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 | Docket No. RM21-17-000 |

**COMMENTS OF**
**TRANSMISSION ACCESS POLICY STUDY GROUP**

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The Transmission Access Policy Study Group ("TAPS") appreciates the opportunity to comment on the Federal Energy Regulatory Commission's ("Commission") July 15, 2021 Advance Notice of Proposed Rulemaking.[1] TAPS applauds the Commission for launching this important effort, and offers comments on subjects included in the ANOPR and subjects that were not included but should be in order for the Commission to achieve its objectives.

TAPS agrees that we need to consider how we can better integrate our changing resource mix, and that continued siloing of the generator interconnection and planning processes is likely to produce *ad hoc* additions that are not the most efficient and cost-effective way to meet our needs. But given the very steep transmission rate increases already faced by TAPS members, we highlight the Commission's Federal Power Act ("FPA") section 217(b)(4)[2] obligation to facilitate planning and expansion to meet the

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[1] *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Generator Interconnection*, 176 FERC ¶ 61,024 (2021) ("ANOPR").

[2] 16 U.S.C. § 824q(b)(4).

reasonable needs of Load Serving Entities ("LSEs"). *See* Part I.A below. We need smart investment in efficient and cost-effective transmission, and planning firmly rooted in LSE needs—not just generator preferences.

To address deficiencies that threaten to impede achievement of Commission objectives, TAPS strongly urges consideration in this rulemaking process of reforms not included in the ANOPR. These include the need to: (1) promote joint ownership, which has a strong track record in getting needed transmission sited and built while minimizing cost; (2) make regional planning in areas outside a Regional Transmission Organization/Independent System Operator (collectively "RTO") real, enabling selection of more efficient and cost-effective projects consistent with Order 1000 and providing a foundation for the additional reforms under consideration; (3) ensure timely consideration, in an open and transparent regional process, of "quick fix" conventional solutions and Grid-Enhancing Technologies ("GETs") to reduce costs to consumers; and (4) improve and provide oversight for local planning processes to provide all consumers with reliable and not-unduly discriminatory transmission service, while protecting against costly additions that are not the more efficient and cost-effective alternative. For each, TAPS identifies reforms meriting consideration. *See* Parts I.B and II.A below.

TAPS also addresses a number of potential proposals identified in the ANOPR. In Part II.B.1, TAPS generally supports better integrating the transmission planning and interconnection processes, building on existing Order 1000 processes.[3] We examine

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[3] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011) ("Order 1000"), *reh'g denied*, Order No. 1000-A, 139 FERC ¶ 61,132 ("Order 1000-A"), *on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2102), *review denied sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (per curiam).

several proactive planning processes, highlighting lessons learned: (1) the need to foster and leverage broadly inclusive, collaborative planning processes, rather than mandate top-down planning; and (2) the importance of having a process and adequate time to convert the results of such collaborative processes into specific project proposals.

To facilitate project selection, in Part II.B.2 we urge continued focus on Order 1000's benefits, while opening the door to regions to propose additional quantifiable benefits relevant to the region. Incorporating difficult- or impossible-to-quantify benefits will frustrate the ability to select more efficient and cost-effective projects. Similarly, TAPS would first allocate costs of proactively planned upgrades to beneficiaries, applying the same benefits used for project selection. If costs remain to be allocated, consideration of load zones expected to rely on the generation that the proactively planned transmission is designed to support could be appropriate. Consistent with fundamental cost allocation principles and given the tensions associated with broad cost allocation, it should be used sparingly. *See* Parts II.B.3.

TAPS urges against complete or substantial elimination of RTO authority to directly assign interconnection-related network upgrades costs; doing so would remove the interconnection customer's ("IC") incentive to site wisely, an inducement that will be essential as we move toward reliance on proactively planned facilities. Recognizing some reduction is appropriate, TAPS' high-level concept would retain a degree of participant funding, with that percentage increasing once proactive plans can affect IC siting. It would be the worst of all worlds for load to fund major, proactively planned lines, while also being required to fund expensive interconnection-related network upgrades for ICs that choose not to take advantage of planned facilities. *See* Parts II.C.1 and 2.

