efficient points. In other words, AGC assigned units will be online, spinning and produce electricity at certain points called Preferred Operating Point (POP), which have enough space to move up and down, based on operating control signals (2-4 seconds signals) as shown in Figure 2.4. Given the regulation reserve capacity, Unit Commitment and Economic Dispatch models leave the required space for AGC assigned units to swing up and down. As the average total demand of the system changes over longer time periods (5 to 10 min), the AGC units may have insufficient space to compensate for load fluctuations in shorter time periods. Therefore, a ramp-up or ramp-down load-following action is required to re-establish the AGC units in better set-points [9].

2.3 Hydroelectric Generation Efficiency

In hydroelectric dominated utilities with multiple reservoirs, various scheduling modules (long-term, short-term and real-time) with different time frames are implemented to maximize the value of water resources [84]. Short-term hydro scheduling models produce optimal daily plant generation, water discharge/spillage and energy/reserve import/export schedules for up to a week [86, 87]. In real-time dynamic Unit Commitment models, most efficient or water constrained units are base-loaded at the optimal schedules obtained from short-term models while less efficient ones are partially loaded in swing mode to meet the required reserve capacity to realize load-following and regulation. The proposed generation control method in this thesis is tied to the real-time operation of swing plants/units which are already selected in short-term hydro scheduling models. So the short-term scheduling models are excluded from the study. Moreover, it is assumed that swing plants are not constrained to discharge maximum water to avoid spillage.
2.3. Hydroelectric Generation Efficiency

2.3.1 Generation Loss Function

In any generation scheduling and operation practice, power loss in hydroelectric generation is the main driving factor of the optimization routines. Generation of a unit in a multi-unit hydroelectric power plant is a function of turbine efficiency, generator efficiency, water discharge and effective water head as \[86\]:

\[ P_{i,j} = g \cdot \rho \cdot \eta_{t,i,j} \cdot \eta_{g,i,j} \cdot h_{e,i,j} \cdot d_{i,j} \cdot 10^6 \]  

(2.1)

where \( P_{i,j} \) (MW) is generated power in unit \( i \) in plant \( j \), \( g \) (m/s\(^2\)) is acceleration of gravity, \( \rho \) (kg/m\(^3\)) is water specific weight, \( \eta_{t,i,j} \) (%) is turbine efficiency of unit \( i \) in plant \( j \), \( \eta_{g,i,j} \) (%) is the efficiency of generator \( i \) in plant \( j \), \( h_{e,i,j} \) (m) is the effective water head of unit \( i \) in plant \( j \) and \( d_{i,j} \) (m\(^3\)/s) is water discharge in unit \( i \) in plant \( j \).

The effective water head \( h_{e,i,j} \) of unit \( i \) in plant \( j \) depends on forebay elevation, tailrace elevation and penstock head loss as:

\[ h_{e,i,j} = h_{f,j} - h_{t,j} - h_{p,j} \]  

(2.2)

where \( h_{f,j} \), \( h_{t,j} \) and \( h_{p,j} \) are forebay elevation (m), tailrace elevation (m) and penstock head loss (m) of plant \( j \), respectively.

As seen in the equations, the power generation in hydroelectric units depends on many variables. The most important variable is water discharge \( d_{i,j} \) (m\(^3\)/s). Output power generation is controlled through changing valve position in turbines which affect water discharge through the turbine. Therefore, generated power in a hydroelectric units is often expressed as an input-output ratio of water discharge-generated power in (MW/m\(^3\)/s) which in turn depends on effective head effect and turbine efficiency.

There are different ways of modeling hydroelectric generation efficiency among which representing generation loss in different output powers of plant has been adopted more in the literature \[86, 88, 89\]. In order to model generation efficiency by a generation loss function, the influence of each variable
of (2.1) on power generation is considered.

**Forebay Elevation**

Forebay elevation is an important factor in mid-term and long-term operational planning of hydroelectric reservoirs. As mentioned in part 2.2, mid-term and long-term operational planning consider a time period of one or more years in weekly or monthly time steps and optimize water level in the reservoirs. On the other hand, in short-term operation planning and real-time dispatch, changes in water level in the reservoirs are negligible. This assumption is more valid in the case of larger reservoirs like the ones in Advanced Metering Infrastructure. Since the proposed generation control schemes of chapters 3 and 4 are in sub-hourly dispatch and real-time operation and the reservoirs are assumed to be large as the ones in Advanced Metering Infrastructure, the forebay elevation is assumed to be constant in evaluating generation loss functions.

**Tailrace Elevation**

Unlike forebay elevation, tailrace elevation could change considerably depending on the amount of released water in the power plant. Increasing the amount of released water through the dam leads to an increase in tailrace elevation. Increasing tailrace elevation decreases the effective water head as in (2.2), consequently.

The tailrace elevation of the plant depends on the released water as [87]:

\[ h_{t,j} = a_0 + a_1 u_j + a_2 u_j^2 + a_3 u_j^3 + a_4 u_j^4 \]  

where \( a_k \) is the \( k^{th} \) degree term coefficient of the 4-degree polynomial model and \( u_j \) is the water release of plant \( j \). The water release is related to water discharge as:

\[ u_j = d_j + s_j \]  

(2.4)
2.3. Hydroelectric Generation Efficiency

where \(d_j\) and \(s_j\) are the total water discharge and water spillage in plant \(j\), respectively. Total discharge of a plant is the sum of unit discharges:

\[
d_j = \sum_{i=1}^{k_j} d_{i,j}
\]  

(2.5)

where \(k_j\) is the number of units in hydroelectric plant \(j\).

Penstock Loss

Penstock head loss \(h_{p,j}\) represents frictional loss in the penstock and is modeled as a quadratic function of water discharge \([87]\):

\[
h_{p,j} = \beta_{i,j} \cdot d_{i,j}^2
\]  

(2.6)

where \(\beta_{i,j}\) is penstock loss constant in \((s^2/m^5)\).

Turbine Efficiency

Turbine efficiency \(\eta_{t,i,j}\) of each unit is a measure of the relation between the potential energy of water discharge in the unit and the output mechanical produced energy. Turbine efficiency is usually expressed as a function of the unit discharged water or unit output power, usually known as “hill-curve”. Figure 2.5 shows a typical efficiency curve of a single hydroelectric unit.

As seen in the figure, as the discharge of water increases, the efficiency increases up to a maximum value \(\eta_{\text{max}}\) (point \(B\)) and then starts to decrease afterwards. To avoid vibration and cavitation, a permissible operating range \(d_{\text{min}}-d_{\text{max}}\) is defined for each effective water head which is between points \(A\) and \(C\) in Figure 2.5.

Reduction in turbine efficiency leads to an equivalent generation loss. This generation loss in a given forebay elevation, can be calculated based on deviations from maximum efficiency \(\eta_{\text{max}}\) of point \(B\) as a reference point.
2.3. Hydroelectric Generation Efficiency

Operation of turbine in points other than point $B$ leads to generation loss:

$$p_{\eta, i,j} = g \cdot \rho \cdot (\eta_{t, i,j} - \eta_{t, i,j, max}) \cdot h_{e, i,j} \cdot d_{i,j} \cdot 10^6$$  \hspace{1cm} (2.7)

where $p_{\eta, i,j}$ (MW) is the generation loss due to drop in efficiency of turbine of unit $i$ in plant $j$ and $\eta_{t, i,j, max}$ (%) is the maximum turbine efficiency of unit $i$ in plant $j$.

**Generator Efficiency**

Generator efficiency $\eta_{g, i,j}$ is a measure between input mechanical energy to the generator and output electric power. In this range of operation, generator efficiency changes by 2% according to [86]. This can be assumed to be a linear change between 96.5% and 98.5%. However, upon availability of real data, exact values of generator efficiency could be obtained by interpolating among generator efficiency data points.

**Total Power Generation Loss**

After evaluating the effects of each variable of (2.1) in generation efficiency, the total power generation loss function for a multi-unit hydroelectric plant with identical units is calculated by algorithm shown in Figure 2.6. As seen in the flowchart, calculation of generation loss starts from an initial water discharge of plant. Since the units are identical, water discharge of the units are simply found as:

$$d_{i,j} = d_j / k_j$$  \hspace{1cm} (2.8)

However, if the units are different, total plant discharge should be distributed optimally among various units.

After calculations based on Figure 2.6 a polynomial function could be fitted to the obtained points. The non-linear Least Squares curve fitting tool of MATLAB [97] was used to fit a polynomial function to the obtained curve. A 2-degree polynomial (quadratic curve) is selected because of relatively good
2.3. Hydroelectric Generation Efficiency

accuracy and simplicity. For a multi-unit hydroelectric power plant, a generation loss curve is derived for every unit combination [86]. These curves could be used in models of Unit Commitment, Economic Dispatch and the proposed generation control schemes of chapters 3 and 4. As expected, the generation loss curve represents combined efficiency losses from tailrace elevation effect, penstock friction effect and overall turbine-generator efficiency characteristics at different loadings of the plant.

Figure 2.7 depicts total generation loss curve for a 4-unit plant when different numbers of units are in operation. It is seen that the plant has higher combined efficiency when more units are operated. For example, unit 1 has about 3 MW of generation loss at 150 MW of generation. This point corresponds to maximum mechanical efficiency of one turbine. However, the combined generation loss when 2 identical units are operated has minimum loss of slightly more than 4 MW, which is more efficient than running 2 units independently (at 2 different reservoirs). Moreover, the combined efficiency curve at higher number of “on” units is wider. This means that, for a specific constant deviation from optimal points in generation axis, generation loss has less increase in higher number of “on” units compared to the lower number of “on” units.

Efficiency and unit characteristics given in [88] are used here. The curves are convex and a quadratic function could be fitted to each one.

2.3.2 Start-up and Shut-down Costs

It is obvious that starting up or shutting down of turbines in generation units have negative effect on their maintenance costs and service life. However, exact modeling of these costs is almost impossible. Reference [98] describes the main cost factors of start-up and shut-down of hydroelectric generating units based on experience of major electric energy producers in Sweden. This reference also evaluates the associated costs and effects on short-term operation planning of hydroelectric units. In this thesis, we scale the costs
evaluated in [98] to the size of considered generation units.

2.4 Hydro Unit Commitment

In this section, the objective of minimizing the number of start-ups and shut-downs of generating units is combined with the objective of minimizing power generation losses through formulation of the hydro Unit Commitment problem.

2.4.1 Problem Formulation

The problem of scheduling the number of generating units in operation on an hourly basis in a multi-unit hydroelectric plant is formulated as a dynamic discrete optimization model. A trade-off between hydroelectric generation efficiency and the start-up and shut-down of generating units can be expressed by an objective function containing both elements. The problem of optimizing the number of operating units in a multi-unit power plant on an hourly basis can be formulated as [86]:

\[
\min_{n^h, P^h} \sum_{h=1}^{24} \{c_{ap} \cdot |\Delta n^h| + c_p \cdot GL(n^h, P^h)\} \\
\text{s.t.} \quad n^h = n^{h-1} + \Delta n^h \\
\quad n_{min}^h \leq n^h \leq n_{max}^h
\]

(2.9)  
(2.10)  
(2.11)

where \( n^h \), \( n_{min}^h \) and \( n_{max}^h \) are the number of “on” units in plant, minimum and maximum number of “on” units in operation in hour \( h \), respectively. Parameters \( c_{ap} \) and \( c_p \) are start-up or shut-down unit cost (\$/start – up) and power generation loss cost (\$/MWh), respectively. \( GL \) is the generation loss function of plant when \( n^h \) units are in operation in hour \( h \) and \( P^h \) is the hourly generation of plant in (MWh). Generation loss function was modeled
2.4. Hydro Unit Commitment

in section 2.3. After scaling the costs evaluated in [98], values of $c_p$ and $c_{ap}$ are considered to be 50 $/MWh and 1200 $ per start-up or shut-down for a 200 MW unit.

Problem (2.9)-(2.11) is non-convex and mixed-integer. Different solution methods have been suggested in the literature among which Dynamic Programming (DP) is selected in thesis. This method have also been used in DUCL model of BC Hydro based on [84].

2.4.2 Dynamic Programming (DP)

In the Dynamic Programming approach that follows, we assume:

- A state consists of an array of units among which specific units are in operation and the rest are off-line

- The start-up or shut-down cost of a unit does not depend on the unit’s history of operation. In other words, the unit start-up or shut-down cost is a fixed amount. This assumption is always valid in hydroelectric units.

- In each interval i.e. hour, a specified minimum amount of generation capacity must be on-line.

A feasible state in each period is one in which the committed units can supply the required hourly forecasted demand, spinning and regulation reserves and the minimum amount of the generation capacity.

