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

Agenda

AD10-12-009
June 26 – 28, 2018

Tuesday, June 26, 2018

9:00 AM	Introduction (Meeting Room 3M-2) **Richard O'Neill**, Federal Energy Regulatory Commission (*Washington, DC*)
9:15 AM	Session T1 (Meeting Room 3M-2) **MISO R&D on Improving Market Clearing Software for Future Market Enhancements** Yonghong Chen, Midcontinent ISO (*Carmel, IN*) Jessica Harrison, Midcontinent ISO (*Carmel, IN*) **PJM Market Enhancements to Improve Market Efficiency, Reliability and Resilience** Anthony Giacomoni, PJM Interconnection (*Audubon, PA*) Patricio Rocha Garrido, PJM Interconnection (*Audubon, PA*) Adam Keech, PJM Interconnection (*Audubon, PA*) Melissa Maxwell, PJM Interconnection (*Audubon, PA*) Cheryl Mae Velasco, PJM Interconnection (*Audubon, PA*) **The Hidden Properties of Fast-Start Pricing** Tongxin Zheng, ISO New England (*Holyoke, MA*) Feng Zhao, ISO New England (*Holyoke, MA*) Dane Schiro, ISO New England (*Holyoke, MA*) Eugene Litvinov, ISO New England (*Holyoke, MA*)
10:45 AM	Break
11:00 AM	Session T2 (Meeting Room 3M-2) **California ISO's Day-Ahead Market Enhancements under High Renewable Penetration Paradigm** Petar Ristanovic, California ISO (*Folsom, CA*) George Angelidis, California ISO (*Folsom, CA*) Don Tretheway, California ISO (*Folsom, CA*) Khaled Abdul-Rahman, California ISO (*Folsom, CA*) **Using Market Optimization Software to Develop a MISO Multi-Day Market Forecast** Chuck Hansen, Midcontinent ISO (*Carmel, IN*) Boris Gisin, PowerGEM LLC (*Clifton Park, NY*) James David, PowerGEM LLC (*Clifton Park, NY*) Shu Xu, Midcontinent ISO (*Carmel, IN*) **Short Term Capacity Reserve Product: Need and Potential Solution Design** Seyi Akinbode, Midcontinent ISO (*Carmel, IN*) Akshay Korad, Midcontinent ISO (*Carmel, IN*) Bill Peters, Midcontinent ISO (*Carmel, IN*) Kevin Vannoy, Midcontinent ISO (*Carmel, IN*)
12:30 PM	Lunch
1:45 PM	Session T3 (Meeting Room 3M-2) **Voltage Security Constraints in SPP Markets using Generalized DC Powerflow** Ryan Schoppe, Southwest Power Pool (*Little Rock, AR*) Gary Rosenwald, The Glarus Group (*Newcastle, WA*) Mingguo Hong, Case Western Reserve University (*Cleveland, OH*) **Uplift Allocation of Voltage and Local Reliability Constraints** Fengyu Wang, Midcontinent ISO (*Carmel, IN*) Yonghong Chen, Consulting Advisor, Midcontinent ISO (*Carmel, IN*) **Synchrophasor-Based Emergency Generation Dispatch** Xiaochuan Luo, ISO New England (*Holyoke, MA*) Eugene Litvinov, ISO New England (*Holyoke, MA*) Song Zhang, ISO New England (*Holyoke, MA*)
3:15 PM	Break

Tuesday, June 26, 2018

3:30 PM	Session T4 (Meeting Room 3M-2) **Enhanced Combined Cycle Modeling - From Market Clearing Pricing to Settlements** Congcong Wang, Midcontinent ISO (*Carmel, IN*) Gary Rosenwald, Glarus Group (*Seattle, WA*) Kevin Vannoy, Midcontinent ISO (*Carmel, IN*) Charles Hansen, Midcontinent ISO (*Carmel, IN*) Yonghong Chen, Midcontinent ISO (*Carmel, IN*) Jason Howard, Midcontinent ISO (*Carmel, IN*) **Transmission Topology Optimization Applications to Increase Market and Planning Efficiency and Enhance Reliability and Resilience** Pablo Ruiz, NewGrid, Inc. (*Boston, MA*) **Incorporating FACTS Set Point Optimization in Day-Ahead Generation Scheduling** Kwok Cheung, GE (*Redmond, WA*)
5:00 PM	Adjourn

Wednesday, June 27, 2018

8:45 AM Arrive and welcome (Meeting Room 3M-2)

9:00 AM Session W1 (Meeting Room 3M-2)

Revisiting Mixed-Integer Programming Gaps and Pricing in RTO-scale Unit Commitment Problems
Brent Eldridge, Federal Energy Regulatory Commission (*Washington, DC*)
Richard O'Neill, Federal Energy Regulatory Commission (*Washington, DC*)

Investment Effects of Pricing Schemes for Non-Convex Markets
Jacob Mays, Northwestern University (*Evanston, IL*)
Richard O'Neill, Federal Energy Regulatory Commission (*Washington, DC*)
David Morton, Northwestern University (*Evanston, IL*)

Pricing Under Uncertainty: A Chance Constraint Approach to a Robust Competitive Equlibrium
Yury Dvorkin, New York University (*New York, NY*)

10:30 AM Break

10:45 AM Session W2-A (Meeting Room 3M-2)

Electricity Market Design with Renewable Energy: A Comparison of the United States and Europe
Audun Botterud, Massachusetts Institute of Technology/Argonne National Laboratory (*Cambridge, MA*)
Hans Auer, Technische Universität Wien (*Vienna, Austria*)

Convex Hull, IP and European Electricity Pricing in a European Power Exchanges Setting with Efficient Computation of Convex Hull Prices
Mehdi Madani, Johns Hopkins University (*Baltimore, MD*)
Carlos Ruiz, Universidad Carlos III de Madrid (*Madrid, Spain*)
Sauleh Siddiqui, Johns Hopkins University (*Baltimore, MD*)
Mathieu Van Vyve, Université catholique de Louvain (*Louvain-la-Neuve, Belgium*)

Scheduling and Pricing of Energy Storage in Electricity Markets
Masood Parvania, University of Utah (*Salt Lake City, UT*)
Roohallah Khatami, University of Utah (*Salt Lake City, UT*)
Pramod Khargonekar, University of California, Irvine (*Irvine, CA*)

Session W2-B (Meeting Room 3M-3)

Power System Restoration through Mixed Integer Linear Programming
Deepak Rajan, Lawrence Livermore National Laboratory (*Livermore, CA*)
Ignacio Andres Aravena Solis, Universite catholique de Louvain (*Louvain-la-Neuve, Belgium*)
Georgios Patsakis, University of California, Berkeley (*Berkeley, CA*)
Schmuel Oren, University of California, Berkeley (*Berkeley, CA*)
Jennifer Rios, Pacific Gas and Electric (*San Francisco, CA*)

Transient Simulation and Optimization of Natural Gas Pipeline Operation and Applications to Gas-Electric Coordination
Aleksandr Rudkevich, Newton Energy Group (*Boston, MA*)
Anatoly Zlotnik, Los Alamos National Laboratory (*Los Alamos, NM*)
John Goldis, Newton Energy Group (*Oakland, CA*)
Pablo Ruiz, Boston University (*Boston, MA*)
Russ Philbrick, Polaris System Optimization (*Seattle, WA*)
Aleksandr Beylin, Newton Energy Group (*Santa Monica, CA*)
Xindi Li, Tabors Caramanis Rudkevich (*Boston, MA*)
Richard Tabors, Tabors Caramanis Rudkevich (*Boston, MA*)

Latest Developments on the Precise Mass-Market DR Participation in the Wholesale Energy Markets through Stochastic Distributed Computing
Alex Papalexopoulos, ECCO International (*San Francisco, CA*)

