UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Increasing Market and Planning Efficiency through Improved Software	Docket No. AD10-12-017

SUPPLEMENTAL NOTICE OF TECHNICAL CONFERENCE ON INCREASING MARKET AND PLANNING EFFICIENCY THROUGH IMPROVED SOFTWARE

(June 5, 2026)

As announced in the Notice of Technical Conference issued in this proceeding on March 4, 2026, Commission staff will convene a technical conference on July 7 and 8, 2026 to discuss grid-enhancing technologies, load forecasting, and opportunities for increasing market and planning efficiency through improved software. This Supplemental Notice provides an initial agenda for the technical conference, which includes panel discussions addressing grid-enhancing technologies and load forecasting on the first day, July 7, and individual presentations on cutting edge research topics the second day, July 8.

The Commission does not intend to discuss any specific proceeding pending before the Commission at this technical conference.

The conference will allow discussion panelists to participate in person and attendees to listen either in-person or virtually and will be transcribed. Presenters and attendees may either listen or participate virtually on the second day of the conference. Further details on both in-person and virtual participation will be available on the conference webpage.[1]

The technical conference will be open to the public. Due to security screening, foreign nationals who plan to attend in person are required to register through the Commission's website on or before June 12, 2026. For technical reasons, virtual attendees who plan to participate in Q&A available on the second day of the conference are encouraged to register through the Commission's website on or before June 12, 2026. All other attendees are encouraged to register through the Commission's website on or

[1] https://www.ferc.gov/news-events/events/increasing-market-and-planning-efficiency-through-improved-software-technical

before June 12, 2026. Registration will help ensure that Commission staff can provide sufficient physical and virtual facilities and to communicate with attendees in the case of unanticipated emergencies or other changes to the conference schedule or location.

Slides for the second day of the conference are due from selected presenters by 5:00 p.m. EDT on Tuesday**,** June 30, 2026. Before 1:00 p.m. EDT on Monday, July 6, 2026, Commission staff will work with presenters to provide quality assurance that their presentation materials are prepared, formatted correctly, and ready for delivery during the conference. All updates to slides submitted before 5:00 p.m. on June 30, 2026 will be posted to the Commission website in advance of the conference. Late submissions will be posted to the Commission website after the conference; however, the live conference may use the slide versions submitted before the deadline.

To stay apprised of issuances in this docket, there is an "eSubscription" link on the Commission's web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). Information on this technical conference will also be posted on the Calendar of Events on the Commission's website, www.ferc.gov, prior to the event. The Commission provides technical support for the free webcasts.

FERC conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations please send an email to accessibility@ferc.gov or call toll free (866) 208-3372 (voice) or (202) 502-8659 (TTY), or send a fax to (202) 208-2106 with the required accommodations.

For further information about the conference, please contact:

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Technical Conference: Increasing Market and Planning Efficiency through Improved Software

Agenda

AD10-12-017
July 7 – 8, 2026

TUESDAY, JULY 7, 2026

9:20 AM – 9:30 AM: Welcome and Opening Remarks

9:30 AM – 12:45 PM: Panel 1 – Grid-Enhancing Technologies

This panel will focus on the opportunities and challenges associated with successfully deploying grid-enhancing technologies (GETs), barriers to implementation, and advances in the development of emerging GETs and related software. The U.S. electrical industry faces significant challenges such as rapidly rising power demand, affordability concerns, aging infrastructure, and the need to integrate new resources quickly.

GETs have the potential to improve the efficient use of the existing transmission grid, reducing costs and increasing reliability. In addition to discussing research and the state of the art in different GETs, the panel will explore transmission owners' and system operators' experience deploying GETs and related software. The panel will also explore the ability of software to both identify opportunities for grid-enhancing technology deployment and manage use of those technologies. This panel may address grid-enhancing technologies including: (1) static synchronous compensators; (2) static VAR compensators; (3) advanced power flow control devices; (4) transmission switching; (5) synchronous condensers; (6) voltage source converters; (7) advanced conductors; (8) dynamic line ratings[2]; and (9) the implementation of, and software related to, ambient-adjusted ratings.[3]

[2] See, generally, *Bldg. for the Future Through Elec. Reg'l Transmission Planning and Cost Allocation,* Order No. 1920, 89 FR 49280 (June 11, 2024), 187 FERC ¶ 61,068 (2024) at P 1198 (referencing a set of alternative transmission technologies); *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 88 FR 61014 (Sept. 6, 2023), 184 FERC ¶ 61,054 (2023) at P 1578 (referencing a set of alternative transmission technologies).

