Transmission Planning Policy For The Future

October 30, 2018, 11:00 am – 12:15 pm

Moderator:
James Bixby, Counsel – Regulatory & Legislative, ITC Holdings Corp.

Speakers:
Justin M. Campbell, Senior Vice President, Chief Development Officer, GridLiance
Larry Gasteiger, Chief, Federal Regulatory Policy, PSEG
Paul Dumais, Chief Executive Officer, Dumais Consulting
Aileen Roder, Attorney Advisor, Federal Energy Regulatory Commission
Transmission Planning Policy for the Future

- FINANCIAL CONSIDERATIONS

- PAUL DUMAIS, CEO DUMAIS CONSULTING -
  DUMAISCONSULTING@OUTLOOK.COM AND 410-703-4517
Keys to Successful Transmission Planning and Project Development

- Clear and Fair Planning Process
- Robust Financial Remuneration
- Clear Distinctions Between RTO and FERC Roles
RTO and FERC Roles

**RTO**
- Determines transmission need
- Conducts solicitation
- Selects most efficient and cost effective project

**FERC - Economic Regulator**
- Just and reasonable rates
- Revenue requirements
- ROE
- Project incentives
- Cost containment
Financial Remuneration

- Fair Base ROE
- Certainty
- Hope and Bluefield
- Transmission Incentives that Address Challenges
- Successful Transmission Project Development
Base Return on Equity

1. *Hope* and *Bluefield*

2. Not one prescriptive approach but use several methodologies and exercise judgement to determine point ROE

3. Should be greater than that provided distribution investments

4. Complete complaint cases within 15 months of filing – need threshold for current rate to be unjust and unreasonable
Project Incentives – Commissioner Glick

1. Conduct Comprehensive Review

1. Ensure any transmission-related reforms work in tandem

Ensure furthering goals of Energy Policy Act of 2005

1. Incentives must “actually incentivize” investment

1. Consistent with Order No. 1000

Consider non-transmission alternatives

Gridliance Order dated July 24, 2018 in EL18-1693
Project Planning and Incentives Reforms

1. ROE incentives cost customers little while providing significant benefits to TOs

Consider technology incentives – dynamic line ratings, etc.

1. Explicitly consider non-transmission alternatives in RTO planning processes

1. Make RTO adder conditioned solely on being part of RTO

Improve interregional planning
Dumais Consulting provides FERC-focused regulatory economic consulting services to electric utilities doing business in the United States.

- Policy analysis and advice
- Transmission, reactive power and other revenue requirements
- Expert witness testimony and settlement support
- Innovative rate mechanisms including cost cap approaches
- Compliance with FERC orders and rules
- FERC accounting and reporting items

www.DumaisConsulting.com
Transmission Planning Policy for the Future

Energy Bar Association
Mid-Year Energy Forum

Larry Gasteiger
PSEG

October 30, 2018
About PSEG

114 year old company; largest electric and gas distribution and transmission utility (2.2 million electric customers; 1.8 million gas customers) in New Jersey

- Received the prestigious ReliabilityOne Award for the Mid-Atlantic region for 16 years in a row; named to Dow Jones Sustainability Index for past 10 years

- Franchised public utility with a state law obligation to serve; system reliability is our paramount concern

- Transmission Owner in PJM

- Among the first utilities to develop electricity transmission lines linking consumers to energy markets across states and regions; transmission assets date back to 1920s.
The Challenges Associated With Transmission Build
Extreme Weather Is Increasingly A Factor

Customers (And Policymakers) Expect Reliable Service

Power outage
Sorry for the inconvenience
it could be worse, there could be zombies.
Order No. 1000: A Well-Intentioned, Bad Idea?
Goals Of Order 1000

• Promote efficient and cost-effective transmission planning

• Remove barriers to development of transmission facilities

• Promote/Increase regional transmission planning processes

• Support state/federal “public policy requirements”, i.e., support renewables
How’s Order No. 1000 Doin’?
• No region in the U.S. that is outside of an organized RTO/ISO market has opened up a single competitive transmission bidding opportunity post-Order 1000.

• ISO-New England has not opened a single competitive solicitation.

• The Southwest Power Pool spent $5 million on a competitive process for an $8 million project that was deemed unneeded and never built.

• The California ISO has not opened a competitive solicitation since 2016. Moreover, in 2015, the California ISO awarded a competitive project to a partnership between a foreign developer and another entity, and the developer subsequently went bankrupt.

• 2016 FERC staff report finds it “difficult to assess” sufficiency of investment in infrastructure and whether investments are more efficient or cost-effective.
“{F]or all its good intentions, [Order 1000] is today a rule that has largely fallen short of accomplishing its goals. Unfortunately, the failure of it to fulfill its potential has not come without costs. ... [N]ow is a good time for the Commission to consider an Order No. 1000 reassessment.”

– Former FERC Commissioner Tony Clark

“[Order 1000] was almost like a solution in search of a problem. ... It’s actually creating more challenges to investment.”

- PJM CEO Andy Ott

“It [Order 1000] created more overhead and more uncertainty at a time when we didn’t need more overhead in order to invest in transmission. ... I’m thankful that we completed the vast majority of our transmission buildout in a pre-Order 1000 environment.”

- SPP CEO Nick Brown
What Has Order No. 1000 Accomplished?

• Political discord among the states

• Confusion as to the process among transmission planners, potential transmission investors, and grid operators

• Added costs and wasted dollars by all involved

• Delay

• Band-aids v. robust reliability planning/solutions
Does Everyone Really Need (Or Want) A Yugo?
Order No. 1000: Time To Reassess

- Two years since FERC held a technical conference to re-examine Order No. 1000 with no further formal action taken

- Congress has held hearings and is calling on FERC to reconsider Order No. 1000

- How does (or doesn’t) Order No. 1000 sync with FERC’s Resilience Initiative?

- Record shows that the problems with the rule are beyond mere growing pains; time to re-consider fundamental aspects of the rule.
Transmission Planning Policy For The Future
Justin Campbell, Chief Development Officer
Energy Bar Association Mid-Year Conference
October 30, 2018
Background on GridLiance

GridLiance is an independent transmission company. We partner with electric cooperatives, municipal utilities, and others to plan for the future of the grid, invest in transmission infrastructure, and improve grid reliability.

What We Do

- Unlock the financial value of existing transmission assets and invest in transmission projects with our partners
- Own and operate nearly 600 miles of transmission lines and related substation equipment
- Build strong business relationships with long-term agreements based on each partner’s needs

Who We Are

- Led by an experienced executive team
- Backed by Blackstone Energy Partners, L.P., a leading energy infrastructure investor, that provides strategic and financial support
- Guided by independent board members who are industry leaders and include Terry Boston (former CEO, Tennessee Valley Authority and PJM Interconnection) and Mike Morris (former CEO, American Electric Power)

Current Partners

- Valley Electric Association, Inc.
- PEC
- TCEC
- NIXA Utilities
- Kansas Power Pool
- MJMEUC
- OMPA
- Oklahoma Municipal Power Authority
One of the most important objectives of our industry is to provide affordable electricity to customers.

Transmission investment is putting upward pressure on customer rates:

- Investment has increased to ~$18 billion in 2017 from ~$2 billion in 1999.
- On average, transmission costs were ~10% of residential retail rates in 2017; this is up from ~6% in 2006.

Managing the cost of transmission is fundamental to keeping electricity affordable.

To achieve affordability, competition in transmission can reduce upward pressure on customer rates.
How did we get here?