Wednesday, June 27, 2018

12:15 PM	Lunch
1:30 PM	Session W3-A (Meeting Room 3M-2) **Stochastic Look-Ahead Unit Commitment for Intra-day and Real-Time Management of Distributed Renewable Generation and Demand Response** Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, NM*) Roger Treinen, Nexant, Inc. (*Chandler, AZ*) Herminio Pinto, Nexant, Inc. (*Chandler, AZ*) Kory Hedman, Arizona State University (*Tempe, AZ*) **Data-Driven Stochastic Optimization for Power Grids Scheduling under High Wind Penetration** Wei Xie, Rensselaer Polytechnic Institute (*Troy, NY*) **Scalable Capacity Expansion for Explicit Representation of Intermittent Generation** Devon Sigler, National Renewable Energy Laboratory (*Golden, CO*) **Recent Advances in MILP Formulations for the Unit Commitment Problem** Ben Knueven, Sandia National Laboratories (*Albuquerque, NM*) Jim Ostrowski, University of Tennessee (*Knoxville, TN*) Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, NM*)
	Session W3-B (Meeting Room 3M-3) **Scalable Corrective Security-Constrained Economic Dispatch Considering Conflicting Contingencies** Yaowen Yu, ABB Enterprise Software (*San Jose, CA*) Peter Luh, University of Connecticut (*Storrs, CT*) Mikhail Bragin, University of Connecticut (*Storrs, CT*) **Generator Contingency Modeling in Electric Energy Markets** Nikita Singhal, Electric Power Research Institute (*Palo Alto, CA*) Kory W. Hedman, Arizona State University (*Tempe, AZ*) **Simultaneous Economic Efficiency and Reliability Benefits from Advanced Operating Reserve Requirement Method: Case Study on the Hawaiian Electric System** Erik Ela, Electric Power Research Institute (*Palo Alto, CA*) **Preventive Power System Operation During Hurricanes** Mostafa Sahraei-Ardakani, University of Utah (*Salt Lake City, UT*) Ge Ou, University of Utah (*Salt Lake City, UT*)
3:30 PM	Break
3:45 PM	Session W4-A (Meeting Room 3M-2) **Distributed Solution Algorithms for Security Constrained Unit Commitment in Evolving Day Ahead Electricity Markets** Jesse Holzer, Pacific Northwest National Laboratory (*Richland, WA*) Feng Pan, Pacific Northwest National Laboratory (*Richland, WA*) Stephen Elbert, Pacific Northwest National Laboratory (*Richland, WA*) **HIPPO - A High-Performance Computing Solver for Security Constrained Unit Commitment Problem** Feng Pan, Pacific Northwest National Laboratory (*Seattle, WA*) Jesse Holzer, Pacific Northwest National Laboratory (*Richland, WA*) Steve Elbert, Pacific Northwest National Laboratory (*Richland, WA*) Yonghong Chen, Midcontinent ISO (*Carmel, IN*) Jie Wan, GE (*Redmond, WA*) Edward Rothberg, GUROBI (*Houston, TX*) Yongpei Guan, University of Florida (*Gainesville, FL*) **Multi-year Detailed Nodal, Cloud-based Modeling of Economic and Environmental Impacts of the Integration of Significant Quantities of Mandated On-shore and Off-shore Renewable Resources into the Regional Electric Power Grid** Richard Tabors, Tabors Caramanis Rudkevich (*Boston, MA*) Alex Rudkevich, Tabors Caramanis Rudkevich (*Boston, MA*) **Advanced On-line Volt/Var Control System: Design, Implementation and High Hosting Capability for Renewable Energy** Yasuyuki Tada, Hitachi, Ltd., Energy Solution Business Unit (*Tokyo, Japan*) Hsiao-Dong Chiang, Cornell University/Bigwood Systems, Inc. (*Ithaca, NY*)

Wednesday, June 27, 2018

	Session W4-B (Meeting Room 3M-3) **Modeling Nuclear Power as a Flexible Resource for the Power Grid** Zhi Zhou, Argonne National Laboratory (*Lemont, IL*) Audun Botterud, Argonne National Laboratory (*Lemont, IL*) Jesse Jenkins, Massachusetts Institute of Technology (*Boston, MA*) Roberto Ponciroli, Argonne National Laboratory (*Lemont, IL*) Francesco Ganda, Argonne National Laboratory (*Lemont, IL*) **Frequency-Optimized Security-Constrained Economic Dispatch (fSCED)** Tom Dautel, Federal Energy Regulatory Commission (*Washington, DC*) Richard O'Neill, Federal Energy Regulatory Commission (*Washington, DC*) **Power System Optimization with an Inertia Study on the IEEE 30-Bus Test System** Sandeep Sadanandan, Kansas State University (*Arlington, VA*) **Modeling of Resilient Electricity Generation after Cascading Collapse** Thomas Popik, Foundation for Resilient Societies (*Nashua, NH*)
5:45 PM	Adjourn

Thursday, June 28, 2018

8:45 AM	Arrive and welcome (Meeting Room 3M-2)
9:00 AM	Session H1 (Meeting Room 3M-2) **Unit Commitment of Integrated Electric and Gas Systems with an Enhanced Second-Order Cone Gas Flow Model** Ramteen Sioshansi, The Ohio State University (*Columbus, OH*) Sheng Chen, The Ohio State University (*Columbus, OH*) Antonio J. Conejo, The Ohio State University (*Columbus, OH*) **Tight MIP Formulation of Transition Trajectories of Combined-Cycle Units** Bowen Hua, University of Texas at Austin (*Austin, TX*) Ross Baldick, University of Texas at Austin (*Austin, TX*) Yonghong Chen, Midcontinent ISO (*Carmel, IN*) **Market Restricting Policies Due to Outdated Technology** Sergio Brignone, Vitol, Inc. (*Houston, TX*) Federico Corteggiano, Vitol, Inc. (*Houston, TX*)
10:30 AM	Break
10:45 AM	Session H2 (Meeting Room 3M-2) **Integrating an Open Power Systems Data Repository and an Open Modeling Framework - DRPOWER and OMF.coop** David Pinney, National Rural Electric Cooperative Association (*Arlington, VA*) Mark Rice, Pacific Northwest National Laboratory (*Richland, WA*) Stephen Elbert, Pacific Northwest National Laboratory (*Richland, WA*) Olga Kuchar, Pacific Northwest National Laboratory (*Richland, WA*) Laruentiu Marinovici, Pacific Northwest National Laboratory (*Richland, WA*) **Experimental Analysis of PMU Data** Daniel Bienstock, Columbia University (*New York, NY*) Mauro Escobar, Columbia University (*New York, NY*) Apurv Shukla, Columbia University (*New York, NY*) Michael Chertkov, Los Alamos National Laboratory (*Los Alamos, NM*) **Improving Grid Reliability through Distributed AI and Machine Learning** Colin Gounden, VIA Science (*Somerville, MA*)
12:15 PM	Adjourn

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

Abstracts

Tuesday, June 26

Opening (Tuesday, June 26, 9:00 AM, Meeting Room 3M-2)

INTRODUCTION

Dr. Richard O'Neill, Chief Economic Advisor, Federal Energy Regulatory Commission (*Washington, DC*)

Session T1 (Tuesday, June 26, 9:15 AM, Meeting Room 3M-2)

MISO R&D ON IMPROVING MARKET CLEARING SOFTWARE FOR FUTURE MARKET ENHANCEMENTS

Dr. Yonghong Chen, Consulting Advisor, Midcontinent ISO (*Carmel, IN*)
Jessica Harrison, R&D Director, Midcontinent ISO (*Carmel, IN*)

This presentation discusses the R&D initiatives at MISO to prepare market clearing software for future market enhancements. These initiatives cover areas of advanced resource modeling (e.g., enhanced hybrid combined cycle modeling and considering configuration transition trajectories, future resource analysis), advanced mathematical formulation to improve computational performance as well as price efficiency, research on pricing under future resource portfolio, reserve deliverability, computational research on better interacting with existing commercial solvers and development on high performance computing based next generation optimization engine under the ARPA-E HIPPO project.

PJM MARKET ENHANCEMENTS TO IMPROVE MARKET EFFICIENCY, RELIABILITY AND RESILIENCE

Dr. Anthony Giacomoni, Senior Market Strategist, PJM Interconnection (*Audubon, PA*)
Dr. Patricio Rocha Garrido, Senior Engineer, PJM Interconnection (*Audubon, PA*)
Mr. Adam Keech, Executive Director Market Operations, PJM Interconnection (*Audubon, PA*)
Ms. Melissa Maxwell, Economic Analyst, PJM Interconnection (*Audubon, PA*)
Ms. Cheryl Mae Velasco, Senior Engineer, PJM Interconnection (*Audubon, PA*)

Currently, PJM is working on several proposed market reforms and related compensation mechanisms to improve market efficiency and advance operational characteristics that support reliability and resilience. These include improved shortage pricing and Operating Reserves market rules, and improved energy price formation that properly values resource attributes. Today we operate under a set of rules that limit the ability of certain generating units operating at the direction of the system operator to contribute to efficient and transparent prices. These units are still compensated individually for their costs to operate, but because they are not able to set clearing prices, the clearing prices on the system do not reflect the true marginal costs of serving load. PJM believes that modifications to these market constructs could and should be made to align with current reliability needs and resilience objectives. Price formation reforms, along with reforms to pricing during certain times when we are approaching temporary shortage conditions, would go a long way to properly valuing all generation needed to serve the demand for electricity. This presentation will discuss several proposed shortage pricing and energy price formation market enhancements that PJM is currently investigating.

