Exhibit No. AMF-1

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act	Docket No. RM20-10-000

Affidavit of Michael P. Gorman

On behalf of

American Manufacturers

July 1, 2020

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<u>Affidavit of Michael P. Gorman</u>

AFFIDAVIT AND EXHIBITS OF
OF MICHAEL P. GORMAN

On Behalf Of

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July 1, 2020

SUMMARY

In this Affidavit, I provide evidence supporting my conclusions on the following:

1. The Federal Energy Regulatory Commission's ("FERC" or "Commission") current incentive policy is based on a "nexus" between the incentives sought and making an investment that ensures reliability and/or reduces the cost of delivered power. Allowing an incentive return if necessary to encourage investment, was consistent with FERC's promotion of reliable and economically efficient transmission and generation of electricity. The FERC is considering changing its incentive policy to a benefits test, which ties incentive returns on equity ("ROE") to forecasted savings, and otherwise eliminates the nexus requirement for awarding an incentive.

   I recommend the FERC reject the benefits-based incentive and continue with its successful nexus incentive policy.

<u>I. Current "Nexus" Incentive Policy is Successful</u>

2. The current FERC policy, including its incentive policy, has encouraged significant investment in transmission infrastructure, and transmission owners ("TO") continue to plan for significant continued investment in transmission infrastructure.

3. FERC's current incentive policy has proven to incentivize economically efficient transmission investments. This includes increasing capital expenditure programs while at the same time managing the financial integrity and credit standing of the TO.

   The proposal to create economic incentives to increase capital expenditures, without managing the financial integrity or impact on rates to customers, can harm customers. Increasing transmission capital expenditure programs can create financial distress on companies, if this balanced approach to capital spending is not managed. Changing the incentive from encouraging economically efficient transmission investments to incenting maximizing capital investments to earn above market rates of return, can distort the economically efficient objective of scheduling prioritization of investments in transmission infrastructure.

4. Creating economic incentives to maximize capital investments that can earn an incentive return can unjustifiably increase prices to customers, with the expectation of benefits occurring many years into the future. This can create unjust impacts on transmission prices, that will not produce benefits for many years later, if at all.

5. Under current FERC protocols and incentive policy, TOs have been highly motivated to make significant investments in transmission assets while maintaining credit standing and access to capital. Capital market participants have responded by providing the industry with significant amounts of low-cost capital under reasonable terms and prices.

6. FERC regulatory policies have encouraged investments in transmission infrastructure, as ratemaking protocols and current incentive policy are regarded as favorable to investors. FERC's current policy minimizes the risk of investing in transmission assets by reducing cost recovery risk, while also mindful of the impact on customer transmission rates.

7. Utility companies generally, and now competitive transmission companies, are highly motivated to make infrastructure investments subject to FERC regulation. Making infrastructure investments allows these companies to grow their rate base, which in turn allows them to grow earnings and dividends, which enhances shareholder value. A fair and reasonable return has proven to induce significant incentive to invest in transmission plant.

<u>II. Proposed Incentive Benefits Will Erode Customer Protections</u>

8. The detriments of the proposed change in incentive policy from a nexus basis to a benefits basis will significantly distort the incentive of TOs and competitive market participants to pursue transmission investments that will quality for ROE incentives, rather than to develop transmission infrastructure in an economically efficient manner.

9. Creating incentives that encourage TOs and competitive transmission companies to maximize transmission investments that earn an above market rate of return will create economic and financial incentives to maximize investments, that can be awarded an above market return. The incentive to maximize transmission investment can have undue negative impact on transmission prices, and can economically incentivize a company to increase capital expenditure programs above that that can reasonably be managed while maintaining the financial integrity of the company. All of these factors can have negative impacts on transmission customers, and potentially erode service quality and reliability.

10. The FERC incentive policy will no longer have a nexus for incentive ROEs only when necessary to support the development of economically efficient capital programs. This includes managing capital programs in a manner that maximizes capital spend, but limited by ensuring the utility is able to also manage its financial integrity and credit standing. This balanced objective meets the economically efficient development objective because it allows the utilities to manage the size of a capital program while also managing financial integrity, cost of capital, access to capital, and support reasonable costs to customers.

    Changing the FERC incentive policy to encourage the maximum amount of capital expenditures to earn above market rates of return can break from the need for a balanced transmission infrastructure capital program that maximizes transmission investment while managing the financial integrity, credit standing and the reasonable rate standard for transmission customers.

<u>III. Proposed Incentives Are Not Just and Reasonable</u>

11. The proposed ROE incentives are excessive and will impair the development of just and reasonable transmission prices. ROE incentives for becoming a regional transmission organization ("RTO") or independent system operator ("ISO") member will increase authorized ROEs by over 10%, and align these ROEs to a level that is more reflective of a higher risk general market investment rather than a below market risk regulated transmission investment. The proposed changed incentives will provide TOs with a return in excess of the level of investment risk, and then unjustifiably increase prices to transmission customers.

    Further, the proposed maximum ROE incentive of 250 basis points will adjust the rate-setting ROE to a level of return that is more reflective of a speculative high-risk investment. Setting rates at a level that is not needed to incent transmission investments, and results in transmission prices being unjustifiably inflated to support an above market rate of return is not just and reasonable, and results in significant economic harm to customers.

<u>IV. Benefits Test is Not Reliable</u>

12. The Commission's proposed use of predominantly production cost studies to identify benefits to justify ROE adders does not reflect sound and balanced ratemaking principles. Production cost savings estimates are based on statistical models that produce "expected" savings in future periods based on an elaborate number of assumptions and projections of the delivery and generation of electric power to forecast loads over many years. The production costs savings are highly uncertain forecasts that do

not meet the known and measurable standard typically relied on for setting just and reasonable rates.

In contrast to the prospective fuel savings, the ROE incentive adder will be a certain known cost to transmission customers. As such, designing rates to include a significant ROE incentive cost, combined with the expectation of uncertain future delivered power costs savings unjustifiably will economically harm customers.

The proposal to provide an incentive ROE for certain types of reliability enhancement is equally unjustified. Utilities must justify the prudence of their proposed capital investments by showing that they are needed for reliability or to produce economic benefits to customers. Providing an incentive ROE above the level of investment risk necessary to undertake such investments distorts the economic incentive of TOs' capital investment programs, and results in unjust and inflated prices. Again, customers would be harmed from such a proposal.

<u>Affidavit of Michael P. Gorman</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this Affidavit.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A The American Manufacturers, as identified in the Comments.

Q WHAT IS THE PURPOSE OF YOUR AFFIDAVIT?

A I will respond to the Federal Energy Regulatory Commission's ("FERC" or "Commission") proposal to revise its existing regulations that were implemented under section 219 of the Federal Power Act ("FPA") related to changes in transmission development and planning.

I. NOPR BACKGROUND

Q WHAT CHANGES IS THE FERC CONSIDERING FOR TRANSMISSION INCENTIVES?