[3] The Commission requires transmission providers to use ambient-adjusted ratings in calculating line ratings. *Managing Transmission Line Ratings*, Order No. 881, 87 FR 2244 (Jan. 13, 2022), 177 FERC ¶ 61,179 (2021).

This panel may include a discussion of the following topics and questions:

1. What do you view as the main challenge in deploying GETs?
    a. What software improvements could address these challenges, or what existing software has potential to do so?

2. For entities that have already deployed GETs or stood up a process to facilitate the use of GETs:
    a. Describe the type of GETs deployed and your experience. How difficult was implementation and how long did it take? What was the scale of the deployment (e.g., a pilot project or system-wide)? Was the implementation process what you expected, or did you encounter unexpected upfront costs or challenges?
    b. Once implemented, what were the benefits and ongoing costs or challenges of using that GET? Were they what you expected? Are you considering broader deployment across your system? Why or why not?
    c. What are key lessons learned for other utilities or system operators exploring GETs deployment (either from the process of preparing for the technology's deployment or from its performance or operation once deployed)?
    d. What helped you arrive at the decision to deploy GETs (such as estimates of economic or reliability benefits)? What studies, simulation software, or other factors helped you to decide to move forward?

3. What specific actions, decisions, software, or processes have helped utilities and system operators successfully deploy GETs?

4. Which GETs are easiest to deploy in terms of cost and time? What aspects of the deployment process—procurement, commissioning, telemetry integration, software integration, or something else—make deployment happen sooner?

5. How are new software platforms, such as real-time analytics, topology optimization engines, and digital twins, changing the way that system operators identify and make use of latent grid capacity? Please describe the current ability of software to 1) identify opportunities for grid-enhancing technology deployment and 2) to manage those technologies once deployed.

6. Does deployment of GETs require new infrastructure and software or can utilities use or repurpose existing infrastructure to help deploy GETs (e.g. switching yards

for topology optimization, weather stations for AARs and DLR)? Can software extend the usefulness of existing infrastructure for deploying GETs?

Panelists:

- *Dr. Alexandre Parisot*, Director of Ecosystem, AI and Energy Systems, Linux Foundation Energy
- *Andrew Schneller,* Vice President – Electric Network Strategy and Regulation, National Grid
- *Alex Watkins*, Manager - Operational Planning, Southwest Power Pool
- *David Quier*, Vice President & COO, PPL Electric Utilities
- *Emilie Tullis,* Vice President of Product, LineVision, Inc.
- *Jake Gentle*, Senior Technical Manager, Idaho National Laboratory
- *Michael Craig*, Manager - Energy Management Systems, Great River Energy
- *Saugata Biswas*, CEO, GridAstra Inc.

12:45 PM – 2:00 PM: Lunch Break

2:00 PM – 5:00 PM: Panel 2 – Load Forecasting

In recent years, rapid load growth, including from large load additions such as data centers, has contributed to load forecasting challenges across the nation. Other broad trends such as electrification across sectors and changes in the resource mix increase the complexity of forecasting bulk power system needs. This panel will focus on the challenges and opportunities associated with improving load forecasting practices in light of these developments. Specifically, the panel will explore how load forecasts are made and how large loads are integrated into those processes, as well as how forecasts are used in planning and operational decisions. The panel will also consider the challenges large loads create for forecasting and how planners and operators are addressing such challenges to enable speed to power including through software solutions, while maintaining system reliability and supporting consumer affordability. Accurate load forecasting can ensure that consumers do not pay for capacity procured for forecasted load that does not result in real demand.

As noted in the Initial Notice, load forecasting is becoming increasingly important as the bulk power system faces historic demand growth driven in part by data centers and other large new loads. This panel may address: (1) forecasting for data centers and other large loads; (2) resource needs to serve new large loads; (3) software improvements to

increase the accuracy of load forecasting; (4) options to enhance data sharing; and (5) underlying assumptions and computational techniques.

This panel may include a discussion of the following topics and questions:

1. For those who prepare load forecasts, how are they developed and used in planning and operations? For other organizations, how do you use load forecasts? What actions have been taken in your regions to improve load forecasting?

2. What are the key similarities and differences in how regions approach load forecasting, both long term and in operations? Are there any characteristics (e.g., transmission topology, existing load characteristics) that necessitate variations? How do, or should, neighboring regions coordinate (e.g., joint scenario planning)?
    a. Are the systems, processes, and software interoperable or comparable?
    b. Could collaboration on software tools improve load forecasting in all regions?