THE HIDDEN PROPERTIES OF FAST START PRICING

Dr. Tongxin Zheng, Technical Director, ISO New England (*Longmeadow, MA*)
Dr. Feng Zhao, Principal Analyst, ISO New England (*Holyoke, MA*)
Dr. Dane Schiro, Senior Analyst, ISO New England (*Holyoke, MA*)
Dr. Eugene Litvinov, Chief Technologist, ISO New England (*Holyoke, MA*)

Fast start (FS) pricing has recently attracted interest from electricity market stakeholders due to a concern that traditional marginal cost pricing is unable to reflect the actual marginal cost of serving load under nonconvexity. Because there is no theoretically perfect pricing method for nonconvex markets, several variations of FS pricing have been proposed and/or implemented. In this presentation, we will formulate the three main FS pricing approaches and discuss both well-known and lesser-known pricing properties. We will conclude by posing several questions about the economic foundation of FS pricing. This work should deepen understanding of FS pricing methods and stimulate broader discussions on market design under nonconvexity.

Session T2 (Tuesday, June 26, 11:00 AM, Meeting Room 3M-2)

CALIFORNIA ISO'S DAY-AHEAD MARKET ENHANCEMENTS UNDER HIGH RENEWABLE PENETRATION PARADIGM

Petar Ristanovic, Vice President, California ISO (*Folsom, CA*)
George Angelidis, Principal, California ISO (*Folsom, CA*)
Don Tretheway, Principal, California ISO (*Folsom, CA*)
Khaled Abdul-Rahman, Executive Director, California ISO (*Folsom, CA*)

California ISO is in the process of introducing new market enhancements to address net load curve and uncertainty previously left to real-time market to deal with. The new enhancements include 15-minutes scheduling granularity in the integrated forward market, day-ahead imbalance reserve product, and combined Integrated Forward Market (IFM) and Residual Unit Commitment (RUC). The 15-min scheduling addresses granularity issues resulting from the current practice of hourly day-ahead scheduling versus the 15-min real-time market scheduling. The day-ahead imbalance reserve ensures sufficient real-time bids to meet imbalances that materialized in real-time market and can be used in real-time market for energy, certified AS, flexible ramping product, forecasted service movements/uncertainty awards, or corrective capacity. Lastly, the integrated IFM/RUC allows the day-ahead imbalance reserve to be procured relative to ISO net load forecast, not the bid in load demand, which allows the ISO to address both upward and downward forecast differences and uncertainties.

USING MARKET OPTIMIZATION SOFTWARE TO DEVELOP A MISO MULTI-DAY MARKET FORECAST

Mr. Chuck Hansen, Senior Market Engineer, Midcontinent ISO (*Carmel, IN*)
Mr. Boris Gisin, President, PowerGEM LLC (*Clifton Park, NY*)
Mr. James David, Market Applications Product Manager, PowerGEM LLC (*Clifton Park, NY*)
Ms. Shu Xu, Sr. Market Engineer, Midcontinent ISO (*Carmel, IN*)

MISO's current Day-Ahead Market is not designed to forecast economic commitments beyond the next day. This results in the inability to economically commit long-lead (or high startup cost) units and can cause uneconomic cycling of certain units across multiple days, typically resulting in over 70% of capacity being committed before day-ahead. This issue is more noticeable due to renewable resources and MISO's footprint expansion. Improving long-lead commitment is a high priority on MISO's Market Roadmap and has support from MISO stakeholders. To evaluate the potential benefits of a multi-day market forecast, MISO developed an approach to perform detailed multi-day market simulation using actual production data. Seven consecutive historic single-day simulations were completed and compared to a single multi-day optimization for all seven days. A robust and powerful market optimization engine is required to perform multi-day unit commitment and economic dispatch, while at the same time modeling all complexities of MISO DA market rules. This presentation details the approach, utilization of PowerGEM's PROBE market optimization model, software performance, and potential benefits provided to the MISO markets resulting from development of a multi-day market forecast.

SHORT TERM CAPACITY RESERVE PRODUCT: NEED AND POTENTIAL SOLUTION DESIGN

Mr. Seyi Akinbode, Senior Engineer, Market Evaluation, Midcontinent ISO (*Carmel, IN*)
Akshay Korad, Midcontinent ISO (*Carmel, IN*)
Bill Peters, Midcontinent ISO (*Carmel, IN*)
Kevin Vannoy, Midcontinent ISO (*Carmel, IN*)

MISO, as the system operator, has an obligation to operate the Bulk Electric System reliably and efficiently. Many of the reliability needs are met by resource flexibility, often provided through defined reserve products, to respond to imbalances in power system supply and demand or to maintain the resiliency of the transmission network. Current ancillary service products provide capacity that can produce energy within defined time periods to satisfy specific system needs and reliability requirements, but the current products are not sufficient to address all of the system and operational needs. MISO's current short term capacity reserve needs can be grouped into three categories: load pocket, regional, and system-wide. To address these reliability needs, Short Term Capacity Reserve product is proposed, which will provide an option to MISO to address short term reliability needs through the Energy and Operating Reserve Market. This new product will provide appropriate price signal to incentivize market participation and potentially attract new resources. This presentation will start from describing current reserve products and its applications, followed by identifying needs of for short term capacity reserves, and then finished with solutions design addressing short term capacity reserves needs.

Session T3 (Tuesday, June 26, 1:45 PM, Meeting Room 3M-2)

VOLTAGE SECURITY CONSTRAINTS IN SPP MARKETS USING GENERALIZED DC POWERFLOW

Mr. Ryan Schoppe, Senior Engineer, Market Forensics, P.E., Southwest Power Pool (*Little Rock, AR*)
Dr. Gary Rosenwald, Senior Vice President of Engineering, The Glarus Group (*Newcastle, WA*)
Dr. Mingguo Hong, Associate Professor, EE & Comp Sci, Case Western Reserve University (*Cleveland, OH*)

Operating the system in order to secure against abnormal voltage levels is important for a variety of reasons ranging from preventing increased losses to avoiding system stability risks. SPP currently mitigates voltage concerns using approximate flow-based constraints in the market that are pre-determined by offline studies and manual operator (outside-of-the-market) actions such as unit commitments and curtailments. As part of a collaborative study using SPP's full network and market models, SPP has applied the Generalized DC (GDC) Power Flow model to directly model voltages in the market clearing process. This transparent market-based method allows voltage constraints to be controlled through either real power or a combination of real and reactive power if reactive market dispatch is available. Both of these options were prototyped during this study in the context of a historical pre-contingent low voltage event. The result of the study provides convincing evidence that the proposed voltage constraint model using the GDC Power Flow model can effectively mitigate power system voltage issues with transparent market prices through only minor modifications to the existing market design in lieu of surrogate flow-based constraints and outside-of-the-market operator actions.

UPLIFT ALLOCATION OF VOLTAGE AND LOCAL RELIABILITY CONSTRAINTS

Dr. Fengyu Wang, R&D Engineer, Midcontinent ISO (*Carmel, IN*)
Dr. Yonghong Chen, Consulting Advisor, Midcontinent ISO (*Carmel, IN*)

Centralized electricity markets currently do not optimize reactive power and voltage in the market clearing software. Voltage and local reliability (VLR) commitment requirements are mostly identified through out of market operational procedures. Failure to maintain VLR may incur voltage collapse, generation, transformer loss, or even blackout. Midcontinent Independent System Operator (MISO) employs binary constraints, minimum/maximum generation constraints, interface constraints, and manual commitments to address VLR requirement in the market clearing process and ensure adequate commitment for reliability. This paper introduces the formulation to incorporate binary VLR constraints in day-ahead SCUC to improve market efficiency. However, VLR constraints may cause uplift cost, and sometimes the associated uplift cost can be very high. An uplift cost allocation method with the consideration of resources commitment reasons is developed in this paper.

SYNCHROPHASOR-BASED EMERGENCY GENERATION DISPATCH

Dr. Xiaochuan Luo, Technical Manager, ISO New England (*Holyoke, MA*)
Dr. Eugene Litvinov, Chief Technologist, ISO New England (*Holyoke, MA*)
Dr. Song Zhang, Senior Analyst, ISO New England (*Holyoke, MA*)

SCADA and EMS are designed for high availability and reliability today; however, low probability events, such as coordinated cyber or physical attack, EMP or natural hazards may cause failure of the SCADA/EMS system. Under such conditions, the grid operators generally have to rely on manual generation dispatch to balance the system load and interchange.