A FERC is considering departing from the nexus test framework of Order No. 679 where incentives were permitted only to the extent the transmission owner ("TO") demonstrated that the incentive sought is "necessary in order to make the desired investment." In this case, the Commission is proposing to depart from this "nexus" test, and instead develop incentives based on a "benefits" test.[1]

The Commission found that the current nexus incentive mechanism required TOs to demonstrate that the incentive sought is necessary in order to ensure that the investment will be made, and the desired investment is needed to ensure reliability or to reduce delivered cost of power.[2]

The benefits test is to be limited to economic benefits related to production cost savings or similar measures related to congestion reduction or certain other quantifiable benefits that are verifiable and not duplicative.[3] The FERC anticipates relying on RTO/ISO economic dispatch savings studies as a relatively simple, transparent, and efficient analysis of economic benefits which it anticipates can be provided to stakeholders.[4] The Commission also notes that public utilities that are not in an RTO/ISO may face challenges with respect to the impact of their transmission investments on a planning region's existing processes for measuring the economic

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[1]Notice of Proposed Rulemaking, 170 FERC ¶ 61,204, March 20, 2020 ("NOPR") at ¶¶ 2-3.
[2]*Id*. at ¶ 15.
[3]*Id*. at ¶ 48.
[4]*Id*. at ¶ 44 and ¶ 52.

benefits and producing benefit-to-cost ratios. But it cites certain other options available to the non-RTO/ISO members to measure economic benefits including transactions between generators and loads in the region.[5]

The Commission also proposes a benefit-to-cost ratio threshold differentiated by the size of the transmission investment, with transmission investments of $25 million (adjusted for annual inflation) as the proposed dividing line between small system modifications and significant transmission facility expansions.[6] The Commission goes on to identify a cost-to-benefit ratio where the savings divided by the project costs produce a cost-to-benefit ratio or factor.[7] Based on historical cost-to-benefit ratio factors, the Commission prescribes a benchmark of 3.98x for significant transmission projects of at least $25 million, and 33.91x for small transmission projects.[8]

Q WHY IS THIS INCENTIVE CHANGE BEING CONSIDERED?

A The Commission states that it is considering making this change that was originally implemented in Order No. 679 and reviewed in transmission incentives and policy in a 2012 policy statement. FERC states that while it is encouraged by the investment in transmission infrastructure to date,[9] it observes that the industry has undergone a transformation, including the landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably. Those changes

[5] *Id*. at ¶ 53.
[6] *Id*. at ¶ 56.
[7] Productive cost savings / project cost.
[8] NOPR at ¶¶ 57-58.
[9] *Id*. at ¶ 31.

include an evolution of resource mix, increases in new resources seeking transmission service, shifts in load patterns, impacts of implementation of the Commission's rulemaking on transmission planning and cost allocation as outlined in Order No. 1000. The Commission states additional reform may be necessary to continue to satisfy our obligations under FPA section 219 in this new transmission planning landscape.[10]

Q WHAT IS THE PURPOSE OF INCENTIVES?

A In Paragraph II.A.12 of the NOPR, the FERC states that the FPA directed it to promulgate a rule providing incentive-based rates for electric transmission for the purpose of "**benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion**."[11] It states that FPA section 219 provides some specific directives in the required rulemaking, including the following:

1. promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of facilities for the transmission of electric energy in interstate commerce, regardless of ownership of the facilities;

2. provide a return on equity ("ROE") that attracts new investment in transmission facilities, including related transmission technologies;

3. encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and

[10] *Id*.
[11] *Id*. at ¶ 12.

4. allow recovery of all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to FPA section 215, and all prudently incurred costs related to transmission infrastructure development pursuant to FPA section 216.[12]

II. CURRENT RISKS AND CHALLENGES (NEXUS) INCENTIVE POLICY IS REASONABLE AND PROVEN TO BE EFFECTIVE

Q SHOULD THE FERC CHANGE ITS INCENTIVE POLICY BASED ON RISKS AND CHALLENGES TO ECONOMIC BENEFITS?

A No. The FERC's current ratemaking policy, including its current "nexus" incentive test, has correlated with significant investments in transmission infrastructure designed to support improved reliability, reduce transmission congestion and to modernize transmission infrastructure. In contrast, the proposal to award incentives based on benefits would be at odds with the FERC's stated objective of promoting "economically efficient" development of transmission assets that benefit customers by ensuring reliability and reducing the costs of delivered power by reducing transmission congestion.[13]

While I agree with the Incentives NOPR that the utility infrastructure landscape is changing due to the advent of renewable technology, changing load characteristics of customers, and movements to more environmentally friendly generation and delivery of energy, the utility industry is highly motivated to respond to these new challenges where utility companies continue to plan and effectively manage construction projects, and capital markets continue to find the utility industry

[12] *Id.*
[13] *Id.* at ¶ 2 and ¶ 12.

a very safe, stable and attractive industry investment option. All of this occurring under the current FERC policies and practices including incentive-based ratemaking, that has resulted in the development of economic and efficient transmission delivery systems, especially when transmission development is being orchestrated by an ISO or RTO as part of an overall regional transmission plan. Providing unjustified ROE incentives will unnecessarily and administratively inflate prices, decrease potential benefits to customers, and put customers at true risk of paying higher prices for the expectation of savings that may or may not be realized.

Q WHY WILL THE CURRENT FERC POLICY CONTINUE TO ENCOURAGE ECONOMICALLY EFFICIENT TRANSMISSION ASSET DEVELOPMENT?

A The current FERC regulatory policy, including its incentive policy, has been proven to create strong incentives for TOs to make significant economically efficient investments in transmission infrastructure assets. I reach this conclusion based on the following:

1. My colleague, Ali Al-Jabir, outlines TOs' participation in RTO/ISO planning processes, and compliance with their obligation to make necessary transmission investments to meet the RTO/ISO improvements in infrastructure reliability, relief of transmission congestion, and improve the efficient operation of the wholesale transmission network. Mr. Al-Jabir also discusses TO members' investments in transmission infrastructure not required by RTO/ISO planning, and the introduction of competitive transmission plant investment that has attracted new non-utility companies to become members of RTO/ISO. These new transmission-owning companies have also proven to be highly motivated to make infrastructure investments, and have actually requested changes in FERC's rules and policies to allow them to an increased amount of transmission investments available for competitive development. All of this is a clear indication that RTO/ISO members are highly motivated and incented to invest in the development of the transmission infrastructure.

2. The electric utility industry generally, and specific transmission providers have planned very large capital programs for continued transmission investment. These transmission investments are supporting the utility companies' efforts to enhance shareholder value by growing earnings and dividends by making infrastructure investment. Energy companies are highly motivated to accomplish this shareholder value enhancement. Without infrastructure development and rate base growth, these utility companies will not accomplish the objective of enhancing shareholder value, and growing earnings and dividends. As such, infrastructure development is critical in enhancing shareholder value, and creates significant incentive for RTO/ISO members to make transmission infrastructure investments.