We set up the algorithm in a forward manner so that it starts from the initial hour and runs to the final hour. If the start-up (or shut-down) cost of generation units depend on the time they have been off (or on), then starting from initial hour is a more suitable approach than starting from last hour. The other advantages are possibility of specifying the initial conditions and moving the computations forward in time as needed. A forward Dynamic Programming algorithm is shown in Algorithm [1]
2.4. Hydro Unit Commitment

Figure 2.4: Regulation up and Regulation down capacity and Preferred Operating Point

**Algorithm 1** Unit Commitment via Forward Dynamic Programming

1: \( K=1 \)
2: \( \{I\} = X \) feasible states in stage 1
3: for all states \( I \) in stage 1 do
4: \( F_{cost}(1, I) = \min_{(L)}[P_{cost}(1, I) + S_{cost}(0, L : 1, I)] \)
5: end for
6: save \( N \) lowest cost strategies in \( \{L\} \)
7: \( K = K + 1 \)
8: \( \{I\} = X \) feasible states in stage \( K \)
9: for all states \( I \) in stage \( K \) do
10: \( F_{cost}(K, I) = \min_{(L)}[P_{cost}(K, I) + S_{cost}(K-1, L : K, I) + F_{cost}(K-1, L)] \)
11: end for
12: save \( N \) lowest cost strategies in \( \{L\} \)
13: if \( K = M \) (last hour) then
14: trace optimal trajectory
15: else
16: go to line 7
17: end if
2.4. Hydro Unit Commitment

![Efficiency Curve](image)

**Figure 2.5**: Typical efficiency curve of a single hydroelectric generation unit

The recursive algorithm to compute the minimum cost in hour $K$ with combination $I$ is formulated as:

$$F_{\text{cost}}(K, I) = \min_{\{L\}} \left[ P_{\text{cost}}(K, I) + S_{\text{cost}}(K - 1, L : K, I) + F_{\text{cost}}(K - 1, L) \right] \quad (2.12)$$

where $F_{\text{cost}}(K, I)$ is the minimum total cost from initial point to reach to state $(K, I)$, $P_{\text{cost}}(K, I)$ is the production cost in state $(K, I)$ and $S_{\text{cost}}(K - 1, L : K, I)$ is the cost of transition from state $(K - 1, L)$ to state $(K, I)$.

In this formulation, state $(K, I)$ is the $I^{th}$ combination of possibilities in hour (stage) $K$. In order to move from one state in one hour to another state in next hour in forward Dynamic Programming, a transition strategy
2.4. Hydro Unit Commitment

Figure 2.6: Algorithm to calculate total power generation loss function in a multi-unit hydroelectric plant
is selected. In this strategy, two control variables are defined. The first control variable is $X$ which is the number of states to search at each period. This variable shrinks the search space. The other variable is $N$ which is the number of paths to save at each hour (stage). In other words, among $X$ searched states, only $N$ paths are made and saved for each stage. Therefore, tuning these two variables controls the computational effort. The maximum value for $X$ and $N$ is $2^n - 1$ which is for complete enumeration where $n$ is the number of units. Reducing the number $N$ leads to neglecting the highest cost paths at each time interval and saving only the $N$ lowest cost paths.

Figure 2.8 depicts the restrictions variables $X$ and $N$ impose on search paths in forward DP algorithm. As seen in the figure, in interval $K$, the
2.4. Hydro Unit Commitment

search space is restricted to 5 combinations out of many possibilities. Also among these 5 combinations, the 3 lowest cost paths are selected and saved for reference to the next interval.

2.4.3 Solution Technique

The problem of (2.9)-(2.11) can be solved efficiently by a forward Dynamic Programming technique described in section 2.4.2 where each interval is an hour, the state variable is the number of generating units in operation for
2.5. Hydro Economic Dispatch

Each interval, and the control variable $X$ is the number of start-ups or shut-downs of generating units in each interval. The state space is defined by the set of natural numbers between the minimum and maximum of generating units which are able to generate the forecasted hourly demand and provide the required spinning and regulation reserves.

The corresponding equations for the problem of (2.9)-(2.11) are:

$$f^1(n^1) = c_{ap} \cdot |\Delta n^1| + c_p \cdot GL(n^1, P^1)$$

For $t = 2, \ldots, 24$

$$f^h(n^h) = \min c_{ap} \cdot |\Delta n^h| + c_p \cdot GL(n^h, P^h) + f^{h-1}(n^h - 1)$$

$$n^h = n^{h-1} + \Delta n^h$$

$$n_{min}^h \leq n^h \leq n_{max}^h$$

where $f^h(n^h)$ is the cumulative minimum cost from the first interval to interval $h$ for state $n^h$.

2.5 Hydro Economic Dispatch

In this section, the objective of minimizing total generation loss or maximizing total generation efficiency of a given set of committed units in sub-hourly time intervals is addressed. The optimization is subject to static and dynamic constraints on generating units and system-wide constraints. This problem is addressed through formulation of a hydro Economic Dispatch problem.

2.5.1 Problem Formulation

The traditional Economic Dispatch problem assumes that the amount of power to be supplied by committed sets of generation units is constant. Since one main constraint is avoiding mechanical stress on equipment, the rate of increase or decrease in the output of generators are restricted to acceptable
2.5. Hydro Economic Dispatch

limits. These ramp-rate constraints change the traditional Economic Dispatch problem to a Dynamic Economic Dispatch (DED) problem. The other concern is to avoid compromising security constraints of transmission system. In other words, an optimized solution which maximizes the generation efficiency should not jeopardize transmission lines’ power flow limits. Security limits of transmission lines change the Economic Dispatch to a SCED problem. As mentioned earlier in this chapter, spinning and regulation reserve constraints also could be included in Economic Dispatch and turn it to RCED. The hydro Economic Dispatch problem of this section, considers all constraints mentioned above. This problem is formulated for sub-hourly time steps of \( t \) with length of \( \Delta t \) for a time window of 1h as:

\[
\begin{align*}
\min_{P^t_j, S^t_j} & \quad C_T = \sum_{t=1}^{T} \sum_{j=1}^{N_j} C_j(P^t_j) \\
\text{s.t.} & \quad \sum_{j=1}^{N} P^t_j = D^t + Loss^t \quad (t = 1, 2, \ldots, T) \\
& \quad DR^t_j \cdot \Delta t \leq P^{t+1}_j - P^t_j \leq UR^t_j \cdot \Delta t \quad (j \in N_j, t = 1, 2, \ldots, T) \\
& \quad P^t_j + S^t_j \leq P_{j,max} \quad (j \in N_j, t = 1, 2, \ldots, T) \\
& \quad P^t_j \geq P_{j,min} \quad (j \in N_j, t = 1, 2, \ldots, T) \\
& \quad 0 \leq S^t_j \leq UR^t_j \quad (j \in N_j, t = 1, 2, \ldots, T) \\
& \quad \sum_{j=1}^{N_j} S^t_j \geq SR^t \quad (t = 1, 2, \ldots, T) \\
& \quad -F^l_{max} \leq F^t_l \leq F^l_{max} \quad (l = 1, 2, \ldots, L)
\end{align*}
\]

In objective function of (2.17), \( C_T \) is total cost of generation from \( t = 1 \) to \( t = T \). Since the time window is 1h, \( C_T \) is the total hourly generation cost which is to be minimized in this formulation. In hydro Economic Dispatch, generation cost could be equivalent to the cost of lost generation due to deviation from maximum efficiency which was modeled in section 2.3. Therefore,
2.5. Hydro Economic Dispatch

The elements of (2.17) which are summed over a time window of 1h are generation loss functions found in part 2.3. Depending on the output of hydro Unit Commitment problem of section 2.4, generation loss functions could change for different hours of the day. Therefore,

\[ C_j(P^t_j) = GL(UC^t_j, P_j) \]  

(2.25)

where \( UC^t_j \) is the status of Unit Commitment of plant \( j \) at time \( t \). In other words, the number of “on” units determines the cost curve (function) as shown in Figure 2.7. If quadratic curves such as those shown in Figure 2.7 are used, the objective function of (2.17) will also be quadratic.

The minimization problem of (2.17)-(2.24) is subject to the following constraints:

Equation (2.18) models the generation-demand balance in time step \( t \) where \( D^t \) is the total demand and losses in transmission system in time step \( t \). The sum of the demand and loss represents the effective system demand. Constraint (2.19) limits the ramp-up and ramp-down rates of plant \( j \) in time step \( t \) where \( UR^t_j \) and \( DR^t_j \) are maximum ramp-up and ramp-down rates of plant \( j \) in time step \( t \). The ramp-up and ramp-down rates of plants depend on the number of “on” units, their characteristics and loading in previous time step. Constraint (2.20) limits the generation and reserve of plant \( j \) to the maximum plant capacity \( P^t_j,_{max} \). Maximum reserve contribution of a plant is limited by its ramp-up rate as in (2.22). System total reserve is the summation over the reserve contributions of plants. Constraint (2.23) ensures that the total reserve of the system in time step \( t \) is greater than minimum required number of \( SR^t \). Security of the system is satisfied through condition (2.24) by restricting line flows to the limit of \( F^t_{max} \) in both directions, where \( l \) is the index of transmission lines and \( L \) is the total number of lines in the transmission system.
2.5. Hydro Economic Dispatch

2.5.2 Transmission Loss Effect

The transmission losses of system $Loss^t$ are related to the generation in plants $P^t_j$ through:

$$\sum_{j=1}^{N_j} \beta_j \cdot P^t_j = D^t_e$$  \hspace{1cm} (2.26)

$$D^t_e = D^t + Loss^t$$  \hspace{1cm} (2.27)

where $D^t_e$ is effective system demand and $\beta_j$ is inverse penalty factor. If the transmission loss is known for the time step before $t$, the loss for the $t^{th}$ time step could be calculated as:

$$Loss^t = Loss^{t-1} + \Delta Loss^t$$  \hspace{1cm} (2.28)

where $\Delta Loss^t$ represents the incremental loss from time step $t - 1$ to $t$. The transmission loss could be modeled as function of injected power in all buses. Therefore, $\Delta Loss^t$ is derived as:

$$\Delta Loss^t = \sum_{j=1}^{N_j} \frac{\partial Loss^{t-1}}{\partial P^t_{j-1}} [P^t_j - P^{t-1}_j] - \sum_{k=1}^{N_k} \frac{\partial Loss^{t-1}}{\partial d^t_{k-1}} [d^t_k - d^{t-1}_k]$$  \hspace{1cm} (2.29)

where $N_k$ is the number of load buses (PQ buses) in the transmission system and $d^t_k$ is the demand in load bus $k$ at time step $t$. The total system demand is sum of demand in load buses:

$$D^t = \sum_{k=1}^{N_k} d^t_k$$  \hspace{1cm} (2.30)

In (2.29), $\frac{\partial Loss^{t-1}}{\partial P^t_{j-1}}$ is the incremental loss due to 1MW generation in plant $j$ and $\frac{\partial Loss^{t-1}}{\partial d^t_{k-1}}$ is the incremental loss due to 1MW consumption at bus $k$ both at time step $t - 1$. It is assumed that the incremental loss does not change
2.5. Hydro Economic Dispatch

in the entire dispatch window of $t = 1$ to $t = T$. Since in a real situation this change is not considerable, this assumption is valid.

Using the transmission loss equation of (2.29) in constraint (2.18) leads to:

$$D^t_e = D^t - \sum_{j=1}^{N_j} \frac{\partial Loss^t_{t-1}}{\partial P^t_{j-1}} \cdot P^t_{j-1} - \sum_{k=1}^{N_k} \frac{\partial Loss^t_{t-1}}{\partial d^t_{k-1}} \cdot [d^t_k - d^t_{k-1}]$$  \hspace{1cm} (2.31)

where $\beta_j$ can be defined as:

$$\beta_j = (1 - \frac{\partial Loss^t_{t-1}}{\partial P^t_{j-1}})$$  \hspace{1cm} (2.32)

2.5.3 Transmission Line Flows

In order to obtain a secure dispatch of generation, constraint (2.24) is added to the Economic Dispatch model. Power flow calculations can relate flows in transmission lines to the generation in power plants through concept of Generation Distribution Factor (GDF) [99, 100]. GDFs only depend on the transmission network and are able to establish line flows independent of generation or demand in different buses.

The set of GDFs is defined as:

$$F_l = \sum_{j=1}^{N_j} \rho_{l,j} \cdot P_j$$  \hspace{1cm} (2.33)

where $F_l$ are real power flow on line $l$ and $\rho_{l,j}$ is GDF for line $l$ due to generation unit $j$. Coefficient $\rho_{l,j}$ represents the portion of generation supplied by generation unit $j$ which flows on line $l$.

It should be pointed out that although (2.33) can be used to calculate line flows based on bus generations, it does not uniquely define GDFs. In order to find GDFs, procedure in [99] is followed and implemented.
2.5. Hydro Economic Dispatch

Using the GDFs of (2.33), the line flow constraint of (2.24) becomes:

\[- \hat{F}_l \leq \sum_{j=1}^{N_j} \rho_{l,j} \cdot (P^t_j + S^t_j) \leq \hat{F}_l \]  \hspace{1cm} (2.34)

where \( \hat{F}_l \) is the real power flow limit on line \( l \) after adjusting the effect of demand distribution.

2.5.4 Solution Technique

Depending on the characteristics of the objective function, the optimization problem formulated in (2.17)-(2.24) needs different solution methods. As mentioned in part 2.3.1, a quadratic function is fitted to the generation loss curve. Doing so, the hydro ED problem formulated in this section is convex and can be expressed as a Quadratic Programming (QP) [101].

For simplicity, the above problem can be written in the form of a standard Quadratic Programming as:

\[
\min_x \quad \frac{1}{2} x^\top H x + f^\top x \\
\text{s.t.} \quad A x \leq b \\
\quad A_{eq} x = b_{eq} \\
\quad lb \leq x \leq ub
\]  \hspace{1cm} (2.35-2.38)

where \( x \) is the variables vector, \( H \) is a symmetric matrix which represents the quadratic terms of the objective function. The linear terms of the objective functions are modeled with vector \( f \). Matrix \( A \) and vector \( b \) implement the inequality constraint (2.36). Matrix \( A_{eq} \) and vector \( b_{eq} \) model the equality constraint (2.37). Vectors \( lb \) and \( ub \) are numbers of lower bound and upper bound for constraint (2.38), respectively.

