RELIABILITY EVALUATION OF HYDROPOWER DOMINANT POWER SYSTEMS

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In Partial Fulfillment of the Requirements
For the Degree of Master of Science
In the Department of Electrical and Computer Engineering
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By

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ABSTRACT

Hydropower is an efficient and clean way to produce electricity as it does not require fuel and does not contribute to green house gas emissions. Hydropower has increased rapidly in the past few years and is expected to increase further in the future due to its economic and environmental advantages. The variability and uncertainty with river flow characteristics in a hydro dominant power system create considerable challenges in planning adequate generation capacity to maintain acceptable reliability criteria. Unlike power system with conventional generations, hydro generations are energy limited due to seasonal and climatic variability in water restriction, and the generation capacity depends on river inflow, operating policy and load levels. Hydro dominant utilities face energy waste caused by water spillage during high inflow season or low load period. However, they do not have adequate generation capacity to meet the load during the peak load period in low inflow season. Therefore, it is very important for hydro dominant utilities to properly manage and utilize their existing facilities to maintain or enhance the system reliability.

This thesis presents three methodologies to manage energy diurnally, seasonally, and yearly for the hydro dominant system. The diurnal energy management transfers energy from the off-peak load hours by operating at derated capacity, and to peak load hours by generating full capacity. The methodology recognizes the storage capability of run-of-river plants that has been ignored in the past studies and enhances system reliability from the collective benefits. Seasonal energy management of storage type hydro is performed to save and have less water spillage when water inflow is high, and use it to supply load in dry months when water inflow is low and system
is not capable to supply load. The year to year energy management strategy is incorporated to save water in a normal or wet year with minimal impact on the system reliability and to maximize the availability of water based on water availability patterns in upcoming energy uncertainty year. The year to year energy management not only includes the energy uncertainty of one year time frame as existing practices, also incorporates the future year energy uncertainty from long term planning perspective.

The proposed models recognize the energy and capacity characteristics of hydro plants and incorporate river flow and load variations to enhance system reliability. The approaches presented in this thesis quantify the impact of energy limitation and implications of river flow variations in hydropower planning. The presented models and strategies provide the useful information and suggestions in the operation and planning of hydropower dominant systems under hydrological uncertainties for long-term system adequacy planning. The proposed methodologies are applied to the IEEE Reliability Test System (RTS) which is modified to create a hydro dominant system.
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<table>
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<th>Description</th>
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<td>COPT</td>
<td>Capacity Outage Probability Table</td>
</tr>
<tr>
<td>DPLVC</td>
<td>Daily Peak Load Variation Curve</td>
</tr>
<tr>
<td>EENS</td>
<td>Expected Energy Not Served</td>
</tr>
<tr>
<td>EPEC</td>
<td>Electrical Power and Energy Conference</td>
</tr>
<tr>
<td>FOR</td>
<td>Forced Outage Rate</td>
</tr>
<tr>
<td>HL-I</td>
<td>Hierarchical Level I</td>
</tr>
<tr>
<td>HL-II</td>
<td>Hierarchical Level II</td>
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<tr>
<td>HL-III</td>
<td>Hierarchical Level III</td>
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<tr>
<td>IEEE-RTS</td>
<td>IEEE Reliability Test System</td>
</tr>
<tr>
<td>LDC</td>
<td>Load Duration Curve</td>
</tr>
<tr>
<td>LFU</td>
<td>Load Forecast Uncertainty LFU</td>
</tr>
<tr>
<td>LOLE</td>
<td>Loss of Load Expectation</td>
</tr>
<tr>
<td>LOEE</td>
<td>Loss of Energy Expectation</td>
</tr>
<tr>
<td>LOLF</td>
<td>Loss of Load Frequency</td>
</tr>
<tr>
<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
</tr>
<tr>
<td>PLCC</td>
<td>Peak Load Carrying Capability</td>
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<tr>
<td>RTS</td>
<td>IEEE Reliability Test System</td>
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CHAPTER 1: INTRODUCTION

1.1 Power System Reliability

An electric power system is a very complex system and it consists of three main facilities: generation facilities to generate power, transmission facilities to deliver power, and distribution facilities to distribute power to industrial, commercial and residential customers. Power systems have been developed over years to provide acceptable quality and continuity of electric supply to satisfy customers’ demand as economically as possible. Failure to meet the acceptable quality and continuity in power system will have financial and social impacts on both the customers and the utilities. Therefore, system reliability is an essential aspect of today’s power system in both planning and operations. The addition of redundant components in power system to prevent forced outage events, contingencies and components maintenance, can increase reliability in the system. However, the financial constraints always limit the amount of reliability that can be increased as shown in Figure 1.1 [1]. Therefore, the power system reliability studies are very import for system planning and operation domains to determine the optimal investment for achieving and maintaining the acceptable system reliability.
1.1.1. Power System Adequacy and Security

The area of power system reliability covers broad studies in the planning and operation domains. It can be categorized into two sub-divisions as shown in Figure 1.2: system adequacy and system security [1]. The system adequacy evaluation is performed in the planning domain, and evaluates the system’s ability to have sufficient generation resources to meet the customer demand, and sufficient transmission and distribution facilities to deliver the energy to customer load points. The system security is the ability of the system to respond to disturbances within an indicated time frame. The disturbances can be local or wide-spread, and includes the loss of generation and delivery facilities or large fluctuations in supply and demand.
1.1.2. Basic Functional Zones and Hierarchical Levels

A power system contains three basic functional zones: generation, transmission and distribution system [1] as shown in Figure 1.3. Most utilities structure their systems into these three zones for the purpose of organization, planning, operation, and analysis.

The reliability evaluation of a power system is usually performed at these three basic functional zones [1]. Hierarchical level I (HL I) only includes generation facilities, and it assesses the ability of total generation system to meet the total system load demand. Hierarchical level II (HL II) includes both generation and transmission facilities and it considers the ability of the system to deliver energy to the bulk supply points. Hierarchical level III (HL III) evaluates three functional zones together, and it considers ability to satisfy the capacity and energy demands of individual consumer [2]. The research work presented in this thesis is focused on HL I studies in the planning domain.

Figure 1.2. Power System Reliability Subdivision
Power system adequacy evaluation relates to long term assessment of system resource adequacy. The measurement of reliability has evolved through practice over the years. The percentage reserve margin had been used in utilities to assess long term system reliability [3], where the adequacy of capacity is measured against the peak load in the system. However, the concerns of using percentage reserve as a criterion for different systems have risen because different generation types or different load characteristics could result in large difference in capacity requirements over the same period for each system [2]. Therefore, a more suitable adequacy criterion was developed to maintain a reserve that is equivalent to capacity of the largest unit in the system plus a fixed percentage of capacity of total system capacity [2,3]. A comprehensive reliability evaluation to fully recognize the stochastic characteristics of power
system component failures and supply demand variations was developed using a probabilistic loss of load approach. This approach not only considers the ability of the overall system capacity to meet the system load demand, but also the availability of individual generation unit, planned or unplanned outage, and load growth. Currently, this approach is the most widely used technique to evaluate generation system reliability [1], and many reliability metrics are developed from this approach such as the loss of load expectation (LOLE), loss of energy expectation (LOEE), expected energy not supplied (EENS), etc. The basic concept in this approach includes the development of three probabilistic models: generation model, load model and risk model.

The long-term probability of a generating unit failure $e$ is called its Forced Outage Rate (FOR). Most generating units can be represented by a two-state Markov model as shown in Figure 1.4, in which $\lambda$ is the failure rate and $\mu$ the repair rate of the generating unit. The generation model for the entire generation system is developed in the form of a capacity outage probability table (COPT) that can be obtained by combining capacity level and the associated availability of each generating unit in the overall generation system.

There are different types of load models that can be used to represent the system load demand. The simplest and most widely used are the daily peak load variation curve (DPLVC) and the load duration curve (LDC). The daily peak loads in the study period are arranged in a descending order to form the DPLVC. The DPLVC does not recognize the variation of the load within a day. The hourly average load data collected for a period are arranged in a descending order to create a load duration curve (LDC). The LDC also indicates the energy demand of the system. The most common reliability indices used to assess generating capacity adequacy are the
loss of load expectation (LOLE), loss of energy expectation (LOEE), and the loss of load frequency (LOLF) [4].

The LOLE is the expected number of days or hours in a study period that the load demand exceeds the generation capacity as shown in (1.1), where $C_t$ is available capacity at time $t$, $L_t$ is forecast peak load at time $t$, $P_t$ is the probability of loss of load on day $t$.

$$\text{LOLE} = \sum_{t=1}^{t} P_t (C_t - L_t)$$ (1.1)

The LOEE is the expected energy not supplied in a study period due to generation inadequacy as shown in (1.2), where $E_t$ is the energy curtailed by a capacity outage.

$$\text{LOEE} = \sum_{t=1}^{t} E_t P_t$$ (1.2)

![Two-state Markov Model for A Generation Unit](image)

Figure 1.4. Two-state Markov Model for A Generation Unit

1.3 Hydropower Generation in Power Systems

Hydropower is an important source of energy generation in the world. Hydropower contributed to 15.9% of the world’s total electricity generation and rose to 1,292 GW in 2018 [5]. Hydropower has grown at a rapid pace. This trend is expected to continue. In 2018, the total new installed capacity of hydropower power in different regions of the world was 21.8 GW as shown
in Figure 1.5. East Asia has most new installed hydro capacity in the world, followed by South America, South and Central Asia, Europe, Africa, and North and Central America. The countries leading in hydropower generation are China, Brazil, USA and Canada.

Canada is the fourth largest producer of hydroelectricity in the world with over 81 GW of installed hydropower capacity by 2018 [5]. The distribution of existing hydro power capacities across Canada are shown in Figure 1.6. where Quebec, British Columbia, Manitoba, Quebec, Newfoundland and Labrador and Yukon each generate over 80% of their electricity from hydroelectricity [6]. Hydropower produces approximately 60% of the total electricity supply in Canada. Fossil fuel is the second most important energy resource in Canada. There is 9% of electricity supply from coal, 9% from natural gas, and 1% from petroleum [7]. However, utilization of fossil fuel is being replaced by renewable energy sources such as wind and solar in recent years. Nuclear power contributes to 15% of total generation in Canada [7].

Normally, utilities or power production entities with thermal dominant power generation systems have firm contracts of coal and natural gas supply and consider storage of the fuel for the supply during short term outages. Therefore, conventional thermal generations are usually assumed not to be energy constrained, and the generation forced outage, unit capacity, and uncertain load requirements are mainly the key factors considered in the reliability studies [8]. In contrast, energy production from hydropower is significantly influenced by the uncertainties in water flow during different seasons of the year, and the hydrological conditions at different years. Hence, the energy limitation in the hydro dominant system due to inadequate water flow during
dry seasons or dry years has a major impact on the system reliability. Failure to meet the load demand in hydro dominant system can be due to energy deficit or power deficit [9].

Figure 1.5. New Installed Capacity by Region (Source: 2019 Hydro Power Status Report, International Hydropower Association)
Hydro power uses the kinetic energy from moving water which is converted into electrical energy via turbine and generator. Hydropower is categorized based on four major topologies [10-12]:

- **Storage hydro generation**: A dam is built to impound water of river or lake in a reservoir. The water is released from reservoir through the operational gate into penstock when needed. The kinetic energy of the flowing water rotates the turbine and the generator thus generating electricity. The size of the reservoir dictates the ability of the
hydropower plant to operate independently of the hydrological river inflow for weeks or even up to months or years. It can operate to serve base load, as well as peak load due to quick ramp up and ramp down characteristics.

- **Run-of-river hydro generation:** Generator turbine is driven by water flow from built canal or river directly. It generally has no storage or limited storage thus minimizes the impact on the surrounding land and environment due to this characteristic. The electricity produced by run-of-river hydro generation heavily depends on hydro hydrological river inflow. It is generally operated to serve the base load as it needs to operate more or less continuously.

- **Pumped storage hydro generation:** The stored water is cycled between upper and lower reservoirs as required. Water is released from upper reservoir through turbine to produce electricity when demand is high in system. Water is pumped back from lower reservoir by consuming electricity from grid during low demand period. It is used as energy storage to meet peak demand, and also serves as a backup reserve to be dispatched immediately if other generation sources or renewable resources are not available.

- **Offshore Marine:** It is less established but promising technology that uses tidal currents to generate electricity from Ocean waves.

The scope of this thesis only involves two most common hydropower topologies: storage and run-of-river hydro generations.
1.4 Research Motivation and Objectives

The hydro dominant system is an energy-based system where failure to meet the load may be caused by energy deficit or capacity deficit. Energy deficit is caused due to uncertainties in the hydrological conditions during different seasons or years. Energy state of the hydro dominant system is determined by the historical hydrological river inflow data, the operating policy and the system load demand in a given period of time [9]. The failure in any of the sub-units, such as the penstock, Butterfly valve, Spiral case, Turbine, Generator, Excitation system, and Speed governor may cause the unit failure. The unit failure affects the availability and reliability of the unit and the power plant [13]. The FOR of hydro units are very low compared to other conventional units, therefore hydrological conditions become a key factor of generation capacity adequacy in hydro systems. Hydro dominant power systems are energy limited system due to inadequate river flow in dry season or dry years. Therefore, power systems with large penetration of hydropower generation are vulnerable to energy and capacity shortage at various periods within a day and year [14]. The situation is more severe in dry season of a drought year. This will have an adverse impact on the system’s long-term reliability. However, during the wet season hydro utilities are forced to spill extra water because of high river flow rate. The excess water in the wet season may be saved with prudent capacity planning and operational strategies for seasonal and year to year energy management.

