

# Resetting FERC ROE Policy:

## A WINDOW OF OPPORTUNITY

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# Notice

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# I. Introduction

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A year ago, in April 2017, the D.C. Circuit Court of Appeals remanded and vacated the U.S. Federal Energy Regulatory Commission’s (FERC) return on equity (ROE) policy for electric transmission in *Emera Me. v. FERC*, 854 F.3d 9, 17 (*Emera*). The decision was significant for its potential impact on electric transmission rates and investor incentives, as well as potential relevance to oil and gas pipelines also regulated by FERC. It was noteworthy in not favoring of any particular stakeholders, at least in the long run. Rather than suggesting any potential resolution, the Court instead determined that FERC had departed from evidentiary standards mandated by Section 206 of the Federal Power Act (FPA).<sup>1</sup> Still, the unanimous decision upended FERC’s existing policy articulated in FERC Opinion No. 531.<sup>2</sup> This left uncertainty both about the “default” policies properly applicable to near-term cases as well as long-term protocols.

Understandably, as the FERC only achieved a quorum toward the end of 2017, attention has focused on stop-gap solutions in the absence of Opinion 531. Meanwhile, there is not yet an announced proceeding addressing the long term. The time is ripe to consider what a new long-term policy should look like. Mere tweaks to the old policy are not unlikely to satisfy stakeholders, nor, more importantly, be responsive to the evolving needs for sophisticated risk analysis and consideration of equitable ROEs for transmission or oil and gas pipelines.

Inevitably, FERC will have to formulate a policy that addresses the specific deficiencies noted in *Emera*. It will also be important to reestablish guidelines for stakeholders, who in the policy vacuum are making their own interpretations of judicial intent and past FERC policy, resulting in increasingly divergent ROE claims. Industry groups like the Edison Electric Institute (EEI) have weighed in on augmenting FERC’s two-step discounted cash flow (DCF) methodology, arguing among other things that it has systematically understated the cost of capital determined by alternative means.<sup>3</sup> By contrast, others have argued that in Opinion 531 “the Commission has

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<sup>1</sup> Intervenor and FERC itself may challenge existing rates under FPA Section 206, with the burden of showing both that the existing rates are unjust and unreasonable and that proposed new rates are just and reasonable.

<sup>2</sup> Opinion No. 531, *Coakley v. Bangor Hydro-Elec. Co.*, 147 F.E.R.C. ¶ 61,234 (2014).

<sup>3</sup> “Transmission Investment: Revisiting the Federal Energy Regulatory Commission’s Two-Step DCF Methodology for Calculating Allowed Returns on Equity,” Edison Electric Institute, December 2017.

created an undefined exception to the presumptive validity of the DCF methodology for ‘anomalous’ market conditions.”<sup>4</sup>

However, the commentary to date has underplayed an opportunity to address changing business risk: transmission owners are simultaneously facing 1) new pressures to invest and 2) heterogeneous demand patterns that could impair (or potentially strand) assets in the long term. *Emera* provides an opportunity to address ROE-related issues that have not been raised in either recent FERC policy statements or the decision itself. While FERC has allowed ROE adders since Order 679 in 2006 to meet *growing demand* for transmission infrastructure, it may now be that *new and intensified risks* justify ROE adders or other mitigants. A corollary may be that cost of capital proceedings must inevitably be accompanied by company risk analysis in the foreseeable future. This paper explores these issues in the context of FERC precedent and recent events.

## II. Background

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### A. FERC PRECEDENT

For many years, FERC has set base ROEs for electric transmission and gas pipelines by estimating returns required by investors for a defined portfolio of comparable companies (or the “proxy group”). The proxy group has been defined as publicly-traded electric utilities with credit ratings close to the subject company and without factors that might tend to affect the stock price temporarily (i.e., recent dividend cuts or merger activity).<sup>5</sup> Once ROEs have been estimated for the proxy group, FERC has applied “tests of reasonableness and economic logic” to exclude low-end outliers.<sup>6</sup> At the other end of the spectrum, starting in 2004, the proxy group was further narrowed to exclude “high-end outliers” defined as those with estimated earnings growth higher than 13.3% or resulting ROE estimates higher than 17.7%.

To estimate ROEs, FERC practice prior to Opinion 531 had long been to rely on the so-called “one-step” DCF methodology. “One-step” referred to the practice of basing the DCF calculation solely on near-term estimates of dividend growth, assumed to apply indefinitely into the future.<sup>7</sup> On this basis, FERC would establish a range of ROEs, or “zone of reasonableness,” derived from

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<sup>4</sup> “Developments in FERC Policy for Determining Return on Equity,” Andrea I. Sarmentero Garzón and Gerit F. Hull. *Energy Law Journal*, Volume 38:375, November 16, 2017.

<sup>5</sup> Opinion 531, Section VI(B).

<sup>6</sup> Id.

<sup>7</sup> The FERC would moderate near-term growth estimates using a “sustainable growth formula” based on expectations for the retention of book earnings plus accretion of equity value.

the equity returns measured for the proxy group as described earlier. Then, from within the zone, an allowed base ROE would be determined, customarily the midpoint (for a group of companies) or median (for a single company).

In order to seek departures from this practice, applicants were required to establish the existence of factors that cast doubt on a mechanical application of the DCF methodology, such as anomalous conditions in the capital markets. Estimation methodologies other than DCF, such as the Capital Asset Pricing Model (CAPM), risk premium, and comparable earnings methods, were generally excluded from the analysis and were used only to refine the allowed ROE within the zone of reasonableness.

Separately, FERC has accommodated adders to base ROE for transmission projects that enhance reliability or reduce congestion, or to motivate membership in RTOs, pursuant to Order 679 in 2006.<sup>8</sup> These were not sized in relation to any formal measures of risk. Rather they were a development incentive.

## B. OPINION NO. 531

FERC Opinion 531 in June 2014 and related Opinions 531-A in October 2014 and 531-B in March 2015 were responsive to a Section 206 claim by Massachusetts Attorney General Martha Coakley on behalf of transmission customers in New England.<sup>9</sup> More importantly, however, the orders effectively set policy for determining allowed ROEs for electric transmission in other cases and beyond New England.

The centerpiece of Opinion 531 was to replace the one-step DCF described above with a “two-step” methodology. This was intended to acknowledge that near-term estimates of dividend growth should not be assumed to persist indefinitely, but, more realistically, could be expected to converge over time to growth in the economy generally. It also recognized that the two-step DCF methodology was already FERC policy for oil and gas pipelines, in the form of a blended dividend growth rate consisting two-thirds of near-term growth rates and one-third of forecast growth in Gross Domestic Product (GDP). Accordingly, this formulation was mandated for electric transmission.