Different algorithms are used to solve this problem among which Interior Point method has been widely accepted in power system optimization and
Economic Dispatch problems [102]. In this thesis, we use `quadprog` function [103] of Optimization Toolbox [104] of MATLAB [105] to solve Quadratic Programming problems including hydro Economic Dispatch problem.

**2.6 Summary**

In this chapter, the concept of generation-demand balance in power systems is briefly described. Generation-based *spinning* and *regulation* reserves are defined. The balance hierarchy in power systems is covered and the different balancing tasks are introduced. The main driving factor in power system balance decision making tools is generation efficiency. Therefore, the derivation method of the generation loss in hydroelectric units is elaborated. The integration method of generation loss curves into the generations scheduling and dispatch modules is also presented. The novel balance structure and logic presented in this thesis are tied to the main balancing tasks of power systems. Therefore, the hydro Unit Commitment and the hydro Economic Dispatch models should be implemented as prerequisites to the proposed schemes. The prerequisite models used in this thesis are described and the formulated problems are elaborated in this chapter. The solution techniques to solve the formulated optimization problems are also briefly explained.
Chapter 3

Demand Side Storage as Sub-hourly Balance Resource

3.1 Introduction

DSM and ESS are two main ingredients of smart power grids to improve efficiency and reliability of the grid by reducing demand peak and variability [5]. A Smart Grid is expected to have improved monitoring and control, system resiliency against component failures and natural disasters as well as increased renewable energy penetration [4]. DSM in general and more specifically Demand Response can be exercised in different time intervals from seconds to several hours or an entire day to serve utility by reducing peak demands and customers by providing a revenue stream.

The fundamental drawback of ESS and interruptible loads in the Demand Response context is that their response duration and frequency are very limited. Load reductions/interruptions cause inconvenience for customers, so these loads are only suitable to serve the power system in contingency events as a reliability resource and in wholesale market price spikes as economic resource. ESS can also provide frequency regulation which does not require high average energy consumption or release.

Some industrial processes e.g. water pumping in drinking water storage systems, aeration in wastewater treatment plants, industrial heating and refrigeration have inherent flexibilities which make them capable of virtually storing enough energy to immediately and continuously respond to control signals of transmission system operator. In other words, the energy is not
physically stored in these loads in another forms like the case in ESS. However, the possibility of shifting the power consumption in these loads let them function as an energy storage asset. Their response time and quality is significantly faster and more accurate than conventional generation resources \[38, 36\]. These loads can realize participation of DSS in longer time steps of grid balance because of high energy density and power capacity. Although some papers reported the capability of industrial responsive loads to provide regulation and spinning reserve without compromising their main function, to the best of our knowledge, no similar “energy-intact” Demand Dispatch scheme in sub-hourly time frame is reported in the literature.

This chapter deals with improving the generation efficiency of hydroelectric units by optimal scheduling and dispatch of pumps in drinking water storage systems. At the time of this study, the only sub-hourly Demand Response program in electricity energy markets is based on load reductions \[6\]. On the other hand, in this chapter a method is proposed to transform a certain amount of energy usage from individual large industrial loads to a scheduled aggregated load profile. The method is based on maximizing customer comfort by maintaining the energy consumption of loads equal to their normal non-responsive operation mode. The industrial responsive loads are scheduled in a sub-hourly (Economic Dispatch) time frame to enhance hydroelectric generation efficiency. The remaining storage of these loads can still be used for “low-energy” balance task of frequency regulation. This formulation can be implemented in VIUs.

This chapter addresses the following:

- A new generation/load scheduling method based on the combined use of DSS and conventional hydroelectric generation units
- Modelling the flexibility of water pumping in water storage systems based on their inherent constraints and water delivery requirements
- Modelling the integration of DSS assets in a power system transmission
3.2. Proposed Control Strategy

network as Virtual Power Plant (VPP)s [106]

- A system-wide optimal scheduling problem considering generation units, DSS and transmission system constraints with the objective of increasing hydroelectric generation efficiency
- A local operation optimization which maximizes the efficiency of pumps in storage systems

Storage and operation data of a DSS system which already provides regulation reserve service in market environment are used. The new formulation and simulations are done to find the achievable flexibility in sub-hourly time steps in a VIU. Since these loads are already used in 4s regulation time steps, the assumptions of available control and communication network infrastructure in sub-hourly time steps is also valid.

The proposed scheme is based on a centralized generation control and DLC in Economic Dispatch time frame. Utility level ESS do not have a common modelling framework in grid balance. The current control structures of power grids in VIUs and ESSs are based on meeting power balance and reserves in real-time operation. However in the presence of DSS, the control structure should be modified to include the “energy constraints” of loads on top of the traditional “power and reserve constraints”.

3.2 Proposed Control Strategy

3.2.1 Grid Balance

The traditional practice of power system operation is based on dispatching generation units in different time intervals to meet real-time “power balance” and there is no constraint on produced energy especially in market-oriented dispatch. Generation units are divided to dispatchable and non-dispatchable units. If the unit is converting stored fuel to electricity, there is no constraint
3.2. Proposed Control Strategy

on produced energy unless the fuel is limited. In hydroelectric units, depending on the levels of reservoirs, the total amount of released water is limited. This constraint limits the amount of produced energy. In the case of intermittent Renewable Energy Resources (RES), predicted renewable generation is included in day-ahead or hour-ahead generation scheduling modules as negative demand while in real-time operation, the deviations from predicted RES power productions are handled by flexible resources or curtailments/spillage of intermittent injected power. Depending on the dominant type of generation resources, every utility designs its own generation scheduling modules with different time steps and level of detailed modeling. In a hydroelectric dominated grid, the common practice is operating the units on hourly time steps derived from hydroelectric generation scheduling modules [86]- [87] and putting the less efficient units on swing mode to realize load-following and regulation.

3.2.2 Control Structure

Figure [3.1] illustrates proposed generation control structure in a VIU with base-loaded generation, flexible generation, DER, DSS and Demand Response. Without loss of generality, Demand Response is assumed to be of DLC type. The generation control scheme is based on an optimizer called the Energy Balance Optimizer (EBO) and a Process Model module. EBO includes characteristics of flexible generation units i.e. economic generation limits, ramp rates, cost/efficiency curves. It also contains status and characteristics of responsive loads (DSS and Demand Response) i.e. storage and power limits, ramp rates, efficiency curves, etc.

The inputs to EBO are:

- Balance demand forecast
- Expected energy consumption of DSS
- Status and generation of flexible generation units
3.2. Proposed Control Strategy

- Status and operation data of Demand Response
- Status and operation data of DSS

Balance Demand Forecast module sends the most updated balance demand and reserve schedule to the EBO. This schedule should be met by the commitment and dispatch of flexible generation units, dispatch of DSS resources as well as load reduction/interruption through DLC Demand Response. To find this, the generation schedule of base-loaded units and the expected generation of DER are subtracted from total demand schedule. Figure 3.2 illustrates this concept. The expected energy consumption of DSS is found by the Process Model module based on the forecast of the load process and sent to the EBO.

The expected energy consumption of DSS determines the amount of allowed energy consumption by DSS. This can be done by modelling normal operation of DSS loads based on current storage and expected process data coming from DSS resources. Doing so, total energy consumption of DSS resources in responsive operation could be set to be same as the amount that would be consumed in non-responsive operation. Therefore, EBO does not cause additional energy costs and the amount of energy consumption is intact. The amount of energy consumption could also be set manually by load owners. This will be further explained in section 3.5. It is assumed that energy cost is constant during scheduling time window of the EBO.

The commitment status and current generation of flexible generation units are used to find static and dynamic constraints of the EBO logic for the scheduling time window. Availability status and operation data of DSS are used to calculate remaining energy storage of DSS for the next scheduling time window which appear in storage constraints of the EBO logic.

The outputs of EBO are:
- Dispatch signals to flexible generation units
- Process control signals to DSS
3.2. Proposed Control Strategy

Figure 3.1: Proposed control structure

Figure 3.2: Demand granularity (left) and resource granularity (right)
3.3. Modelling

- Load reduction/interruption signal to Demand Response

Dispatch signals to the flexible generation units are selected optimally to increase generation efficiency. Process control signals to DSS determine power consumption of loads to affect generation/demand balance. Process Model is described in section 3.3.

3.2.3 Grid interface

The challenge of aggregating many DSSs to make a single operating profile fitting in current operating frameworks, is met by using the concept of VPP [106]. In this thesis, since the control structure is different from current control frameworks in VIUs and ISOs and each DSS has considerable energy and power density, we treat each one as a single controllable asset which is directly controlled and enabled to communicate with the EBO. The DC power flow equations are used to model the transmission system. Each DSS is treated as a generator with negative controlled generation, which is connected to a transmission bus. The concept of Generalized Generation Distribution Factors [99] is used to find the active power flow in the transmission lines due to positive or negative power injections by the generation units and DSS.

3.3 Modelling

3.3.1 Framework

In order to include the flexibility of DSS in grid balance applications, the first step is to obtain a model which transforms the power/energy of the loads to their main function during the scheduling time window. Doing so, the physical operation flexibility could be transformed to a virtual energy storage capable of consuming (absorbing) and not-consuming (releasing) real power. The amount and dynamics of the power/energy of the load is determined by the consumption process and variables representing the operating condition.
3.3. Modelling

Once the model is obtained, the permissible operating range of each load is translated to equivalent power/energy equations as well as power/energy constraints. Then these equations and constraints are used in optimization routines of the proposed control strategy to realize efficient grid balance. The behaviour of each asset under different operating conditions results in different power and energy constraints.

There are two types of constraints: “dynamic constraints” and “storage constraints”. Dynamic constraints are determined based on power ratings, ramp rates and power to asset rate conversion. Storage constraints are integral constraints which couple different control time intervals. These coupling constraints require look-ahead capability over a time window which is satisfied through forecasting the operating condition of each load during operating period. Since operation of each load follows cycles, historical data of operating conditions give necessary information on operating condition during considered operating time window.
3.3. Modelling

3.3.2 Water Pumps in Drinking Water Storage Systems

Figure 3.3 shows scheme of a drinking water storage facility which has a number of controllable input pumps. For simplicity, only one pump is shown. The water outflow is non-controllable and depends on the water consumption pattern of consumers. On the other hand, water inflow is controlled by the operator. Based on the inflow and the outflow rates of storage \( s \), the storage level \( V_s^t \) is updated as:

\[
V_s^t = V_s^{t-1} + (q_s^t - r_s^t) \cdot \Delta t
\]  

(3.1)

where

\[
q_s^t = \sum_{p=1}^{N_s} q_{p,s}^t = \sum_{p=1}^{N_s} f_{p,s}(p_{p,s}, V_s, t)
\]

(3.2)

where \( f_{p,s} \) is a generic nonlinear function that transforms the power consumption of each pump to its water pumping rate. The water inflow rate into storage \( s \) is sum of individual inflow rates of pumps into storage \( s \).

Normal Operation

The normal operation model is used in the Process Model module to update the demand forecast and expected energy consumption as in Figure 3.1. Each industrial water pump has a characteristic curve that relates the amount of power consumption to water pumping rate. The curve is generally nonlinear and each pump is normally operated at the peak efficiency point in its "on" state or not operated at all. In normal operation, a simple "on/off" control algorithm could be used to maintain enough water in the tank. At each control time step, based on available water in the tank, a binary number representing the ideal "on/off" states of the pumps is found:

\[
\hat{n}_s^t = N_s - floor(V_s^t \times (N_s + 1))
\]

(3.3)
3.3. Modelling

The volume of the tank is normalized by dividing to \( N_s + 1 \) segments. Hence, according to (3.3) the number of "on" pumps linearly increases as the water level approaches to \( V_{\text{min}} \) and vice versa. A dead-band of (3.4) is used to avoid excessive switching of pumps to reduce wear and tear:

\[
n_s^t = \begin{cases} 
    n_s^{t-1} & \text{if } |\hat{n}_s^t - n_s^{t-1}| < 1 \\
    \hat{n}_s^t & \text{else} 
\end{cases} \tag{3.4}
\]

This logic leads to operating \( n_s \) pumps at their highest mechanical efficiency:

\[
q_s^t = n_s^t \times Q_{p,s} \tag{3.5}
\]

**Smart Operation**

If each water pump is enabled with a Variable Frequency Drive (VFD) that can operate the pump at speeds lower than nominal speed, a continuous range of flexibility is achieved. In smart operation, the VFD controls the water inflow rate and isolates the frequency response of the load from the grid. This pump is enabled to respond to dispatch signals from the control centre to change its pumping speed immediately to achieve the desired pumping rate and power consumption. Based on the affinity laws of a centrifugal pump for a fixed wheel diameter, pumping rate \( q \), head \( H \) and power \( P \) in different speeds of \( N_1 \) and \( N_2 \) follow:

\[
q_2/q_1 = N_2/N_1 \tag{3.6}
\]

\[
H_2/H_1 = (N_2/N_1)^2 \tag{3.7}
\]

\[
P_2/P_1 = (N_1/N_2)^3 \tag{3.8}
\]

If the pump head is constant and the speed is reduced below the rated speed of the motor, the mechanical efficiency drops. Using the pump operation data, pumping rate, mechanical efficiency and total efficiency are found in
3.3. Modelling

discrete increments of mechanical input power. Then a curve is fitted to these points which relates pumping rate to electric power. Calculations based on real data show mechanical efficiency highly drops below 80% of nominal speed. So the pumps are not allowed to operate below that point. Total efficiency equals mechanical efficiency times electrical efficiency, which is assumed to be constant in this range. The curve is generally nonlinear but in the operating range of 80% to 100% of nominal speed, it is adequate to be independent of tank volume and operation time. For example, for a 550kW and 1200rpm pump, the fitted curve is linear between 222kW and 550kW. The curve is modelled as:

\[ f_{p,s}(p_{p,s}, V_s, t) \simeq a_{p,s} \cdot p_{p,s}^t + b_{p,s} \]  

(3.9)

where \( f_{p,s} \) is linear approximately and \( a_{p,s} \) and \( b_{p,s} \) are constants.

