**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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| **Notice of Proposed Rulemaking** | ) | **Docket No. RM20-10-000** |
| **Electric Transmission Incentives Policy** | ) | |
| **Under Section 219 of the Federal Power Act** | ) | |

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# COMMENTS OF POTOMAC ECONOMICS, LTD.

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Pursuant to the above-captioned Notice of Proposed Rulemaking Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act (NOPR) initiated by the Federal Energy Regulatory Commission (the "Commission"), Potomac Economics hereby submits these comments. The Commission seeks comments on the proposed rulemaking on changes to its electric transmission incentives regulations and policy. Potomac Economics appreciates the Commission's focus and recognition of the importance of incentives in this area to help ensure reliability and reduce the cost of delivered power by reducing congestion.

Potomac Economics submitted comments and participated in both the NOI on Transmission Incentives[1] and the GET Tech Conference[2]. Potomac Economics' comments

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[1] Inquiry Regarding the Commission's Electric Transmission Incentives Policy, 84 FR 11759 (Mar. 28, 2019), 166 FERC 61,208 (2019) (2019 Notice of Inquiry).

[2] Grid-Enhancing Technologies, Docket No. AD19-19-000.

addressed many of the objectives of the NOPR, and the comments focused on additional areas where our monitoring roles provide useful insight on the potential for efficiency gains through increased transmission utilization and improved market incentives for new investment. We believe our analysis and recommendations in the areas of transmission utilization and investment is highly instructive, and we provide these comments to the Commission to help further the development of the Commission's incentive policies.

Potomac Economics is the Independent Market Monitor (IMM) for Midcontinent ISO (MISO) and ERCOT, the Market Monitoring Unit (MMU) for the New York ISO (NYISO), and the External Market Monitor (EMM) for ISO New England. In these roles, we are responsible for monitoring and evaluating the performance of each RTO's energy and operating reserve markets. We also recommend market design changes to improve the performance of the markets and evaluate design changes proposed by the RTOs or market participants.

Potomac Economics' role as market monitor for several of the RTOs/ISOs provides us with unique insight regarding how transmission is utilized in RTO markets. This includes insight regarding the development and use of the transmission system over many time horizons, including from the planning horizon (investment and construction) through the operating horizon in real time (5-minute dispatch and Reliability Coordination).

## I. NOTICE AND COMMUNICATIONS

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## II. BACKGROUND AND INTRODUCTION

The Commissions' NOPR on its Electric Transmission Incentives Policy covers both new and existing transmission.[3] In this NOPR, the Commission proposes to:

(a) Transition from a "risks and challenges" model to one based on benefits to more closely align with FPA section 219;

(b) Offer 50 to 100 basis points for transmission projects based on having relatively high benefit to cost ratios;

(c) Offer 50 basis points for projects that provide potential reliability benefits;

(d) Allow utilities to recover the costs of projects cancelled due to factors out of their control;

(e) Eliminate current incentives for Transcos;

(f) Provide a consistent 100 basis point incentive for any utility that is a member in an Independent System Operator (ISO) or Regional Transmission Organization (RTO);

(g) Offer a 100 basis point incentive for technologies that improve the reliability, efficiency, or operation of transmission facilities; and

(h) Cap the total ROE incentives at 250 basis points.

The Commission states in the NOPR that "many transmission technologies discussed at Grid-Enhancing Technologies ("GET") Workshop are smaller in scale, and…. many of the costs of transmission technologies are not currently capitalized and hence do not benefit from ROE incentives."[4]

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3 Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act, 85 CFR 18784 (April 2, 2020), 170 FERC ¶ 61,204 (2020) ("NOPR").

