UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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| Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection | )<br>)<br>) | Docket No. RM21-17-000 |

**COMMENTS OF**
**THE OFFICE OF THE PEOPLE'S COUNSEL FOR THE DISTRICT OF COLUMBIA AND THE MARYLAND OFFICE OF PEOPLE'S COUNSEL REGARDING THE NOTICE OF PROPOSED RULEMAKING**

The Office of the People's Counsel for the District of Columbia ("DC OPC") and the Maryland Office of People's Counsel ("MD OPC") (together, the "Joint PCs"), respectfully provide the following reply comments on the Federal Energy Regulatory Commission's ("FERC" or "Commission") Notice of Proposed Rulemaking on planning for the future electric grid.[1] As the statutory advocates for ratepayers in Maryland[2] and District of Columbia ("District")[3], respectively, the Joint PCs are charged with ensuring that electric utility rates paid by consumers in their respective jurisdictions, including the rates for wholesale transmission service, are just and reasonable and not unduly discriminatory. Additionally, as consumer advocates representing jurisdictions with ambitious clean energy and decarbonization goals[4], our respective offices are

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 179 FERC ¶ 61,028 (2022) ("NOPR").

[2] Md. Code, Public Utilities Article ("PUA"), §§ 2-201 *et seq.*

[3] D.C. Code § 34-804.

[4] The District of Columbia Council ("the Council") has mandated a 100% Renewable Portfolio Standard by 2032 (D.C. Code § 34-1432 (c)) and the Mayor has announced the District of Columbia's official policy is to become carbon neutral by 2050 which the District Council is considering codifying into law. See, D.C. Comm. Transp. and Env't, Climate Commitment Act of 2021, B24-0267, available at https://lims.dccouncil.us/downloads/LIMS/47264/Introduction/B24-0267-Introduction.pdf. Additionally, by 2041 ten

committed to ensuring that the energy transition currently underway is done in a cost-efficient and equitable fashion and recognize the important role that effective transmission planning implemented using competitive transmission solicitations will play in the transition.[5] Finally, as Members of PJM Interconnection, L.L.C. ("PJM") we are uniquely attuned to the challenges and barriers posed to regionally planned, forward-looking, transmission planning. Thus, the Joint PCs respectfully provide the following comments on the NOPR from the prospective of consumer advocates, of state agencies seeking to enable a cost-efficient transition to a clean energy grid, and as members of the nation's largest organized market.

At the outset, the Joint PCs applaud the Commission for tackling an issue that is critical to the reliability, resiliency and long-term efficiency of the grid while equal parts technically and politically challenging. The Joint PCs appreciate the opportunity the Commission provided in the Advanced Notice of Proposed Rulemaking[6] for both initial and reply comments[7] as well as the opportunity to participate in the Commission's November 15, 2021 Technical Conference.[8]

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percent of the renewable energy portfolio must be met from solar facilities located within the District of Columbia. D.C. Code §34-1432(c)(31). In 2022 Maryland enacted the Climate Solutions Now Act of 2022, which, among other matters, targets state-wide GHG emission reductions (from 2006 levels) of 60% by 2031 and achieving net-zero GHG emissions by 2045. 2022 Md. Laws, Ch. 38, amending Md. Enviro. Art. § 2-1204.1). In 2019, Maryland enacted the Clean Energy Jobs Act which requires electric consumers in the state to consume at least 50% of their electric energy from renewable resources by 2030. Md. Code, PUA §§ 7-701 *et seq.*

[5] In addition to our individual comments the Joint PCs are also members of and signatories to the comments of the Electricity Transmission Competition Coalition filed in this proceeding and support the Joint Statement in Support of the Commission's Proposed Rule to Strengthen Regional Transmission Planning, eLibrary No. 20220816-5129 (Aug. 16, 2022).

[6] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 176 FERC ¶ 61,024 (2021) ("ANOPR").

[7] Comments of the Office of the People's Counsel for the District of Columbia on the Advanced Notice of Proposed Rulemaking, eLibrary No. 20211012-5553 (Oct. 12, 2021) ("DC OPC Initial Comments"), Comments of the State Agencies, eLibrary No. 20211012-5584 (Oct. 12, 2021) (State Agencies Initial Comments"), Reply Comments of Office of the People's Counsel for the District of Columbia on the Advanced Notice of Proposed Rulemaking, eLibrary No. 20211130-5296 (Nov. 30, 2021) ("DC OPC Reply Comments").

[8] Technical Conference on Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Panel 1: Factors to Consider in Long-term Future Scenarios, Comments of Erik Heinle, Assistant People's Counsel, Office of the People's Counsel for the District of Columbia (Nov. 15, 2021).

Meaningful and transparent engagement by all stakeholders, as the Commission has demonstrated throughout the NOPR process, is critical in the planning, selection, and development of transmission projects—not only to ensure broad stakeholder confidence in the solutions chosen, but to ensure that those are the very best solutions for the long-term reliability, resiliency, and cost-effectiveness of the grid.

As discussed in the body of our comments, the Joint PCs believe that the NOPR provides the Commission, all stakeholders, and consumers a unique opportunity to develop rules that will shape not only the future of the electric grid but the resources that depend on it. In other words, our collective ability to meet the energy transition in a just, equitable, efficient, reliable and resilient fashion will be directly impacted by the final rules promulgated from this proceeding. The proper role of regional transmission planners is to account for the changing resource mix, as driven by state policies and other factors, and plan a reliable and efficient grid given that expected future resource mix.

In order to optimize our energy future, the Joint PCs recommend that the Commission (i) require transmission planners to employ a 20-year transmission planning horizon with scenarios regularly updated on an every three years basis; (ii) require transmission planners employ all seven factors listed in the NOPR in their planning processes; (iii) require the use of plausible and diverse long-term scenarios in transmission planning; (iv) require the use of "best available data inputs" for transmission planning as well transparency and broad stakeholder feedback on the selection data inputs; (v) employ a flexible approach to the development of geographic transmission zones; (vi) require that interconnection processes are efficient and costs are allocated fairly; (vii) adopt the list of benefits enumerated in the NOPR for transmission planning as well as a benefit around the decarbonization value of transmission projects; (viii) encourage the deployment of grid enhancing technologies ("GETs") that provide demonstrated cost savings; (ix) ensure State Entities have a meaningful role not only in the cost allocation process but also in the initial selection of projects to better facilitate equitable cost allocation; (x) direct the establishment of an independent transmission monitor function for each RTO/ISO to assist and coordinate regional transmission planning to better achieve cost control and mitigate institutional biases in regional planning; and (xi) reaffirm the need for, and benefits of, competitive transmission solicitations, and expand, rather than eliminate the opportunities for transmission competition, to ensure both cost control and the selection of optimal transmission solutions—especially in regions, such as PJM, where Order No. 1000 has already had demonstrable benefits.

# I. COMMENTS OF THE JOINT PCs

## A. Long-Term Regional Transmission Planning

In the NOPR the Commission explains the need for transmission planning reform, finding that "existing regional transmission planning processes may not be planning on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand, leading to the piecemeal and inefficient development of new transmission facilities in a manner that is not more efficient or cost-effective."[9] The Joint PCs agree with that assessment. As consumer representatives from states with ambitious decarbonization and clean energy goals we recognize the important role transmission will play in enabling our respective jurisdictions to meet their stated goals. As participants in, and Members of, PJM, we have witnessed first-hand how the current piecemeal planning process is locally driven, inefficient, lacking in transparency and opportunities for stakeholder engagement, and largely ignores, rather than utilizes, the potential benefits of competition. And as consumer advocates we have witnessed how

[9] NOPR ¶ 64.

transmission costs have increased in absolute amount at a rate significantly faster than the total electric bill, and, accordingly, have become an ever-increasing potion of our ratepayers' bill—from 7% (or $4.34/MWh) in 2011 to 27% (or $10.94/MWh) in 2020.[10] Like the Commission, we view transmission reform as not merely desirable, but necessary to "to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential."[11]

The NOPR proposes reforms to long-term regional transmission planning focusing on (i) planning horizons and frequency, (ii) factors, (iii) number and range of long-term scenarios, (iv) specificity of data inputs, and (v) identification of geographic zones. The Joint PCs will comment on each of these items individually. However, before addressing the specifics of the NOPR's proposed reforms, it is important to provide a general overview of transmission planning and the role of consumers, RTOs/ISOs, and other stakeholders. As the Commission has long-recognized, independence "is the 'bedrock' upon which the [RTO/ISO] must be built."[12] RTO/ISO independence is particularly critical when it comes to long-term transmission planning. While the NOPR has appropriately cited the potential consumer benefits of long-term transmission planning done right, the potential costs to consumers of poorly planned transmission are significant. To ensure that best practices rather than parochial interests guide transmission planning, the Commission should consider ways to enhance RTO/ISO independence. For example, in its initial comments on the ANOPR, DC OPC suggested two potential reforms to strengthen RTO/ISO

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[10] Data sourced from PJM Transmission Owner NITS Rates.

[11] NOPR ¶ 1.

[12] *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285 (1999) ("Order No. 2000") ¶ 193.

independence: (i) the imposition of strict exit requirements and fees to ensure the continued participation of transmission owners in RTOs/ISOs and stability of the transmission planning process; and (ii) the institution of information sharing requirements that direct RTOs/ISOs to file with FERC for FERC's approval any confidentiality agreements that the RTO/ISO enters into with specific sector members.[13] While not explicitly included in the NOPR, the Commission should consider these and other reforms that reaffirm the principles of Order No. 2000 in any final rule as part of the Commission's mandate that transmission rates are just and reasonable and are not discriminatory or preferential. It is critical for both transmission planning and the ability of any RTO/ISO to run effective competitive solicitation processes to have full independence from transmission owners.