*Dynamic* constraints are defined by power ratings and ramp rates of pump as:

\[ p_{p,s,min} \leq p_{p,s}^t \leq p_{p,s,max} \]  

(3.10)

\[ -\delta_{p,s} \cdot \Delta t \leq p_{p,s}^t - p_{p,s}^{t-1} \leq \delta_{p,s} \cdot \Delta t \]  

(3.11)

*Storage* constraints are determined by minimum and maximum operating limits of tank and operating condition. The expected water consumption values can be calculated from historical data. The storage constraints are found as follows:

The volume of water in the tank should be between minimum and maximum operation limits during each control interval:

\[ V_{s,min} \leq V_s^t \leq V_{s,max} \]  

(3.12)

If \( V_s^0 \) at the beginning of scheduling time window \((t = 1, ..., T)\) is known, by
3.3. Modelling

using (3.1) and (3.2) the storage level at each time step is updated as:

\[ V_s^t = V_s^0 + \sum_{k=1}^{t} \left( \sum_{p=1}^{N_s} q_{p,s}^k - r_s^k \right) \cdot \Delta t \]  (3.13)

substituting (3.13) in (3.12) yields:

\[ \sum_{k=1}^{t} \sum_{p=1}^{N_s} p_{p,s}^k \cdot \Delta t \geq \frac{V_{s,min} - V_s^0 - (t \cdot b_{p,s} - \sum_{k=1}^{t} r_s^k) \cdot \Delta t}{a_{p,s}} \]

\[ \sum_{k=1}^{t} \sum_{p=1}^{N_s} p_{p,s}^k \cdot \Delta t \leq \frac{V_{s,max} - V_s^0 - (t \cdot b_{p,s} - \sum_{k=1}^{t} r_s^k) \cdot \Delta t}{a_{p,s}} \]  (3.14)

The left-hand sides of (3.14) represent the energy consumption of pumps between dispatch intervals 1 and t in storage s which couples the control variables in different time steps. The right-hand sides define the minimum and maximum energy storage limits based on the expected storage water outflow \( r_s \).

The other storage constraint is total amount of energy consumption of load in Smart operation mode during the scheduling time window:

\[ \sum_{p=1}^{N_s} \sum_{t=1}^{T} p_{p,s}^t = E_{s,T} \]  (3.15)

where \( E_{s,T} \) is the total energy that would be consumed in storage s if expected outflow \( r_s \) was happened during the scheduling time window. This constraint ensures that the total amount of energy consumption remains intact.

Once the total consumption in each DSS is found by system-wide logic of EBO, pumps should be optimally turned “on” and “off” and operated in their continuous range to minimize the efficiency drop.
3.4 Balance Logic Formulation

In what follows we define two optimization problems of EBO:

- System-wide balance which minimizes the generation loss in hydroelectric plants.
- Local operation optimization which maximizes the efficiency of pumps in each DSS.

3.4.1 System-wide Balance

In a power system with \( N \) control buses, \( N_g \) hydroelectric power plants and \( N_b \) DSS at each control bus, the objective of the system-wide EBO logic is to minimize the sum of generation loss in the hydroelectric swing plants during scheduling time window \( (t = 1, 2, ..., T) \). The variables of the optimization problem are generation of hydroelectric swing plants \( P(t) \), reserve of hydroelectric swing plants \( R(t) \) and total power consumption in each storage system \( S(t) \). Elements of diagonal matrix \( \alpha(t) \) and row vector \( \beta(t) \) are coefficients of quadratic and linear terms of the fitted functions to hourly generation loss curves of hydroelectric swing plants, respectively. As depicted in Figure [2.7] depending on the number of “on” units, the generation loss curves change so the elements of diagonal matrix and row vector of the objective function are time-dependent. Constant terms of the fitted curves do
3.4. Balance Logic Formulation

not affect the optimization.

\[
\min_{P,R,S} \sum_{t=1}^{T} \left[ P(t)^\top \times \alpha(t) \times P(t) + \beta(t) \times P(t) \right] \tag{3.16}
\]

s.t. \( 1^\top \times S(t) = E_{total} \tag{3.17} \)

for \( t = 1, \ldots, T : \)

\[
P(t)^\top \times 1 - 1^\top \times S(t) \times 1 = D^t_e \tag{3.18}
\]

\[
R(t)^\top \times 1 + 1^\top \times S(t) \times 1 \geq SR^t + RR^t \tag{3.19}
\]

\[
P(t) \geq P_{\min}(t) \tag{3.20}
\]

\[
P(t) + R(t) \leq P_{\max}(t) \tag{3.21}
\]

\[
0 \leq R(t) \leq R_{\max}(t) \tag{3.22}
\]

\[
S_{\min} \leq S(t) \leq S_{\max} \tag{3.23}
\]

\[
E_{\min}(t) \leq E \times S(t) \leq E_{\max}(t) \tag{3.24}
\]

\[- \delta_g(t) \leq P(t) - P(t - 1) \leq \delta_g(t) \tag{3.25}\]

\[- \delta_s(t) \leq S(t) - S(t - 1) \leq \delta_s(t) \tag{3.26}\]

\[- F \leq \Gamma(GEN(t) + RES(t)) \leq F \tag{3.27}\]

where

\[
P(t) = [P_1(t), \ldots, P_{Ng}(t)]^\top \quad \alpha(t) = \text{diag}(\alpha_1(t), \ldots, \alpha_{Ng}(t))
\]

\[
S(t) = [S_1(t), \ldots, S_{Ng}(t)]^\top \quad \beta(t) = [\beta_1(t), \ldots, \beta_{Ng}(t)]
\]

\[
R(t) = [R_1(t), \ldots, R_{Ng}(t)]
\]

Constraint \(3.17\) limits the total consumption of DSS loads to \( E_{total} \) which is found by summation of \( E_{s,T} \) for all \( s \) as in \(3.15\). Equation \(3.18\) is the generation/demand balance constraint. Effective system demand represents the Balance Demand Forecast described in part \(3.2.2\). System spinning and regulation reserve is met by constraint \(3.19\). In hydroelectric plants, spinning and regulation reserves are treated the same. The spinning reserve
3.4. Balance Logic Formulation

capacity is modeled as a function of demand uncertainties and the capacity of the largest committed unit in the system as [95]:

\[ SR^t = \alpha_d D^t_e + \alpha_g \times \max(P^t_{j,sch}) \]  \hspace{1cm} (3.28)

where \( \alpha_d \) and \( \alpha_g \) are constant values. Regulation reserve capacity is chosen to be a constant percentage of maximum system demand. Constraints (3.20)-(3.23) limit the maximum and minimum power generation, reserve and DSS consumption. Constraint (3.24) limits the integral of power consumption from first interval to \( t \)-th interval according to (3.14). Matrix \( E \) includes lower unitriangular matrices with all non-zero elements equal to “1”, and \( E_{\text{min}}(t) \) and \( E_{\text{max}}(t) \) include right-hand side of (3.14). Constraints (3.25)-(3.26) limit the ramp-rate of power generation in hydroelectric swing plants and power consumption in DSSs. Power flows in the lines are determined based on the DC power system model through matrix \( \Gamma \) where \( \Gamma_{lb} \) is the GDF of line \( l \) with respect to bus \( b \) [99]. The net injected power in each bus \( \text{GEN}(t) \) equals to the generation of each bus minus the total consumption of DSS. The net reserve in each bus \( \text{RES}(t) \) equals to the generation-based reserve plus DSS-based reserve of each bus.

According to the model of (3.16)-(3.27), the objective function (3.16) is quadratic while the constraints are linear. Quadratic Programming can be used to solve this optimization problem.

3.4.2 Local DSS Optimization

In DSS system \( s \) with \( N_s \) pumps, the objective of the local EBO operation is to maximize the efficiency of pumps during scheduling time window \( (t = 1, 2, ..., T) \). The variables of the optimization problem are “on/off” states of
3.4. Balance Logic Formulation

pumps $U(t)$ and their power consumption $L(t)$.

$$\max_{U,L} \sum_{t=1}^{T} \left[ U(t)^\top \cdot F_s^\top \times L(t) \right]$$  \hspace{1cm} (3.29)

s.t. for $t = 1, \ldots, T$:

$$L_{\text{min}} \leq L(t) \leq L_{\text{max}}$$  \hspace{1cm} (3.30)

$$-\delta_t \leq L(t) - L(t-1) \leq \delta_t$$  \hspace{1cm} (3.31)

$$U(t)^\top \times L(t) = S_s(t)$$  \hspace{1cm} (3.32)

where

$$U(t) = [U_1(t), \ldots, U_{N_s}(t)]^\top$$

$$L(t) = [L_1(t), \ldots, L_{N_s}(t)]^\top$$

$$F_s(t) = [F_1(t), \ldots, F_{N_s}(t)]^\top$$

Vector $F_s$ in objective function (3.29) contains linear terms of linear efficiency curves of pumps $(1, \ldots, N_s)$ in storage system $s$. Constant terms of the efficiency curves of the pumps do not affect the optimization. Elements of vector $U(t)$ are 1 in “on” state and 0 in “off” state of each pump. Elements of vector $L(t)$ are continuous and in the range of (3.10) which is ensured through constraint (3.30). Constraint (3.31) models the ramp rate limit of individual pumps as in (3.11). Finally, constraint (3.32) ensures that the total power consumption of pumps is equal to the DSS power of storage $s$ found in the system-wide problem.

According to the model of (3.29)-(3.32), the problem is mixed integer linear.

### 3.4.3 Mixed Integer Linear Programming

In the problem formulated in section 3.4.2, some of the variables (status of pumps) are restricted to integers while the objective function and the constraints are linear. Therefore, the problem of defining the “on” and “off”
3.4. Balance Logic Formulation

states of the pumps and the amount of power consumption in each pump could be formulated as a MILP \[9\]. Among different solution method, La-grange multiplier and dual optimization technique is used to solve the problem. This procedure is explained below for a simple case. The same procedure is applicable for the bigger problem of section \[3.4.2\].

The primal problem could be simply stated as:

\[
\begin{align*}
\min_{x_1, x_2} & \quad f(x_1, x_2) \\
\text{s.t.} & \quad w(x_1, x_2) = 0
\end{align*}
\] (3.33)

where its Lagrangian function is:

\[
\varphi(x_1, x_2, \lambda) = f(x_1, x_2) + \lambda w(x_1, x_2) \tag{3.34}
\]

If we define a dual function, \(q(\lambda)\) as:

\[
q(\lambda) = \min_{x_1, x_2} \varphi(x_1, x_2, \lambda) \tag{3.35}
\]

then the dual problem is to find:

\[
q^*(\lambda) = \max_{\lambda \geq 0} q(\lambda) \tag{3.36}
\]

The solution procedure involves solving two separate optimization problems. The first problem starts with initial value(s) for \(\lambda\) (set of \(\lambda_s\)). Then in the next step, the value of \(\lambda\) is held as a constant and the second problem is formulated and solved for \(x_1\) and \(x_2\) to minimize \(\varphi(x_1, x_2, \lambda)\). After this step, the value of \(\lambda\) is adjusted so that \(q(\lambda)\) is moved from its current value towards a larger value. A simple way to do this to use a gradient adjustment so that:

\[
\lambda^1 = \lambda^0 + \left[\frac{d}{d\lambda} q(\lambda)\right] \alpha \tag{3.37}
\]
where $\alpha$ adjusts the behavior of the gradient. A good way for applying the gradient technique is to lower the rate of $\lambda$ update in downward direction. For example:

$$\alpha = 0.5 \quad \text{when} \quad \frac{d}{d\lambda} q(\lambda) > 0$$
$$\alpha = 0.1 \quad \text{when} \quad \frac{d}{d\lambda} q(\lambda) < 0$$ (3.38)

This process is iterated to find the solution. The closeness to the solution in a dual optimization problem is measured by size of the gap between the primal and the dual functions. The difference between the solutions of the primal and the dual functions is called duality gap as:

$$g = J^* - q^*$$ (3.39)

where $J^*$ is the optimal value of the primal function in one iteration and $q^*$ is the value of dual function in the same iteration. For a convex problem with continuous variables, the duality gap will become zero at the final solution but in our non-convex MILP problem it will never actually become zero.

The simple method mentioned above is used to attack MILP of local operation optimization of part 3.4.2.

3.5 Numerical Results & Discussion

3.5.1 Simulation Environment

The balance logic developed was tested on IEEE 24 bus Reliability Test System [107]. The single line diagram of the test system is shown in the Appendix. The transmission network consists of 24 bus locations, 20 of which are PQ, PV or slack (control buses) which are connected by 34 transmission lines or transformers. The generation unit data of considered benchmark
3.5. Numerical Results & Discussion

Table 3.1: Generation Unit Locations

<table>
<thead>
<tr>
<th>Plant</th>
<th>Bus</th>
<th>Unit 1</th>
<th>Unit 2</th>
<th>Nuclear</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>6</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
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<td>1</td>
</tr>
<tr>
<td>4</td>
<td>21</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>5</td>
<td>22</td>
<td>6</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>6</td>
<td>23</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
</tbody>
</table>

power system is changed to a system with 3 hydroelectric plants and 3 nuclear plants. Two hydroelectric unit types are called (Hydro 1 and Hydro 2). Data of Hydro 1 and nuclear units are given in [107] and data of Hydro 2 are used from a real case. The plant locations and number of units in each location is presented in Table 3.1.