TAPS also expresses concern about eliminating or substantially reducing upfront funding and crediting requirements. Doing so would shift to load all risks of stranded costs for upgrades associated with generators that fail to achieve commercial operation, and aggravate rate increases driven by proactively planned upgrades. *See* Part II.C.3.

In addition to asking the Commission to carefully structure planning processes to minimize costs to consumers, TAPS agrees that enhanced oversight is needed to protect consumers from excessive costs. The ANOPR's concept of an Independent Transmission Monitor could play an important role in non-RTO regions and for local planning in RTOs. TAPS suggests additional oversight and cost containment mechanisms, such as one modeled after the Southwest Power Pool, Inc.'s ("SPP") Regional State Committee, and enhanced stakeholder participation. And we urge the Commission not to abandon competitive transmission development, which has been effective in reducing costs where it has been used. *See* Part II.D.1. On the other hand, cost-increasing incentives (e.g., return on equity ("ROE") adders) would defeat cost containment and burden consumers with unnecessary costs, threatening achievement of the ANOPR's goals. *See* Part II.D.2.

## INTEREST OF TAPS

TAPS is an association of transmission-dependent utilities ("TDUs") in thirty-five states promoting open and non-discriminatory transmission access.[4] As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members recognize the importance of a robust transmission grid, and have long

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[4] *See* https://www.tapsgroup.org (last visited Oct. 6, 2021). David Geschwind, Southern Minnesota Municipal Power Agency, chairs the TAPS Board. Jane Cirrincione, Northern California Power Agency, is TAPS Vice Chair. Terry Huval is TAPS Executive Director.

been outspoken on the need for improved transmission and ways to get needed transmission built.[5] TAPS recognizes the critical roles played by an open, inclusive, and transparent planning process, and fair cost allocation in achieving needed transmission expansion.

As municipal, cooperative, and investor-owned LSEs, TAPS members are responsible for providing reliable and affordable service to the consumers and businesses that rely on them and their members. As we approach the ANOPR, a paramount concern is reliable service at reasonable cost to consumers, consistent with FPA section 217(b)(4)'s directive that the Commission facilitate the planning and expansion of the grid to meet the reasonable load-serving needs of LSEs. TAPS vigorously supported Order 1000's objective of ensuring selection of the more efficient and cost-effective alternatives in transmission plans, which goal should guide the Commission as it addresses how to plan and expand the grid to accommodate the resource transformation now underway.

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[5] *See* TAPS, Effective Solutions for Getting Needed Transmission Built at Reasonable Cost (June 2004) ("TAPS 2004 White Paper"), https://www.tapsgroup.org/wp-content/uploads/2013/01/effectivesolutions.pdf.

## COMMENTS

## I. NEED FOR REFORM

### *A. Needs Identified in the ANOPR*

TAPS agrees that the time is ripe to reassess the Commission's interconnection, planning, and cost allocation policies in light of our quickly evolving resource mix. For example, we agree that failure to better integrate the generator interconnection process with the planning process is likely to produce *ad hoc* additions that are not the most efficient and cost-effective way to meet our needs. *See* ANOPR PP 31-36.

But moving toward a more holistic approach to planning does not mean soup-to-nuts revisions of Order 1000, especially in RTOs where considerable progress has been made on planning and interconnection reform. The Commission should not adopt a one-size-fits-all approach that sets back positive efforts now underway.

A more holistic approach comes with its own challenges, including the need to respect Congress' directive to the Commission in FPA section 217(b)(4) to facilitate planning and expansion to meet the reasonable needs of LSEs. A "build it and they will come" approach would not be consistent with that directive. And the Commission's focus on new generation shouldn't blind it to the need to better ensure that existing and future load and generation pockets are timely addressed, so that LSEs are not burdened with congestion costs and receive the benefits of renewable generation for which they have contracted.

Even before the anticipated build-out animating the ANOPR, TAPS members have been subjected to huge transmission rate increases. For instance, the Network Integration Transmission Service ("NITS") rate in SPP's Empire District Electric

Company zone increased 41% in just one year—from 2020 to 2021.[6] Similarly, from 2018 to 2021, NITS rate increases for a number of PJM Interconnection, L.L.C. ("PJM") transmission owners ("TOs") ranged up to a staggering 66%.[7] Cost to consumers needs to be a key concern as we contemplate significant transmission expansion.