3. The current regulatory practices for utilities generally, and at the FERC specifically, have resulted in substantial increases in investments in utility electric plant in-service that has accommodated change in generation infrastructure, a significant investment in modernization and expansion of transmission infrastructure, and the modernization of distribution structures. No change to current incentives is justified.

4. The electric industry generally, and the major electric utility companies specifically, aggressively enhance shareholder value by making infrastructure investments to allow for growth in utilities' earnings and dividends but do so while managing the financial integrity and credit standing of the utilities. This managed approach to capital spending enhances shareholder value today, but preserves the utilities' access to external capital markets under reasonable terms and prices into the future.

5. Current policy where incentives are only allowed in the event of need has encouraged the efficient utilization of resources, and best achieves the FERC's stated goal of economically efficient investments in the transmission infrastructure which result in reasonable costs to customers.

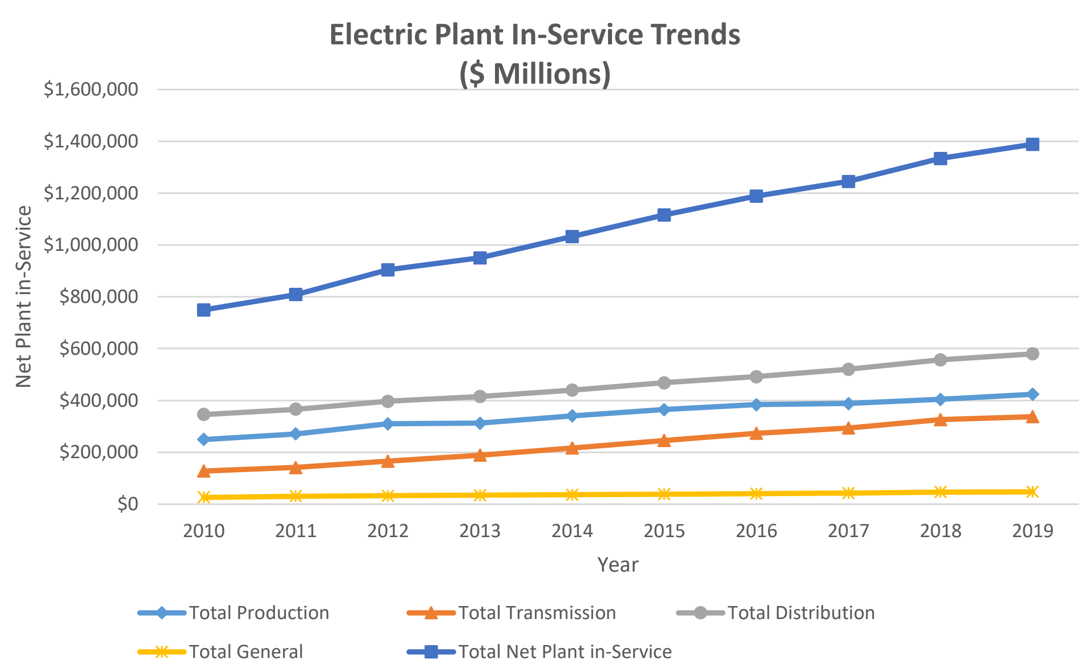
6. The current FERC incentives based on need and challenges also incent utility management to manage capital programs in a manner that maintains financial integrity and credit standing, and thus supports utilities' access to external capital markets under reasonable costs and terms. A FERC incentive policy that encourages these competing but balanced management objectives supports economically efficient transmission infrastructure development.

7. The investment community has made positive comments about the supportive regulatory treatment at FERC to encourage investments and maintain strong credit standing. A change to the FERC incentive policy is not necessary to support TO access to capital.

Q PLEASE DESCRIBE WHY YOU BELIEVE EVIDENCE CLEARLY ESTABLISHES THAT UTILITIES HAVE STRONG ECONOMIC INCENTIVE TO MAKE INFRASTRUCTURE INVESTMENTS.

A The utility industry has been making significant investments in transmission infrastructure for at least since 2010, a date preceding the current FERC incentive policy in 2012. The electric utility industry's plant in-service ("PIS") as recorded in FERC Form 1 data, has grown by approximately $750 billion in 2010 to over $1,390 billion in 2019. This is shown graphically in Figure 1 below.

FIGURE 1



Source:
Exhibit No. AMF-2

Of significance, while PIS has grown overall for electric utilities, transmission plant has realized the most significant increase in PIS. Transmission net PIS grew from $127.6 billion in 2010 to $337.4 billion in 2019. Overall, net PIS grew by 85% over this time period, but transmission plant grew by almost 165%, nearly twice as fast as the overall electric utility net PIS.

There are many reasons why net PIS has been growing so significantly for electric utilities over the last decade and why the cause of plant investments is not as relevant as the fact that electric utilities have made the investments, and have been able to do so by attracting significant amounts of external capital under reasonable terms and prices. Indeed, electric utilities' efforts to enhance shareholder value by growing their net PIS is expressed in their industry trade organizations and in investor reports by utilities to the investment public.

Q IS THERE EVIDENCE THAT THE ELECTRIC UTILITY INDUSTRY CONTINUES TO HAVE A STRONG INCENTIVE TO MAKE INFRASTRUCTURE INVESTMENTS?

A Yes. This investment allows utilities to grow their companies and enhance shareholder value. This perspective is noted by the current Edison Electric Institute ("EEI") president. In the EEI 2019 Financial Review of the electric utility industry, the current president made the following statements concerning the robust outlook of the industry:

> As you will see in this year's Financial Review, EEI's member companies continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the sixth straight year in

> 2019, after increasing from the BBB average that previously had held since 2004. This improved credit quality greatly supports the continued level of elevated capital expenditures, which set another record high of $124.1 billion in 2019.
>
> The EEI Index gained 25.8 percent in 2019, and our industry extended its long-term trend of widespread dividend increases. A total of 37 companies, or 93 percent of the industry, increased their dividend in 2019, matching the record-high percentage set in 2018. The industry's average dividend yield at the end of 2019 stood at 3.0 percent, while its dividend payout ratio was 64.1 percent for calendar year 2019. Among the primary U.S. business sectors, those results only trailed the energy sector. As of December 31, 2019, 39 of the 40 companies in the EEI Index were paying a common stock dividend.[14]

This statement by an industry trade organization is clear. Utilities grow their companies to appease their shareholders. Shareholders want increased stock value and increased dividend payments. Companies grow their earnings and ability to increase their dividends by making infrastructure investments.