References [15-17] present hydro unit operating models for reliability and economic assessment. The volume of the reservoir depends on the geometric shape of the reservoir, and trapezoidal cross-section is assumed to simplify computation in most research papers. The hydro
generator output depends on the turbine discharge rate, which depends on reservoir head correlated to the instantaneous water volume in the reservoir. The energy management of hydro units is conducted by the operating policy. Most researches are focused on the coordination of energy limited hydro units with different energy sources, and the optimization of hydro plant operation based on available energy in the reservoir. An operating policy with the thermal generation as a function of the amount of hydro energy in the system is applied in [9], and the operating priorities are focused on not violating reservoir upper or lower bound limits. References [15, 17] present the impact of operating policy of hydrothermal generation system on generation reliability, where hydro units are modeled with thermal units based on economic condition, avoiding spillage of water, emergency condition and load level. The long-term reliability of a hydrothermal power system with wind penetration is improved in [16] by managing the number of hydro units to operate in coordination with wind power, and the rest of the hydro units are used as peaking units to serve the load demand. The reliability of a mixed wind, solar and hydro generation system is modeled in [18]. Reference [19] proposes to mitigate wind power fluctuations and maximize clean energy utilization by coordinating wind and hydro power. The solar radiation, wind speed and precipitation are included in the model to evaluate the reliability of the mixed system using Monte Carlo simulation. The impact of long-term stochastic energy uncertainty of hydro dominant system on system reliability and the possibility of reliability enhancement aspect is not addressed in these papers. Seasonal models of hydro units with random natural inflows are presented in [20]. The operating policy consists of peak shaving and base load with coordination of thermal units to enhance the reliability of generation system and to reduce the production cost. The river inflow is
represented as a stationary stochastic process modeled by multi-state Markov chain and the generator unit is modeled by a two state Markov model in [21]. The method is applied to demonstrate its accuracy and applicability in reliability evaluation. In [22], the allocation of hydro energy from random river inflows to the different sub-periods of a year is optimized according to economic criteria and market rules on system reliability. Reference [23] modeled waterflow variation with seasonal changes using universal generating function methods and concluded that the Small Hydro Power plants with bigger capacity will have greater impact on system reliability due to water flow variations. In the past research, the reliability concerns of energy uncertainty with short-term energy limitation caused by diurnal and seasonal variation of river flow on both run-of-river and storage type hydro units in same hydro system were not adequately addressed in reliability assessment. Furthermore, the penetration of hydro units was not large enough to cause energy limitation concerns in the power systems considered in the past researches. There is a lack of research in the long-term reliability impact of energy uncertainty caused by hydrological variability from year to year. Moreover, the reliability enhancement strategies under energy limitation for hydro plants without getting assistance from other types of energy sources has not been addressed in the past research work.

For long term reliability assessment of resource adequacy in the past, North American Electric Reliability Corporation (NERC) had recommended planning reserve margin of 15% for predominately thermal systems, and 10% for predominately hydro systems, and specifically noted that it is not for power system with energy limitation [24]. Today, most utilities in North America refer to an LOLE in 0.1 days per year as their planning criterion to calculate the system planning
It is possible to implement diurnal energy management in many run of river hydro generation plants by shifting the energy usage within a day in response to hourly load patterns of the day [26] utilizing its limited storage capacity. The widely used index, LOLE in days/year ignores this hourly variation within a day, and therefore, is not responsive to diurnal energy/capacity management operations. Utilities containing large percentage of energy-based generations have shown concerns on the LOLE days/year index in reliability assessment of their generation adequacy. Therefore, it is necessary to re-evaluate usefulness of this index, and provide recommendation of other indices that are more appropriate for energy limited systems.

Utilities schedule periodic maintenance for generation units to prolong the useful life of the equipment and ensure acceptable system reliability level. The maintenance of thermal generation units’ costs and benefits have been well studied in reference [27] and [28]. The mathematical methods and development of maintenance evaluation tools for power system components are described in Reference [29]. Periodic maintenance of generation units in firm capacity generation units are normally scheduled during off peak load season. But hydro units may exploit maintenance scheduling opportunities during water restriction periods regardless of system load conditions. It is important to explore the benefits and system reliability impacts based on characteristics of hydro units which were not studied in previous literatures.

The main objectives of this research work are:

- To quantify the reliability impact of variability and uncertainty of river flow in hydro dominant power system.
• To improve/maintain system reliability based on characteristics of different types of hydro generations by using available resources.

The specific objectives of this research work are:

• To develop analytical reliability models of two most common hydro generation plants – run of river hydro plants and storage type hydro plants to improve system reliability under energy limitation diurnally and seasonally from a short-term planning perspective.

• To develop analytical reliability models to consider year to year energy management to minimize the adverse impact of energy uncertainty and maintain system reliability from a long-term planning perspective.

• To assess the usefulness of the NERC recommended reliability criterion in e hydro dominant power systems and make recommendations on suitable reliability indices.

• To develop a methodology to benefit hydro dominant system from maintenance schedule coordination with load levels and inflow restrictions.

1.5 Organization of Thesis

This thesis is written in manuscript style and contains six chapters. Excluding Chapter 1 and Chapter 6, which are introductory and concluding chapters of this thesis, remaining four chapters are preceded by a preface to the corresponding chapter. The preface is aimed to provide a general review of the immediately following chapter containing a technical paper published or submitted for publication, and explain how it ties up to the central theme of the thesis.
Chapter 1 is an introduction of the thesis and provides an overview of power system reliability evaluation and the contribution of hydro generation in the world. This chapter presents characteristics of different hydro generation types and indicates the raising issues and problems with energy limited hydro dominant power system. Furthermore, Chapter 1 lays out the objectives and scope of this research work presented in this thesis.

Chapter 2 presents the analytical reliability models of head pond and power generation of run-of-river hydro to recognize energy storage and the magnitude and time-shift of output power to match the diurnal load profile during energy limited periods of the year. It presents results to illustrate the reliability improvement on the system.

Chapter 3 presents the analytical reliability models containing energy limitation with seasonal analysis of storage type hydro to avoid or reduce water spillage when water inflow is high, and use the stored water to supply load in dry months when water inflow is low, and the system generation is not capable to supply load. The reliability benefits of this models are shown in detail in this chapter.

Chapter 4 presents a methodology to integrate the diurnal and seasonal energy management models developed in Chapter 2 and Chapter 3 respectively. It presents reliability models of combining the two energy management strategies for run-of-river and large storage type hydro to recognize their energy and capacity characteristics to benefit the overall system reliability. The usefulness of the NERC recommended reliability criterion is discussed in this chapter. The different maintenance coordination strategies of hydro units and thermal units are proposed and discussed in this chapter.
Chapter 5 presents the probabilistic approach to incorporate diurnal, seasonal, yearly energy management strategies to minimize the impact of energy uncertainty from year to year on long term system reliability. The impacts of reservoir capacity and demand side management on water utilization and system reliability are investigated. The achieved benefits of the reliability enhancement strategies are analyzed and compared.

Chapter 6 summarizes the overall research work. The general conclusions drawn from various studies and results of proposed methodologies in different chapters of the thesis are presented in this chapter.

1.6 References


PREFACE TO CHAPTER 2: RELIABILITY ASSESSMENT OF HYDRO DOMINANT SYSTEMS WITH DIURNAL ENERGY MANAGEMENT

The manuscript titled “Reliability Assessment of Hydro Dominant Systems with Diurnal Energy Management” is presented as Chapter 2. The manuscript has been published and presented in the 2017 IEEE Electrical Power and Energy Conference (EPEC). The basics of reliability modelling of a run-of-river hydro generation plant considering energy limitations is presented in this chapter. The work presented in Chapter 2 addresses the research objective of developing analytical reliability models to improve system reliability under energy limitation during the peak hours of the day in during low river inflow periods of the year.
CHAPTER 2: RELIABILITY ASSESSMENT OF HYDRO DOMINANT SYSTEMS
WITH DIURNAL ENERGY MANAGEMENT

Fang Fang, Rajesh Karki, Senior Member, IEEE

2.1 Abstract

Hydro-electric generation is often energy limited due to insufficient river inflow during dry seasons. This can result in significant adverse impact on long term system adequacy. Most hydro plants are run-of-river types that have small head pond with limited storage capability to manage available energy to follow the demand variation. The opportunity for reliability enhancement of a hydro-dominant system through diurnal water management with the limited storage needs to be properly investigated. This paper presents analytical reliability models of head pond and power generation to recognize energy storage and the magnitude and time-shift of output power to match the diurnal load profile during energy limited periods of the year. The developed models are applied to the IEEE Reliability Test System that is modified to create a hydro dominant system. The impact on system reliability of diurnal energy management and the number plants involved in energy management are investigated in the study.

2.2 Introduction

The Hydro power is an efficient and clean way to produce electricity. Canada is the third largest hydropower producer in the world with 60% of total electricity produced by hydropower [1]. Canada had 542 hydroelectric generation stations with 78,359 MW of installed capacity in
2014 according to Natural Resources Canada [1], and Canadian Geographic estimated it has ability to increase to 160,000 MW [2].

Fuel supply restrictions are energy limitation factors for conventional thermal generations [3]. Similarly, the historical river inflow, operating policy and load levels determine the energy and capacity states of the hydro plants [4]. Inadequate river inflow during the dry months of the year causes energy limitation in hydro plants which can have significant impact on the overall system reliability.

Generation adequacy assessment is a study to determine if a power system has adequate generation to meet system load demand in the foreseeable future. The capacity outage of a thermal generating unit mainly depends on its forced outage rate (FOR) [5]. The capacity outage of a hydraulic unit, however, also depends on energy deficit due to water restrictions.

There has been considerable research work on the reliability of hydro-thermal power generation systems. Most of the reported work mainly focus on the effects of FOR and load uncertainty [3] on hydro-thermal systems, but do not consider impacts of energy limitation on the reliability of hydro-dominant systems. The effects of water operating policies and reservoir depletion are analysed and presented in [4] and [6]. The operation and coordination between wind power, thermal generation and hydro generation are presented in [7-9]. Past works on hydro plants mainly focus on the reliability benefits of the system with coordination of the hydro-thermal plants and operating policies with available energy in storage-type reservoir. As most run-of-river plants have very little storage capability, the benefits of storage and water management in these plants have largely been ignored in the past studies. However, there are many hydro dominant power
systems that have large number of run-of-river plants, and the collective benefits may result in significant reliability enhancement. The opportunity for reliability enhancement of a hydro-dominant system through diurnal water management with the limited storage needs to be properly investigated. This paper presents analytical reliability models of head pond and hydropower generation to recognize energy storage and the magnitude and time-shift of output power to match the diurnal load profile during energy limited periods of the year.

The study in this paper considers a hydro dominant power system consisting of a large number of run-of-river plants that are energy limited due to insufficient water in-flow during the dry months of the year. The developed models are applied to the IEEE Reliability Test System (RTS) [10] that is modified to create a hydro dominant system consisting of 7 hydro plants and 2 thermal plants. A range of reliability studies are carried out to assess the benefits of energy management of the run-of-river plants with limited storage. The impact of energy limited hydro plants with energy management on overall system generation adequacy is illustrated.

2.3 Power System Reliability Modeling

2.3.1 Reservoir Model

The power output of a hydro plant depends on the river inflow rate, the reservoir head and the discharge rate at the turbine. The reservoir head depends on the water volume in the reservoir. The reservoir volume \( V(i) \) at the beginning of the \( i^{th} \) hour can be calculated using (2.1).

\[
V(i) = V(i - 1) + InV(i - 1) - OutV(i - 1) \tag{2.1}
\]
where, \( InV(i-1) \) is inflow water volume in \((i-1)\)th hour and \( OutV(i-1) \) is outflow water volume in the \((i-1)\)th hour.

The net head \( H(i) \) of the hydro plant at the beginning of the \( i \)th hour is calculated using (2.2). It is assumed in this study that the reservoir is cuboidal shape, and \( A \) is the surface area of cuboid.

\[
V(i) = A \times H(i)
\]

(2.2)

The power output \( P \) in MW of a generating unit in the hydro plant can be obtained using (2.3), where \( g \) is the gravitational constant, \( \alpha \) is the overall efficiency of the turbine generator, \( Q(i) \) is the turbine discharge rate in the \( i \)th hour, and \( s \) is the specific weight of water.

\[
P = g \times \alpha \times H(i) \times Q(i) \times s / 10^6
\]

(2.3)

The hydrological data of a river in the British Colombia province of Canada is used in this study [11], and Figure 2.1 shows the probability distribution of the average monthly river inflow. It can be seen that the water inflow is significantly reduced during the months between October and March, and therefore results in limited output capacity of the hydro generation plants.
2.3.2 Load Model

For run-of-river hydro plants with limited reservoir capacity, water can be stored for short periods within a day and managed to produce full power output for limited time during the peak load hours. Since the river inflow varies from month to month, the system load model is created for each month to perform a period analysis [12]. A sequential daily load profile is created for each month by averaging hourly loads for the particular month. Figure 2.2 shows the average daily load profile for the month of January.
The daily load profile is divided into two sub-periods, the peak load period and the off peak period as shown in Figure 2.2. The average hourly load data in each sub-period are arranged in decreasing order to create load duration curves (LDC) [5]. Figure 2.3 shows the LDC for each sub-period of an average day for the month of January. The loads are shown in per unit of the system annual peak load.

Figure 2.8. Daily Load Profile for the Month of January
2.3.3 Generating System Model

The power output of a conventional generating unit mainly depends on the availability of the unit. However, for hydro generation, energy limitation due to reduced water inflow also affects the power output of the generating units. The power output of a run-of-river hydro plant with limited reservoir is derated due to limited water inflow.

The total energy $E$ that can be produced by a hydro plant in a day is calculated using (2.4).

$$E = \sum_{k=1}^{24} P_k$$  \hspace{1cm} (2.4)

where, $P_k$ is the power output of the plant at hour $k$ calculated using (2.3). The limited storage capacity of the plant is exploited to generate rated capacity $F$ during the peak hour period $hrp$, and
the remaining energy is utilized to supply the load at derated output capacity $D_W$ during the off peak hours $hr_o$ that is calculated using (2.5).

$$D_W = \frac{E - F \cdot hr_p}{hr_o} \quad (2.5)$$

The generation model of a run-of-river hydro unit for each sub-period within a day under energy management is represented by a two-state Markov model as shown in Figure 2.4. The “up state” corresponds rated capacity and derated capacity respectively for the peak hour and off hour periods, whereas the “down state” corresponds to forced outage state with the FOR probability. The individual unit models are aggregated to obtain the hydro plant model for each sub-period of the day. The generation models of run-of-river hydro plants under energy management are combined with the remaining hydro and other conventional plants of the system to create the overall generation model.

