South Carolina EMRM Advisory Board/Brattle Meeting #3

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PRESENTED FOR

South Carolina EMRM Advisory Board

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Brattle

Agenda

1 Modeling Approach

2 Benefit and Cost Metrics

3 Next Steps with Advisory Board

Overview of Modeling Approach

To assess operational benefits of market reforms, we propose to run a production cost simulation of the Southeast under different market structures and compare outcomes of the simulations

Our modeling team employs an advanced production cost simulation model called Power System Optimizer (PSO) to simulate the power systems in the U.S.

- Brattle licenses PSO from the developer, Enelytix, and we maintain a deep relationship with them, advising on the development of new features
- Nodal production cost model; it will represent each load bus and generator bus in the Southeast
- Can we calibrated to fully capture day-ahead forecasting uncertainty for load and renewable resources
- Granular operating reserve and ancillary service product definition
- As part of our licensing, Enelytix will provide a pre-populated model of the Southeast region
- We updated modeling assumptions to reflect the most recent resource plans for several WMEG members and CA; and updated other assumptions with recent forecasts of system conditions and costs

Uniquely suited to simulate bilateral trading, joint dispatch, imbalance markets, and RTOs

Study Framework and Benefits and Costs Calculation

Model of Southeast Developed with Input of Advisory Board

Model Improvements:

- Latest Resource Plans for Southeast Utilities
- Updated Fuel Price Forecasts
- Wind and Solar Day-Ahead Forecast Error
- Updates to the Transmission Topology
- Reflect Important Transmission Constraint
- Operational Features of Generation
- Market Characteristics (e.g., SEEM, Bilateral)

Power Systems Optimizer (PSO) Simulation of Southeast

Status Quo Case

Market Reform Case

Operational Benefits or Costs of Market Reform

Additional Potential Benefit Metrics Calculated Outside PSO:

- Reduced planning reserve margin due to market participation
- Wheeling revenues (could be a cost) due to market participation

Other Benefits or of Market Reform

Costs and Risks of Market Reform Assessed Outside of PSO

Costs and Risks of Market Reform

Multi-Functional Simulation of the Power System

Markets/RTO Functions & Configurations

State and Federal Energy Policies

Operating Reserve Sharing Groups

Balancing Area Authority Functions

Bilateral Contract Paths and Transmission Rights

Physical Transmission Flows and Constraints

PSO employs multi-layer simulations to represent the various physical, policy, and operational facets of the power system

- Physical transmission grid with all buses, lines, and generators in the Southeast represented
- All balancing areas (BAAs) represented in the model
- Representation of reserve sharing groups that reduce OR requirements in the Status Quo (and reserve sharing in RTO markets)
- Modeling of state and federal clean energy policies
- Bilateral trading relationships, transfer limits between utilities, and transmission rights
- Renewable diversity, day-ahead forecast uncertainty, real-time operations

Independent Simulation of Multiple Time Horizons

PSO simulates multiple independent decision cycles to capture day-ahead vs. real-time unit commitment and dispatch

D-1 (am)

DA Unit Commitment

- Unit commitment decisions (utility-specific or RTO market)
- DA trades on long-term or incremental transmission rights

D-1 (~noon)

DA Economic Dispatch

- Economic dispatch decisions (utility-specific or RTO market)
- Bilateral trading with long-term or incremental transmission rights

D

EIM (RT Balancing)

- BAA balancing (Status Quo and RTO)
- Economic trades, bilateral, SEEM, JDA, EIM, or RTO
- In SEEM, JDA, and EIM remaining transmission rights freed for trading

Unit Commitment Cycle → **Economic Dispatch Cycle** → **Real Time Cycle**

Day-ahead decision cycles capture bilateral trading, market clearing, and BAA functions

Independent real-time decision cycle necessary to accurately simulate RT markets (e.g., SEEM, JDA, EIM).

Used to simulate DA vs. RT, including forecast error for wind and solar.