- FERC Order No. 1000 (July 2011) opened the door for competition
  - **Regional Participation**: Every transmission owner must join a regional planning group and each region must implement competition for regionally planned/cost-shared projects
  - **Right of First Refusal**: FERC-approved tariffs cannot have a federal right of first refusal
  - **Cost Allocation**: Regional process must have a regional cost allocation methodology
- However, since then few projects have been sourced using competitive processes

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<tbody>
<tr>
<td><strong>FERC Orders and Compliance Filings</strong></td>
<td>Orders 1000, 1000-A, and 1000-B</td>
<td>CAISO Compliance Filings</td>
<td>MISO Compliance Filings</td>
<td>SPP Compliance Filings</td>
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Since January 2016, there has been only 1 competitive project in CAISO, MISO and SPP

= RFP issuance for a transmission project; the one project in SPP was ultimately canceled
Are there benefits when competition is used?

- **Demonstrable savings from lower capital costs**: On average, winning bids have been approximately 10% - 60% below initial planning cost estimates or lowest-cost incumbent bids.

- **Risk reduction for customers**: Winning bids normally include binding cost caps or cost-control measures, with limited exclusions; this shifts the risk of cost increases to developers from utility customers.

- **Creativity**: In regions with “solution-based” processes (e.g., PJM) competition can foster design innovations. In other markets, developers have been creative in the terms and conditions they offer to control cost to customers.

- **Demonstrable reliability**: Construction quality comparable to incumbents.

### Example Projects ($ in millions)

<table>
<thead>
<tr>
<th>Example Projects</th>
<th>Planning Estimate</th>
<th>Winning Bid</th>
<th>Estimated Savings(^{(1)})</th>
<th>Binding Cost Containment?</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAISO Delaney-Colorado River</td>
<td>$300</td>
<td>$280</td>
<td>7%</td>
<td>Yes</td>
</tr>
<tr>
<td>CAISO Estrella Substation</td>
<td>$35 - $45</td>
<td>$20</td>
<td>56%</td>
<td>Yes</td>
</tr>
<tr>
<td>CAISO Wheeler Ridge</td>
<td>$90 - $140</td>
<td>$60</td>
<td>57%</td>
<td>No</td>
</tr>
<tr>
<td>CAISO Suncrest</td>
<td>$50 - $75</td>
<td>$37</td>
<td>50%</td>
<td>Yes</td>
</tr>
<tr>
<td>CAISO Spring Substation</td>
<td>$35 - $45</td>
<td>$28</td>
<td>38%</td>
<td>No</td>
</tr>
<tr>
<td>SPP Walkemeyer-North Liberal</td>
<td>$17</td>
<td>$8</td>
<td>50%</td>
<td>No</td>
</tr>
<tr>
<td>MISO Duff-Coleman</td>
<td>$59</td>
<td>$50</td>
<td>15%</td>
<td>Yes</td>
</tr>
<tr>
<td>CAISO Harry Allen-Eldorado</td>
<td>$144</td>
<td>$133</td>
<td>8%</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Source: Brattle Group analysis of RTO annual transmission expansion reports and quarterly status reports, company filings, and FERC filings

\(^{(1)}\) Difference between winning bid and upper bound of planning estimates, if applicable

**When competition is used, customers face lower transmission costs and lower risk of cost overruns**
What is preventing competition?

- **Unnecessarily restrictive rules are limiting the scope of competition**
  - Categorical exclusions enumerated in Order 1000 (e.g., local cost allocation, upgrades, State ROFRs)
  - Whole categories of transmission are not subject to regional cost allocation and, therefore, subject to federal ROFRs (e.g., MISO Baseline Reliability Projects, PJM Supplemental Projects)
  - Minimum voltage thresholds (e.g., 300-kV in MISO)

![Bar chart showing project costs over years in MISO, CAISO, and SPP](chart)

**Since Order 1000, approx. 98% of investment is still made without competition**

Without reforms, customers will continue to pay much more than necessary and grid expansion will continue to be sub-optimal

Source: Annual RTO transmission expansion reports.
Getting the rules right at FERC

GridLiance recommends FERC take the following steps to ensure Order No. 1000 competitive processes fully achieve their potential benefits for customers

1. **Enhance Project Cost Transparency**
   - **Require RTO Cost Tracking/Reporting:** (1) tracking and disclosing costs for all projects included in RTO plans, (ii) comparing those costs to planning estimates, and (iii) distinguishing between competitively sourced and non-competitively sourced projects

2. **Broaden the Scope of Competition**
   - **Expand Eligibility Criteria:** Consider delinking the nexus between competition and regional cost allocation and adopting a universal minimum project threshold, or extending regional cost allocation to certain non-competitive projects in key RTOs
   - **Scrutinize Near-Term Projects:** Carve-outs for “immediate need reliability” projects should be narrowed and oversight should be increased

3. **Improve Competitive Processes**
   - **Strengthen Pre-Qualification:** Entry criteria should be strengthened and relied upon so that bidder qualifications are not part of project RFPs
   - **Streamline RFP Process:** Processes should (i) be shortened in most RTOs, (ii) focus on project cost and design (instead of bidder qualifications), and (iii) emphasize objective factors like cost and cost containment terms
Dear Chairman and Commissioners:

As you are aware, the role that electric transmission infrastructure plays in maintaining a reliable and resilient power grid cannot be understated. The thousands of miles of high-voltage transmission lines that deliver electricity across the country are an integral part of the bulk power system and influence everything from our quality of life to our national economy. However, the challenges associated with the planning and construction of new transmission lines, particularly between transmission planning regions, were brought to our attention during a recent hearing on May 8, 2018.

The Subcommittee on Energy is now examining the effect of existing federal laws and regulations on the development and planning of interstate transmission subject to FERC's jurisdiction. This review includes FERC's attempts to correct deficiencies with respect to transmission planning processes and cost allocation methods, culminating in the issuance of Order No. 1000 in 2011. However, in the nearly seven years that Order No. 1000 has been in effect, we have heard concerns from current and former FERC Commissioners, as well as stakeholders, that despite FERC's best intentions, its transmission reforms and the rule have not accomplished the Commission's primary goals.

During our May 8th hearing on transmission development we heard from a panel of expert witnesses expressing a range of concerns with Order No 1000. Former FERC Commissioner Tony Clark testified that the rule has created more bureaucracy than benefits and must undergo a rigorous evaluation. PSEG's CEO, Ralph Izzo, informed this Subcommittee that Order No. 1000 has been “chaotically” implemented from the start, has not resulted in the construction of any significant transmission projects, and he ultimately recommended that the
rule be repealed outright. Notably, not a single witness appearing before this Subcommittee testified that Order No. 1000 has succeeded in achieving the Commission's goals. To the contrary, they testified that the Order is failing to develop needed transmission infrastructure between regions, to promote competition between transmission developers, and to foster the deployment of non-transmission alternatives to new wires where cost effective. We would encourage you to review the public record developed by this Subcommittee.

Moreover, as recently as last October, FERC issued a staff report evaluating whether the key goals of Order No. 1000 are being met, and to inform whether additional transmission investment and development is needed in the United States. Your agency's report found that "It is difficult to assess whether the electric industry is investing in sufficient transmission infrastructure to meet the nation's needs and whether the investments made are more efficient or cost-effective." The findings of your staff are concerning and indicative that substantial changes to Order No. 1000 are necessary.