In addition to requiring that planning authorities such as RTOs/ISOs operate in a non-discriminatory fashion, the Commission also has an obligation to ensure that the planning process is transparent and allows for meaningful input by all stakeholders. As the Commission is well aware, the past decade has seen a proliferation of local, utility-designated, self-approved transmission projects. In the PJM region spending on Supplemental Projects—transmission projects that are not part of PJM's regional planning process or approved by PJM's Board of Managers—was four times that of Baseline Projects planned through PJM's regional planning process.[14] Supplemental Projects are planned under Attachment M-3 to the PJM Tariff, with stakeholders provided an opportunity for notice and comment, but with the proposing transmission owner under no obligation to incorporate or even respond to feedback. This is the antithesis of a

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[13] DC OPC Initial Comments, pp. 7-8.

[14] Combined spending on Supplemental Projects from 2018-2020 was approximately $16.988 billion while spending on Baseline Projects during the same time period was approximately $4.069 billion.

transparent planning process where all stakeholders participate in a meaningful fashion. The results of such an approach are both predictable and well chronicled—significant balkanization of the planning process, with projects chosen based on the individual transmission owner's purported need for its transmission footprint rather than through a coordinated whole-of-grid approach, frustrating cost-effective, forward-looking, holistic regional planning. This approach is particularly troublesome when transmission is sited in one jurisdiction, but cost allocated to others; thus, denying public service commissions—that have a statutory responsibility to ensure projects cost allocated to their ratepayers are just and reasonable—the ability to review those projects. The remedy for this is a strong, empowered regional planner that is independent and a develops a planning process that incorporates meaningful participation from all stakeholders beginning with the determination of any needs through the project selection phase.

The proposed rules discussed below make significant progress towards that goal, but the Commission must continue to look for opportunities to increase stakeholder engagement and input including ensuring that historically disadvantaged groups have a voice in the process. This is especially fundamental during this moment of energy transition and a heightened, and long overdue, recognition of the impact of transmission planning and siting decisions on historically marginalized communities. As others have more eloquently stated, the proposed rules represent a "chance to acknowledge and correct the historic discrimination caused by the infrastructure development approach used for the past hundred years" and the Commission—and all stakeholders—should proactively ensure that "the voices of representative members of these communities [are] elevated so their experiences and perspectives are an inherent part of the decision-making processes."[15]

### 1. Transmission Planning Horizon and Frequency

The NOPR proposes that "public utility transmission providers develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon."[16] Additionally, to ensure that transmission plans do not become static, the NOPR would require "that public utility transmission providers develop Long-Term Scenarios at least every three years, by reassessing whether the data inputs and factors incorporated in their previously developed Long-Term Scenarios need to be updated and then revising their Long-Term Scenarios as needed to reflect updated data inputs and factors" and that these every three years assessments be completed prior to the next assessment period beginning.[17]

The Joint PCs support the proposed rules regarding long-term transmission planning horizons. We agree with the NOPR's reasoning that "a 20-year transmission planning horizon would allow public utility transmission providers to better leverage economies of scale by sizing transmission facilities to meet not only nearer-term needs but also longer-term transmission needs driven by changes in the resource mix and demand over time."[18] Furthermore, because the 20-year transmission planning horizon "strikes a reasonable balance" between the current short-term transmission planning that is widely prevalent today and even longer planning horizons "a 20-year planning horizon would allow for sufficient time to identify, plan, and obtain siting and permitting approval and to construct regional transmission facilities to meet long-term regional transmission

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[15] State Agencies Initial Comments, p. 26.

[16] NOPR ¶ 97.

[17] NOPR ¶ 97.

[18] NOPR ¶ 98.

needs"[19] The Joint PCs also support the requirement that long-term scenarios be regularly updated on a every three years basis so that "new transmission needs driven by changes in the resource mix and demand during the interim years of the transmission planning period"[20] can be incorporated into long-term transmission planning.

The need for reliable, thoughtfully developed, long-term transmission planning is well documented. For example, while severe weather events alone are estimated to cost Americans between $25 and $70 billion each year,[21] transmission can play a critical role in reducing that burden. There have been multiples instances of transmission lines keeping the lights on and saving hundreds of millions of dollars for consumers. During Winter Storm Uri an additional 1 GW of transmission ties between ERCOT and the Southeastern U.S. could have saved nearly $1 billion. Each 1 GW of transmission ties could have saved an additional $100 million to consumers in the Great Plains (SPP region) and Gulf Coast States (MISO region).[22]

Long-term transmission planning is also an essential component of a cost-effective energy transition. Reliable de-carbonization with grid expansion results in lower cost for consumers than relying on local resources alone. Massachusetts Institute of Technology researchers Patrick Brown and Audun Botterud found it was 46 % cheaper if national transmission capacity is doubled. If transmission capacity is doubled through a reliance on very high voltage lines, then there would not be a need for a similar percentage increase in line-miles or corridors, because high-capacity lines can carry 7.5 times more power than smaller lines over a given distance. The study also

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[19] NOPR ¶ 98.

[20] NOPR ¶ 98.

[21] Executive Office of the President, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages* (August, 2013) *available at* https://www.energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf).

[22] Michael Goggin, https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.

evaluated the choice between low-cost flexible nuclear, long-duration storage, or low-cost renewables (wind and solar) and Li-ion batteries and found that low-cost renewables and batteries lead to the lowest electricity cost when transmission expansion is allowed.[23] For these reasons, and others, the Commission should approve the proposed rule's minimum 20-year transmission planning horizon as well as the requirement that long-term scenarios are updated on a regular every three years basis.

### 2. Factors

The NOPR proposes "to require that public utility transmission providers incorporate specific categories of factors in the development of Long-Term Scenarios as part of Long-Term Regional Transmission Planning. Specifically, [the Commission] propose[s] to require that public utility transmission providers incorporate, at a minimum, the following categories of factors into the development of Long-Term Scenarios: (1) federal, state, and local laws and regulations that affect the future resource mix and demand; (2) federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand."[24]

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[23] Patrick Brown and Audun Botterud, The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System https://www.sciencedirect.com/science/article/pii/S2542435120305572?dgcid=author%20_blank.

[24] NOPR ¶ 104.

The Joint PCs support a final rule requiring the seven factors listed by the Commission. It is critical for states and the District that system planners plan for the future generation mix as guided by state public policies and the other factors listed by the Commission. It is self-evident that planners should plan based on best assessments of future need using any and all publicly available information.

However, the Joint PCs are concerned that the Commission proposes to only require the first three factors above to be incorporated but allows the other factors to be discounted.[25] We urge the Commission to require that all seven factors be incorporated into planning. FERC is the federal regulator in charge of transmission planning protocols and has a responsibility to ensure sound transmission planning practices are employed. We do not find a compelling basis for a transmission planner to ignore factors 4, 5, 6, or 7. For example, electrification forecasts are increasing load estimates by 30 percent in some areas. We expect similar uptake of electric vehicles in the Maryland, District and broader Mid-Atlantic area as municipalities and utilities work on charging stations and incentives, complementing the significant Electric Vehicle ("EV") incentives just passed by Congress. If planners ignore these realities of both the magnitude and location of load, in addition to changes in the supply mix, the grid will almost certainly become less reliable.

Considering all seven factors does *not* mean there would be no regional flexibility. For example, some states will likely forecast much higher and faster EV penetration than other states, and that is the sort of regional difference that would be allowed. Regional flexibility will be in the

[25] NOPR ¶ 106.

forecasted inputs and outputs in the analysis, not in the method or factors planners are required to incorporate.

The final rule should provide for more explicit means for state entities to provide information on the factors. The NOPR only proposes that "public utility transmission providers may be able to modify and expand these existing procedures for identifying transmission needs driven by Public Policy Requirements to meet these proposed requirements regarding the identification of factors for incorporation into Long-Term Scenarios."[26] In a context in which large and influential RTO/ISO stakeholder sectors often have economic incentives to inhibit state achievement of their energy objectives, FERC should not merely allow "stakeholders" to decide what inputs are provided. Rather, certain information should come directly from appropriate authorities. State agencies should provide the information about state targets. State consumer advocates should be explicitly included as state agencies for this input.

The NOPR includes no requirement for severe weather to be included in the factors. While the issue appears in other sections, the Joint PCs believe it is also a factor to consider along with the other factors that affect generation and load. Planners should incorporate estimates of Polar Vortex incidents in the PJM region, for example, because we have experienced multiple such events in recent years. Planners should take into account not only historic weather patterns but also incorporate future conditions impacted by climate change. Planners should take account of how the grid tends to operate during stressed conditions. The recent LBNL study shows that up to 50% of the value of transmission is concentrated in as little as 5% of the hours when the grid is

[26] NOPR ¶ 110.

under stress,[27] yet most power system modeling does not include these conditions—rather it assumes that all facilities are in service and congestion is low. In reality, the grid tends to be more constrained that it is in typical prospective dispatch and power flow modeling. By including severe weather as a factor, it can enter the analysis in the base case, not just as one scenario. Unfortunately, severe weather such as polar vortices in the Mid-Atlantic region and heat waves or other patterns in other regions, is now to be expected; it is no longer just a possibility.

### 3. Number and Range of Long-Term Scenarios

The NOPR proposes to require four scenarios that include the factors described above. These scenarios must be "plausible" and "diverse."[28] One of these scenarios must address high-impact low-frequency events.[29]

The Joint PCs support the use of plausible and diverse scenarios, as important to the construction of any meaningful transmission analysis and plan. Transmission can be extremely useful in certain scenarios even if not expected to be useful in a steady-state, business-as-usual type scenario. Over the 50 years or more that transmission assets are in place, these facilities will be in service through many different situations and may be useful in many of them. That should be taken into account.

We are agnostic on the exact number of scenarios, whether that is four or some other number. However, we do believe the Commission's proposal for multiple scenarios that are plausible and diverse should be retained in the final rule.

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[27] Dev Millstein, Ryan H Wiser, Will Gorman, Seongeun Jeong, James Hyungkwan Kim, Amos Ancell, Lawrence Berkeley National Lab, Empirical Estimates of Transmission Value using Locational Marginal Prices, August 2022, https://emp.lbl.gov/publications/empirical-estimates-transmission.