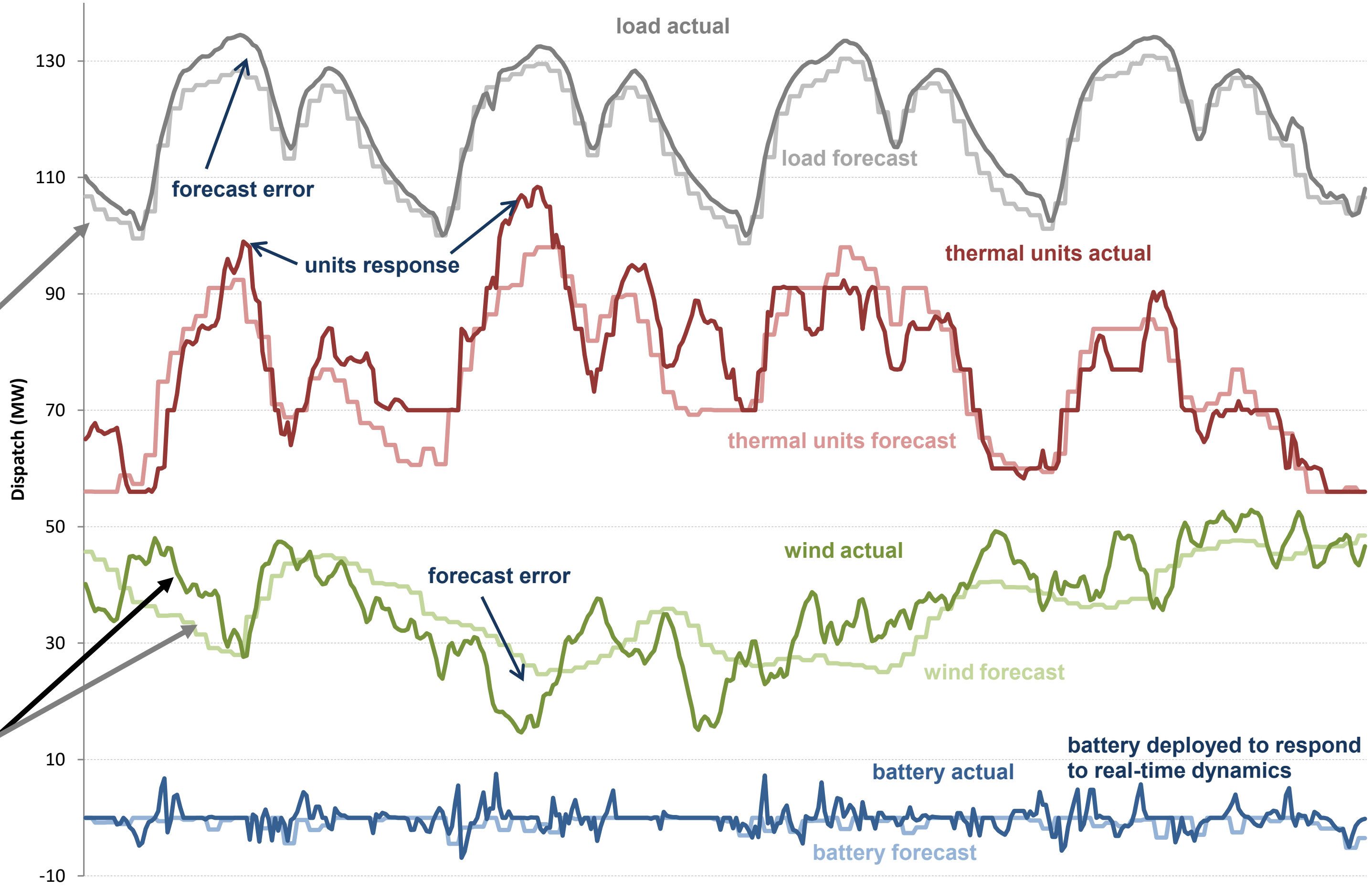
Forecast Uncertainty can be a Major Driver of Production Costs

Our study starts with the conventional "Perfect Foresight" study approach by simulating multiple scheduling horizons with day-ahead load and renewable generation forecasts

A "Perfect Foresight" simulation typically focuses on just one view, often the day-ahead

We additionally simulate the need to respond to uncertainty and intra-hour variance in real-time with a more limited set of resources, considering both scheduling and actual operations

Illustrative 4-Day Operations Simulation Summary



Dark lines are real-time "actual" outcomes

Light lines are day-ahead scheduling outcomes, based on forecasted conditions

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Potential Key Metrics to Assess Benefits and Costs

Operational or Investment Metrics may indicate an <u>increase</u> in costs for the footprint, or for certain utilities within the footprint

Key Result Metric: Adjusted Production Cost

Adjusted Production Cost (APC) is a standard metric used to capture the direct variable energy-related costs from a customer impact perspective

The APC is the sum of production costs and purchased power less off-system sales revenue:

(+) Production costs (fuel, startup, variable O&M, emissions costs) for generation owned or contracted by the load-serving entities

(+) Cost of bilateral and market purchases valued at the BAA load-weighted energy price