Figure 2.10. Two-State Hydro Unit Generation Model

2.4 Application of Energy Management on the Test System

The IEEE RTS system has 32 units with installed generation capacity of 3405 MW. This system is modified to create a hydro dominant system consisting of 2 thermal plants and 7 hydro plants as shown in Table 2.1.
Table 2.1. Modified Hydro Dominant RTS

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Plant Capacity (MW)</th>
<th>Units</th>
<th>Capacity (MW)</th>
<th>FOR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>60</td>
<td>5</td>
<td>12</td>
<td>0.097</td>
</tr>
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<td>4</td>
<td>20</td>
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<td>Hydro</td>
<td>300</td>
<td>6</td>
<td>50</td>
<td>0.0262</td>
</tr>
<tr>
<td>Hydro</td>
<td>300</td>
<td>3</td>
<td>100</td>
<td>0.0507</td>
</tr>
<tr>
<td>Hydro</td>
<td>304</td>
<td>4</td>
<td>76</td>
<td>0.0262</td>
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<td>Hydro</td>
<td>591</td>
<td>3</td>
<td>197</td>
<td>0.0129</td>
</tr>
<tr>
<td>Thermal</td>
<td>350</td>
<td>1</td>
<td>350</td>
<td>0.08</td>
</tr>
<tr>
<td>Thermal</td>
<td>800</td>
<td>2</td>
<td>400</td>
<td>0.08</td>
</tr>
</tbody>
</table>

2.4.1 Reliability Impact of Energy Limitation in a Hydro Dominant Power System

A study was carried out on the modified RTS shown in Table 2.1 assuming that the hydro plants listed in the top three rows are energy limited during the periods between October and March. Table 2.2 shows the monthly data that are used to model the energy limited hydro plants. All other hydro and thermal plants can generate rated power unless on forced outage. The system generation models are created for such sub-period of the month and convolved with the corresponding load models to obtain the loss of load expectation (LOLE) for each month. The monthly LOLE values are combined to obtain the annual system LOLE. Figure 2.5 shows the annual LOLE as a function of the system peak load for three cases: (i) the original RTS, (ii) the modified hydro-dominant RTS assuming no energy limitation, and (iii) the modified hydro-dominant RTS assuming energy limitation during the months between October and March.

Figure 2.5 shows that the system LOLE increases with the increase in the peak load for all cases. The FOR of hydro units are typically lower than that of thermal units of similar sizes, and
therefore, the LOLE for Case (ii) is significantly lower than that of the original RTS in Case (i). However, due to the energy limitation in hydro units during the 7 months, the LOLE for Case (iii) is substantially increased, and therefore, the corresponding LOLE curve is shifted up. The degradation of system reliability due to energy limitation in river flow can however be mitigated using proper water management.

Table 2.2. Energy Limited Hydro Plants Data

<table>
<thead>
<tr>
<th>Plant Capacity (MW)</th>
<th>Max Head (m)</th>
<th>Max Vol (m³)</th>
<th>Month</th>
<th>Inflow Rate (m³/s)</th>
<th>Plant Power Output (MW)</th>
<th>Unit Power Output (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>60</td>
<td>254.8</td>
<td>10.8x10⁶</td>
<td>Jan/Feb/Nov/Dec</td>
<td>15</td>
<td>30</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Mar/ Oct</td>
<td>22.5</td>
<td>45</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Apr-Sep</td>
<td>30+</td>
<td>60</td>
<td>12</td>
</tr>
<tr>
<td>80</td>
<td>339.8</td>
<td>16.2x10⁶</td>
<td>Jan/Feb/Nov/Dec</td>
<td>15</td>
<td>40</td>
<td>10</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Mar/ Oct</td>
<td>22.5</td>
<td>60</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Apr-Sep</td>
<td>30+</td>
<td>80</td>
<td>20</td>
</tr>
<tr>
<td>300</td>
<td>637.1</td>
<td>25.9x10⁶</td>
<td>Jan/Feb/Nov/Dec</td>
<td>30</td>
<td>150</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Mar/ Oct</td>
<td>45</td>
<td>225</td>
<td>37.5</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Apr-Sep</td>
<td>60+</td>
<td>300</td>
<td>50</td>
</tr>
</tbody>
</table>
It was discussed in the previous section that river inflow limitations in the dry months can severely degrade the reliability of a hydro-dominant power system. Many hydro dominant systems consist of a large number of run-of-river type hydro plants. But since their storage capability is very limited, the reliability impacts of diurnal energy management in their head ponds are generally not considered. This study evaluates the reliability of the modified RTS by integrating the energy management models presented in Section 2.2 of this paper. These models are created...
for the four run-of-river hydro plants shown in the top four rows of Table 2.1 for each month of the year. Energy management has been applied to these four plants to reduce loss of load by saving water during the off-peak period by operating at derated capacity, and generating full capacity during peak load period. These plants are operated as four-hour peak rating units. The diurnal hourly loads are separated into four peak hours and twenty off peak hours in this study. The system generation and models are created for these two periods for each month of the year. The generation model is initially created by sequentially simulating the river inflow and pond head for each hour of the off-peak period considering a constant power output at the derated capacity level. The time sequential simulation is then continued into the peak-hour period considering rated capacity output of the plant. Figure 2.6 shows the reservoir head and turbine discharge rate of the 60 MW run-of-river plant for each hour of the average January day.

It should be noted that Hour 17 in Figure 2.6 corresponds to 5 PM, which is the beginning of the peak-hour period as illustrated in Figure 2.1. At this time, the reservoir head is at its peak level, and it drops rapidly as rated power is generated in the next four hours as shown in Figure 2.6. It also shows the water discharge rate to generate the rated 60 MW power in the four peak hours. Hour 21 in Figure 2.6 corresponds to 9 PM, which is the beginning of the off-hour period. At this time, the reservoir head is at its minimum level. Figure 2.6 shows the discharge rate reduced to generate a derated capacity of 24 MW for the next 20 hours of the off-load period. As water is allowed to accumulate in the pond by reducing the discharge rate, the pond head increased linearly as shown in Figure 2.6 until it reaches its peak level at the beginning of the peak-load hour. The 80MW and 300 MW plants are all modelled using the same procedure.
The total energy that can be produced by a run-of-river plant in a day during a dry month depends on the river inflow and is the same regardless of the operating strategy. Figure 2.7 shows the power output of the 60 MW plant before and after water management. The plant is operated continuously at 30 MW capacity during the dry month when water management is not done. It should be noted that the total energy or the areas under the two curves in Figure 2.7 are the same. The capacity outputs required for energy management of all the 4 run-of-river plants for the different months of the year are shown in Table 2.3.
The system LOLE was calculated using the period and sub-period analysis as discussed in Section II of this paper for different case studies. The system annual peak load of the modified RTS was assumed to be 2500 MW. The LOLE results are shown in Figure 2.8.
Figure 2.8 shows that the system LOLE is 3.3698 h/yr when the 4 hydro plants are energy limited but energy management is not done during plant operation. The reliability of the system improves as the LOLE drops to 3.1222 h/yr when energy management is performed on the 60 MW plant. The system reliability is further improved when the 80 MW plant is also under energy management operation. With the addition of the 300 MW plant under energy management, the system LOLE drops to its lowest level as shown in Figure 2.8. The LOLE, however, is increased when the fourth 300 MW plant is also operated for energy management. This is due to the increase in loss of load probability during the off-load period caused by significant reduction in generation capacity of the 4 plants during this period. These types of studies should be carried out before deciding which plants and how many of them should be operated under energy management to achieve a target level of system reliability.
Another study was carried out to investigate the impact on system reliability of varying the peak rating hours of the hydro units under energy management. It assumed that the first 3 plants in Table 2.1 are operated for energy management, but the peak rating hours are varied from 2 hours to 6 hours. The results are shown in Figure 2.9. It can be seen that the system reliability is increased as the peak rating hours of the hydro units are increased from 2 to 5 hours. The system reliability is, however, decreased when the peak rating exceeds 5 hours as shown in Figure 2.9.

![Graph showing LOLE (hr/yr) vs. Number of Peak Rating Hour](image)

**Figure 2.15. Reliability Impact of Peak Rating Hours of Hydro Units under Energy Management Operation**

### 2.5 Conclusion

Hydroelectric power generation is an efficient way to produce clean energy. Hydroelectric plants are typically more reliable than thermal plants due to low FOR of the generating units unless there is significant seasonal water inflow variation causing energy limitation. A hydro plant becomes an energy limited source when insufficient water inflow occurs during the seasons, and
this adversely affects the long-term system adequacy. A large portion of a hydro-dominant power system is typically composed of run-of-river plants with small head ponds. Although these plants have virtually no ability to store energy during the wet seasons to use them in the dry seasons, they do have the ability to transfer energy from the off-peak hours to the peak load hours within a day.

This paper presents a generation model of a run-of-river plant by correlating the water condition in the reservoir with the power output of the plant. A methodology involves a monthly period analysis to incorporate the seasonal correlation between the river conditions and the system load, and further sub-period analysis to incorporate diurnal water management from the off-load hours to the peak-load hours. The results from selected studies show that there is noticeable increase in the system reliability due to energy management of run-of-river plants. The system reliability improves as the energy management strategy is applied to an increasing number of hydro plants up to a certain limit, after which the system reliability will decrease due to excessive reduction in generation capacity during the off-load period. The optimum number of run-of-river plants to be operated with the energy management scheme can be determined as illustrated in the paper. The paper also illustrates the method to determine the peak rating hours for the energy limited hydro plants. This depends on the unit ratings, reservoir volume and river inflow. The illustrated example shows that the 5-hour peak rating results in maximum system reliability. The presented models and results provide useful information and suggestion for utilities to minimize the impacts of energy limitation on generation adequacy of hydro plants with small head pond during energy limited periods.
2.6 Reference


PREFACE TO CHAPTER 3: SEASONAL RESERVOIR MANAGEMENT IN HYDRO DOMINANT POWER SYSTEMS TO ENHANCE AVAILABILITY

The manuscript titled “Seasonal Reservoir Management in Hydro Dominant Power Systems to Enhance Availability” is presented as Chapter 3. The manuscript has been published and presented in the 2017 IEEE Electrical Power and Energy Conference (EPEC). The basics of reliability modelling of a storage type hydro generation plant considering energy limited period of the year is presented in this chapter. The work presented in Chapter 3 addresses the research objective of developing analytical reliability models to improve system reliability under seasonal energy limitations.
CHAPTER 3: SEASONAL RESERVOIR MANAGEMENT IN HYDRO DOMINANT POWER SYSTEMS TO ENHANCE AVAILABILITY

N. Chattha, Fang Fang, Rajesh Karki, Senior Member, IEEE

3.1 Abstract

This paper presents reliability evaluation techniques and models for a hydro dominant system using analytical methods. Generation adequacy evaluation is done using the IEEE reliability test system modeled as a hydro dominant system, taking into account energy storage limitations of hydro plants. Seasonal analysis of storage type hydro is performed to save and have less water spillage when water inflow is high, and use it to supply load in dry months when water inflow is low and system is not capable to supply load. Studies represented in this paper specifically utilize different operating policies to save and transfer energy from wet season to dry season, and analyze its reliability benefits.

3.2 Introduction

Modern society has become very sensitive to electric energy demand and therefore reliability of power systems plays an important role in meeting electric demand of customers. Power systems use various sources to generate electricity such as coal, gas, hydro, wind, nuclear etc. Hydropower usage across the globe has increased in past few years and is further expected to increase in the future [1]. It is a clean source of electric energy as it does not emit any air pollutants and has ultra-low greenhouse gas emissions [1]. It is very flexible as it can be quickly ramped up and down relative to other energy generating technologies. Also, as energy can be stored in the reservoir, it
can assist in incorporating other variable renewable energy sources such as wind and solar energy.

Modern power systems are very complex and highly integrated, and therefore, it is difficult to analyze the entire power system as a single entity [2]. Reliability assessment of power systems can be done at different levels of generation, transmission and distribution, also known as hierarchy levels. This paper focuses on hierarchy level I (HLI) study, which takes into account the total system generation ability including any interconnected assistance to meet the total system load demand [2]. HLI study is also called generating capacity adequacy evaluation, and it does not consider the transmission and distribution networks.

Significant work has been done in past regarding modeling of hydro power plants and coordination between wind and hydro units [3-6]. A reliability evaluation approach that combines analytical and Monte Carlo simulation techniques to evaluate hydrothermal generating systems has been discussed in [7]. Reference [8] represents the reliability effects of variation in the number of hydro plants and in usage of water in the reservoir. There is limited work on seasonal analysis and effect of energy transfer on the reliability implications of hydro-dominant systems. This paper presents an analytical method that correlates the seasonal water in-flow with the system load variation, and assesses the appropriate seasonal transfer of energy in the reservoir of large storage hydro plants to enhance the generation adequacy of the system.

Hydropower generation is affected by water inflow, operating policies, storage capacity, and water management policies. There are different types of hydro plants, such as run of river, storage, pumped storage and offshore plants. Most of the installed hydro infrastructures contain either run of river or storage type hydro. Run of river hydro contains little or no water storage facilities,
whereas storage type hydro have reservoirs and uses dam to store water. When water inflow is high, most hydro dominant utilities face problems of water spillage, and on the other hand, they are not able to meet load when inflow is very low. To solve this problem, energy storage capability of storage type hydro is exercised to transfer energy from wet season to dry season, utilizing different operating policies. This paper describes evaluation techniques and models used for reliability evaluation of a hydro dominant system using a probabilistic approach. Different operating strategies are compared and the resulting reliability benefits are evaluated. Energy limitation of hydro plants are introduced due to water storage limits of reservoir. Generation adequacy assessment is done using the IEEE Reliability Test System (RTS), which is further modified to represent a hydro dominant system, taking into account energy storage limitation of hydro plants.

3.3 Modelling

A probabilistic approach to calculate system reliability takes into account inherent risk of component failures and load variations [2]. In this approach, the system reliability is quantified in terms of risk indices that are evaluated from a risk model, which is further calculated by combining generation model and load model. Generation model is developed based on the operating characteristics of all of the generating units. In hydropower systems, generation capacity of a unit depends on the reservoir head at a given instant, as well as the planned and forced outages of the generating units. The loss of load in a hydro dominant power system can be either due to energy deficit i.e. water storage limits of the hydro plants or due to power deficit i.e. due to peak capacity limits of the hydro plants [8].
3.3.1 Load Model

Different types of load models can be used to represent the system load demand. However, daily peak load variation curve (DPLVC) and load duration curve (LDC) are the most widely used models to calculate reliability indices. Arranging the individual daily peak load in descending order over a period generates the DPLVC, which will therefore provide results in terms of days per period. Whereas, arranging individual hourly peak loads over a period of time creates the LDC and the area under LDC represents energy demand for the system. Load data for case studies represented in this paper is taken from a hydro-dominant Canadian utility as provided in [10]. Most electric utilities use a reliability criterion in days per year that is obtained using the DPLVC as the load model. Since hydropower systems are often constrained by energy limitation due to water inflow or reservoir size, the LDC is a more appropriate model to assess energy-based indices. The studies presented in this paper, therefore, use both the DPLVC and the LDC to represent system load demand and are plotted for each month of year. Figure 3.1 shows DPLVC and LDC for the month of January.
3.3.2 Generation Model

The IEEE RTS system generation model [9] is used for base case studies and later on it is modified to represent a hydro dominant system, which consists of two thermal plants and seven hydro plants as shown in Table 3.1. Studies are done in this paper to show the effect of storage type hydro plant on system reliability and hence only one plant is taken as storage hydro while others are represented as run of river hydro plants. The 591 MW plant having 3 units of 197 MW each is chosen in case study to represent the storage hydro plant. When energy limitation is introduced, run of river plants in dry season run at de-rated capacity as water inflow is greatly reduced during this time and the run-of-river plants have negligible storage facility. Whereas, storage hydro units will use water stored in the reservoir based on water inflow, to generate power,
which is further limited by water storage level, rated capacity, and minimum reservoir level that needs to be maintained as per operating policies under water agreements. The modeling of a storage hydro plant is described in next section.