Daily peak demand is 2650 MW. Plant 1 is base-loaded at 100 MW and the rest of the capacity is dedicated to provide spinning reserve. Plant 5 is operated at its maximum capacity during hours 8:00-22:00 and is on-line at other times only to provide reserve. Nuclear plants are base-loaded at 400 MW. Plant 2 is operated in swing mode and meets the rest of the system demand and reserve requirements.

System net demand (system demand minus DER generation e.g. wind power,...) is simulated and reproduced from trend and variations of a real case for 24 hours with 5 min resolution. No Demand Response considered in this study and all responsive loads are of DSS type. The distribution of non-responsive loads in different PQ bus locations follow 17 bus Load Distribution Coefficients (LDC) of the benchmark transmission system which are given in [107]. On the other hand, responsive loads (DSS in this study) are distributed in the transmission system arbitrarily. Without loss of generality, in this study it is assumed that each control bus contains equal number of DSSs. Bus demand values are assumed to have the same proportional rela-
3.5. Numerical Results & Discussion

tion to maximum system demand for times other than peak hour. Spinning reserve requirement of (3.28) is found taking $\alpha_d = 0.05$ and $\alpha_g = 0.25$. The regulation reserve requirement is taken as 1% of the peak demand.

Depending on the variation of total system demand and variations in generation/reserve of other plants, hourly scheduled generation and reserve of swing plant varies. As a result, the number of "on" units of swing power plant in each hour is different. An hourly UC is solved for the entire day to find the number of units in operation based on forecasted demand and reserve to be followed by swing power plant.

The Unit Commitment problem of section 2.4 is formulated and solved for this system. The results are shown in Table 3.2. Hourly generation of all units are given in Figure 3.4.

In this simulation, it is assumed that 3 water storage facilities are fed by each of 20 control buses. Each storage system has 4 pumps and only swing plant is dispatched, so $N, N_g, N_b$ and $N_s$ are 20, 1, 3 and 4, respectively. In this research, the industry partner provided access to real field data of one storage system which is already providing regulation service. The data of this storage system is used for this new formulation. Data of water tank volume, pump characteristic curves and pump power ratings of real case is used for all storage systems. Since limited data was available, operational data of this storage system for different days of year is used as operation data of different storages in 1 day of this simulation. This provides one sample path which makes the simulations deterministic. However, whenever operational data of all storage systems is available, Monte Carlo simulations could be used to better treat the uncertainty of the water outflow. The minimum and maximum limits of tank volume are 20% and 80%, respectively. Total tank volume is 60.5 km$^3$ and rating of each pump is 550 kW.

The scheduling time step $\Delta t$ is 5 min, while time window $T$ of different lengths are used in simulations. It is assumed that the optimizer has access to all needed data during each time window i.e. storage, outflow and con-
3.5. Numerical Results & Discussion

Table 3.2: 24 Hour Unit Commitment Schedule of Swing Power Plant

<table>
<thead>
<tr>
<th>Hour</th>
<th># of Units</th>
<th>Hour</th>
<th># of Units</th>
<th>Hour</th>
<th># of Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>9</td>
<td>3</td>
<td>17</td>
<td>2</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>10</td>
<td>3</td>
<td>18</td>
<td>3</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>11</td>
<td>3</td>
<td>19</td>
<td>3</td>
</tr>
<tr>
<td>4</td>
<td>1</td>
<td>12</td>
<td>3</td>
<td>20</td>
<td>3</td>
</tr>
<tr>
<td>5</td>
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<td>21</td>
<td>3</td>
</tr>
<tr>
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<td>2</td>
<td>14</td>
<td>3</td>
<td>22</td>
<td>3</td>
</tr>
<tr>
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<td>2</td>
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<td>2</td>
<td>23</td>
<td>3</td>
</tr>
<tr>
<td>8</td>
<td>3</td>
<td>16</td>
<td>2</td>
<td>24</td>
<td>2</td>
</tr>
</tbody>
</table>

Figure 3.4: Hourly generation schedule of base-loaded plants and swing plant
3.5. Numerical Results & Discussion

Sumption data. The 24 hours of day is divided to $T$ segments. Doing so, $24/T$ runs are needed for 24 hours. For example in the case of $T = 1$ h, the first run is for hour 1:00 to 2:00 and the second run is for hour 2:00 to 3:00 and so on.

The model is implemented in a MATLAB environment. Depending on $T$, model statistics change. For example, in the case of a 1h scheduling time window and for the considered system, the system-wide balance model of EBO has 1224 variables, 2314 inequality constraints, 13 equality constraints and 2448 bound constraints. The local operation optimization model of EBO has 96 variables half of which are of integer type, 88 inequality constraints, 1 equality constraint and 8 bound constraints.

MATLAB Optimization Toolbox is used to solve QP of system-wide balance optimization. Lagrangian method described in part 3.4.3 is used to solve the MILP of local operation optimization. In each iteration of solved dual optimization [9], Linear Programming (LP) problems are solved with MATLAB Optimization Toolbox. The corresponding time to solve 24 of the first and 60 of the second problem is: 77.61s on a system with Intel Core i5-2400 3.1GHz CPU.

3.5.2 Results

Two cases are compared: the first case is when all pumps are in Normal mode so all loads of system are non-responsive. In this case, only generation units are controlled and dispatched to meet generation/demand balance. The second case is where all pumps work in Smart mode and are following dispatch request signals coming from the EBO. In this case, the power consumption of the loads are treated as control variables. Obviously, the rest of system loads are still non-responsive.
3.5. Numerical Results & Discussion

Normal Operation

In this mode, base-loaded plants generate based on their hourly schedule and only swing plant is dispatched to meet the remaining demand and reserve requirements. The power consumption of the pumps is simulated based on logic given in section 3.3.2. Figure 3.5 shows individual and simulated diversified demand of a sample bus with 5 water storage system for an entire day in Normal operation. This simulated demand is used in Demand Forecast Module to calculate effective demand in (3.18).

Figure 3.5: Individual and aggregate demand of loads in Normal mode
3.5. Numerical Results & Discussion

Smart Operation

In this mode, base-loaded plants still generate based on their hourly schedule and DSSs are scheduled to be dispatched together with swing plant. The Dispatchable Demand Forecast module described in [3.2.2] is used to find $D_c^e$ in (3.18). Figure 3.6 shows the loading of swing power plant in both modes with scheduling time step and window of 5 min and 1 h, respectively. To better show the difference, only a time span between hour 10:00 to 14:00 is illustrated.

![Swing plant loading](image)

Figure 3.6: Swing plant loading in Normal and Smart modes

Loading of the swing plant has less variation in Smart mode compared to Normal mode. According to Table 3.2, UC does not change during these hours. Therefore, the best efficiency point which is the minimum of curve...
with 3 units in Fig. 2.7 is constant and around 450 MW. The balance logic keeps loading of power plant near hourly optimum points and variations of system demand are transferred to the DSS side rather than the plant side.

Figure 3.7 shows aggregate power consumption of DSS in Normal and Smart modes of operation for the same time span of Figure 3.6. It is seen that the aggregated DSS power is constrained to its maximum limit at $t = 720$ min and to its minimum at $t = 605$ min. Mechanical wear and tear will also be reduced due to less variation in swing plant side.

![Figure 3.7: Aggregate DSS power consumption in Normal and Smart modes](image)

Figure 3.8 shows the volume of a sample tank in the same time span. At the end of hour 13:00, the volume of the tank reaches to the maximum limit in Normal mode. However, constraint 3.10 guarantees tank volume to
always remain below this limit in *Smart* mode.

![Graph showing volume of a sample tank in Normal and Smart modes](image)

Figure 3.8: Volume of a sample tank in *Normal* and *Smart* modes

Figure 3.9 shows how 4 pumps in one DSS are operated based on local operation optimization.

Among all 4 pumps of one sample storage system, the efficiency curve of pump 1 is the most flat one while pump 4 has the steepest efficiency curve. In other words, if the consumed power (i.e. speed) of all pumps drop equally below their rated power, the efficiency of pump 1 drops less than that of pump 2 and so on. In this scenario, pump 1 is a better choice for partial loading compared to pump 2 because partial loading of pump 2 incurs more efficiency loss. If pump 1 has the most flat efficiency curve (most efficient in partial loadings) and pump 4 has the steepest one (less efficient in partial
Figure 3.9: *Smart* operation of 4 pumps in one storage system loadings) among all 4 pumps, pump 1 has the tendency to be more partially loaded than others and pump 4 has the least. As see in Figure [3.9](#) the local optimization problem of part [3.4.2](#) gives the same results. The red line (pump 1) is more partially loaded than other pumps and the grey line (pump 4) is almost always “on” or “off” and not partially loaded at all. Doing so the overall operation efficiency of pumps is maximized.

After scheduling the Preferred Operating Points (POPs) [26](#) of DSSs in 5 min time steps, the remaining up and down storage capacities of each DSS are calculated. Figure [3.10](#) shows the total hourly average of load-based up and down reserve capacities obtained in different scheduling time windows.

Water release and generation loss of swing plant are also calculated based
3.5. Numerical Results & Discussion

Figure 3.10: Total hourly average of Regulation Up and Regulation Down capacity for different lengths of scheduling time window on hydroelectric generation model of part 2.3 and compared to the Normal case. Table 3.3 shows total daily savings in water release and generation loss compared to the Normal case in different lengths of scheduling time window. Although consumed electric energy of DSS system is guaranteed to be the same as in the Normal mode, less pumping efficiency leads to more energy consumption for pumping the same amount of water. Therefore if EBO restricts energy consumption of DSS to the Normal case, less water is pumped into the tanks and the customer comfort is jeopardized. The remaining water could be pumped into the tank by running one of the idle pumps in its maximum efficiency point. This incurs extra consumption of energy in the DSS side. The amount of extra energy consumption due to efficiency loss in DSS side is also shown in last column of Table 3.3.

Fig. 3.11 shows the daily water savings in different DSS penetration. The x-axis represents the power capacity of DSS and the y-axis presents the sav-
3.5. Numerical Results & Discussion

ings in discharged water. For example, if the total capacity of all DSS assets in the simulated system is 60 MW and the scheduling time window is 1h, 0.8% less water discharge is required to generate the same amount of energy that would be generated when these loads are operated in Normal mode. The maximum DSS capacity is 132 MW which is a realistic assumption of penetration of water pumping loads in a real power system as also described in the simulated case mentioned in section 3.5.1.

![Graph showing daily average water savings in different DSS penetration](image.png)

**Figure 3.11**: Daily average water savings in different DSS penetration

As seen in the figure, the amount of savings monotonically increases as DSS penetration increases. However, the incremental savings vary in different DSS penetration. As mentioned earlier, the savings are calculated based on generation loss functions which are dependent to Unit Commitment
3.5. Numerical Results & Discussion

Table 3.3: Daily results

<table>
<thead>
<tr>
<th>Time Window (h)</th>
<th>Water Savings (%)</th>
<th>Energy Savings (MWh)</th>
<th>DSS Loss (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.73</td>
<td>258.17</td>
<td>82.42</td>
</tr>
<tr>
<td>6</td>
<td>1.93</td>
<td>288.54</td>
<td>66.90</td>
</tr>
<tr>
<td>24</td>
<td>1.95</td>
<td>291.34</td>
<td>91.16</td>
</tr>
</tbody>
</table>

status of the system. As the DSS penetration changes, the Unit Commit-
ment could also change which imposes different generation loss curves, con-
sequently. Therefore, the amount of savings and incremental savings highly
depend on the status of Unit Commitment which is already dependent to
many factors e.g. system demand, unit availability, water constraints, ...

Theoretically, increasing the DSS capacity leads to more savings in the
generation efficiency. The theoretical limit for efficiency improvement is
where all generation units are operated at their maximum efficiency points
and all the swings are transferred to DSS side. Although this seems ideal,
it is not practical. Because the cost of changing all flexible loads to respon-
sive DSS could exceed the benefits of savings in generation efficiency. The
other reason is that there is a practical limit for DSS penetration capacity
as all loads in a power system territory are not potentially flexible. More
discussion about the results are presented in the following.

3.5.3 Discussion

The amount of savings highly depends on Unit Commitment, demand and
reserve obligations. As described in section 2.3, the number of “on” units
defines the hourly generation loss curves and affect the objective function of
(3.16). The length of scheduling time window also influences the savings in
generation efficiency. Through constraint (3.17), the EBO logic limits the
total energy consumption of DSSs. Therefore as the length of scheduling
time window \(T\) in objective function) increases, the feasible region of the
optimization problem expands. In other words, the equality constraint is less restrictive. Therefore, the optimal solution has lower objective function value in longer scheduling time windows.

Because of hard constraint (3.17), mathematically, there could be a case when a feasible region does not exist. In this case, the problem will be infeasible and have no solution. The virtual energy storage of loads is equivalent to real water storage in the tanks. If for a scheduling time window, tank overflow or lack of water is avoided according to the model of Normal operation, feasibility is guaranteed in Smart mode of operation for the same scheduling time window. Thus, the feasibility of the problem depends on the model of Normal operation which gives the hard equality constraints. As load aggregator adds more storage systems to the control network, feasible region is expanded. Increasing the length of scheduling time window also expands the feasible region. Moreover, a safety margin of 20% for maximum and minimum volume limits of tanks is considered to compensate for the errors associated with water outflow forecast.

