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Revision 0

Report on Integration of Existing Grid Models for N-R HES Interaction Focused on Balancing Authorities for Sub-hour Penalties and Opportunities

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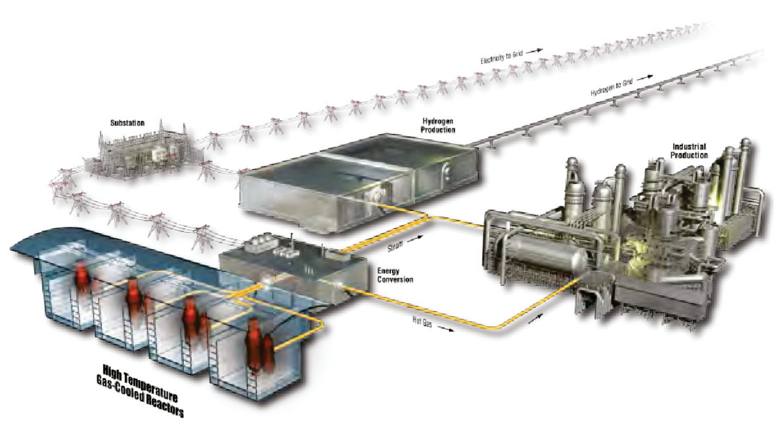
June 2017



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CONTENTS

FIGURES

ACRONYMS

ACE	Area Control Error
ARMA	Autoregressive Moving Average
BA	Balancing Authority
BPA	Bonneville Power Authority
FERC	Federal Energy Regulatory Commission
INL	Idaho National Laboratory
MISO	Midcontinent Independent System Operator
NERC	North American Energy Reliability Corporation
NPP	Nuclear Power Plant
NPV	Net Present Value
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
RAVEN	Risk Analysis Virtual Environment

Report on Integration of Existing Grid Models for N-R HES Interaction Focused on Balancing Authorities for Sub-hour Penalties and Opportunities

1. INTRODUCTION

This report provides a summary of how existing grid models might be integrated with the modeling and simulation efforts in Nuclear-Renewable Hybrid Energy System (N-R HES) project. This evaluation considers the factors selected for optimization in the Risk Analysis Virtual Environment (RAVEN) and Modelica [1] optimizations and economic analyses that have been the focus of the project to date to use shorter time intervals in existing electric grid models.

Any electricity generator connected to the electric grid has a physical connection through conductors, transformers, etc. The time constants of the purely electromagnetic physics are on time scales much shorter than the thermodynamics and mechanical components of a N-R HES. Models of the electricity grid components can be constructed in many ways, including transient models and power flow models, and methods that consider the interaction of power flow with the generation and synchronous loads of the overall system.

The primary interaction of the grid with the control system for the generator (N-R HES in this case) is dispatch signals. Dispatch signals include market signals for energy markets, which the current optimization considers, and signals related to reserve markets and the need for the external grid to use the reserves contracted by the authority responsible for overseeing the reliability of the grid. Since the current models are not focused on issues of transients but with the dispatch choices between the industrial process and supply of energy to the grid, the logical focus appears to be on the servicing of frequency and voltage stability aspects of the grid control that are supplied by a generating utility or N-R HES. The capacity of the N-R HES as a source of supply power to the greater electricity grid will be limited by the distribution and transmission network; this consideration is mentioned here briefly. Choices of voltage, location, conductor type and configuration of the inter-tie to the grid will set those limits. The distances and available voltages for inter-ties in the region will impact siting choices, as will local market constraints. However, for this report, we will assume those assets are chosen inline with the maximum expected power transfer to and from the N-R HES, such that the report can focus on the interaction of time intervals of less than 15 minutes but greater than seconds.