It is assumed that the time between forced outages and duration of the unit forced outages of generating units are independent and are exponentially distributed and that a forced outage of any unit causes loss of total unit capacity [8]. It is also assumed that repair is taken as soon as unit fails and there are enough workmen to repair failed units, also that the repair is always successful and is independent of any other repairs or failures [8].

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Plant Capacity</th>
<th>Units</th>
<th>Unit Capacity (MW)</th>
<th>FOR</th>
</tr>
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<td>Hydro</td>
<td>80</td>
<td>4</td>
<td>20</td>
<td>0.097</td>
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<td>Hydro</td>
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<td>0.0129</td>
</tr>
<tr>
<td>Thermal</td>
<td>350</td>
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<td>350</td>
<td>0.08</td>
</tr>
<tr>
<td>Thermal</td>
<td>800</td>
<td>2</td>
<td>400</td>
<td>0.08</td>
</tr>
</tbody>
</table>

3.3.2.1 Storage Hydro Plant Model

The potential energy that stored in water in a reservoir is transformed into electrical energy by means of turbines and generators. The input energy is associated with water inflow to the reservoir and output energy with electricity generation. The water inflow mainly comes from seasonal rainstorms and snowmelts. It is assumed that all the generating units within a storage
hydro plant are operated in the same way for each day of a month. Table 3.2 shows the water inflow data that is used in this study. The mean water inflow for the year is 80 $m^3/s$. Table 3.3 provides the storage type hydro plant data that is used in the study.

The natural sites that are used to create a reservoir have different elevations and hence the water head changes differently. The net head $H_i$ of the hydro plant at the beginning of the $i^{th}$ hour is calculated from the reservoir volume $V_i$ at the beginning of the $i^{th}$ hour using (3.1). It is assumed that the reservoir under study has vertical sides and a second order equation representing trapezoidal cross section is used to represent reservoir [4]. The constant $a$, $b$, $c$ are reservoir model coefficients.

$$V_i = a.H_i^2 + b.H_i + c$$  \hspace{1cm} (3.1)

The reservoir volume $V_i$ can be calculated using (3.2).

$$V_i = \begin{cases} \frac{V_{(i-1)} - R_{(i-1)} - S_{(i-1)} + I_{(i)}}{V_{max}} & \text{if} \quad V_i - V_{max} = S_i > 0 \\ V_{max} & \text{if} \quad V_{max} = S_i \leq 0 \end{cases}$$  \hspace{1cm} (3.2)

where, $R_{(i-1)}$ is the released water volume to support fisheries, flood management, recreation, wildlife and archeological resources in $(i-1)^{th}$ hour and $I_{(i)}$ is inflow water volume in the $i^{th}$ hour. $S_i$ is the water spillage volume in $i^{th}$ hour, also calculated from (3.2).

The power output $P_i$ of a generating unit in the hydro plant can be obtained using (3.3), where $g$ is the gravitational constant, $\alpha$ is the overall efficiency of the turbine generator, $Q$ is the turbine discharge rate in the $i^{th}$ hour, and $s$ is the specific weight of water.
\[ P_i = g.\alpha. H_i. Q. s/10^6 \]  

(3.3)

Table 3.5. Water Inflow Data

<table>
<thead>
<tr>
<th>Month</th>
<th>% Inflow</th>
<th>Inflow (m³/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>2</td>
<td>19.2</td>
</tr>
<tr>
<td>Feb</td>
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<td>19.2</td>
</tr>
<tr>
<td>Mar</td>
<td>3</td>
<td>28.8</td>
</tr>
<tr>
<td>Apr</td>
<td>7</td>
<td>67.2</td>
</tr>
<tr>
<td>May</td>
<td>24</td>
<td>230.4</td>
</tr>
<tr>
<td>Jun</td>
<td>26</td>
<td>249.6</td>
</tr>
<tr>
<td>Jul</td>
<td>16</td>
<td>153.6</td>
</tr>
<tr>
<td>Aug</td>
<td>9</td>
<td>86.4</td>
</tr>
<tr>
<td>Sep</td>
<td>4</td>
<td>38.4</td>
</tr>
<tr>
<td>Oct</td>
<td>3</td>
<td>28.8</td>
</tr>
<tr>
<td>Nov</td>
<td>2</td>
<td>19.2</td>
</tr>
<tr>
<td>Dec</td>
<td>2</td>
<td>19.2</td>
</tr>
</tbody>
</table>

Table 3.6. Hydro Plant Data

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Hydro Units</td>
<td>3</td>
</tr>
<tr>
<td>Plant Efficiency</td>
<td>0.8</td>
</tr>
<tr>
<td>Maximum Water Head</td>
<td>682 m</td>
</tr>
<tr>
<td>Reservoir Coefficients: a</td>
<td>0.00241</td>
</tr>
<tr>
<td></td>
<td>b 0.111</td>
</tr>
<tr>
<td></td>
<td>c 2</td>
</tr>
<tr>
<td>Minimum Water Volume</td>
<td>260Mm³</td>
</tr>
<tr>
<td>Maximum Water Volume</td>
<td>1200Mm³</td>
</tr>
<tr>
<td>Minimum water release for</td>
<td>5m³/s</td>
</tr>
<tr>
<td>fisheries</td>
<td></td>
</tr>
</tbody>
</table>

3.4 Reliability Impact of Energy Limitation in A Hydro Dominant Power System

A study was done using three different generation profiles to calculate the system LOLE. First, the IEEE RTS generation data [9] and the load data [10] are used to evaluate results. Second, the IEEE RTS system is modified to represent a hydro dominant system as described in previous
section. In this case, it is assumed that the hydro plants in the system have unlimited flow of water and hence have no energy limitation. The third case considers energy limitation of the hydropower plants. For this study, a year is divided in two seasons based on water inflow. The months from April to September fall within the wet season, whereas October to March months are in the dry season as shown by the water inflow data in Table 3.2. The run of river plants in energy limited hydro system have de-rated capacity in dry months because of reduced water inflow. It is assumed that the run of river hydro plants are derated to 70 percentage of rated capacity in the dry season, however they are capable to operate at rated capacity during wet months because of high water inflow. The capacity of the storage type hydro units depends on the water inflow and energy available in the reservoir.

The LOLE of the system was evaluated for the three different cases described above, and the results are displayed in Figure 3.2. The hydro dominant system without energy limitation performs better than the original RTS because of the fact that forced outage rates of hydro units are less than thermal units for same MW capacity ratings. It can be seen that the LOLE values increased significantly in the case of the energy limited hydro dominant system, mainly because of the restricted water flow and storage capacity. The LOLE in days per period was also calculated, and it shows a similar trend as shown in Figure 3.3.
Figure 3.17. LOLE (hr/yr) for the Original RTS, Hydro Dominant System without Energy Limitation and Hydro Dominant System with Energy Limitation

Figure 3.18. LOLE (days/yr) for the Original RTS, Hydro Dominant System without Energy Limitation and Hydro Dominant System with Energy Limitation
3.5 Application of Energy Management on the Test System

The reliability of a system can be improved in various ways. One way to improve the system reliability without adding additional units is changing the operating strategy of hydro plants. The monthly peak load of the system under consideration is plotted in Figure 3.4. It is observed that peak load is high during dry months, and relatively low during the wet months. The wet months, however, have high generating capacity due to high water inflow. Therefore, it is decided to transfer energy from wet season to dry season to serve the high load during the dry season. This possibility is realized by reducing capacity of the units in wet months to save energy and use that energy to generate more power during dry season.

![The Monthly Peak Load of the System](image)

The reliability of a system can be expressed in terms of various indices. Most common used indices by North American utilities are loss of load expectation (LOLE) and percentage reserve. The LOLE gives indication of number of hours or days in a period considered that total generation
system will not be able to supply the load demand. Whereas, the percentage reserve provides information about stand-by capacity that a system should maintain to supply load in the event of an unplanned outage. In addition to above mentioned indices, loss of energy expectation (LOEE) and peak load carrying capability (PLCC) of the system are also calculated, as they provide valuable information about system inadequacy in terms of energy and load carrying capability.

![Graph showing system peak load and monthly change in generating capacity of the hydro units before and after energy transfer.](image)

**Figure 3.20.** Hydro Dominant System Peak Load and Generation Capacity of Storage Hydro Plant before and after Energy Transfer.

The system peak load and monthly change in generating capacity of the hydro units before and after energy transfer are displayed in Figure 3.5. The Case 1 shows the monthly power generation of 591MW hydro plant before energy transfer and the Case 2 displays power generation profile after energy is transferred from wet to dry season. The generation capacity of the plant is increased in the months when load demand is high. It can be stated that hydro plant generation
The reliability indices are evaluated for 2000 MW peak load as displayed in Table 3.4. All indices show improvement in their value after transfer of energy. The loss of load and energy expectations reduced significantly for dry season, mainly because of increase in generation capacity of the units, further attributed to increase in available hydro energy transferred into dry season. The peak load carrying capability of the system calculated at LOLE of 0.1 days/year also increased from 25318.3 MW to 25326.1 MW i.e. increase of 7.8 MW. Hence, the value of energy storage can be expressed as the increase in peak load carrying capability of the system by 7.8 MW. The considerable increase in capacity reserve is also observed, it is seen that the minimum capacity percent reserve for the system increases two times from 14.8 to 28.1, without the need for the additional generation or decrease in load.

The water volume change in reservoir before and after energy transfer is shown in Figure 3.6, where the volume of water in the reservoir at the start of each month is plotted for each month of the year. The reservoir is full in the month of July because of the high water inflow during this month and preceding months. As shown in Figure 3.5, the hydro units operate at high capacity from July to November before energy transfer, because of the decent amount of hydro energy available along with high water inflow. Hence, the water gets depleted in reservoir fast during this period and the reservoir reaches its minimum level in December. Therefore, the units operate as
per the available inflow afterwards and the water level remains constant at its lowest level in reservoir as shown in Figure 3.6, until the inflow increases and the reservoir starts getting filled up. The reservoir gets filled up to its maximum volume during the month of June.

In second case, the units are operated in wet season at a capacity to avoid water spillage while maintaining the full reservoir volume until the start of dry season. Now, as more hydro energy is available in the dry season, the hydro units operate at higher capacity than the case 1 and the reservoir gets depleted gradually in the dry season. The reservoir reaches its minimum level in the month of April and gets filled up in June.

Table 3.7. Results for Hydro Dominant System

<table>
<thead>
<tr>
<th>Reliability Indices</th>
<th>Period</th>
<th>Before energy transfer</th>
<th>After energy transfer</th>
</tr>
</thead>
<tbody>
<tr>
<td>LOLE (days/pd)</td>
<td>Dry season</td>
<td>2.5292</td>
<td>0.1672</td>
</tr>
<tr>
<td></td>
<td>Wet season</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Year total</td>
<td>2.5292</td>
<td>0.1672</td>
</tr>
<tr>
<td>LOLE (hrs/pd)</td>
<td>Dry season</td>
<td>21.4551</td>
<td>1.3868</td>
</tr>
<tr>
<td></td>
<td>Wet season</td>
<td>0.0002</td>
<td>0.0001</td>
</tr>
<tr>
<td></td>
<td>Year total</td>
<td>21.4553</td>
<td>1.3869</td>
</tr>
<tr>
<td>LOEE (MWh/pd)</td>
<td>Dry season</td>
<td>2687.0490</td>
<td>156.1210</td>
</tr>
<tr>
<td></td>
<td>Wet season</td>
<td>0.006</td>
<td>0.003</td>
</tr>
<tr>
<td></td>
<td>Year total</td>
<td>2687.0550</td>
<td>156.1240</td>
</tr>
<tr>
<td>PLCC of System (MW)</td>
<td></td>
<td>25,318.3</td>
<td>25,326.1</td>
</tr>
<tr>
<td>Percentage Reserve (%)</td>
<td></td>
<td>14.8501</td>
<td>28.1041</td>
</tr>
</tbody>
</table>
3.6 Conclusion

This paper described the modeling of a hydro dominant power system and the operating policies that can be used to improve reliability of a hydro dominant system. The different operating strategies are compared and resulting reliability benefits are evaluated. The analytical techniques have been used to calculate reliability indices for the IEEE RTS system, which is further modified to represent a hydro dominant system, containing run of river and storage hydro plants. The energy limitation of hydro plants is introduced and the energy storage capability of storage hydro plants is practiced to transfer energy from wet season to dry season. The results calculated show significant improvement in LOLE and LOEE for the dry season, further attributed to change in operating policies and energy management. It is also observed that the percentage reserve capacity that the system is able to maintain also increased without the need for additional generating unit.
for a peak load. Moreover, the system also observed increase in peak load carrying capability, which provides a positive value of energy storage.

3.7 Reference

PREFACE TO CHAPTER 4: RELIABILITY IMPLICATIONS OF RIVERFLOW VARIATIONS IN PLANNING HYDROPOWER SYSTEMS

This chapter is organized as a manuscript titled “Reliability Implications of Riverflow Variations in Planning Hydropower Systems”. The manuscript is published and presented in the IEEE SusTech 2018 Conference. The fundamental concept of hydro dominant system reliability analysis used in Chapter 2 and 3 have been extended and integrated to investigate suitable reliability indices for hydro dominant power system. The reliability implications of river flow variations and load uncertainty, the impact of water management strategy, and maintenance coordination with river flow limitations in hydro dominant systems were analyzed and presented in the paper. The objectives of the research, as stated in Section 1.4: ‘to assess the usefulness of NERC recommended reliability criterion in energy based hydro dominant system and make recommendations on reliability indices’ and ‘To develop methodology to benefit hydro dominant system from maintenance schedule coordination with load levels and inflow restrictions’ were met in this chapter.
CHAPTER 4: RELIABILITY IMPLICATIONS OF RIVERFLOW VARIATIONS IN PLANNING HYDROPOWER SYSTEMS

Fang Fang, Rajesh Karki, Senior Member, IEEE

4.1 Abstract

The variability and uncertainty with river flow characteristics in hydro-dominant power systems create considerable challenges in planning adequate generation capacity to maintain a target level of reliability. Unlike other firm capacity generation sources, hydropower sources are energy-limited by seasonal and climactic variability in water restrictions. These utilities face energy wastage caused by water spillage during high inflow season or low load period of the day. On the other hand, they have inadequate generation capacity to meet the load during peak load period or low inflow season. It becomes very important for hydro dominant utilities to properly manage and utilize their water resource to maintain or enhance the system reliability. Energy-based utilities are also concerned on the suitable reliability criteria they should use to fully capture energy management based on hydrological characteristics. This paper presents reliability models of run-of-river and large storage-type hydro plants to recognize their energy and capacity characteristics and proposes a methodology to incorporate water management strategies for reliability enhancement of hydro dominant power systems. The usefulness of NERC recommended reliability criterion in energy-based hydro dominant system has also assessed and discussed in the studies. The reliability impacts of proposed methodology with river flow variations, load uncertainty and maintenance schedule coordination with load levels and inflow restrictions are
evaluated using the IEEE Reliability Test System that is modified to create a hydro dominant system.