[28] NOPR ¶ 123.

[29] NOPR ¶ 124.

To ensure confidence in the planning scenarios we submit that it is critical that all modeling inputs be publicly disclosed, and all relevant stakeholders be given a meaningful opportunity to provide feedback.

#### 4. Specificity of Data Inputs

The NOPR proposed to require the use of "best available data inputs,"[30] defined as "timely," "developed using diverse and expert perspectives," adopted via a transparent process, and that reflects the seven factors.[31]

The Joint PCs support the use of "best available data inputs" for transmission planning. It is standard public utility regulatory practice to require the use of best available information when making forecasts of needs. Every type of public utility has uncertain future states, and every economic regulator of these utilities and types of public utilities must deal with uncertainty. We agree with the Commission that regulators must utilize the best available information and consider scenarios to see if the value of the investments being considered change significantly if the inputs change. Requiring best available inputs and use of scenarios is standard practice in public utility regulation, as it should be.

We also support the proposal to provide for transparency and broad stakeholder feedback on the selection data inputs. The confidence of consumer advocates and other stakeholders will rely on their ability to know what information inputs are used and the sources and basis for them.

[30] NOPR ¶ 130.

[31] NOPR ¶ 131.

### 5. Identification of Geographic Zones

The NOPR proposes to require transmission planners to "consider whether to" identify geographic zones for future development of large amounts of generation.[32] Some parties recommended against a requirement but instead advocate for permitting load-serving entities to identify geographic zones when developing their resource plans, described as more of a "bottom up" approach.[33]

The Joint PCs support the concept of identifying geographic transmission zones. Geographic zone identification can be a useful tool, particularly for state and local policy makers to provide information into transmission planning processes to reflect realities of where generation is likely to be developed based on land use and other considerations. Since the exact geographic definition of a "zone" is not necessarily important, and the approaches to doing so can vary by region, however, we are agnostic on whether this element of the NOPR should be required, encouraged, or just permitted.

We support the concept put forward by APPA regarding ground-up identifications of resource plans by load-serving entities. The Commission should consider a requirement that load-serving entities provide transmission planners with information on their expected future resource mix, in terms of the type, quantity, and location of additions and retirements. Transmission planners should not have to guess at those plans. Load-serving entities who may want to utilize the transmission, or who may argue that they will never use it and should not be allocated the cost, should be required to state their plans, so that planners can accurately assess needs and assign costs to beneficiaries.

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[32] NOPR ¶ 135.

[33] APPA Comments, p. 17.

It is important to allow for meaningful state and local feedback in any process, and this particularly critical for geographic zones because in multi-state planning regions, they will likely cover multiple state jurisdictions and whose cost allocation may include jurisdictions outside the identified geographic zone.

### B. Coordination of Regional Transmission Planning and Generator Interconnection Processes

The NOPR (and ANOPR before it) correctly identified the lack of coordination between upgrades necessary for generator interconnection and the regional planning process. As the NOPR explains, "there has been a dramatic increase in recent years in the level of spending on interconnection-related network upgrades, driving the cost of interconnecting new generation to the transmission system higher and higher … this trend is leading to more and more interconnection customers withdrawing their interconnection requests in the face of significant costs associated with interconnection-related network upgrades."[34] This trend has two potential detrimental impacts on consumers, particularly those from jurisdictions with ambitious clean energy and decarbonization goals like Maryland and the District. First, as the general cost of interconnection increases, generation resources will increase their wholesale energy and capacity market prices to cover that additional cost. Thus, the failure of the transmission system to timely and cost-efficiently interconnect generation will lead to increased wholesale energy and capacity costs to consumers. Second, renewable and storage resources account for over 90% of requests currently in the PJM queue.[35] Barriers to those resources' ability to interconnect to the grid will

[34] NOPR ¶ 162.

[35] PJM Interconnection, L.L.C., Grid of the Future: PJM's Regional Planning Perspective (May 10, 2022), https://pjm.com/-/media/library/reports-notices/special-reports/2022/20220510-grid-of-the-future-pjms-regional-planning-perspective.ashx, p. 2.

result in some projects simply not being developed—a loss of resources that will make it more difficult and costly for states and commercial consumers to achieve their clean energy goals.

Recently, PJM has filed with the Commission reforms to its interconnection process intended to reduce both the time and expense related to interconnecting with its transmission system.[36] The Joint PCs supported these reforms in the stakeholder process.[37] The Commission has also recently issue a NOPR on *Improvements to Generator Interconnection Procedures and Agreements*[38] to which the Joint PCs look forward to participating in the rule making process. Finally, the Joint PCs note the current paper hearing taking place at the Commission with respect to certain network upgrade changes proposed by some PJM transmission owners.[39] We view each of these proceedings as critical to ensuring that the interconnection process functions properly within the regional planning process, allocates costs and risk appropriately, and ensures that the resources needed for the energy transition can timely and cost effectively interconnect to the grid.

### C. Evaluation of the Benefits of Regional Transmission Facilities

The Joint PCs are much encouraged by and generally supportive of the Commission's proposal for the evaluation of the benefits of regional transmission facilities.[40] The Joint PCs support the Commission's proposal to establish a benefit evaluation "framework" or set of best practices for regional transmission planners to utilize in the planning of regional transmission

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[36] PJM Interconnection, L.L.C., Tariff Revisions for Interconnection Process Reform, Request for Commission Action by October 3, 2022, and Request for 30-Day Comment Period, eLibrary No. 20220614-5081 (June 14, 2022).

[37] PJM Interconnection, L.L.C., PJM Members Committee, Supplemental Voting Results, https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-mc-voting-report-1-interconnection-reform-process-main-motion.ashx (April 27, 2022).

[38] 179 FERC ¶ 61,194 (2022).

[39] *PPL Electric Utilities Corp. and PJM Interconnection, LLC*, Order Accepting and Suspending Tariff Revisions and Establishing Paper Hearing Procedures, 177 FERC ¶ 61,123 (2021).

[40] NOPR, ¶¶ 175 *et seq.*

facilities. This framework should require the regional transmission planners: (i) to identify and define, in a clear and transparent manner, an expansive listing of quantifiable benefits to be considered, inclusive of but not necessarily limited to those listed by the Commission in its proposal; (ii) to consider these benefits jointly rather than in silos; and (iii) to determine these benefits in response to portfolios of resources, both generating resources and connecting transmission facilities, in the proper circumstances identified by states and beyond those proposed by resource developers alone, rather than specific projects (either transmission projects or resources or both), where feasible. Below, the Joint PCs offer specific comments on each of the benefits which the NOPR identifies for consideration.

The Joint PCs also encourage the Commission to allow, and not preclude, the consideration of other benefits not directly referenced by the NOPR proposed by regional transmission planners—specifically those benefits relating to regional transmission enhancements that advance grid decarbonization goals aligned with state policies and that serve as legal mandates for the electric distribution companies ("EDCs") over which they have regulatory jurisdiction and the EDCs' delivery-level customers, serving their electric consumption through the EDCs or third-party suppliers ("TPSs"). As noted at the outset, both Maryland and the District have adopted ambitious jurisdiction-wide decarbonization policies applicable to the EDCs regulated by their respective public service commissions. In the case of Maryland and the District, incorporating this benefit expressly into PJM's regional transmission process is of particular importance. Otherwise, these two jurisdictions, among others in the PJM footprint, will see transmission facilities planned, and their ratepayers assigned costs, through regional transmission planning process whose evaluation affords no consideration for a major driver for the procurement of electric supply for their customers. This would improperly truncate the pro-active enabling of transmission facility planning and construction, intended by the Commission in the NOPR, to the end of supporting further the cost-effective provision of electric supply to end-use customers. A broader pool of identified benefits, to include those created by decarbonization, will better facilitate the agreements among states needed, even if not always sufficient alone, for successful development of regional interstate transmission projects (and its correlate, equitable cost allocation of the projects' costs). Any such additional expressly considered benefits, if included in the regional transmission planner's evaluation of benefits, would need to follow the same general principles for adoption and use which the NOPR urges with respect to the benefit categories it discusses, namely that it be a transparent and accurate of measurement according to a pre-defined metric.

**1. Benefits Assessments.**

The NOPR seeks comment on "whether public utility transmission providers should be required to use some or all of the Long-Term Regional Transmission Benefits as a minimum set of benefits for their Long-Term Regional Transmission Planning process."[41] Standard economic policy, for benefit-cost analysis and public utility regulation, dictates that all benefits and all costs should be incorporated and compared. If some costs are ignored, the result will be biased towards over-building, and if some benefits are ignored, the opposite result of an under-building bias would be built into the process. Just and reasonable rates require an unbiased assessment. "Multi-benefit" analysis should be required in Long Term Regional Transmission Planning in order to capture all of the benefits. One would be hard-pressed to find a line that supports economics alone

[41] NOPR ¶ 188.

and not reliability, and vice versa. However, it is current standard practice in the industry to evaluate these benefits in separate silos.

### 2. **Benefit Categories.**

The NOPR provides a list of benefits that is not exhaustive and transmission providers have flexibility to propose what benefits to use.[42] This list includes:

> (1) Avoided or deferred reliability transmission projects and aging infrastructure replacement;
> (2) either reduced loss of load probability or reduced planning reserve margin;
> (3) production cost savings;
> (4) reduced transmission energy losses;
> (5) reduced congestion due to transmission outages;
> (6) mitigation of extreme events and system contingencies;
> (7) mitigation of weather and load uncertainty;
> (8) capacity cost benefits from reduced peak energy losses;
> (9) deferred generation capacity investments;
> (10) access to lower cost generation;
> (11) increased competition;
> (12) increased market liquidity.[43]

As discussed in greater detail below, the Joint PCs support adoption of the evaluation of each of these benefits in the regional transmission planner's processes.