Implementation of the two-step DCF methodology tended to narrow the range of ROEs from the proxy group, because the proxy companies were deemed to all share the same long-term growth rate. Additionally, since near-term earnings growth estimates have historically exceeded forecast GDP growth, the two-step DCF tended to produce a lower zone of reasonableness for any given

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<sup>8</sup> Order 679 came in response to FPA Section 219, which was added as part of the Energy Policy Act of 2005 to authorize rate adders to motivate investment in electric transmission.

<sup>9</sup> *Martha Coakley, Massachusetts Attorney General, et al. v. Bangor Hydro-Electric Company, et al.*, the New England Transmission Owners, or “NETOs” (Docket No. EL11-66-001).

proxy group than the one-step DCF. In recognition of these effects, Opinion 531 dispensed with the high-end outlier test described above, which was based upon a belief that high earnings growth rates were not sustainable in the long term. Reliance on a forecast of long-term GDP growth helped to remove the concern that long-term growth rates were unsustainable, though it implicitly also assumed that long-term opportunities were equivalent for all transmission companies.<sup>10</sup>

Separately, FERC found it reasonable in the circumstances of the time to depart from a mechanistic application of the DCF. This was based on acknowledging the “model risk” inherent in applying the DCF under “anomalous” capital market conditions, namely the historically low interest rate environment that had existed since the financial crisis. Accordingly, Opinion 531 called for setting the allowed ROE halfway between the midpoint of the zone of reasonableness and the top of the zone.

Opinion 531 established a zone of reasonableness as the range from 7.03% to 11.74%. The allowed ROE was set at 10.57%, the midpoint of the upper half of this zone. Importantly, the ROE previously established by Opinion 489 in 2006, 11.14%, remained in the zone of reasonableness, but somewhat paradoxically it was no longer deemed just and reasonable because it exceeded 10.57%.

## C. THE EMERA DECISION

In a sense, the Circuit Court remand and vacatur of Opinion 531 could be viewed as quite narrow and technical, without broad implications for future FERC policy. The context was the particular Section 206 proceeding brought by *Coakley et. al.*, as opposed to a more broadly-applicable ROE determination under Section 205. Section 206 mandates a “dual burden” of showing in the first instance 1) that the existing rates are not just and reasonable, and 2) contingent upon the first showing, that the proposed alternative rates are in fact reasonable.

As discussed further below, the Court held that FERC had failed to show that 11.14% was not just and reasonable independent of (and as a condition precedent to) its recommendation of 10.57%, nor had it established a “rational connection” between its recommendation and the evidence brought to bear. In other words, if the currently allowed ROE remained within the range of reasonableness, why was it not “just and reasonable?”

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<sup>10</sup> This policy also implicitly assumed that all transmission companies are equally sensitive to the overall growth of the economy. In fact, as discussed further, much of the planned expansion for the next decade has very little connection to foreseen economic growth, but instead responds largely to aging infrastructure, resiliency considerations, and new sources of generation (including distributed energy resources).

However, beyond these technical questions and as a practical matter under a new commission, the *Emera* decision opens the way for a comprehensive recasting of FERC ROE policy, which we believe is appropriate in light of the more complex financial and energy market conditions facing transmission owners now and in the future.

## D. DIVERGING STAKEHOLDER CLAIMS

For most of the year after April 2017, FERC was without a quorum of commissioners, and hence unable to process routine approvals, much less respond to the *Emera* decision. This has left stakeholders to make their own interpretation of judicial intent and past FERC policy. There have been four ongoing transmission rate proceedings affecting the New England Transmission Owners (NETOs), and some in other regions, in which stakeholders have invoked the *Emera* decision to support their claims.<sup>11</sup> Somewhat awkwardly, the parties have resorted to both claiming consistency with Opinion 531 and dissenting from it, as suit the issues at hand.

Transmission owners have argued for reinstating the base ROE that applied before Opinion 531, or 11.14%, reasoning that with the Court vacatur of Opinion 531, the applicable rate should devolve back to the pre-531 *status quo*.<sup>12</sup> While FERC rejected this request on October 6, 2017, this was more on administrative than substantive grounds pending FERC's eventual order on remand. Thus the question of what is the "existing ROE" remains open, as well as how it should be evaluated under a new policy.

Meanwhile, in the series of Section 206 challenges that have followed in the footsteps of *Coakley*, transmission customers, advocates thereof, and FERC Trial Staff (collectively the "Section 206 Claimants") have mounted challenges to Opinion 531 for their own purposes, again invoking *Emera*. Most conspicuously, the Section 206 Claimants have dissented from FERC's recognition of anomalous capital market conditions (and, accordingly, dismissed any need to review alternative benchmarks to DCF):

"At some point, the term anomalous is no longer an appropriate label for this new equilibrium. That point is now. It is arbitrary and capricious to set base ROEs on the expectation by some – continually wrong since 2009 – that capital market conditions are on the cusp of dramatic or swift change."<sup>13, 14</sup>

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<sup>11</sup> These have been referred to as Complaints I – IV. In addition to *Coakley*, they are *ENE (Environment Northeast), et al. v. Bangor Hydro-Electric Company, et al.* (Docket No. EL13-33-000), *Attorney General of the Commonwealth of Massachusetts, et al. v. Bangor Hydro-Electric Company, et al.* (Docket No. EL14-86-000), and *Belmont Municipal Light Department, et al. v. Central Maine Power Company, et al.* (Docket No. EL16-64-000).

<sup>12</sup> NETOs Amended Compliance Filing, Docket Nos. ER15-414-002 and EL11-66-004, June 5, 2017.

<sup>13</sup> Initial Brief of Commission Trial Staff, Docket No. EL16-64-002, January 19, 2018. Page 30.