4.2 Introduction

Many power systems around the world are primarily supplied with hydropower sources. Hydropower sources have economic and environmental advantages over other types of energy generation resources since hydropower generation does not consume fuel, nor contribute to greenhouse gas emissions. Short lead times and high ramp rates of hydraulic units can provide low cost operating reserves and regulating margin to enhance the operating reliability of power systems. The variability and uncertainty with river flow characteristics, however, creates considerable challenges in planning adequate generation capacity to maintain a target level of reliability. Unlike other firm capacity generation sources, hydropower sources are energy-limited by seasonal and climactic variability in water restrictions. Their capacity is determined by river inflow, operating policy and load levels [1]. There are mainly two types of hydro plants installed in the utilities: run-of-river and storage type hydro plants. Run-of-river hydro contain small head pond with limited storage capacity, whereas storage type hydro have large reservoirs to store water. Most hydro dominant utilities face energy wastage caused by water spillage during high inflow season or low load period of the day. On the other hand, they have inadequate generation capacity to meet the load during peak load period or low inflow season. It becomes very important for hydro dominant utilities to properly manage and utilize their water resource to maintain or enhance the system reliability.
Past research is reported on reliability of hydro-thermal power systems, where the hydro units are operated with other types of generating units to minimize power fluctuations, coordinate with maintenance, consider reservoir depletion, and to meet target economic benefits [2-5]. The water operating policy of hydroelectric units located on the same river system is evaluated in [6]. The reliability implications of river flow variations and load uncertainty, and the impact of proper water management from a reliability perspective in hydro dominant systems are not considered. Many North American power utilities utilize the North American Reliability Corporation (NERC) recommended criterion, i.e. a loss of load expectation (LOLE) of 0.1 days per year, in long-term capacity planning [7]. This index neglects the variations within a day, and therefore, is not responsive to diurnal capacity management or energy limitations in hydro dominant systems. Utilities containing significant energy-based generation facilities have showed concern on the usefulness of this index in reliability assessment of their systems. It is therefore important to assess the value of this index and identify more suitable reliability metrics for hydro dominant power systems. Power utilities schedule periodic maintenance of all the generating units to prolong useful life and ensure acceptable system reliability. The cost and benefits of thermal units’ maintenance have been studied and reported in [8] and [9]. Ref. [10] presents mathematical methods and the development of maintenance evaluation tools. The periodic maintenance of most firm capacity units are scheduled during the low load periods of the year. But hydro units can exploit maintenance scheduling opportunities during severe water restriction periods with little adverse impact on the system reliability. Past research have not evaluated the quantitative reliability impacts of such maintenance coordination. It is however very important to understand the
reliability implications of maintenance scheduling in coordination with river flow limitations, load levels and the maintenance schedule of other firm generating units in the system.

This paper presents reliability models of run-of-river and large storage-type hydro units and plants to recognize their energy and capacity availability characteristics, and proposes a methodology to incorporate water management and maintenance strategies for reliability enhancement of hydro dominant power systems. The proposed methodology recognizes the ability of diurnal water management in the small reservoir of run-of-river plants and seasonal water management of larger storage plants to enhance system reliability. The paper also presents studies to assess the practicality of the existing LOLE criterion and determine suitable indices for hydro dominant utilities to capture all the relevant characteristics of hydropower generation and restrictions. The reliability impacts of river flow variations, maintenance schedule coordination with load levels and inflow restrictions and load uncertainty are evaluated using the IEEE Reliability Test System (RTS) [11].

4.3 Hydro Plant Reliability Modeling and Methodology

4.3.1 Hydro Plant Modeling

The generation model of a hydro plant depends on the water operating policy and failures of individual generating units. The generation capacity is determined by the net head \( H(i) \) of reservoir, which depends on the reservoir volume \( V(i) \) at the instant \( i \) as shown in (4.1). It is assumed that the reservoir is cuboidal shape, and \( A \) is the surface area. The reservoir volume in a given hour \( i \)
depends on the inflow volume $InV(i-1)$, outflow $OutV(i-1)$ and the previous reservoir condition as shown in (4.2).

$$H(i) = \frac{V(i)}{A} \quad (4.1)$$

$$V(i) = V(i-1) + InV(i-1) - OutV(i-1) \quad (4.2)$$

The generation capacity $P$ in MW of a hydro plant can be obtained using (4.3) unless it is on forced outage characterized by its forced outage rate (FOR) [12].

$$P = g \times \alpha \times H \times Q \times s / 10^6 \quad (4.3)$$

Where, $g$ is the gravitational constant, $\alpha$ is the overall efficiency of the turbine generator, $Q$ is the turbine discharge rate, and $s$ is the specific weight of water.

A run-of-river hydro plant has a small head pond with limited storage capability. It usually has limited ability to manage its water resource to follow the load variation within a day, whereas large storage-type hydro units have ability to carry water from wet season to dry season in coordination with river flow load variation. The detailed explanation of these two energy management models are presented in [13] and [14] respectively. The two models are integrated using a suitable methodology for reliability assessment of a hydro dominant system in this paper. The water is stored for short periods within a day and managed to generate full capacity output for limited time during peak load hours in a run-of-river type hydro plant. A generation model is created for a seasonal period consisting of days with similar river inflow characteristics. The seasonal period can be a season, month or a week depending on the river flow characteristics of the plant location. A sequential hourly load profile is created for the day of each seasonal period. Figure 4.1 shows an example of an hourly load profile of a power system for an average day in the
month of January. The average hourly load profile is divided into peak load and off peak load sub
periods, and the loads in each sub period are arranged in descending order to create load duration
curves (LDC) [12]. Energy limitation in dry seasons affects generation capacity of hydro units.
The generation capacity in each hour of the day can be calculated using (4.3) to obtain the total
diurnal energy $E$ in the reservoir using (4.4). The plant is operated at rated capacity $C$ for $hr_p$ hours
during the peak hours, and the remaining energy in reservoir is utilized to supply load at a constant
reduced generation capacity $D$ that is calculated in (4.5). The reservoir volume is updated for each
hour using (4.1) as water is utilized to generate power.

\[
E = \sum_{k=1}^{24} P_k
\]  
(4.4)
\[
D = \frac{E - C + hr_p}{24 - hr_p}
\]  
(4.5)
Large storage type hydro plants can be operated to save and accumulate water during high inflow and low load seasonal periods of the year by reducing the plant generation capacity, and shift the energy to increase the generation capacity in the high load periods of the year. Separate generation models are thus created for each seasonal periods of the year.

4.3.2 Proposed Methodology

The proposed methodology integrates the diurnal and seasonal energy management in hydro dominant systems to enhance the capacity value of the total hydro power plants in meeting the system load. An evaluation year is divided into $p$ periods consisting of a number of days with similar load and river inflow characteristics, within which $q$ periods have energy limitations to satisfy the load requirement. The $q$ periods are further sub-divided two diurnal sub-periods, the peak and off peak periods. Generation models are created for each run-of-river and storage type hydro plants in a power system for each sub-period of the year and are convolved with each other and with other non-hydro generating units, such as thermal units, to obtain the overall system generation model for each sub-period. Load models in the form of load duration curves are also created for each sub-period. The system generation model and the load model for each sub-period are convolved to obtain the risk index $R_{ij}$, for period $i$ and sub-period $j$, where $j \epsilon q$, and $n_i$ is the number of days in period $q_i$. The annual reliability index is obtained using (4.6).

$$R = \sum_{i=1}^{p-q} R_j + \sum_{i=1}^q n_i * \sum_{j=1}^2 R_{ij} \quad (4.6)$$
4.3.3 Application of the Proposed Methodology

The proposed methodology is applied to the IEEE-RTS modified as shown in Table 4.1 to create a hydro dominant system. All the hydro plants, except the 620 MW plant, face energy limitations in the months between October to March. The hydrological data [15] and the system load [16] in per unit of the peak are shown in Figure 4.2. The FOR of the hydro units were obtained from [17], and the individual river inflow rates of hydro plants are shown in Figure 4.2.

Each day in the energy limited months between October to March is divided into two sub-periods of 4 peak load hours and 20 off-peak hours, and a generation model created for each sub-period for the run-of-river hydro plants. The generation models of large storage-type hydro were created for each month by reducing generation capacity in the wet months between April to September to save water in order to increase generation output in the energy limited months between October to March. The system generation models for the June and December monthly periods are shown in Figure 4.3. Each discrete state of the model shows the cumulative probability of at least a certain MW capacity being available in the generation system to serve the system demand.
Table 4.8. Modified IEEE-RTS Generation data

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Plant Capacity (MW)</th>
<th>Units</th>
<th>Capacity (MW)</th>
<th>FOR</th>
</tr>
</thead>
<tbody>
<tr>
<td>RofR Hydro</td>
<td>60</td>
<td>5</td>
<td>12</td>
<td>0.097</td>
</tr>
<tr>
<td>RofR Hydro</td>
<td>80</td>
<td>4</td>
<td>20</td>
<td>0.097</td>
</tr>
<tr>
<td>RofR Hydro</td>
<td>300</td>
<td>6</td>
<td>50</td>
<td>0.0262</td>
</tr>
<tr>
<td>Storage Hydro</td>
<td>300</td>
<td>3</td>
<td>100</td>
<td>0.0507</td>
</tr>
<tr>
<td>Storage Hydro</td>
<td>304</td>
<td>4</td>
<td>76</td>
<td>0.0262</td>
</tr>
<tr>
<td>Storage Hydro</td>
<td>620</td>
<td>4</td>
<td>155</td>
<td>0.0129</td>
</tr>
<tr>
<td>Storage Hydro</td>
<td>591</td>
<td>3</td>
<td>197</td>
<td>0.0129</td>
</tr>
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<td>Thermal</td>
<td>350</td>
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<td>350</td>
<td>0.08</td>
</tr>
<tr>
<td>Thermal</td>
<td>800</td>
<td>2</td>
<td>400</td>
<td>0.08</td>
</tr>
</tbody>
</table>

Figure 4.23. River Inflow Rate of Each Hydro Plant
4.4 Impact of Water Management on Reliability Indices

Two case studies were carried out on the test system with different water operating policy. Case (i) does not consider water management, and the plant generation capacity is dictated by the inflow rate for both the run-of-river and storage type hydro plants. In this case, the plant capacity is equal to the rated capacity in the wet season, and is derated in the dry season as shown in Tables 4.2 and 4.3. Case (ii) considers water management. The storage type plants are operated to store water in the wet season and use the stored water to increase the capacity in the dry season. The run-of-river hydro plants are operated at rated capacity during the 4 peak hours and at reduced capacity for the remaining 20 hours during the dry season as shown in Table 4.2 in order to accumulate water back to the highest level and prepare for the next day cycle. The peak load of the test system is 1960 MW. The load duration curves were created for each sub-period of each
monthly period. The system LOLE values were evaluated for each sub-periods and aggregated to first obtain the monthly indices and finally the annual LOLE in days/year.

Table 4.9. Run-of-river hydro generation capacity

<table>
<thead>
<tr>
<th>Installed Plant Capacity (MW)</th>
<th>Month</th>
<th>Inflow Rate (m3/s)</th>
<th>Based on Inflow Gen Cap (MW)</th>
<th>Diurnal Energy Management (MW)</th>
</tr>
</thead>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Peak Hour</td>
</tr>
<tr>
<td>60</td>
<td>Jan/Feb/Nov/Dec</td>
<td>15</td>
<td>30</td>
<td>60</td>
</tr>
<tr>
<td></td>
<td>Mar/ Oct</td>
<td>22.5</td>
<td>45</td>
<td>60</td>
</tr>
<tr>
<td>80</td>
<td>Jan/Feb/Nov/Dec</td>
<td>15</td>
<td>40</td>
<td>80</td>
</tr>
<tr>
<td></td>
<td>Mar/ Oct</td>
<td>22.5</td>
<td>60</td>
<td>80</td>
</tr>
<tr>
<td>300</td>
<td>Jan/Feb/Nov/Dec</td>
<td>30</td>
<td>150</td>
<td>300</td>
</tr>
<tr>
<td></td>
<td>Mar/ Oct</td>
<td>45</td>
<td>225</td>
<td>300</td>
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</table>

Table 4.10. Large Storage-type Hydro Generation Capacity

<table>
<thead>
<tr>
<th>Month</th>
<th>300 MW Plant Gen Cap (MW)</th>
<th>304MW Plant Gen Cap (MW)</th>
<th>591MW Plant Gen Cap (MW)</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Based on Inflow</td>
<td>Seasonal Energy Management</td>
<td>Based on Inflow</td>
</tr>
<tr>
<td>Jan</td>
<td>38</td>
<td>171.57</td>
<td>38.626</td>
</tr>
<tr>
<td>Feb</td>
<td>38</td>
<td>100</td>
<td>38.626</td>
</tr>
<tr>
<td>Mar</td>
<td>59.2367</td>
<td>91</td>
<td>57</td>
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<tr>
<td>April</td>
<td>138.219</td>
<td>136</td>
<td>136.654</td>
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<tr>
<td>May</td>
<td>300</td>
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<tr>
<td>June</td>
<td>300</td>
<td>300</td>
<td>304</td>
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<tr>
<td>July</td>
<td>300</td>
<td>300</td>
<td>304</td>
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</table>
Figure 4.4 shows the annual LOLE, and the LOLE during the energy limited months for the two cases for comparison. It can be seen that the reliability in the dry months is greatly improved with water management in Case (ii), and specially in December and January during which the system loads are the highest in the year. The annual LOLE is decreased from 9.6104 days/year to 0.0991 days/year due to energy management. The system peak load carrying capacity (PLCC) at an LOLE criterion of 0.1 days/year is increased from 1400 MW in case (i) to 1960 MW in case (ii).

