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**Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency and Enhancing Resilience through Improved Software**

**Agenda**

**AD10-12-011**

**June 23 – 25, 2020**

| Tuesday, June 23, 2020 |
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| 9:30 AM | WebEx connection available for attendees to connect and check their settings (music will be playing) |
| 9:45 AM | Introduction (WebEx)Thomas Dautel, Federal Energy Regulatory Commission (*Washington, DC*)Richard O’Neill, US Department of Energy (*Washington, DC*) |
| 10:00 AM | Session T1 (WebEx)**Market Implications of Reserve Deliverability Enhancement with the Application to Short-term Reserve**Fengyu Wang, Midcontinent ISO (*Carmel, IN*)Yonghong Chen, Midcontinent ISO (*Carmel, IN*)**Modelling of Energy Storage Resources in New York Electricity Market**Sina Parhizi, New York ISO (*Rensselaer, NY*)**MISO Reliability Needs & Patterns Assessment**Long Zhao, Midcontinent ISO (*Carmel, IN*)Jessica Harrison, Midcontinent ISO (*Carmel, IN*)Jordan Bakke, Midcontinent ISO (*Eagan, MN*)Liangying Hecker, Midcontinent ISO (*Eagan, MN*)**Transmission Constraint Management at ISO New England**Slava Maslennikov, ISO New England (*Holyoke, MA*)Xiaochuan Luo, ISO New England (*Holyoke, MA*)Eugene Litvinov, ISO New England (*Holyoke, MA*) |
| 12:00 PM | Lunch |
| 1:30 PM | Session T2 (WebEx)**Economic Interpretation of Demand Curves in Multi-product Electricity Markets**Feng Zhao, ISO New England (*Holyoke, MA*)Tongxin Zheng, ISO New England (*Holyoke, MA*)Eugene Litvinov, ISO New England (*Holyoke, MA*)**SCUC Performance Challenges and Improvements**Matthew Musto, New York ISO (*Rensselaer, NY*)**Optimizing Hydroelectric Pumped Storage Schedules in PJM’s Day-Ahead Energy Market**Anthony Giacomoni, PJM Interconnection (*Audubon, PA*)Qun Gu, PowerGEM (*Clifton Park, NY*)Boris Gisin, PowerGEM (*Clifton Park, NY*) |
| 3:00 PM | Break |
| 4:00 PM | Session T3 (WebEx)**HIPPO - Solving Large Security Constrained Unit Commitment Problem**Feng Pan, Pacific Northwest National Laboratory (*Richland, WA*)Jesse Holzer, Pacific Northwest National Laboratory (*Richland, WA*)Yonghong Chen, Midcontinent ISO (*Carmel, IN*)**Fast Day-Ahead SCUC for Integrating Large-Scale DERs into Wholesale Energy Market**Lei Wu, Stevens Institute of Technology (*Hoboken, NJ*)Yonghong Chen, Midcontinent ISO (*Carmel, IN*)**Sub-hourly Unit Commitment with Large Numbers of Generators and Virtual Transactions: An Ordinal Optimization-based Decomposition and Coordination Approach**Jianghua Wu, University of Connecticut (*Storrs, CT*)Peter B. Luh, University of Connecticut (*Storrs, CT*)Yonghong Chen, Midcontinent ISO (*Carmel, IN*)Mikhail Bragin, University of Connecticut (*Storrs, CT*)Yang Bin, Rochester Institute of Technology (*Rochester, NY*) |
| 5:30 PM | Adjourn |

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| Wednesday, June 24, 2020 |
| 9:30 AM | WebEx connection available for attendees to connect and check their settings (music will be playing) |
| 9:45 AM | Introduction |
| 10:00 AM | Session W1 (WebEx)**Optimality Conditions and Cost Recovery in Electricity Markets with Variable Renewable Energy and Energy Storage**Audun Botterud, Massachusetts Institute of Technology and Argonne National Laboratory (*Cambridge, MA*) Magnus Korpås, Norwegian University of Science and Technology (*Trondheim, Norway)***On the Equilibria and Efficiency of Electricity Markets with Renewable Power Producers and Congestion Constraints**Yue Zhao, Stony Brook University (*Stony Brook, NY*)Hossein Khazaei, Stony Brook University (*Stony Brook, NY*)X. Andy Sun, Georgia Institute of Technology (*Atlanta, GA*)**Coordinated Ramping Product Procurement using Multi-Scale Probabilistic Solar Power Forecasts**Benjamin Hobbs, Johns Hopkins University (*Baltimore, MD*)Venkat Krishnan, National Renewable Energy Laboratory *(Golden, CO)*Paul Edwards, National Renewable Energy Laboratory *(Golden, CO)*Haiku Sky, National Renewable Energy Laboratory *(Golden, CO)*Elina Spyrou, National Renewable Energy Laboratory *(Golden, CO)*Hendrik Hamann, IBM (*Yorktown Heights, NY*)Rui Zhang, IBM (*Yorktown Heights, NY*)Jie Zhang, University of Texas at Dallas (*Dallas, TX*)Binghui Li, University of Texas at Dallas (*Dallas, TX*)Qungyu Xu, Johns Hopkins University (*Baltimore, MD*)Josephine Wang, Johns Hopkins University (*Baltimore, MD*)Shu Zhang, Johns Hopkins University (*Baltimore, MD*)**Stochastic Nodal Adequacy Platform (SNAP)**Richard D. Tabors, Tabors Carmanis Rudkevich (*Newton, MA*)Aleksandr Rudkevich, Tabors Carmanis Rudkevich (*Newton, MA*) |
| 12:00 AM | Lunch |
| 1:30 PM | Session W2 (WebEx)**A Unified Approach to Solve Convex Hull Pricing and Average Incremental Cost Pricing**Yonghong Chen, Midcontinent ISO (*Carmel, IN*)Richard O’Neill, US Department of Energy (*Washington, DC*)**Computational Studies on Primal Formulation Approaches for Convex Hull Pricing**Yongpei Guan, University of Florida (*Gainesville, FL*)Yonghong Chen, Midcontinent ISO (*Carmel, IN*)Tong Zhang, University of Florida (*Gainesville, FL*)Yanan Yu, University of Florida (*Gainesville, FL*)**A Computationally Efficient Algorithm for Computing Convex Hull Prices**Bernard Knueven, National Renewable Energy Laboratory (*Golden, CO*)James Ostrowski, University of Tennessee (*Knoxville, TN*)Anya Castillo, Sandia National Laboratories (*Albuquerque, NM*)**Exploiting Dense Sensitivity Matrices in Linear Optimal Power Flow**Brent Eldridge, Federal Energy Regulatory Commission (*Baltimore, MD*)Anya Castillo, Sandia National Laboratories (*Albuquerque, NM*)Ben Knueven, National Renewable Energy Laboratory (*Golden, CO*) |
| 3:30 PM | Break |
| 4:00 PM | Session W3**Transmission Topology Optimization Case Studies on Market Efficiency Improvements and Reliability and Resilience Enhancements**Pablo Ruiz, NewGrid, Inc (*Somerville, MA*)**Benchmarking Software for Power Systems with Retiring Power Plants and Wind Power Plants**Marija Ilic, Massachusetts Institute of TechnologyRupimathi Jaddivada, Massachusetts Institute of Technology**Transient Optimization of Large Natural Gas Pipeline Networks using Linear Programming**Aleksandr Rudkevich, Newton Energy Group LLC (*Newton, MA*)Aleksandr Beylin, Newton Energy Group LLC (*Newton, MA*)Anatoly Zlotnik, Los Alamos National Laboratory (*Los Alamos, NM*)**North American Natural Gas Market and Infrastructure Developments Under Different Mechanisms of Renewable Policy Coordination** Charalampos Avraam, Johns Hopkins University (*Baltimore, MD*)John E.T. Bistline, Electric Power Research Institute (*Palo Alto, CA*)Maxwell Brown, National Renewable Energy Laboratory (*Golden, CO*)Kathleen Vaillancourt, Esmia Consultants (*Blainville, Canada*)Sauleh Siddiqui, American University (*Washington, DC*) |
| 6:00 PM | Adjourn |