We understand that FERC is aware of these concerns, particularly with respect to the lack of competitive transmission development and the ongoing inability to develop new transmission lines between planning regions. We also note that it has been two years since FERC convened a technical conference (in June 2016 in Docket No. AD16-18) to review concerns regarding Order No. 1000. Since then, FERC has not taken any formal actions with respect to its reconsideration of Order No. 1000. We are, therefore, requesting that FERC now provide this Subcommittee with updates regarding its reconsideration of Order No. 1000's requirements.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

Bobby L. Rush
Ranking Member
Subcommittee on Energy

Pete Olson
Vice Chairman
Subcommittee on Energy
“Transmission Planning Policy For the Future”

Energy Bar Association – Mid-year Energy Forum

Theodore J. Paradise

ASSISTANT GENERAL COUNSEL, OPERATIONS AND PLANNING
KEY MESSAGES

• Transmission development varies by region, but has seen a significant build out in the 2000s in New England and other regions

• On top of a much expanded transmission system that has eliminated congestion and allowed energy markets to function, state policies and technology are eliminating (so far) overall load growth and changing the drivers of system reliability needs, e.g. low load voltage issues, distributed generation injections onto the transmission system

• Policy and technology are driving changes that blur the traditional wholesale / retail & federal / state split of the Federal Power Act and state regulators have a critical role with federal entities in not only ensuring reliability, but crafting what the hybrid grid will look like and what functionality it has

• It may be time to revisit the reliability criteria and the law / rules around power system planning to try and better accommodate the ever faster changes happening on the system that are unlikely to slow down while the energy bar and engineers thoughtfully ponder
THE STATE OF THINGS

The present state of transmission planning and how we got here
ISO New England (ISO) Has Two Decades of Experience Overseeing the Region’s Restructured Electric Power System

• Regulated a Regional Transmission Organization by the Federal Energy Regulatory Commission

• Reliability Coordinator and Planning Coordinator for New England under the North American Electric Reliability Corporation

• Independent of companies in the marketplace, ISO New England oversees the planning process for the New England region
Transmission Development Varies by Region

The millennial build out:

• During the 1980s and 1990s, transmission development was not significant in the New England region. Supply was located close to load and some transmission connected these areas, but certain generation was needed for the system to function.

• Starting in the early 2000s, significant system needs were identified under the ISO planning process and a period of system build out began
  – $10.6 billion invested since 2002, with another $1.7 planned, proposed, or under construction
  – Reduced significant congestion to minimal levels and allowed the energy market to work with fewer out-of-market security dispatches

• Some areas have had similar buildouts but other areas have favored resource development
  – MISO has made significant transmission investments
  – NYISO on the other hand has developed resources to address criteria requirements
Region Has Made Major Investments in Transmission Infrastructure to Ensure a Reliable Electric Grid

Annual Investment in Transmission to Maintain Reliability (in billions)

Cumulative Investment through March 2018: $10.6 billion
Estimated Future Investment through 2022: $1.7 billion

Source: ISO New England RSP Transmission Project Listing, June 2018
Estimated future investment includes projects under construction, planned and proposed.
New England’s Transmission Grid Is the Interstate Highway System for Electricity

- **9,000 miles** of high-voltage transmission lines (115 kV and above)
- **13 transmission interconnections** to power systems in New York and Eastern Canada
- **17%** of region’s energy needs met by imports in 2017
- **$10.6 billion** invested to strengthen transmission system reliability since 2002; **$1.7 billion** planned
- Developers have proposed multiple transmission projects to access **non-carbon-emitting resources** inside and outside the region
The Impact of the Investments

- The impact of the investments in transmission across the New England region has been significant in terms of the elimination of any significant congestion and the ability to deliver power around the system, a capability that has allowed the region to benefit from lower fuel prices (by far the largest component of any residential power bill).

- This build out has also set the stage for allowing greater distribution of resources around the system – not just large generators next to load centers.

- At the same time this has been going on, other investments have been made that have significantly impacted the composition of the power system and, therefore, transmission planning...
ISO New England Forecasts Strong Growth in Solar Photovoltaic (PV) Resources

December 2017 Solar PV Installed Capacity (MW\textsubscript{ac})

<table>
<thead>
<tr>
<th>State</th>
<th>Installed Capacity (MW\textsubscript{ac})</th>
<th>No. of Installations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connecticut</td>
<td>365.6</td>
<td>29,512</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>1,602.3</td>
<td>78,047</td>
</tr>
<tr>
<td>Maine</td>
<td>33.5</td>
<td>3,598</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>69.7</td>
<td>7,330</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>62.2</td>
<td>4,148</td>
</tr>
<tr>
<td>Vermont</td>
<td>257.2</td>
<td>9,773</td>
</tr>
<tr>
<td>New England</td>
<td>2,390.5</td>
<td>132,408</td>
</tr>
</tbody>
</table>

Cumulative Growth in Solar PV through 2027 (MW\textsubscript{ac})

- January 2010: 40 MW
- Thru 2017: 2,391 MW
- 2027: 5,833 MW

Note: The bar chart reflects the ISO’s projections for nameplate capacity from PV resources participating in the region’s wholesale electricity markets, as well as those connected “behind the meter.” Source: Final 2018 PV Forecast (March 2018); MW values are AC nameplate.
Renewable Energy Is on the Rise

State policy requirements are a major driver

State Renewable Portfolio Standard (RPS)*
for Class I or New Renewable Energy

Notes: State RPS requirements promote the development of renewable energy resources by requiring electricity providers (electric distribution companies and competitive suppliers) to serve a minimum percentage of their retail load using renewable energy. Connecticut’s Class I RPS requirement plateaus at 40% in 2030. Maine’s Class I RPS requirement plateaus at 10% in 2017 and expires in 2022 (but has been held constant in this chart for illustrative purposes). Massachusetts’ Class I RPS requirement increases by 2% each year between 2020 and 2030, reverting back to 1% each year thereafter, with no stated expiration date. New Hampshire’s percentages include the requirements for both Class I and Class II resources (Class II resources are new solar technologies beginning operation after January 1, 2006). New Hampshire’s Class I and Class II RPS requirements plateau at 15.7% in 2025. Rhode Island’s requirement for ‘new’ renewable energy plateaus at 36.5% in 2035. Vermont’s ‘total renewable energy’ requirement plateaus at 75% in 2032; it recognizes all forms of new and existing renewable energy and is unique in classifying large-scale hydropower as renewable.
Behind the Meter PV Map

Installed Behind-the-Meter Solar Power by Town
(Nameplate Capacity through December 31, 2017)

Source: ISO New England
Energy Efficiency Is a Priority for State Policymakers

2018 State Energy-Efficiency Scorecard

Ranking of state EE efforts by the American Council for an Energy-Efficient Economy:

- Massachusetts 1
- Rhode Island 3
- Vermont 4
- Connecticut 5
- Maine 14
- New Hampshire 21

• Billions spent over the past few years and more on the horizon
  - Nearly $4.9 billion invested from 2011 to 2016
  - ISO estimates $7.1 billion to be invested in EE from 2022 to 2027
Energy Efficiency and Behind-the-Meter Solar Are Reducing Peak Demand and Annual Energy Use

### Projected Summer Peak Demand (MW)
- With and Without EE and PV Savings
- Gross Peak
- Minus PV
- Minus PV, EE

### Projected Annual Energy Use (GWh)
- With and Without EE and PV Savings
- Gross Load
- Minus PV
- Minus PV, EE

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• 7.2 million retail electricity customers drive the demand for electricity in New England (14.8 million population)
  ➢ Region’s all-time summer peak demand: **28,130 MW** on August 2, 2006
  ➢ Region’s all-time winter peak demand: **22,818 MW** on January 15, 2004

• Energy efficiency (EE) and behind-the-meter (BTM) solar are **reducing** peak demand growth and overall electricity use over the next ten years
  ➢ -0.2% annual growth rate for summer peak demand (with EE and BTM solar)
  ➢ -0.9% annual growth rate for overall electricity use (with EE and BTM solar)

• BTM solar is **shifting** peak demand later in the day in the summertime

Note: Without energy efficiency and solar, the region’s peak demand is forecasted to grow 0.8% annually and the region’s overall electricity demand is forecasted to grow 0.9% annually. Summer peak demand is based on the “90/10” forecast for extreme summer weather.
The Great Driver of Transmission Expansion Disappears

• Load growth has been a driver of transmission planning over a future horizon for decades.

• As you can see from the previous slides, overall system load growth is declining and with it the thermal and voltage issues that have traditionally demanded upgrades in capability are not (as much of) an issue
  – There is still local load growth – load reduction programs vary by state

And if that weren’t enough to completely change transmission planning ...
THE GRID IS CHANGING.
THE GRID HAS ALREADY CHANGED.