As seen in Figure 3.10, the scheduling time window also affects the average hourly load-based regulation reserve. Since the objective of EBO logic is to maximize generation efficiency, load-based reserve capacity is not necessarily equal in up and down directions. It is observed that the average hourly capacities of regulation reserve in up and down directions are equal for the time window of 1 h. Because the scheduling time horizon is same as the averaging time horizon of regulation reserve capacity, which is 1 h. However in other Ts, this is not true and the up and down reserve capacities are not equal.

The system-wide and the local problems of EBO are decoupled to simplify the optimization problem. If “on/off” status of individual pumps and their efficiency characteristics are considered in the system-wide problem, the scheduling problem would be large mixed-integer and quadratic. Although solving the large Mixed-Integer Nonlinear Programming (MINP) problem
3.5. Numerical Results & Discussion

gives the optimal result, the number of variables highly increases and execution time will be orders of magnitude higher than the proposed decoupled scheme. On the other hand, the sub-optimal results of the decoupled scheme has the benefit of fewer variables and very short execution time. The modeling proposed in this chapter is based on inherent virtual energy storage of pumps in drinking water facilities. However, other large industrial loads e.g. aeration in wastewater treatment plants, industrial heating and refrigeration could also be added to DSS network. Depending on the nonlinearity of the consumption models of these loads, the coupled approach would have much higher complexity.

Since the savings are in generation side and the costs are in DSS side, in the proposed formulation customer discomfort and the generation efficiency savings are not lumped together in the system-wide objective function. DSS owners would prefer to tolerate the discomfort or predict the equivalent energy of the discomfort and input the amount in EBO problem through (3.15). If the benefits are to be split between DSS owner and utility, the bilateral agreement defines how the discomfort is managed. In the VIU environment, load aggregators can sign bilateral contracts with individual large industrial load owners and utility operator/owner. The benefits of shown energy savings could be split between the load owners, the aggregators and the utility. As long as the normal load process is intact or slightly jeopardized, customers could benefit directly from new revenue stream by allowing aggregators/VIU operator to use the flexibility of their loads. Aggregators use their communication, control and network infrastructure and exchange the required information with VIU operator and individual loads operators.

Because of the scheduling nature of the proposed problem, the look-ahead capability and full future knowledge is required. On the other hand, load forecast error in large scheduling time windows is more than short scheduling time windows. However, the operating point of any flexible resource would deviate from sub-hourly POPs to realize frequency regulation in 4s time steps.
3.5. Numerical Results & Discussion

The amount which these deviations occur highly depends on frequency of the interconnection, AGC logic and balancing behaviour of other Balancing Authorities in the interconnection. So the real efficiency gain could be calculated after real-time operation. As a very important implementation issue, any proposed generation control strategy should be compatible with utilities’ generation control practices including load forecast execution frequency. Thus if the load-forecast and sub-hourly dispatch are hourly updated, the proposed method with 1-h scheduling time window would be more compatible. The other benefit of 1-h scheduling over longer scheduling time windows is less forecast error.

Although 5 min POP of DSSs are scheduled in EBO, DSSs still have virtual stored energy that could be used as regulation reserve or spinning reserve. The value of this reserve capacity is on top of efficiency savings obtained from scheduling POPs of DSSs. In real-time operation, depending on the frequency of the interconnection and frequency control standards, AGC driven operating points deviate from 5 min schedules.
Chapter 4

Frequency Control in BRD Standard Paradigm

4.1 Introduction

In hydroelectric dominated power systems or systems with enough hydroelectric resources, load-following and AGC are less costly. However, tight ACE control deviates the real-time AGC operating points of the units from the scheduled optimal ones in Economic Dispatch (ED) time frame. Avoiding these deviations increases the generation efficiency and mechanical wear and tear of the units.

This chapter proposes a heuristic real-time frequency control method to maximize the benefits of a hydroelectric dominated BA in real-time generation control under BRD frequency control standards. The performance of the method is assessed through modeling and simulation of primary, secondary and tertiary frequency control of a Balancing Authority operated in an interconnection. This method is based on the flexibility of hydroelectric units and could be implemented without fundamental changes to the AGC logics based on CPS limits. The performance of this method is evaluated against an AGC logic based on CPS standards and a classic AGC logic.

This chapter addresses the followings:

- A new real-time generation control strategy in a VIU based on wide ACE bounds to maximize the efficiency of hydroelectric generation units.
4.2. NERC’s Frequency Control Standards

- Dynamic simulation of the primary and the secondary frequency control together with Economic Dispatch and Unit Commitment modules.

- Evaluation of new draft standards under scenarios where maximum benefits of wider bounds are gained.

4.2 NERC’s Frequency Control Standards

4.2.1 Control Performance Standards (CPS)

In interconnected power systems, frequency and interchange power control responsibility is realized through tie-line biased control scheme [10]. Each area has obligation consisting of local demand and losses, scheduled interchange and share of interconnection frequency control support. In the presence of internal generation and primary frequency control, ACE measures the degree to which each area meets its obligation. ACE is calculated as:

$$ACE = NI_a - NI_s - 10B(F_a - F_s)$$

where $NI$ and $F$ are net interchange power and frequency and subscripts $a$ and $s$ stand for “actual” and “scheduled” values, respectively. $B$ is the area’s frequency bias coefficient in $MW/0.1Hz$ which is based on system natural response $\beta$.

In order to maintain frequency reliability of an interconnection, magnitude and average of frequency error $\Delta F$ should be kept within tolerable limits. During decades of interconnected operation, frequency control standards have been used to specify the amount which each BA should control its ACE to fairly share the benefits of interconnected operation. NERC’s Control Performance Standards (CPS1 and CPS2) became effective in 1997 and described by Jaleeli and VanSlyck in [18][108]. These statistical criteria tend to maximize and fairly distribute the benefits of interconnected operation.
among BAs.

In the rest of this chapter, y-min average of $X$ will be noted as $\overline{X_y}$. It is shown in [108] that if ACEs of Balancing Authoritys are random and non-coincident, Root-Mean-Square (RMS) of $\Delta F_T$ will decay at rate of $1/\sqrt{T}$. CPS1 aims to maintain RMS of $\overline{\Delta F_1}$ within a statistically defined target $\epsilon_1$ which is found based on data stratification of experienced $\Delta F$ in the interconnection at different time intervals and applying proper decay rates. Keeping this decaying rate ensures randomness of ACEs of Balancing Authoritys and fairly distributes the benefits of interconnected operation. Ideally RMS of $\overline{\Delta F_T}$ at all $T$s should be limited at a rate of $1/\sqrt{T}$ to make ACEs random and non-coincident but in real situation this is not the case. So the experienced ACEs are coincident and $\Delta F$ have a structure. CPS1 is non-sensitive to accumulation of $\Delta F$ and is not able to make ACEs random in larger averaging time intervals.

CPS2 meant to limit inadvertent interchanges by limiting RMS of ACE over longer averaging time intervals i.e. 10 min. Technically defensible statistical tolerance limits for CPS2 were found in [108]. However, it was argued both by industry and academia that under typical conditions in North American interconnections, CPS1 and CPS2 are redundant and once CPS1 is satisfied, CPS2 is not required [18, 19].

### 4.2.2 Balance Resource and Demand (BRD) Standard

NERC proposed BRD standards in 2006. Currently most Balancing Authorities of North America are under field trial for this standard. Based on these standards, Balancing Authoritys are required to balance their resources and demand so that:

- 12-months rolling average of their Control Performance Measure (CPM) is more than 100%.
4.2. NERC’s Frequency Control Standards

- Real-time $\overline{ACE}_1$ does not exceed their interconnection frequency dependent Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes.

Long-term performance

CPM measure is same as old CPS1. It assigns each Balancing Authority a share of steady-state frequency control directly proportional to Balancing Authority frequency bias $B$. For each 1-min period, CPM Compliance Factor of area $i$ is calculated as:

$$CF_i = \left( \frac{\overline{ACE}_i}{-10B_i} \right) \times \left( \frac{\overline{\Delta F}}{\epsilon_1^2} \right)$$  (4.2)

where $\epsilon_1$ is constant statistical target on RMS of interconnection $\overline{\Delta F}_1$. Clock-minute CPM is then calculated as:

$$CPM_i = (2 - CF_i) \times 100\%$$  (4.3)

Once clock-minute CPMs are calculated, one-month average and rolling 12-month average of all of the 12 preceding months’ clock-minute CPMs can be calculated at the end of each month. Each BA shall maintain its 12-month rolling average of clock-minute CPMs at least at 100%.

Based on (4.2) and (4.3), if $\overline{ACE}_1$ and $\overline{\Delta F}_1$ have opposite signs, area CPM has a value more than 200%. So a positive $\overline{ACE}_1$ when frequency is low and negative $\overline{ACE}_1$ when frequency is high is a good strategy to get high CPM score. On the other hand, same signs for $\overline{ACE}_1$ and $\overline{\Delta F}_1$ will get CPM scores less than 200%.
4.2. NERC’s Frequency Control Standards

Real-time performance

Balancing Authority ACE Limits of high and low $\Delta F_1$ for area $i$ are defined as:

$$\text{BAAL}_{l,i} = -10B_i \times (FTL_{l,i} - F_{s,i}) \times \frac{(FTL_{l,i} - F_{s,i})}{F_{a,i} - F_{s,i}}$$  \hspace{1cm} (4.4)

$$\text{BAAL}_{h,i} = -10B_i \times (FTL_{h,i} - F_{s,i}) \times \frac{(FTL_{h,i} - F_{s,i})}{F_{a,i} - F_{s,i}}$$  \hspace{1cm} (4.5)

where $FTL_{h,i}$ and $FTL_{l,i}$ are high and low constant Frequency Trigger Limit (FTL) established for each interconnection $i$, respectively. They are calculated as:

$$FTL_{l,i} = F_{s,i} - 3\epsilon_1$$  \hspace{1cm} (4.6)

$$FTL_{h,i} = F_{s,i} + 3\epsilon_1$$  \hspace{1cm} (4.7)

If a BA operates outside these limits, it will contribute more than its share of risk to the interconnection reliability.

Figure 4.1 shows real-time BAAL limits and long-term 100% CPM score for positive and negative frequency error when $F_s = 60$ Hz and no Time Error Correction is scheduled. Based on this standard, there is an acceptable $\Delta F - ACE$ operation region within which Balancing Authorities can maintain their $ACE_1$. Shaded area in Figure 4.1 shows the acceptable region. If $\Delta F > 0$, $ACE$ can be negative to assist interconnection frequency or be less than $BAAL_h$ and if $\Delta F < 0$, $ACE$ can be positive to assist interconnection frequency or be less than $BAAL_l$. Long-term average CPM Compliance Factor still should be less than limits shown in the figure. Non-zero $ACE$ brings the benefit of less unit maneuvering and less deviations from Economic Dispatch set points. If ACE is large in 1st and 3rd quadrants, CPM CF will be low. However, operating in 2nd and 4th quadrants always accumulates high CPM CF score and assists BA to bring average CPM CF to an acceptable level.

These new limits are intended to be replacement to previous CPS2 and
4.2. NERC’s Frequency Control Standards

Figure 4.1: BA’s BAAL and CPM limits

Figure 4.2: Control scheme of proposed AGC logic
enhance the reliability of interconnection by keeping frequency within predefined limits in all conditions. The CPS2 was designed to limit accumulation of inadvertent interchange of Balancing Authorities by limiting average of their ACE within defined bounds [18]. Unlike CPS2, BAALs are dynamic, address the interconnection frequency and do not allow Balancing Authority’s ACE to be unbounded for 10% of the time i.e. 72 hours per month. On the other hand, BAALs of high and low frequency sides, depending on the interconnection frequency, allow Balancing Authorities to deviate their clock-minute ACE average from zero more freely compared to CPS2. Balancing Authorities are still required to comply with long-term CCPM.

4.3 Proposed Real-time ACE Control

Figure 4.2 illustrates the proposed generation control scheme for AGC assigned hydroelectric units. This generation control scheme has an Economic Dispatch module and a Real-Time BAAL Control module. Economic Dispatch module finds the economic operating points of generation unit in sub-hourly time intervals. This module works in coordination with Unit Commitment program which schedules hourly “on/off” states of the unit. UC program is not shown in the control scheme since it is not run online.

Real-time BAAL Control logic is based on monitoring $\Delta F_1$ and $ACE_1$ and finding required generation raise/lower signal $\Delta P_c$ sent to speed governor of the units. Real-time operating point of generation units are obtained by adding generation adjustment $\Delta P_c$ to sub-hourly ED operating point $P_{ED}$.

4.3.1 Economic Dispatch Control

This control module runs Economic Dispatch optimization problem based on most updated real-time demand forecast and finds operating points of AGC assigned units in sub-hourly intervals. Generation schedule of base-loaded units are subtracted from system local demand and interchange schedule and
4.3. Proposed Real-time ACE Control

an optimization problem is solved to minimize system generation efficiency loss as described in section 2.2.2. The minimization is subject to static, dynamic and system-wide constraints. Hourly sets of available units are found through Unit Commitment problem described in section 2.2.1.

4.3.2 Real-time ACE Control

Real-time ACE control consists of two control modules: BAAL control module and CPM control module. These modules track compliance with real-time and long-term limits, respectively and are coordinated to make a single generation adjustment at each control time step. BAAL control module ramps the hydroelectric plant to the desired operating region and has higher priority since it directly affects interconnection frequency. CPM control module makes smaller generation adjustments when BAAL control module is idle. In other words, BAAL control module has higher priority than CPM control module.