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| Thursday, June 25, 2020 |
| 9:30 AM | WebEx connection available for attendees to connect and check their settings (music will be playing) |
| 9:45 AM | Introduction |
| 10:00 AM | Session H1**An Integrated Platform for Wind Plant Operations: From Atmosphere to Electrons to the Grid**Evangelia Spyrou, National Renewable Energy Laboratory *(Golden, CO)*Jennifer King, National Renewable Energy Laboratory *(Golden, CO)*Andrew Kumler, National Renewable Energy Laboratory *(Golden, CO)*Christopher Bay, National Renewable Energy Laboratory *(Golden, CO)*Yingchen Zhang, National Renewable Energy Laboratory *(Golden, CO)*Vahan Gevorgian, National Renewable Energy Laboratory *(Golden, CO)*Dave Corbus, National Renewable Energy Laboratory *(Golden, CO)***Scalable Energy System Expansion Under Uncertainty Using Multi-stage Stochastic Optimization**Devon Sigler, National Renewable Energy Laboratory (*Golden, CO*)Wesley Jones, National Renewable Energy Laboratory (*Golden, CO*)Jonathan Maack, National Renewable Energy Laboratory (*Golden, CO*)Ignas Satkauskas, National Renewable Energy Laboratory (*Golden, CO*)Matthew Reynolds, National Renewable Energy Laboratory (*Golden, CO*)**Machine Learning Assisted Preventive Stochastic Unit Commitment**Mostafa Sahraei-Ardakani, University of Utah *(Salt Lake City, UT)*Ge “Gaby” Ou, University of Utah *(Salt Lake City, UT)* |
| 11:30 PM | Lunch |
| 1:00 PM | Session H2**State of Charge Management Concepts and Options for Stand-alone Electric Storage Resources**Nikita Singhal, Electric Power Research Institute (*Palo Alto, CA*)Erik Ela, Electric Power Research Institute (*Palo Alto, CA*)**Analysis of GO Competition Challenge 1 Final Event Problem Difficulty**Stephen Elbert, Pacific Northwest National Laboratory (*Richland, WA*)Hans Mittelmann, Arizona State University (*Tempe, AZ*)**What Does it Take to Achieve Carbon Neutrality in the Electric Network?**Henry “Hank” He, Tabors Carmanis Rudkevich (*Newton, MA*)Ninad Kumthekar, Tabors Carmanis Rudkevich (*Boston, MA*)Xindi Li, Tabors Carmanis Rudkevich (*Boston, MA*)Chen Ling, Tabors Carmanis Rudkevich (*Boston, MA*)Russ Philbrick, Polaris Systems Optimization (*Seattle, WA*) Aleksandr Rudkevich, Newton Energy Group LLC (*Boston, MA*) |
| 3:00 PM | Break |
| 3:30 PM | Session H3**Enhanced Flexible Ramping Product: Design and Analysis**Mojdeh Khorsnad Hedman, Arizona State University (*Tempe, AZ*)Mohammad Ghaljehei, Arizona State University (*Tempe, AZ*)**Quasi-Stochastic Electricity Markets**Jacob Mays, Cornell University (*Ithaca, NY*)**Probabilistic Zonal Reserve Requirements for Improved Energy Dispatch and Deliverability with Wind Power Uncertainty**Zhi Zhou, Argonne National Laboratory (*Lemont, IL*)Byungkwon Park, Oak Ridge National Laboratory (*Oak Ridge, TN*)Audun Botterud, Argonne National Laboratory (*Lemont, IL*)Prakash Thimmapuram, Argonne National Laboratory (*Lemont, IL*) |
| 5:00 PM | Adjourn |

**Staff Technical Conference on Increasing Real-Time and Day-Ahead Market efficiency and Enhancing Resilience through Improved Software**

**Presenters’ Abstracts**

Introduction (Tuesday, June 23, 9:45 AM, WebEx)

**Introduction**

**Thomas Dautel,** Deputy Director, Division of Economic and Technical Analysis, Federal Energy Regulatory Commission (*Washington, DC*)

**Dr. Richard O’Neill, Distinguished Senior Technical Fellow, US Department of Energy** (*Washington, DC*)

Session T1 (Tuesday, June 23, 10:00 AM, WebEx)

**Market Implications of Reserve Deliverability Enhancement with the Application to Short-term Reserve**

**Dr. Fengyu Wang**, Senior R&D Engineer, Midcontinent ISO (*Carmel, IN*)

Dr. Yonghong Chen, Consulting Advisor, Midcontinent ISO (*Carmel, IN*)

Insufficient deliverable reserve may require additional operator manual adjustments, which may be uneconomic and distort the market price signal. Traditionally, reserve is acquired on a zonal basis. However, transmission bottlenecks in the power system may inhibit the deliverability of STR and the zonal reserve clearing model may not guarantee reserve deliverability on a nodal basis. To improve reserve deliverability and distribute reserve across the grid at a more granular level, a nodal STR clearing model is considered. Pros and cons on the practicality of implementation will also be discussed. The Midcontinent Independent System Operator (MISO) plans to introduce a 30-minute short-term reserve (STR) to address 30 minutes system flexibility needs. The presentation will have STR as a use case of nodal reserve clearing model and compare the market outcomes between zonal STR model and nodal STR model. A new design on penalty function is also considered to reflect the true value of security constraints for reserve deployment with the consideration of multiple events.