The NETOs argue that anomalous conditions persist today, pointing out that interest rates remain well below historic averages and that “U.S. and global interest rates and financial markets remain subject to powerful and unprecedented monetary policy actions by the Federal Reserve Bank and other global central banks.”<sup>15</sup>

Perhaps unsurprisingly, claims have diverged significantly further from the *status quo* than in the past, as shown in Table 1. A comparison between the relative positions of Trial Staff in *Coakley*—which challenged an ROE of long vintage that straddled the financial crisis—and in Complaint IV (*Belmont Municipal Light Department vs. Central Maine Power*), is instructive. Even though *Belmont* was challenging the more recent ROE determined by Opinion 531, in relatively similar economic conditions, Trial Staff departed from the previously approved ROE by seeking a reduction of 285 basis points, nearly double the reduction of 148 basis points sought in *Coakley*.<sup>16</sup>

**Table 1: ROE Claims in Coakley and Belmont Cases**

	Martha Coakley, Massachusetts Attorney General, et al. v. Bangor Hydro-Electric Company, et al. Docket No. EL11-66-001			Belmont Municipal Light Department, et al. v. Central Maine Power Company, et al. Docket No. EL16-64-000		
	2006 Opinion 489	Difference	2013 Trial Staff	2014 Opinion 531	Difference	2017 Trial Staff*
High	13.10%	-0.59%	12.51%	11.74%	-2.34%	9.40%
Adjusted for Market Conditions	11.14%			10.57%		
Midpoint	10.40%	-0.74%	9.66%	9.39%	-1.67%	7.72%
Low	7.30%	-0.48%	6.82%	7.03%	-0.99%	6.04%
Recommended	11.14%	-1.48%	9.66%	10.57%	-2.85%	7.72%

\* Later amended upward for adjustments to proxy group outliers.

Source: FERC filings

Continued from previous page

<sup>14</sup> Claimants have also defined proxy group criteria in a manner that, relative to precedent, reduces sample sizes, eases the screen on low-end outliers, and omits purported high-end outliers. In the latter case, claimants have sought to roll back the reasoning relied upon in Opinion 531 that a two-step DCF model removed the need to cap admissible growth rates or ROEs from sample data.

<sup>15</sup> Initial Brief of the New England Transmission Owners, Docket No. EL16-64-002, January 19, 2018. Page 22.

<sup>16</sup> In March 2018, a FERC administrative law judge issued an initial decision in *Belmont*, finding that the currently filed base ROE of 10.57% is “not unjust and unreasonable.” The decision was predicated principally on matters relating to assembling an appropriate proxy group.



### III. What a New Policy Must Address

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A variety of factors have led to the divergence shown above and form key points of focus for a new FERC order on remand. These can be viewed through the lens of addressing “model risk” and associated technical debates, as discussed below. However, the greater opportunity may be to consider fundamental changes in the transmission business environment and how to address them.

#### A. ARE ANOMALOUS MARKET CONDITIONS THE ONLY DRIVER OF MODEL RISK?

The Commission has recognized the hazards of “model risk” in producing distorted outcomes. Opinion 531 reflected the definition of model risk set forth by the NETOs: “the risk that a theoretical model that is used to value real-world transactions fails to predict or represent the real phenomenon that is being modeled.”<sup>17</sup> An implication of model risk is that model results should not be automatically adopted, but rather subjected to adjustment based on reasoned judgment.

Capital markets have departed from historic norms since the financial crisis of 2008-2009. This is most clearly seen in yields on government bonds. For instance, the historical average of annual yields on long-term government bonds was 5.23% from 1926 to 2010, but the long-term government bond yield stood at just 2.72% in 2016.<sup>18</sup> This has been, in part, the result of a deliberate policy by the Fed to lower bond yields in an effort to induce investors to move to riskier assets such as stocks, and thus a departure from equilibrium conditions. While current Federal Reserve policy is to let interest rates gradually rise, this goal is frustrated by negative interest rates in much of the rest of the world.

Under these conditions, asset pricing models heavily reliant upon currently measured stock prices such as the DCF methodology may break down. Among other things, the DCF methodology assumes that stock prices and expected cash flows are linked by a discount rate reflecting perceived risk. However, all else equal, abnormally low interest rates drive demand for equities and drive stock prices up (per the Fed’s intent), and thus returns measured via the DCF analysis down. This masks the risk/reward relationship that would obtain in equilibrium conditions. While it may be a valid short run description of investor tastes, it is not likely a

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<sup>17</sup> Opinion 531. Page 69.

<sup>18</sup> See Duff & Phelps’s Ibbotson *Stocks, Bonds, Bills, and Inflation* (SBBI) 2017 Valuation Yearbook at 2-9.

sufficient measure of risk and return needed to attract or sustain long-term investments in critical infrastructure.

As indicated above, recent debate continues to center on the empirical question of whether anomalous capital markets conditions continue to prevail. The Section 206 Claimants side step the more general question of model risk:

“Even if one assumes that the DCF model is subject to the same level of model risk as other methods, with that even playing field all the reasons the Commission had previously to prefer the DCF method over the alternate methods still exist *in this stable environment.*” (emphasis added)<sup>19</sup>

By contrast, the NETOs have argued for a more holistic view:

“[The Section 206 claimants] ask that the Presiding Judge mechanically apply the DCF model in the absence of a finding of anomalous capital market conditions. But because ‘there is no failsafe method to estimate investors’ required cost of equity, approaches other than the DCF model have earned widespread acceptance with investment and finance professionals, as well as regulatory agencies throughout the United States.’” NET-02700 at 26:5-8.<sup>20</sup>

While clearly important, we would argue that anomalous financial market conditions are not the only facet of model risk to consider. As we discuss in greater detail later in this paper, it is apparent that the risk characteristics of the regulated wholesale services to markets the FERC oversees are becoming more extreme, heterogeneous, and uncertain. These complex conditions make it less plausible that a broadly applied, one-method risk-measurement approach will suffice. For example, a wider diversity of business risks may mean that the profile of any one company is less and less captured by the characteristics of proxy groups. Also, in a regulated setting, risks will be asymmetric, or one-sided, and hence not reflected in standard cost of capital metrics.

## B. CHANGES IN THE TRANSMISSION BUSINESS ENVIRONMENT

Until recent years, regulated electric transmission companies generally operated in a more predictable environment than today. Load growth was steady, and transmission was added primarily to reliably transmit electricity from large fossil generators to load centers. Transmission cost was generally a low portion of delivered supply cost, utilization factors were high and

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<sup>19</sup> Initial Brief of Commission Trial Staff, Docket No. EL16-64-002, January 19, 2018. Page 7.

<sup>20</sup> Initial Brief of the New England Transmission Owners, Docket No. EL16-64-002, January 19, 2018. Page 10.

steady, and the priorities were assuring reliable load delivery and network security. To a lesser extent, transmission was deployed to achieve economic savings (e.g., by relieving congestion).

While that remains partly true today, it is also the case that new demands on transmission owners have proliferated, sometimes in opposing ways to other industry developments that create new tensions. Drivers include: 1) heightened concerns about system reliability, flexibility, and resiliency; 2) increasing demand for congestion relief and economic efficiency; 3) supporting environmental policy by accessing remote renewable resources; and 4) accommodating diverse changes in flow patterns arising from the growing dominance of natural gas, the retirement of older power plants, and distributed energy resources.