4 NOPR at para. 67.

As is clear from the list of proposed incentives, the focus of most of the Commission's current policies on incentives has been and continues to be focused on utilizing Return on Equity (ROE) incentives and primarily on new transmission investment. As discussed in these comments, this focus limits the benefits of what could be achieved by improving transmission incentives. We encourage the Commission to consider supplementing the proposed ROE incentives with market-based incentives. Additionally, we recommend that the Commission consider enhancing its focus on actions to improve the utilization of existing transmission facilities, including more efficient incentives to employ grid-enhancing technologies (GET) and to adjust transmission ratings with temperatures and other factors.

In the sections below, we separately address incentives applicable to the operation of existing transmission facilities and for investment in new transmission facilities. We believe new market-based incentives that include incentivizing increased network capacity, facility ratings, and efficient grid utilization, rather than specific technologies, will provide flexibility to transmission owners and other market participants and best achieve the Commission's goals.

## III. INCENTIVES FOR EXISTING TRANSMISSION FACILITIES

The Commission's focus on incentives in this NOPR have been on providing regulatory incentives through enhanced ROEs for new transmission facilities. This is intended to recognize that new transmission facilities can provide substantial benefits by relieving key bottlenecks. Operating existing transmission facilities in a manner that allows greater network flows can also produce sizable benefits, but with little or no capital investment. The primary incentive proposed in this area is the continuation of the 100-basis point ROE incentive for participating in an RTO.

It is true that participating in an RTO improves the utilization of transmission by improving market signals, increasing coordination of injections into and withdrawals from the transmission network over a wider area, and establishing market-oriented congestion management across Reliability Coordination Seams. However, RTO membership alone does not lead to full utilization of transmission.

As the market monitor for four of the nation's RTOs, we have identified a number of shortcomings in the operation of transmission facilities that limit the utilization of the network and increase congestion. We attribute many of these operational shortcomings to an unfortunate lack of efficient incentives for transmission owners to take actions that maximize the utilization of the existing network, including:

- Providing Ambient-Adjusted Ratings (AAR) and Emergency Ratings;[5]
- Facilitating and deploying Dynamic Line Ratings ("DLR") technologies;
- Scheduling outages to minimize congestion; and
- Optimizing the operation of transmission equipment.

This section will discuss recommended incentives in each of these areas and identify potential benefits associated with making these improvements.

### A. Incentives to Provide Efficient Transmission Ratings

Facility ratings are used in virtually every aspect of electricity market and system operations, from the planning horizon to real-time operations. A rating simply reflects the amount of power that can safely and reliably flow through a transmission facility (e.g., a line or a transformer). A normal (or Continuous) rating is an amount that can flow indefinitely, while an Emergency Rating, sometimes referred to as "short-term emergency" rating is an amount that

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[5] The terminology has evolved through FERC proceedings, including the Technical Conference on Managing Transmission Line Ratings (AD19-15). Ambient-Adjusted Ratings (AARs) may be implemented with or without Dynamic Line Rating (DLR) technologies. Ambient temperature is the dominant factor in the determination of a rating, and broad and readily available temperature measurements can be used to provide AARs. To provide better forecasts and more precise ratings, DLR technologies may be employed which generally enables higher ratings.

can be safely accommodated for a defined period, typically only 2 to 4 hours. These ratings are the basis for the transmission limits used as inputs to the RTO market models that ultimately determine the resources committed and dispatched to meet load in real time and to manage congestion (keep flows at or below transmission limits).

Using ratings that are understated (below their design criteria under prevailing conditions) will cause the RTO to operate inefficiently and lead to:

- Higher congestion costs for RTO customers;
- Reduced availability of transmission service;
- Higher local resource adequacy and transmission security requirements; and
- Increased perceived need to invest in new transmission facilities.

Ratings for conductors and other types of elements generally vary with ambient conditions.[6] Seasonal static ratings are calculated assuming appropriately conservative weather conditions. However, the actual ratings in any hour depend on the current ambient conditions, including temperature, wind speed and direction, and humidity. Since the seasonal ratings are appropriately based on conservative assumptions (e.g., high temperatures), Ambient-Adjusted Ratings (AARs) are almost always significantly higher than the seasonal ratings.