The Commission seeks comment on each of the Long-Term Regional Transmission Benefits, and how to ensure that each type of benefit is distinct such that the list of benefits does not "double count" benefits.[44] We find the list to be a mutually exclusive set of benefits. Some transmission planners may wish to mix and match the categories based on the modeling tools they use which may not disaggregate them in exactly the way described in the NOPR.

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[42] NOPR ¶¶ 184-186.

[43] NOPR ¶ 158.

[44] NOPR ¶ 187.

*(1) Avoided or deferred reliability transmission projects and aging infrastructure replacement*[45]

This benefit reflects that reliability considerations and replacing aging assets drive significant investment in transmission and account for almost all of the approximately $25 billion per year being spent nationally on transmission.[46] Economic considerations rarely enter those investments; rather they are undertaken if reliability standards say they are needed. This benefit has been incorporated into a number of planning studies and plans.[47] The Joint PCs support inclusion of this benefit in the evaluation and selection of regional transmission projects.

*(2) Either reduced loss of load probability or reduced planning reserve margin*[48]

In a high penetration renewable energy system the resource adequacy benefit of geographic diversification to capture the reliability benefit of renewables in different wind regimes, weather patterns, and time zones will be significant. With properly measured capacity value that includes wind in different areas and the complementarity deployment of wind and solar resources together, diverse renewable penetration will have capacity value that reduces loss of load expectation.

Geographic diversification results in higher capacity values for geographically diverse renewable resources. The effect was about 5% capacity value increase in the Eastern Wind Integration and Transmission Study, prepared for The National Renewable Energy Laboratory

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[45] NOPR ¶¶ 189-193.

[46] *Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs*, p. 2 (Oct. 2021)

[47] Order No. 1000, 136 FERC ¶ 61,051, ¶ 81; See, e.g., *S.C. Elec. & Gas Co.*, 143 FERC ¶ 61,058, ¶ 232 (2013); Brattle-Grid Strategies Oct. 2021 Report, p. 37; SPP Benefit Metrics Manual, SPP Engineering, p. 15 (Nov. 6, 2020); The Brattle Group, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, The Brattle Group, p. 114 (Sept. 15, 2015). Midwest ISO (MISO), *Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop*, August 22, 2011, pp. 42-44. Australian Energy Market Operator 2022 Integrated System Plan, (June 2022), p. 64.

[48] NOPR ¶¶ 194-197.

(U.S. Department of Energy).[49] A recent Telos/ESIG report stated (referring to output at different times through the metric of "net load"--load minus renewable output), "[w]here resource adequacy and resilience benefits stand out, however, is in connecting systems with loosely correlated net load behavior."[50] This suggests significant and growing value in this category of transmission benefits.

While current renewable penetration in PJM is relatively low compared to other RTOs/ISOs and the cited benefits of geographic diversity beginning to accrue in other RTO/ISO footprints are less evident in PJM, it is anticipated, particularly with the expansion of offshore wind resources along the Mid-Atlantic coast, that these historical limitations will abate over the planning horizons posited by the NOPR. In anticipation of these changes, PJM's planning should in increasingly incorporate the benefits of geographic diversity for renewable resources into its evaluations consistent with PJM's changing resource portfolio.

Reduced loss of load expectation can be estimated by the value of lost load. Valuing averted load loss has been done in a number of cases.[51] This is one way to measure this benefit. Another way to measure this benefit, as the NOPR's label for the category suggests, is in terms of generation capital cost savings from the lower required planning reserve margins achievable through transmission. This approach has also been used in multiple cases.[52] The NOPR's

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[49] Enernex Corporation, Eastern Wind Integration and Transmission Study, NREL Report No. SR-550-47078 (Jan. 2010) *available at* www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf

[50] ESIG/Telos p. 47 https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf

[51] SPP, *Benefits for the 2013 Regional Cost Allocation Review*, at 25 (Sept. 13, 2012). J. Frayer, E. Wang, R. Wang, et al. (London Economics International, Inc.), *How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment, A WIRES report*, (Jan. 8, 2018).

[52] MISO, *Proposed Multi Value Project Portfolio: Business Case Workshop*, p. 36-38 (Sept. 19 & 29, 2011). Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 5.1. Public Service Commission (PSC) of Wisconsin (WI), Order, re Investigation on the Commission's Own Motion to Review

categories suggest one or the other (but not both) are acceptable ways to measure this benefit. As MISO stated in its stakeholder process, "transmission is the enabler of reserve sharing for the MISO pool so that each load serving entity does not need to cover its own reserves but can share those resources when needed most."[53] In a region like PJM, this analysis for planning purposes and cost allocation can be performed separately for each LDA.

A report prepared for FERC staff by Brattle and Astrape illustrates the lower cost to consumers from transmission interties. The lower lines in the graph below have more transmission, and lower costs for consumers.

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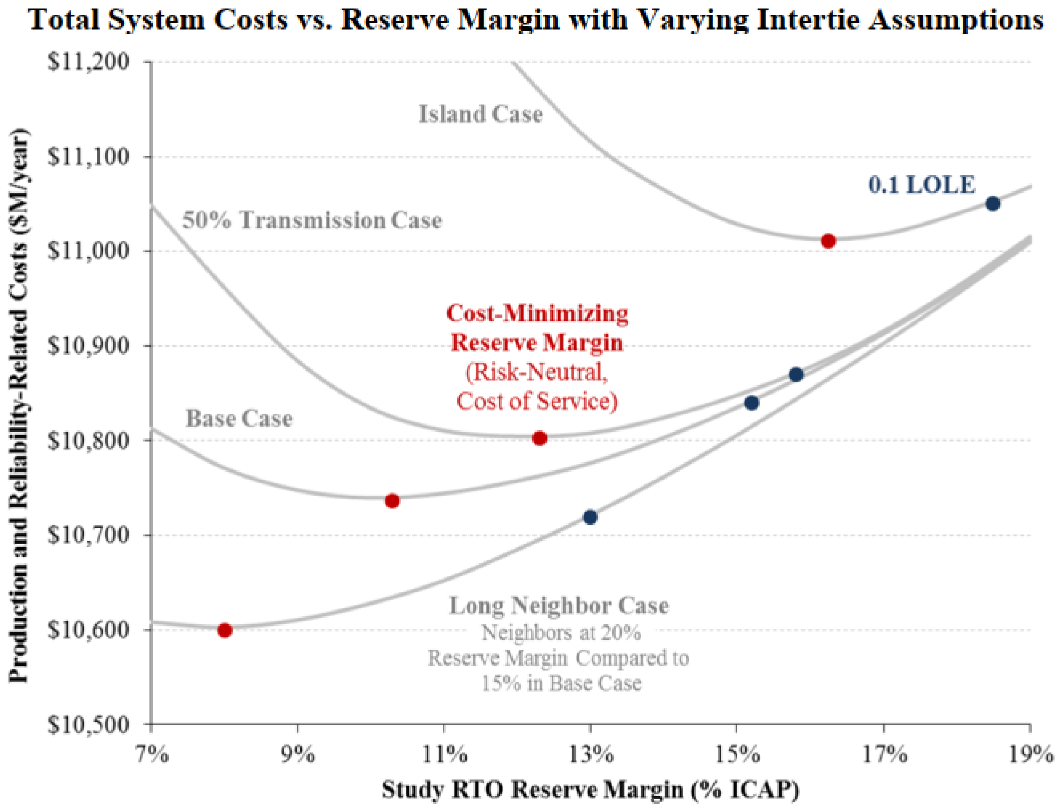
the 18 Percent Planning Reserve Margin Requirement, Docket 5-EI-141, PSC REF#:102692, dated October 9, 2008, received October 11, 2008, p. 5. Southwest Power Pool (SPP), *The Value of Transmission*, January 26, 2016, p. 16. MISO, *MISO Value Proposition 2020, Detailed Circulation Description*, n.d., p. 22. PJM, *Value Proposition*, 2019, p. 2. Australian Energy Market Operator 2022 Integrated System Plan (June 2022), p. 64.

[53] https://cdn.misoenergy.org/20220527%20PAC%20Item%2002a%20MTEP21%20Addendum%20Appendix%20F%20-%20LRTP%20Tranche%201%20Substantive%20Comments624805.pdf, p. 4.

**Figure 1: Brattle/Astrape Illustration of Lower Generation Capacity Costs from Stronger Transmission Ties[54]**




The lower cost for consumers based on lower generation reserve margins that are enabled by stronger transmission ties should be evaluated by transmission planners and incorporated as a benefit.

54 https://www.brattle.com/wp-content/uploads/2017/10/6092_resource_adequacy_requirements_pfeifenberger_spees_ferc_sept_2013.pdf Figure 19, p. 59.

*(3) Production cost savings*[55]

This benefit can be studied relatively easily with standard production cost software and data. It has been used in a number of planning efforts.[56] The category includes fuel and variable operating cost savings, and adjustments for imports from neighboring regions. The category should also include ancillary service cost savings (unless that is treated as a separate category), which can include the reduced cost of cycling power plants, reduced amounts and costs of operating reserves and other ancillary services, and mitigation of reliability-must-run (RMR) conditions.

*(4) Reduced transmission energy losses*

The lower losses that result from greater transmission capacity produce real operational savings.[57] This has been demonstrated in various studies.[58]

*(5) Reduced congestion due to transmission outages*

A lot of expensive congestion that consumers pay for results from transmission outages.[59] Most planning models include planned, but not unplanned transmission outages and thus conceal

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[55] NOPR ¶¶198-201.