The benefit of shareholders' value growth by making infrastructure investment is also evident in an executive financial presentation to investors. As shown on the attached Exhibit No. AMF-3, it is a common theme for utility executives to discuss value enhancement factors for shareholders. Utility executives outline the opportunities for enhancing shareholder value via increases in earnings and dividends that are largely fueled by making capital expenditure investment in growing rate base. These outlooks are expressed on my Exhibit No. AMF-3, where I highlight the utility executives' shareholder key enhancement value points made to the investment community.

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[14]Edison Electric Institute: *2019 Financial Review: Annual Report of the U.S. Investor-Owned Electric Utility Industry*, at ¶ II.A.12, provided as Exhibit No. AMF-4, pages 1-88.

This shareholder value tied to infrastructure investments is also stated in a Standard & Poor's ("S&P") Market Intelligence report on the utility industry. There, reports to the investment community related to utility capital programs, and the related impact on earnings and dividend-paying ability of the utilities are stated as follows:

> Estimated capital expenditures for electric transmission and distribution (T&D) infrastructure for U.S. electric and multiutility holding companies in the RRA universe are projected to reach $53.6 billion in 2020 and to rise approximately 5% in 2021 to $56.4 billion. T&D spending in 2022-2023 is expected to remain robust at more than $50 billion in each year, before tapering to $35.5 billion in 2024. These conclusions flow from the June 8 Financial Focus report, "US energy utility capex undeterred by coronavirus to date, slated to reach $141B." By business category, T&D spending is forecast to comprise <u>more than half of overall utility capex between 2020 and 2022</u>, on par with levels observed in recent years and representing a <u>substantial contribution to utility earnings growth in the years ahead</u>. These investments also form an important component of many utilities' environmental, social and governance, or ESG, strategies, amid a broader utility sector transition toward decarbonization through electric grid modernization and renewable energy expansion. The increase in number of renewable generation sources, which are often great distances from load centers, will continue to drive new transmission line projects.[15]

[15] S&P Global Market Intelligence: "Financial Focus: Utility electric T&D capex on upward trend; forecast nears $54B in 2020," June 15, 2020, emphasis added, provided as Exhibit No. AMF-4, pages 89-93.

Q AS THE ELECTRIC UTILITY INDUSTRY MANAGED THESE LARGE CAPITAL PROGRAMS, SHOULD CONSIDERATION BE GIVEN TO A BALANCED MANAGEABLE PROGRAM, RATHER THAN SIMPLY AN INCENTIVE TO TRY TO ENCOURAGE THE INDUSTRY TO INCREASE CAPITAL SPENDING UNCHECKED?

A Yes. Effectively, there are many reasons why a managed capital program is a key factor in meeting the FERC's economically efficient transmission infrastructure development objective. First, the industry must manage the level of capital spend at a level that allows it to effectively manage its financial integrity and credit standing. Increasing capital expenditure programs to a level that cannot be reasonably managed by the utilities can have a detrimental impact on their credit standing, access to capital, and if not managed effectively will negatively impact the cost of capital.

Second, prices to customers can be impacted by the timing of capital expenditures. Specifically, certain transmission investments may be expected to produce benefits to transmission customers, however those benefits may be realized at different points in time. Creating economic incentives that encourage electric utilities to accelerate capital investments can increase prices to customers immediately, while benefits may not be realized by customers for many years out into the future. In reality, accelerated development of transmission assets asked customers to pay higher prices now, for expected benefits that will be realized by future generations of customers. As such, imbalanced FERC incentives can create harm to customers by increasing transmission prices for increased development cost (rate base growth) and enhanced ROE, with the expectation of uncertain lower energy costs, and benefits where if those benefits are realized they are more likely passed on to future generations of customers. Again, this is not consistent with the objective of creating economically efficient transmission investment, and setting just and reasonable prices.

The FERC's current incentive policy of identifying transmission investments consistent with RTO/ISO planning, or encouraging incentives only when an incentive is necessary to create the priority development of transmission assets, balances these incentive mechanisms by prioritizing transmission development based RTO/ISO system improvement. The RTO/ISO development pace has supported the TOs' ability to responsibly grow capital spend and maintain financial integrity. This responsible pace of capital spending is consistent with the stated goal of efficient and economic development of infrastructure assets. FERC should not abandon its current successful approach.

Q EXPLAIN HOW TRANSMISSION INVESTMENT DEVELOPMENT HAS BEEN MANAGED IN A MANNER THAT SUPPORTS FINANCIAL INTEGRITY AND CREDIT RATINGS.

A The electric utility industry generally manages capital programs so as to have a reasonable balance of capital expenditures in a controlled manner that allows them to make large capital expenditures while managing investment risk and credit ratings. Changing the incentive policy to encourage TOs to further expand transmission investments may constrain utility credit ratings, erode credit quality, limit their access to external capital markets, and increase utility cost of external capital.

Utility companies have managed the level of capital expenditures to be a relatively stable portion of depreciation expense and cash flow from operations, as shown in Table 1 below.[16]

TABLE 1

Electric Utilities
Cap. Ex. and Cash Coverages
($ Millions)

Year	CapEx (1)	CapEx/ D&A (2)	CapEx/ OCF (3)
2019	$83,417	2.3x	0.6x
2015	$85,819	2.4x	1.0x
2010	$56,900	2.2x	0.9x

Sources:
[1]*S&P Global Market Intelligence*: "Utility Capital Expenditures Update", June 8, 2020, provided as Exhibit No. AMF-4, pages 94-98.
[2]*S&P Global Market Intelligence Financial Focus*: "Capital Expenditure Update", October 27, 2016, provided as Exhibit No. AMF-4, pages 99-107.

Notes:
[1]D&A = Depreciation and Amortization.
[2]OCF = Operating Cash Flow.

As shown in the table above, utilities have managed the size of capital expenditure programs as a proportion of internally generated cash, which is used in part to fund the capital programs. This practice manages the amount of external

[16]The data for Table 1 is provided as Exhibit No. AMF-4, pages 94-107, which are capital expenditure tracking reports published by Regulatory Research Associates ("RRA"), a subsidiary of S&P Global Market Intelligence. These RRA reports show that historically electric utilities have managed increased capital spending while maintaining the utilities' financial integrity.

capital needed to fund the program. This in turn manages construction risk and supports the utility's financial integrity, credit standing and access to external capital markets.

As such, as utilities' internally generated cash increases, with their embedded plant growing and rates increasing, utilities have systematically increased their level of capital spending. As shown in the table below, electric utilities' capital spending has increased from about $56.9 billion in 2010 up to approximately $83.4 billion in 2019. This is an approximate 50% increase. However, while the capital expenditures have been increasing, the table shows that the relative comparison of capital expenditures to depreciation and amortization recoveries in utility rates has remained relatively stable. The same kind of comparison is evident from a comparison of the capital expenditures to operating cash flow ("OCF") in the table. However, OCF has temporarily been reduced as a result of the Tax Cuts and Jobs Act of 2017.