In the other words, the water management strategy is equivalent to 560 MW of new generation.
The diurnal water management in the Case (ii) study was done on a varying number of run-of-river plants. The resulting system reliability were evaluated using three different indices, the LOLE in days/year, LOLE in hours/year and the LOEE. The diurnal energy management does not affect the LOLE day/year index since each day is represented by its peak load in the load model while evaluating this index. It therefore remains at 0.0991 days/year irrespective of the dirurnal energy management strategy. The LOLE in hours/year and LOEE respond to the variation in the system load within the day since an hourly load model is required to obtain these indices. These indices therefore change as the number of run-of-river hydro units selected to operate under water management is varied as shown in Figure 4.5. It can be seen that the LOLE in hours per year is reduced from 0.9031 to 0.8774, and the LOEE is decreased from 99.38 to 95.47 MWh/year when the diurnal energy management is applied to the 60 MW plant alone. The incremental increase in reliability is however reduced as more units are run with the energy management operating strategy.
The LOLE in days/year only responds to seasonal energy management, and therefore is unaffected by the diurnal energy management. The NERC recommended criterion of LOLE of 0.1 days/year is therefore not suitable to energy-based power systems, such as a hydro-dominant system. The 0.1 days/year planning criterion is found to be equivalent to LOLE of 0.9031 hours/year in this study. Figure 4.6 shows the PLCC using these two criteria. With 0.9031 hours/year planning criterion, the PLCC is increased from 1960 MW to 1974 MW due to diurnal energy management. However, the PLCC remains the same using the 0.1 days/year criterion as seen in Figure 4.6.

Figure 4.26. System Reliability Measured using Different Indices
Figure 4.27. PLCC Obtained by Daily and Hourly Index

The uncertainty in load forecast can also have considerable impact on the reliability planning of hydro dominant systems. A study was carried out to include load forecast uncertainty (LFU) by modeling it using a discrete normal distribution [13] with a standard deviation representing the uncertainty from the forecast mean value. The load model is modified by a seven-step approximation of the normal distribution with a standard deviation of 2% of the forecast peak load of 1960 MW. The system LOLE evaluated for the month of June in the dry season and the month of December in the wet season are shown in Figure 4.7. The increase in LFU can be presented by increasing standard deviation of the load model. The impact of the increase in the standard deviation from 2% to 4% are also shown in Figure 4.7. The 0% standard deviation indicates that LFU is not considered in the assessment, and this provides a very optimistic result as shown in Figure 4.7 for the month of December. The system reliability degrades significantly in the dry season where LOLE is increased from 0.0206 hours/year with no LFU to 0.0235 hours/year with
2% LFU, and increased further to 0.0298 hours/year with 4% LFU. Figure 4.7 shows that the impact of LFU in the wet month is negligible since the loss of load probability in this season is very small. The significant reliability impact of LFU in the energy limited months will have considerable influence the overall system reliability.

![Figure 4.7](image)

**Figure 4.28. Reliability Impact of Load Forecast Uncertainty**

### 4.5 Reliability Impact of Scheduled Maintenance

Preventive maintenance of generating units is scheduled at appropriate times in a year when the system has relatively high reserve capacity in order to minimize the impact on the overall system reliability. This generally occurs in the period when the system load is relatively low. In hydro dominant power systems, the seasonal river inflow pattern can greatly affect the periods of high reserve capacity to schedule planned maintenance. The periods with energy limitations in reservoirs of large storage-type hydro plants also provide opportunities for maintenance on one or
more hydro units while remaining units in the same plant have the capability to generate the power that is available in the plant with little impact on the system reliability. This section compares the reliability impact of two different scheduled maintenance strategies using annual planned maintenance outage data shown in Table 4.4.

Table 4.11. Maintenance Outage Data

<table>
<thead>
<tr>
<th>Plant Size MW</th>
<th>Unit Size MW</th>
<th>Number of Units</th>
<th>Scheduled Maintenance weeks/year</th>
</tr>
</thead>
<tbody>
<tr>
<td>60</td>
<td>12</td>
<td>5</td>
<td>2</td>
</tr>
<tr>
<td>80</td>
<td>20</td>
<td>4</td>
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<tr>
<td>300</td>
<td>50</td>
<td>6</td>
<td>2</td>
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<tr>
<td>304</td>
<td>76</td>
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<td>3</td>
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<tr>
<td>300</td>
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<tr>
<td>620</td>
<td>155</td>
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<tr>
<td>591</td>
<td>197</td>
<td>3</td>
<td>4</td>
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<tr>
<td>350</td>
<td>350</td>
<td>1</td>
<td>5</td>
</tr>
<tr>
<td>800</td>
<td>400</td>
<td>2</td>
<td>6</td>
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</table>

The RTS has a total installed capacity of 3405 MW and a winter peaking load profile as shown in Figure 4.8. The system has high reserve capacity between the months of April and September, during which planned maintenance is scheduled to minimize the adverse impact on the system reliability. The impact of maintenance scheduling of the thermal dominant RTS on its system reliability is studied considering two maintenance scheduling cases. Case (i) considers a maintenance schedule during the high capacity reserve periods as shown in Table 4.5. Case (ii) schedules some of the maintenance during the high load periods as well as shown in Table 4.6. It is assumed that only one unit in the same plant is under maintenance at one time, and the maintenance is done sequentially on each unit of the plant.
Figure 4.29. Generation and Load Pattern for the Thermal-Dominant RTS

Table 4.12. Scheduled Maintenance Case (i)

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<tr>
<th>Plant (MW)</th>
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Table 4.13. Scheduled Maintenance Case (ii)

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The system reliability generally decreases as generating units are removed from the system for maintenance. Figure 4.9 compares the annual and monthly reliability results calculated for a summer month and a winter month considering the two maintenance scheduling cases on the RTS considering a peak load of 2500 MW. The annual system reliability degrades with year around maintenance scheduling in Case (ii) when compared to maintenance scheduled during high reserve capacity in Case (i). Figure 4.9 shows a substantial increase in the LOLE in month December from Case (i) to Case (ii). It should be noted that the LOLE is decreased in the month of June due to less capacity removed for maintenance in Case (ii). The impact of the summer LOLE on the annual LOLE is however insignificant.
A similar study considering the two maintenance scheduling cases were also performed on the hydro dominant system with a system peak load of 1990 MW. Figure 4.10 shows that the reserve capacity is greatly affected by the water availability. In the period during which a hydro plant is energy limited due to water restriction, one of the units undergoes scheduled maintenance while other units are capable of generating the available plant capacity for the period. Figure 4.11 compares the annual and monthly reliability results calculated for a summer month and a winter month considering the two maintenance scheduling cases.
Figure 4.31. Generation and Load Pattern for Hydro Dominant System

Figure 4.32. LOLE of Hydro Dominant System with Scheduled Maintenance
Figure 4.11 shows that the annual LOLE in both the cases are close. Case (i) provides a significantly lower LOLE during the wet month of June, and a slightly higher LOLE during the dry month of December. The results show that there is a greater flexibility in scheduling maintenance over the year by strategically selecting high capacity reserve periods and energy limited periods in a hydro-dominant system. This also provides opportunities to improve maintenance coordination with other types of generation plants.

4.6 Conclusion

The performance of hydro dominant power systems is largely influenced by the variability and uncertainty of river flow causing considerable challenges in resource planning, operation and water management strategy to continuously maintain acceptable level of system reliability. This paper presents reliability models of run-of-river and large storage-type hydro units and plants to recognize their energy and capacity availability characteristics, and proposes a methodology to incorporate water management and maintenance strategies for the reliability enhancement of hydro dominant power systems. The proposed methodology is applied to evaluate the reliability impact of diurnal and seasonal water management and maintenance scheduling strategies on a hydro-dominant system. The results show significant improvement in reliability using the LOLE and LOEE indices, and that the system can also carry an increased system peak load within same reliability level. The results show that the LOLE in days/year only responds to seasonal energy management, but is unaffected by the diurnal energy management, and therefore, is not a suitable adequacy index for a hydro-dominant system. The results show that the system reliability can be improved by operating a larger number of run-of-river units with the diurnal water management
strategy. The incremental increase in reliability is however reduced as more units are run with this operating strategy, and the right number can be determined using the presented methodology. The uncertainty in load forecast can also have considerable impact on the reliability planning of hydro dominant systems. The results show that there is significant reliability impact in the energy limited months, leading to considerable influence on the overall system reliability. The impact of various maintenance schedules on the system reliability were also investigated. It can be concluded from the study results that an energy-based hydro-dominant system is more flexible than a capacity based thermal dominant system in scheduling maintenance over the year by strategically selecting high capacity reserve periods and energy limited periods. The maintenance can and should be scheduled to provide reliability centric coordination with other generating facilities.

4.7 Reference


PREFACE TO CHAPTER 5: PROBABILISTIC RELIABILITY ENHANCEMENT STRATEGIES OF HYDRO DOMINANT POWER SYSTEM UNDER ENERGY UNCERTAINTY

This chapter is organized as a manuscript titled “Probabilistic Reliability Enhancement Strategies of Hydro Dominant Power Systems under Energy Uncertainty”. The manuscript is submitted to the Elsevier journal of Electric Power Systems Research. The fundamental concept of hydro dominant system reliability analysis used through Chapter 2, 3 and 4 have been extended and integrated to incorporate diurnal, seasonal and year-to-year energy management strategies in hydro dominant system to minimize the adverse impact of energy uncertainty and maintain long-term system adequacy. The impacts of reservoir capacity and demand side management on water utilization and system reliability are analyzed and demonstrated in this chapter. The objectives of the research, as stated in Section 1.4: ‘to develop analytical reliability models to consider year to year energy management to minimize the adverse impact of energy uncertainty and maintain system reliability from long term planning perspectives.’ were addressed in this chapter.
CHAPTER 5. PROBABILISTIC RELIABILITY ENHANCEMENT STRATEGIES OF HYDRO DOMINANT POWER SYSTEMS UNDER ENERGY UNCERTAINTY

Fang Fang, Rajesh Karki, Prasanna Piya

5.1 Abstract

Climatic hydrological changes cause considerable seasonal and yearly energy variation in hydro dominant electric power systems. Extreme weather events are becoming more frequent in recent years causing dramatic impacts on energy availability in such systems. A significant amount of energy is often wasted due to reservoir overflow during wet seasons. Whereas, the scarcity of water in dry seasons results in inadequate power generation to meet the system demand, and therefore, degrades overall system reliability. The high risks associated with an extreme dry hydrological condition should not be ignored in long term system adequacy planning of hydro dominant utilities. This paper presents a probabilistic method to incorporate diurnal, seasonal and yearly energy management strategies in run-of-river and storage type hydropower plant planning and operation in order to minimize the adverse impact of energy uncertainty and maintain long-term system adequacy. The impacts of reservoir capacity and demand side management on water utilization and system reliability are investigated with case studies illustrated using the IEEE Reliability Test System which is modified to create a hydro dominant system. The achieved benefits of reliability enhancement strategies are analyzed and compared in this paper.
5.2 Introduction

Hydropower is one of the most efficient, cost-effective, and clean source of electricity generation. The worldwide installed capacity of hydropower rose to 1,292 GW in 2018 [1]. China, United States, Brazil, and Canada are the countries with the highest hydropower installed capacity. The hydropower generation is growing rapidly in East Asia, followed by South America, South, and Central Asia, Europe, Africa, and North and Central America. Canada had 81 GW of installed hydropower capacity in 2018 [1]. Approximately 63% of Canada’s total electricity demand and most of Canada’s electricity exports come from hydropower [2]. Canada has the potential of another 160 GW of hydro capacity. In addition to clean and low-cost energy production, hydropower has a high ramp rate and a quick start capability which support the integration of highly intermittent renewable energy resources such as wind and solar into the conventional grid [3].

A hydro unit can be unavailable or only partially available due to river inflow restrictions. In a hydro dominant power system, the scarcity of water in the dry season can cause inadequate generation to meet the load demand. This issue is even more severe in a dry year. Furthermore, there has been an increase in the occurrence of extreme adverse weather in recent years. The energy uncertainty will have an adverse impact on system reliability. Therefore, the high risks associated with the extreme dry hydrological condition should not be ignored in long term system adequacy planning of hydro dominant utilities.

Many approaches have been explored and developed to properly model energy uncertainty as a constraint in hydro units in their reliability models. In [4] and [5], the models are developed
to represent an energy source with limited energy input for generation reliability evaluation. The energy management of hydro units due to energy uncertainty is studied and applied mainly into two areas.

The first area of study is to develop the operating policy based on energy uncertainty of hydro plants to optimize the operating cost of the system. In reference [6] and [7], with limited energy, the usage of a hydro unit as a base unit and/or peak shaving unit are compared based on reliability and production cost factors. In reference [8], the optimal allocation of stored energy resulting from random river inflows to the different subperiods of a year to sell in the energy market, as well as to cover any unplanned outages of thermal units is presented. The main objective of this work is to manage the energy generation from the hydro units and to assess the impact of the market rules on the reliability of the system. However, these researches did not consider the coordination of energy management among different hydro units in a hydro dominant system when facing energy uncertainty. The main focus of these works was on optimizing the operating cost.

The second area of study is to coordinate the periodic energy uncertainty of hydro units with other types of generation in a mixed generation system. An integrated model for long term operation planning and reliability evaluation of hydrothermal systems is presented in [9]. An optimal amount of discharge of hydro units and energy output of thermal units is developed in that work with the objective of minimizing the total cost of the energy. A simple multivariable weather model is developed in [10] to include rainfall for hydro units. The hydropower plant is used as energy storage to study wind and solar penetration into the system from a reliability point of view. Three types of weather conditions, wet, dry, and normal were modeled in [11] with equal
probability of occurrence and randomly chosen during the simulation. The operation incorporated the coordination with thermal and wind power systems to show the system adequacy depending on the capacity and number of hydro units assigned to operate in coordination with wind power.

The focus of the existing literature is either on the energy management of hydropower for optimizing the operation cost or on the coordination of hydropower with other types of generation to manage the energy uncertainty due to hydrological conditions. However, the impact of energy uncertainty caused by hydrological variability from year to year on system reliability in the hydro dominant system has not been studied. Moreover, there is a need for research in the field of reliability enhancement strategies under energy limitation for hydro plants without getting assistance from other types of energy sources.

This paper develops a new probabilistic method to incorporate diurnal, seasonal and yearly management strategies of run-of-river and storage hydro units in a hydro dominant system. The impacts of reservoir size and demand side management on water utilization and system reliability are investigated. The proposed strategies consider energy uncertainty and strategically manage energy utilization, based on water availability patterns to minimize reliability issues in energy deficient seasons. Two analytical methods are developed and integrated for reliability evaluation of hydro-dominant systems. A diurnal energy management method [12] is applied to the run of river hydro units to manage energy to follow the daily load variation. A seasonal energy management method [13] is applied to large storage hydro units to transfer energy so that it follows seasonal load variation. These two methods are integrated and used simultaneously to maximize the utilization of limited energy and minimize the reliability impact of energy uncertainty in order
to enhance long-term system adequacy. The proposed strategies are applied to the modified IEEE Reliability Test System (RTS) [14] which incorporates the hydrological data of wet year, normal year, dry year and extreme dry year.