[56] MISO, FERC Electric Tariff, Attach. FF, Benefit Metrics § (I)(A)(1) (33.0.0). *See PJM Interconnection L.L.C.,* 142 FERC ¶ 61,214, ¶ 416 (2013) (PJM First Regional Compliance Order); *New York Independent System Operator Corp.,* 143 FERC ¶ 61,059, ¶¶ 268, 269, n.516 (2013) (NYISO First Regional Compliance Order); NYISO, NYISO Tariffs, OATT, Attach. Y, § 31.5 (27.0.0), § 31.5.4.3.2. *Pub. Serv. Co. of Colo.,* 142 FERC ¶ 61,206, ¶ 314 (2013); ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137-CE-149, App. C, Ex. 1, pp. 34-38 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007). SPP, Regional Cost Allocation Review (RCAR II), p. 5 (July 11, 2016), https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf. Australian Energy Market Operator 2022 Integrated System Plan (June 2022), p. 64.

[57] NOPR ¶202.

[58] ATC, *Planning Analysis of the Paddock-Rockdale Project*, Docket No. 137-CE-149, app. C, Ex. 1, pp. 34-38 (Wisc. Pub. Serv. SPP, Regional Cost Allocation Review (RCAR II), p. 5 (July 11, 2016), https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf. Comm'n Apr. 5, 2007).

[59] NOPR ¶ 205.

this benefit.[60] Yet it has been done and can be used by any planning entity.[61] One can see this effect in recent experiences. For example, in the NERC/FERC report about winter storm Uri, "the Event triggered numerous transmission facility outages, causing transmission owners to submit a large volume of manually-updated information (as with generator owners/generator operators, this information included causes of outages and estimates of restoration time)."[62] The separate FERC NOPR on extreme weather notes that "concurrent outages occur nearly simultaneously in different planning areas due to the same extreme weather events, such as the unplanned generator outages associated with the major extreme heat and cold events discussed above."[63]

*(6) Mitigation of extreme events and system contingencies*

Energy cost savings can be extremely high in very short time periods due to severe weather. Generation of all types is susceptible to extreme hot, extreme cold, and drought. The NOPR defines this benefit as "reductions in production costs resulting from reduced high-cost generation and emergency procurements necessary to support the transmission system during extreme events (such as unusual weather conditions, fuel shortages, or multiple or sustained generation and transmission outages) and system contingencies."[64] This benefit is very evident looking backwards after the fact at the hundreds of millions of dollars that would have been saved if

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[60] Brattle-Grid Strategies, Oct. 2021 Report, p. 79.

[61] SPP, *Regional Cost Allocation Review (RCAR II)*, pp. 51-52.

[62] NOPR ¶ 232; Winter 2021 NERC Report.

[63] NOPR ¶ 68.

[64] NOPR ¶ 206.

transmission capacity had been greater during a number of actual severe weather episodes.[65] Prospectively, one can assess this value probabilistically as has been done.[66]

The benefit should also include reduction in energy prices to consumers, not just production cost savings. Many regions have scarcity pricing where price is set administratively high during times of scarcity, and in the future, they may have prices set by actual demand side bids. These prices can be well above the generation production cost. Transmission that mitigates these prices produces real consumer benefits.

This category of benefit should also include increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility. There are also operational benefits associated with HVDC lines that should be included in this category.[67] Grid strength is also a reliability benefit that should go in this category, if not its own category.[68] Transmission can also support the concept that has been called "resilience," or "fuel security."[69] In ISO-NE where fuel

[65] Michael Goggin, https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

[66] Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project, Application 05-04-015 (Cal. Comm'n Jan. 27, 2007). ATC, *Planning Analysis of the Paddock-Rockdale Project*, Docket No. 137-CE-149, app. C, Ex. 1, at 4, 50-53 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007).

[67] PJM Interconnection, *2008 RTEP — Reliability Analysis Update," Transmission Expansion Advisory Committee (TEAC) Meeting*, October 15, 2008, pp. 8-10. L. P. Lazaridis, *Economic Comparison of HVAC and HVDC Solutions for Large Offshore Wind Farms under Special Consideration of Reliability*, Master's Thesis X-ETS/ESS-0505, Royal Institute of Technology Department of Electrical Engineering, 2005, p. 34. Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society, HVDC Systems & Trans Bay Cable, presentation, March 16, 2005, p. 75. S. Wang, J. Zhu, L. Trinh, and J Pan, *Economic Assessment of HVDC Project in Deregulated Energy Markets," Electric Utility Deregulation and Restructuring and Power Technologies*, 2008. DRPT 2008. IEEE Third International Conference, pp.18, 23, 6-9 April 2008, p. 19.

[68] See, for example, the MISO RIIA study discussion of grid strength and the ability of transmission to support it: MISO, MISO's Renewable Integration Impact Assessment (RIIA) study, Summary Report, February 2021.

[69] V. Budhraja, J. Balance, J. Dyer, and F. Mobasher, *Transmission Benefit Quantification, Cost Allocation and Cost Recovery, Final Project Report* prepared for CIEE by Lawrence Berkeley National Laboratory and CERTS, Proj. Mgr. J. Eto, June 2008, pp. 43-44.

security has been a major concern of the ISO and NERC, imports from other regions showed up as providing significant mitigation.[70]

*(7) Mitigation of weather and load uncertainty*

This is a benefit stemming from the uncertainty associated with load and generation, and the value of transmission to integrate areas with load, generation, and "net load" diversity.[71] It has been incorporated in certain cases.[72] Recent research suggests significant value from transmission when real world uncertainty is taken into account, as compared to deterministic modeling.[73] The Brattle-Grid Strategies report on transmission planning methods called this "Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability."[74]

*(8) Capacity cost benefits from reduced peak energy losses*

This is a distinct benefit category[75] that has been measured before.[76]

*(9) Deferred generation capacity investments*

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[70] ISO-NE Operational Fuel Security Analysis, 2018, p.33, Figure 4 "more imports." https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf

[71] NOPR ¶¶ 208-209.

[72] ERCOT, Economic Planning Criteria: Question 1: 1/7/2011 Joint CMWG/PLWG Meeting, p. 10 (Mar. 4, 2011). The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant Energy estimated probabilities for the same scenarios.

[73] Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, BU-ISE, (Oct. 14, 2020) *available at* https://open.bu.edu/handle/2144/41451.

[74] *Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs* at 2, 34, 78, 85-86, 99 (Oct. 2021).

[75] NOPR ¶¶ 210-212.

[76] ITC Holdings Co., Joint Application, Docket No. EC12-145-000, at Ex. ITC-600, 77-78 (Test. of Pfeifenberger) (filed Sept. 24, 2012). Southwest Power Pool, SPP Priority Projects Phase II Report, Rev. 1, April 27, 2010, p 26. American Transmission Company LLC (ATC), Planning Analysis of the Paddock-Rockdale Project, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598), pp. 4, 63. Midwest ISO (MISO), Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 25 and 27.

This benefit reflects the substitution of transmission for generation, which may result in savings.[77] These savings can be calculated and have been in various planning efforts.[78] The NOPR defines this as transmission that "either defers or negates the need to invest in generation capacity resources within a transmission planning region by increasing import capability from neighboring regions into resource-constrained areas."[79] Thus it is a more localized concept, and separate from the system-wide resource adequacy benefit defined above. CAISO includes a "local capacity benefit" which "corresponds to a situation where a transmission solution leads to a reduction of local capacity requirement in a load area or accessing an otherwise inaccessible resource"[80] and is distinct from their "system resource adequacy" category. Avoided reliability must-run payments would fit in this category.

*(10) Access to lower-cost generation* [81]

Generation capacity cost savings are separate from production cost savings described above. It has been included in a number of transmission valuation efforts.[82] There is often a tradeoff between more remote low-cost generation delivered with transmission, and more local higher cost generation that requires less transmission. Planners should assess this tradeoff. As

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[77] NOPR ¶¶ 212-214.

[78] ITC Holdings Co., Joint Application, Docket No. EC12-145-000, at Ex. ITC-600 (Test. of Pfeifenberger) (filed Sept. 24, 2012) at 58-59. Australian Energy Market Operator 2022 Integrated System Plan, June 2022. p. 64.

[79] NOPR ¶ 214.

[80] CAISO 2021-2021 Transmission Plan at 242 (Mar. 24, 2021) *available at* http://www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf.

[81] NOPR ¶¶ 216-218.

[82] Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project, Application 05-04-015 (Cal. Comm'n Jan. 27, 2007). Midwest ISO, *RGOS: Regional Generation Outlet Study*, November 19, 2010, p. 32 and Appendix A. ERCOT *Competitive Renewable Energy Zones (CEA) Transmission Optimization Study* (Apr. 2, 2008) *available at* https://www.nrc.gov/docs/ML0914/ML091420467.pdf; Australian Energy Market Operator 2022 Integrated System Plan, June 2022. p. 64. American Transmission Company LLC (ATC), *Arrowhead-Weston Transmission Line: Benefits Report*, February 2009, p 7.

available local sites are used up over time, it is reasonable to expect a greater need for and reliance on remote resources, justifying more transmission.

MISO's Regional Generation Outlet Study in 2010, and subsequent planning exercises explicitly analyzed and incorporated this tradeoff.[83] By accessing cheaper generation, MISO's initial analysis found that its MVP portfolio reduced the present value of wind generation investments by between $1.4 billion and $2.5 billion, offsetting approximately 15% of the transmission project costs.[84]

*(11) Increased competition*

Transmission can broaden the "geographic market," enabling more suppliers to compete, driving down prices. The NOPR describes a few ways to analyze this benefit[85] which has already been incorporated in some transmission planning.[86]

*(12) Increased market liquidity*

This distinct benefit relates to the increased number of transactions when more trade is possible, reducing the variation in prices and increasing the transparency of the market.[87]

**3. Additional Benefit Category.**

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[83] *RGOS: Regional Generation Outlet Study*, November 19, 2010, p. 32.

[84] Midwest ISO (MISO), *Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop*, August 22, 2011, pp. 25 and 38-41.

[85] NOPR ¶¶ 219-224, citing *Brattle-Grid Strategies* Oct. 2021 Report, pp. 46-47 and F. A. Wolak, *Managing Unilateral Market Power in Electricity*, Policy Research Working Paper; No. 3691. World Bank, Washington, DC, at 8 (2005).