Risks associated with new investment include more capital outlay, especially for development, longer investment horizons, more permitting and regulatory risk, and heightened competitive bidding risks. Some increase in risk has already been recognized by FERC, which acknowledged in Opinion 531 that transmission bears greater risks than distribution operations regulated by the states.<sup>21</sup>

What may be less obvious is the potential for more concentration, heterogeneity, and unpredictability in business risk likely to face transmission owners in the future. Increased risks are being borne in an environment of anemic load growth. All else equal, this will magnify transmission as a portion of end-user electricity costs and make debates over cost allocation more acute. The new demands are also taking hold unevenly around the country and sometimes in the context of changing demand shapes due increased penetration of renewables and demand side energy resources. Accordingly, the new requirements are being addressed by diverse changes in market design (in RTOs and elsewhere). Risks are thus likely to be more specific to particular regions and stakeholders than in the past. There is greater possibility that the original rationale for new transmission may change considerably over the life of the asset (e.g., if load or flow patterns shift). This could, region by region, lead to overdevelopment and cost-recovery difficulties, theoretically including stranded asset risk.

Importantly, some of these risks are asymmetric (or one-sided), as described further below.

## 1. Demand for Transmission Investment has not Abated

Imperatives to expand the nation's transmission infrastructure have not abated, but only intensified in recent years. At first blush, this is counter-intuitive. Due to technology improvements, end-use electricity demand has been flat or growing at a very modest rate in much of the country. Meanwhile, demand for electricity *delivered* by traditional utilities may be

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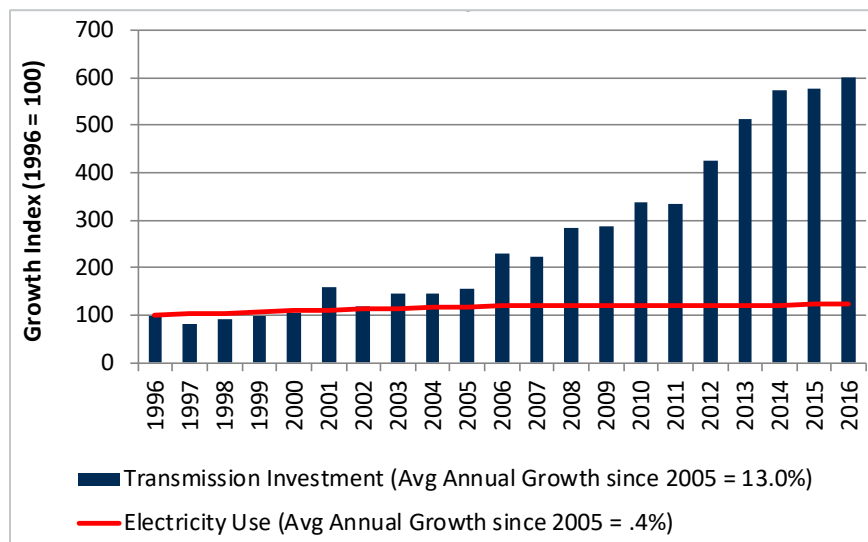
<sup>21</sup> Opinion 531, pages 72-73.

in greater jeopardy, eroded by technology developments that enable end-users to serve some or all of their own needs.<sup>22</sup>

However, transmission demand has many more drivers than just load growth. In 2015, the Department of Energy’s (DOE) Quadrennial Energy Review (QER) noted that, a decade prior, the DOE had pronounced the U.S. electricity grid as “aging, inefficient, congested, and incapable of meeting the future energy needs of the information economy without significant operational changes and substantial public-private capital investment over the next several decades.”<sup>23</sup> While significant improvements had been made to the grid by 2015, the QER stated that “the basic conclusion of the need to modernize the grid remains salient.”

Thus it has been the case that annual additions to transmission plants have far outpaced electricity load growth. Data from the U.S. Energy Information Administration (EIA) shows that annual transmission investment by major U.S. utilities ramped up sharply after 2005, when it stood at approximately \$5.5 billion. Thereafter it grew nearly four-fold to reach \$21 billion in 2016, an average annual rate of 13.0%. Meanwhile, electricity use grew by only 0.4% per annum over the same period. Relative growth is shown in Figure 1 (1996 = 100).

**Figure 1: Growth in Transmission Plant vs. Electricity Use**



Sources: U.S. Energy Information Administration – Today In Energy, February 9, 2018; U.S. Energy Information Administration – Annual Energy Outlook 2018

<sup>22</sup> See also, “[Compensating Risk in Evolving Utility Business Models](#),” The Brattle Group, June 2017.

<sup>23</sup> See pp. 1-3 of Office of Energy Policy & Systems Analysis’ (EPISA) “Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure,” April 2015.

EEI recently forecast a continuation of this trend, with incremental transmission spending by its members well in excess of \$20 billion each year through 2020.<sup>24</sup> Clearly, the demand for transmission investment is being driven by factors other than load growth. Key drivers include:

- *Increased System Reliability Standards and New Resiliency Concerns:* A material part of recent transmission investment can be attributed to more stringent standards for maintaining system reliability (such as NERC and RTO/ISO standards), and system hardening and resiliency. Together, these are intended to ensure that the grid is capable of managing more extreme electrical and physical disturbances, as concerns about massive system disruptions were triggered by the 2003 Northeast U.S. blackout and have intensified more recently with increasing occurrences of extreme weather events. This expansion may prove critical, or it could be little used, as it is largely needed for defense against rare, extreme events. However, it is likely unavoidable since, if the increasing prevalence of extreme climate events should involve a destructive disaster, the transmission owner may face imprudence allegations and irrecoverable repair costs.
- *Economic efficiency:* Economic efficiency goals have included de-bottlenecking congestion and promoting interregional coordination of wholesale markets, requiring additional transmission capacity. In the past, economic efficiency has received lower priority than reliability goal, with the result that there is now pent up demand for more transmission. State policymakers in RTOs such as NYISO and ISO New England have responded by seeking competitive procurement of new transmission. In New York, for example, the state public service commission has declared a public policy need for major transmission upgrades to provide congestion relief and to enable access to a new resource mix as the state’s energy landscape is shifting.
- *Accessing remote renewables:* State decarbonization targets, as well as declining technology costs, have led to, among other things, large-scale buildout of renewable wind generation resources. To optimize the capture of wind resources and high capacity factors, wind generators are increasingly being built in remote locations. This phenomenon has accelerated as wind technologies have improved to take advantage of higher wind speeds in these locations. These developing “wind generation pockets” require new transmission investments for grid integration, often consisting of lines that span longer lengths, higher voltages, and greater permitting and siting risks.