From the central power station model to distributed energy resources connected across voltage levels and operating jurisdictions
Generation and Demand Resources Are Used to Meet New England’s Energy Needs

- **350** dispatchable generators in the region
- **Over 130,000 PV installations** – most are behind the meter and **NOT** in the ISO-NE Markets
- **29,200 MW** of generating capacity (market resources)
- **15,000 MW** of proposed generation in the ISO Queue
  - Mostly wind and natural gas
  - Does **not** include most proposed PV installations
- **4,600 MW** of generation has retired or will retire in the next few years
- **400 MW** of active demand response and **2,300 MW** of energy efficiency with obligations in the Forward Capacity Market*
  - Beginning June 1, 2018, demand resources will have further opportunities in the wholesale markets

*In the Forward Capacity Market, demand-reduction resources are treated as capacity resources.*
ISO New England Forecasts Growth in Distributed Generation Resources

• Since 2013, the ISO has led a regional **Distributed Generation Forecast Working Group** (DGFWG) to collect data on distributed generation (DG) policies and implementation, and to forecast long-term incremental DG growth in New England.

• The DGFWG focuses on the following types of DG resources:
  
  – Under 5 MW
  – Connected to the distribution system
  – Not visible to the ISO directly
  – Specifically solar photovoltaic (PV) resources, the largest DG component

• The ISO forecasts strong growth in solar PV over the next 10 years.
The ISO Has Engaged Stakeholders on DER Standards

ISO New England has played an active role in discussions on the need to update state interconnection standards for DERs to protect the reliability of the BES

• The ISO has concerns that New England may lose significant amounts of DERs due to faults on the transmission system, and has recommended the following capabilities for DERs:
  – High/low frequency and voltage ride-through
  – Default and emergency ramp rate limits
  – Reconnect by “soft start” methods after disconnect
  – Voltage support
  – Communication capabilities to support other functionalities

• Since 2012, the ISO has discussed these concerns with several stakeholder groups:
  – Planning Advisory Committee (PAC)
  – Distributed Generation Forecast Working Group (DGFWG)
  – Massachusetts Department of Public Utilities (Grid Modernization docket)
  – Massachusetts Technical Standards Review Group (TSRG)
The ISO Is Leading Efforts to Account for Solar Resources Connected to the Distribution System

• **Forecasting Long-Term Solar Growth**
  – The ISO tracks historical solar growth and forecasts long-term solar growth working with distribution utilities and state agencies
  – The solar forecast is used in transmission planning and market needs assessments

• **Forecasting Short-Term Solar Performance**
  – The ISO creates daily forecasts of solar generation production to improve daily load forecasts and situational awareness for grid operators

• **Improving Interconnection Rules**
  – The ISO is actively engaged with industry stakeholders to strengthen interconnection standards and reduce reliability concerns
ISO New England’s Source Requirements Document Contains Updated Standards for Inverter-Based PV

- All inverter-based solar PV projects 100 kW or less with applications submitted on or after June 1, 2018 are subject to the ISO-NE Source Requirements Document.

- All inverter-based solar PV projects greater than 100 kW with applications submitted on or after March 1, 2018 are subject to the ISO-NE Source Requirements Document.

- The updated standards require certain frequency and voltage trip settings (and associated voltage and frequency ride-through performance) that are consistent with the allowable ranges of the revised IEEE 1547 standards and NPCC requirements.
DER Visibility

- As noted, the vast majority of DERs are connected to the electric system in a configuration that is known as “behind-the-meter” – that is, it is behind a revenue quality meter and the load / generation shown to the bulk power system is a net number.

- DER may choose to participate in the electric system at the retail vs. the wholesale market level and this also affects grid operator visibility:
  - Settlement Only Generators – no telemetry required, not dispatchable, but are registered with ISO, subject to ISO standards and have revenue quality meters.
  - Above 5 MW, or dispatchable below, have telemetry to the ISO.
  - The retail / wholesale jurisdictional split creates limits on what the ISO can require.
DER Visibility, Continued.

• Visibility of non-telemetered DER is an ever evolving challenge: the more DERs there are, the more important it is.

• The ISO has contracted with data providers who have access to PV inverter data to receive 5 minute data for a sample of 10,000 PV installations across the region

  – The ISO can’t require this information to be provided to it, but needs visibility regarding location and amount of load and distributed supply given the ever greater impact that additions of DER bring with them
The Important Role of States

• Given that many DERs are located on the distribution system, the standards that states are developing and putting in place will have a critical impact on what the power system looks like going forward

• Technical standards and requirements (and the funding to put those standards / requirements in place) vary not just by state, but can vary by utility within a state

• As the ISO has looked at these issues from the bulk power system down, New England states have initiated dockets to look at these issues from the distribution level up.
  – State and federal entities recognize that this is no longer a power system that is neatly divided between bulk and distribution level assets, visibility and control issues but has already become a hybrid grid
  – The construct of the Federal Power Act struggles with this new reality and current efforts are the result of federal regulators and regulated entities (like the ISO) and state regulators and regulated entities (distribution companies) trying to do what is needed as technology and policy lead ahead of changes to the law
THIS IS NOT YOUR PARENTS’ POWER SYSTEM

So Where Are We Now (and Where Are We Going)? Current Drivers and Challenges in Power System Planning
Transmission Planning Needs Continue

• With the developments noted above leading to a power system that is changing by the month, power system planning needs are not decreasing ... but they are changing

• The system still requires traditional power system capability to move large amounts of power around the system, but several different issues are driving today’s power system planning, such as:
  – Low loads, and
  – Power flowing from distribution systems up to the transmission system (rather than the other way around)

• Will fuel issues create yet other new drivers for transmission to import and move more power around the system where markets have not led to fuel delivery infrastructure?

So what does that mean for a planning world that didn’t change for a long time?
The System Has Changed But ...

- Rules lag – we still have the Federal Power Act split of wholesale and retail from the mid-1930s
- System planning looks at 10 years and projects often take five or more years to develop and build. Anticipating WHAT we need to build is much more challenging.
- But, fortune-telling is hard. What will the digital world bring us in a year or two or five? There was effectively no PV in New England in 2010. Now there are over 2,500 MW. Panels improve on a consumer electronics cycle as do technologies like batteries, and last year’s wind turbine blade is quickly supplanted by a better design – all while equipment prices are falling.
The Changing System, continued

• System Planning (and operations) is currently working with and around existing constructs, but it is the time to think though:
  – Are the planning standards still adequate?
  – Is the RTO authority for planning what it needs to be or should regional planning be done down to much lower voltage levels given the changing nature of the fleet?
  – Does the FPA split even make sense anymore, and if not, what needs to change and, practically speaking, will it if no one wants to give up what the FPA’s mix of federalism protects?

• The fascinating thing about this is that the change in the power system is underway without regard to the above issues, and it will continue in some manner regardless of the resolution of those issues.
Closing Thoughts…

• The New England region has significantly improved the transmission system over the past 16 years – eliminating congestion and allowing power to move around based on price.

• State policy and power system technologies are changing the shape of the grid, and creating a hybrid system of both large and distributed resources, often at the distribution level.

• ISO New England will continue to work with utilities and regulators in each state to integrate DERs in a way that (must!) keep the power system reliable
  – ISO New England will continue to work with utilities to optimize the utilization of advanced inverter functions that will be available under the revised IEEE 1547 standards
  – Visibility

• The energy industry is keeping up, but the basic constructs may have a limited shelf-life. The time to think about the tools we need for current planning is now.
For More Information...