[86] Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project, Application 05-04-015 (Cal. Comm'n Jan. 27, 2007); CAISO, Transmission Economic Assessment Methodology, Chapter 4 (Jun. 2004); ATC, *Planning Analysis of the Paddock-Rockdale Project*, at 44-49 (Apr. 5, 2007). ATC, *Planning Analysis of the Paddock-Rockdale Project*, Docket No. 137-CE-149, app. C, Ex. 1, at 44 & n.11 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007). CAISO, *Transmission Economic Assessment Methodology*, Chapter 4, 1-12 (2004). Regression equation found at id. 3-6.

[87] NOPR ¶ 225; *Brattle-Grid Strategies* Oct. 2021 Report p. 50

As noted *supra*, the Joint PCs also urge the Commission to allow for (and not preclude) the addition of the additional benefit category of grid decarbonization to those proposed by the NOPR. As noted above, Maryland and the District have ambitious decarbonization goals for the supply of their electric consumers. Achieving these goals may or will be foreclosed by a regional transmission grid that fails to consider the benefits of decarbonization in its planning criteria. It also exacerbates the risk of conflict between the power procurement needs and actions of these jurisdictions and their retail regulated EDCs and the configuration and evolution of the regional transmission grid which the NOPR's hoped for more enlightened transmission planning processes seeks to avoid.

Inclusion of this additional benefit category can take several forms. Provided adoption of this benefit category in the regional transmission planner's planning process is done in a transparent manner, pursuant to articulated and reasonable criteria, and can be measured in a transparent manner, the Joint PCs urge the Commission to consider (and, at a minimum permit) this additional benefit category for evaluation by regional transmission planners. This in fact is already occurring. For example, MISO's recently approved the "Tranche 1 Portfolio" of its Long-Range Transmission Plan ("LRTP") included a suite of regional transmission projects across the MISO footprint allowing the interconnection of up to 56 GW of new renewables.[88] In approving these facilities, MISO explicitly included decarbonization as a benefit by valuing the avoided greenhouse gas ("GHG") emissions through production cost savings analyses.[89] The economic value of these benefits were a significant share of the total net benefits for the approved package

[88] MISO, *Reliability Imperative: Long Range Transmission Planning* (Board of Directors, July 2022); ACORE et al., *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis. A Case Study of MISO's Long Range Transmission Planning* (Aug. 2022).

[89] *Id*., MISO, p. 8 (valuing "decarbonization" due to the enhanced access for renewable generation at between $3.5-17.4B present value (2022$), compared to a total net benefit of $23.2-52.2B for the Tranche 1 portfolio).

of transmission projects, and were determined to be shared broadly across the MISO footprint among multiple states, such that their inclusion in MISO's planning evaluation, if not decisive, were material to MISO's approval. Decarbonization was expressly considered in MISO's planning process and incorporated through the economic analysis under the rubric of production cost savings analysis. The Joint PCs submit that MISO's procedure, in this respect, should be considered among the "best practices" for adoption by regional transmission planners.[90]

Adopting a different, still evolving approach to grid decarbonization (and dependent on alignment with the planning frameworks of its two regional transmission planners, PJM and MISO), Illinois has initiated an effort to facilitate the establishment of Renewable Energy Access Areas (or "REAAs").[91] Illinois is evaluating the need to access renewable generation in designated areas which may depend for their success on major expansions of the transmission grid, implicating if not requiring the construction of regional transmission facilities (or having an equivalent impact on the regional grid). These goals are in furtherance of the State's decarbonization mandates, and their fulfillment likely can only be done at large-scale, beyond the confines of incremental project-by-project additions of a generating resource and its connecting transmission facilities. Absent recognition of the decarbonization benefits arising from these REAAs, there is likely to be a considerable gap between regional transmission expansion and Illinois' REAP initiative.

Illinois' power requirements operate at a much larger scale than those of Maryland or the District, given its larger size and electric load. Nevertheless, given the greater population density

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[90] *See* fn. 51, ACORE *et al.*

[91] *See,* Illinois Commerce Commission Staff et al., *Illinois Renewable Energy Access Plan, First Draft for Public Comments* (July 2022).

and attendant land-use restrictions of Maryland and the District, their ability to access sufficient renewable generation to meet their grid decarbonization goals may require similar, non-incremental expansions of the transmission system (implicating the regional transmission system). As noted in the NOPR, the Maryland Energy Administration offered in its comment on the ANOPR a Straw Man proposal that echoed elements of Illinois REAP plan.[92] The Joint PCs urge the Commission to permit and not preclude the expansion of the benefit categories considered by the regional transmission planners in their conduct of regional transmission planning and the selection of regional transmission projects.

#### 4. Project Selection

The NOPR says the criteria for project selection "must aim to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand. Public utility transmission providers should seek to maximize benefits to consumers over time without over-building transmission facilities."[93] Selection criteria must ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan and that public utility transmission providers should seek to maximize benefits to consumers over time without over-building transmission facilities. That means the decision rule should be to maximize net benefits. For example, if a transmission planner selected decarbonization as one if its benefits, it could quantify the economic benefit by applying the carbon price of the marginal GHG emissions reductions that the transmission asset makes possible.

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[92] NOPR ¶ 252, fn. 399 (referencing the Maryland Energy Administration's comments (Oct. 2021), filed during the ANOPR phase).

[93] NOPR ¶ 245.

### 5. Use of Benefits in Cost Allocation.

The list of benefits adopted in the final rule for planning should also include the same minimum set of benefits for cost allocation purposes. If costs are allocated in a way that ignores when that particular load provides benefits, it would violate the "beneficiary pays" rule to which the Commission must adhere. Costs of LTRTP facilities must be assigned in a way that is "roughly commensurate" with the benefits received, consistent with the *Illinois Commerce Commission v. FERC*[94] line of cases. As noted in E below, the Commission should allow the inclusion of additional benefit categories for evaluation quantifying these additional benefits proposed by State Entity(ies) that opt into pro-active participation in the regional transmission planning process, with the ability of the participating State Entity(ies) to consent to the allocation of costs that align with these additional benefits; but, at a minimum, the distribution of the pool of benefits from selected regional project(s) determined utilizing the NOPR proposed list of benefit categories should align with the allocation of the costs to the State Entity(ies) thereby benefitted.

## D. Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices in Long-Term Regional Transmission Planning

The NOPR asked for input on proposed rules aimed at facilitating greater adoption of GETs where warranted. Due to the promise of greater efficiencies and cost-effectiveness, the Joint PCs are supportive of the NOPR's initiative to promote greater use of GETs in a targeted manner.

The NOPR notes that there has been a willingness on the part of RTOs/ISOs to consider implementing GETs in their transmission planning process. In its discussion, the NOPR has narrowed GETs to two specific technologies, dynamic line ratings and advanced power flow

[94] *Illinois Commerce Comm'n v. FERC*, 576 F.3d 470 (7th Cir. 2009) (*ICC I*); *Illinois Commerce Comm'n v. FERC*, 756 F.3d 556 (7th Cir. 2014) (*ICC II*); *Illinois Commerce Comm'n v. FERC*, 721 F.3d 764 (7th Cir. 2013) (*ICC III*).

control devices. The NOPR's proposals would not mandate GETs but would at least require consideration of dynamic line ratings and advanced power flow control devices, and their potential benefits, in the transmission planning process.

The first proposal involves requiring public utility transmission providers within a transmission planning region, to consider GETs and factor any added efficiencies or cost effectiveness they bring, compared to those transmission facilities that do not incorporate such technologies, for purposes of cost allocation.[95] This analysis would further factor (1) whether incorporating GETs into existing transmission facilities could meet the transmission needs of a region more efficiently or cost-effectively than other potential facilities; and (2) whether there would be any potential efficiencies, from a cost-allocation perspective, gained by incorporating GETs into potential transmission facilities being considered for selection into a regional transmission plan. The NOPR proposes this apply to all aspects of the regional transmission planning process, including existing transmission planning in the near term as well as long term. Costs to incorporate either dynamic line ratings or advanced power flow control devices are proposed to be allocated using "the applicable regional cost allocation method."

Pursuant to Order No. 1000, a determination detailing the transmission planning process and why a particular transmission facility was chosen is required. Accordingly, the NOPR also proposes that this determination now include a discussion on the consideration of GETs in the transmission planning process, including, in the event they are not selected, an explanation as to why.

[95] NOPR ¶¶ 217, 274.

The NOPR also requested input on any other transmission technologies that should be considered in the transmission process and whether non-RTO/ISO regions should adjust their energy management systems, if incorporating GETs in a regional transmission plan proves to be more efficient or cost effective for purposes of cost allocation.

The Joint PCs support integrating the use of GETs into the transmission planning process. RTOs/ISOs should be required to factor the efficiencies that could be achieved by utilizing these technologies and the cost-effectiveness of GETs when considering expansion projects. We are supportive of also considering the potential benefits of incorporating dynamic line ratings and advanced power flow control devices into transmission facilities selected as part of a transmission plan.

GETs should be used in transmission planning as a potential alternative to investing in new transmission projects, and data collected from DLRs should be shared with stakeholders, subject to CEII requirements, to provide further transparency as to the necessity or economic efficiency of certain transmission upgrades. Similarly, the Joint PCs are supportive of requiring an explanation of how GETs were considered in the planning process, and in the event, they were not utilized, an explanation detailing why. Further discussion and detail are required to ensure that GETs receive proper consideration and that costs projections for implementing these technologies are accurate. Therefore, a mechanism should be in place to independently review the projected costs and benefits from an efficiency and cost-allocation perspective.

The Joint PCs suggest storage-as-transmission be added as a GET in the planning process. We also suggest that advanced conductors and increasing capacity on existing lines and rights of way be fully incorporated into planning processes because those approaches are often very cost-effective relative to new lines and rights of way. The Joint PCs agree that cost allocation be pursued under the processes in place for regional transmission organizations.