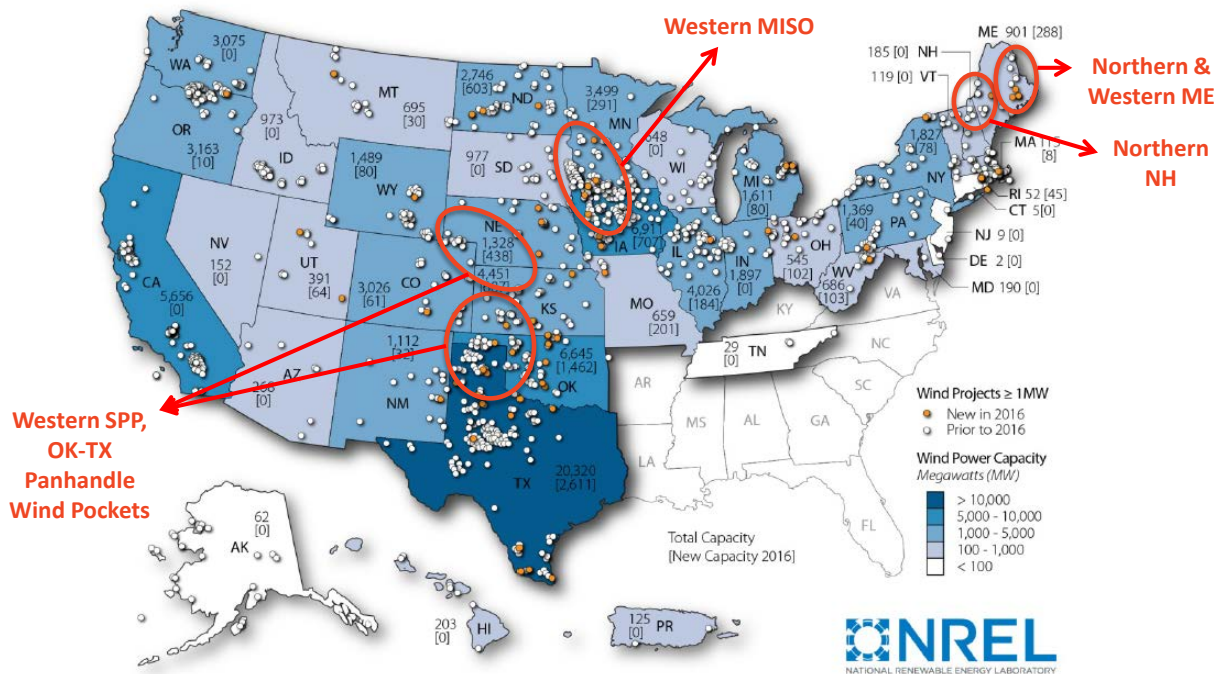
Figure 2 illustrates inland wind generation plant locations in the U.S. As shown, the interior region and northern New York/New England have experienced large-scale wind generation buildout, creating increasingly congested “wind pockets” and affecting transmission system stability, and also triggering other operational and market design issues. As significant transmission system reinforcements, such as ERCOT’s Competitive Renewable Energy Zones

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<sup>24</sup> “Transmission Investment: Revisiting the Federal Energy Regulatory Commission’s Two-Step DCF Methodology for Calculating Allowed Returns on Equity,” Edison Electric Institute, December 2017.

(CREZ), have been developed specifically to access remote renewables, they have also enabled even more wind generation development, which may soon require additional transmission buildout to manage growing congestion between wind-rich areas and demand centers. Other regions, such as Southwest Power Pool (SPP), have also experienced significantly low location market prices in wind-rich locations, like in western SPP compared those in eastern SPP, where much of the demand is located<sup>25</sup>. As even more wind resources attempt to interconnect, these price differentials will exacerbate further, requiring significant transmission buildout. Similarly, transmission owners in ISO New England have been assessing various transmission buildout options to integrate queued-up large-scale remote renewables in northern New England, and to deliver their low-cost energy to higher priced demand centers in southern New England.

**Figure 2: Wind Project Locations across the U.S. (through 2016)**



Source: Ryan Wiser and Mark Bolinger. 2017. *2016 Wind Technologies Market Report*. Figure 6, Page 8. U.S. Department of Energy (DOE). DOE/GO-102017-5033. <https://doi.org/10.2172/1393638>.

- *Responding to the natural gas boom:* At a scale greater than just the introduction of renewables, the nation’s generating mix has been undergoing profound changes largely driven by the shift from coal to natural gas. This has naturally increased reliance on gas infrastructure of all kinds, not least to export gas from new shale gas supply centers not yet fully served by pipeline capacity. The gas boom has also

<sup>25</sup> See pp. 4-6 of SPP’s State of the Market, Fall 2017; accessed here: [https://www.spp.org/documents/56353/spp\\_mmu\\_quarterly\\_fall\\_2017\\_v2.pdf](https://www.spp.org/documents/56353/spp_mmu_quarterly_fall_2017_v2.pdf)

- augmented the role of electric transmission, with significant new investment to supply electricity to the new gas extraction operations. Electric transmission is also being expanded to address the circumstances of new gas generators. These include both new locations relative to the capacity the gas generators are replacing as well as reinforcements to hedge against potential interruptions of gas supply.
- *Distributed energy resources (DERs)*: The current and potential impact of DERs, such as residential solar photovoltaics, are well documented. While not yet very large, the prospects over the next decade are for considerable DER growth, potentially causing material power market changes well within the long lives of transmission assets. These are expected to be augmented by recent developments in battery and storage technologies that will enable end-users to further decrease their reliance on electricity delivered by utilities. DERs add to the capabilities required from transmission and distribution networks as they call for two-way services and make flow patterns more complex to manage or predict.

## 2. Transmission Business Risk is Increasing

The current transmission infrastructure of RTOs is not generally configured to allow for the easy integration of new and potentially geographically-remote resources. Connecting new assets to load centers will require extensive transmission development and significant reinforcements to existing transmission infrastructure to accommodate variability and contingent flows. Moreover, transmission needed for such supply integration tend to be longer, more capital intensive, and are typically exposed to high development costs and lengthy approval processes to comply with environmental and siting requirements.