A power flow model will provide the most utility in connecting the N-R HES to the bulk grid, with dynamics of frequency changes calculated based on the spinning mechanical inertia dynamics of the N-R HES on one end of a transmission connection and the inertia of the bulk grid. Such a model is described by Ulbig, et. al [2]. The inputs require data from the bulk grid at the boundary, the power balance and voltage at the N-R HES generation plants, and a description of the impedance of the connecting transmission line. However, the impact of the bulk grid behavior and the potential demands on generation assets is described succinctly through the data acquired by the Balancing Authorities who act to maintain stability, as described in this report. It is assumed for this report that reactive power support of voltage is maintained adequately at both the N-R HES and the bulk grid.

The work presented here specifically considers the potential value of rotating mechanical inertia and opportunities or penalties that may occur due to the ability or inability of the N-R HES to deliver on the contracted power delivery. Longer-term contracts are written in pure market economics terms. Short-term considerations must also include the impact on the grid frequency and voltage stability that is managed by BAs and regulated through policy set by the Federal Energy Regulatory Commission (FERC) and enforced by a FERC certified Electricity Reliability Organization (ERO). North American Energy

Reliability Corporation (NERC) is the FERC certified ERO. This report focuses on the reliability standards and measures for the grid frequency stability and control that relate to the electric grid services and attached markets used to drive reliability of the system. This report summarizes the critical aspects of the grid that drive stability, explains the basis evaluation and control expression referred to as Area Control Error (ACE), describes in summary the current market and some proposed market mechanisms to incentivize the services to stabilize the system, and provides context, conclusions and future possibilities for the economic optimization of N-R HES that include reserve and ancillary services of value to the electric grid given the flexible nature of N-R HES.

2. FREQUENCY STABILITY AND BALANCING AUTHORITIES

This section summarizes details of how errors in power balance are tracked in a particular area of the grid as it relates to frequency stability. It also introduces the mechanism and markets that are used within the grid. This is important to N-R HES because economic optimization for a flexible asset like N-R HES impacts decisions about entry into the energy markets (e.g. day ahead, hour ahead) and the reserve markets (i.e. ancillary markets).

2.1 Frequency Drivers

The frequency of the electric grid is regulated through the balancing of power generated with power delivered to loads and the losses in the transmission and distribution systems. The rate at which the grid frequency increases or decreases is inversely proportional to the amount of spinning kinetic energy in the synchronous spinning machines (generators and synchronous motors) connected to the alternating current (AC) electric grid. With a bulk assumption regarding the amount of inertia on the grid, the relationship between frequency and power imbalance is described by the "swing equation":

$$J\omega \frac{\partial \omega}{\partial t} = \Delta P, \tag{1}$$

where J in $kg \cdot m^2$ is the bulk inertia of the grid, ω is the frequency of the spinning machines in radians per second, and ΔP is the difference in generated power and the power consumed by loads and losses in watts for the system. The frequency of the AC electric cycle, f, typically specified in hertz, is linearly proportional to the angular frequency of the spinning machines, $f\ 2\pi\omega/Np$, where Np is number of magnetic poles in a given spinning machine. A frequency excursion caused by a disturbance, such as an unplanned loss of load or generation, must be compensated by action from balancing reserves.

2.2 Balancing Authorities in North America

The North American electric grid is divided into regions called balancing authorities (BA) that have responsibility to "integrate resource planning ahead of time, maintain load interchange generation balance within the balancing authority area, and support interconnection frequency in real time."[3] There are 71 balancing authorities in the U.S. and Canada [4], as shown in Figure 1.