**Modelling of Energy Storage Resources in New York Electricity Market**

**Dr. Sina Parhizi**, Energy Market Engineer, New York ISO (*Rensselaer, NY*)

New York Independent System Operator (NYISO) has been working with their stakeholders on an energy storage (ESR) participation model. FERC Order 841 accelerated the timeline to allow ESRs to participate in the wholesale markets. In addition to the recommendations in the FERC Order, NYISO’s design includes parameters like round trip efficiency in the ESR participation model to ensure feasible dispatch schedules. This presentation will review the modeling of energy level constraints for a storage resource or State of Charge (SoC) management and how it interacts with round trip efficiency and bidding strategies in the wholesale markets.

**Economic Interpretation of Demand Curves in Multi-product Electricity Markets.**

**Dr. Feng Zhao**, Principal Analyst, ISO New England (*Holyoke, MA*)

Dr. Tongxin Zheng, Technical Director, ISO New England (*Holyoke, MA*)

Dr. Eugene Litvinov, Chief Technologist, ISO New England (*Holyoke, MA*)

In the absence of demand-side bids for certain reliability products in wholesale electricity markets, ISOs traditionally use fixed requirements with penalty factors to clear the market. This approach does not allow proper tradeoffs between cost and reliability due to the inelasticity of the fixed requirements. So ISOs have been replacing the fixed requirements with sloped demand curves. However, the economic meaning of demand curves, especially for multiple coupled products, is largely missing in both theory and practice. This could lead to the misrepresentation of the demand benefit and the market clearing objective. Using a two-product market model, we reveal two distinct interpretations of demand curves, each associated with a specific form of the market clearing problem. This implies that the construction of demand curves and the use of them in market clearing must be consistent with their economic interpretation. We also show that demand curves in some existing markets do not lead to clearly defined demand benefits. Additional assumptions on these curves are required. We present two assumptions that result in the two aforementioned interpretations of demand curves. A small example is used to compare the two assumptions. Our work provides a much needed guide for the proper construction and use of demand curves at a time when the demand curve is increasingly used as an important pricing tool for the markets with significant penetration of near-zero marginal cost resources.

**MISO Reliability Needs & Patterns Assessment**

**Dr. Long Zhao**, Research and Development Advisor, Midcontinent ISO (*Carmel, IN*)

 Jessica Harrison, Senior Director of Research and Development, Midcontinent ISO (*Carmel, IN*)

 Jordan Bakke, Senior Manager of Policy Studies, Midcontinent ISO (*Eagan, MN*)

 Liangying Hecker, Senior Manager of Probabilistic Resource Studies, Midcontinent ISO (*Eagan, MN*)

The resource portfolio in the MISO region is undergoing a sizable change, with units aging and new variable resources coming online. In preparation for this shift, and in light of needs to address near-term risks, MISO is assessing reliability needs through 2030. These needs are intended to inform resource adequacy and day ahead and real time market modifications. Initial findings on changing needs/patterns have been generated via data analytics and simulations. Approaches and initial findings will be presented, along with initial findings regarding resource adequacy approaches.

Session T2 (Tuesday, June 23, 1:30 PM, WebEx)

**Transmission Constraint Management at ISO New England**

**Dr. Slava Maslennikov**, Technical Manager, ISO New England (*Holyoke, MA*)

Dr. Xiaochuan Luo, Technical Manager, ISO New England (*Holyoke, MA*)

Dr. Eugene Litvinov, Chief Technologist, ISO New England (*Holyoke, MA*)

Existing transmission constraint management process has been developed over decades for traditional power systems. Dramatic changes related to the increasing penetration of renewables, increasing range of variability and uncertainties and more frequent extreme weather events require significant changes in the process. Modern power systems will need to transition from the reliability-based to resilience-based dispatch. Traditional operation targeting the elimination of thermal, voltage and stability violations needs a risk-based approach. This presentation discusses the ISO New England strategy for the enhancement of the transmission constraint management and a practical way of shifting to a risk-based, resilient operation. The specific topics include:

* Online Cascading Analysis (OCA) as a basis for shifting towards risk-based dispatch. Pilot implementation of the OCA includes steady-state and time-domain analysis of the processes triggered by complex initiating events.
* Tracking the weather related increase of probabilities of N-k outages and studying the corresponding system impact in OCA is a practical way for situational awareness beyond N-1.
* Shifting offline calculation of interface limits online.
* Formalization and standardization of Transmission Operating Guides (TOG) allowing to drastically increase the efficiency of the TOG utilization.

**SCUC Performance Challenges and Improvements**

**Mr. Matthew Musto**, Technical Specialist, New York ISO (*Rensselaer, NY*)

Continued expansion of grid resources and market features have significantly increased performance requirements within SCUC. Specifically, as the NYISO implements Energy Storage and Distributed Energy Resources (ESR and DER) the requirement for a timely market close and post is unchanging; resulting in a greater pressure on computation time. This presentation will provide an overview of those challenges and what the NYISO has done and plans to do in regard to solution execution time.

**Optimizing Hydroelectric Pumped Storage Schedules in PJM’s Day-Ahead Energy Market**

**Dr. Anthony Giacomoni**, Senior Market Strategist, PJM Interconnection (*Audubon, PA*)

Dr. Qun Gu, Principal Consultant, PowerGEM (*Clifton Park, NY*)

Dr. Boris Gisin, President, PowerGEM (*Clifton Park, NY*)

The 2018 Federal Energy Regulatory Commission (FERC) Order 841 urged RTOs and ISOs to open their markets to eligible electric storage resources (ESR). One of the current challenges of integrating large amounts of ESR into wholesale energy markets is managing their state of charge (SOC). However, since 2006, PJM has been optimizing the schedules of the hydroelectric pumped storage units in its Day-Ahead Energy Market. PJM has several large pumped storage units in its territory including the world’s largest, Bath County Pumped Storage Station with a maximum generation capacity of over 3,000 MW and 24,000 MWh of storage. The dispatch of large pumped storage units is especially challenging because the dispatch of these units can have major impacts on transmission congestion and the LMPs in their surrounding locations, which in turn has propagating impacts on how pump storage and other units in the vicinity should be dispatched.