### *B. Need for Reforms Not Highlighted in the ANOPR*

The ANOPR is sweeping in scope, encompassing potential reforms to planning, cost allocation, and interconnection policies to address integration of new renewable resources. But it overlooks significant shortcomings of our current approach to planning and cost allocation, as well as opportunities. TAPS identifies additional areas warranting reform and potential reforms that should be considered in conjunction with those in the ANOPR to achieve the Commission's goals in a manner that protects consumers.

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[6] The Empire District Electric Company - Transmission Formula Rate Annual Update Narrative 1, http://www.oasis.oati.com/woa/docs/EDE/EDEdocs/TFR_Annual_Update_Narrative_(2021).docx.

[7] **Rate ($/MW/Year) and Rate Change for PJM Transmission Owners with January 1 Rate Update**

| **Transmission Owners** | Jan. 1, 2018 | Jan. 1, 2019 | Jan. 1, 2020 | Jan. 1, 2021 | Total Change 2018-2021 |
|---|---|---|---|---|---|
| AEP | $59,818.14 | $65,923.43 (+10.21%) | $80,306.41 (+21.82%) | $95,597.51 (+19.04%) | $35,779.37 (+59.81%) |
| ATSI | $54, 689.39 | $55,185.23 (+0.91%) | $57,482.35 (+4.16%) | $66,744.13 (+16.11%) | $12,054.74 (+22.04%) |
| Dayton | $13,295.76 | $12,561.48 (-5.52%) | $12,561.48 (±0.00%) | $19,175.06 (+52.65%) | $5,879.30 (+44.22%) |

**Rate ($/MW/Year) and Rate Change for PJM Transmission Owners with June 1 Rate Update**

| **Transmission Owners** | June 1, 2018 | June 1, 2019 | June 1, 2020 | June 1, 2021 | Total Change 2018-2021 |
|---|---|---|---|---|---|
| Duke | $24,077.00 | $25,840.00 (+7.32%) | $32,143.00 (+24.39%) | $35,136.00 (+9.31%) | $11,059.00 (+45.93%) |
| PPL | $58,865.00 | $68,031.00 (+15.57%) | $75,204.00 (+10.54%) | $97,811.00 (+30.06%) | $38.946.00 (+66.16%) |

The data in these tables were derived from data available on the "Billing, Settlements, & Credit" section of PJM's website, subsection "Network Integration Transmission Service Revenue Requirements & Rates," https://www.pjm.com/markets-and-operations/billing-settlements-and-credit (last visited Sept. 29, 2021).

### 1. Joint Ownership Needs to be Considered and Encouraged as Part of Any Planning and Expansion Reforms

As the nation embarks on a new round of major investments to transform the grid, the Commission should ensure that efficiency and equity benefits of inclusive joint ownership are an integral part of the path forward. The Commission has repeatedly recognized the benefits of and encouraged joint ownership arrangements. In crafting rules to accommodate our changing resource mix, it should seize upon opportunities to make such encouragement of joint ownership arrangements real.

As explained in TAPS' recent white paper, "Inclusive Joint Transmission Ownership Arrangements: An Effective Means to Site and Build Transmission Needed to Support our Changing Resource Mix,"[8] inclusive joint transmission ownership arrangements—which invite participation on reasonable and comparable terms to all LSEs in the relevant footprint—have been shown effective in getting needed transmission built in a manner that benefits consumers. Such arrangements—whether structured as an inclusive transco,[9] a shared system,[10] or joint ownership of new transmission

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[8] TAPS 2021 White Paper (June 25, 2021), https://www.tapsgroup.org/wp-content/uploads/2021/09/TAPS-Inclusive-Joint-Ownership-White-Paper.pdf ("TAPS 2021 White Paper"). Additional detail is provided in the TAPS 2004 White Paper. *See also* Comments of TAPS 29-38 (July 1, 2020), eLibrary No. 20200701-5410 ("TAPS 2020 Incentive NOPR Comments").