3. How does accounting for large loads change current long term load forecasting methodologies? How do your forecasts address uncertain large load additions? What form would such changes take (e.g., changes to process, data collection, coordination or software)?

4. On the planning horizon, how do planners and others use load forecasts to procure capacity for anticipated large load additions? What would be the consequences, both long term and in day-to-day operations, of significantly over-forecasting (or under-forecasting) load growth in the planning horizon?

5. To what extent, and how, do large load additions need to demonstrate meaningful and verifiable commitments as part of the long term planning process, such as through financial commitments or executed agreements, to ensure they result in real demand?

6. How do current load forecasts, both in operations and long term planning, obtain sufficient information about a new large load's operational profile, such as size, ramp rates, or information about any behind-the-meter generation serving the load? How can access to this data be improved?

7. What, if any, software or analytical tool improvements are needed to better capture the unique characteristics of large loads? How could or are these changes being integrated into planning processes?

8. What role should probabilistic or scenario-based approaches play in planning decisions? Would it be useful to express the range of uncertainty inherent in load forecasts in new ways, e.g., incorporating confidence bands for different scenarios? Are there software tools that could better support producing or visualizing these probabilistic outputs?

Panelists

- *Casey Cathey*, Vice President, Engineering, Southwest Power Pool
- *DL Oates,* Executive Director, Market and Grid Research, Midcontinent ISO
- *Greg Poulos*, Executive Director, Consumer Advocates of the PJM States
- *John Moura*, Director, Reliability Assessment and Performance Analysis, North American Electric Reliability Corporation
- *John Wilson*, Vice President, Grid Strategies
- *Kent Chandler*, Non-Resident Senior Fellow, R Street Institute
- *Mudita Suri*, Head of Energy and Water Strategy, US West, Amazon Web Services

WEDNESDAY, JULY 8, 2026

9:00 AM – 9:05 AM: Introduction

9:05 AM – 10:35 AM: Session 1- Storage

Session Overview: Software for the optimization of rechargeable storage resources could realize large improvements for reliability and affordability for ratepayers due to both storage's fast response time and its rapid growth, as the fastest growing resource on the bulk power system by both percentage of the current fleet and total nameplate capacity installed in 2025.

Presentations

RELIABILITY ASSESSMENT OF ENERGY STORAGE AS A TRANSMISSION ASSET WITH LINE OUTAGE MODELING AND LOCATIONAL EVALUATIONS

Dr. Dongwei Zhao, Argonne National Laboratory, (*Lemont, IL*)[4]
Dr. Zhi Zhou, Argonne National Laboratory, (*Lemont, IL*)
Dr. David Sehloff, Argonne National Laboratory, (*Lemont, IL*)
Dr. Jonghwan Kwon, Argonne National Laboratory, (*Lemont, IL*)
Dr. Todd Levin, Argonne National Laboratory, (*Lemont, IL*)

Energy storage can function as a transmission asset by providing grid services such as congestion relief and reliability enhancement, offering an alternative to conventional transmission line upgrade solutions. This work develops a reliability assessment framework that explicitly models storage as an asset that supports the transmission system. The framework jointly samples generator and transmission-line outages and evaluates post-contingency dispatch to assess reliability impacts. To enable efficient line-outage simulation, we adopt a flow-cancellation method that leverages a power transfer distribution factor (PTDF) formulation for post-contingency economic dispatch. Using this framework, we quantify reliability-equivalent storage solutions relative to traditional transmission-line upgrades and demonstrate that explicit modeling of line outage reduces the required equivalent storage capacity, thereby improving the valuation of the storage's reliability benefits. We further introduce locational reliability contribution metrics, which

[4] Expected primary presenter at the Conference is bolded, though other authors listed may present as well

reveal pronounced spatial heterogeneity and underscore the importance of storage siting for cost savings and allocation.