In general, transmission owners have the authority to determine the transmission ratings. Ideally, transmission owners would provide AARs in real-time or at least hourly since these ratings can be substantially higher than the seasonal ratings. Additionally, RTOs should typically use emergency ratings (which are typically 10 percent or more higher than normal ratings) for most constraints that are "contingency constraints".

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6 The standard used by the industry to establish overhead line ratings is IEEE Standard 738-2012. This standard identifies a methodology based on a set of inputs (ambient temperature, conductor temperature, wind speed and direction with respect to the conductor, type of conductor, sun/no sun, emissivity index, absorptivity index, longitude/latitude, etc.) that go into the heat balance equation to determine the ampacity limit of the conductor.

A contingency constraint involves a "Monitored" facility and a "Contingent" facility. These constraints are managed with limits that allow for the additional flows on the Monitored facility that will result if the Contingent facility fails. Contingency analysis enables Reliability Coordinators to ensure that if the most significant contingency occurs the flow on the Monitored facility will not exceed its post-contingency limits. Emergency ratings are appropriate for these constraints because this flow will only occur after the contingency occurs, and the real-time dispatch and additional RTO actions that can be taken after the contingency will reduce the flow back down to the normal rating.

Using AARs and emergency ratings is most important in the real-time market dispatch. In this timeframe, transmission owners have (or could have) accurate information on temperature, wind speed/direction, and other factors that allow them to calculate AARs. In practice, however, very few transmission owners provide AARs, and only some consistently provide emergency ratings. We believe the primary reason for this is that utilities lack the incentive to provide such ratings, which significantly increases congestion and reduces the utilization of the transmission network. Ironically, the proposals in the Commission's NOPR could exacerbate the incentive concerns.

Since transmission owners are guaranteed recovery of their costs, their revenues are generally unaffected by the rating levels of their facilities. Transmission owners have incentives to satisfy reliability standards and protect against equipment damage and degradation. These incentives generally result in *lower* ratings.

As the NOPR recognizes, increases in ratings for existing facilities may be achieved through O&M expenses for which there may be no return on investment, which reduces the incentive to incur these expenses and ultimately leads to *lower* ratings. Finally, improvements in ratings for existing facilities may compete with new transmission projects that are a source of increased revenues for transmission owners. Unfortunately, increasing the ROE for new transmission investment will increase the incentive for utilities to provide *lower* ratings for existing transmission facilities. Unfortunately, the Commission requires little or no oversight over the calculation of transmission ratings, and the validation of ratings by most RTOs is insufficient or entirely lacking.

These existing incentives explain why few transmission owners in RTO areas provide AARs and emergency ratings that allow the RTO to maximize its utilization of the transmission network, despite the enormous system-wide economic benefits of doing so. We have estimated these benefits for MISO and believe that comparable benefits would be available in most other RTO areas. In our *2019 State of The Market Report* for MISO, we estimate MISO could have saved more than $114 million in production costs in 2019 by using temperature-adjusted and emergency ratings as shown in the table below.[7]

**Benefits of Temperature-Adjusted and Emergency Ratings**
2018-2019

| | | Savings ($ Millions) | | | # of Facilites for 2/3 of Savings | Share of Congestion |
|---|---|---|---|---|---|---|
| | | **Ambient Adj. Ratings** | **Emergency Ratings** | **Total** | | |
| **Total Estimated Benefits** | | | | | | |
| **2018** | Midwest | $77 | $48 | $125 | 19 | 12.7% |
| | South | $7 | $18 | $25 | 2 | 7.1% |
| | **Total** | **$85** | **$66** | **$150** | **21** | **11.2%** |
| **2019** | Midwest | $62 | $36 | $98 | 18 | 14.5% |
| | South | $4 | $12 | $16 | 3 | 8.0% |
| | **Total** | **$66** | **$48** | **$114** | **21** | **13.0%** |

7 This analysis is described in detail in Section VI.E of the Analytic Appendix of our SOM.

To facilitate achieving these benefits, the Commission could consider two alternative approaches for improving transmission owners' incentives:

- Improving the RTO participation incentive; and/or
- Providing market-based incentives for AARs.