BAAL Control Module

This module is designed to maintain BA’s $\overline{ACE}_1$ within acceptable operating region of Figure 4.1. It tracks $\overline{ACE}_1$ and $\Delta F_1$ and makes minimum necessary unit maneuvering while maximizing the generation efficiency as follows:

Figure 4.3 shows a typical combined efficiency curve of a multi-unit hydroelectric plant with 4 different commitment combinations. Depending on the number of “on” units, one of the curves at a time is effective. Points A, B, C and D are local maximums in combined efficiency-power curve for different numbers of “on” units. For example, point A represents peak efficiency point in “hill-curve” characteristics of 1 “on” unit while point B shows the power (discharge) at which 2 hydroelectric turbines are at their peak efficiency points and so on [86, 87]. If the plant is operated in “swing” mode to realize load-following and AGC, the operating points deviate from
4.3. Proposed Real-time ACE Control

local maximums and generation efficiency is lost. Shaded area of the curve shows efficiency drop because of deviations from local maximums.

![Combined efficiency curve](image)

Figure 4.3: Combined efficiency curve of a multi-unit hydroelectric plant

Assume a case where the interconnection $\Delta F$ is negative and BA’s ACE will be zero by loading the plant somewhere between $B$ and $C$. The balance logic ramps the plant to point $C$ to build positive ACE, operate in safe region of $2^{nd}$ quadrant of $\Delta F - ACE$ plane of Figure 4.1 and get high CPM CF while generating at optimum efficiency. As Balancing Authority is supporting interconnection by positive Area Control Error, $\Delta F$ will move toward positive region and the operating point will shift towards $1^{st}$ quadrant which is bounded by $BAAL_h$. Wide ACE bound in $1^{st}$ quadrant allows BA to still operate at $C$ and “lean” on the interconnection without ACE control. As Balancing Authority’s ACE or $\Delta F$ increase, the operating point will reach $BAAL_h$. According to BRD frequency control standard, BA must bring the $ACE$ back below $BAAL_h$ within 30 consecutive clock minutes.

Generation adjustment is obtained by Algorithm 2 where $\delta_{i,j}(t)$ is ramp rate capacity of AGC plant $i$ with $j$ committed units and $C$ is the $BAAL$ violation counter. This algorithm ramps the plant toward another optimum efficiency point while making negative ACE to compensate the poor CPM CF of operating in $1^{st}$ quadrant. In the assumed case, the balance logic moves
4.4 Simulation Environment

toward left in Figure 4.3 and stops at B or A depending on the size of units. This is equivalent to operating somewhere in the 4th quadrant of $\Delta F - ACE$ where BA “assists” the interconnection and get high CPM CF. With large negative ACE, $\Delta F$ will be pushed toward negative values where BA is limited by $BAAL_i$ in 3rd quadrant. BA can still “lean” on the interconnection with low CPM CF score up to reaching to the $BAAL_i$ and triggering the $BAAL$ violation counter.

**CMP Control Module**

This module calculates clock-minute moving average of CPM CF based on $ACE$ and $\Delta F$ as:

$$cpm = MAVG_{1-min}\left(\frac{ACE}{10B\epsilon_1}\right) \times MAVG_{1-min}\left(\frac{\Delta F}{\epsilon_1}\right)$$  \hspace{1cm} (4.8)

where $MAVG_{1-min}(Y)$ denotes 1-min moving average of $Y$. Then $cpm$ is compared to a predetermined threshold $C_{th}$. If a control action is needed $\Delta P_c$ is set to integral of $ACE$, otherwise $\Delta P_c = 0$. Control threshold $C_{th}$ is selected so that very poor instantaneous CPM CF is avoided. This logic is presented in Algorithm 3 where $c(t)$ denotes the control signal.

### 4.4 Simulation Environment

The effectiveness of the proposed real-time ACE control method is studied in a simulation environment described as follows:

#### 4.4.1 Power System

A power system with $N$ Balancing Authorities is considered in simulations which are interconnected as shown in Figure 4.4. The first and second areas (BA 1 and BA 2) are studied in detail considering system-wide scheduling and dispatch models together with system level and individual dynamic models.
Algorithm 2 Real-time BAAL Control Module Logic

1: Calculate $ACE_1(t)$ & $\Delta F_1(t)$
2: if $|ACE_1(t)| < |BAAL(t)|$ then
3: \[ P(t+1) = P(t), t \leftarrow t+1, C = 0 \] go to line 1
4: else
5: \[ C \leftarrow C + 1 \]
6: if $C < 30$ min then
7: \[ P(t+1) = P(t), t \leftarrow t+1, \text{go to line 1} \]
8: else
9: if $ACE_1(t) > 0$ then
10: while $P(t) < P_n$ do
11: \[ t = t + 1, P(t+1) = P(t) + \Delta t \cdot \delta_{i,j}(t) \]
12: end while
13: go to line 1
14: else
15: while $P > P_p$ do
16: \[ t = t + 1, P(t+1) = P(t) - \Delta t \cdot \delta_{i,j}(t) \]
17: end while
18: end if
19: end if
20: end if
21: go to line 1

Algorithm 3 Real-time CPM Control Module Logic

1: Calculate $cpm$ as in (4.8)
2: if $cpm < C_{th}$ then
3: \[ c(t+1) = K_f \cdot \int ACE(t).dt \]
4: else
5: \[ c(t+1) = 0 \]
6: end if
4.4. Simulation Environment

of real-time AGC. BAs (3, ..., N) are modeled as a 3 large equivalent units. Total generation capacity and peak demand of areas are shown in Figure 4.4. BA 1 is all hydroelectric while BA 2 has hydroelectric units, thermal units with reheat steam turbine and thermal units with non-reheat turbine. The capacity of equivalent units of BAs (3, ..., N) is selected to be 30% nuclear, 50% thermal and 20% hydroelectric. Types and number of units in BA1 and BA2 are shown in Table 4.1. The generation capacities of unit types T1 to T6 are 500MW, 400MW, 250MW, 300MW, 200MW and 1000MW, respectively.

Figure 4.4: Interconnection comprised of N BAs

In BA1 nuclear units are base-loaded at their maximum capacity while T2 and T3 hydroelectric units are base-loaded at their best efficiency points. A 5-unit hydroelectric plant of type T1 is operated in swing mode to realize load-following and AGC. In BA2 thermal units are base-loaded at their maximum capacity and a 4-unit hydroelectric plant of type T3 is operated in swing
4.4. Simulation Environment

Table 4.1: Generation capacities of BA1 & BA2

<table>
<thead>
<tr>
<th>Area</th>
<th>Hydro</th>
<th>Th. w reh.</th>
<th>Th. w/o reh.</th>
<th>Nuclear</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>5T1 + 5T2 + 8T3</td>
<td>-</td>
<td>-</td>
<td>4T6</td>
</tr>
<tr>
<td>2</td>
<td>4T3</td>
<td>6T4</td>
<td>7T5</td>
<td>-</td>
</tr>
</tbody>
</table>

mode to realize load-following and AGC.

4.4.2 Dynamic Model

Dynamic models of generation units, load damping, speed governors and turbines are obtained from [8, 109]. Inertia response of all units in one area together with load damping effect are lumped as a single equivalent rotating machine and a single damping factor representing overall frequency response performance. This model is adequate since in AGC studies inter-machine oscillations within each area are neglected [8, 9].

Equivalent inertia $H_{eq,i}$ for area $i$ is calculated as [48]:

$$H_{eq,i} = \frac{\sum_{j=1}^{n} M_{ij} \cdot H_{i,j}}{\sum_{j=1}^{n} M_{i,j}}$$  \hspace{1cm} (4.9)

where $M_{ij}$ and $H_{i,j}$ are MVA base and inertia constant of generator $j$ in the area $i$, respectively.

A model of constant 5% primary frequency regulation is considered for all units. For equivalent units of areas $(3, ..., N)$, equivalent primary frequency regulation (droop) $R_{eq,i}$ is calculated as [48]:

$$R_{eq,i} = (\sum_{j=1}^{n} \frac{1}{R_{i,j}})^{-1}$$  \hspace{1cm} (4.10)

where $R_{i,j}$ is primary frequency regulation of unit $j$ in area $i$. Constant 1.5% load-damping is considered for all areas. Governor dead-bands selected to be $0.036 H \text{z}$ for thermal units and $0.012 H \text{z}$ for hydroelectric units. Ramp rate
of units are selected based on their typical ramping capability.

Since the new ACE limits are based on the interconnection frequency and address the whole frequency control efforts of BAs normal and abnormal conditions, the primary and the secondary control should be jointly considered in simulations and performance assessments. As suggested by NERC, frequency bias coefficient $B$ of BAs should be at least equal to the primary frequency response $\beta$. Therefore finding the “proper” value of BA’s $\beta$ is of high importance. Commitment, generation level, maximum capacity, ramp rate and reserve allocation restrict the amount of up-reserve or “headroom” of units and BA’s primary frequency response, consequently. Therefore, the method suggested in NERC standard BAL-003-01 was simulated to find the “proper” $\beta$ in the presence of all these nonlinearities. Large step disturbances which lead to large frequency deviations (greater than 0.036 Hz) were applied to the simulation model. Interchange errors were used to find $\beta$ of each BA. Then $B$s of BAs were selected to be same as found $\beta$s to tune BAs share of the interconnection frequency control support. The amount of regulation reserve capacity of each BA is considered to be 1% of system peak demand.

The amount of spinning reserve of each BA is chosen to be dependent to hourly demand $D^t$ and the capacity of largest committed unit in the system $P^t_{j,sch}$ as:

$$SR = \alpha_d D^t + \alpha_g \times max(P^t_{j,sch})$$

(4.11)

where $\alpha_d$ and $\alpha_g$ are constant values. Spinning and regulation reserves are met by non-base loaded units in BA1 and BA2 and by model of equivalent unit in the rest of interconnection.

Model of synchronizing torque is used to tie the BAs and the value of synchronizing torques were selected to represent tie-lines capacity and ratio of BA sizes.
4.4.3 Static Scheduling Model

The simulation environment involves modules of day-ahead Unit Commitment and hour-ahead Economic Dispatch for BA1 and BA2. Base-loaded units are excluded from Unit Commitment and Economic Dispatch. The Unit Commitment model of section 2.4 is used to find the number of operating units in a multi-unit power plant in each hour. Based on the results, the combined efficiency curves of the units are found in each hour to be used in the proposed real-time ACE control of section 4.3. Inputs to the Unit Commitment model are units’ data e.g. efficiency curves, generation capacity, ramp rate. They also include cost of power generation loss, start-up and shut-down costs as well as requirements of hourly generation, spinning and regulation reserves. Real efficiency data is used for hydroelectric plants of BA1 and BA2. The unit cost of power generation loss and switching costs are $50/MWh and $1200 per start-up or shut-down for a 200MW unit.

4.4.4 Load Data

Short-term and random load fluctuations drive the primary and the secondary frequency control and load-following control of BAs. Real 5-min generation data of a utility was scaled to the size of each area and used as their short-term load. A random Gaussian noise with zero mean and standard deviation proportional to square-root of BA’s size [20] was also added to each area’s short-term load as random load fluctuations.

Generation of base-loaded units was taken out from total area load to find swing plant load. Therefore, swing plant load consists of short-term and random fluctuations which should be followed by generation maneuvering.
4.5 Simulation Results and Discussion

4.5.1 Results

Table 4.2 shows the UC schedule of swing plants in BA1 and BA2. Since the units are identical, the value of each row of table shows the number of hourly “on” units in swing plants of BA1 and BA2. These numbers define the plant capacity, ramp rate and maximum efficiency points in each hour.

Figure 4.5 shows the results of ED module and maximum efficiency points for swing plants of BA1 and BA2. It is seen that following sub-hourly demand, even with ED logic, leads to deviations of operating points from maximum efficiency points. In the real-time operation, however, the operating points in AGC time frame are defined based on frequency control logic of BAs and control manner of the rest of the interconnection.

The AGC logic proposed in section 4.3 is simulated for two study cases and the results are compared with a benchmark logic in terms of CPM performance, generation efficiency and unit maneuvering. The AGC logics of each BA in study cases and benchmark are presented in Table 4.3 where BAAL refers to the proposed method based on maximum benefits from BRD standard and CPS refers to the method proposed in [16] based on maximum
4.5. Simulation Results and Discussion

Figure 4.5: Results of Economic Dispatch for BA1 and BA2

Table 4.3: AGC logics of each BA in each study case

<table>
<thead>
<tr>
<th>BA</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>BAAL</td>
<td>BAAL</td>
<td>CPS</td>
</tr>
<tr>
<td>2</td>
<td>BAAL</td>
<td>CPS</td>
<td>CPS</td>
</tr>
<tr>
<td>(3, ..., N)</td>
<td>Generic</td>
<td>Generic</td>
<td>Generic</td>
</tr>
</tbody>
</table>

benefits from CPS standards. The AGC logic of the rest of the interconnection is a generic AGC which models negative frequency error during load pick-up hours and positive frequency error during load drop-off hours.