• Subscribe to the **ISO Newswire**
  – **ISO Newswire** is your source for regular news about ISO New England and the wholesale electricity industry within the six-state region

• Log on to **ISO Express**
  – **ISO Express** provides real-time data on New England’s wholesale electricity markets and power system operations

• Follow the ISO on **Twitter**
  – @isonewengland

• Download the **ISO to Go App**
  – **ISO to Go** is a free mobile application that puts real-time wholesale electricity pricing and power grid information in the palm of your hand
Key Transmission Issues

Aileen Roder
Office of Energy Policy and Innovation
October 30, 2018
Disclaimer

Any views expressed in this presentation are those of the presenter and not necessarily those of the Commission, individual commissioners, or other members of commission staff.
Key Transmission Topics

- Return on Equity (ROE)
- Transmission Incentives
- Regional Transmission Planning and Cost Allocation
- Interregional Transmission Coordination
- Transmission Metrics
Return on Equity

- The Commission issued an order on the remand on October 16, 2018.
- Where do we go from here?
Transmission Incentives

• Policy Statement of 2012: Provided new guidance about the Commission’s transmission incentives policy.
• Case-by-case assessments of transmission incentives requests.
Transmission Planning and Cost Allocation

• Many regional and interregional compliance filings so implementation of Order No. 1000 has taken time.

• Technical Conference on Competitive Transmission Development (June 2016) (Docket No. AD16-18-000).

• Individual cost allocation proceedings such as for the Artificial Island Project in PJM. *Delaware Public Service Commission and Maryland Public Service Commission v. PJM Interconnection, L.L.C. and Certain Transmission Owners Designated under CTOA RS FERC No. 42, 164 FERC ¶ 61,035 (2018).*
Interregional Transmission Coordination

• Order No. 1000 included transmission coordination requirements for pairs of adjacent transmission planning regions.

• Each neighboring pair of transmission planning regions must:
  – Share information regarding their respective needs and potential solutions to those needs;
  – Identify and jointly evaluate interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs; and
  – Have a cost allocation method for interregional transmission facilities.
Transmission Metrics

- In 2016, Commission staff developed several metrics that assessed transmission investment patterns, as described in a resulting staff report released in March 2016.
- Meant to explore the state of transmission investment in the U.S.
- Commission staff produced an update of the report in October 2017.
Order No. 1000 at the Crossroads: Reflections on the Rule and Its Future

Tony Clark

APRIL 2018

With thanks to my colleagues Michael Keegan and Robin Lunt.
I. Overview

With the passage of the better part of a decade since its adoption, now is an appropriate time for the Federal Energy Regulatory Commission (FERC) to engage in a meaningful assessment of Order No. 1000. This paper concludes that one of the paradoxical results of the rule has been that major transmission projects of the kind that many thought the order would spur came out of a pre-Order No. 1000 world. Meanwhile, the post-Order No. 1000 timeframe has been marked by bureaucracy, but few tangible projects. The paper concludes that FERC should better tailor the rule to certain predominantly restructured regions of the country while substantially unburdening those regions for whom the compliance regime seems to have quickly reached a point of diminishing returns.

II. Introduction

If the success of a rule promulgated by FERC is measured solely by the amount of industry discussion and trade press coverage, then FERC Order No. 1000 has a rightful place in the pantheon of great Commission rulings. Yet today, few who follow the electricity industry would argue that Order No. 1000 comes close to having successfully achieved its stated goals in a fashion similar to previous FERC reforms like the unbundling of electric transmission or pipeline transportation. Put plainly, Order No. 1000, you're no 888 or 636.

Why has Order No. 1000 in practice never matched its hype? Why is it that many of the biggest regional transmission buildouts, the type of projects that Order No. 1000 purportedly encouraged, happened prior to Order No. 1000, while the period since its promulgation has seen relatively little transmission development? In short, even its biggest proponents must agree that Order No. 1000 somehow missed the mark, or concede that at best, its impact has been underwhelming. And with the benefit of hindsight, what lessons have we learned? That is the focus of this White Paper.

After laying out the background of Order No. 1000 and discussing the myriad of goals that the rule was meant to support, this paper identifies one of the major pitfalls of the rule: it imposes bureaucratic planning requirements on the national transmission system, largely without considering that each region’s needs, priorities, and processes are different. After reviewing some of the significant differences that exist between the regions and the changes that have occurred in the electric industry since the rule was promulgated, I ask, “Where are we and where do we go from here?”

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1 Of course, Order No. 1000 is only applicable to the extent of FERC’s jurisdiction over the transmission of electric energy in interstate commerce.
III. FERC Order No. 1000 Background

FERC aficionados can feel free to skip this section, but in the interest of thoroughness, I provide the basics of Order No. 1000. FERC's own website offers a concise overview of the 620 page order, its background and features of the rule. Rather than reinventing a summary, FERC’s explanation is provided in its own words:

Order No. 1000 is a Final Rule that reforms the Commission’s electric transmission planning and cost allocation requirements for public utility transmission providers. The rule builds on the reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods.

Background
On June 17, 2010, FERC issued a Notice of Proposed Rulemaking seeking comment on potential changes to its transmission planning and cost allocation requirements. Industry participants and other stakeholders provided extensive comment in response to the Notice of Proposed Rulemaking. The Commission received more than 180 initial comments and more than 65 reply comments.

Planning Reforms
The rule establishes three requirements for transmission planning:

Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.

Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.

Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

Cost Allocation Reforms
The rule establishes three requirements for transmission cost allocation:

Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the
regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles. Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles. Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.

**Nonincumbent Developer Reforms**

Public utility transmission providers must remove from Commission-approved tariffs and agreements a federal right of first refusal for a transmission facility selected in a regional transmission plan for purposes of cost allocation, subject to four limitations:

This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.

This allows, but does not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers.

Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.

The rule recognizes that incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend its tariff to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.

**Compliance**

Order No. 1000 takes effect 60 days from publication in the Federal Register.

Each public utility transmission provider is required to make a compliance filing with the Commission within 12 months of the effective date of the Final Rule.

Compliance filings for interregional transmission coordination and interregional cost allocation are required within 18 months of the effective date.²

A reader unfamiliar with much of the history and contemporary practice of the electric utility industry would be forgiven if, after reading this summary, s/he responded with a shrug. On its surface, it really doesn’t look like much more than:

- transmission regions (including independent system operators (ISOs) and regional transmission organizations (RTOs)) should be talking amongst themselves and with each other to rationally plan the electric grid;
- regions should figure out how to pay for transmission; and
- there should be an opportunity for non-incumbent utilities to build transmission.

While the preceding description of the rule is accurate, as far as it goes, a 50,000 foot explanation of Order No. 1000 understates the more robust list of motivations that inspired it. Frankly, if those three points were all that Order No.1000 sought to accomplish, one might think it could be done with something less than the thousands of pages of regulations that comprise Order Nos. 1000, 1000-A, 1000-B and the numerous subsequent regional compliance Orders. To better understand the policy environment that gave us the rule and its numerous subsequent compliance filings, a little more color commentary is needed. It helps explain why nearly seven years after the rule was adopted, multiple industry observers wonder why something seems amiss.