IMPROVING RELIABILITY OF GRID OPERATIONS THROUGH ENHANCED COMMITMENT AND STORAGE MANAGEMENT TOOLS

Dr. Shubo Zhang, New York Independent System Operator (NYISO), (*Rensselaer, NY*)
Dr. Hossein Lotfi, New York Independent System Operator, (*Rensselaer, NY*)

As power systems face growing uncertainty from renewable variability, fuel limitations, load forecast error, changing grid conditions, and increasing distributed energy resource participation, operators increasingly need software tools that can economically address reliability needs after the Day-Ahead market closes. This work presents the New York Independent System Operator's Capacity Analysis Commitment Tool (CACT), a developing operator support application designed to evaluate the commitment of additional long-lead-time resources and adjustments to existing Day-Ahead commitments using updated system conditions. CACT includes two core functions: a commitment scheduler that evaluates the economic commitment of additional resources not committed in the Day-Ahead market, and a commitment shift function that evaluates adjustments to existing schedules to address capacity deficiencies. Building on this framework, we also present an energy storage management approach based on target state-of-charge hold-up constraints that preserve stored energy for later high-demand periods and improve reliability under uncertainty. Unlike a conventional intraday market engine, the proposed framework is derived from Day-Ahead and real-time market-clearing principles in a form suitable for operator studies. Simulation results indicate that the combined commitment and storage-management framework can improve resource availability during stressed periods, reduce deficiency exposure, and lower operating costs, demonstrating how enhanced software can strengthen reliability, intertemporal resource management, and operational efficiency in ISO/RTO operations.

LIMITATIONS OF PRODUCTION COST MODELING HEURISTICS IN CAPTURING INTERTEMPORAL CONGESTION DYNAMICS OF ENERGY STORAGE

Mr. Alejandro Elenes, Energy Exemplar, (*Salt Lake City, UT*)
Mr. Rob Homer, Energy Exemplar, (*Salt Lake City, UT*)

This presentation examines how different software approaches to modeling energy storage resources with intertemporal constraints influence dispatch outcomes and congestion patterns in power system analysis. Energy storage introduces temporal coupling across intervals, requiring optimization frameworks that capture state-of-charge dynamics and interactions with transmission constraints. Publicly available methodologies, including those used in MISO studies, indicate that production cost modeling approaches may apply simplifying assumptions—such as fixed storage dispatch profiles and reduced transmission constraint sets—to maintain computational tractability at higher levels of storage deployment. The novelty lies in highlighting differences between prevailing industry modeling practices and new formulations that more fully capture intertemporal and network interactions. Using a case study based on these methodologies, we replicate such approaches and compare them to a chronological optimization framework that endogenously determines storage dispatch while preserving intertemporal and transmission constraints. The comparison focuses on how differences in formulation affect storage behavior and its interaction with congestion over time. Results show that simplified representations can lead to different dispatch patterns and congestion outcomes relative to formulations that co-optimize storage and transmission constraints across multiple intervals. These differences become more pronounced as storage duration and system reliance increase. These findings highlight the importance of accurately representing intertemporal constraints in software used for system operations and analysis as storage resources play an increasing role in managing transmission system conditions.

10:35 AM – 10:50 AM: Break

10:50 AM – 12:20 PM: Session 2 - Special Topics

Session Overview: These presentations on various topics support the Commission's work on the efficiency, affordability, and reliability of the bulk power and gas systems.

Presentations:

ADVANCING MISO DAY-AHEAD LOAD FORECASTING PERFORMANCE WITH A NOVEL DEEP RESIDUAL AND CROSS-ATTENTION MODEL

Dr. Arezou Ghesmati, MISO Energy, (*Carmel, IN*)
Dr. Long Zhao, MISO Energy, (*Carmel, IN*)
Dr. Congcong Wang, MISO Energy, (*Carmel, IN*)
Dr. Cong Feng, National Laboratory of the Rockies, (*Golden, CO*)

Zhenlong Jiang, MISO Energy, (*Carmel, IN*)

Accurate load forecasting is essential for reliable power system operations and market efficiency, supporting key functions such as unit commitment, dispatch, and system reliability planning. To reduce the risk of bias from any single model, operators typically rely on multiple forecasting sources, including vendor-provided predictions and ensemble-based approaches. In practice, organizations such as the Midcontinent Independent System Operator (MISO) face the challenge of effectively combining multiple forecasts. The primary issue is not the availability of predictions, but the need for robust methods to evaluate and integrate them into a single, consistent forecast that improves accuracy while mitigating individual model weaknesses. Currently, MISO adjusts day-ahead load forecasts based on risk assessments especially during extreme weather-driven operating events. This research introduces a novel LSTM–Attention Fusion Network with Error Representation (LAF-Net), which is designed to learn from the historical data and events in a more nuanced way. Instead of treating all vendor forecasts equally, the model builds a kind of "memory" of historical errors, learning when and where each vendor tends to be more or less accurate. When forecasting future demand, it dynamically consults this memory, assigning hour-by-hour trust levels to each vendor. It then fine-tunes the combined prediction by correcting recurring patterns of error, especially those that appear at specific times. Tested on MISO's historical day-ahead load forecast data over a limited time period, the model consistency outperformed the most accurate individual vendor forecast. The LAF-Net model improvements were notable, with reductions in overall error (average Mean Absolute Error reduction of 14%) and system-level peak-hour error (reduction exceeding 40%) when accuracy is needed most. MISO will continue assessing the model in the coming months to analyze its performance under a variety of weather conditions. Additionally, we intend to highlight findings from MISO's work examining challenges managing non-conforming and large loads.