**1. Improving the Proposed RTO Participation Incentive**

Because simply joining an RTO is not sufficient to deliver the full benefits of the RTO's transmission coordination, the Commission should consider improving its RTO participation incentive. Unfortunately, the lack of incentive to maximize ratings or the existing affirmative incentives to lower ratings persists after joining an RTO and is generally not disciplined or otherwise addressed by the RTOs.

Therefore, we recommend in the final rule that utilities be required to commit to providing AARs and emergency ratings where and when appropriate in order to receive the Commission's full ROE incentive for participating in the RTO.

**2. Market-Based Incentive for AARs and Dynamic Ratings**

In the alternative, a market-based incentive could bring transmission owners' incentives into better alignment system efficiency. Although we argued in the FERC Technical Conference on Managing Line Ratings[8] that we support the Commission requiring AARs since they are consistent with good utility practice, making the provisions of AARs incentive-compatible for the transmission owners is nonetheless reasonable. Additional benefits from higher ratings could be achieved by installing Dynamic Line Rating (DLR) equipment that can provide more detailed measurements of ambient conditions used in Ratings formulae. These

[8] See Comments in Docket No. AD19-15.

technologies can also provide other data on the status of transmission facilities (e.g. span clearance and line sag).

All of these actions would be facilitated by establishing market-based incentives that allow transmission owners to capture increased revenues that are directly related to the benefits of increasing transmission ratings. Providing market-based incentives will motivate the most cost-effective actions by transmission owners and RTOs that can increase ratings and, ultimately, the utilization of the transmission network. To establish market-based incentives, we recommend that RTOs provide revenues to transmission owners equal to some of the congestion surpluses that result from the higher transmission ratings. The congestion surplus would equal:

*Shadow Price of the Constraint ($/MW) * (Ambient-Adjusted Rating – Seasonal Rating)*

This approach would provide an economic incentive to the transmission owners that is directly related to the benefits of the additional transmission capability. This is reasonable because using higher transmission ratings reduces congestion and the overall costs of managing the system. Even if all the surplus is paid to the transmission owner, loads will still benefit as:

- The shadow price falls and congestion costs decrease; and
- Fewer uplift costs are incurred to commit resources to manage congestion and address local reliability concerns.

Since FTR markets generally limit flows to the static seasonal ratings, use of temperature-adjusted day-ahead ratings will result in day-ahead congestion surpluses. As RTOs develop the tariff provisions, they would need to combine day-ahead congestion surplus with real-time surplus in a manner that avoids any double counting.

As an alternative to simply providing a higher rating as temperatures fall, some RTOs may be able to use adjustments to constraint demand curves. If using the higher temperature-adjusted ratings have some costs, such that transmission owners would prefer to utilize the higher ratings only if the congestion is costly, the transmission owners could specify a price above which the additional capability could be used. This option would align their expectation of incremental risk/cost with potential surplus compensation. In practice, this would cause the RTO to insert an additional step in its transmission constraint demand curve (TCDC) rather than increasing the rating/limit, which would shift the entire TCDC. This would allow the flow to rise to the higher rating level at a specified price/range, but only if the marginal value (i.e., the shadow price) exceeds the value provided by the transmission owner.

In the NOPR, the Commission proposes rate-based incentives for equipment that would facilitate dynamic line ratings or otherwise improve the utilization of the existing transmission system.[9] We believe that market-based incentives are likely to be far more effective that rate-based incentives. This is due in part to the fact that that capital costs may be a small percentage of the costs of deploying of these technologies. In addition, to the extent that these investments would compete with new transmission facilities, market-based incentives help ensure that the most efficient investments are made, not simply the most capital intensive.