IV. The Many Goals of Order No. 1000

Depending on the audience and the person or group discussing the goals of the rule, the benefits of Order No. 1000 might variously be purported to be:

- The rule is designed to support state or federal “public policy requirements” in electricity. It should be acknowledged that, however nebulous the term, “public policy requirements,” in reality, it was often code for “supporting renewables.” It would be difficult, however, for FERC to just come out and say, “Order 1000 is promulgated to support politically advantaged renewables.” The Federal Power Act does not work like that, and FERC would have been called on the carpet in the courts had it tried it. Nonetheless, the state public policy considerations referenced in Order No. 1000 were clearly aimed at expanding transmission to support things like state renewable portfolio mandates, not expanding opportunities for coal, nuclear or natural gas powered resources. Order 1000 envisioned the building of big, interregional projects, or energy superhighways stretching from geographically distant, but renewable rich, areas to the nation’s load centers. Even more amorphous is the notion of “federal public policy requirements.” In the context of 2010, it would be reasonable to assume FERC might have written this in anticipation of the Obama Administration’s imposing of a theroetofore unstated national energy policy; in all likelihood driven by carbon emissions constraints. But that never came to pass and if the nation has a coherent, stated national energy policy that lasts beyond the predilections of any given presidential administration, it would be hard to identify it.
• The rule is designed to break down the silos between utilities and amongst regions of the country. In many ways, this argument was part and parcel of the one preceding it. For example, many felt that FERC needed to facilitate the delivery of wind-generated energy from places like the sparsely-populated, wind-rich Upper Midwest and Great Plains regions (located in the MISO and SPP regional transmission organizations), to the Mid-Atlantic and Midwestern population centers located in the PJM Interconnection. To the degree silos needed to be broken down, it was because states and regions were looking to realize the benefit of moving power (presumably renewables) across broader geographic regions, or so the argument went.

• The rule is designed to increase competition in the transmission industry. By eliminating a federal right of first refusal for incumbent transmission providers to construct proposed transmission projects and requiring regions to have a formal planning (and often a competitive bidding) process for transmission projects, competition in transmission development would rule and consumers could benefit commensurately.

• The rule is designed to help overcome the inherent tension between generation and transmission. This argument was particularly salient in restructured regions of the country where an incumbent merchant generator might have self-interested reasons to maintain the price separation available to a generator in an area with transmission congestion.

In sum, if the following questions were asked of FERC:

“Is the main purpose of Order No. 1000 to get more transmission investment or is it to increase competition in the transmission business? OR, is Order No. 1000 designed to overcome the potential self-interest of generators or is it to promote renewable generators? OR, is it designed to support individual state public policies or is it a federal initiative to increase regional planning conducted by the RTOs rather than by the individual state regulated utilities themselves?”

The answer would seem to be an unequivocal “YES!”

Therein lay some of the unresolved tensions within Order No. 1000 which differentiates it from prior FERC orders like 888 and 636. While, like Order No. 1000, Order Nos. 888 and 636 entailed hard regulatory choices, stakeholder arguments and numerous complicated proceedings to implement them, FERC itself seemed to be pulling industry toward a fairly clear goal of what was to be accomplished under each of these seminal Orders.

Such clarity and single-minded purpose escapes the grasp of Order No. 1000. The Rule is held in the eye of the beholder. If you like supporting state or federal public policy requirements
V. Implementing Changes Nationally without Fully Appreciating Regional Differences

Not only does Order No 1000’s lack of focus create internal tensions within the rule itself, but these tensions are then superimposed on an electric industry that is highly regional in polity and practice; and these are factors that Order No. 1000 has little ability to accommodate; though through its implementation, it does its best to avoid acknowledging this reality.3

A. Order No. 1000 in Regions with Vertically Integrated States in Traditional Bilateral Markets

One of my own “lightbulb” moments as it related to this issue was in contemplating how little sense the full Order No. 1000 compliance regime made in a state like Florida. I hope readers will pardon me if I quote from my own separate statement attached to the 2013 Florida compliance order:

… this filing raises in my mind certain broader concerns regarding the general direction Order No. 1000 takes us in relation to non-market, non-RTO/ISO regions. As I have previously written, there is much I can find worth supporting in Order No. 1000 and some of the subsequent compliance filings. Facilitating cost-effective transmission solutions, encouraging regional planning to meet customer needs and ensuring fair cost allocation are worthy endeavors. Greater standardization of those efforts would seem to hold a good deal of potential, especially in those regions of the country that have already voluntarily organized themselves into functioning RTOs and ISOs. But Order No. 1000 may not fit quite as well in certain regions of the country. Florida is a prime example.

Order No. 1000 seeks to ensure that transmission projects are planned in a cost-effective manner and in such a way that public policy goals are met. In highly integrated regions, where there is

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3 In the spirit of full disclosure, this has long been a topic about which I have expressed a degree of concern. While I was not a member of FERC when Orders Nos. 1000 and 1000-A were adopted (and was recused from Order No. 1000-B), I did have the opportunity to review and vote on the many regional compliance orders that were filed during my term on the Commission (2012-2016). While individual regions had some degree of flexibility to tailor their compliance filings, that flexibility often seemed to me a bit illusory.
central dispatching, locational marginal pricing, and numerous state public policies that support geographically remote sources of generation, Order No. 1000 seems a reasonable effort to ensure just outcomes.

But in a region like Florida, I cannot help but ask if the bureaucracy imposed by Order No. 1000 may outweigh the benefits to be gained.

The FERC jurisdictional utilities that serve Florida are vertically-integrated, monopoly utilities whose planning and operations are comprehensively regulated by the State of Florida. Integrated resource planning and facility siting, as approved by the state, ensures that generation and transmission decisions are viewed and approved holistically. The Florida utilities’ integration with the rest of the greater southeast region is limited physically due to Florida’s unique geography. There is no central dispatching entity and no LMPs to reflect local congestion. Florida utilities have exercised their right to retain control of their transmission by not choosing to join an RTO/ISO. The Florida Parties state that there are no identified public policy requirements driving regional transmission needs. Thus, in large part, the rationale for Order No. 1000 is lacking in Florida.

Therefore, I am not entirely sure what is accomplished by Order No. 1000 in such a region. On one hand, since a good deal of integrated resource planning is already happening, there is a chance the real net effect of these changes will fall somewhere between minimally and modestly beneficial. But I fear by shoehorning Order No. 1000 into a region with existing and extensive state-led planning, we could risk the creation of an expensive, potentially litigious, and time-consuming additional layer of unnecessary bureaucracy. If this happens, the counter-productive result will not be more cost-effective and timely built transmission, but less.4

At the risk of appearing self-congratulatory, these concerns from 2013 have been largely realized in the non-RTO, bilateral market regions of the country.5 Though I am unaware of a comprehensive study of the total costs of Order No. 1000 implementation, if anecdotal discussions with industry participants are any guide, initial and ongoing compliance expenses are greater than immaterial.

As to the benefits, one would be hard pressed

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5 For purposes of the white paper I use the terms like bilateral market regions, and non-RTO, non-organized market regions to differentiate them from those regions of the country that operate within FERC jurisdictional, organized, centrally-dispatched energy markets such as those served by SPP, CAISO, MISO, PJM, ISO-New England and the New York-ISO.
to point to concrete Order No. 1000 successes in these bilateral market regions of the country. No doubt some good has come from the mandate that regions do a more systematic job of planning and determining cost allocation principles, but one would struggle to pinpoint major accomplishments that were not already being achieved through the traditional state-led regulatory processes that oversee the vertically integrated utilities that exist in these bilateral market regions of the country.

To once again juxtapose Order Nos. 888 and 636, one of the reasons those rules have had greater impact and staying power was that FERC focused its reforms on areas in which its regulatory jurisdiction was more comprehensive—the terms and conditions of interstate electric transmission and natural gas transportation service. In contrast, Order No. 1000 occupies that blurry space at the intersection of state and federal policy. While FERC has undisputed authority over wholesale electric rates and over rate setting and cost allocation for interstate transmission service, Order No. 1000 closely intersects with areas that are just as clearly within state jurisdiction: integrated resource planning, resource adequacy, transmission certification and siting, not to mention state public policy goals that promote various forms of energy generation. Given all that, it is little wonder the impact of Order No. 1000 on actual transmission planning and construction has proved most ineffectual in those regions of the country where states have maintained the greatest degree of regulatory authority.

B. Order No. 1000 in Regions with Vertically Integrated Utilities in Organized Markets

The foregoing discussion is not to suggest that Order No. 1000 has conversely been a rousing success in the organized market regions of the country, only that the Rule’s ineffectiveness has been most pronounced exactly where you would expect: where state authority is still most comprehensive.