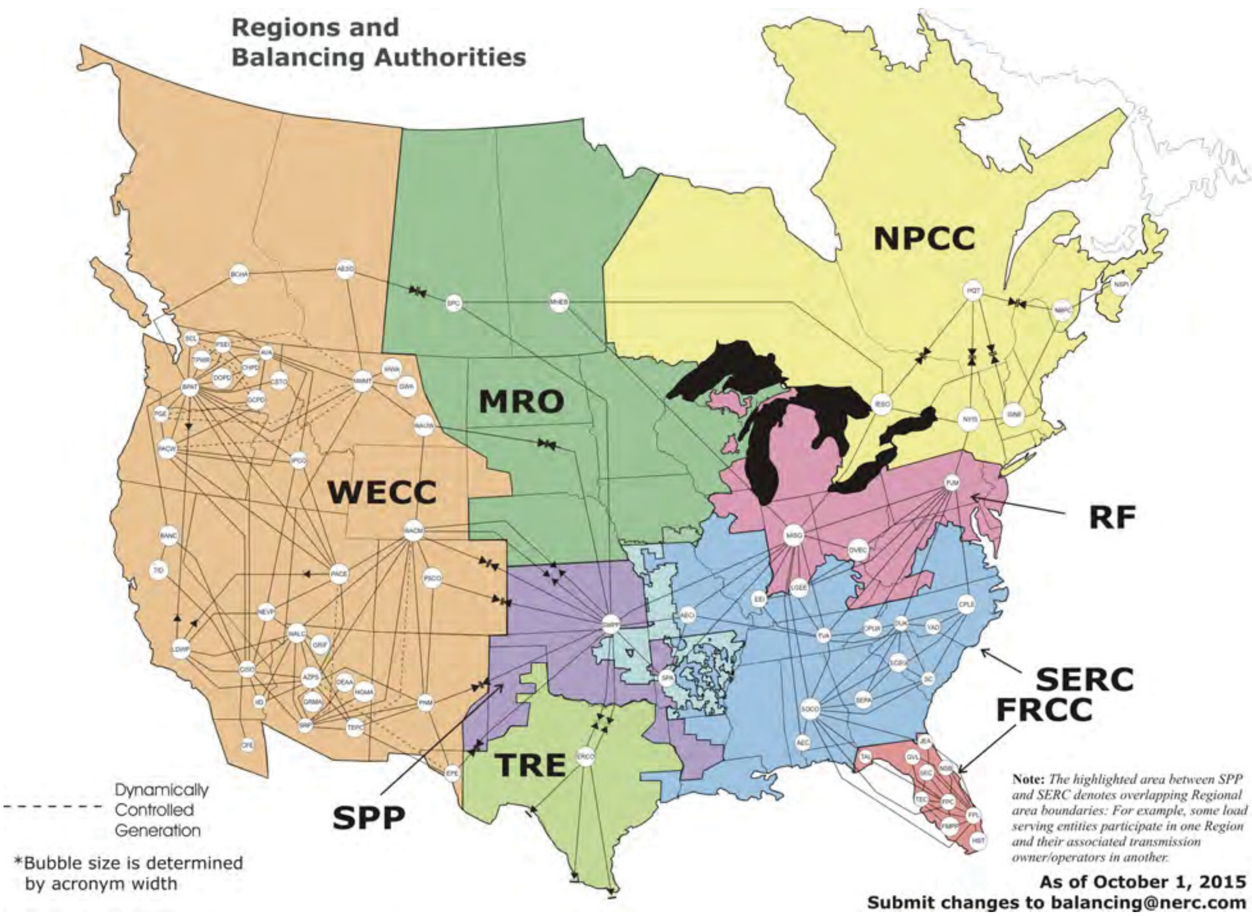

Figure 1. Division of North American electric grid into balancing areas.
(https://www.eia.gov/todayinenergy/images/2016.07.20/main.png)