Therefore, we recommend the Commission consider encouraging RTOs to develop market-based incentives in the final rule to utilize dynamic transmission ratings, including the use of emergency ratings on contingent constraints. The benefits of such provisions in the Commission's final rule would be very large as shown in the table above for MISO.

### B. Incentives for GETs and Transmission System Optimization

In addition to facility ratings, transmission congestion costs are impacted by the transmission topology (i.e. it may be possible to reduce line flows and reduce the amount of

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[9] NOPR at para. 101.

congestion by altering the topology of the transmission system in response to real-time conditions). For example, RTOs/ISOs may develop operating guides with transmission owners to implement a reconfiguration of the system under specified operating conditions (i.e. based on line loadings, contingencies, load levels) to reduce flows on highly congested facilities.

Flexible transmission system operation or topology optimization options could be expanded or enhanced to include the use of other existing controllable devices, such as the use of phase angle regulators (PARs) that can be used to control flows. Since some of these options could put load at risk or result in wear and tear on equipment, they may require capital investment (i.e. to enhance controls, telemetry). Again, transmission owners generally have no market-based incentives to make these investments or make topology changes to reduce congestion costs.

Consequently, the Commission should further consider in this rulemaking the development of market-based incentives in this area as well. These incentives may be less straightforward than the incentives we recommended above and may require additional research. Finally, we note that expanded use of grid management technologies and reconfiguration options in the operating horizon by RTOs may be limited without significant changes and increases in RTO operational control over transmission assets. Hence, the final rule could include a requirement for each RTO to file a plan after some period of time, e.g., one year, to develop market-based incentives and changes in system operations to facilitate the use of GETs and transmission system optimization.

## IV. IMPROVING INCENTIVES FOR NEW TRANSMISSION FACILITIES

Investment in new transmission projects has traditionally occurred under a regulated cost-of-service framework. The NOPR proposes to continue this approach by establishing ROE incentives for highly beneficial new transmission projects. Although there are several areas where additional transmission can significantly alleviate grid congestion and enhance reliability, there has been relatively little market-based investment in transmission projects. This is unfortunate because the markets have the potential to provide powerful incentives to identify and facilitate the most cost-effective investments. In this section, we discuss the barriers to merchant investment in transmission, design of market-based incentives, and illustrate the impact of market-based incentives on investment decisions for new transmission projects.

New transmission projects can benefit the system in multiple ways. Two primary benefits of new transmission projects are: (a) reducing grid congestion and, (b) enhancing reliability by lowering planning reserve requirements. A significant portion of both these benefits can be measured and priced through the markets. However, transmission projects generally receive little or no market-based compensation for the benefits they provide. For instance, in NYISO, investment in transmission projects can reduce the required installed capacity reserve margins, but they are not compensated for their reliability value through the capacity markets.

Consequently, developers are likely to rely on incentives from regulators to invest in and develop new projects. The absence of market-based compensation has hindered merchant investment in transmission projects. Even with additional rate-based incentives, compensation for the most valuable investments is likely to be far less than their benefits. In addition to the efficiency benefits, merchant investment in transmission is valuable because it shifts the project risk from consumers to private investors, and leverages competition between transmission developers and generation, to unlock consumer savings.

### A. Market-based Incentives for Transmission Investment

A key step in providing market-based incentives for private investment in transmission is to create and allocate economic property rights to the investor that capture all the benefits it provides. We believe that this should include allocating:

- Financial Transmission Rights (FTRs) that would provide payments in accordance with the LMP differentials between two points; and
- Financial Capacity Transfer Rights (or "FCTRs") that would provide revenues for reducing the capacity requirements) to new transmission projects would provide strong incentives to merchant developers.