These pressures for new investment amplify the conventional risks of transmission investment recognized by Order 531, namely siting, development, and permitting costs. This can be simply a function of the longer transmission lines needed to reach renewable resources, as well as new rights of way and environmental implications. Clearly, transmission projects built to serve off-shore wind resources will face significantly heightened risk in these areas.

Relatedly, operating risk for transmission systems built to integrate remotely-located renewable supply resources can be expected to be higher than that for the traditional transmission function of reliable load delivery at predictable utilization levels. The integration of intermittent resources means more complex load shapes, more ancillary service needs, and greater volatility in utilization.

New risks have also been introduced under new procurement rubrics. For example, the competitive bidding program in New York described earlier attracted 22 finalist bids. To gain competitive advantage, some competing bids offered to assume a portion of the risk of any cost overruns, if selected. Thus, even as the absolute levels of risk associated with larger, more complex projects increase, the allocation of those risks is shifting more in the direction of developers.

It is worth noting that all of these risks will be borne in a new tax regime that increases cash flow and liquidity risk for regulated utilities.<sup>26</sup>

### 3. Transmission Business Risk is More Heterogeneous

Changes in the transmission business environment are not confined to linear amplifications of previously recognized risks. They are also based in sectoral and geographic shifts that may disturb traditional patterns of operation and usefulness for infrastructure investment. The new demands outlined earlier can be expected to be both region-specific and qualitatively diverse.

For example, mandates for resiliency will need to be responsive to regional threats of growing frequency (such as the wildfires recently experienced in California) and based on distinctive regulatory and legal precedents. Economic efficiency projects will be motivated by local congestion bottlenecks and result in collapsed basis differentials with unforeseeable effects. Accessing remote renewable resources will also be highly region-specific and will incur integration challenges. The prevalence of natural gas has changed the logic of siting electric transmission lines (as well as gas pipelines). Low cost shale gas is causing the retirement of baseload coal, for which the layout and capacity of the existing grid was originally configured, including shorter distances between generation and loads.

Similarly, though not as far advanced yet in influencing transmission needs, the penetration of DERs is occurring very differently region by region. This can have several effects on the wires that traditionally support such regions: demand may decline further (and may become flatter or spikier, depending on how it is controlled locally), congestion prices across the lines from remote supply sources may drop radically, and local backup requirements may increase (inviting smaller, fast-response generation or storage at the load centers).

A corollary to the greater heterogeneity of risks is a wider framework for the assessment of costs and benefits, and thus more room for stakeholder conflict. Investments will vary widely by regulatory mandate and be increasingly subject to challenge. Resiliency debates, for example, are likely to occur in the wake of adverse events resulting in extreme costs and frustration for customers. Routine planning will contend with concentrated and unexpected factors such as collapsed congestion premiums, dispatch shifting, new flow patterns on wires and pipes, and DERs. All of these could weaken the presumption of regulatory support for traditional long-haul lines, making planning more difficult and potentially impinging on cost recovery. Shifting rationales for transmission infrastructure can certainly result in the cancellation of new projects (with loss of sunken development cost).

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<sup>26</sup> Under the new tax regime, overall revenues will likely be reduced, and variances in revenue and costs that would previously be buffered by federal tax sharing at a 35% rate are now shared at a 21% rate, with greater risk now falling more significantly on investors. See also, [“Six Implications of the New Tax Law for Regulated Utilities,”](#) The Brattle Group, January 2018.



## 4. The Base for Cost Allocation is Narrowing

In the past, it has generally been possible to repurpose transmission infrastructure no longer suited to its original purpose, with incremental costs (if any) socialized across a wide system. It is less clear that in the future transmission owners will be able to reliably allocate and recover increasingly contestable costs. For instance, in some jurisdictions, transmission costs are recovered on the basis of customers' share of coincident peak. DERs may allow large customers to avoid most or all of that coincidence, even while they remain users of the grid. Also, the emergence of DER technologies combined with transmission spending growing much faster than electricity demand may increase customers' desire and ability to avoid payment for shares of the grid, even when they still need it at their reduced net usage. Such reductions in demand may expose transmission assets to greater financial uncertainty in planning and operations. It also may alter the useful lifespans of conventional or even newly developed assets, because the market may simply move out from under them over the next decade or two. The question facing today's transmission owners is whether previously customary repurposing/socialization will be sustainable indefinitely.

## 5. The Problem of Asymmetric Risk

Some of the potential risks facing regulated transmission and pipelines tend to be asymmetric (i.e., not balanced between upside and downside possibilities more skewed to the down side). This is important because such risks generally are not fully reflected in the estimation techniques used to determine allowed ROEs. This is because ROE estimation metrics and models such as CAPM and DCF only measure symmetric risks (i.e., risks that are two-sided).

Regulated utility assets are normally deemed to be prudent for development when they are fulfilling a demonstrated and agreed upon need and when the chosen type of assets is expected to be more cost-effective than the next best alternative. When such assets are built, even though they are a source of cost savings over other possible solutions, investors do not obtain any excess returns from the net benefit their investment creates relative to the next best alternative. Instead, they just get a fair, risk-adjusted allowed return on the book value of equity. Investors do not share in any "upside," which instead accrues entirely to consumers. Utility investors do face downside risks, however; if there is a chance of regulatory disallowance in the future (or infeasibility of collecting allowed costs) due to changing adverse circumstances over which they may have little or no control (or even ability to anticipate).

As an example, it would be instructive to compare a utility equity investor to an investor in a corporate bond with some default risk. The asymmetric risk facing an investor in a regulated utility is similar to the risk facing the investor of a corporate bond. Both have the opportunity to earn a stipulated return: the allowed cost of equity for the utility, and the promised coupons for the bondholder. For both the bondholder and the utility equity investor there is little or no upside even if the underlying asset performs very well in the market, while there is significant downside (albeit ideally with low probability) if the investment turns sour. For example, a corporate bond default can wipe out the entire value of the bond. Similarly, long-lived, capital-

intensive utility investments are exposed to adverse “black swan” events that, while rare by definition, have the potential to severely handicap or even bankrupt the company and similarly wipe out much of its value, especially if those circumstances result in prudence challenges or not used-and-useful findings resulting in disallowances. Both the bondholder and the utility investor face a situation in which they do not gain any excess returns if the underlying assets prove very valuable (all those benefits go to customers for the utility or shareholders for the bond investors), while they can lose if conditions turn sour.