[9] The American Transmission Company LLC ("ATC") is a transco jointly owned by twenty-six utilities: four investor-owned utilities and twenty-two public power and cooperative utilities, including TDUs, in Wisconsin, Michigan, Minnesota, and Illinois. ATC has grown from $550 million in assets in 2001 to $5.5 billion, with more than 710 miles of new line. *See* TAPS 2021 White Paper at 2, describing Vermont Electric Power Company ("VELCO"), a long-standing inclusive transco.

[10] In shared system arrangements (including those long in place in Georgia, Indiana, Minnesota, North Dakota and South Dakota), transmission facilities of two or more utilities are planned and operated jointly, as a single system, pursuant to a long-term agreement. Ownership is generally in proportion to each participant's load ratio share of connected customer load, which can be achieved in a variety of ways, e.g., owning an undivided share of the entire joint system; owning discrete facilities; owning new facilities. *See* TAPS 2021 White Paper at 3 (describing the more recent MidAmerican Energy Company/Midwest Municipal Transmission Group shared system arrangement).

facilities[11]—result in collaborative and inclusive planning, development, and siting of transmission, and have proven highly effective in getting transmission built to meet the needs of all LSEs. Their benefits include:

1. *Improving the transmission planning process by making joint planning real*. Although Commission rules require open, coordinated, and transparent planning, there is a big practical difference when all LSEs are at the table as owners, aligning the ownership structure with the reality of the way the network operates and should be planned. For example, existing barriers to TDU participation in local transmission planning processes leave TDUs' reliability and grid access subject to their host utility (often a competitor) and too often result in uneven, discriminatory service and long-standing weaknesses in portions of the grid serving TDUs. In TAPS members' experience, joint ownership has been crucial to empowering transmission customers in planning processes, getting local grid weaknesses addressed, and obtaining fair and equitable service. When diverse parties are owners, openness, transparency, and more balanced decision-making flow automatically. Now is the time to leverage this attribute to ensure that the major transmission investments needed to transform the grid are equitably planned and reduce, rather than exacerbate, discrimination.

2. *Facilitating a more efficient build-out of the transmission system*. Combining what was then five systems into one jointly-owned transco, ATC, has led to a more rationally-developed system than the previously balkanized planning and construction. We also saw this in the CapX2020 process, which proactively planned and constructed major upgrades needed to support the changing generation mix, rather than reactively designing and building piecemeal additions in response to individual transmission or interconnection service requests. The transformation of the nation's grid would be greatly facilitated by a broadly shared vision of future needs and buy-in from a wide range of LSEs, TOs, and stakeholders. Inclusive joint ownership arrangements have proven they can deliver those crucial ingredients.

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[11] For example, as discussed in Part II.B.1, below, CapX2020 (now Grid North Partners), a joint transmission-planning process in the northern Midwest, is a recent joint ownership success story. The CapX utilities—investor-owned, municipal, and rural cooperative utilities in Minnesota, North Dakota, South Dakota, and Wisconsin—jointly planned needed transmission upgrades and had opportunities to jointly own them. Each project is jointly owned by a subgroup of CapX2020 utilities, with a lead entity that serves as construction manager on behalf of the owners. *See* TAPS 2021 White Paper at 3-4 for two recent joint ownership examples. The first, involving TAPS member Kansas Power Pool, the City of Winfield, and GridLiance High Plains LLC, facilitated timely completion of facilities necessary to preserve and enhance service reliability for Winfield and the surrounding SPP area. The second, involving TAPS member Missouri Joint Municipal Electric Utility Commission ("MJMEUC") and Ameren, will result in construction of a $30 million project in Northeast Missouri that strengthens the Midcontinent Independent System Operator, Inc. ("MISO") transmission system and enhances reliability for MJMEUC member Hannibal, Missouri, and Ameren.

3. *Facilitating siting*. By meeting the needs of multiple utilities, a joint project is able to demonstrate multiple benefits. And although joint ownership participation by TDUs may be relatively small percentage-wise, these utilities bring a wealth of political support to the state approval process. This diverse support can make all the difference in speeding up permitting and addressing local concerns. It is particularly important for the types of projects needed to support the nation's changing resource mix—large, integrated regional and interregional projects that run through multiple states and may have very different benefits and costs in different locations.