The provisions governing the allocation of these rights are very important. Some of the existing rules related to the allocation of FTRs may cause transmission projects to be undercompensated relative to the value they provide to the system.[10]

Adopting a framework that provides transparent market-based incentives for transmission projects would produce a variety of benefits over the long term. These benefits include:

- Directing transmission investment to areas with large congestion and/or reliability needs and would result in overall production and investment cost savings.
- Compensating transmission projects in a manner that is comparable to generation would support efficient allocation of investment across the two resource types.

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[10] For instance, in NYISO, the Transmission Congestions Contracts ("TCCs" which are analogous to FTRs in other markets) are (a) sold only for day-ahead congestion and none are sold for real-time market congestion, (b) allocated based on assumed congestion patterns, which could differ substantially from actual market outcomes, and (c) awarded for only 10 years, which is well below the likely economic life of a new transmission line. Consequently, the compensation to TCC holders is likely to be much lower relative to their value to the system.

- Enabling 'right sizing' of investment in new transmission projects. A merchant developer would size the transmission project at level where the marginal cost of expansion would equal the marginal benefit from increased revenue rights.

When paired with allowing investment from non-incumbents in existing facilities, this will also impose competitive discipline on incumbents and result in lower costs for consumers. Recent Order 1000 transmission processes NYISO have demonstrated that non-incumbents can often propose more cost-efficient solutions transmission solutions.

To illustrate the significance of providing market-based compensation for new transmission projects, we present the impact of FCTRs on the investment signals for a transmission project in the NYISO footprint that was completed in 2016. The value of the FCTRs in our illustration are based on how much installed capacity requirements are reduced by the upgrade.

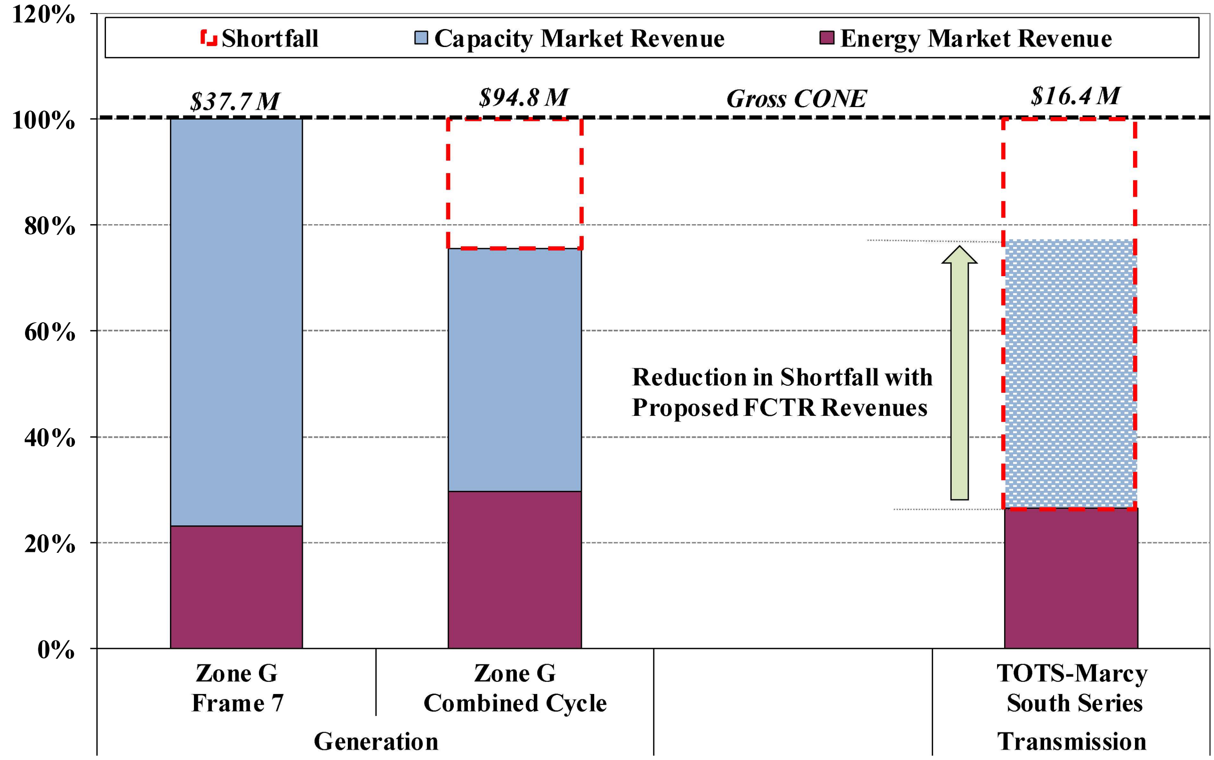
The figure below compares the breakdown of capacity and energy revenues for two hypothetical new generators (Frame CT and a combined cycle) in Zone G of NYISO with the revenue breakdown for a transmission project (the Marcy-South Series Compensation or the "MSSC" project). [11] For the MSSC project, the figure shows the Incremental TCC revenues received by the project under "Energy Market Revenue." The figure reports capacity value (i.e., the revenue that a generator or demand response resource would receive for having the same effect on LOLE) of increased transfer capability in the resource adequacy model under "Capacity Market Revenue." Transmission projects do not receive actual revenue for this capacity value.