### E. Regional Transmission Cost Allocation

The Joint PCs generally endorse the Commission's view, as proposed by in the NOPR, that "State Entities" (including entities like Maryland and the District of Columbia with regulatory responsibilities at retail over the EDCs operating within their jurisdictions) should be afforded a defined and expansive role in participation in the process for selecting a regional transmission project expansion, anchored by their ability to agree in a timely manner on regional cost allocations of transmission expansions selected through the regional planning process.[96] The Joint PCs suggest several items for clarification to this aspect of the NOPR proposal.

The NOPR proposal can be read to imply a cabining of the process of regional transmission project selection, first, and cost allocation of the selected projects, second, in sequence. As discussed below, this sequential approach should be reconfigured to better enable and make more likely full State Entity participation and agreement in regional transmission expansion projects and a more transparent selection of projects.

First, there is an emerging paradigm, suggested by the NOPR, for the regional transmission system planner to promote regional grid expansions that optimize the interconnection of **portfolios** of resources rather than individual projects. In in the near and intermediate term, these portfolios may be defined by interconnection "clusters", vintaged by the time of application conforming to evolving RTO/ISO interconnection practices, but, with a more strategic view enabled by the longer term planning proposed by the NOPR, also may be defined by designated geographic areas, with

[96] NOPR ¶¶ 278-327.

development over more extended time frames than allowed for by the clustering process.[97] These portfolios, in turn, are increasingly likely to result from power supply procurement commitments made in conformity with State policies, which value, in addition to the NOPR proposed benefits, decarbonization of the grid or expansion of clean energy as a benefit (among others). Regional transmission planning and regional grid expansion should not foreclose this possibility, but rather enable it.

Second, State Entities, if afforded an explicit role in cost allocation decisions only sequentially, following project selection will be foreclosed from considering regional transmission expansions that better address the power supply needs of the particular State Entities, because the benefit of grid decarbonization may be or is excluded from the regional transmission planner's decision-making process. This will make it less likely, contrary to the Commission's intent, to facilitate State Entity agreement on cost allocation.

In these circumstances, the Joint PCs suggest that regional transmission planner should plan and select regional transmission expansions which optimize the interconnection of portfolios of resources, including those which address and deliver and are valued based on benefits arising from grid decarbonization while also providing the NOPR's listed benefits. To advance this salutary goal, State Entities should be afforded an opportunity to participate, at their option, earlier in the planning process, during the project evaluation and selection phase. This will allow for an

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[97] Such as, for example, the very large and geographically extensive offshore wind ("OSW") energy production projects, in various stages of planning extending over more than a decade into the future, encompassing areas leased by the Bureau of Ocean Energy Management ("BOEM") extending longitudinally all along the East Coast of the US (recently expanded by BOEM to include the West and Gulf Coasts). The National Renewable Energy Lab (NREL) estimates that there are about 23 GW of OSW projects in the development pipeline, comprising various stages of permitting and site control acquisition, along the East Coast. Additionally, there approximately an additional 12 GW of unleased wind area potential (capacity estimated using a 3 MW/km2 wind turbine density function). DOE, Office of Energy Efficiency and Renewable Energy, *Offshore Wind Market Report* 2021 Edition (see Table 3, pp. 16-17). The just published 2022 version of DOE's Offshore Wind Market Report (2022 Edition) shows even further expansion of the project pipeline and size of the potential resources from that reported in 2021.

explicit consideration of a broader suite of benefits as determined by the participating State Entities in the selection of the optimal transmission expansion, to be followed by a procedure for securing agreement on the cost allocation of the selected transmission expansion projects, which are prioritized based on maximizing the broader measure of benefits.

The regional transmission planner would also establish a residual quantum of benefits arising from the proposed regional transmission expansion reflecting the NOPR-listed benefits, excluding the participating State Entities' "additional benefits", to determine all beneficiaries of the proposed expansion. The cost allocation of the project expansion, exhibiting such residual benefits, would follow the default cost allocation of the regional transmission planner aligning cost allocation strictly with the NOPR-listed benefits, to the extent incorporated into the regional transmission planner's evaluation process. Participating State Entities would do so based on the benefit evaluation, broadened to include the participating State Entities designated additional benefits; the non-participating State Entities would do so on the basis of the default cost allocation.

The predicate to this State Entity participation would be voluntary agreement by the State Entities opting for this participation. The arrangements for participation would follow but be more expansive than that provided for in the existing State Agreement Approach ("SAA") in PJM, in that they would also allow for a parallel default allocation of costs to the State Entities not opting in, but narrowed to aligning the NOPR-listed benefits (absent the State Entity additional benefit) attributed to the expansion with the allocation of costs, in a second round of cost allocation after the participating State Entities have shared costs aligned with the broader measure of benefits. [98]

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[98] *PJM Interconnection, LLC, Order Accepting Agreement*, 179 FERC ¶ 61,024 (April 14, 2022) (Individual state designated transmission expansion planned and administered by PJM and the participating state, inclusion in the regional transmission expansion plan for informational purposes only, limiting cost allocation to the state participating in the agreement and precluding the project from regional cost allocation). The failure to provide for allocation of

The opting-in State Entities would also satisfy the requirements of the Commission's policy statement on voluntary agreements.[99]

### F. Regional Transmission Monitor

The Joint PCs remain supportive of an independent regional transmission monitor. While this idea was circulated in the ANOPR, it was not included in the NOPR. Both DC OPC and MD OPC expressed support for an independent transmission monitor in separate comments submitted in response to the ANOPR[100] and collectively we remain hopeful that the idea is discussed during the Commission's upcoming technical conference on transmission planning and cost management.[101] We believe that the Commission should encourage the formation of independent regional transmission monitors, while leaving the exact design up to each region. For example, the monitor could be entirely independent or be branched under an RTO/ISO; furthermore, it could serve under an existing market monitor within a region.

An independent regional monitor would be particularly helpful when considering the incorporation of dynamic line ratings and other GETs, from both an efficiency and cost-effectiveness standpoint. RTOs do not have the requisite level of independence, due to the

transmission expansion costs to State Entity(ies) that choose not to participate in a transmission project, that nevertheless affords the narrower NOPR-listed benefits to customers in the jurisdiction of the non-participating State Entity(ies), exacerbates the undesired free-rider problem adverted to in the NOPR (NOPR, ¶ 325) and is not addressed in the New Jersey/PJM SAA approved by the Commission. The proposal described in the text adds the provision for a minimum cost allocation to non-participants to address this problem, while leaving the inclusion of "additional benefits" open to the participating State Entity(ies) in project selection, and their assumption of the additional cost allocation responsibility to the extent of that inclusion.

[99] *State Voluntary Agreements to Plan and Pay for Transmission Facil*ities, 175 FERC ¶ 61,225 (June 17, 2021).

[100] DC OPC Initial Comments, pp. 8-10. MD OPC supported this position in its joint filing with a coalition of indicated state agencies of comments on the ANOPR. See, Comments of the State Agencies, pp. 2, 3, 33-37 (Oct. 12, 2021).

[101] Notice of Technical Conference on Transmission Planning and Cost Management, eLibrary No. 20220421-3091 (April 21, 2022).

dependent relationship with transmission owners, as perhaps previously thought. Regardless, an independent body that can provide added insight would enhance the transmission planning process.

### G. Return of the ROFR and the Rightsizing of Transmission Facilities

#### 1. Return of Right-of-First-Refusal.

When the Commission issued Order No. 1000 in 2011, it recognized that competition could lead to "the identification and evaluation of more efficient or cost-effective alternatives to regional transmission needs."[102] In order to promote competition, the Commission required the removal of provisions that grant a federal right-of-first-refusal ("ROFR") to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. The Commission found such action necessary because "it is not in the economic self-interest of incumbent transmission providers to permit new entrants to develop transmission facilities, even if proposals submitted by new entrants would result in a more efficient or cost-effective solution to the region's needs."[103] Rather the Commission recognized that "[t]he presence of multiple transmission developers would lower costs to customers."[104]

The benefits to consumers of the removal of the ROFR for regional transmission projects are clear. Even with a relatively modest sample size since the promulgation of Order No. 1000,[105] a report by The Brattle Group found that projects selected through competition "were priced significantly below the initial project cost estimates prepared by the ISO/RTOs or incumbent

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[102] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, ¶ 226 (2011) ("Order No. 1000").

[103] Order No. 1000 ¶ 284.

[104] Order No. 1000 ¶ 268 (quoting *Cleco Power LLC*, 101 FERC ¶ 61,008, ¶ 117 (2002)).

[105] The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission*, p. 19 (April 2019) Figure 6, https://brattlefiles.blob.core.windows.net/files/15987_brattle_competitive_transmission_report_final_with_data_tables_04-09-2019.pdf ("Brattle Report"). For the PJM region, only 5.1 percent of total transmission investment between 2013 and 2017 was open to competition.

transmission owners prior to receiving proposals through the competitive process."[106] In fact, the Brattle Report's analysis demonstrated that competitive solicitations lead to transmission projects priced anywhere from 15% to 60% lower compared to RTO/ISO estimates or incumbent bids.[107] Additionally, projects selected through competitive processes had additional benefits for ratepayers, as many of the selected projects "included cost caps or cost-control measures, *which are expected to reduce the risks to ratepayers of cost escalations* as the projects are developed and constructed in the coming years."[108] As previously discussed in the Joint PCs' comments, the energy transition necessary to meet public policy goals and consumer preferences will require a significant expansion of transmission capacity at a time when transmission rates are an increasingly large share of ratepayers' wholesale electric bills. *Even at the low end of the Brattle Report's demonstrated savings, the potential reduced costs for consumers are in the billions of dollars*.

Beyond costs savings and a reduction of ratepayer risk, transmission competition can play an important role in the type of grid transformation envisioned by the ANOPR—especially in a region with a "sponsorship" solutions-based competitive procurement process like PJM. As the Brattle Report explains, "competition can foster significant additional benefits from innovative project design and risk mitigation to address the identified need."[109] Under the sponsorship approach, developers and incumbent transmission owners are not only competing on price, but on design qualities. Such an approach ensures that *the best project* is selected—one that is not only cost conscious, but also best addresses the transmission needs for the region it will serve. It is this

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[106] Brattle Report, p. 8-9.