The FERC's intent to create economically efficient incentives for utilities to manage their transmission infrastructure should continue to recognize the need to balance increasing capital expenditure programs with the utilities' need to maintain their financial integrity, credit rating and access to capital. Abandonment of the nexus test, combined with the potential for significant ROE adders, would work directly contrary to this objective.

Q DOES UTILITIES' MANAGEMENT OF LARGE CAPITAL PROGRAMS TO PRESERVE FINANCIAL INTEGRITY AND CREDIT STANDING ALSO NEED TO CONSIDER THE IMPACT ON TRANSMISSION RATES?

A Yes. In order to maintain credit standing, the transmission utilities must maintain as competitive a transmission rate as possible. To the extent transmission rates are increased to the point where they are no longer competitive, customers may seek alternative forms of energy, seek behind-the-meter generation, or move to locations where energy is more economical. Encouraging incentives that expand capital programs that do not maintain financial integrity, and unjustifiably increase transmission rates, will erode credit standing and is another factor that can result in the increase to cost of capital and transmission rates. This could have a devastating impact on TOs to the extent customers aggressively seek alternative means of managing energy costs.

Uncompetitive utility prices can have a negative impact on the utility's credit standing, and on the utilization of the transmission network. However, a more balanced approach where transmission rates are managed to a competitive level, in turn supports the utility's cash flow from operations to support capital investments and maintain financial integrity.

Again, there is a discipline to TOs' ability to responsibly and efficiently increase capital spending and it is not tied to only the awarded ROE. As the company increases its capital investment, and adjusts rates to reflect that increased capital investment, the company's depreciation expense and cash flow recovered through operations increase. This increase in cash flow then allows the utility to financially support a larger capital expenditure program, and support credit. This measured approach to managing a capital program that can be supported by the financial resources of the utility, allows the utility to increase capital expenditures while managing its credit rating. This is a critical aspect in allowing the utility to manage the capital expenditure program and maintain its access to capital under reasonable terms and prices. This responsible capital expenditure management is critical in ensuring that customers receive reasonably priced transmission service and high quality, reliable service.

Q HAVE CREDIT RATING AGENCIES NOTED THERE IS A CONCERN ABOUT RISKS ASSOCIATED WITH THE SIZE OF CAPITAL EXPENDITURE PROGRAMS FOR UTILITIES?

A Yes. Because capital programs can have a significant impact on the utilities' cash flows, credit rating agencies carefully monitor the level of capital expenditure programs currently being undertaken by the utilities. Credit rating agencies are also concerned about the impact on rates to the extent customers may have difficulty paying bills if growth in invested capital results in uncompetitive utility rate structures.

For example, S&P states the following concerning assessment of the size of a capital program, the impact on a utility's cash flows, and affordability of service is considered in the assessment of credit ratings:

> **2. Regulation and public policy support earnings and cash flow**
>
> We expect that regulators will continue to provide utilities with constructive frameworks that support credit quality. For most

> regulators, the requirement that utilities provide safe, reliable, and affordable utility services remains a priority. This regulatory perspective is balanced against an increasing awareness that the utility infrastructure in North America is aging, and that utilities may have to invest necessary capital to maintain and improve the infrastructure apparatus for electric, gas, and water systems. Such regulated infrastructure capital spending most often translates to low-risk rate base growth. In addition, regulatory support ensuring timely recovery of costs generally remains favorable for utilities' credit quality.[17]

Moody's also forms its credit outlook based on a combination of cash flow (Funds From Operations) coverage of capital expenditures, managing customers' rates, and receiving regulatory support of capital programs. Moody's notes that significant changes in any of these relevant factors could negatively impact utilities' credit standing. Moody's statements of the regulated electric and gas utility industry credit outlooks include the following:

> **2020 outlook moves to stable on supportive regulation, weaker but steady credit metrics**
>
> - **FFO-to-debt ratios will hold steady in 2020 but at lower levels.**
> - **Customer rates remain steady despite elevated capital spending to grow rate base.**
> - **State regulators and legislators will remain supportive of utility credit quality.**
> - **What could change our outlook.** We would consider shifting our outlook to positive if regulation turns more credit-supportive or if the sector's consolidated FFO-to-debt ratio rises to around 18% on a sustainable basis. We would consider changing our outlook to negative if weakened cash flow causes the ratio to fall to around 14%. A more contentious regulatory environment or an increase in

[17] *S&P Global Ratings*: "Industry Top Trends 2019: North American Regulated Utilities," November 8, 2018, at 5, emphasis added, provided as Exhibit No. AMF-4, pages 108-118.

> leverage within the utility sector's capital structure could also change our outlook to negative.[18]

Finally, Fitch also makes comments concerning the impact of construction programs on the utility's financial capacity to manage the capital program, and consider the impact on rate affordability. Fitch states as follows:

> **Constructive Regulation Supports Recovery in Credit Metrics**
>
> **Fitch's Sector Outlook: Stable**
> Fitch Ratings' stable outlook embeds an expectation that sector <u>credit metrics will begin to stabilize in 2020</u>, driven by an increase in FFO after the record capex in 2019 and conclusion of a majority of tax reform-related refunds. Low commodity prices and interest rates, O&M cost savings, in part due to the ongoing transition to cleaner generation mix, and tax refunds are providing ample headroom to utilities to <u>seek recovery for capital investments without undue pressure on customer bills</u>.
>
> We expect utility <u>capex to remain elevated in 2020</u>. Much of this is driven by investments in <u>grid modernization</u> and resiliency, renewable generation, and natural gas pipeline replacement and safety, all of which are consistent with public policy goals and garner wide regulatory support.
>
> **Rating Outlook: Stable**
> With approximately 88% of ratings on Stable Outlook, we expect <u>limited rating movement in 2020</u>.[19]

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[18]*Moody's Investors Service Outlook*: "Regulated electric and gas utilities – US: 2020 outlook moves to stable on supportive regulation, weaker but steady credit metrics," November 7, 2019, at 1, provided as Exhibit No. AMF-4, pages 119-135.

[19]*Fitch Ratings*: "Fitch Ratings 2020 Outlook: North American Utilities, Power & Gas," December 4, 2019, at 1, underlining emphasis added, provided as Exhibit No. AMF-4, pages 136-141.

Q HAVE CREDIT RATING AGENCIES NOTED WHETHER OR NOT CURRENT FERC REGULATORY POLICIES AND INCENTIVES SUPPORT FINANCIAL INTEGRITY AND CREDIT STANDING OF UTILITIES?

A Yes. FERC has consistently noted that transmission utilities regulated by FERC have a high probability of full cost recovery under the existing FERC rate-setting protocols. I have outlined some comments below related to only transmission companies operating before FERC.

Credit rating agencies have also noted the need to manage capital expenditure programs reasonably. Unjustifiably inflating capital programs to chase ROE incentives could have a negative impact on the TO's credit rating, and ability to access external capital markets.