This presentation will provide an overview of the pumped storage optimization model currently being used in PJM’s Day-Ahead Energy Market. As PJM’s wholesale energy markets have continued to evolve, there is a need to further enhance the current model, including the need for greater flexibility in how pumped storage units are able to bid into the market and to account for the anticipated growth of ESR. Several of these challenges will be discussed along with enhancements currently under development to further improve the performance of the model.

Session T3 (Tuesday, June 23, 4:00 PM, WebEx)

**HIPPO - Solving Large Security Constrained Unit Commitment Problem**

**Dr. Feng Pan**, Scientist, Pacific Northwest National Laboratory (*Richland, WA*)

Dr. Jesse Holzer, Scientist, Pacific Northwest National Laboratory (*Richland, WA*)

Dr. Yonghong Chen, Consulting Advisor, Midcontinent ISO (*Carmel, IN*)

In the day-ahead electricity market, security constrained unit commitment (SCUC) is solved with simultaneous feasibility test (SFT) to ensure cost efficiency and physical reliability. HIPPO software aims to provide fast solution techniques for solve SCUC and SFT, and it includes a concurrent optimizer, fast SFT solver and solution repairing methods. In this talk, we will discuss these features implemented in HIPPO for speeding up the runtime and share our experience in solving SCUC in MISO’s day-ahead market cases.

**Fast Day-Ahead SCUC for Integrating Large-Scale DERs into Wholesale Energy Market**

**Dr. Lei Wu**, Professor, Stevens Institute of Technology (*Hoboken, NJ*)

 Yonghong Chen, Consulting Advisor, Midcontinent ISO (*Carmel, IN*)

This presentation will discuss some recent work in collaboration with MISO to address modeling and computational challenges associated with a high penetration of DERs in wholesale energy market.

On one hand, DERs could greatly increase the number of variables and non-zeros in associated network security constraints of the SCUC model, challenging its effective computation. We explored a suite of efficient aggregation method to approximate the original network security constraints with reduced number of variables and non-zeros, in order to improve computational performance of SCUC while achieving sufficiently good solutions.

On the other hand, in ISOs’ current energy market clearing process, primary distribution systems are usually simplified as fixed or flexible loads. This may not work well for emerging distribution systems with an increasing number of DERs, which could reform power flow patterns and induce congestions in distribution networks. Indeed, scheduling results from the simplified model could trigger line congestion and under/over-voltage issues in distribution networks, while also misrepresenting contributions of DERs on economic operations. We explored a feasible region projection-based approach to effectively capture configuration details of distribution systems and fully respect their internal physical limits. It does not require ISO collecting configuration details of or conducting an iterative procedure, thus compatible to the current ISO market practice.

**Sub-hourly Unit Commitment with Large Numbers of Generators and Virtual Transactions: An Ordinal Optimization-based Decomposition and Coordination Approach**

**Mr. Jianghua Wu**, Ph.D. Student, University of Connecticut (*Storrs, CT*)

Dr. Peter B. Luh, Professor, University of Connecticut (*Storrs, CT*)

Dr. Yonghong Chen, Consulting Advisor, Midcontinent ISO (*Carmel, IN*)

Dr. Mikhail Bragin, Assistant Research Professor, University of Connecticut (*Storrs, CT*)

Dr. Yang Bin, Assistant Professor, Rochester Institute of Technology (*Rochester, NY*)

Sub-hourly Unit Commitment (UC) is a way to improve the flexibility and performance of power systems. Compared to hourly UC, such a problem is larger because of the increased number of periods, and generally has more active ramping constraints because of reduced unit ramping capabilities per period. For certain systems, there are also a very large number of virtual transactions with continuous variables only and linear costs. When coupled with transmission constraints, they lead to increased computation because of dense constraint matrices. To overcome the above difficulties, an ordinal optimization-based decomposition and coordination approach is presented where: 1) the goal of solving a subproblem is softened to just satisfy the algorithm convergence condition without formally pursuing optimality; 2) the time to solve a subproblem is consequently reduced drastically through “ordering” solution candidates which are quickly derived by simplified models or modified from previous solutions. A parallel version is also developed to further reduce the CPU time while considering the very large number of virtual transactions whose solutions are very sensitive to multiplier values. Multiple MISO cases with about 1,100 generators and 15,000 virtual transactions over 36 hours with 15 minute time intervals are tested on the “HIPPO” platform. Results demonstrate that the new approach obtains near-optimal solutions efficiently, is robust, and significantly outperforms existing methods.

Introduction (Wednesday, June 24, 9:45 AM, WebEx)

Session W1 (Wednesday, June 24, 10:00 AM, WebEx)

**Optimality Conditions and Cost Recovery in Electricity Markets with Variable Renewable Energy and Energy Storage**

**Dr. Audun Botterud**, Principal Research Scientist, MIT/ANL (*Cambridge, MA*)

Dr. Magnus Korpås, Professor, Norwegian University of Science and Technology (*Trondheim, Norway*)

We formulate generation capacity portfolio planning in the power grid as a least-cost optimization problem and derive analytical expressions for the optimality conditions for dispatchable generation, variable renewable energy (VRE), and energy storage systems (EES) using a generalized net load duration curve approach. This is done for different operational strategies for EES with and without VRE in the system. For all studied combinations of technologies and operational strategies, we show that all units, including VRE and EES, recover their costs and maximize their profits in the system optimum, for an ideal short-term electricity market based on marginal cost and scarcity pricing. We verify the analytical findings through a numerical example, which shows that the general net load duration curve approach gives identical results to a standard capacity expansion model with sequential operation of the generation and ESS units, under the assumption of limited power capacity but infinite energy capacity of EES. The results highlight that the net load duration curve models presented in this paper can be a useful supplement to more detailed simulation studies of markets with high penetration of VRE and EES, to better understand the underlying factors that determines the optimal capacity mix and profitability of each technology in energy-only electricity markets.