[11] The FCTR revenues for the MSSC project equal the product of the following three inputs: (a) the effect on the UPNY-SENY transfer limit of adding the new facility to the as-found system, (b) the improvement in LOLE by increasing the transfer limit of UNPY-SENY by 1 MW, and (c) the value of reliability in dollars per unit of LOLE. Based on the results of the GE-MARS simulations, (c) is assumed to be $2.9 million per 0.001 events change in LOLE. The energy market revenues for the transmission projects are estimated using the value of incremental TCCs that were assigned to the MSSC project.

The figure also compares the net revenues for these projects against their gross CONE and highlights the reduction in shortfall of revenues due to the proposed FCTRs.

**Valuation of Generation and Transmission Projects**

Annualized Cost of New Entry vs. Revenue




The results illustrate the disadvantages that transmission projects have relative to generation in receiving market-based compensation for the benefits they provide. Capacity markets provide a critical portion of the incentive (up to 77 percent) for a new generator in Zone G. In the absence of analogous FCTR rights to the MSSC project, the project would recoup only 27 percent of its annualized gross CONE. However, granting FCTRs to the project based on its capacity value would have provided an additional 51 percent of the annualized gross CONE, thus significantly increasing the incentive for merchant transmission developers.

This analysis illustrates the potential effects on investment decisions of providing market-based compensation for the reliability services provided by transmission projects in NYISO and other RTOs. Market-based investments in transmission will be under-compensated if transmission developers cannot receive capacity market compensation. Consequently, the shortfall in revenues for any new transmission investment will have to be recovered through cost-of-service mechanisms.

In general, the market compensation to transmission projects is currently lower than their marginal benefits to the system. Designing transparent markets that would compensate these resources in accordance with their benefits would provide efficient incentives for private transmission investment and ultimate result in large consumer cost savings. Therefore, in addition to pursuing potential rate-based incentives, we recommend the Commission incorporate in its rulemaking a proposal that would capture:

- the energy and ancillary services markets benefits of transmission through enhancements to the FTR/TCC rules, and
- the planning value of transmission by providing compensation through the allocation of capacity transfer rights.

### B. Comments on the Commission Proposed ROE Incentives for New Investment

The proposes a number of changes in ROE incentives that would be applicable to new investment. Although we prefer the development of market-based incentives to address most of the Commission's incentive objectives, we provide limited comments on the NOPR proposals in this section.

#### 1. Benefits-Based ROE Incentives

The NOPR proposes a move from the "risks and challenges" model to one based on benefits, and clarifies that the benefits are to be measured based on adjusted production costs savings, which is consistent with most RTO's planning processes. Further, it proposes to offer

50 to 100 basis points for transmission projects for projects that have relatively high benefit to cost ratios.