S&P makes positive comments about FERC's regulatory treatment for ensuring cost recovery, and the supportive strong financial conditions of transmission affiliates. For example, S&P stated the following concerning companies that are predominantly transmission-only utility companies that are regulated by the FERC. These companies include American Transmission Company ("ATC") and International Transmission Company ("ITC") and its affiliate, Michigan Electric Transmission Company ("METC").

S&P commented about ATC:

> Formulaic, forward-looking rate-setting structure under the Federal Energy Regulatory Commission (FERC) supports American Transmission Co.'s (ATC's) effective management of regulatory risk.

* * *

> ***We expect American Transmission Co. (ATC) to effectively manage regulatory risk, supporting our assessment of its excellent business risk profile***. This reflects the company's essential transmission operations under a credit-supportive Federal Energy Regulatory Commission (FERC) regulatory framework.[20]

Similar comments about METC and ITC:

> Our assessment of ITC Midwest's business risk reflects our view of its fully rate-regulated and lower-risk transmission business operating within the FERC's highly supportive regulatory construct.
>
> * * *
>
> **Financial Risk: Modest**
>
> We assess ITC Midwest's financial risk profile against our most relaxed financial benchmark tables, compared to the typical corporate issuer, reflecting the company's low-risk transmission business and its effective management of regulatory risk under the FERC's supportive regulatory construct.[21]

S&P notes that transmission companies being rated against the more relaxed financial ratio benchmarks is an indication that their operating risk is very low, and allows them to more easily maintain financial coverage ratios that support strong credit standing. Indeed, S&P typically provides these lower risk metric rating categories to only companies that do not have direct commodity risk. Those typically include transmission companies regulated by FERC, and water utilities. As such, it is clear evidence that credit rating agencies believe that FERC regulated transmission companies are among the most low business risk of all utility companies.

[20] *S&P Global Ratings RatingsDirect*: "American Transmission Co.," April 29, 2020, at 2, emphasis added, provided as Exhibit No. AMF-4, pages 142-149.

[21] *S&P Global Ratings RatingsDirect*: "Summary: ITC Midwest LLC," December 20, 2017, at 3-4, emphasis added, provided as Exhibit No. AMF-4, pages 150-157.

III. THE COSTS OF THE PROPOSED INCENTIVE CAN BE A SIGNIFICANT AND UNJUSTIFIED COST BURDEN ON TRANSMISSION CUSTOMERS

Q WHAT ARE THE POTENTIAL COSTS ON CUSTOMERS IF THE FERC IMPLEMENTS ITS INCREASED ROE ADDERS BASED ON ITS PROPOSED INCENTIVE TARGETS?

A The proposed ROE incentives will transform a base ROE into a return more in line with speculative enterprises and would produce a return that is not just and reasonable. This is particularly true in face of today's very low capital market costs. For example, in FERC Opinion Nos. 569 and 569-A, the Commission set base ROEs for MISO TOs at 9.88% and 10.02%, respectively. A 1 percentage point premium for joining an RTO/ISO would add over approximately a 10% premium to this earnings level. The proposal for such a significant increase in the base ROE will unjustifiably award TOs with a return that compensates for far greater risk than the TOs assume by making FERC regulated transmission investments. Further, the resulting ROEs of 10.88% and 11%, respectively, are nearing the estimated return on the market of 11.8% used in the CAPM analysis in reaching these base ROEs.[22] The full maximum amount of the ROE incentives of 250 basis points represents an enormous premium to the base ROE, of over 25%, and would provide TOs with returns well above that of expected market returns. This level of ROE is competitive with the expected returns of speculative, high risk, ventures. The resulting impact on transmission prices would produce unjust and unreasonable rates to transmission customers.

[22] EL14-12-003, Initial Brief of the Commission Trial Staff, Attachment A, page 6; and EL15-45-000, Initial Brief of the Commission Trial Staff, Attachment A, page 6.

The direct impact on measurement of transmission revenue requirement is equally excessive based on these proposed ROE adders. The increase in total costs to customers that take transmission service can be significant. For example, simply looking at the transmission rate base for companies that participate in RTOs/ISOs, the potential increased cost to those customers of the various incentives is stated as follows:

One component of the proposed new incentive policy will provide all TOs that join an RTO/ISO a 100 basis point ROE adder. Currently, the RTO/ISO adder is 50 basis points, and only made available to TOs that voluntarily join the RTO/ISO. It is important to note that many TOs have joined RTOs/ISOs as a matter of regulatory commitments, or mergers and acquisitions, or based on changes in regulatory rules within state jurisdictions. It is not reasonable to ask customers to pay higher transmission prices to award a utility to do something it agreed to as part of a settlement, or is obligated to do as part of its state regulatory requirements.

Table 2 below, shows the increase in transmission prices for the various RTO regions based on a 100 basis point ROE adder.

TABLE 2

Revenue Impact 100 bpt ROE
($000)

RTO/ISO	Amount
CAISO	$125,092
MISO	$196,625
NEISO	$72,032
NYISO	$14,426
PJM	$282,308
SPP	$69,912
Total	$760,396

Source: Exhibit No. AMF-5

As shown in the table above, each of the various RTO/ISO regions' prices and revenue collections from customers will increase dramatically. On average, these increases in prices equate to an approximately $760 million increase in transmission rates. This annual cost will increase as RTO/ISO rate base or net plant grows over time.

Another aspect is to provide ROE incentive adders of 50 basis points to 100 basis points for certain economic benefit tests. There are material deficiencies in these economic benefit tests as discussed below. However, the potential increase in costs for transmission customers will depend on the assets qualifying for these incentives. Because a production cost study can be impacted by the inputs, and changes in factors underlying the outlook for changes in market conditions, the results can be very controversial. Under such circumstances, the costs to transmission customers would be dramatic. If TOs start adding to their current rate base, transmission assets that are qualifying for economic benefits, and these accumulate over time, eventually the transmission assets that qualify for a benefit could be a significant portion of the total transmission rate base.

Over time, if the maximum ROE incentive of 250 basis points is applied to a portion of a utility's rate base, then the cost outlined in Table 2 above would be increased by this additional adder cost. If initially the 250 basis points are applied to approximately 10% of the rate base, the annual cost in Table 2 above would be increased by another $150 million. As the incentive ROE grows up to a greater portion of rate base, up to all of rate base, the increase could be as much as two and a half times the estimate outlined in Table 2 above, or in excess of $2 billion per year. It is difficult to imagine just how expensive this could be, but largely depends on the level of maximum ROE incentive permitted to be included in the development of rates.

IV. UNJUSTIFIED FINANCIAL INCENTIVES CONFLICT WITH THE NOPR'S STATED GOAL OF ECONOMICALLY EFFICIENT INFRASTRUCTURE INVESTMENTS

Q DO YOU BELIEVE THAT THE PROPOSED CHANGE OF THE INCENTIVES TEST FROM BEING A NEXUS TEST TO BEING A BENEFITS TEST WILL ACHIEVE THE FERC'S OBJECTIVES?