2.3 Area Control Error

Each BA assures the reliability of the grid by effectively balancing generation, load (and losses), and inter-area exchanges. Each area has sufficient metering on the transmission between areas to account for a total of inflow and outflow of power to adjacent balancing areas. Interchange traditionally is planned ahead through bi-lateral long term contracts that schedule expected transfer of power in terms of hourly blocks of energy transfers, with recent additions of Energy Imbalance Markets (EIM) providing real-time markets for exchange between participating BAs (e.g. Western EIM [5]). The transmission lines between BAs are called tie lines. The method used to track whether transfer is on the contractual schedule between the BAs is called Tie Line Balance (TLB). The TLB method calculates the error in the balance using the Area Control Error (ACE) as defined by NERC. The ACE calculations account for the real-time deviation in planned or scheduled interchange of power with adjacent BAs, the measured frequency error, and other correction factors given in:

$$ACE = (NIA - NIS) - 10B(FA - FS) - IME + IATEC\,. \quad (2)$$

The first factor in the ACE calculation is the difference in Net Power Interchange Actual (NIA) and the Net Power Interchange Scheduled (NIS). This describes the measured difference in power flow between the actual instantaneous power flow and the planned power flow due to contracts. The second factor is the difference between the measured Frequency Actual (FA) and the Frequency Scheduled (FS) multiplied by the frequency bias setting, *B,* assigned to the BA in MWe/0.1 Hz. Frequency is typically scheduled at 60Hz for the North American electricity grid. The frequency error occurs as the accumulation of errors in power generated and power consumed. Each BA accepts a certain amount of responsibility for correcting for the frequency error. The Interchange Metering Error (IME) factor is a correction that may be applied due to real time metering errors that can be corrected based on more accurate cumulative hourly measurements. Finally, Interchange Automatic Time Error Correction Factor (IATEC) corrects for the accumulation of frequency errors that occur when the average frequency error over time is not zero. This not only ensures that analog clocks run on time but also balances out overall energy balance over the grid (i.e. a fast or slow clock is an indication of total energy balance error). A more detailed explanation can be found in NERC documents [6-7].

The resulting *ACE* term is in units of power (MWe) and describes the needed change in power within the BA to provide for obligations to frequency stabilization. The BA uses this value to advise control of the assets held in operating reserve by the BA or bid into the reserve market for spinning reserve, non-spinning reserve, up and down regulation capacity of dispatched generation, and demand response. The details of the types of reserves are described in the WECC standard balancing reserve document [8]. The bias, *B*, is the contribution assigned to the BA as the BA's contribution to respond to a frequency droop or spike. As an example, the bias for Pennsylvania New Jersey Maryland Interconnection LLC (PJM) is set annually by NERC and is based on 1% peak load estimate for the year [9]. NERC has published the agreed upon biases for all BAs in [10] for calendar year 2017, e.g. -1,355.2 for PJM and -1,101.3 for MISO.

The *ACE* serves as a measure of the BA performance and is reported to NERC in averages over one minute intervals. The *ACE* is also used as the input to the algorithms for applying automatic generation control (AGC) from the reserve capacity.