**On the Equilibria and Efficiency of Electricity Markets with Renewable Power Producers and Congestion Constraints**

**Dr. Yue Zhao**, Assistant Professor, Stony Brook University (*Stony Brook, NY*)

Mr. Hossein Khazaei, Ph.D. Student, Stony Brook University (*Stony Brook, NY*)

Dr. X. Andy Sun, Associate Professor, Georgia Institute of Technology (*Atlanta, GA*)

With increasing renewable penetration in power systems, a prominent challenge in efficient and reliable power system operation is handling the uncertainties inherent in the renewable generation. We propose a simple two-settlement market mechanism in which renewable power producers (RPPs) participate, so that: a) the independent system operator (ISO) does not need to consider the uncertainties of the renewables in its economic dispatch, and yet b) the market equilibrium is shown to approach social efficiency as if the ISO solves a stochastic optimization taking into account all the uncertainties. In showing this result, a key innovation is a new approach of efficiently computing the Nash equilibrium (NE) among the strategic RPPs in congestion-constrained power networks. In particular, the proposed approach decouples finding an NE into searching over congestion patterns and computing an NE candidate assuming a congestion pattern. As such, the computational complexity of finding an NE grows only cubically with the number of RPPs in the market. We demonstrate our results in the IEEE 14-bus system and show that the NE approaches social efficiency as the number of RPPs grows.

**Coordinated Ramping Product Procurement using Multi-Scale Probabilistic Solar Power Forecasts**

**Dr. Benjamin Hobbs**, Schad Professor, Johns Hopkins University (*Baltimore, MD*)

Venkat Krishnan, Researcher IV, National Renewable Energy Laboratory *(Golden, CO)*

Paul Edwards, Software Architect, National Renewable Energy Laboratory *(Golden, CO)*

Haiku Sky, GDS/OpenCarto Project Manager, National Renewable Energy Laboratory *(Golden, CO)*

Dr. Evangelia Spyrou, Research Engineer, National Renewable Energy Laboratory *(Golden, CO)*

Hendrik Hamann, Chief Scientist for Geoinformatics, IBM (*Yorktown Heights, NY*)

Rui Zhang, Research Staff Member, IBM (*Yorktown Heights, NY*)

Jie Zhang, Assistant Professor, University of Texas at Dallas (*Dallas, TX*)

Binghui Li, Research Assistant, University of Texas at Dallas (*Dallas, TX*)

Dr. Qungyu Xu, Postdoctoral Researcher, Johns Hopkins University (*Baltimore, MD*)

Josephine Wang, Ph.D. Student, Johns Hopkins University (*Baltimore, MD*)

Shu Zhang, Graduate Student, Johns Hopkins University (*Baltimore, MD*)

How can probabilistic solar forecasts lower costs and improve reliability for ISO markets? We tackle this question by, first, describing the ability of the IBM Watt-Sun system to provide well-calibrated probabilistic forecasts. We then relate the degree of uncertainty in those forecasts to errors distributions for net load ramps for the California ISO using statistical and machine learning methods. Operators need to prepare for the possibility of extreme up- and down-ramps, especially as increased wind and solar penetration increase their magnitude and uncertainty. Projected net load errors conditioned on solar uncertainty are translated into ramping product requirements that therefore reflect "day-of" meteorological risks, improving on present procedures that are not conditioned on weather. Finally, we examine how such conditional ramp requirements save costs by lowering requirements when unconditional forecasts are too conservative, and improve reliability by increasing requirements when unconditional forecasts understate the actual ramp uncertainty. The cost and reliability improvements are estimated by simulating ISO-scale unit commitment and dispatch under the improved ramp requirements.

**Stochastic Nodal Adequacy Platform (SNAP)**

**Dr. Richard D. Tabors**, Tabors Carmanis Rudkevich (*Newton, MA*)

Aleksandr Rudkevich, President, Newton Energy Group LLC (*Boston, MA*)

Stochastic Nodal Adequacy Platform (SNAP) will provide a novel and theoretically correct approach to valuing the contribution to system reliability of all elements of the interconnected electrical network – generation, transmission and demand side resources. As designed, SNAP daily performs locational probabilistic assessment of system adequacy using dual variables of Reliability Dispatch (RD) – the optimization problem minimizing the expected value of the system-wide cost of unserved demand. SNAP simulates RD outcomes under hundreds of thousands of system conditions defined as dynamic probabilistic scenarios of energy delivery by wind, solar (both utility scale and rooftop) as well as the demand for electricity determined by weather in combination with random outages of conventional generations and transmission elements.

As a platform, SNAP is envisioned to provide a close to real-time spot market for system adequacy delivered to consumers and provided by physical assets and services. Among adequacy metrics developed by SNAP is the payment computed for each hour and for each system element measuring the economic value provided by, or delivered to, that element, such as generator, transmission facility or load served at a given substation. The presentation will focus on the SNAP design and underlying economic principles and mathematical properties.

SNAP development planned for a three year period 2020-2023 is funded by the ARPA-E PERFORM program.

Session W2 (Wednesday, June 24, 1:30 PM, WebEx)

**A Unified Approach to Solve Convex Hull Pricing and Average Incremental Cost Pricing**

**Dr. Yonghong Chen**, Consulting Advisor, Midcontinent ISO (*Carmel, IN*)

Dr. Richard O’Neill, Distinguished Senior Fellow, US Department of Energy (*Washington, DC*)

This presentation introduces a unified approach to solving convex hull pricing (CHP) and average incremental cost (AIC) pricing problems. By developing a convex hull and convex envelope formulation for individual resources, a CHP model that achieves the goal of uplift minimization can be solved by linear programming (LP) using relaxation of the binary terms of the security constrained unit commitment (SCUC) problem. By adjusting resource upper bounds based on the SCUC solution, the LP relaxation of the SCUC problem can also be used to derive AIC prices, eliminating make-whole payments under the optimal UCED solution.

**Computational Studies on Primal Formulation Approaches for Convex Hull Pricing**

**Dr. Yongpei Guan**, Professor, University of Florida (*Gainesville, FL*)

Ms. Yonghong Chen, Consultant Advisor, Midcontinent ISO (*Carmel, IN*)

Ms. Tong Zhang, Ph.D. Student, University of Florida (*Gainesville, FL*)

Ms. Yanan Yu, Ph.D. Student, University of Florida (*Gainesville, FL*)

Convex hull pricing has been introduced to increase transparency and reduce uplift payments for U.S. wholesale markets. A convex primal formulation approach is one of the most efficient methods to obtain a high-quality convex hull price. Even though significant progress has been made on the research side, there are challenges in practice to implement it. In this presentation, we talk about the practical physical restrictions and the approaches we proposed to address them. We will also report the results of our computational case studies.