[107] Brattle Report, Table 20.

[108] Brattle Report, p. 9 (emphasis added).

[109] Brattle Report, p. 11.

goal—transmission projects that transform the grid through innovative solutions—that was behind the Commission's desire to issue the NOPR.

Building on the legacy of Order No. 1000, the need to remove existing ROFRs at both the federal and state level is more beneficial than ever. For example, members of the Commission have recently recognized the impact of ROFRs in limiting transmission competition in areas such as transmission upgrades. For example, Commissioner Clements accurately noted that "it is hard to imagine how [an RTO] can leverage competitive forces in the planning process for consumers' benefits if [transmission owners] are permitted to stifle competition through their exercise of rights of first refusal over upgrades within a new transmission facility project."[110] Similarly state ROFR laws subvert the intent of Order No. 1000 and undermine the benefits of competition both for consumers within those states and *consumers in others states who rely on that transmission capacity*.

Unfortunately, the NOPR proposes to "establish[ ] [of] a federal right of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities."[111] This is an unfortunate step backwards—abandoning rather than enhancing opportunities for competitive transmission solicitation. The Joint PCs vigorously oppose this proposed rule as it will raise consumer costs in an unjustified and unreasonable fashion, is clearly discriminatory, and will lead to decreased innovation in transmission solutions at a time when creativity and flexibility should

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[110] *Order on Petition for Declaratory Order*, 175 FERC ¶ 61,038, Concurring Opinion of Commissioner Clements (2021).

[111] NOPR ¶ 365.

be paramount. It is particularly distressing that the NOPR would not even allow the existing competitive solicitation structure in regions and markets, such as PJM, where they have a proven history of successfully bringing transmission projects on-line while saving ratepayer dollars.

The NOPR bases its proposal on its finding that "Order No. 1000 nonincumbent transmission developer reforms may in fact be inadvertently discouraging investment in and development of regional transmission facilities to some extent" because incumbent transmission owners "may be presented with perverse investment incentives that do not adequately encourage those incumbent transmission providers to develop and advocate for transmission facilities that benefit more than just their own local retail distribution service territory or footprint."[112] In this respect the Joint PCs are in complete agreement with the NOPR. The existing framework does encourage too many projects to be planned at the local, rather then regional, level; relegating the RTO/ISO—the nominal regional transmission planner—to a secondary and often subservient role. In this respect, the promise of Order No. 1000 has not been fulfilled.

But the NOPR errs gravely in its remedy. Rather than looking for opportunities to enhance competition it backtracks toward relying on an outmoded model of transmission planning. While recognizing the current incentive structure is not working as intended, rather than developing new incentives that place a premium on competitive solutions for regional planning, the NOPR rewards those who have perverted the incentives for regional planning. The Commission has long recognized the benefits to all stakeholders from competitive wholesale markets for energy and capacity—it would simply be unimaginable for the Commission to backtrack from Order No. 888 and its progeny which have delivered lower cost, lower carbon, more diverse, and more resilient

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[112] NOPR ¶ 350.

energy to consumers. Yet that is what the NOPR is proposing with respect to transmission policy. Abandoning the competitive principles enshrined in Order No. 1000 will result in more costly transmission projects that may not meet the generation, reliability and resilience, and consumer needs of the grid of the future.

To begin with, the proposal is nearly as unworkable as it is illogical and illegal. The NOPR provides scant rules defining exactly how any potential joint ownership would operate. For example, what level of ownership of the unaffiliated entity would be required for their investment to be "meaningful"? What level of management and control by the unaffiliated entity would be required for their participation to be "meaningful"? What if the level of investment and management of the unaffiliated entity were non-synchronous (for example, the unaffiliated entity contributes 80% of the project capital, but all its interest are class "B", non-voting shares)? Does the unaffiliated entity's interest and investment need to remain constant throughout the life of the project or can the incumbent utility buy out some or all of its' partner's interest (with ratepayer money)? If so, when—immediately after solicitation is finalized; during construction; or only after the facility has been in-service for a set time period? These aren't simply hypothetical questions but go to the heart of whether the unaffiliated entity is a true partner in the joint ownership of the transmission facility or simply a front to subvert competitive solicitation. The lack of clarity on these important questions this late in the development of any potential final rule undermines the legitimacy of the rulemaking process and calls into question the reasoned decision making regarding this aspect of the NOPR.

Additionally, the NOPR's proposal on ROFRs cannot be legally implemented pursuant to Section 309 of the Federal Power Act ("FPA"), which does not provide a means for FERC to discard its prior findings under Section 206 of the FPA. Those findings in Order No. 1000 and elsewhere hold that federal ROFRs for regional transmission projects are unjust, unreasonable, unduly discriminatory, and contrary to the public interest. Those findings are based on sound economic theory regarding the inherent price controlling and benefit optimizing value of competition. Moreover, as previously discussed, those findings have been proven correct in studies such as the Brattle Report. The NOPR provides no justification for discarding its prior findings, other than perhaps those findings that have been more difficult to implement then expected. But the difficulty in implementing the correct, and legally justified, policy, *cannot excuse* the NOPR's decision to backtrack on that policy.

Finally, the return of the ROFR is simply bad transmission policy. As previously stated, but worth repeating, transmission competition serves as the most effective way of containing transmission costs, especially at a time when transmission expansion is both underway and needed. For the U.S. to reach carbon neutrality, the current transmission system will need to expand three to five times by 2050, at a total cost of $2-$4 trillion.[113] Assuming 20-30% savings and 25-33% penetration of competition solicitations, consumers could save an estimated $100-$400 billion through 2050 if competition is preserved. Moreover, transmission competition is leading the way in developing the generation resources needed for a low carbon grid, as demonstrated by projects like ERCOT's Competitive Renewable Energy Zones and the recent New Jersey and New York offshore wind solicitations. Far from slowing down transmission development, competitive projects that are solicited with guaranteed construction and delivery schedules often absent from incumbent transmission projects, are delivering the transmission infrastructure on-time and on-budget for consumers *and* generation resources.

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[113] *Princeton "Net-Zero America: Potential Pathways, Infrastructure, and Impacts".*

Instead of reinstating a costly and discriminatory policy like federal ROFR, the NOPR could tackle the deficiencies of Order No. 1000 by removing the requirement that cost allocation or project size are determinative in a project's eligibility for competitive solicitation. While Order No. 1000 originally tied regional cost allocation to a project's eligibility for competition there is no existing logical basis to retain this threshold requirement and tying competition to cost allocation is not only a vestige of a different planning era but inhibits the necessary reforms to meet the transmission needs of the future. Similarly competitive solicitations should be available for nearly every project of 100 kV and above. In Order No. 743 the Commission recognized:

> many facilities operated at 100 kV and above have a significant effect on the overall functioning of the grid. The majority of 100 kV and above facilities in the United States operate in parallel with other high voltage and extra high voltage facilities, interconnect significant amounts of generation sources and operate as part of a defined flow gate, which illustrates their parallel nature and therefore their necessity to the reliable operation of the interconnected transmission system[114]

Setting a voltage threshold for competition limits the ability of incumbent transmission owners to evade the regional planning process while still leaving truly local transmission to the EDCs.

### 2. Opportunities to Right-Size Replacement Transmission Facilities

The NOPR also proposes to end-of-life transmission planning by incorporating in its rules a process that is nearly identical to the existing Attachment M-3 process in PJM.[115] As previously discussed, the current Attachment M-3 has utterly failed to either control spending or provide opportunities for meaningful stakeholder participation in the PJM

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[114] *Revision to the Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 133 FERC ¶ 61,150, ¶ 73 (2010).

[115] NOPR ¶ 400.

region. Spending on Supplemental Projects (planned through the Attachment M-3 process) regularly outstrips spending on Baseline Projects (planned through the PJM regional transmission plan) and stakeholders are provided no more than a notice and comment opportunity. Adoption of an Attachment M-3 like process will result another new avenue for incumbent transmission owners to exercise a ROFR, all but ensuring that competition will be eliminated and further unjustifiably raising consumer costs. The NOPR's faulty reasoning is based on the illogical and unfounded assumption that a rational incumbent will imprudently proceed with an "under-sized" in-kind replacement project rendered duplicative by a "right- sized" project moving forward in the regional planning process. There is no debate that a significant rebuild of aging transmission infrastructure is both necessary and already occurring. However, granting incumbent transmission owners a ROFR on end-of-life projects demotes the RTO/ISO role as the regional planner at a time when that responsibility is most needed. As Commissioner Clements explained in her concurrence in a set of orders regarding PJM end-of-life transmission planning, proposals like the one offered in the NOPR will have important and long-lasting ramifications as the Commission, RTO/ISOs, and other stakeholders look to address future transmission needs in an evolving grid:

> [T]he grid mix is rapidly changing … given these changes, simply rebuilding the system of the past will not cost-effectively meet future needs. It will result in a system that is either more costly, less reliable, or both.
>
> Yet the result of the Majority Order, pursuant to which the PJM Transmission Owners retain authority over even regional EOL Projects so long as they plan to exactly replace those facilities, is perverse. Holistically assessing system needs and considering design expansion or modifications in a manner that ensures customers avoid overpaying requires PJM to have what the [consolidated transmission owner

> agreement] confers upon it: the responsibility to plan for grid expansion and enhancement involving regional benefits.[116]

## II. CONCLUSION

For the reasons stated herein, the Joint PCs respectfully request that the Commission consider the instant comments in developing its final rule regarding regional transmission planning and cost allocation and generator interconnection.

Respectfully submitted,


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[116] Concurring Opinion of Commissioner Clements, pp. 22-23, 176 FERC ¶ 61,053.

## CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated on this 17th day of August, 2022.

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