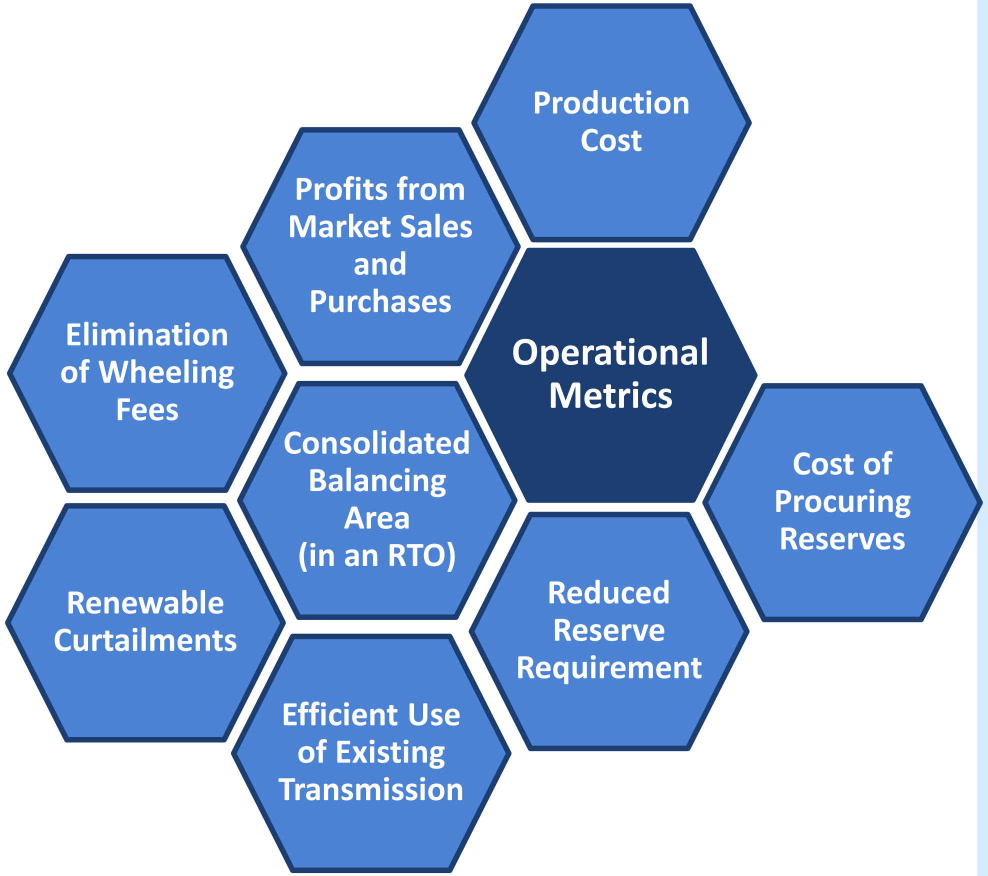
(−) Revenues from bilateral and market sales valued at the BAA generation-weighted energy price

Typically, production cost simulation produce conservative estimates of APC savings, due to the use of weather-normalized loads, absence of extreme system events, and transmission outages

The APC is calculated for the Status Quo Case and for the Market Reform Cases (each representing a new market structure) to determine the APC savings due to market reform

- The APC metric does not capture benefits (or costs) associated with changes in wheeling revenues, or other benefits or costs (see next slides)

Key Performance Metrics



The Adjusted Production Cost metric captures most of the operational benefits

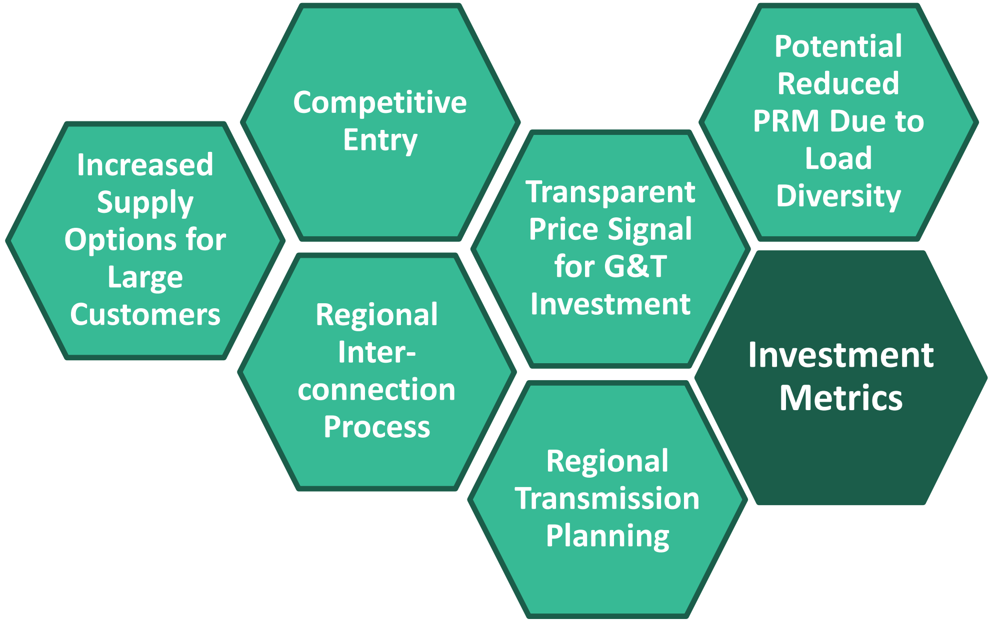
- Others can be calculated separately using the model results. For example, changes in wheeling revenues due to market formation, which could be a net loss
- We expect operational benefits to be larger as you move to more integrated market structures (SEEM -> JDA -> EIM -> RTO)
- We expect operational benefits to be larger as you move to a larger geographic footprint
- Individual utilities may see costs increases in a market structure, even if the footprint benefits
- We hope to get input from the Advisory Board on other operational benefits it thinks should be assessed, or different approaches for estimating benefits