4. *Facilitating approval by state retail rate regulators*. When state commissions are presented with projects that are least-cost because they meet multiple needs, when they see unity among utilities on need, and when they are faced with a broad base of support from diverse stakeholders, it is far easier to grant requested authorizations.

5. *Making it easier for consumers to accept the cost increases associated with new transmission projects, easing cost allocation issues*. Joint ownership can provide LSEs with a level of comfort that transmission expansions have been equitably planned and will have broad benefits for all consumers, not just for existing TOs. It can mitigate the adverse competitive impacts of increasing transmission costs—an important consideration given the scale of anticipated new investment. For transmission-owning LSEs, new projects represent an earnings opportunity, not just an obligation to pay. Joint ownership arrangements can provide TDUs a comparable opportunity to hedge the cost increases associated with the anticipated transmission build-out. For instance, although transmission rates paid by ATC customers have materially increased because of ATC's construction program, joint ownership has enabled ATC's municipal and cooperative owners to partially offset that increase. This ability has made it much easier for them to support ATC's build-out. And it makes cost allocation issues (although still thorny) easier to resolve.

6. *Spreading the risk of major projects broadly and providing a variety of sources of capital for projects*. The financial diversity and strength achieved through joint ownership arrangements are valuable, particularly given the magnitude of the investments likely to be necessary going forward. Rating agencies have recognized that ATC's inclusiveness is a significant benefit.

7. *Obtaining the broad base of support that can be essential to securing state legislative action required to better align retail rate recovery with the need for supporting major transmission investment*, as has occurred in Minnesota with the full support of the CapX2020 group.

8. *Benefitting consumers by reducing transmission rates*. Where public power ownership is direct, consumers receive several rate-reducing benefits. Public power utilities are not subject to income taxes, and they flow their tax savings through to ratepayers. Their lower debt cost further reduces rates. Even when set on a hypothetical basis, public power utilities' capital structures commonly include less equity than investor-owned utilities' actual capital structures. While not all these rate-reducing attributes apply to inclusive transcos, some may, depending on the corporate

structure. For example, the lack of tax allowance for ATC's public power owners reduces ATC's rates. Given the large transmission investments contemplated, timely Commission action that takes advantage of these types of rate-reducing benefits is needed to decrease the burden on consumers to the extent possible.

9. *Reducing the need for the Commission to referee rate and other disputes,* because decisions about project need and the prudency of expenditures are vetted through the joint ownership arrangement.

Given these substantial benefits, the Commission has repeatedly encouraged inclusive joint ownership arrangements. In Order 1000, it highlighted their value in "increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission customers."[12] It has recognized that TDU participation in joint ownership is consistent with FPA section 219's goal of "encouraging a deep pool of participants,"[13] and the benefit to consumers as well as TDUs that can use revenues from transmission ownership to offset increasing transmission rates.[14] The 2012 Policy Statement made that encouragement more concrete, expressing the expectation that ROE incentive applicants demonstrate that they are minimizing their risks during project development, and identifying joint ownership arrangements as a risk-reducing measure to be considered.[15]

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[12] Order 1000, P 776 (citing *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 118 FERC ¶ 61,119, P 593 (2007)). *See also* Order 1000-A, P 81.

[13] *Promoting Transmission Inv. through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, PP 354, 357 ("Order 679"), *on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006) ("Order 679-A"), *clarified*, 119 FERC ¶ 61,062 (2007); *see also* Order 679-A, P 102.

[14] *See Cent. Minn. Mun. Power Agency*, 134 FERC ¶ 61,115, P 19 n.23 (2011). It also stated: "[A]llowing Central Minnesota to receive a revenue requirement . . . that reflects the higher capital costs of the investor-owned utilities' will offset the Midwest ISO transmission rates that its members pay, which largely reflect those investor-owned utilities' higher capital costs, thereby allowing Central Minnesota and its members to effectively reduce their future transmission rates to reflect their lower capital costs to mitigate their investment risks associated with the project." *Id.* P 31.