5.3 Reliability Evaluation of Hydro Dominant Power System

Generation system reliability can be defined as the ability of total installed power generation to meet the total system load considering generating unit failures and load variations. The energy availability is also considered for energy-based generations, such as hydro units. The generation model is developed by combining hydro units and other conventional units in the system to create a probability distribution of generation capacity states, commonly known as the capacity outage probability table (COPT) [15]. The loss of load expectation (LOLE) and loss of energy expectation (LOEE) are the most widely used reliability indices, which are calculated by convolving the COPT with the load model of the system. The LOLE is the expected time that the system load exceeds the available generating capacity, and LOEE is the expected amount of energy that is not supplied when needed due to power interruptions [15]. The LOLE and LOEE can be calculated using Equation (5.1) and (5.2) respectively.

\[ \text{LOLE} = \sum_{k=1}^{n} p_k \times t_k \]  \hspace{1cm} (5.1)

\[ \text{LOEE} = \sum_{k=1}^{n} p_k \times E_k \]  \hspace{1cm} (5.2)

where \( n \) is the number of capacity outage states, \( p_k \) is the probability of the \( k \)th outage state, \( E_k \) is the energy not supplied in the outage state, and \( t_k \) is the time of load loss due to the outage.

The monthly energy availability of a hydropower plant varies due to river inflow variations
from one month to another in the wet, normal, dry and extreme dry years. Therefore, the reliability indices are evaluated in monthly intervals in this paper. The annual LOLE and LOEE are then determined by summing the monthly LOLEs and LOEEs in the study year.

5.3.1 Modeling of a hydro unit

The water level in the reservoir of a hydropower plant depends on the discharge rate of the hydro unit and the river inflow rate into the reservoir. The output ability of the hydro unit depends on the availability of the unit and the water operating policy based on available energy and water usage regulations at the instant. The turbine discharge rate $Q(i)$ in the $i^{th}$ hour can be adjusted to generate a steady output power $P$ in MW as shown in (5.3).

$$P = g \cdot \alpha \cdot H(i) \cdot Q(i) \cdot s / 10^6 \quad (5.3)$$

where $g$ is the gravitational constant, $\alpha$ is the overall efficiency of the turbine generator, and $s$ is the specific weight of water. The net head $H(i)$ in the $i^{th}$ hour can be obtained by dividing the reservoir volume $V(i)$ by its area $A$ as shown in (5.4). The reservoir volume changes continuously depending on the river inflow and outflow and is obtained from (5.5).

$$H(i) = V(i) / A \quad (5.4)$$

$$V(i) = V(i - 1) + InV(i - 1) - OutV(i - 1) \quad (5.5)$$

Here, $V(i-1)$ is the reservoir volume in the previous hour, $InV(i-1)$ is the inflow water volume into the reservoir in previous hour, and $OutV(i-1)$ is the outflow water volume from the reservoir in the previous hour. It is assumed that the reservoir is a cuboidal shape to illustrate the method developed.
in this work.

The total period of study is divided into sub-periods with similar hydrological conditions. The generation output varies in the different sub-periods based on hydrological condition and water operating policy. The total energy output $E$ of the study period can be found by summing up the energy outputs in the sub-periods as given in (5.6)

$$E = \sum_i P_i * t_i$$  \hspace{1cm} (5.6)

where $P_i$ is the output power and $t_i$ is the duration of the $i^{th}$ sub-period.

### 5.3.2 Diurnal and seasonal energy management modeling

A run-of-river hydro plant has a small head pond with limited storage capacity. The underlying concepts used in evaluating the power output from a run-of-river hydro plant are described in [12]. It usually has limited ability to manage water resource to follow the load variation within a day to enhance system reliability [16]. The generating capacity in each hour of the day can be calculated by (5.3), and the total available energy of the day can be calculated by (5.6). The hydro unit is operated at rated capacity $C$ for $h_{peak}$ hours during peak hours of the day, and the remaining energy in the reservoir is utilized to supply load at a constant reduced generation capacity $D$ that is calculated in (5.7).

$$D = \frac{E - C * h_{peak}}{24 - h_{peak}}$$  \hspace{1cm} (5.7)
An example of diurnal energy management of a run-of-river plant is shown in Figure 5.1. The hydro unit operates at rated capacity during peak load hours from Hour 17 to Hour 20 and at 40% of its rated capacity during the off-peak load hours.

Figure 5.33. Diurnal Energy Management Modeling

A large storage type hydro unit has the ability to carry water from one season to another. It can, therefore, be operated to save water by reducing generation output during high inflow and low load periods. The accumulated water can be carried to next year and utilized to increase the generation capacity output during peak load periods in the dry months. Figure 5.2 depicts the monthly water inflow of a large storage type hydro plant and the total system load variation over a year. The figure shows that there is plenty of water from April to August that can be saved and used in the months of scarce water with peak loads from October to March.
The method described in [17] is used to integrate the diurnal and seasonal energy management strategies of hydro dominant systems. The study year is divided into \( p \) periods consisting of a number of days with similar load and river inflow. The \( p \) period is divided into the \( q \) sub-periods as energy limitation days and energy adequate days. The energy limitation days represent the generation capacity output is not adequate to satisfy the load demand and resulting high number in loss of load. The \( q \) sub-periods are further divided into two diurnal sub-periods of peak and off-peak periods in hours. The generation models of run-off-river are created for two diurnal subperiods in the energy-limited months, so it can increase capacity in peak load hours of the day. The generation models of storage type hydro are created for each sub-periods to manage the energy in the energy-limited period. During the \( q \) sub-periods, the run-of-river hydro generation model in peak load period is combined with the storage type hydro generation model in the same month to get the overall generation model in peak period. The system load models are created as load duration curves for each diurnal peak and off-peak period in each sub-period. The system generation models are convolved with each corresponding load model in the sub-period to
obtain the risk index $R_{ij}$, where $i$ period and $j$ sub-period, where $j \in q$ and $n_i$ is the number of the days in period $q_i$. The annual reliability index of combined run-of-river and storage hydro units can be obtained by using (5.8).

$$R = \sum_{j=1}^{p} R_j + \sum_{i=1}^{q} n_i \times \sum_{j=1}^{2} R_{ij}$$  \hspace{1cm} (5.8)$$

where, $n_i$ is the number of days in the $i^{th}$ sub-period, and $R_{ij}$ is the risk index calculated for the $j^{th}$ period of the $i^{th}$ sub-period of the year.

5.4 Proposed Method

This section presents a probabilistic method to incorporate diurnal, seasonal and yearly energy management strategies to operate the run-of-river and storage type hydro units to minimize the impact of energy uncertainty and maintain long-term system adequacy. The impacts of reservoir size and demand side management on water utilization and system reliability are also investigated in this section.

5.4.1 Year-to-year Energy Management

The energy management of hydro units depends on the reservoir size, load variation profiles and hydrological conditions in the study year. The objective of this method is to save water in a normal or wet year with minimal adverse impact on the system reliability by incorporating diurnal, seasonal and yearly energy management, such that, a maximum amount of water will be available for the upcoming energy uncertainty year. The uncertainty in the hydrological condition in an
upcoming year is represented by an expected monthly or seasonal variation in hydrological data in this work, which is obtained using Equation (5.9).

\[ W = \sum_{X} P(X) \times W_X \]  \hspace{1cm} (5.9)

\( \forall X \in \{\text{wet year, normal year, dry year, extreme dry year}\} \)

Where, \( X \) represents the hydrological condition of the year, \( W_X \) is the average monthly or seasonal hydrological data for the year with hydrological condition \( X \) as shown in Figure 5.3 [18]. \( P(X) \) is the probability that a year will have hydrological condition \( X \) which is shown in Figure 5.4 for the four different hydrological conditions: wet year, normal year, dry year and extreme dry year.

![Figure 5.35. Monthly Variation in Hydrological Data](image-url)
The algorithm involved in implementing the methodology is shown in Figure 5.5 and described in the following steps:

1. The hydrological condition of the current year is known. Determine the expected hydrological data of the upcoming year using the probabilistic hydrological model obtained from Equation (5.9).

2. Integrate the diurnal and seasonal energy management strategy of the hydro dominant system as described in Section 2 into the hydro operating simulation. Evaluate the system reliability indices, such as the LOLE, for each sub-period of the current year and following year using Equation (5.8) to understand the characteristics of the system.

3. If the reservoir is full at the end of the current year, further energy management is not needed. Otherwise, sort the LOLE values of the sub-period in the current year in ascending order. Check the reservoir capacity of the sub-period with the lowest LOLE. If it is not full, decrease the hydropower output in the sub-period to save more water in the reservoir. Then
run the whole year simulation again to evaluate the LOLE values and reservoir levels for each sub-period.

4. If the hydro operating simulation results reservoir full in the lowest LOLE sub-period, then follow the ascending order and find the next lowest LOLE sub-period with water storage capability in a reservoir in the current year, and modify year to year energy management strategy to reduce the amount of generation in the sub-period. In the following year, the generation output capability of the hydro unit is increased in the sub-periods with the highest LOLE values by utilizing saved water from the year to year energy management in the previous year. Then run the two-year simulation again to update the LOLE values for each sub-period and the water level in reservoirs.

5. If the total two-year LOLE value after applying the most recent year to year energy management is lower than the previous LOLE value, then repeat step 3.

6. If the total two-year LOLE value after applying the most recent year to year energy management is higher than the previous LOLE value, then slightly increase the hydropower output in the sub-period in the descending order of the LOLE values of the current year. If the small amount of increase of hydropower output will result in a huge amount of LOLE increase, then move to the next highest LOLE value sub-period. Again, run the two year simulation to identify the total LOLE values.

7. Repeat step 5 and 6 to keep adjusting the year to year energy management until the maximum storage of water is reached with the lowest two-year total LOLE values.
Figure 5.37. Flow Chart for Year to Year Energy Management Methodology
The year to year energy management is applied to the modified IEEE RTS system consisting of 6 hydro plants (with 3 run-of-river and 3 storage hydro plants) and 2 thermal plants. The historical river flow pattern of BC province in Canada [18] is used in the study. The data includes the inflow rate at monthly intervals for the different rivers in different hydrological years as shown in Figure 5.3. The generation output capability can be calculated using Equation (5.3) based on the inflow pattern for each month in Figure 5.3 and the reservoir condition of every hour can be updated using Equations (5.4) and (5.5). A study was done assuming the current as a normal hydrological year which has a wet season from May to October, and a dry season from November to April. The following year was assumed as a dry year in the study with reduced water in the wet season and inadequate water in the dry season as shown in Figure 5.3.

Without the year to year energy management, November and December in the current year were simulated at its rated generation capacity to meet peak load demand as shown in Figure 5.6. As a result, the reservoir was full until October and the stored water in the reservoir began to rapidly decrease from the November of the current year due to low river inflow in the dry season. The generation capacity output dropped each month from the current year to the next year in the dry season.

With the implementation of the year to year energy management, the amount of water that can be carried from one year to another is very restricted due to the reservoir capacity as shown in Figure 5.7. However, the amount of water can be distributed at critical times between January to March to mitigate the scarcity of energy during the dry months of the following dry year. The contribution of the saved water can be seen in Figure 5.6. The water saved by reducing generation
in the current year is used to increase the generation capacity output from January to March in the following year to meet the load demand.

Figure 5.38. Simulated Generation Capacity Output Variation from One Year to Another

Figure 5.39. Reservoir Water Variation by Applying Energy Management
5.4.2 Increase of reservoir size

The size or capacity of the reservoir is one of the main limitations in energy management, as discussed in Section 5.4.1. With current reservoir size restraints, a large amount of water in the wet season is wasted as spillage. The reliability can be enhanced by increasing the reservoir size to avoid water spillage. It can store and manage additional energy from year to year as needed.

Figure 5.8. shows a reservoir head and water spillage for 300 MW storage type hydro plant. A study was carried out by increasing the reservoir size by 30%. With the increased size, it takes a longer time to fill the reservoir to its maximum head in July as shown in Figure 5.8. More water is saved during the wet season due to reduced spillage in July, and the stored water is carried over from the current year to the upcoming year. The saved water is distributed in the dry months from January to March of the following dry year where there is a severe shortage of water. At the end of April, the saved water is all used up and the head value reaches its lowest limit. The corresponding MW capacity output of the 300 MW hydro unit after the increase in reservoir size is shown in Figure 5.9. Starting with the same head, the reservoir with 30% increased size stores more water in the reservoir and yields more capacity output in the energy-limited months than the original size reservoir from January to April in the current year. With the increased reservoir size, the capacity output in the dry months from January to April of the following dry year will increase significantly due to additional water stored from the current year to use in the upcoming year.
Figure 5.40. Net Head and Water Spillage of the Reservoir Before and After Increase Size of the Reservoir

Figure 5.41. Corresponding 300 MW Capacity Output of Reservoir Enlargement
5.4.3 Demand Side Management

A winter peaking load and a summer peaking load represent two distinctly different load patterns. They are studied in this paper to investigate the impact of correlation between load pattern and generation capacity output on the system reliability. Figure 5.10 shows the winter peaking load and summer peaking load patterns, and the generation output capability of the hydro dominant system with the dry year hydrological pattern. The hydro units can generate rated output during the wet season from May to September but generate reduced output during the dry season from December to April.

A winter peaking load pattern shows a negative correlation with the generation capability of the hydro generation output as depicted in Figure 5.10. The system peak load occurs during the dry months (Dec-Jan) when the generating units have derated outputs which increases the loss of load probability. On the other hand, the system off-peak load occurs during the wet months (May-Jul) when the generation units have rated capacity output which is not necessary to meet the light load demand.

For a system with the summer peaking load pattern, the system peak load occurs in the wet season where the hydro units can generate the rated capacity output to meet the high load demand. In the dry season, the generation output capability is derated, but the load is also at the minimum during the period, so the loss of load mainly depends on random failures of the generating units during this period.

It is desired that the load variation pattern and the generation output capability have a positive correlation so that the hydro units have adequate energy in time sequence to satisfy the system
peak load. Applying demand side management is one of the effective ways to slow the increase in electricity demand and transform the system load pattern toward to the desired trend, in this case, following positive correlation with the hydropower output capability.

![Graph showing Load and Generation Correlation](image)

Figure 5.42. Load and Generation Correlation

Therefore, a strong positive correlation between the generation output capability and the load pattern has a great positive impact on system reliability. Application of the demand side management to change the system’s load pattern to obtain the desired correlation with the hydrological condition can significantly improve the reliability of the hydro dominant system.