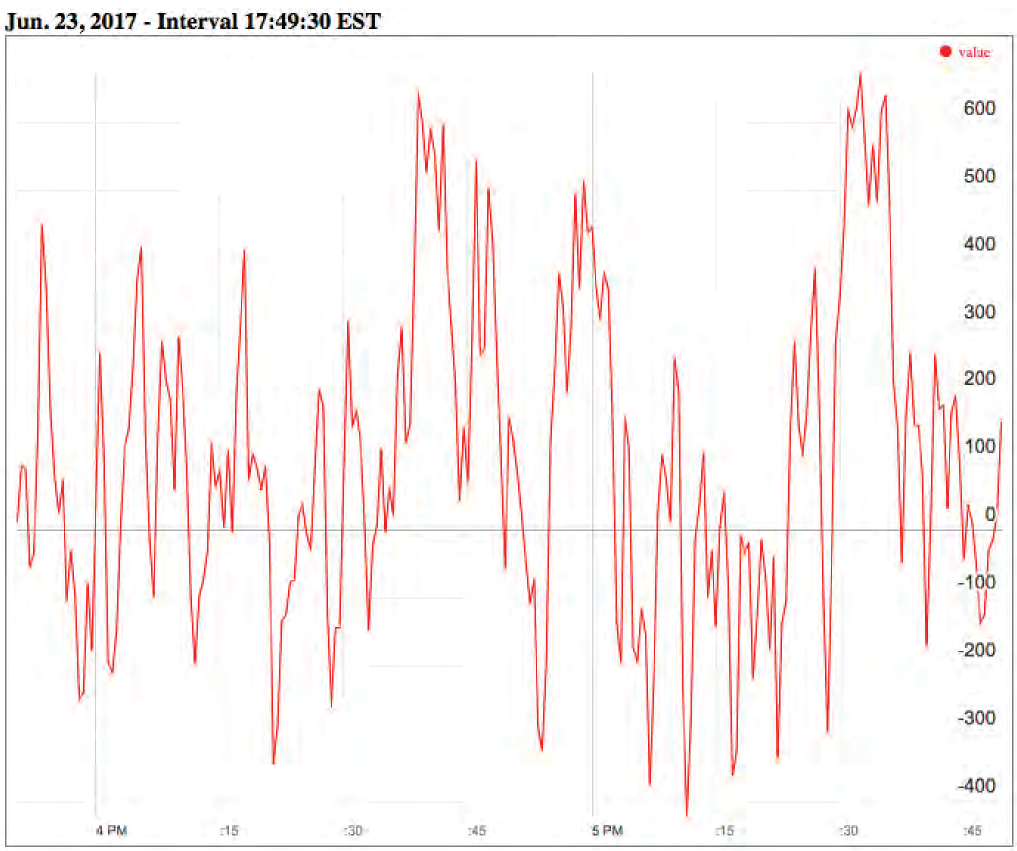

Figure 2. Area Control Error for Midcontinent Independent System Operator (MISO) for a 2-hour snapshot of time; y-axis values are in MWe.
(https://www.misoenergy.org/MarketsOperations/RealTimeMarketData/Pages/ACEChart.aspx)