A No. As stated above, the current FERC policy is to provide fair compensation with prudent and reasonable infrastructure investment that complies with the FERC's goal of economically efficient transmission systems. Incentives are only allowed when a demonstration of need exists, and that need is shown to be consistent with the public interest.

In significant contrast, allowing for a benefits test would change the dynamics of transmission investment on the part of TOs. TOs will have a financial and economic incentive to maximize transmission investments that are subject to an enhanced ROE. This can create more controversy in the system planning process, can create controversy in identifying whether or not there are any economic benefits associated with transmission investments, and whether or not the transmission investments are needed for improving reliability.

Under the FERC policy, TOs will be permitted to earn a well above market rate of return on transmission investments subject to an ROE incentive. This incentive can be up to 250 basis points, and will not be limited by the high-end of the zone of reasonableness established as appropriate for setting fair compensation for TOs. This opportunity to earn above market rates of return will create significant economic incentives and financial incentives for TOs to maximize transmission investments to achieve this windfall opportunity. The transmission planning will convert to a process that is searching for transmission investments that will earn an incentive ROE rather than purely look for investments that are needed for improvements to reliability and for relieving transmission constraints. TOs will be economically and financially incented to influence the RTO/ISO planning process to identify and prioritize transmission investments that qualify for incentive rates of return. This will complicate and potentially weaken the RTO/ISO planning process and skew the identification and assessment of whether new transmission investments truly will create economic benefits through fuel savings or are truly needed for system reliability benefits.

Equally as important, the TOs will likely have strong financial and economic incentives to invest in transmission plant that are provided well above market rates of return, that may no longer continue to plan and manage levels of capital investments so as to maintain large capital programs, while at the same time manage financial integrity and credit standing. Utilities may be more willing to expand capital programs above cash flow coverages and weaken credit, potentially impair access to external capital, or increase their cost of external capital.

The incentive to maximize transmission investments may also result in TOs hiring less qualified external contractors, or overloading existing internal engineering and technicians capable of economically and efficiently designing, planning and constructing transmission investments. In either case, the ability of the utility to manage an efficient and economic capital program can become impaired and the costs of the programs can suffer. Further, the reliability and life of the assets could also be detrimentally impacted. All of the impacts will negatively impact transmission customers.

Q IS THERE CONCERN THAT UTILITIES MAY NOT HAVE THE RESOURCES TO MANAGE A CONTINUED GROWTH IN CAPITAL EXPENDITURES?

A Yes. This is evident from certain concerns stated by certain executives that the aging of the technical work force of the utility is nearing retirement, and some utilities are having difficulty finding adequate engineering replacements. Several prominent transmission companies have stated concern about the risk of attracting and retaining a qualified work force.

Specifically, ITC Holdings Corp. ("ITC") outlines work force as components of risk related to its business. ITC states the following:

> **We contract with third parties to provide services for certain aspects of our business. If any of these agreements are terminated, we may face a <u>shortage of labor or replacement contractors</u> to provide the services formerly provided by these third parties.**
>
> We enter into various agreements and arrangements with third parties to provide services for construction, maintenance and operations of certain aspects of our business, and we utilize the services of contractors to a significant extent. If any of these agreements or arrangements is terminated for any reason, <u>it could result in a shortage of a readily available workforce</u> to provide such services and we may face difficulty finding a qualified replacement workforce. In such a situation, if we are unable to find adequate replacements for contractors in a timely manner, it could have an adverse effect on our results of operations and the ability to carry on our business.[23]

Ameren Corporation also states concern about work force risk:

> **INDUSTRY ISSUES**
>
> * * *
>
> - the availability of a skilled work force, including retaining the <u>specialized skills</u> of those who are nearing retirement
>
> * * *
>
> **We are subject to employee work force factors that could adversely affect our operations.**
>
> Our businesses depend upon our <u>ability to employ and retain key officers and other skilled professional and technical employees. A significant portion of our work force is nearing retirement, including</u>

[23]ITC Holdings Corp.'s 2019 Form 10-K at 15-16, underlining emphasis added, provided as Exhibit No. AMF-4, pages 249-251.

> <u>many employees with specialized skills</u>, such as maintaining and servicing our electric and natural gas infrastructure and operating our energy centers. We are also party to collective bargaining agreements that collectively represent about 51% of Ameren's total employees. Any work stoppage experienced in connection with negotiations of collective bargaining agreements could adversely affect our operations.[24]

V. THE PROPOSED BENEFIT TEST WILL NOT PROTECT CUSTOMERS FROM EXCESSIVE ROE AWARDS

Q DID THE FERC OUTLINE THE OBJECTIVES IN DEVELOPING A BENEFITS TEST AS PART OF ITS INCENTIVE POLICY?

A Yes. The FERC stated it wanted to limit measurement of economic benefits to adjusted production costs or similar measures of congestion reduction or certain other quantifiable benefits that are verifiable and not duplicative. FERC stated the analysis seeks to minimize total system costs by evaluating the security constrained unit commitment and economic dispatch of the system over a given time horizon.[25] FERC stated it expects that these economic dispatch runs will be based on the RTO/ISO analyses of the economic benefits of transmission projects.[26] While the Commission noted that these economic dispatch studies can be confidential, it is assuming that the stakeholders will have access to these economic dispatch results.[27]

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[24]Ameren Corporation 2018 Form 10-K at 14, 16 and 25, underlining emphasis added, provided as Exhibit No. AMF-4, pages 252-257.
[25]NOPR at ¶ 48.
[26]*Id*. at ¶ 44.
[27]*Id*.

Q DOES FERC'S PROPOSAL FOR OUTLINING THE MEASUREMENT OF ECONOMIC BENEFITS IN SUPPORT OF SIGNIFICANT ROE INCENTIVE ADDERS PROVIDE ADEQUATE PROTECTION TO CUSTOMERS?

A No. The use of production cost studies for measuring benefits to justify ROE incentives is far from sufficient to ensure that customers' interests are protected. Production cost studies generally are statistically based methodologies that project over a long time horizon, in an effort to estimate the impacts on delivered energy cost that will be impacted by changes in load (growth and time of day shape), changes and reliability of production resources, changes in transmission constraints, changes in fuel costs, changes in environmental regulations, and additions and retirements of generating resources.

All of these highly uncertain variables are modeled under wide ranges of assumptions that are believed to capture the range of impacts on future energy costs. The production cost runs are really thousands of different scenarios that are assigned probability of occurrences to produce a statistical outlook of an "expected" production cost result. The fuel saving estimated from these long-term production cost planning tools does not produce a known and measurable energy savings that can be used to reliably offset a known ROE cost increase, and have any confidence that rates charged to transmission customers are just and reasonable.