5.5 Simulation Results of Applying the Developed Models to the Test System

Long term reliability analysis of a power system is normally carried out every year for a planning horizon of several years using annual indices. Such analysis can also be conducted for a season, a year or a longer period of time [19]. This paper considers long term energy uncertainty
of hydro dominant power system due to hydrological uncertainty. Since proper management of reservoir water usage requires the knowledge of energy availability and demand scenarios in the immediate future years, a two-year study period is chosen to incorporate the current year and future year’s hydrological conditions.

A modified IEEE RTS system as described in Section 3 is used for reliability studies. A calendar year is assumed to have one of the four hydrological conditions, namely wet, normal, dry and extreme dry year as shown in Figure 5.3, with the probabilities shown in Figure 5.4. This data was obtained from hydrological information obtained for the Canadian province of British Columbia. The normal hydrological year has the highest occurrence probability of 0.78. Therefore, the study is assumed to start with a normal hydrological year. But in fact, the hydrological condition of the current year is known with relatively low uncertainty. A winter peaking load pattern as shown in Figure 5.10 [19] is used considering a peak load of 2380 MW in the following studies.

The proposed methodology of water management for reliability enhancement was applied to the modified RTS system to investigate the reliability impacts. Figure 5.11 shows the LOLE for the four hydrological condition years with and without implementing the energy management strategy. Figure 5.11 also shows the expected LOLE for the upcoming year obtained by multiplying the LOLE for each of the four hydrological conditions by the probability of its occurrence. The expected LOLE is 0.48 hours/year. This is equivalent to LOLE of 0.1 days/year, which is the widely used reliability planning criterion [20] in major power utilities.
Figure 5.11 shows that the LOLE is the lowest in the wet year. The LOLE in the normal year almost reaches the criterion value even before applying the energy management strategy. After applying the year to year energy management strategy, LOLE decreases to 0.35 hours/year. The LOLE values in dry and extreme dry years are very high. Although the year to year energy management in these conditions can significantly improve the system reliability, it is not able to transfer enough energy to meet the reliability criterion. It should, however, be noted that the expected LOLE meets the reliability criterion after the year to year energy management. The widely accepted LOLE criterion may be suitable for a particular year, but its compliance would require significant capital investment in dry and extremely dry years. An appropriate value of expected LOLE considering the different hydrological years can be used as a planning criterion for hydro-dominant systems. Figure 5.11, however, shows that the equivalent of 0.1 days/year may
not be an acceptable value since the LOLE in the dry and extreme dry year cases are very high. A reliability cost worth analysis in the dry and extreme dry scenarios is needed to determine the suitable criterion values.

The peak load carrying capacity (PLCC) [15] of a system is the peak load that the system can carry without violating its reliability planning criterion. The PLCCs of the system are shown in Figure 5.12 for the four hydrological conditions assuming a planning criterion of LOLE = 0.48 hours/year. The system can carry a higher peak load after applying the year to year energy management in all hydrological conditions.

![Figure 5.44. Increase in PLCC after Year to Year Energy Management](image)

Another study was carried out to investigate the impact of reservoir capacity on the system reliability in the different hydrological years with year to year energy management. Three different
reservoir sizes were considered: (1) the original size, (2) a 30% increase in reservoir volume, and (3) a reservoir with infinite volume. The results are shown in Figure 5.13.

The LOLE in the normal hydrological year is 0.46 hours/year which scarcely meets the reliability criterion of 0.48 hours/year without any changes in the reservoir size. When the reservoir size is increased by 30%, there is an additional 30% of stored water volume in the current year. The additional 30% increase in reservoir size improved the system reliability by lowering the LOLE to 0.08 hours/year. Similar reliability improvements are observed for the dry and extreme dry years as shown in Figure 5.13. An infinite reservoir has sufficient size to prevent the spillage of water that makes the hydro system as a non-energy limited system with energy management. In
In this case, the LOLE is mainly caused by the forced outages of the generating units. The infinite reservoir has lower expected LOLE than increase 30% of reservoir size as shown in Figure 5.13.

Figure 5.14 shows the PLCC of the system considering the impact of the three reservoir sizes and the four hydrological condition years. The PLCC has increased for all hydrological condition years with 30% increase of reservoir size and infinite reservoir size. The PLCC has increased significantly in a dry year from 2240 MW to 2520 MW for 30% increase of reservoir, and in extreme dry year from 2150 MW to 2420 MW. With infinite reservoir size, the PLCC is increased to 2630 MW in a dry year and 2540 MW in extreme dry year.

![Graph showing PLCC increase](image)

**Figure 5.46. Increase in PLCC after Increase of Reservoir Size**
The correlation between the system load variation pattern and the hydrological pattern determines the energy limitation levels in a hydro dominant system. A study was carried out considering two different load variation patterns: (1) a winter peaking load which has a poor correlation with the hydrological pattern, and (2) a summer peaking load system which has a high correlation with the hydrological pattern. The impact on system reliability of the correlations of the load and river-flow patterns in the years with the different hydrological conditions is reflected in the LOLE results as shown in Figure 5.15.

Figure 5.47. LOLE of Different Load Patterns and Hydrological Conditions

For the winter peaking load pattern, LOLE in the normal year is 0.46 hours/year. This value is within the reliability criterion of 0.48 hours/year. In the dry year and extreme dry year, the LOLE values exceed the reliability criterion of the system due to the energy limitation of the hydro system caused by the poor correlation between the river-flow and load variation patterns. However, for the summer peaking load pattern, the wet year, normal year and even dry year has high system
reliability with LOLE of 0.04 hours/year, 0.04 hours/year, and 0.06 hours/year respectively. The LOLE of the extreme year is 0.21 hours/year which shows that the capacity reserve is well above that required by the reliability criterion. Figure 5.16 shows the PLCC at the LOLE criterion of 0.48 hours/year. For winter peaking load pattern, the PLCC varies from 2570 MW in the wet year to 2150 MW in the extreme dry year. The difference in capacity reserve requirements in the two extreme hydrological conditions is at least 420 MW, which amounts to huge capacity investments under uncertainty. For the summer peaking load pattern, the PLCC values of the hydro system reduce gradually from 2650 MW in the wet year to 2470 MW in extreme dry year. It should be noted that the peak load of the test system is 2380 MW, but the system can carry 90 MW additional system load even in an extreme dry year if the load variation is in high correlation with the river-flow variation. With the summer peaking load, the difference in PLCC in the two extreme hydrological conditions is only 180 MW, the capacity costs of which can be compared to the costs of 420 MW for the winter peaking load. A demand side management policy to improve the correlation of the load with the river-flow variation is highly desired in a hydro-dominant power system.
A sensitivity analysis was performed on the modified IEEE-RTS to assess the impact of the energy management strategy on the loss of load and energy indices by varying the system peak demand, reservoir size and system load variation pattern. The expected system LOLE and LOEE were evaluated with and without implementing the year to year energy management strategy for reliability enhancement on the base system. These indices were also evaluated considering 30% increase in reservoir volume and varying the system peak load and the load profile obtained through demand-side management with high correlation with the seasonal river-flow. Figure 5.17 and Figure 5.18 respectively show the expected system LOLE and LOEE increase with the increase in the system peak load considering the above mentioned factors. As compared to the case without energy management, the year to year energy management results in a significant reduction in the system LOLE and LOEE. The figures show that there is further improvement in system reliability with the increase in reservoir size by 30%, and the implantation of the demand side management. It can be noted that the application of the demand side management provides a
relatively large improvement in the reliability of the system as shown in Figure 5.17 and Figure 5.18.

Figure 5.49. Variation in Expected LOLE with the System Peak Load using Different Reliability Enhancement Strategies

Figure 5.50. Variation in Expected LOEE with the System Peak Load using Different Reliability Enhancement Strategies
5.6 Conclusion

The reliability of the hydro dominant system is significantly affected by the seasonal and yearly variation of the hydrological conditions. This paper presents a new probabilistic method that accounts for the uncertainties in the hydrological condition in the energy management strategy to improve the reliability of the system. Diurnal, seasonal and yearly energy management strategies are applied in run-of-river and storage type hydropower plant operation to minimize the reliability impact of energy uncertainty and maintain long-term system adequacy. Furthermore, these energy management strategies are incorporated into the year to year energy management strategy to save water in a normal or wet year with minimal impact on the system reliability and to maximize the availability of water in upcoming energy uncertainty year. Although year to year energy management improves the reliability of the system, the amount of water that can be carried from one year to another is restricted due to the reservoir capacity. Therefore, the result of increasing the reservoir capacity together with the year to year energy management was investigated. Increasing the reservoir capacity results in a larger volume of water that can be carried over from the current year to the upcoming year which further improves the reliability of the system. But increasing the reservoir capacity is not always a feasible solution. The studies presented in this work shows that a strong positive correlation between the river flow pattern and the load has a great positive impact on the system reliability. The application of the demand side management to change the system’s load pattern to follow the hydrological condition can significantly improve the reliability of a hydro dominant system. Therefore, all these reliability enhancement strategies have significant importance in the operation and planning of the hydro dominant system under
hydrological uncertainties. The methodology proposed and the case studies presented in the paper provide a practical approach for a long-term system adequacy planning of the hydro dominant system.

5.7 Reference


CHAPTER 6. SUMMARY AND CONCLUSIONS

Hydro power is one of the clean sources of electricity generation as it does not emit air pollutants and has very low greenhouse gas emissions. Hydro power has rapidly increased in past few years and is expected to further increase in the future. Unlike other firm capacity generation sources, hydro power sources can be energy limited due to water restrictions caused by seasonal and climatic variability. The generation capacity is determined by river inflow, operating policies and load level. This variability and uncertainty of river flow characteristics create challenges in planning generation adequacy to maintain a target reliability level. These hydro dominant utilities face energy waste issues caused by water spillage during high inflow season or low load of the day. In the contrast, inadequate generation capacity to meet system load demand occurs during peak load period within low inflow season, and this would cause severe system reliability issues.

The main objectives of this research were to quantify the reliability impact of variability and uncertainty of river flow in hydro dominant power system and to improve/maintain system reliability based on characteristics of hydro generations by using available resources in the power system. There are two main types of hydro plants installed in the utilities: storage type hydro and run-of-river hydro plants. The reliability models of these two types of hydro plants were developed and are demonstrated in this research work. The presented study results have shown the improvement of system reliability by applying diurnal, seasonal and yearly energy management strategies on the IEEE-RTS which was modified to represent a hydro dominant power system.
The reliability indices used in this thesis are LOLE and LOEE, and the assessment was done at the HL I level.

Chapter 1 presents a brief introduction to power system reliability including basic concepts of functional zones and hierarchical levels, and general approaches of reliability assessment. The different types of hydro plants and their characteristics are introduced in this chapter. Energy limitation caused by variability and uncertainty of river flow of hydro generation is discussed in Chapter 1, and the research objectives are defined in this chapter as well.

Chapter 2 investigates the reliability enhancement of a hydro dominant system through diurnal energy management of run-of-river hydro plants with the limited storage. The paper presents analytical reliability models of head pond and hydropower generation to recognize energy storage and the magnitude and time-shift of output power to match the diurnal load profile during energy limited periods of the year. The sensitivity studies were done to determine optimum numbers of energy management units and peak rating hours for energy limited hydro plants.

In Chapter 3, the reservoir of a storage type hydro is modeled to transfer energy seasonally by utilizing different operating policies. The probabilistic approaches are used for the evaluation techniques and the reliability models. Different operating strategies are compared in the paper and the resulting reliability benefits are evaluated.

Chapter 4 integrates both diurnal and seasonal energy management models from Chapter 2 and 3 to maximize the reliability improvement from available resources in the hydro dominant power system. Also, this paper presents studies to assess the practicality of the existing recommended LOLE criterion and determine suitable indices for hydro dominant system to capture all the characteristics of hydro generation and restrictions. The reliability impacts of river
flow variations, restrictions, scheduled maintenance coordination with river flow and load level are evaluated in this chapter.

In Chapter 5, the hydro dominant system is modelled to minimize the adverse impact of energy uncertainty and maintain long-term system adequacy by applying the proposed probabilistic method to incorporate diurnal, seasonal and yearly energy management strategies. The impacts of reservoir capacity and demand side management on water utilization and system adequacy were evaluated in this chapter to analyze and compare the achieved benefits of the strategies.

In conclusion, this thesis presents the probabilistic frameworks and reliability models of the storage type and run-of-river hydro plants in a hydro dominant power system. The results quantify the reliability benefits of applying energy management strategies during the energy limited periods. The energy management methodology for run-of-river hydro plants involves a monthly period analysis to incorporate the seasonal correlation between the river conditions and the system load, and further sub-period analysis to incorporate diurnal water management from the off-load hours to the peak-load hours. The results from the studies show a noticeable increase in system reliability due to the diurnal energy management. The seasonal energy management methodology is applied to storage type hydro plants which have the capability of transferring energy from the wet season to the dry season of the year. The LOLE and LOEE values improve significantly in the energy limited period, as well as the reserve capacity that the system maintained is also increased without the need for additional generating capacity installations. The proposed methodology is applied to evaluate the reliability impact of diurnal and seasonal energy management the results show significant improvement in reliability using the LOLE and LOEE indices, and examples show that the system can also carry an increased system peak load at the same reliability level.
NERC recommend reliability index, LOLE in days/year only responds to seasonal energy management, but is unaffected by the diurnal energy management, and therefore, it is not a suitable adequacy index for a hydro dominant power system. It is recommended that an energy-based index LOEE be used for the adequacy evaluation of such systems. There is significant reliability impact of load forecast uncertainty in the energy limited months, which would have considerable influence on the overall system reliability. For the maintenance schedules, the study results show that the hydro dominant system has greater flexibility than a capacity based thermal dominant system. Based on the study results, it is concluded that the maintenance schedules of the different hydro plants and other power plants should be properly coordinated to achieve optimum reliability benefits. A probabilistic method to incorporate diurnal, seasonal and yearly energy management strategies in the run-of-river and storage type hydropower plant operation is proposed to further address energy uncertainty to save water in normal or wet year with minimal impact on system reliability and to maximize the availability of water in upcoming energy uncertainty year. Increasing the reservoir capacity together with the year to year energy management to carry over larger volume of water from the current year to the upcoming year was studied, and the simulation results show further improvement on the reliability of the system. Also, the study shows a strong correlation between the river flow pattern and load result a great positive impact on the system reliability. The application of the demand side management to change the system’s load pattern to follow the hydrological condition can significantly improve the reliability of a hydro dominant system. The results showed that the adverse impact of energy uncertainty has been minimized and the long-term system adequacy has been maintained. The presented models and strategies provide the useful information and suggestions in the operation and planning of the hydro dominant system under hydrological uncertainties for long-term system adequacy planning.