First, we agree completely that adjusted production cost savings is the most appropriate measure of potential benefits. However, we believe this proposal could have unintended consequences. As we described above, actions that cause increase the incentives to build new capital-intensive transmission facilities also provide an incentive to understate the capabilities of the existing transmission facilities.

If the Commission includes this proposal in the final rule, we recommend that the benefits be measured assuming that transmission facilities are operated at AARs and at short-term emergency rating levels. This will eliminate estimated benefits that are attributed solely to the unreasonably conservative ratings that prevail on a large share of the transmission facilities currently.

### 2. Incentives for Reliability Investment and Incentives for Transcos

The NOPR proposes a 50 basis point incentive for projects that provide potential reliability benefits, including security benefits. This seems to be a solution to a problem that may not exist. While economic investment in transmission has not been common in many areas, investment in facilities that are justified on reliability grounds is common. There is little evidence in the RTO areas that we monitor that there is a concern that reliability investments are hindered, or that standard ROE applied to such investment would fail to facilitate such investments. Further, enhancing this incentive could result in rent-seeking whereby developers of potential new projects would claim dubious and difficult to validate reliability benefits in order to be guaranteed the inflated return on the investment. For these reasons, we recommend that the Commission not include this incentive in the final rule.

The Commission also proposes to eliminate incentives for transcos, which we support. The transfer of transmission facilities to a transco has not been shown to generate benefits that would warrant incentive payments. Therefore, we support the elimination of this incentive.

### 3. Incentives for GETs and Non-Traditional Transmission Investment

The NOPR proposes to offer a 100 basis point incentive for technologies that improve the reliability, efficiency, or operation of transmission facilities. As we described above, such equipment often requires modest capital investment, but can deliver sizable operational benefits. Hence, ROE incentives are not likely to be very effective in promoting efficient investment in these technologies. We reiterate the superior attributes of a market-based incentive for such technologies and encourage the Commission to commission the RTOs to develop such incentives. Nonetheless, since market-based incentives may not be possible or practical for some technologies, the incentive proposed could be beneficial.

## V. CONCLUSIONS

We strongly support the Commission's interest in incentives for new and existing transmission. However, we are concerned about the exclusive reliance of the Commission on ROE regulatory incentives to the exclusion of more efficient and effective market-based incentives. Additionally, we recommend changes in the proposed ROE incentives to improve their effectiveness and address potential unintended consequences.

To improve the utilization of existing transmission facilities, we respectfully recommend the following changes in the NOPR proposals:

- Create market-based incentives for transmission owners to provide increased capability through AARs and the installation of DLR technologies by allocating a portion of the resulting congestion surplus to them;

- Modify the ISO/RTO participation incentive to make the full incentive contingent on utilities committing to provide AAR and emergency ratings for use by the ISO/RTOs.
- Require each RTO to file a plan to develop market-based incentives and changes in system operations to facilitate the use of GETs and transmission system optimization;

With regard to new transmission investment, we respectfully recommend the following improvements to the proposals in the NOPR:

- Provide market-based incentives for investment in new transmission by allocating rights related to the congestion benefits and capacity market benefits associated with the new transmission;
- If the Commission retains the benefit-based ROE incentives, measuring the benefits of new investments assuming that transmission facilities are operated at AARs and at short-term emergency rating levels; and
- Eliminate the proposed incentive for reliability investment.

We appreciate focus of the Commission on transmission incentives, which are key for the long-term efficiency that can be provided by the markets, and the opportunity to provide these comments.

Respectfully submitted,

*/s/ David B. Patton*

David Patton
President
Potomac Economics, Ltd.
July 1, 2020

## CERTIFICATE OF SERVICE

I hereby certify that I have this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 1st day of July 2020 in Fairfax, VA.

*/s/ David B. Patton*

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