Key Performance Metrics

We expect investment benefits to be limited in less-integrated market types (e.g., SEEM, JDA, EIM)

- Production cost simulations (like PSO) will not capture any investment benefits or costs
- The tools available for quantifying investment benefits or costs are imprecise, and quantifying specific values is challenging
- Therefore, we are not proposing to quantify investment benefits or costs; we will assess the experience in the existing regional markets

We are not proposing to model generation divestiture, but would plan to discuss the potential benefits, costs, and risk in the study and highlight experience from other jurisdictions

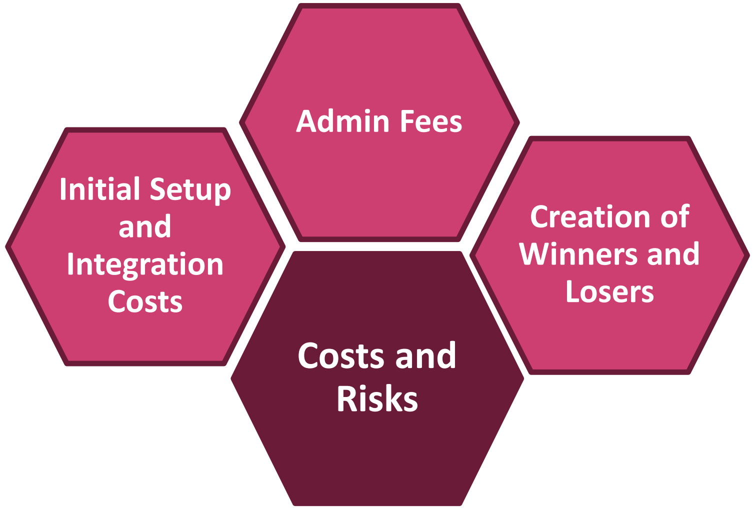


Key Performance Metrics

Several cost metrics can be assessed from experience in other jurisdictions, such as administrative fees and integration costs

- We can use the results of our production cost simulations to check if any utilities experience an increase in APC or other increases in operational costs
- Other costs and risks can be assessed qualitatively from experience in other markets
- We welcome input on additional costs/risks to assess

We are not proposing to analyze generation divestiture, therefore potential costs or risks associated with divestiture are not analyzed (same with retail choice)



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Gathering Input from Advisory Board Members

The model we would start with, licensed from our vender, would come populated with data on generation resources, fuel prices, transmission topology, and hourly load profiles; we will ask the relevant Advisory Board members to review, update, and provide data on the following topics:

- Operational characteristics of gen units (e.g., min gen, ramp rates, heat curves, VOM, startup/emissions costs, etc.)
- Joint ownership of resources
- Hourly load profiles and forecasts
- Location of load by each bus
- Transfer capabilities with neighboring utilities
- Important transmission constraints not included in the model
- Production profiles for renewables and hydro resources
- Day-ahead forecast error to renewable resources and load
- Operational characteristics of the transmission system (e.g., historical flows, TTC, constraints, etc.)
- Forecasted fuel costs
- Information on bilateral trading/power marketing

Next Steps with Advisory Board Members

- We have circulated a multi-party NDA to put in place with Duke, Dominion, Santee Cooper, Central, the municipal utility reps, and the renewable developers.
- There are also some key study questions we would like to begin discussing with the Advisory Board members, which would require conversations with in-house experts on the market rules and potentially in-house modeling teams
  - How best to represent the SEEM market in our Status Quo Case?
  - How best to represent the differences between SEEM, JDA, and EIM?