**A Computationally Efficient Algorithm for Computing Convex Hull Prices**

**Dr. Bernard Knueven**, Researcher III, National Renewable Energy Laboratory (*Golden, CO*)

Dr. James Ostrowski, Associate Professor, University of Tennessee (*Knoxville, TN*)

Dr. Anya Castillo, Senior Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)

Dr. Jean-Paul Watson, Senior Research Scientist, Lawrence Livermore National Laboratory (*Livermore, CA*)

Electricity markets worldwide allow participants to bid non-convex production offers. While non-convex offers can more accurately reflect a resource's capabilities, they create challenges for market clearing processes. For example, system operators may execute side payments when a participant’s cost is not covered through energy sale settlements from locational marginal pricing schemes, or when a participant incurs lost opportunity costs to follow the dispatch signal. Convex hull pricing minimizes these and other types of side payments while providing uniform (i.e., locationally and temporally consistent) prices. However, computing convex hull prices involves solving either a large-scale linear program - which in turn requires explicit descriptions of market participants’ convex hulls - or the Lagrangian dual of the corresponding non-convex scheduling problem. Here, we propose a computationally feasible and industrially scalable Benders decomposition approach to computing convex hull prices at least an order of magnitude faster than the current state-of-the-art while leveraging recent advances in convex hull formulations for thermal generating units.

**Exploiting Dense Sensitivity Matrices in Linear Optimal Power Flow**

**Mr. Brent Eldridge**, Operations Research Analyst, Federal Energy Regulatory Commission (*Baltimore, MD*)

Dr. Anya Castillo, Senior Researcher, Sandia National Laboratories (*Albuquerque, NM*)

Dr. Ben Knueven, Researcher, National Renewable Energy Laboratory (*Golden, CO*)

Sparse OPF formulations like the standard B-theta formulation of the DC OPF almost always provide better speed performance compared to numerically dense PTDF-based DC OPF formulations. We present a handful of simplifying techniques that can improve the performance of dense OPF formulations. Results show that these techniques - namely factor truncation and active set algorithms - can improve PTDF-based OPF solution times to the point of out-performing sparse OPF models in test cases with 100-1,000 buses.

Session W3 (Wednesday, June 24, 4:00 PM, WebEx)

**Transmission Topology Optimization Case Studies on Market Efficiency Improvements and Reliability and Resilience Enhancements**

**Dr. Pablo Ruiz**, CEO and CTO, NewGrid, Inc (*Somerville, MA*)

Transmission topology optimization is a software technology that finds grid reconfiguration options to route flow around congested/overloaded facilities. These reconfigurations, implemented by opening or closing selected circuit breakers, enable power flow control using existing equipment and increase the utilization of the transmission network. By optimally adapting the grid topology to meet system conditions and needs, the transfer capabilities increase in the desired directions, providing significant cost savings and reliability and resilience improvements to consumers. In this presentation we will illustrate the topology optimization impacts using case studies conducted with RTO operations and planning cases. Typically, we find increases in available transfer capacity of over 10%, load shedding relief under emergency conditions and extreme events and reductions in the cost of congestion of over 50%.

**Benchmarking Software for Power Systems with Retiring Power Plants and Wind Power Plants**

Marija Ilic, Professor Emeritus, Massachusetts Institute of Technology/Carnegie Mellon University (*Pittsburgh, PA*)

Rupimathi Jaddivada, Graduate Research Assistant, Massachusetts Institute of Technology (*Boston, MA*)

In this talk we follow up on the challenge problem presented at the 10th FERC Software Conference by the first author. We consider a relatively simple IEEE 14 node power system in which three generators are retired and one wind power plant is added (typical power output). The problem is to simulate what would the operator schedule for typical daily demand. There are two key problems: for some time intervals there is no power flow solution, and, second, the problem is at some hours ramp rate limited. We will share the case with the conference participants and seek solutions to be offered at some later stage. At the conference we will describe the benchmark solution we proposed at the 10th FERC Conference. The solution should be (N-1)/(N-2) secure. Benchmarking will be done using technical, economic and environmental performance metrics.

**Transient Optimization of Large Natural Gas Pipeline Networks using Linear Programming**

**Dr. Aleksandr Rudkevich**, President, Newton Energy Group LLC (*Newton, MA*)

Dr. Aleksandr Beylin, Senior Developer, Newton Energy Group LLC (*Newton, MA*)

Dr. Anatoly Zlotnik, Staff Scientist, Los Alamos National Laboratory (*Los Alamos, NM*)

We introduce a linearization procedure that transforms gas pipeline transient optimization problems to linear programs using a piece-wise local discretization scheme that enables closed-form solution of partial differential equations for gas flow. Our approach models an entire pipeline system including junctions and compressors. Feasible regions for compressor operation are approximated by inscribed convex polygons represented by a set of linear inequality. The reduction of the pipeline optimization problem to linear programming enables acceleration of solution time for nonlinear optimization of large-scale systems by several orders of magnitude compared with known methods, and enables the incorporation of binary decision variables in future extensions. In the presentation we provide a numerical comparison of solutions obtained with our method to solutions obtained using previously validated methods and assess accuracy and computation time using a case study based on a section of an actual pipeline system. We conclude our presentation with the discussion of technical opportunities created by the proposed method and policy implications of realizing these opportunities.

**North American Natural Gas Market and Infrastructure Developments Under Different Mechanisms of Renewable Policy Coordination**

**Mr. Charalampos Avraam**, Ph.D. Candidate, Johns Hopkins University (*Baltimore, MD*)

John E.T. Bistline, Senior Technical Leader, Electric Power Research Institute (*Palo Alto, CA*)

Maxwell Brown, Energy System Modeler, National Renewable Energy Laboratory (*Golden, CO*)

Kathleen Vaillancourt, President, Esmia Consultants (*Blainville, Canada*)

Sauleh Siddiqui, Assistant Professor, American University (*Washington, DC*)

Renewable Portfolio Standards (RPS) accelerate renewables deployment but their impact on fuel-fired plants remains ambiguous. North American natural gas consumption has been growing due to its decreasing cost in North America, policy initiatives, and its relatively low CO2 emissions rate compared to coal. In this paper, we study the implications for the natural gas sector of more stringent RPS under different coordination schemes in an integrated North American natural gas market. The scenarios assume that Renewable Energy Certificates generated in each region are traded 1) among all countries, 2) only within each country, and 3) only within model regions. We implement the three policies in four different energy and electricity models to generate projections of future natural gas consumption. Subsequently, we feed regional or state-level consumption changes of each model in each scenario to the North American Natural Gas Model. We find that lower RPS coordination among regions results in increased U.S. natural gas exports to Canada, increased Canadian natural gas prices, and decreased net U.S. natural gas exports to Mexico in the long term. Moreover, international coordination of RPS in the electricity sector leads to smaller price discrepancies in the natural gas market when compared to the Reference scenario.