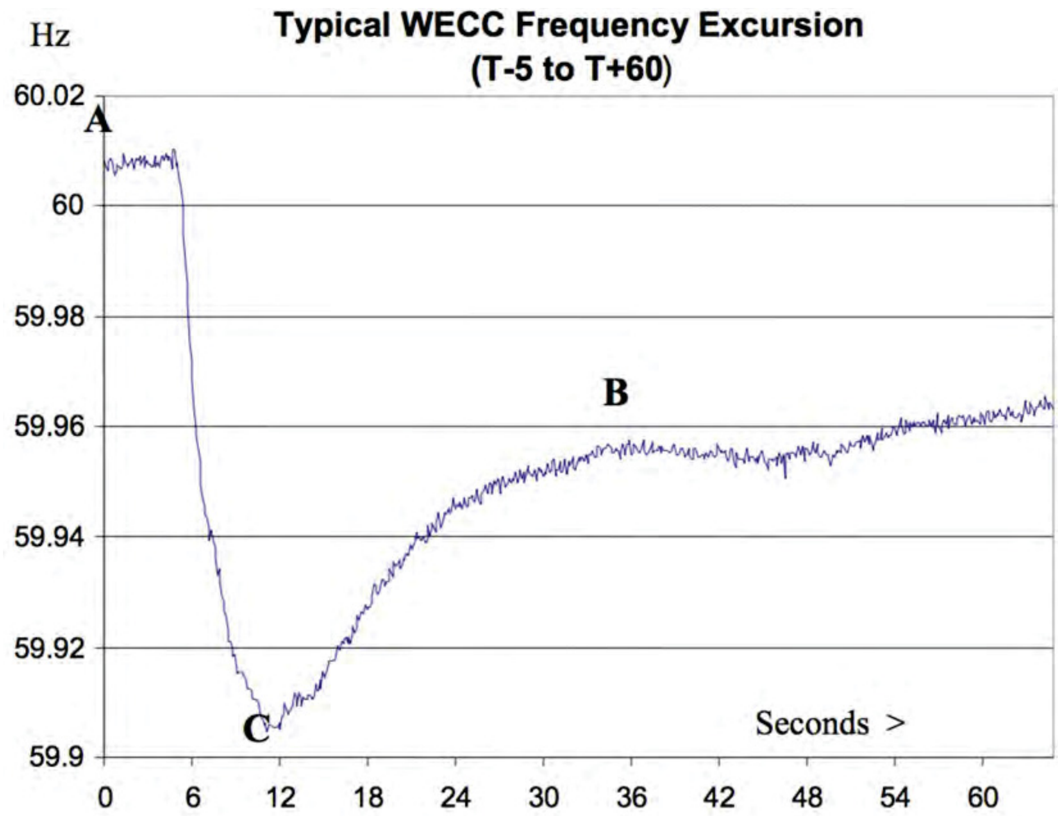

Figure 3. Frequency excursion example due to an unexpected change in generation [5].

2.4 Reserves

The reserve markets and ancillary markets provide BAs the ability to acquire sufficient reserves to accommodate variability in load and generation, particularly renewable generation, as well as contingency events such as unexpected outages of generation. NERC requires the BA to have sufficient reserves for these events. For generation that can provide this flexibility there is opportunity to bid in to be compensated for holding some assets in reserve as up or down regulation, spinning reserve, non-spinning reserve, etc. The time frame for the generation to respond after a request to fulfill is dependent on the particular market:

- Frequency Response (automatic response) – 0-30 seconds
- Up/Down Regulation – 4-300 seconds
- Spinning and Non-spinning Reserve – 10-105 minutes
- Replacement Reserve – 30 minutes.

The utility then responds to signals or requests from the BA to adjust the output of operating generation or to bring up spinning or non-spinning reserves in response to the instantaneous ACE measures. Spinning and non-spinning reserve must ramp to full commitment within 10 minutes of the signal. The utility is compensated on the energy dispatched or curtailed. As with energy markets, there are day ahead and real time markets for reserve capacity. For assets such as N-R HES that offer flexibility, there is an additional potential economic benefit to owners and investors to apply to the markets as BAs are challenged with more variable generation.

2.5 Possibility of Future Penalties

The current energy markets do not exist for the instantaneous benefit to frequency stability. As shown in Figure 3., the frequency of the grid changes rapidly after a disturbance, such as unexpected loss of a generator. The slope of the frequency is slowed directly by the transfer of kinetic energy of the spinning machines to the electric grid as the machines slow. If there were less inertia in the grid assets the slope would be steeper and the frequency excursion greater. Inertia is an inherent physical property that engages without signals from the BA. It can be argued that there needs to be a market for this benefit provided to the grid [11]. It is premature to formulate a method for optimizing N-R HES at this time; however, potential developers may want to consider this argument.

3. FREQUENCY RESPONSE AS A CONSIDERATION FOR OPTIMIZING N-R HES

This section summarizes a possible mechanism to consider the frequency response capabilities and flexibility of N-R HES in system design and operational optimization. As the ACE provides the drivers for response to tie line and frequency imbalances, the ACE also serves as a direct indicator of the demand for auxiliary services. In a FERC technical conference [12], Mark Lively proposed a set of functions to describe the monetary value of variations in commitment from renewable generators that becomes a manageable form to analyze the cost of the inability to meet commitment for delivery of energy [13]. Further, he suggests a market based on those curves where a contract delivery might intentionally be missed in a direction that would push the ACE to a smaller error in order to be rewarded with bonuses. Figure 4 shows the price adjustment curve based on hyperbolic sine functions with different multipliers. A multiplier can be chosen as a large number to be more punitive or rewarding. The ACE in this presentation is the real time measurement and the penalty/bonus determined by multiplying the penalty factor ($/MWh) by the energy that is deficient in the commitment during the time period of the ACE generation.