The synchrophasor system deployed in New England with the support from the Smart Grid Investment Grant (SGIG) provides an independent infrastructure (other than the ICCP links) to transmit the GPS synchronized phasor data from the substations to the ISO-NE at 30 samples per second. The measurements consist of frequency, voltage and current phasors at key locations in New England, including all tie lines and point-of-interconnections (POI) of 19 large generators. In the event of SCADA/EMS failure, the synchrophasor data received through this independent infrastructure is an ideal substitute of SCADA for system monitoring and could also be used for emergency generation dispatch and automatic generation control.

ISO-NE is prototyping an innovative emergency generation dispatch tool based on real-time synchrophasor measurements. The tool will help grid operators to maintain the area balancing and control the frequency and interchange in the event of SCADA/EMS failure, while still complying with NERC's BAL requirements. The proposed scheme has already been validated on a closed-loop simulation platform developed at the ISO-NE.

Session T4 (Tuesday, June 26, 3:30 PM, Meeting Room 3M-2)

ENHANCED COMBINED CYCLE MODELING - FROM MARKET CLEARING PRICING TO SETTLEMENTS

Dr. Congcong Wang, Senior Market Design Engineer, Midcontinent ISO (*Carmel, IN*)
Dr. Gary Rosenwald, Glarus Group (*Seattle, WA*)
Mr. Kevin Vannoy, Director, Market Design, Midcontinent ISO (*Carmel, IN*)
Dr. Charles Hansen, Market Design Advisor, Midcontinent ISO (*Carmel, IN*)
Dr. Yonghong Chen, Consulting Advisor, Midcontinent ISO (*Carmel, IN*)
Mr. Jason Howard, Manager, Market Settlements, Midcontinent ISO (*Carmel, IN*)

MISO currently hosts 44 Combined Cycle Gas Turbine (CCGT) resources with more expected in the near future. Traditional simplified CCGT modeling reduces system flexibility and increases production costs, because these resources cannot fully capture their costs and operating characteristics within their market offers. Recent advances in SCUC problem formulation and solver performance have enabled MISO and its participants to explore improved CCGT modeling. Instead of making a simple on/off commitment decision, MISO will direct a resource to operate in a specific plant configuration, and will then utilize special operating logic for transitions or duct-firing modes. Changes to pricing and settlements will capture the more sophisticated cost causation. This presentation will cover the enhanced market clearing model for combined cycle resources, impacts on the ELMP framework, and the settlement changes needed to ensure cost recovery for resources that enhance the reliability of the RTO's operations.

TRANSMISSION TOPOLOGY OPTIMIZATION APPLICATIONS TO INCREASE MARKET AND PLANNING EFFICIENCY AND ENHANCE RELIABILITY AND RESILIENCE

Dr. Pablo Ruiz, Chief Executive Officer, NewGrid, Inc. (*Boston, MA*)

Transmission topology optimization (line switching) supports congestion management by routing power flow away from congested / overloaded facilities to the rest of the system which has available transmission capacity. The reconfigurations are implemented by opening or closing existing circuit breaker equipment. The result is an increase in transfer capabilities in the desired directions (e.g., from low-cost resources to demand centers) with significant potential for market efficiency, reliability and resilience benefits. In this presentation we will discuss case studies of topology optimization applications ranging from long-term and operations planning to operations and markets. In these studies, conducted with different RTOs, we found that topology optimization can typically increase available transfer capacity by over 10%, relieve the need to shed load under emergency outage conditions and decrease the cost of congestion by over 50%.

INCORPORATING FACTS SET POINT OPTIMIZATION IN DAY-AHEAD GENERATION SCHEDULING

Dr. Kwok Cheung, GE (*Redmond, WA*)

Day-Ahead Unit Commitment is a typical business process for regional transmission organizations (RTO) to ensure enough generation capacity is committed day-ahead to meet the load for the next day. In many cases, transmission constraints are required to be taken into consideration under the framework of security-constrained unit commitment (SCUC). Transmission equipment such as Flexible AC Transmission Systems (FACTS) is traditionally treated as non-dispatchable assets. Co-optimizing FACTS devices with generation dispatch, and leveraging grid controllability could be a viable way to improve economic efficiency of system operations. In a market environment, day-ahead reliability unit commitment (DA-RUC) performs a simultaneous solution of minimizing the cost of commitment for resources to meet forecasted load, net scheduled interchange and operating reserve requirements using SCUC followed by a Security Constrained Economic Dispatch (SCED) solution that is subjected to system constraints and transmission constraints for each hour identified in the study period. This paper applies FACTS optimization in DA-RUC using an iterative linear programming approach to solve a bilinear programming problem of generation scheduling based on a DC load flow formulation. Simulation results will be presented to demonstrate generation dispatch combined with FACTS optimization in each hour could reduce congestion cost and significantly lower generation cost.

Wednesday, June 27

Session W1 (Wednesday, June 27, 9:00 AM, Meeting Room 3M-2)

REVISITING MIXED-IINTEGER PROGRAMMING GAPS AND PRICING IN RTO-SCALE UNIT COMMITMENT PROBLEMS

Mr. Brent Eldridge, Operations Research Analyst, Federal Energy Regulatory Commission (*Washington, DC*)
Dr. Richard O'Neill, Chief Economic Advisor, Federal Energy Regulatory Commission (*Washington, DC*)

The talk consists of two parts. First, recent developments in electricity market pricing methodologies are put into context with existing economic literature. Problems concerning lumpiness and nonconvexities have been discussed in the context of second-best pricing for many decades. More recently, similar problems have been discussed in reference to combinatorial auction mechanisms, such as those proposed for the FCCs spectrum auctions. Equilibrium strategies for such auctions are analytically difficult and have instead been assessed by experimental means. The second part of the presentation discusses arbitrariness and consistency of near-optimal integer solutions, an issue that has been problematic for LMP calculations. We discuss how these issues are affected by new pricing methods and present preliminary results on a large-scale unit commitment problem.

INVESTMENT EFFECTS OF PRICING SCHEMES FOR NON-CONVEX MARKETS

Mr. Jacob Mays, PhD Candidate, Northwestern University (*Evanston, IL*)
Dr. Richard O'Neill, Chief Economic Advisor, Federal Energy Regulatory Commission (*Washington, DC*)
Dr. David Morton, Professor, Northwestern University (*Evanston, IL*)

A major motivation for competitive markets in electricity is their potential to coordinate efficient entry and exit of generation resources. The efficiency of these decisions depends on the availability of transparent and complete price signals. Determining appropriate prices in non-convex markets, however, is not a straightforward task. To help resolve the incentive compatibility issues that arise when clearing these markets, operators have introduced a variety of price formation and uplift payment schemes. In this talk, we develop a two-stage capacity expansion model to investigate the impact that the choice of pricing scheme can have on generation investment decisions. Our results suggest that despite the presence of fixed cost elements, prices derived from marginal costs support the optimal capacity mix. The use of uplift payments to supplement these prices could lead to significant distortion of the capacity mix arising in competitive markets. Judicious implementation of enhanced price formation schemes, to the extent they eliminate the need for discriminatory side payments, may enable system operators to alleviate this distortion.

PRICING UNDER UNCERTAINTY: A CHANCE CONSTRAINT APPROACH TO A ROBUST COMPETITIVE EQULIBRIUM

Mr. Yury Dvorkin, Assistant Professor, New York University (*Brooklyn, NY*)

This presentation will describe a stochastic electricity market design, in which the uncertainty is handled using a proportional control law and chance security constraints. We prove that in this framework, market clearing prices yielding a robust competitive market equilibrium can be computed and used for stochastic market settlements by risk-aware system operators. An illustrative case study corroborates the usefulness of the proposed approach.