MODELING GAS SUPPLY LIMITATIONS IN ISO NEW ENGLAND'S CAPACITY MARKET

Dr. Dane Andrew Schiro, ISO New England, (*Holyoke, MA*)
Dr. Feng Zhao, ISO New England, (*Holyoke, MA*)
Dr. Zeky Murra Anton, ISO New England, (*Holyoke, MA*)

In the winter, gas generator output in New England may be limited by natural gas availability and deliverability. As part of ISO New England's Capacity Auction Reforms project, a gas capacity demand curve that reflects the incremental reliability impact of gas capacity relative to non-gas capacity has been proposed. This presentation discusses the demand curve's conceptual framework, input assumptions, and calculation. The gas

capacity demand curve calculated as part of the Capacity Auction Reforms Impact Analysis will also be provided.

SPP'S CONSOLIDATED PLANNING PROCESS (CPP)

Sunny Raheem, Southwest Power Pool, (*Little Rock, AR*)

In March 2026, FERC approved SPP's Consolidated Planning Process (CPP), a landmark initiative by Southwest Power Pool (SPP) to revolutionize its generator interconnection (GI) and long-term planning processes. SPP anticipates the CPP will reduce administrative overhead and optimize future transmission planning portfolios, yielding hundreds of millions of dollars in savings. Before the CPP, SPP handled GI requests and its annual Integrated Transmission Plan (ITP) separately. The CPP introduces a streamlined approach to transmission planning that forecasts overall needs and takes all grid requirements into account. It will provide more certainty to investors in planning their budgets and a revamped funding structure to meet multiple needs. SPP will open its first CPP window in April 2026 and publish the first Generalized Rate for Interconnection Development-Contribution (GRID-C) this fall: a new, standardized rate for system upgrade contributions that gives developers far greater upfront cost certainty before they commit to interconnection. Transitional work will bridge the gap between the current ITP/GI and CPP frameworks. This presentation will describe the history, processes, and software behind the CPP.

12:20 PM – 1:35 PM: Lunch Break

1:35 PM – 3:35 PM: Session 3- Grid Planning

Session Overview: This session focuses on software for optimization of existing generators and transmission infrastructure to improve reliability, via improved modeling, more efficient valuation and thus deployment of reserves, and rapid deployment of resources near load via distributed energy resources (DERs).

Presentations

AI FOR GRID OPERATIONS AND ELECTRICITY MARKETS: ACCELERATING INTERCONNECTION STUDIES, ENHANCING MARKET CLEARING ENGINE, AND UNCERTAINTY-AWARE DECISION SUPPORT

Dr. Xian Guo, GE Vernova Advanced Research, (*Niskayuna, NY*)
Dr. Reetam Sen Biswas, GE Vernova Advanced Research, Lead Engineer, (*Niskayuna, NY*)

The electric power sector is entering a period of unprecedented operational complexity driven by rapid load growth, increasing penetration of variable renewable generation, expansion of DERs, growth of data centers, and greater exposure to extreme weather. These trends are stressing both transmission-level market operations and distribution-level interconnection processes, while exposing the limitations from deterministic planning and manually intensive software workflows. However, utilities and ISO/RTOs are required to improve affordability, accelerate infrastructure decisions, and maintain reliability across both bulk power and distribution systems. This presentation brings together three complementary GE Vernova R&D efforts that address these challenges through advanced software with leveraging AI/ML algorithms and advanced optimization techniques. (1) Accelerating Interconnection Studies: The team developed Customized Applications (Base-case Manager, Network Model Updater, Simulation Orchestrator, ML based scenario pruning app) integrated with GE Vernova's GridOS distributed energy resource management systems (DERMS) product to enable a fully automated load interconnection study. These new Applications were developed and tested with real customer data. This project validates the effectiveness of ML pruning application, demonstrates the automated end-to-end load interconnection assessment process and enables faster bridging solution analysis with full AC optimal power flow by at least 3x. By bridging the planning needs with operation tools through automation, simulation, and ML-driven prioritization, this POC establishes a scalable, efficient, and technically robust framework for modernizing load interconnection assessments—critical for grid reliability and scalability in the clean energy transition. (2) Enhancing Market Clearing Engine: As the core of market clearing engine, security constrained unit commitment (SCUC) problems must be solved repeatedly and under tight operational timelines, reducing non-binding constraints can significantly improve electricity market software performance. This work formulates SCUC as a supervised multi-label learning problem using thousands of solved optimization instances and explores approaches including classification, label-space clustering, synthetic minority oversampling technique (SMOTE) based oversampling and regression models. Results show meaningful optimization speedups, with a maximum reduction in solving time of up to 87%. (3) Uncertainty-Aware Decision Support: The team proposes a vision to improve the real-time and day-ahead decision making under variability through an uncertainty-aware market optimization framework. It studies stochastic look-ahead unit commitment (UC) as a two-stage problem in which slower generators are committed in the first stage, while