For this reason, a bond coupon “promises” a return to investors that somewhat exceeds the *expected* return, accounting for the probability of a downside outcome. Here, however, the analogy between bondholders and utility equity investors breaks down. This is because the financial economic models used to estimate a utility’s cost of capital reflect just the expected outcome, not some analogue to the “promised” outcome. CAPM, for example, commonly relies on historical data to estimate betas and the market risk premium, and those historical data show undiversifiable bad outcomes as well as good ones. Similarly, the DCF model uses forecasts of dividend or earnings’ growth rates. Those forecasts already reflect the possibility of bad, asymmetric outcomes, but so does the market price against which the DCF model solves for the required return. The effect is on both sides, so there is no premium. In neither case can we observe what the return would be that is equivalent to a corporate bond’s “in full and on time” outcome and then adjust it to being a default-weighted yield. Thus, an allowed rate of return equal to the cost of capital does not provide an adequate rate of return for a regulated company faced with substantial loss from asymmetric risk, even when the cost of capital is estimated perfectly and the market is fully aware of the risks facing the regulated company.

In essence, the obligation to serve forces utilities to put up \$100 for an asset that has returns net of obsolescence risk only worth \$90 (or some other low figure reflecting the probability that an adverse event will wipe out some of the planned collection). And critically, there is no opportunity for the utility to benefit from excess returns if unforeseen events make the assets more valuable. This asymmetry needs to be offset in regulation, either by offering a better return or by providing immunity from stranded costs. These types of risks are called asymmetric risks.

Because delivered power is becoming increasingly price elastic and even out-right avoidable by customers who self-supply (and who often choose to do so expressly to avoid upstream costs), transmission assets may become increasingly exposed to asymmetry in their cost recovery prospects, with more chance of difficulty achieving allowed revenues than possibilities for exceeding them. This has not been an issue in the past, but is an emerging possibility in the future.

## IV. Conclusion

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In the wake of *Emera*, FERC faces both a fundamental challenge and a rare opportunity to re-articulate its ROE policy.

It is unavoidable that FERC must develop more robust economic rationales responsive to the issues raised in *Emera*. The Circuit Court decision suggests strongly that FERC should expand its historic reliance on DCF methodologies to include alternative benchmarks. Meanwhile, basic guidelines must be reestablished for stakeholders, who in the vacuum left by *Emera* are making their own interpretations of judicial intent and past FERC policy, resulting in increasingly divergent ROE claims.

FERC also has the opportunity to address ROE-related issues that have not been raised in either recent FERC policy statements or the *Emera* decision. Transmission owners are simultaneously facing 1) new pressures to invest and 2) heterogeneous demand patterns that could impair (or potentially strand) assets in the long term, with little or no offsetting upside potential. *Emera* provides an opportunity to address ROE-related issues that have not been raised in either recent FERC policy statements or the *Emera* decision. While FERC has allowed ROE adders since Order 679 in 2006 to meet *growing demand* for transmission infrastructure, it may now be that *new and intensified risks* justify ROE adders or other mitigants.

Cost of capital estimations and risk positioning at FERC will require a richer menu of tools and practices. Some proposed changes have been vigorously debated in recent cases and are thus well known to FERC. These include expanding the suite of estimation methodologies and models, adoption of more diverse proxy groups, treatment of deemed outliers, other modeled fundamentals such as long-term growth assumptions, and consideration of benchmarks such as ROEs awarded to distribution utilities at the state level.<sup>27</sup> However, even if successfully refined, these tools must also be better mapped to varied market circumstances. This should include differentiating and weighting models by company context/market conditions, acknowledging heterogeneity of “business risk” in assembling proxy groups and treating outliers, and considering more tailored application of assumptions such as long-term growth rates.

A corollary may be that cost of capital proceedings must inevitably be accompanied by company risk analysis in the foreseeable future, as it will likely be less credible to assume they are all roughly equivalent in the type and timing of economic risks or opportunities they are facing.

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<sup>27</sup> As noted in the Appendix, Opinion 531 acknowledged that transmission bears greater risks than distribution operations regulated by the states.

## V. Appendix: Tweaking the Models

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### A. EMERA SUGGESTS FERC SHOULD RELY ON ALTERNATIVE BENCHMARKS IN ADDITION TO DCF

At minimum, a reworking of FERC’s electric transmission ROE policy should be responsive to specific concerns raised in *Emera*. As noted earlier, the first of these is FERC’s Section 206 burden to show that prior ROEs are unjust and unreasonable, while the second is the perceived failure of Opinion 531 to support its recommended ROE. The Court was concerned that FERC’s process in making both determinations was elliptical and lacked explicit analysis. Per *Emera*, FERC “never actually explained how the existing ROE was unjust and unreasonable.”<sup>28</sup> Meanwhile, the decision continued, FERC “failed to establish a ‘rational connection’ between the record evidence and its decision.”<sup>29</sup>

The *Emera* decision hinted strongly that FERC’s near-exclusive reliance on the DCF methodology played a role in these shortcomings. FERC had indeed considered alternative benchmarks: “1) risk premium analysis; 2) Capital Asset Pricing Model (CAPM) analysis; 3) expected earnings analysis; and 4) comparison of state commission-approved ROEs.”<sup>30</sup> However, “FERC stressed that it used the alternative analyses *only* ‘to inform the just and reasonable placement of the ROE within the zone of reasonableness.’”<sup>31</sup> As a result, the Court drew the following conclusion:

“FERC’s reasoning is unclear. On the one hand, it argued that the alternative analyses supported its decision to place the base ROE above the midpoint, but on the other hand, it stressed that none of these analyses were used to select the 10.57 percent base ROE.”<sup>32</sup>

*Emera*, therefore, invited FERC to consider a more central role for the alternative benchmarks in developing a recommended ROE (as customarily occurs at the state level).<sup>33</sup>

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<sup>28</sup> *Emera*, p. 24

<sup>29</sup> *Id.*, p. 28

<sup>30</sup> *Id.*, p. 9

<sup>31</sup> *Id.*, p. 29

<sup>32</sup> *Id.*, p. 29

<sup>33</sup> Logically, a similar analysis could also make sense in disqualifying existing ROEs.