[15] *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129, P 24 & n.33 (2012) ("2012 Policy Statement"):

> [A]pplicants may take measures to mitigate risks associated with siting and environmental impacts

Inclusive joint ownership arrangements nevertheless remain the exception. Investor-owned utilities continue to be reluctant to share transmission ownership with TDUs, preferring to keep transmission investments at Commission-approved ROEs to themselves. Offers by TAPS members to invest in the grid have too often been rebuffed, and joint ownership efforts have been stymied even where the TDU has a willing partner or a state commission-approved memorandum of understanding.[16] Reliability has suffered[17]—an outcome others have also documented.[18] The result has been service not comparable to what public utility TOs provide their own end-users and at higher cost, in

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> by pursuing joint ownership arrangements. The Commission encourages incentives applicants to participate in joint ownership arrangements and agrees with commenters to the NOI that such arrangements can be beneficial by diversifying financial risk across multiple owners and minimizing siting risks.[33]
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> [33] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at PP 354, 357; Order No. 679-A FERC Stats. & Regs. ¶ 31,236, at P 102. See also Central Maine Power Company, 125 FERC ¶ 61,182, at P 61 (2008); Xcel Energy, 121 FERC ¶ 61,284 at P 55 (2007). Evidence regarding whether an applicant for incentives considered joint ownership arrangements may be relevant in assessing whether the applicant took appropriate steps to minimize its risks during project development.

[16] See examples described in TAPS 2021 White Paper at 6 n.11.

[17] For more than a decade, TAPS member Oklahoma Municipal Power Authority ("OMPA") has struggled to improve reliability for two member municipal utilities, Duncan (50 MW) and Marlow (11.5 MW). Each is connected to American Electric Power's ("AEP") 138 kV transmission system via a single radial line, leaving them vulnerable to lengthy outages from ice storms, tornadoes, and other events. Duncan previously had a second interconnection, but a 2007 state road project required its relocation and it has not been replaced. After unsuccessful efforts to address the situation with AEP, OMPA (partnering with GridLiance) proposed a new 138 kV line that would loop through Duncan; significantly reduce the radial feed to Marlow; improve reliability to a nearby city served by the Public Service Company of Oklahoma ("PSO"); and connect to a recently constructed AEP switching station. AEP instead offered to install automated switches, leaving Duncan and Marlow each with a single radial connection. These reliability issues have yet to be solved. Rejection of GridLiance's proposal to expand its local transmission planning process to enable it to plan and recover the cost of projects like this, *GridLiance High Plains LLC*, 174 FERC ¶ 61,078 (2021) ("*GridLiance"*), has further delayed improving reliability for the two cities.

[18] Initial Comments of GridLiance 11-17, *Inquiry Regarding the Commission's Electric Transmission Incentive Policy*, Docket No. PL19-3-000 (June 26, 2019), eLibrary No. 20190626-5308 ("GridLiance Incentive NOI Comments"); *id.*, attach. A ("Pardikes Affidavit") (demonstrating the role of public power participation in transmission ownership in creating a more reliable transmission grid and more competitive wholesale markets). The Pardikes Affidavit identified significant barriers to such participation (at 41-42), and documented the resulting under-investment (at 5-23), despite the interest of many in increasing their investment (at 26).

violation of the basic principle that "[g]rid reliability and resilience should not depend on who provides the wholesale and retail service to an end-user if their circumstances are otherwise similar."[19] Now the 2012 Policy Statement's inducement to inclusive joint ownership is at risk in the pending 2020 Incentives NOPR,[20] which proposes to move from a risks-and-challenges approach to benefits-based incentives, without mentioning any obligation by applicants to take risk-reducing *measures*, including joint ownership.

How the nation plans, develops, and funds the major transmission investments required to transform the grid and support the changing resource mix will shape the industry for decades. The Commission's objective of modifying planning and expansion requirements to accommodate our changing resource mix, while minimizing costs to consumers, would be thwarted if costs are unnecessarily increased or needed projects are not timely built because they face greater financial or siting risk without joint ownership.