Session W2-A (Wednesday, June 27, 10:45 AM, Meeting Room 3M-2)

ELECTRICITY MARKET DESIGN WITH RENEWABLE ENERGY: A COMPARISON OF THE UNITED STATES AND EUROPE

Dr. Audun Botterud, Principal Research Scientist, Massachusetts Institute of Technology/Argonne National Laboratory (*Cambridge, MA*)
Dr. Hans Auer, Associate Professor, Technische Universität Wien (*Vienna, Austria*)

We conduct a comparative analysis between the United States and Europe and identify some fundamental differences, but also many similarities in electricity market design on the two continents. We discuss how the different approaches to electricity market design impact the optimization problems solved by system/market operators and the individual market participants. We provide a list of general and specific recommendations for improved electricity markets with higher penetration levels of renewable energy, and illustrate how these changes would affect selected decision problems in the power grid. We argue that the key to achieve a market-compatible integration of renewable energy is to focus on correct price formation in the short-term. Increased demand-side participation, improved pricing during scarcity conditions, and a transition from technology-specific subsidies of renewables towards adequate pricing of carbon emissions are important measures towards this end. Our review identifies favorable solutions and unique challenges in the United States as well as Europe. Overall, as electricity markets continue the transition towards a low-carbon future on both continents, lessons can and should be learned in both directions.

CONVEX HULL, IP AND EUROPEAN ELECTRICITY PRICING IN A EUROPEAN POWER EXCHANGES SETTING WITH EFFICIENT COMPUTATION OF CONVEX HULL PRICES

Dr. Mehdi Madani, Postdoctoral Research Fellow, Johns Hopkins University (*Baltimore, MD*)
Dr. Carlos Ruiz, Asssistant Professor, Universidad Carlos III de Madrid (*Madrid, Spain*)
Dr. Sauleh Siddiqui, Assistant Professor, Johns Hopkins University (*Baltimore, MD*)
Dr. Mathieu Van Vyve, Associate Professor, Universite catholique de Louvain (*Louvain-la-Neuve, Belgium*)

This paper introduces a computationally efficient comparative approach to classical pricing rules for day-ahead electricity markets, namely Convex Hull Pricing, IP Pricing and European-like market rules, in a Power Exchange setting with non-convex demand bids. These demand bids can, for example, be useful to large industrial consumers, and extend demand block orders in use by European Power Exchanges. For this purpose, we show that Convex Hull Prices can be efficiently computed using continuous relaxations for bidding products involving start-up costs, minimum power output levels and ramp constraints, or analogous versions on the demand side. Relying on existing efficient algorithmic approaches to handle European-like market rules for such bidding products, we provide comparative numerical experiments using realistic data, which, together with stylized examples, elucidates the relative merits of each pricing rule from economic and computational perspectives. The motivation for this work is the prospective need for mid-term evolution of day-ahead markets in Europe and in the US, as well as the importance of day-ahead price signals, since these (spot) prices are used as reference prices for many power derivatives. The datasets, models and algorithms programmed in Julia/JuMP are provided in an online Git repository.

SCHEDULING AND PRICING OF ENERGY STORAGE IN ELECTRICITY MARKETS

Dr. Masood Parvania, Assistant Professor, University of Utah (*Salt Lake City, UT*)
Mr. Roohallah Khatami, University of Utah (*Salt Lake City, UT*)
Dr. Pramod Khargonekar, University of California, Irvine (*Irvine, CA*)

This presentation proposes a fundamental model for scheduling and marginal pricing of energy storage in day-ahead power systems operation. The day-ahead market clearing problem with generating units and energy storage (ES) devices is formulated as an optimal control problem, where the Lagrange multiplier trajectory associated with the variational power balance constraint is proven to be the marginal price of energy generation and storage. The marginal price is calculated in closed-form, which shows that in addition to the incremental cost rates of generating units, the marginal price embeds the financial ES charging and discharging bids that are defined as incremental charging utility and incremental discharging cost rates. A function space-based solution method is developed to solve the problem, which is based on reducing the dimensionality of the decision and parameter trajectories by modeling them in a finite-order function space formed by Bernstein polynomials. The proposed method converts the continuous-time problem into a mixed-integer linear programming problem with the Bernstein coefficients of the trajectories as the

decision variables. The proposed method not only allows for full exploitation of the ES flexibility through higher-order solutions, but also includes the traditional discrete-time solution as a special case.

Session W2-B (Wednesday, June 27, 10:45 AM, Meeting Room 3M-3)

POWER SYSTEM RESTORATION THROUGH MIXED INTEGER LINEAR PROGRAMMING

Mr. Ignacio Andres Aravena Solis, PhD Student, Universite Catholique de Louvain (*Livermore, CA*)
Dr. Deepak Rajan, Research Scientist, Lawrence Livermore National Laboratory (*Livermore, CA*)
Mr. Georgios Patsakis, PhD Student, University of California, Berkeley (*Berkeley, CA*)
Dr. Shmuel Oren, Professor, University of California, Berkeley (*Berkeley, CA*)
Mrs. Jennifer Rios, Operations System Engineer, Pacific Gas & Electric (*San Francisco, CA*)

We present a novel framework for optimizing power system restoration and black-start allocation using mixed integer linear programming. The framework is divided in two parts. (i) First, we build piece-wise linear approximations of power flow equations that account for the regime of excess of reactive power typical during restoration. These approximation are built by minimizing the root-squared mean approximation error over the feasible domain of the power flow equations, rather than constructing first order approximations at particular points. (ii) Then, we propose an integer L-shaped algorithm that decouples the power flow equations from the combinatorial dynamics of the restoration process. This separation allows to share cuts between time periods and to formulate feasibility cuts per island, improving the convergence of the method. At the same time, we parallelize the evaluation of the power flow equations over time periods and over the islands formed during the restoration process. We present simulation results for the restoration problem and for the black-start allocation problem on modified IEEE test systems and on models of the WECC and the Chilean power grids, recovering AC feasible solutions in all cases, demonstrating the effectiveness of the proposed approach.

TRANSIENT SIMULATION AND OPTIMIZATION OF NATURAL GAS PIPELINE OPERATION AND APPLICATIONS TO GAS-ELECTRIC COORDINATION

Aleksandr Rudkevich, Newton Energy Group (*Boston, MA*)
Anatoly Zlotnik, Los Alamos National Laboratory (*Los Alamos, NM*)
John Goldis, Newton Energy Group (*Oakland, CA*)
Pablo Ruiz, Boston University (*Boston, MA*)
Russ Philbrick, Polaris System Optimization (*Seattle, WA*)
Aleksandr Beylin, Newton Energy Group (*Santa Monica, CA*)
Xindi Li, Tabors Caramanis Rudkevich (*Boston, MA*)
Richard Tabors, Tabors Caramanis Rudkevich (*Boston, MA*)

Our presentation focus on transient simulation and optimization of pipeline operation using real data. Simulation results are benchmarked against SCADA measurements.

Optimization results illustrate the potential to increase pipeline throughput under constrained conditions. We discuss applications of these techniques to improve coordination of natural gas and electric network operation.

LATEST DEVELOPMENTS ON THE PRECISE MASS-MARKET DR PARTICIPATION IN THE WHOLESALE ENERGY MARKETS THROUGH STOCHASTIC DISTRIBUTED COMPUTING

Dr. Alex Papalexopoulos, President and CEO, ECCO International (*San Francisco, CA*)

As a result of the confluence of policy and technological innovation distributed energy resources (DERs), such as demand response (DR) and energy storage systems have emerged that can offer products and services to the wholesale energy markets. The flexibility of these resources creates new opportunities in the energy markets but also new challenges that need to be properly managed to ensure that their maximum value is materialized for the benefits of the consumers. ISO markets are currently being reconfigured to allow these resources to compete with traditional resources to provide services critical to the reliable operation of the energy markets. In this presentation a fundamentally different DR approach, based on service priority tiers and on stochastic distributed computing that overcome problems of scalability, robustness, fairness and accuracy will be presented. We'll present the stochastic mathematical formulation based on Markov processes and show how to estimate the state of DR assets and have these assets respond to market signals within a few seconds to provide various ancillary and grid services to the wholesale energy markets. We'll show how the aggregation of DR assets and their organization into service priority tiers allows them to be de-commoditized and be a potent force for improving the efficiency of energy markets.