While a more central role for alternative methods and benchmarks would be directly responsive to issues raised in *Emera*, it is also likely to address a broad range of stakeholder concerns. It is common practice in U.S. state and international jurisdictions to consider evidence from multiple models and multiple versions of the same model (e.g., both a single-stage and a multi-stage DCF). At the Federal level, the Surface Transportation Board (STB) specifies the use of a multi-stage DCF and the CAPM, and places equal weight on each in determining the ROE for the U.S. Class 1 railroads. The CAPM is also, unlike the DCF method, grounded in a formal theory of financial market equilibrium across securities of different risk. Its very structure provides some guidance for how to adjust ROE allowances for different circumstances (e.g., by reviewing how the current levels of its estimated parameters compare to the past). Like the FERC, the STB has expressed a desire to have a consistent and “objective” approach to setting the ROE and has recognized the importance of using multiple models in pursuit of that goal.<sup>34</sup>

Another key benchmark that should be considered by the FERC is allowed ROEs at the state level. Opinion 531 acknowledged that transmission bears greater risks than distribution operations regulated by the states:

“[I]nvestors providing capital for electric transmission infrastructure face risks including the following: long delays in transmission siting, greater project complexity, environmental impact proceedings, requiring regulatory approval from multiple jurisdictions overseeing permits and rights of way, liquidity risk from financing projects that are large relative to the size of a balance sheet, and shorter investment history.”<sup>35</sup>

To the degree that the “spread” between allowed ROEs at FERC and the state level has narrowed, the results from the current model would tend to reduce the incentive to invest in electric transmission. As noted, states utilize a wide variety of estimation methods. Collectively they evaluate a much larger sample of companies than the FERC is likely to be able to include in its proxy groups. Thus any trends or shifts in average state allowances for distribution can and should inform FERC allowances, at least directionally, for transmission.

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<sup>34</sup> This concept was articulated some decades ago by our colleague Stewart C. Myers, the Robert C. Merton Professor of Finance at MIT: “Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information.” Stewart C. Myers, “On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment,” *Financial Management*, Autumn 1978, p. 67.

<sup>35</sup> Opinion 531, pages 72-73.

## B. THE MODELS NEED CALIBRATING

### 1. Proxy Group Criteria

Developing a properly representative proxy group is crucial to the integrity of any model. Although there is a relatively large sample of regulated electric utilities (compared to natural gas or oil pipeline companies that make up other proxy groups to which FERC applies the DCF model), there is a question of comparability for use by the FERC because none of the potential sample companies are “pure play” (or even predominantly) electric transmission companies. This leads to the question of whether there is a need for an expanded or otherwise modified proxy group.

Also, there is little, if any, evidence that FERC’s current practice of restricting the relevant sample to companies within one credit rating notch of the target company improves the comparability of the sample. Debt ratings are of course known to equity investors along with all the consequences of having more debt and higher rates. That is partly why proper estimates of the cost of capital involve delivering the samples and re-levering for the target company. Unless and until ratings become junk, there is little reason to believe that a sample spanning several levels is not informative about equity risks. Notably, in *Belmont*, Trial Staff stipulated a narrower proxy group than the transmission owners, which may be justified, but implicitly excludes even more information about risk. This needs to be done very carefully, not in a cookie cutter fashion, because of the diversity of market conditions facing transmission companies.

### 2. Outlier Tests

Whereas Opinion 531 dispensed with a high-end outlier test in recognition of the two-step DCF methodology, recent Section 206 complainants have sought to define new rubrics to exclude comparable companies with high growth rates or ROEs. In *Belmont*, the complainants applied a “dispersion test” to exclude high end ROEs more than two standard deviations from the mean.<sup>36</sup> Trial Staff echoed this approach based on the magnitude of the gap between high-end outliers and the closest adjacent data point.<sup>37</sup>

It is not clear how these approaches are grounded in statistical theory. Simply referencing standard deviations may be a particularly dangerous guideline to use if there is a small sample, as tends to be true for transmission companies. At the very least any such treatment should be tempered by careful scrutiny of the operating and financial circumstances surrounding the alleged outliers.

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<sup>36</sup> Docket No. EL16-64-002: Answering Testimony and Exhibits of Adrien M. McKenzie, CFA, on behalf of The New England Transmission Owners, March 24, 2017.

<sup>37</sup> Docket No. EL16-64-002: Prepared Direct and Answering Testimony of Robert J. Keyton, Witness for the Trial Staff of the Federal Energy Regulatory Commission, September 25, 2017.

Also for low-end outliers, the Section 206 complainants have sought to establish novel treatment. Opinion 531 affirmed prior FERC policy of excluding outlier ROEs below the average bond yield for utilities rated Baa plus 100 basis points, reasoning that it would be illogical for returns on stock to so close to the cost of debt. However, in *Belmont*, Trial Staff asserted that the threshold should be based on average bond yields for utilities rated A, three notches higher with correspondingly lower yields. A FERC order on remand will need to reestablish the proper relationship between ROEs and bond yields (including whether the 100 basis point margin is high enough to reflect the difference between debt and equity risk). Some of the non-DCF models (especially CAPM and its variants) explicitly treat this issue. Using them would be far less arbitrary than subjectively curtailing the proxy sample.

### 3. Interpretation of “Central Tendency”

Opinion 531 also affirmed prior FERC policy to use the *midpoint* of a proxy group to reflect its “central tendency” in cases setting a single ROE for multiple companies. However, the claimants in *Belmont* have attempted to justify the use of the proxy group median. Here too, there should be a reasoned basis, not just analyst preference. The usual reason for using medians is that there is material skewness in the sample distribution and that some of the extremes have too much weight. But in stock returns, assuming an efficient market, there is no reason to assume each observation is not fairly reflecting the price of risk. Omitting outliers also already crops for some of the skewness that might be feared. Thus the expected value would nominally be appropriate, unless some of the extremes face highly atypical risk.

### 4. The Two-Step DCF

Under current economic conditions, with forecast GDP growth at an historic low, stakeholders are concerned that the FERC policy of weighting GDP by one-third tends to reduce the measured ROE for many companies in a typical proxy group because forecast GDP growth is generally lower than earnings growth forecasts for individual companies. Depending on market conditions, this may be mitigated by complementing the DCF process with alternative benchmarks. The question remains, however, whether lowering the GDP weighting—or moving away from GDP altogether—would be appropriate or desirable.

There would be potential trade-offs in pursuing such a policy, because of the issue of “sustainable” EPS growth rates. As noted above, under FERC policy prior to adoption of the two-step methodology, FERC would disregard ROE outcomes based on forecast dividend growth rates in excess of 13.3% or ROE outcomes in excess of 17.7%. Including GDP incorporated the presumption that combined growth rates and resulting ROEs no longer had to be bounded by those limitations because forecast growth of the GDP pace is presumed sustainable. De-emphasizing or removing GDP could invite re-establishing the upper bounds, potentially removing proxy companies with high dividend growth rates or ROEs from consideration, potentially lowering ROE outcomes for the group. The actual outcome would of course be fact-specific and dependent on features of evolving FERC policy (such as whether to reference midpoint, mean or median ROEs).

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