It's time for the Commission to use its full range of tools to structure the planning process to encourage inclusive joint ownership and leverage its many benefits, consistent with FPA section 217(b)(4)'s directive to the Commission to exercise its "authority . . . under [the Act] in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities." Reforms designed to do so include:

*(i) Make inclusive joint ownership arrangements a factor in selection of regional and interregional projects for inclusion in transmission plans*. Projects with inclusive joint ownership have significant advantages in the often-challenging siting process. To serve the Commission's goal of getting efficient and cost-effective projects actually built,

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[19] GridLiance Incentive NOI Comments at 9-10; Pardikes Affidavit at 24-26. *See also* Pardikes Affidavit at 29-35 (describing other barriers to public power transmission ownership).

[20] *Elec. Transmission Incentives Policy Under Section 219 of the Fed. Power Act*, 170 FERC ¶ 61,204 ("2020 Incentives NOPR"), *corrected*, 171 FERC ¶ 61,072 (2020).

processes for selecting regional and interregional projects for inclusion in transmission plans should favor such projects.

*(ii) Allow additional flexibility to planning processes that assures a meaningful opportunity for joint ownership*: To the extent the Commission modifies existing transmission planning requirements through this rulemaking process, the Commission could allow variation from strict application of those new requirements where the regional or local planning process is fully transparent and collaborative *and* provides a meaningful opportunity for inclusive joint transmission ownership, thereby assuring full TDU input into the planning and expansion process. The demonstrated contribution of such inclusiveness to effective planning and expansion where such processes are in place (e.g., ATC, VELCO) reduces the need for rigid application of new requirements.

*(iii) Provide opportunities for TDU joint ownership and planning as a feature of the local planning process*. To ensure that TDUs and the consumers that rely on them have comparable and reliable service, the Commission should empower TDUs (including third-party planning, construction, and financing capabilities they enlist) to conduct local transmission planning in coordination with the regional transmission planning process. Subject to approval of TDU-planned projects through a comparable planning process that applies comparable planning criteria and considers impacts on neighboring interconnected facilities or systems (e.g., by the RTO), TDUs (with third parties they enlist) should be allowed to implement approved plans with cost recovery of the resulting facilities on a comparable basis to their host utility. To facilitate such efforts and harness joint ownership as a mechanism to prevent discrimination and enhance reliability, the Commission should revisit and revise existing tariff restrictions on TDU planning. [21]

*(iv) Provide for bidding out the cost of construction and associated capital requirements of regional and interregional projects selected for inclusion in transmission plans, with bidding structured to provide an opportunity for all TDUs in the footprint to participate in supplying their fair share of the required capital.* As highlighted by the contentiousness of the right of first refusal ("ROFR") issue in Order 1000 processes and by controversies as to which utility has the right to build a given project,[22] there is no scarcity of willing constructors. Particularly if, despite TAPS' urging, the Commission chooses not to take steps requested above to promote inclusive joint ownership

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[21] *See GridLiance*, PP 46-47; *see id.* Clements, Comm'r, concurring.

[22] *See, e.g., Xcel Energy Serv., Inc. v. Am. Transmission Co., LLC*, 140 FERC ¶ 61,058 (2012), *reh'g denied*, 147 FERC ¶ 61,089 (2014) (granting complaint challenging ATC's claim to construction and ownership rights associated with the 145-mile, 345 kV LaCrosse-Madison Line). The Commission addressed similar disputes in *Am. Transmission Co., LLC v. Midwest Indep. Sys. Operator, Inc.*, 142 FERC ¶ 61,090 (2013) and *ITC Midwest, LLC v. Am. Transmission Co., LLC*, 142 FERC ¶ 61,096 (2013), *reh'g denied*, 152 FERC ¶ 61,155 (2015). A developer granted a 150 basis point risk-based incentive for new transmission unsuccessfully sought to block joint ownership by the host TO—which did not seek that same rate incentive—to claim rights to build and own 100% of the facility. *Pioneer Transmission, LLC* 126 FERC ¶ 61,281 (2009), *clarified and reh'g denied*, 130 FERC ¶ 61,044 (2010); *Pioneer Transmission, LLC,* 130 FERC ¶ 61,044 (2010); *Pioneer Transmission, LLC v. N. Ind. Pub. Serv. Co.*, 140 FERC ¶ 61,057 (2012); *Midcontinent Indep. Sys. Operator, Inc.*, 164 FERC ¶ 61,155, PP 3-14 (2018).

arrangements, it should provide for competitive bidding of the cost of construction and associated capital requirements (currently an option available to planning regions), to yield the lowest cost to consumers, while structuring those processes to provide TDUs in the footprint opportunities to participate in supplying their fair share of the required capital. Inclusive joint ownership should be treated as a positive factor in evaluating bids.