the fast start generators were used as flexible variables whose final commitment and schedules could be determined during real-time commitment stage when the true forecast is realized. The approach helps the system operators to better interpret results and translate them into controllable actions. Compared with deterministic UC on a test system, the stochastic approach required less reserve procurement and lower ancillary service cost by explicitly recognizing operational flexibility, while also improving reliability in low-probability, high-impact scenarios. Together, these efforts define a coherent software vision for the future power system to automate complex interconnection workflows, use AI/ML to reduce optimization burden, and incorporate uncertainty directly into operational decision-making. It validates that leveraging AI/ML and advanced optimization algorithms can help power system software achieve greater speed, reliability, affordability, and interpretability.

FLEXIBLE INTERCONNECTION STUDIES POWERED BY SAINT

Dr. Carlo Branucci, encoord, (*Edgewater, CO*)
Dr. Wallace Kenyon, encoord, (*Edgewater, CO*)

Data center developers are flooding interconnection queues with requests to connect new large loads on the order of hundreds to thousands of MWs. In most cases, the transmission network has limited capacity to accommodate these loads under traditional firm interconnection agreements without costly and lengthy transmission upgrades. Speed to power is a priority for many developers, and many are willing to pursue flexible interconnection arrangements by committing to reduce grid consumption during system stress events in exchange for faster timelines to connect. One of the key challenges to making flexible interconnections a reality is the ability to define expected flexibility requirements for large loads, so that developers and utilities can agree on the conditions under which the load will be required to reduce grid consumption. Utilities can assess how much new load can be interconnected in different parts of the network without requiring upgrades, and they can also define the upgrades, along with associated timelines and costs, needed to serve additional demand. However, traditional firm interconnection studies, which rely on a limited set of planning cases representing system operation at a few snapshots in time, are not well suited to determining how much new demand can be flexibly connected at a specific location, or what the expected flexibility requirements will be throughout the year. encoord's integrated planning software, SAInt, was developed to address planning problems that require iteration between economics-driven production cost modeling, reliability-driven power flow simulations, and contingency analysis. SAInt is designed to perform flexible interconnection studies and quantify the expected flexibility requirements for new large loads interconnected under a

flexible interconnection agreement. These agreements may include a defined firm interconnection capacity. Above this firm level, the load is expected to reduce electricity consumption from the grid during periods when operating at full capacity would violate network voltage or thermal limits. SAInt enables utilities to perform individual flexible interconnection studies in days or weeks, and its Application Programming Interface (API) enables SAInt to serve as the core modeling platform for a repeatable and automated flexible interconnection study process.

BEYOND BLACK BOXES: AI AGENTS THAT PROGRAM THE TOOLS OF GRID PLANNING

Dr. Wei Gao, Argonne National Laboratory, (*Lemont, IL*)
Dr. Alinson S. Xavier, Argonne National Laboratory, (*Lemont, IL*)
Dr. Feng Qiu, Group Leader, Argonne National Laboratory, (*Lemont, IL*)