Session W3-A (Wednesday, June 27, 1:30 PM, Meeting Room 3M-2)

STOCHASTIC LOOK-AHEAD UNIT COMMITMENT FOR INTRA-DAY AND REAL-TIME MANAGEMENT OF DISTRIBUTED RENEWABLE GENERATION AND DEMAND RESPONSE

Dr. Jean-Paul Watson, Analytics Department Staff, Sandia National Laboratories (*Albuquerque, NM*)
Dr. Roger Treinen, Principal, Nexant, Inc. (*Chandler, AZ*)
Dr. Herminio Pinto, Application Manager, Nexant, Inc. (*Chandler*, *AZ*)
Dr. Kory Hedman, Professor, Arizona State University (*Tempe, AZ*)

An intra-day and real-time prototype stochastic based advisory tool is being developed for ISOs and utilities in an effort to show that such a tool can enhance system security and improve energy market surplus. This tool consists of a two-stage stochastic look-ahead unit commitment and a component that translates the stochastic based output into meaningful information that the grid and market operators can use as input in the deterministic hour-ahead unit commitment and real-time clearing market. Such a tool will help ISOs and utilities to enhance their modeling and management of key operational uncertainties associated with, for example, distributed energy resources, wind and solar renewables, demand response, contingencies, interchange, loop flow, and generator non-compliance. New algorithms and technologies, such as progressive hedging, are being implemented and developed to ensure the needed performance of such an advisory tool is sufficient to handle both the required time frame and the amount of uncertainty analyzed. The proposed technology and tool will fundamentally change the way that bulk renewable resources, distributed energy resources and demand response are represented within the bulk wholesale electricity markets, scheduling tools, and reliability assessment tools.

DATA-DRIVEN STOCHASTIC OPTIMIZATION FOR POWER GRIDS SCHEDULING UNDER HIGH WIND PENETRATION

Mrs. Wei Xie, Assistant Professor, Rensselaer Polytechnic Institute (*Troy, NY*)

The stochastic unit commitment is often employed to guide power grids scheduling, especially when there is high wind penetration. It is critically important to find the optimal decision hedging against the prediction risk accounting for all sources of uncertainty. Except the inherent stochastic uncertainty of wind power generation, there are two other sources of uncertainty, which are often ignored in the classical stochastic optimization. First, the input model characterizing the stochastic uncertainty of wind power generation is often estimated from finite historical data, which introduces the model risk. Second, the sample average approximation is typically used to estimate the expected cost in the planning horizon, which further introduces finite sampling error. In this paper, we propose a Bayesian framework to deliver the optimal unit commitment decision hedging against all sources of uncertainty. We first present a data-driven stochastic optimization accounting for both stochastic uncertainty of wind energy generation and input model risk. Then, we introduce a two-stage optimization procedure to further control the finite sampling error and efficiently search for the optimal solution by using parallel computing. Our framework is rigorously supported, and the empirical study also demonstrates that it has the superior finite budget performance.

SCALABLE CAPACITY EXPANSION FOR EXPLICIT REPRESENTATION OF INTERMITTENT GENERATION

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

Capacity expansion models are used to inform power system infrastructure planning decisions in order to meet future electrical power demand on the grid economically and reliably. To meet these goals such optimization models must consider the operational implications of the infrastructure built. With a growing amount energy on the grid coming from renewable energy sources the number of operational scenarios that must be considered to meet these goals is growing due to the complexity introduced by the intermittent nature of renewable energy. As more operational scenarios are considered the size of the optimization model grows, which historically has limited how many scenarios are considered in planning models.

We have developed a scalable capacity expansion model that uses the horizontal decomposition technique, progressive hedging, to solve the model via parallel computing. Our model is written in python and utilizes the open source multi-stage stochastic programming framework PySP, which provides access to the progressive hedging algorithm. Constructing a model in this framework allows for the model to be solved when considering a large number of operational scenarios, which allows for the effects of intermittent energy sources to be directly accounted for and understood with respect to infrastructure planning. We present results from using this model to compute planning decisions, which consider a large number of operation scenarios.

RECENT ADVANCES IN MILP FORMULATIONS FOR THE UNIT COMMITMENT PROBLEM

Dr. Ben Knueven, Senior Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)
Dr. Jim Ostrowski, Assistant Professor, University of Tennessee (*Knoxville, TN*)
Dr. Jean-Paul Watson, Distinguished Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)

This talk presents some recent work on MILP formulations for unit commitment (UC). In particular, we present a novel formulation for time-dependent startup costs in UC. The proposed formulation is tested empirically against existing formulations on large-scale unit commitment instances drawn from real-world data. While requiring more variables than the current state-of-the-art formulation, the proposed formulation requires fewer constraints, and is as tight as a perfect formulation for startup costs. This tightening can reduce the computational burden in comparison to existing formulations. When combined with other recent formulation improvements, we demonstrate that large-scale unit commitment instances often have very tight integrality gaps, without the addition of cut-generation routines.

Session W3-B (Wednesday, June 27, 1:30 PM, Meeting Room 3M-3)

SCALABLE CORRECTIVE SECURITY-CONSTRAINED ECONOMIC DISPATCH CONSIDERING CONFLICTING CONTINGENCIES

Dr. Yaowen Yu, Senior Application Engineer, ABB Enterprise Software (*San Jose, CA*)
Dr. Peter Luh, Professor, University of Connecticut (*Storrs, CT*)
Dr. Mikhail Bragin, Assistant Research Professor, University of Connecticut (*Storrs, CT*)

Achieving high market efficiency requires secure and effective usage of the transmission grid. Corrective security-constrained economic dispatch (SCED), which allows corrective actions to be taken after the occurrence of a contingency, uses transmission and market resources more efficiently in comparison with conventional preventive SCED. Corrective SCED, however, requires a complex model and presents challenges in real-time operations because of a large number of contingencies and the strict time limits. The possible existence of "conflicting contingencies" whose constraints cannot be satisfied at the same time further complicates the problem. To overcome these difficulties, a new iterative contingency filtering approach will be presented to manage "N−1" transmission and generator contingencies via decomposition and coordination. By introducing penalty terms for individual contingencies, multiple conflicting contingencies can be simultaneously identified. This feature provides system operators with an important option to keep conflicting contingencies for improved reliability as validated by simulation results, instead of always removing them as presented in the literature. Moreover, computational performance of our approach is significantly enhanced by novel warm-start of subproblem models and by parallel computing. Our approach solves the Polish 2383-bus system with all transmission contingencies within two minutes, demonstrating its potential for practical use.

GENERATOR CONTINGENCY MODELING IN ELECTRIC ENERGY MARKETS

Dr. Nikita Singhal, Senior Engineer, Electric Power Research Institute (*Palo Alto, CA*)
Dr. Kory W. Hedman, Associate Professor, Arizona State University (*Tempe, AZ*)

Traditional electric energy markets do not explicitly model generator contingencies. In an effort to improve the representation of resources and to enhance the modeling of uncertainty, existing markets are moving in the direction of including generator contingencies and remedial action schemes within market action models. Recent literature suggests modifying the contemporary market auction models to include post-contingency transmission flow constraints for generator contingencies explicitly. These constraints aim to preemptively anticipate post-contingency congestion patterns in the event of a generator contingency. The enhanced formulations utilize pre-determined factors to predict the influence of recourse actions during critical generator contingencies. The primary goal is to acknowledge and enhance reserve deliverability in the post-generator contingency state. This research derives and analyzes auction reformulations and the corresponding effect on market prices, settlements, and revenues, to streamline market reform associated to uncertainty modeling and modeling of corrective actions. A comparison to existing market structures is also included. Furthermore, a detailed analysis of impending changes and the necessary recommendations are also provided to ensure a fair and transparent market structure.

SIMULTANEOUS ECONOMIC EFFICIENCY AND RELIABILITY BENEFITS FROM ADVANCED OPERATING RESERVE REQUIREMENT METHOD: CASE STUDY ON THE HAWAIIAN ELECTRIC SYSTEM

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

EPRI has been conducting research on advanced methods for determining operating reserve requirements for a number of years. The method focuses on examining the exact need due to intra-interval variability, inter-interval variability, and uncertainty of the net load, determining explanatory variables that can better predict those needs, and forecast the needs for future conditions. A recent study was completed in collaboration with the Hawaiian Electric Company for the Island of Oahu. The use of these methods were found to lead to substantial simultaneous reliability and economic benefits. The presentation will discuss the method, means for evaluating it against existing methods, and specific results for the HECO Study.

Preventive Power System Operation During Hurricanes

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

Severe weather is the primary cause of power outages in the U.S. Despite the availability of weather forecast information to power system operators, such data is not systematically integrated in operation models. This talk presents an integrated platform to convert the weather data into appropriate information for operation, during hurricanes. First, a structural model of the transmission towers is developed to enable stability analysis with dynamic wind loading. The model produces failure probabilities as a function of the wind speed. These probabilities are, then, integrated within a day-ahead security-constrained unit commitment framework to guide preventive operation. The resulting day-ahead schedule will be more secure as it will rely less on the elements that are likely to fail due to the hurricane. Simulation studies are conducted on IEEE 118-bus system, affected by synthesized Irma and Harvey hurricanes, to test the effectiveness of the method. The platform, presented in this paper, was able to prevent 33% to 83% of the blackouts induced by the hurricanes, in our simulation studies.