In my statement on the 2013 Florida compliance filing, I directed my suspicions about the efficacy of the Order No. 1000 planning regime, in part, towards those regions of the country that did not have an organized dispatch market, mentioning as a distinguishing characteristic, “There is no central dispatching entity and no LMPs to reflect local congestion. Florida utilities have exercised their right to retain control of their transmission by not choosing to join an RTO/ISO.”

Order No. 1000’s mismatch is most glaring… anywhere states continue to exercise their oversight of the traditional vertically integrated utility business model, whether in an organized market or outside of one.

This point is critical in understanding one of those underpinnings of FERC’s Order No. 1000 rationale: the tension between generator self-interest and the impact of transmission planning. And while the point is valid, in retrospect, I think I drew the distinction in the wrong place. Specifically, Order No. 1000’s mismatch is most glaring not just in regions outside of organized markets, but rather, anywhere states continue to exercise their oversight of the traditional vertically integrated utility business model, whether in an organized market or outside of one.

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Over the years, I have come to appreciate that the primary distinguishing characteristic between different electric utility regulatory ecosystems is how each state chooses to structure it. In this light, I postulate that an Xcel Energy in MISO and a Dominion Energy in PJM share more in common with a Florida Power & Light in Florida, than any of them share with a fully unbundled Exelon operating in a restructured state like Pennsylvania.

This only makes sense. Much like the example of Florida utilities planning distribution, generation and transmission holistically for a region (with the oversight of the state), vertically integrated utilities within an organized market undergo a similar planning process. It’s just that in the day-ahead and real-time energy markets their units are centrally dispatched by an independent market operator. This is far different than in restructured states, where only distribution operates as a monopoly, and transmission and generation operate independently of each other, with wholesale administrative market mechanisms established by FERC to help inform the business decision making process of merchant operators.

With this understanding, it should come as little surprise that the unimpressive effects of Order No. 1000 on the organized markets in the vertically integrated regions of the country mirror the effects on regions outside of the organized markets.

SPP and MISO offer two real-world examples of the pitfalls of Order No. 1000 in practice.

Dating back to my time as a member of the North Dakota Public Service Commission, I had a pretty good sense of what I thought Order No. 1000 was trying to accomplish. It looked and sounded an awful lot like what we had already been doing, but with an overlay of additional FERC compliance burdens.

From 2008-2010, I was a member of an initiative started by the Governors of the States of Iowa, Minnesota, North Dakota, South Dakota and Wisconsin, known as the Upper Midwest Transmission Development Initiative (UMTDI). Like nearly all other states in MISO, these are all vertically integrated states. While each state had its own reason for joining, the collaboration helped vet a series of transmission projects that seemed to establish a baseline of “no regrets” lines that met the needs of each state.

The work of UMTDI dovetailed with other regional efforts like the “Cost Allocation and Regional Planning” process and the utility-driven CapX2020 initiative, which provided various levels of support for plans that all eventually funneled into a suite of broadly acceptable transmission projects that became known as “Multi-Value Projects” (MVPs). The MVPs were approved by MISO and integrated with its transmission planning process, and ultimately upheld by both FERC and the courts. As the name suggests, these projects served multiple needs. They displayed shared characteristics of reliability lines, market efficiency lines and lines that supported various state public policies.
These efforts were bottom-up, inclusive, cognizant of state public policy initiatives, and successful in getting a lot of needed transmission built. It was also done before FERC Order No. 1000.

In a similar way, the SPP region (another region made up of vertically integrated utilities) had successfully ushered in a series of reforms through its highway-byway model prior to Order No. 1000.

Yet since the rule has been promulgated, much of this type of transmission activity has slowed to a crawl in the very regions where it had previously been most robust. While some of this may be attributed to flattening electricity load growth, and the fact that these projects alleviated some of the pent-up need for additional transmission projects, I would suggest that an ossified and bureaucratic Order No. 1000 planning process actually stifles what was previously happening organically. Insofar as this is true, it would indicate Order No. 1000 has not just been ineffective in certain regions of the country, it is actually counterproductive.

It is in regions where vertically integrated (and state-regulated) utilities participate in organized markets that we can see most clearly the effects of Order No. 1000’s series of unresolved and sometimes contradictory goals. If the rule’s goal was to incorporate state public policy planning and establish cost allocation certainty in order to build transmission, then these regions were already doing that.

Yet these regions were admittedly not at the forefront of prioritizing the injection of non-incumbent transmission competition into the planning process because, frankly, the concept has limited value and appeal in a region where the states themselves have determined that they prefer the regulated, vertically integrated utility ecosystem. In addition, FERC’s insistence that even one penny of regional cost allocation ended an incumbent transmission owner’s federal right of first refusal caused a series of cost allocation methodologies that previously had garnered widespread acceptance to fall apart.

In short, at least within MISO and SPP, the two RTOs that are most representative of joint dispatch markets composed of vertically integrated utilities, Order No. 1000’s pro-non-incumbent “competition” goals ran headlong into its state public policy and pro-transmission investment goals. We have been left in, arguably, a worse position than where we began: more process, more compliance, more delay, more paperwork, more planning; less transmission actually being built.

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7 Indeed, a number of states continue to assert a state right of first refusal, further emphasizing this point.


9 Beyond the scope of this paper is a comprehensive analysis of how Order No. 1000 is unfolding in each distinct region of the country. Sagas like the PJM Artificial Island project will prove instructive as to the promises and
VI. The Times They Are A Changin’

In a turbulent era, Bob Dylan reminded the world that “The Times They Are a Changin’.” So, too, have there been a lot of changes in the electric industry since the Order No. 1000 rulemaking process started in 2010.

Order No. 1000 has its roots in the transmission planning principles FERC established in 2007 in Order No. 890 and was influenced by the Energy Policy Act of 2005’s (EPAct 2005) emphasis on reinforcing the transmission system and encouraging the construction of new transmission facilities. In 2007, gas prices were high and growth in electric energy usage seemed limitless. Transforming the transmission system, or at least building it out, would be necessary to bring renewable energy resources online that could satisfy the country’s appetite for electricity and wean the nation off of natural gas. As I describe above, regional transmission planning was already underway before FERC promulgated Order No. 1000. Numerous multi-region high voltage transmission projects—the type that seemed to be the goal of rule—were being developed by the time FERC issued its proposed rule in 2010.

Now that the rule has been promulgated and the planning processes have been formalized, where are the projects?

A lot has changed since the Order No. 1000 rulemaking process was begun in June 2010 — flattened demand, increased reliance on cheap natural gas, increased energy efficiency, and the growth of demand response and distributed generation. The combined effect of these and other changes may have made multi-state superhighway transmission projects less viable (and less necessary in order to satisfy state or national policy goals). Order No. 1000 was designed to address problems that existed when Order No. 890 was being implemented, and to facilitate the goals of EPAct 2005. The Order remains, but the problems it was designed to address, to the extent they were truly problems, have largely gone away or transformed themselves.

VII. Where Are We and Where Do We Go from Here?

If it is true, as psychologist Nathaniel Branden said, that “the first step towards change is awareness,” then Order No. 1000 may be ripe for a reassessment. There seems to be a growing number of individuals aware that the rule has missed its target, or targets, as it were.

pitfalls of Order No. 1000 compliance. On the plus side, PJM has identified a potentially cost saving project, but challenges have abounded: disputes over the project selection process, internecine strife amongst states based on cost allocation decisions, and difficulties for the RTO itself, which has become much more of a project development manager than it probably ever intended or hoped.

11 In 2016, ScottMadden published a whitepaper that examined the effectiveness of Order No. 1000, stating “it is useful to assess whether the industry has achieved competitive processes as originally intended. While opinions vary
Unfortunately, there is less agreement about what to do about it. The camps basically break into three, and view the current status of Order No. 1000 as either:

A. A fundamentally sound idea that is making painfully slow progress towards some goals, but not others, such as large interregional transmission projects; or

B. Something that may not ultimately accomplish a lot, but it seems to encourage some laudable things; or

C. Proof of the law of unintended consequences; a rule, as currently constructed, that is generating more costs than benefits.