The U.S. power grid is undergoing rapid transformation, with interconnection queues exceeding 2,300 GW, surging load from AI-driven data centers, and FERC Order 1920 mandating broader scenario coverage. Yet the analytical processes guiding planning decisions have remained largely unchanged. ISOs continue to rely on fragmented, labor-intensive workflows in which engineers manually construct scenarios, write ad hoc scripts, and adapt rigid tools to each new study. When planning tools cannot be easily customized, critical analyses go unstudied, beneficial investments go unidentified, and engineering time becomes the binding constraint on planning quality. A key bottleneck lies in how planners interact with analytical software: today's tools are treated as black boxes, accessible only through fixed interfaces that cannot be modified without vendor involvement. This talk presents an AI agent that breaks this constraint by treating planning tools as programmable substrates. The agent accepts planning questions in natural language and responds by autonomously generating, validating, and executing code through each tool's native programming interface. Rather than relying on a fixed set of predefined operations, the agent is equipped with a library of pluggable skills, modular and reusable code-generation capabilities covering scenario construction, model configuration, post-processing, and result synthesis, that can be extended without modifying the agent core. We demonstrate the approach using UnitCommitment.jl, Argonne's open-source production cost modeling framework, and PowerSAS, Argonne's security assessment solver. The agent translates analyst-specified questions into executable Julia and Python code, constructs study inputs, invokes solvers, and returns structured, interpretable outputs with built-in validation checks, all without manual scripting. The agent is designed as a composable building block within the broader AI-

orchestrated planning platform, offering ISOs a practical and extensible pathway toward more flexible, scalable, and transparent grid planning.

QUEST GRID PLANNING TOOLBOX: OPEN-SOURCE GRID PLANNING TOOLS FOR IMPROVED POWER SYSTEM PLANNING AND OPERATIONS

Dr. Cody Newlun, Sandia National Laboratories, (*Omaha, NE*)
Dr. Atri Bera, Sandia National Laboratories, (*Albuquerque, NM*)
Dr. Dilip Pandit, Sandia National Laboratories, (*Albuquerque, NM*)
Dr. Tu Nguyen, Sandia National Laboratories, (*Albuquerque, NM*)
Dr. Raymond Byrne, Sandia National Laboratories, (*Albuquerque, NM*)

Rapid load growth, evolving reliability risks, and increasing deployment of energy storage systems (ESS) are transforming traditional planning and operational studies of the U.S. bulk power system. Grid planners and operators require robust software solutions to make economic, reliable, and efficient decisions across long-term planning and near-term operations. This presentation will discuss the QuESt Grid Planning Toolbox, an open-source suite of complementary power-system planning tools developed by Sandia National Laboratories to support open-source availability that enables users to extend models, connect datasets, and leverage the toolbox into existing grid planning processes and research efforts. The presentation will highlight three core capabilities and how they can coordinate with one another: 1) QuESt Planning – a long-term capacity expansion planning framework for optimizing generation, transmission, and ESS investments under uncertainty and policy or technology constraints; 2) Probabilistic Grid Reliability Analysis with Energy Storage Systems (ProGRESS) – an open-source tool for assessing the resource adequacy of the evolving electric power grid integrated with ESSs; and 3) QuESt PCM – a power system production cost modeling tool designed for high-fidelity representation of ESS and generation to quantify operational costs and feasibility. A central theme will be coordinating these tools, which are Python-based, to create an end-to-end workflow that explores investment options with capacity expansion, validates reliability with resource adequacy metrics, and tests operational performance with production cost modeling. The presentation will also focus on ESS modeling considerations across timescales, including representation of duration, state-of-charge constraints, and reliability contribution of several ESS technologies. Lastly, a discussion on the impacts of rapid load growth (e.g. due to datacenters) on grid planning models will be provided. SNL is managed and operated by NTESS under DOE NNSA contract DE-NA0003525. SAND2026-18598A.

3:35 PM – 3:50PM: Break

3:50 PM – 5:20 PM: Session 4 - Optimizing Existing Assets for Reliability

Session Overview: This session focuses on software for optimization of existing generators and transmission infrastructure to improve reliability, via improved modeling, more efficient valuation and thus deployment of reserves, and rapid deployment of resources near load via distributed energy resources (DERs).

Presentations

MODERNIZING RESOURCE ADEQUACY FOR AN ENERGY-CONSTRAINED GRID

Jonathan Surls, Energy Exemplar, (*Salt Lake City*, *UT*)

For decades, resource adequacy planning has focused on meeting peak demand using metrics like loss of load expectation (LOLE). But as the grid evolves, this approach increasingly fails to capture not only emerging reliability risks, but also the true cost of maintaining reliability. With growing shares of renewables, storage, and distributed resources, system risks are now driven by prolonged renewable droughts, steep net load ramps, and sub-hourly flexibility needs. Traditional adequacy frameworks often miss these dynamics—leading to inefficient investment and higher costs for consumers. This presentation explores how modern modeling approaches—such as chronological simulation, expanded adequacy metrics, and event-based stress testing—provide a more complete view of both reliability and affordability. Through practical examples, using PLEXOS, we demonstrate how incorporating energy adequacy and flexibility requirements enables more accurate planning, avoids over- or under-procurement, and leads to more cost-effective, resilient systems.