Session W4-A (Wednesday, June 27, 3:45 PM, Meeting Room 3M-2)

Distributed Solution Algorithms for Security Constrained Unit Commitment in Evolving Day Ahead Electricity Markets

Dr. Jesse Holzer, Scientist, Pacific Northwest National Laboratory (*Richland, WA*)
Dr. Feng Pan, Scientist, Pacific Northwest National Laboratory (*Richland, WA*)
Dr. Stephen Elbert, Specialist, Pacific Northwest National Laboratory (*Richland, WA*)

The security constrained unit commitment problem is the computational engine supporting day ahead wholesale electricity markets. As these markets evolve, larger market areas and numerous virtual bidders and smaller energy resources pose increasing computational challenges for standard mixed integer programming solution approaches. This talk describes two alternative solution methods for security constrained unit commitment adapted to these changing problem characteristics and implemented as distributed algorithms in a high performance computing environment: (1) an application of the alternating direction method of multipliers and (2) a problem-specific enhancement of the relaxation induced neighborhood technique. Computational results will be presented to show the effectiveness of these algorithms. This work is part of the HIPPO project, which is funded by ARPA-E and performed by a team from Pacific Northwest National Laboratory, Midcontinent Independent System Operator, General Electric, Gurobi, and University of Florida.

HIPPO - A HIGH-PERFORMANCE COMPUTING SOLVER FOR SECURITY CONSTRAINED UNIT COMMITMENT PROBLEM

Dr. Feng Pan, Scientist, Pacific Northwest National Laboratory (*Seattle, WA*)
Dr. Jesse Holzer, Scientist, Pacific Northwest National Laboratory (*Richland, WA*)
Dr. Steve Elbert, Manager, Pacific Northwest National Laboratory (*Richland, WA*)
Dr. Yonghong Chen, Principal Advisor, Midcontinent ISO (*Carmel, IN*)
Dr. Jie Wan, Manager, GE (*Redmond, WA*)
Dr. Edward Rothberg, CEO, GUROBI (*Houston, TX*)
Dr. Yongpei Guan, Professor, University of Florida (*Gainesville, FL*)

HIPPO is a software library for solving the security constrained unit commitment (SCUC) problem. The goal of HIPPO is to reduce the solution time for solving SCUC in ISO/RTO day-ahead energy markets. The team is developing a concurrent optimization solver consisting of several algorithmic approaches such as branch-and-bound, decomposition methods and market based heuristics. These algorithms are implemented to Leverage high-performance computing clusters to further improve the algorithm performance. This talk will provide an overview of the HIPPO software which includes SCUC models, algorithms in HIPPO and their performance. The project is funded by ARPA-E and the team consists of Pacific Northwest National Laboratory, Midcontinent Independent System Operator, General Electric, GUROBI and University of Florida.

MULTI-YEAR DETAILED NODAL, CLOUD-BASED MODELING OF ECONOMIC AND ENVIRONMENTAL IMPACTS OF THE INTEGRATION OF SIGNIFICANT QUANTITIES OF MANDATED ON-SHORE AND OFF-SHORE RENEWABLE RESOURCES INTO THE REGIONAL ELECTRIC POWER GRID

Dr. Richard D. Tabors, President, Tabors Caramanis Rudkevich (*Boston, MA*)
Dr. Alexander Rudkevich, President, Newton Energy Group (*Boston, MA*)

Massachusetts has mandated that the distribution utilities in the Commonwealth will acquire 9,450 gigawatt hours of land-based renewables and up to 1600 MW of offshore wind technology to reduce carbon emissions under Sections 83D and 83C of Chapter 169 of the Acts of 2008 the Green Communities Act, as amended in 2016 by the Energy Diversity Act. Tabors Caramanis Rudkevich (supporting National Grid US, Eversource, Unitil and the Massachusetts Department of Environmental Resources) developed and implanted a detail modeling system operating off of a common data base to calculate 40 years of resource adequacy; 25 years of hourly LMPs; regional emissions and net impacts of global warming emissions on the Massachusetts objectives. The integration of parallelized cloud-based computation with data retrieval, aggregation and communication in familiar spreadsheet format will be highlighted with a focus on speed and efficiency of analysis as well as upon communication of results to diverse stakeholders and the ability to reproduce and defend results before state regulatory bodies.

ADVANCED ON-LINE VOLT/VAR CONTROL SYSTEM: DESIGN, IMPLEMENTATION AND HIGH HOSTING CAPABILITY FOR RENEWABLE ENERGY

Dr. Yasuyuki Tada, Hitachi, Ltd., Energy Solution Business Unit (*Tokyo, Japan*)
Hsiao-Dong Chiang, Cornell University/Bigwood Systems, Inc. (*Ithaca, NY*)

We will present an Advanced Voltage Control (AVC) system which is a three-tiered online volt/VAR control system designed to improve system reliability and operational efficiency, such as voltage profile and available transfer capability for transferring renewable energy, with optimal control strategy.

The proposed three-tiered AVC System employs three-level hierarchical voltage control architecture. The tertiary tier is performed every hour, and it focuses on increasing system available transfer capability (ATC) subjected to voltage stability constraints. It will determine the optimal selection of pilot buses and their voltage setting. The secondary tier will perform every 15 minutes to optimize the regional desired objectives, such as enhancing operating efficiency or reducing system losses, while maintaining the voltage setting of the pilot buses determined by the tertiary tier and satisfying system operational and engineering constraints. Control actions include generator terminal voltages, transformer taps, shunt capacitor settings real power rescheduling, etc. The optimal setting decided by the secondary tier will be sent to the primary tier as control signals, and will be executed by the control devices located at the substation level and the power plant level on a minute basis.

The proposed AVC system is highly adaptive to network changes and achieve high-quality optimal AVC results. The benefits of the proposed AVC system include the following without additional infrastructure investment:

- Increased Available Transfer Capability of power grids
- Reduced Power Losses
- Improved Voltage Profile

Session W4-B (Wednesday, June 27, 3:45 PM, Meeting Room 3M-3)

MODELING NUCLEAR POWER AS A FLEXIBLE RESOURCE FOR THE POWER GRID

Dr. Zhi Zhou, Principal Computational Scientist, Argonne National Laboratory (*Lemont, IL*)
Dr. Audun Botterud, Principal Energy System Engineer, Argonne National Laboratory (*Lemont, IL*)
Mr. Jesse Jenkins, Graduate Student, Massachusetts Institute of Technology (*Boston, MA*)
Dr. Roberto Ponciroli, Nuclear Engineer, Argonne National Laboratory (*Lemont, IL*)
Dr. Francesco Ganda, Principal Nuclear Engineer, Argonne National Laboratory (*Lemont, IL*)

The economic viability of nuclear energy is increasingly challenged in the U.S. deregulated electricity markets due to large availability of cheap natural gas and increased penetration of renewables. It is critical to improve the competitiveness of nuclear energy to maintain energy supply diversity. In current U.S. markets, nuclear power plants are commonly operated in a "baseload" mode at maximum rated capacity whenever online. However, nuclear power plants are technically capable of flexible operation, including changing power output over time and providing regulation and operating reserves. Flexible operation can help integrate variable energy resources, meet system reliability requirements, and improve power system resilience. In this study, we present a novel model to accurately represent the technical operating constraints and flexibility of nuclear power plants, including impacts of xenon transients in the reactor core and how it changes over the fuel cycle. We integrate the improved nuclear power plant model into a unit commitment and economic dispatch model for the power system. In a case study, we investigate the economic impact of flexible nuclear operations on plant profitability and system cost in a market with high shares of renewable energy. The results show that operational flexibility can not only increase a nuclear plant's profit, but also have benefit to the system in terms of reduced operating costs and lower curtailment of renewable energy.

FREQUENCY-OPTIMIZED SECURITY-CONSTRAINED ECONOMIC DISPATCH (fSCED)

Mr. Tom Dautel, Supervisory Economist, Federal Energy Regulatory Commission (*Washington, DC*)
Dr. Richard O'Neill, Chief Economic Advisor, Federal Energy Regulatory Commission (*Washington, DC*)

We present an approach that optimally dispatches electric resources to control system frequency. The proposed frequency-optimized security-constrained economic dispatch (fSCED) model can accurately relate resource and load dispatch to changes in system frequency, and then use those mathematics to determine the dispatch that meets system needs (including frequency control) at lowest cost. The Commission and other stakeholders have recently been considering how to incorporate more system requirements and constraints into economic dispatch, for both efficiency and pricing reasons. The fSCED model proposed represents a possible approach to further incorporating some aspects of frequency control into the economic dispatch.