Case 1

In this case, BA1 and BA2 are operated under AGC logic proposed in this chapter and the results are compared with the benchmark. Figure 4.6 shows
4.5. Simulation Results and Discussion

\(\textit{ACE}_1\) in Case 1 and the benchmark, \(BAAL_H\), \(BAAL_L\) and CPS2 limits for BA1 in Case 1. Depending on the interconnection frequency and \(\textit{ACE}_1\) i.e. operating quadrant of Figure 4.1, only one of \(BAAL_H\), \(BAAL_L\) may be active in each clock minute. Based on CPS2 standard, \(\overline{\textit{ACE}}_{10}\) of each BA must be less than constant number \(L_{10}\) [16]. As seen in Figure 4.6, \(\overline{\textit{ACE}}_1\) is less restricted by \(BAAL\) limits than \(L_{10}\). Because of very large values of \(BAAL_H\) and \(BAAL_L\) in some clock minutes, only the values between 1000 MW and -1000 MW are shown. Although large bounds of BAAL are less restrictive compared to CPS2 requirement, large instantaneous ACE values lead to poor CPM score. In other words, large temporary deviations of ACE are tolerable only if tighter ACE control in the future brings the average CPM score within the required number of (4.3). The CPM Control Module of section 4.3 ensures the clock-minute values of CPM remain bounded. As
4.5. Simulation Results and Discussion

Figure 4.7: $\overline{ACE}_1$ and $BAAL_h, BAAL_L$ and CPS2 limits for BA2 in Case 1 seen in Figure 4.6 although ACE is loosely controlled, BAAL limits are not violated.

Figure 4.7 shows $\overline{ACE}_1$ in Case 1 and the benchmark, $BAAL_H, BAAL_L$ and CPS2 limits for BA2 in Case 1. As seen in the figure, $\overline{ACE}_1$ of BA2 reaches to $BAAL_H$ and $BAAL_L$ limits 13 times during the day but the logic BAAL Control Module brings makes large generation maneuvering to bring $\overline{ACE}_1$ to acceptable region. According to BRD standard, $\overline{ACE}_1$ should not violate $BAAL_H$ or $BAAL_L$ for more than 30 consecutive clock minutes. In this simulation, conservatively $\overline{ACE}_1$ is brought back in far less than 30 consecutive clock minutes. This is done not to compromise interconnection frequency reliability because of gaining generation efficiency. However, BAs can still tolerate violated $BAAL_H$ or $BAAL_L$ for about 30 consecutive clock minutes. Although magnitude of $\overline{ACE}_1$ can be as high as $BAAL_H$ or $BAAL_L$
4.5. Simulation Results and Discussion

for 30 consecutive clock minutes, very poor CPM score will built up during this time. In this case, CPM Control Module makes small generation adjustments to avoid very poor CPM score. As seen in Table 4.4, CPM score for BA1 and BA2 in Case 1 are above 100%. This means gaining efficiency has not compromised CPM compliance level over the simulated time i.e. 24 hours.

Case 2

![Figure 4.8: $\text{ACE}_1$ and $\text{BAAL}_l$, $\text{BAAL}_h$ and $\text{CPS2}$ limits for BA1 in Case 2](image.png)

Table 4.4: Average daily CPM score

<table>
<thead>
<tr>
<th>BA</th>
<th>Case 1</th>
<th>Case 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>109.75%</td>
<td>111.5%</td>
</tr>
<tr>
<td>2</td>
<td>171.3%</td>
<td>122.1%</td>
</tr>
</tbody>
</table>
In this case, BA1 and BA2 are operated under AGC logic proposed in this chapter and the one in [16] respectively and the results are compared with the Benchmark. Figure 4.8 and Figure 4.9 show $\overline{ACE_1}$ in Case 2 and the Benchmark as well as $BAAL_H$, $BAAL_L$ and CPS2 limits for BA1 and BA2 in Case 2. According to the results, BA1 can tolerate large ACE within its territory and gain efficiency. Since BA2 is operating under CPS, ACE variations will be in the order of the Benchmark, as demonstrated in Figure 4.9. As seen in Table 4.4, average CPM score for Case 2 is also compliant with BRD standard. BA2 has higher CPM score since its logic does not focus on efficiency and more generation maneuvering is done.

Table 4.5 shows average daily efficiency gains in BA1 and BA2 compared to the Benchmark. Efficiency gains are calculated based on total generation and discharged water in hydroelectric units using efficiency curves. In Case 1,
since the BAAL logic keeps the generation on optimum efficiency points and small generation adjustments are minimized, efficiency is improved in both areas. However in Case2, CPS logic of BA2 leads to more generation adjustments while BAAL logic in BA1 leads to more interconnection frequency deviation. More frequency deviations in the interconnection leads to more required generation adjustments in BA2 and aggravates the overall efficiency in BA2.

Table 4.5: Efficiency gains compared to the benchmark

<table>
<thead>
<tr>
<th>BA</th>
<th>Case 1</th>
<th>Case 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.65%</td>
<td>1.3%</td>
</tr>
<tr>
<td>2</td>
<td>0.41%</td>
<td>-0.61%</td>
</tr>
</tbody>
</table>

Figure 4.10 compares generation adjustments in BA1 for Case1 and the Benchmark. In the upper figure, generation adjustments of CPM module of BAAL logic are shown while in the lower figure, those of CPS logic in the Benchmark are demonstrated. Generation maneuvering capacity of both modules are set to be 150 MW both in up and down directions. As seen in the figure, BAAL logic leads to extremely lower number of generation adjustments both in up and down directions which in turn leads to lower mechanical wear and tear on hydroelectric units. According to Figure 4.11, the number of generation pulses in Case2 for BA2 is more than the Benchmark. The reason is less generation control in BA1 which is operated under BAAL logic.
4.5. Simulation Results and Discussion

Figure 4.10: Number of generation control swings in BA1 in Case1 (upper figure) and in Benchmark (lower figure)
Figure 4.11: Number of generation control swings in BA2 in Case2 (upper figure) and in Benchmark (lower figure)
Chapter 5

Conclusion and Future Work

5.1 Contributions

This work focuses on finding new “strategies” that hydroelectric dominated VIUs can deploy using Demand Side Management and the newly proposed NERC AGC standard to make hydroelectric generation more efficient.

In this thesis, different balance tasks in a hydroelectric dominated VIUs are described. Also derivation of hydroelectric generation loss function as the main contributing factor in generation scheduling decision making tools is elaborated. The flexibility of water pumping load in drinking water storage facilities is modeled as a Demand Dispatch resource. Moreover, two different generation control schemes are proposed. The first one is based on utilizing DSS through aggregation and direct control of flexible industrial loads. This generation control method is based on a sub-hourly balance logic and combined use of hydroelectric generation units and responsive loads. The second generation control method is a real-time AGC logic based on taking maximum advantage of wide ACE bounds in NERC’s latest draft standard i.e. BRD frequency control standard.

In general, one contribution of this thesis is to provide an approach to do the cost benefit analysis of different strategies. With respect to the initial objectives of this research, the contributions of this works can be summarized as follows:
5.1. Contributions

5.1.1 Objective 1

In Chapter 3, the inherent flexibility of water pumping in drinking water storage systems is modeled as a Demand Dispatch resource. Operation of pumps in Normal and Smart modes are described and mathematically modeled. A mathematical model which transforms the power/energy constraints of this load to its main function in both modes of operation is developed. The permissible operating range of the load is translated to equivalent power/energy equations which could be used in any scheduling optimization as static and dynamic constraints. Dynamic constraints are derived based on power ratings, ramp rates and power to asset rate conversion. Storage constraints are modeled as integral constraints coupling different operating control time steps. Storage constraints are added to ensure energy-neutrality of the balance logic. In other words, the power consumption of loads in Smart mode of operation does not exceed the value of energy consumption Normal operation mode. Doing so, customer comfort is maintained and Smart operation is justified more. This model is general and could be used in any centralized balance logic or aggregation design method.

5.1.2 Objective 2

The fluctuating system demand and generation capacity set aside for operating reserves, reduces the efficiency of hydroelectric power generation. In Chapter 3, a new sub-hourly generation/load balance structure and scheduling optimization is proposed. This method is based on the outcomes regarding to the Objective 1. Integration of DSS assets in power system transmission network is realized through the concept of VPP. A system-wide optimal scheduling problem is formulated considering generation units, DSS and transmission system constraints. The objective of system-wide balance is to maximize hydroelectric generation efficiency while minimizing the customer discomfort. Therefore, POP of swing power plant and DSSs are scheduled
5.1. Contributions

to be dispatched in 5 min time steps. The formulation is a DLC scheme and based on centralized control of generation and DSSs. Customer comfort is maximized by equalizing total energy consumption of responsive loads with their normal water serving requirements, which is modeled as Objective 1. A local operation optimization in the form of MILP is also designed to minimize efficiency drops in Smart mode of operation for the modeled DSSs. Simulations were done on a benchmark power system (IEEE 24 BUS Reliability Test System shown in Appendix) using real data of hydroelectric generation and responsive loads. In the simulated system, through replacement of about 5% of system peak demand with continuous-range controlled DSS, up to 2% savings in hydroelectric generation efficiency in swing-mode is achieved.

5.1.3 Objective 3

Based on NERC’s latest frequency standard, Balancing Authorities can tolerate larger ACE within their areas and practice less generation maneuvering. According to BRD standard, Balancing Authorities are responsible to keep their ACE within frequency dependent limits i.e. BAAL. The heuristic real-time frequency control method proposed in Chapter 4 of this thesis is based on taking maximum advantage of new draft standards i.e. BRD standards. A two-layer AGC logic is designed where the first layer i.e. BAAL Control Module implements large generation swings and the second layer i.e. CPM Control Module implements 4s deviations from optimum points. The effectiveness of the proposed method is assessed through modeling of Unit Commitment and Economic Dispatch as well as dynamic simulation of the novel real-time AGC logic in hydroelectric dominated VIUs. The proposed AGC logic is tested for different study cases on two Balancing Authorities with different sizes which are tied in an interconnection. The results are compared with a benchmark case where all Balancing Authorities are operated under CPS standards. It is demonstrated that under BRD standards, hydroelectric generation efficiency is increased up to 1.3%. Also, deviations of
5.2. Future Work

As the next steps of this study, the author would like to point out these directions and tasks.

- Although water pump in drinking water storage systems is modeled as DSS to realize Demand Dispatch, there are other loads with inherent storages that could also be turned into DSS by adding metering, control and communication infrastructure. Aeration in wastewater treatment plants, industrial heating and refrigeration have large amount of virtual energy storage within their assets making them capable of providing sub-hourly Demand Dispatch. The method proposed in Chapter 3 is suggested to be investigated for development of DSS models for these industrial loads.

- The centralized generation control scheme of Chapter 3 is based on VIU structure. In ISO framework however, it is the responsibility of aggregator to transform a certain amount of energy usage to a scheduled load response and bid into Ancillary Services market as Demand Response products e.g. load-based regulation and spinning reserve. Therefore, the structure is no longer centralized among responsive loads and generation units. Because the load aggregator is a market participant and there is no common benefit between Generation Company (GENCO), Distribution Company (DISCO), aggregator and ISO. In this framework, DSSs could be modeled as standard Demand Response products. The objective is maximizing the benefits of aggregator while maintaining customer comfort. Related works such as [49, 50, 53, 51, 52] are
5.2. Future Work

about optimal charging and discharging strategies for V2Gs to maximize the benefits of aggregators. Extending this concept to industrial DSS is suggested as a research topic which looks promising for academia and industry.

- Scheduling the POP of DSSs in sub-hourly time frame defines their Up and Down regulation capacity such as the case shown in Figure 3.10. This capacity still can be used for real-time balance in AGC time frame. In real-time operation, ISOs split the AGC signal among selected resources based on market clearing status. On the other hand, the AGC signal could be split among different resources also in VIU framework where load-based regulation could also be one of these resources. If the operator owns the generation, the energy efficiency/fuel cost is a legit reason to use load-based flexibility. Another legit reason is freeing up the capacity of tie-lines dedicated to import/export of energy and not to import/export regulation. A dynamic AGC signal distribution method which maximizes the benefits of VIUs in terms of generation efficiency is suggested as a future step of this study.

- The AGC logic developed in this thesis is based on maximizing the generation efficiency and minimizing the unit maneuvering. However, one drawback of gaining efficiency and less unit maneuvering is large inadvertent energy exchange between Balancing Authorities. For utilities with weak tie-lines, large inadvertent could results in tie-line congestions. In this case, energy and regulation import/export capacity is compromised for gaining generation efficiency. Using DSSs and ESSs as regulation capacity could result in freeing up the tie-lines’ capacity while maximizing generation efficiency. This topic and evaluation of the benefits associated with this objective is also suggested as continuation of the studies in this thesis.
Bibliography


Bibliography


[34] B. Yang, Y. Makarov, J. Desteese, V. Viswanathan, P. Nyeng, B. McManus, and J. Pease, “On the use of energy storage technologies for regulation services in electric power systems with significant penetration of


Appendix A

Transmission System Data

Figure A.1 shows the single line diagram of IEEE 24 BUS Reliability Test System. Plant types and locations are given in Table 3.1 and transmission lines data are given in Table A.1.

Table A.1: Transmission Lines Data of IEEE 24 BUS Reliability Test System

<table>
<thead>
<tr>
<th>From</th>
<th>To</th>
<th>Reactance (p.u.)</th>
<th>Capacity (MVA)</th>
<th>From</th>
<th>To</th>
<th>Reactance (p.u.)</th>
<th>Capacity (MVA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2</td>
<td>0.146</td>
<td>175</td>
<td>11</td>
<td>13</td>
<td>0.488</td>
<td>500</td>
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<td>3</td>
<td>0.2253</td>
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<td>11</td>
<td>14</td>
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<td>500</td>
</tr>
<tr>
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<td>13</td>
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<td>500</td>
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Figure A.1: Single Line Diagram of IEEE 24 BUS Reliability Test System