LOCATIONAL MARGINAL PRICING OF DYNAMIC RESERVES – A NYISO (THE NEW YORK INDEPENDENT SYSTEM OPERATOR) CASE STUDY

Dr. Edward Lo, Hitachi Energy, (*Menlo Park, CA*)
Matthew Musto, Raptrix Power, (*Rensselaer, NY*)
Kanchan Upadhyay, New York ISO, (*Rensselaer, NY*)
Dr. Sushant Varghese, New York ISO, (*Rensselaer, NY*)
Dr. Kush Khanna, Hitachi Energy, (*Santa Clara, CA*)

This presentation reports on the locational marginal pricing of the Security Constrained Unit Commitment and Economic Dispatch (SCUC/ED) under the Dynamic Reserves Framework. Dynamic Reserves enable efficient scheduling of operating reserves based on system conditions and transmission system capacity. Optimization formulation models NYCA (NYISO Control Area)-wide reserve requirements and locational shift-factor based requirements that resolve the secured facility flow limit violation following generator/line outages. The expressions of locational prices of reserves have been presented in the FERC Conference in 2024. In this presentation, locational price of load is derived and its implications for the cost allocation to loads for the reserve are examined. Two key findings are: 1) largest generator contingency and its impact on reserve requirements and 2) the locational price of load as a combination of energy and reserve as the increase in the consumption of load increases energy production and increases reserve requirements both from global and locational perspectives. In the current ISO market model, the costs of reserves allocated to loads are socialized within reserve regions. Under dynamic reserves, the cost of reserves is embedded within the locational based overall cost of energy and reserves. The explanation of how the ISO is revenue-neutral under the dynamic reserve framework is covered.

AI-ENABLED SCALABLE INTEGRATION OF DER AGGREGATORS IN WHOLESALE ELECTRICITY MARKETS

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The rapid growth of distributed energy resources (DERs), including rooftop solar, behind-the-meter storage, and flexible demand, is transforming the structure of electricity systems by enabling large populations of prosumers to participate in wholesale markets through aggregators. Policy initiatives such as FERC Order 2222 enable this participation, but they also introduce new operational and planning challenges for market operators. When DER aggregators participate simultaneously, their collective charging, discharging, and demand-shifting decisions can materially influence wholesale electricity prices. This creates a closed feedback loop between aggregator actions and price formation, fundamentally changing the dynamics of electricity markets and raising important questions for market software, operational tools, and planning models. This work presents a scalable computational framework for fully decentralized, learning-based, price-driven DER aggregators participating in wholesale electricity markets. The framework models aggregators as learning agents that optimize charging and discharging policies for energy storage across large populations of prosumers under uncertainty in

renewable generation, electricity demand, and market prices. A key modeling idea is to treat locational marginal prices (LMPs), as a system wide signal that summarizes the aggregate effects of supply, demand, and transmission constraints. Aggregators update their operational policies using reinforcement learning while responding to evolving price signals produced by market clearing. The resulting framework captures the feedback between decentralized aggregator decisions and system level market outcomes. The proposed framework also provides insights relevant for market design and market software. In particular, stable operation of decentralized learning agents requires consistent expectations about future price signals. Aggregators must maintain evolving beliefs or forecasts of LMP trajectories when learning operational policies, and convergence of decentralized learning depends on these price beliefs stabilizing over time. This observation suggests that market platforms or system operators may play an important role in providing reliable price forecasting infrastructure, standardized price signal updates, or other software tools that facilitate convergence of decentralized decision making. Without such coordination mechanisms, large-scale DER participation could amplify price volatility or produce unstable learning dynamics. Numerical experiments on a synthetic representation of the Oahu power system illustrate the system-level impacts of large-scale DER aggregation under the proposed framework. The results show that coordinated storage control learned through the framework can substantially reduce LMP volatility, smooth net demand profiles, and lower total system costs. In particular, aggregators learn to shift charging toward periods of abundant renewable generation and reduce demand during peak periods, mitigating the “duck curve” phenomenon and improving operational efficiency. Comparisons with alternative decentralized control approaches highlight the importance of incorporating market feedback and scalable learning mechanisms when designing software systems for coordinating large populations of DERs.