Introduction (Thursday, June 25, 9:45 AM, WebEx)

Session H1 (Thursday, June 25, 10:00 AM, WebEx)

**An Integrated Platform for Wind Plant Operations: From Atmosphere to Electrons to the Grid**

**Dr. Evangelia Spyrou,** Research Engineer, National Renewable Energy Laboratory *(Golden, CO)*

Jennifer King, Research Engineer, National Renewable Energy Laboratory *(Golden, CO)*

Andrew Kumler, Scientist II, National Renewable Energy Laboratory *(Golden, CO)*

Christopher Bay, Research Engineer, National Renewable Energy Laboratory *(Golden, CO)*

Yingchen Zhang, Group Manager, National Renewable Energy Laboratory *(Golden, CO)*

Vahan Gevorgian, Chief Engineer, National Renewable Energy Laboratory *(Golden, CO)*

Dave Corbus, Program Manager VI, National Renewable Energy Laboratory *(Golden, CO)*

Under the Atmosphere to Electrons to Grid project (A2e2g), the National Renewable Energy Laboratory (NREL) is developing an optimization platform for wind plant operations. The platform merges forecasting tools with aerodynamic and economic models in order to identify optimal operating schedules and controller functions that will maximize a wind plant's value streams for energy and other grid services. In this presentation, we will describe functionalities of the platform. We will also discuss the implications the use of the platform might have for understanding and valuing the capabilities of wind resources for power system operations.

**Scalable Energy System Expansion Under Uncertainty Using Multi-stage Stochastic Optimization**

**Dr. Devon Sigler**, Researcher, National Renewable Energy Laboratory (*Golden, CO*)

Dr. Wesley Jones, Senior Scientist, National Renewable Energy Laboratory (*Golden, CO*)

Dr. Jonathan Maack, Researcher, National Renewable Energy Laboratory (*Golden, CO*)

Dr. Ignas Satkauskas, Researcher, National Renewable Energy Laboratory (*Golden, CO*)

Dr. Matthew Reynolds, Reseacher, National Renewable Energy Laboratory (*Golden, CO*)

The intermittent nature of power from renewable energy sources poses new challenges for electrical grids. This is due to the variable and uncertain nature of the power output from these resources. These features of renewable generation are becoming more relevant to energy system planning as grids reach higher penetration levels of renewable energy. In this presentation we present approaches for energy system planning based on scalable computational approaches which enable the explicit consideration of operational uncertainties in the planning process. Using multi-stage stochastic programming and the progressive hedging algorithm, we compute energy system expansion decisions on modified versions of the RTS-GMLC test system augmented with large amounts of renewable generation.

**Machine Learning Assisted Preventive Stochastic Unit Commitment**

**Dr. Mostafa Sahraei-Ardakani**, Assistant Professor, University of Utah (*Salt Lake City, UT*)

Dr. Ge “Gaby” Ou, Assistant Professor, University of Utah (*Salt Lake City, UT*)

 Extreme weather events, such as hurricanes, are the leading cause of blackouts in the United States. The power outages are mainly due to the damage and failure of transmission and distribution elements. While distribution-level failures usually cannot be alleviated with enhanced operation, transmission failures can be mitigated through a preventive power system dispatch. To calculate a preventive dispatch, first weather forecast should be used to predict line outage probabilities. These probabilities, can, then be included in the unit commitment problem, to generate a preventive stochastic unit commitment model. While this model is very effective in finding an efficient preventive dispatch, it can be rather computationally demanding for large system. This talk explores a potential solution to this problem by taking advantage of machine learning. In this framework, early but inaccurate hurricane forecasts are used to generate many trajectories, each of which is solved independently. The solution dataset is, then, used to train a model that assists the stochastic unit commitment solver with later and more accurate hurricane forcasts. The machine-learning-assisted model predicts a set of binding constraints, which helps the preventive unit commitment solver remove the majority of unnecessary constraints, as well as a near-optimal initial solution. Consequently, day-ahead preventive stochastic unit commitment can be solved substantially faster, making industry adoption practical.

Session H2 (Thursday, June 25, 1:00 PM, WebEx)

**State of Charge Management Concepts and Options for Stand-alone Electric Storage Resources**

**Dr. Nikita Singhal**, Senior Engineer Sci., Electric Power Research Institute (*Palo Alto, CA*)

Dr. Erik Ela, Principal Project Manager, Electric Power Research Institute (*Palo Alto, CA*)

Electric storage resources (ESRs) are presently being incorporated into bulk power systems in increasing numbers, with more ESRs planned and under study within interconnection queues. System operators are currently researching ways to effectively integrate ESRs into their existing system operation and market operation processes. This includes a comprehensive evaluation of the different state of charge (SOC) management options and their corresponding market implications. This research provides a description of the concepts of SOC management for ESRs and updated considerations on the different levels of SOC management while notably emphasizing a few key differences in the understanding of ISO-SOC-Management and SOC-Management-Lite. This includes the use of SOC as a variable (ISO-SOC-Management) or a parameter (SOC-Management-Lite) as well as the use of simultaneous economic dispatch (ISO-SOC-Management) compared to sequential economic dispatch (SOC-Management-Lite) depending on the software solution of the market clearing software. The impact that the SOC management option and software solution has on the meaning of an ESR offer is illustrated through examples.