These production cost model projections are useful in identifying the expected need for new transmission investments. If the prices for those transmission investment developments are based on prudent cost with fair compensation then the public benefits are supported by rational planning. As such, production cost models are beneficial tools in the economically efficient planning of transmission infrastructure. However, even on a resource planning perspective, a production cost model alone is not sufficient to economically justify transmission investments.

Q HAVE THERE BEEN ANY STUDIES THAT QUESTION THE USEFULNESS OF MEASURING TRANSMISSION INVESTMENT ECONOMIC BENEFITS USING ONLY PRODUCTION COST STUDIES?

A Yes. One such study was performed by The Brattle Group. The Brattle Group study questioned identifying prudent transmission investments only on the basis of a production cost study, concluding the following:

- Importance of Considering All Benefits
  - Not all proposed transmission projects can (or should) be justified economically
  - Transmission projects can provide a wide range of benefits—economic, public, and reliability—to a range of market participants and regions
  - Narrow or conservative evaluation of transmission benefits risks rejection of valuable projects
  - Transmission benefits in large part are a reduction in system-wide costs
  - Not considering the full economic benefits of transmission investments means not considering all costs and the potentially very-high-cost outcomes that market participants would face without these investments
  - Production cost simulations have become a standard tool to assess "economic benefits" of transmission, but only considers short-term dispatch-cost savings under very simplified system conditions (e.g., no transmission outages)

  - Simplified simulations reflect incomplete production cost savings, thus only a smaller portion of the overall economy-wide benefits

- Other Benefits considered by RTOs when performing transmission planning
  - Facilitation of the retirement of aging power plants
  - Encouraging fuel diversity
  - Improved reserve sharing
  - Increased voltage support
  - Enabling future markets
  - Storm hardening
  - Improving operating practices/maintenance schedules
  - Lowering reliability margins
  - Improving dynamic performance and grid stability during extreme events
  - Societal economic benefits
  - Mitigation of weather uncertainty
  - Mitigation of renewable generation uncertainty
  - Reduced cycling of baseload plants
  - Increased ability to hedge congestion costs
  - Increased competition and liquidity
  - Reduced air emissions
  - Avoided reliability projects
  - Avoided generation investment
- Long life of transmission assets requires comparison of long-term benefits and costs

  - Either on a present value or levelized annual basis
  - Over a time period, such as 40 or 50 years, that approaches the useful life of the physical assets

- How benefits and costs accrue over time and across future scenarios will help optimize the timing of investments

- Near- and long-term uncertainties need to be addressed to develop robust plans and least-regret projects

- Long-term uncertainties

  - (industry structure, new technologies, fundamental policy changes, and shifts in fuel market fundamentals) can be addressed through scenario-based analyses
  - Near-term uncertainties within long-term scenarios (uncertainties in loads, fuel prices, transmission and generation outages) should be evaluated through sensitivity or "probabilistic" analyses[28]

Modifying the ratemaking incentives as proposed will create ROE adders that are tied specifically to the development of simplistic production cost model runs, which estimate potential fuel savings in the future. This will modify the prioritization of transmission investments for at least transmission providers, and may have undue influence on RTO/ISO planning studies in prioritizing transmission investments. This will essentially move away from economically efficient transmission infrastructure development, and move it toward maximizing shareholder value by choosing transmission projects that can earn and enhance ROE as opposed to creating greater system benefit. The proposed change is simply inappropriate and does not meet the FERC's stated goal of economically efficient transmission infrastructure development.

[28]The Brattle Group Presentation: "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," July 31, 2013, provided as Exhibit No. AMF-4, pages 258-282.

Q IF PRODUCTION COST STUDIES ARE NOT BY THEMSELVES ADEQUATE FOR TRANSMISSION SYSTEM PLANNING, SHOULD PRODUCTION COST STUDIES ALONE BE ADEQUATE FOR MEASURING ECONOMIC BENEFITS OF TRANSMISSION ASSETS?

A No. Production cost studies simply are not reliable enough to measure economic benefits associated with transmission investments that can justify an incentive ROE adder. Production cost studies are long-term studies that try to capture highly uncertain variables which can impact the need and drive economic investments in new infrastructure assets. It does produce expected values but it does not produce actual values. As a consequence, it is an appropriate tool for planning, but should not be the only tool utilized in identifying new infrastructure investments. A production cost study does not produce known and measurable cost savings and therefore should not be used to justify increased costs to customers to pay TOs ROE incentives. The net impact on customers is highly uncertain from the production cost study, but customers' rates certainly will go up by the inclusion of ROE adders.

Q DO THE PROPOSED INCENTIVES RELATED TO RELIABILITY INCENTIVES PROVIDE ADEQUATE PROTECTION TO CUSTOMERS?

A No. The proposed incentive policy will add a 50 basis point ROE incentive for transmission projects that provide significant and demonstrable reliability benefits.[29] This proposal is unreasonable for several reasons. First, transmission investment that can improve reliability is generally the standard which demonstrates that a

[29]NOPR at ¶ 65.

transmission investment is prudent and reasonable and should be undertaken. A fair and reasonable return for making transmission reliability investments is at the FERC's base ROE without any adders. The risk of such investment is low due to FERC's investor friendly cost recovery rate-setting protocols along with a fair and reasonable risk-adjusted base ROE. An above market rate of return is not justified for transmission companies undertaking the investment opportunities that align with the low-risk nature of making transmission infrastructure investments subject to minimal cost recovery risk uncertainty based on FERC current ratemaking policies.

It is clear from the FERC's standards that there are many ways to measure reliability, and therefore the awarded return on equity cannot be clearly distinguished from simply making a prudent investment decision, and an incentive ROE which is necessary to provide adequate incentive for the transmission infrastructure investment to actually be made. The proposal for an incentive ROE based on enhanced reliability is unjustified, unneeded, and should not be adopted.

Q DOES THIS CONCLUDE YOUR AFFIDAVIT?

A Yes.

Qualifications of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Arkansas, Arizona, California, Colorado, Delaware, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas;

presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

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Acronyms and Abbreviations

ATC	American Transmission Company
BAI	Brubaker & Associates, Inc.
CFA	Chartered Financial Analyst
Commission	Federal Energy Regulatory Commission
DBA	Drazen-Brubaker & Associates, Inc.
EEI	Edison Electric Institute
FERC	Federal Energy Regulatory Commission
Form 730	Report of Transmission Investment Activity
FPA	Federal Power Act
ICC	Illinois Commerce Commission
ISO	Independent System Operator
ITC	International Transmission Company
NOPR	Notice of Proposed Rulemaking
OCF	Operating Cash Flow
PIS	Plant In-Service
RFP	Request for Proposals
ROE	Return on Equity
RRA	Regulatory Research Associates
RTO	Regional Transmission Organization
S&P	Standard & Poor’s
Transcos	Transmission Companies
TO	Transmission Owner