What you think should be done to change the rule is ultimately dependent on which camp you fall into.

For those who see the rule as generally described in proposition “A” there will be a temptation to double-down on Order No. 1000’s most prescriptive aspects. If new projects aren’t being built, it must be because incumbents and states have dug-in their collective heels, goes the theory. They are gaming whatever flexibility was provided in the original compliance filings so it is time to tighten the screws. Less flexibility is the answer and let us drive Order No. 1000 deeper and deeper into the grid. Let’s drive it down to lower voltages. Let’s make sure those projects don’t escape our planning processes by popping up as thinly veiled “reliability projects.”

Let us call this approach, “the beatings will continue until morale approves!” solution.

I strongly urge that we avoid this path.

If the goal is to make sure that even less gets built than under “Classic Order No. 1000,” then this is would be the way to accomplish it. Order No. 1000’s requirements have changed the goals of transmission planning. Before the rule, the purpose of the planning processes was to identify necessary improvements in electric energy infrastructure. The imposition of Order No. 1000 has created a new litmus test for success: identifying projects that can satisfy the rule, particularly a project that is eligible for interregional cost-sharing.12

As I describe earlier, Order No. 1000’s requirements are oftentimes redundant to pre-existing state regulatory schemes for vertically-integrated utilities, simply adding an unnecessary layer of regulatory process. Expecting regions and RTOs, which are already struggling under the weight of their existing regional and interregional planning processes, to impose said process even further down to the next level on the grid invites even more stagnation and death by bureaucracy. All of the unresolved internal conflicts with the divergent goals of Order No. 1000 that I have written about by stakeholder and region, we believe the answer to this question is a resounding ‘no.”’


12 As an aside, it’s interesting that a transmission project located entirely in Missouri might cross through multiple regions, and, therefore, be a success under Order No. 1000 interregional planning; but a transmission project that would run the length of the Mississippi River could be located entirely in the MISO region, and, therefore, worthy of no particular merit under the rule.
become more problematic at this level. This change wouldn’t alleviate Order No. 1000’s problems, it would exacerbate them.

Those who fall into camp “B,” “Order 1000 may not ultimately accomplish a lot, but it seems to encourage some laudable things” are the most status quo oriented of the bunch. They are probably aware that the rule is not working as intended, but are cautious by nature, and think that any problems should be addressed incrementally. Their argument might be: At the very least, letting the rules collect a bit more dust wouldn’t seem to do much harm while we give Order No. 1000 more time to mature. People who fall into this camp may also be of the opinion that Order No. 1000 is actually doing more harm than good, but they are concerned that once FERC begins tinkering with it, they might end up with something worse: better the devil you know than the devil you don’t.

Finally, are the people who are in camp “C,” those who have come to the conclusion that no matter how well-intentioned the rule, the cumulative weight of it can no longer be justified by its results, or lack thereof. Count me among their number.

Even within Camp C, no doubt, there is a variety of opinion on what to do about the failed Order. “Be done with it already” is certainly one path, and given the paucity of hard data that supports Order No. 1000’s efficacy, and the difficulty in evaluating what data exists, it would be an understandable response. However, realists about government action have to acknowledge that history is not replete with examples of government regulatory agencies on their own “calling a mulligan” and dismantling a regulation of Order No. 1000’s scope.

VIII. The Order No. 1000 Reboot

My suggestion is for FERC to step back and reassess Order No. 1000’s key goals and adjust accordingly.

The “supporting public policy requirements” goal, while a nice sounding bumper sticker, fails in practice. State policies, to the degree they happen in vertically integrated states, are already self-supporting through state-led resource adequacy and integrated resource planning that has gone on for years. In restructured states, goals and requirements have been shifting rapidly in recent months, as state governments in such places as diverse as Illinois, New York, New Jersey, Massachusetts and Connecticut devise around market actions to prop-up ailing and politically favored generators. At the Federal level, to the degree the nation has public policy requirements that would establish a national energy policy; they are vague, at best. As previously noted, there is no stated national energy policy. To the degree there is an implicit energy policy guided by

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13 See, e.g., Federal Energy Regulatory Commission, 2017 Transmission Metrics: Staff Report, Oct. 6, 2017 at __, available at https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf. The Staff Report notes that “it is difficult to assess whether the electric industry is investing in sufficient transmission infrastructure to meet the nation’s needs and whether investments made are more efficient or cost effective.” Id. at 6.
Presidential ambitions, in the last 18 months it has shifted from an administration for whom GHG policy was the overriding factor to one that emphasize energy dominance, security and economic development. Given the nature of these competing state and federal energy visions, it would be better for FERC to step away from this aspect of Order No. 1000. At most, a FERC requirement that that utilities located in the same and adjacent regions compare notes and plan for efficiencies should be more than enough to deal with this matter.

Eliminating the public policy requirements goal also has the benefit of discarding one of the thornier problems embedded in Order No. 1000. When state goals come into conflict (e.g., state A has a particular flavor of an RPS, state B does not, and would like to support its own native generation, thank you very much), who decides which state’s requirements are valid? The planning region? The RTO? FERC?

Even in regions that might support some of the competition goals of Order No. 1000, the public policy requirements goals sound better on paper than in practice. Take for example, recent efforts in New England to build transmission from Canada for access to Canadian hydro. The region is predominantly restructured. Massachusetts has a state public policy to use more hydro power. But New Hampshire does not, and has shown no intention of allowing a transmission line to be sited through it for the benefit of Massachusetts energy priorities.14 FERC rules or not, there is nothing in the Federal Power Act that resolves that situation. And multistate RTOs are not in a position to pick which state’s policy should take precedence over that of another state.

So if we take out the canard of supporting state and federal public policy requirements, what are we left with? I would suggest that a potential nugget within FERC Order No. 1000 that bears ongoing consideration is related to the notion that in certain restructured regions of the country, there is a potential disconnect between transmission planning decisions and generation/market decisions. Issues related to the changing generation portfolio, the desire for fuel diversity, and effects of low gas prices and the growth of renewables are related to the challenges of transmission congestion reduction. The way to address these related concerns is to require transparent regional transmission planning, interjected with the ability of non-incumbents to compete for those projects.

But here is the rub; that problem statement should not be addressed through nationwide fiat, but rather as a rule primarily targeted towards “Restructured Administrative Markets.”15

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If FERC more clearly targets Order No. 1000 to address this issue, then it need not impose the requirements on those regions where they make little sense. If that sounds somewhat familiar, it should, because it is essentially the policy call FERC made when it only approved capacity markets for regions of the country that had substantially restructured. For all of the problems and controversies that exist with capacity markets, at least it can be said that FERC has tacitly acknowledged that they only seem to have a role where the structural characteristics of the market fit.

If only FERC would make such an acknowledgment in the Order No. 1000 planning space, much of the Order No. 1000 conundrum could be avoided. It could accomplish this by targeting the bulk of the Rule to the Eastern Capacity Market regions of the country, while substantially repealing or reducing it in those areas where it is less justified, and which were inarguably meeting much of the spirit of Order No. 1000 prior to its imposition.

IX. Conclusion

FERC Order No. 1000, for all its good intentions, is today a rule that has largely fallen short of accomplishing its goals. Unfortunately, the failure of it to fulfill its potential has not come without costs. Given the changes in the electricity industry over the last decade, now is a good time for the Commission to consider an Order No. 1000 reassessment. FERC would do well to ask, “What are we really trying to accomplish?” and then tailor the rule narrowly to achieve those goals. Clinging to an increasingly odd fitting rule in the face of growing evidence that it is not working will only increase the difficulty of reforming it when that time eventually comes.