**Analysis of GO Competition Challenge 1 Final Event Problem Difficulty**

**Dr. Stephen Elbert**, Advisor, Pacific Northwest National Laboratory (*Richland, WA*)

Dr. Hans Mittelmann, Professor, Arizona State University (*Tempe, AZ*)

The GO Competition Challenge 1 Final Event presented two variations of 340 synthetic and 12 industry scenario datasets (an Offline version with no starting information and a Real-Time version with starting information - each with different time limits) for solution by 26 teams. There were a significant number of failures to reach a solution, which raises the question: were the problems too difficult? We answer that question by developing an a posteriori method along the lines of judging the quality of a result based on the “gap” between upper and lower bound. Here we use the gap between the best and second best result using the reasoning that when teams get nearly the same result the problem is likely to be easier than when the gap is larger. The number of teams that get within a 1% threshold of the best result is further confirmation of the difficulty. We also checked against another a posteriori method developed by the ARPA-E Benchmark developer, Carleton Coffrin. His “hardness” index is based on the performance of the Benchmark code while our “gap” measure is code independent but requires multiple results so cannot make predictions before a competition event, only after. We came up with a scale of very easy (gap <0.5%), easy (gap >0.5% but less than 1.0%), difficult (gap >1.0% and <2.0%), somewhat hard (gap >2.0% and <4.0%), and exceedingly hard (gap >4.0%). The majority of the scenarios were very easy but a few fell into each of the other categories.

**What Does it Take to Achieve Carbon Neutrality in the Electric Network?**

**Dr. Hank He**, Tabors Carmanis Rudkevich (*Newton, MA*)

Ninad Kumthekar, Senior Industry Analyst, Tabors Carmanis Rudkevich (*Newton, MA*)

Xindi Li, Senior Analyst, Tabors Carmanis Rudkevich (*Newton, MA*)

Chen Ling, Analyst, Tabors Carmanis Rudkevich (*Newton, MA*)

Russ Philbrick, Consultant, Polaris Systems Optimization (*Seattle, WA*)

Aleksandr Rudkevich, President, Newton Energy Group LLC (*Boston, MA*)

There is a growing movement among commercial and industrial energy users to reduce their Greenhouse Gas (GHG) emissions often defined as their carbon footprint. Some companies, such as Google and Microsoft target to become carbon neutral or even carbon negative though the procurement of zero emission energy supply and sophisticated management of energy use. Their strategies are complicated because of the lack of reliable and verifiable metrics for assessing the actual impact of energy consumption, delivery and production on GHG emission. This is particularly true for the electric industry where the impact attribution is highly complicated by network properties of the synchronized electrical grid. In the absence of such metrics, carbon neutrality is a moot target and both the efficacy and efficiency of strategies pursuing that goal is highly problematic.

In this presentation we outline a rigorous method for carbon accounting within the electrical grid based on concepts of Locational Marginal Emission Rates and Shadow Emission Intensity of transmission and on the Carbon Footprint Theorem. Through a precise emission attribution to all elements of the electric network, our method accurately identifies Carbon Footprint of any portfolio of physical assets and financial contracts and leads to efficient strategies for energy buyers to achieve carbon neutrality. The presentation will be illustrated with numerical simulation of the NYISO system using ENELYTIX/PSO modeling system.

Session H3 (Thursday, June 25, 3:30 PM, WebEx)

**Enhanced Flexible Ramping Product: Design and Analysis**

**Dr. Mojdeh Khorsnad Hedman**, Assistant Professor, Arizona State University (*Tempe, AZ*)

Mr. Mohammad Ghaljehei, Assistant Professor, Arizona State University (*Tempe, AZ*)

Renewable resources are imposing operational complexities to modern power systems by intensifying uncertainty and variability, which leads to a significant need for ramp capabilities as illustrated by the “duck curve” of California independent system operator (CAISO). To address this issue, some ISOs have been augmenting their market models with flexible ramping products (FRPs). Prior work has primarily focused on including FRPs in real-time markets. However, representing FRPs in real-time market without its inclusion in day-ahead market results in market discrepancy. CAISO intends to add FRPs to their day-ahead market. This work formulates a day-ahead market model with FRP constraints analogous to CAISO’s day-ahead market model. Then, it sheds light on a subtle issue that can potentially happen in the next market processes after day-ahead market, as a result of procurement of day-ahead ramp capabilities only based on the hourly net load variability and uncertainty. A new FRP requirement is proposed to address this issue. In the proposed formulation, the day-ahead FRP design is modified to capture the impacts of 15-min net load variability and uncertainty on ramping requirement. The proposed model enhances FRP requirement by considering both hourly and fifteen-minute net load variability and uncertainty while identifying generators commitment and dispatch for hourly net load. Moreover, this work proposes a data-driven approach to include deliverability constraint for FRPs.

**Quasi-Stochastic Electricity Markets**

**Dr. Jacob Mays**, Postdoctoral Associate, Cornell University (*Ithaca, NY*)

With wind and solar becoming major contributors to electricity production in many systems, wholesale market operators have become increasingly aware of the need to address uncertainty when forming prices. While implementing theoretically ideal stochastic market clearing to address uncertainty may be impossible, the use of operating reserve demand curves allows market designers to inject an element of stochasticity into deterministic market clearing formulations. The construction of these curves, which alter the procurement of reserves and therefore the pricing of both reserves and energy, relies on contentious administrative parameters that lack strong theoretical justification. This paper proposes instead to construct curves based on reserve valuations implicit in non-market reliability processes performed by system operators. The proposed strategy promotes greater consistency between commitment decisions and eventual prices, reducing the need for discriminatory uplift payments or enhanced pricing schemes to address non-convexity.

**Probabilistic Zonal Reserve Requirements for Improved Energy Dispatch and Deliverability with Wind Power Uncertainty**

**Dr. Zhi Zhou**, Principal Computational Scientist, Argonne National Laboratory (*Lemont, IL*)

Dr. Byungkwon Park, Postdoctoral Research Associate, Oak Ridge Nat’l Lab. (*Oak Ridge, TN*)

Dr. Audun Botterud, Principal Energy Systems Engineer, Argonne Nat’l Lab. (*Lemont, IL*)

Mr. Prakash Thimmapuram, Group Manager, Argonne National Laboratory (*Lemont, IL*)

In power systems with high penetration of renewable energy resources, uncertainty and variability of these stochastic resources introduce additional challenges for the operation of power systems. To improve the power system’s reliability in the face of uncertainty, reserves are required as additional generation capacity to rebalance the power system following random disturbances. However, reserve deliverability is not guaranteed, because it may encounter potential transmission line congestion. Zonal reserve requirements can address this issue, but operators lack efficient ways to allocate reserves to zones while accounting for wind power forecast uncertainty. We propose a methodology for probabilistic zonal reserve requirements to address wind power forecast uncertainties. This method estimates the probability distribution of line flows based on the system generation margin and injection shift factor. This estimate is then used to construct pre-defined and post-zonal reserve requirements. Case studies demonstrate that the proposed method efficiently schedules energy and reserves to balance energy and manage deliverability with wind power forecast uncertainty. We also discuss operational implications of the proposed method.