POWER SYSTEM OPTIMIZATION WITH AN INERTIA STUDY ON THE IEEE 30-BUS TEST SYSTEM

Mr. Sandeep Sadanandan, Energy Analyst/Student, Kansas State University (*Arlington, VA*)

Inertia on the power system is an important issue for study and analysis. With the national movement to low inertia green energies, the lack of inertia on the power system could be a significant issue. The purpose of this paper is to include inertia in a power system optimization of the IEEE 30-bus system. The objective function of generation cost is minimized subject to constraints of active power generator limits, active power reserves, and system inertia. As generation is lost on the system, frequency drops. The early response of the system comes from the inertia on the system. With the replacement of large synchronous machines by renewable resources, which are often lower inertia units, the need to maintain a system inertia constant (Hsys) becomes a necessary goal of power system planners and operators. For our IEEE 30 Bus System with 4 low inertia units, the proposed approach allows the system to maintain 59.7 Hz or higher frequency for the loss of 0.0239 pu of generation.

Modeling of Resilient Electricity Generation after Cascading Collapse

Mr. Thomas Popik, Chairman and President, Foundation for Resilient Societies (*Nashua, NH*)

Most modeling of electricity markets and security constrained economic dispatch assumes balancing areas operate under continuous control. But what happens when a cascading collapse affects all or most of a balancing area? Impacts to modeling assumptions would be immediate and discontinuous. For example, due to neutron poisoning after reactor SCRAMs, all baseload generation from nuclear plants will be lost for several days. Lack of electricity for control systems and electric compressors of pipeline networks may affect supply of natural gas for generation. Non-dispatchable and intermittent energy resources, such as wind and solar, cannot be relied upon during system restoration, especially when rolling blackouts last days or weeks. During post-collapse conditions, the duration of energy stored on-site at generation plants can become a binding system constraint. Resilient energy sources for generators have not been an explicit part of the design for capacity markets, a policy that works well on most days but probably not after cascading collapse. For this presentation, the author proposes to build on previous analytic work for FERC Dockets AD17-8-000 and RM18-1-000 to show that energy stored on-site, along with dual-fuel capability for natural gas plants, are critical contributors to system resilience. Modeling of resource adequacy after cascading collapse should be an essential part of resilient design for electricity markets.

Thursday, June 28

Session H1 (Thursday, June 28, 9:00 AM, Meeting Room 3M-2)

UNIT COMMITMENT OF INTEGRATED ELECTRIC AND GAS SYSTEMS WITH AN ENHANCED SOC GAS FLOW MODEL

Dr. Ramteen Sioshansi, Associate Professor, The Ohio State University (*Columbus, OH*)
Sheng Chen, The Ohio State University (*Columbus, OH*)
Antonio J. Conejo, The Ohio State University (*Columbus, OH*)

Interdependent electric power and natural gas systems require a co-ordinated operations framework. This paper proposes a unit commitment (UC) model for the integrated electric and natural gas systems. A second-order cone (SOC) dynamic natural gas-flow model is employed to formulate the UC model as a mixed-integer SOC programming problem. The formulation is enhanced using convex envelopes of bilinear terms. By fixing the binary variables at their optimal values, we define the electricity and natural gas locational marginal prices (ELMPs and NGLMPs) as the dual variables of power and natural gas flow-balance equations, respectively. The interdependence between ELMPs and NGLMPs is also discussed.

TIGHT MIP FORMULATION OF TRANSITION TRAJECTORIES OF COMBINED-CYCLE UNITS

Mr. Bowen Hua, Graduate Research Assistant, University of Texas at Austin (*Austin, TX*)
Dr. Ross Baldick, Professor, University of Texas at Austin (*Austin, TX*)
Dr. Yonghong Chen, Principle Advisor, Midcontinent ISO (*Carmel, IN*)

Combined-cycle units (CCUs) have limited ability to follow an exterior control signal during transitions between configurations. Depending on the physical characteristics of the turbines, a transition might last up to several hours. However, current CCU models implemented in different ISOs assume that any transition completes within a single interval and ignore the power trajectory during transitions. We propose a mixed-integer linear programming formulation of a unit commitment problem that explicitly models the transition trajectories of CCUs. We show theoretical results on the tightness of our formulation. We present numerical results and examine pricing consequences.

MARKET RESTRICTING POLICIES DUE TO OUTDATED TECHNOLOGY

Dr. Sergio Brignone, FTR Director, Vitol, Inc. (*Houston, TX*)
Dr. Federico Corteggiano, FTR Director, Vitol, Inc. (*Houston, TX*)

Lately, many nodal market policies are making electricity markets less transparent and liquid, affecting system resiliency and efficiency. These initiatives seem to be derived only by the fact that ISOs are supporting their operations with outdated information technologies. Examples of these initiatives are policies to limit the

number of pricing points in markets, which don't add any value and only hide inefficiencies reflected in higher prices.

We are noting lack of progress in market designs as consequence of outdated systems. Current technology would allow electricity markets to improve transparency and granularity, for example with state of the art systems, ISOs could be able to run rolling Day Ahead or even Week Ahead markets every hour allowing participants readjusts their bids and offers as fuel markets move; or run rolling annual FTR Auctions every day with hourly resolution to model outages and minimizing risk of underfunding, or run properly implemented FTR options.

Given our experience as software developers and market participants, our proposal is to show to the commission a system architecture using state of the art system software components that could be implemented to speed up the solution order of magnitude all power system algorithms (optimal power flow, unit commitment, security constraint energy dispatch) and its integration into power markets to allow the improvements previously mentioned.

Session H2 (Thursday, June 28, 10:45 AM, Meeting Room 3M-2)

INTEGRATING AN OPEN POWER SYSTEMS DATA REPOSITORY AND AN OPEN MODELING FRAMEWORK - DRPOWER AND OMF.COOP

Mr. David Pinney, Analytics Program Manager, National Rural Electric Cooperative Association (*Arlington, VA*)
Dr. Mark Rice, Electrical Power Systems Researcher, Eng, Pacific Northwest National Laboratory (*Richland, WA*)
Dr. Stephen Elbert, Manager, Pacific Northwest National Laboratory (*Richland, WA*)
Ms. Olga Kuchar, Senior Research Scientist, Pacific Northwest National Laboratory (*Richland, WA*)
Dr. Laruentiu Marinovici, Research and Development Engineer, Pacific Northwest National Laboratory (*Richland, WA*)

The National Rural Electric Cooperative Association (NRECA) has developed an Open Modeling Framework (omf.coop) that offers open source power system simulation, visualization, and model editing capabilities. More recently, the Pacific Northwest National Lab has developed a open data repository for power systems models (DRPOWER). This presentation will discuss how the two have been integrated to allow users of the website (eggriddata.org) to visualize, edit and run power flows on the complex distribution and transmission models in the repository.

EXPERIMENTAL ANALYSIS OF PMU DATA

Dr. Daniel Bienstock, Professor, Columbia University (*New York, NY*)
Mauro Escobar, Columbia University (*New York, NY*)
Apurv Shukla, Columbia University (*New York, NY*)
Michael Chertkov, Los Alamos National Laboratory (*Los Alamos, NM*)

We describe ongoing work using PMU data obtained through an industrial collaboration. The data encompasses two years worth of output from some two hundred PMUS. The goal of the work is to determine stochastic properties of the data, such as (empirical) distributions, and, in particular, spatial and temporal correlations of observed deviations. A second goal is to determine whether it is possible, through limited observations, to rapidly determine changes in operating conditions and, in particular, in the structure of correlation between locations in a transmission system. If time permits we will describe a closely related mathematical problem, the approximate computation of factor decompositions of covariance matrices from streaming data.

IMPROVING GRID RELIABILITY THROUGH DISTRIBUTED AI AND MACHINE LEARNING

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To date, most improvements in market and planning efficiency have occurred through deterministic software. AI and machine learning have enormous potential to further enhance flexibility, modeling, and efficiency through more probabilistic approaches. The challenge that most AI systems face is the huge amounts of data required for training are often unavailable to AI experts due to data security and issues and the distributed locations of their data. Recent advances in differential privacy, homomorphic encryption, and smart contracting technology may provide a solution to many of the issues limiting AI learning to improve grid resiliency. This presentation will focus on a specific application, Trusted Analytics Chain, to address four common AI training data issues: too little data, too much data, physically distributed data, and information privacy.