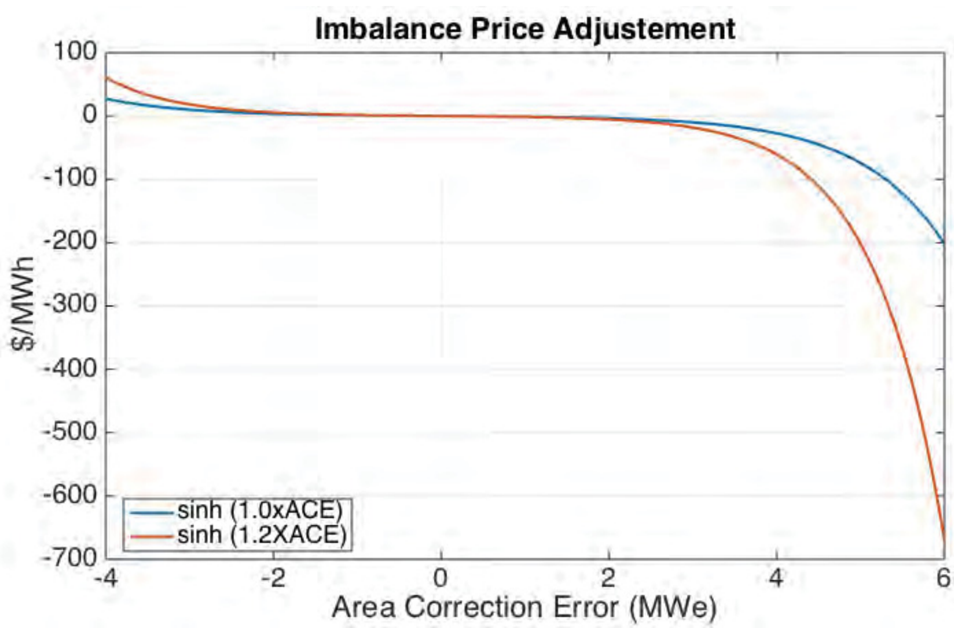

Figure 4. Price adjustment based on ACE measured imbalance providing penalties and bonuses for variation in delivery on a market contract, as proposed by Mark Lively [12]. Penalties are applied for deficiency in energy sales commitment that increase the ACE and bonuses are applied for those that act to offset the ACE.

To use the ACE and penalty/bonus factors for optimization of size and configuration an understanding of the profitability of designing N-R HES with or without reserve capacity that will target the reserve markets is necessary. One proposal is to fit an Autoregressive Moving Average (ARMA) model to the behavior of ACE through the annual cycle. Data on historical ACE values for the BAs are available through the BA reports data posted online for some Bas, such as Bonneville Power Authority (BPA) and MISO:

- BPA - https://transmission.bpa.gov/business/operations/ACE_FERC784/
- MISO - https://www.misoenergy.org/Library/MarketReports/Pages/MarketReports.aspx

The value of the market in the annual cycle can be estimated by mapping the curve proposed by Lively versus the ACE values from the ARMA representation. The value of reserve capacity designed into the N-R HES could be determined by multiplying by the ACE value on an annual basis.

4. CONCLUSION

The economic benefit of a N-R HES to the electric grid frequency stability requirements, and the control and markets that support balancing authority duties to grid reliability, has been considered in this initial investigation. The ACE is a measure on which balancing authorities base control decisions for grid stability and is also a NERC reportable statistic. As such, it is a parameter that, when combined with a monetization of the value of frequency support, provides further possibilities for optimization of the N-R HES size per the established RAVEN toolset. This report summarizes the concepts of frequency response and provides a possible path forward to consider reserve markets in system design optimization. An argument is also possible to accounting for the provided inertia as an intrinsic stabilizing characteristic of the nuclear and natural gas components of the system, although this characteristic is not available in monetized form. With respect to specific electric grid models that should be considered for integration into Modelica and RAVEN, optimization can be performed with information contained in the interaction of control with the balancing authority.

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