### 2. Need to Reform Non-RTO Region Planning Processes to Make Them Real and Provide a Foundation for New Reforms

While Order 1000 has spurred significant planning and expansion in RTO regions, it has *not* been productive in non-RTO regions. For example, in the peninsular Florida region, no project has ever been approved as more efficient and cost-effective through the biennial Order 1000 process, despite areas of congestion (e.g., central Florida[23]). That concerning deficiency is driven in significant part by limitations on the factors the region considers in evaluating possible economic projects. In the Order 1000 compliance process, TAPS member Florida Municipal Power Agency ("FMPA") argued for consideration of congestion relief for the purpose of selecting projects for inclusion in the regional plan, but the filing Florida utilities argued that use of production cost savings was too speculative in the absence of centralized dispatch.[24] The Commission disagreed with the filing utilities, noting the adoption of production cost savings in other non-RTO regions.[25] But it "decline[d] to impose … [use of production cost modeling in Florida] at

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[23] Central Florida is a multi-seamed area where many Florida systems converge: e.g., Florida Power & Light Co. ("FPL"), Duke Energy Florida, Tampa Electric Company, Orlando Utilities Commission, Lakeland Electric, FMPA, Kissimmee Utility Authority, Seminole Electric Cooperative, Inc., and Reedy Creek Improvement District. Central Florida includes both a major export zone where significant generation is sent to other areas of the state, as well as some of the highest load growth in the nation. Congestion "band-aids" are evident. For example, in the last few years, Florida utilities have agreed to (and documented) numerous Operational Remedies to reliably address third-party impacts in contingency situations (including first contingency situations) from new generator interconnection and transmission service requests. Multiple Remedial Action Schemes are also in place, along with associated Reliability Coordinator special operating procedures.

[24] *Tampa Elec. Co.*, 148 FERC ¶ 61,172, P 406 (2014) ("Second Compliance Order").

[25] *Id.* P 420, (citing *Tampa Elec. Co.* 143 FERC ¶ 61,254, P 254 (2013) ("First Compliance Order"), which

this time."[26] As a result, the process developed by the filing Florida utilities only contains process steps for avoided cost of displaced projects and transmission losses to be considered in evaluating regional projects.

In addition to missing opportunities for more efficient and cost-effective projects because their benefits are undervalued, the region's heavy reliance on the avoided cost of displaced projects in its Order 1000 selection process creates perverse incentives. The main predicate for proposing a regional project is the presence of TO projects in the base case that can be displaced by a more efficient and cost-effective alternative. TOs are able to limit the ability of others to propose superior alternative regional projects by simply failing to disclose their planned local projects until the eleventh hour. For example, a TO may know an upgrade is needed five years in the future, but may not reveal it until immediately prior to the biennial Order 1000 process, frustrating the ability to develop regional alternatives that, with more lead time, could have been proposed.

Further, when a regional alternative to a TO-planned project has been identified, that TO can move the goalpost by unilaterally eliminating, modifying, or changing the timing of the base case local projects that a regional alternative would displace. Because the Florida Order 1000 process affords no opportunity for those offering alternatives to modify them to address such TO amendments, these TO changes can prevent regional projects from ever being selected and constructed.

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at P 254 n.404 cites as an example, *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206, PP 314, 317 (2013), *order on reh'g and compliance*, 148 FERC ¶ 61,213 (2014), *order on reh'g and compliance*, 151 FERC ¶ 61,128 (2015), *part vac. El Paso Elec. Co.*, 832 F.3d 495 (5th Cir. 2016), *order on remand*, 161 FERC ¶ 61,188 (2017)).

[26] Second Compliance Order, P 425.

And under Florida's Order 1000 process, before any consideration of the benefits of an alternative project, a full technical analysis that affords flexibility to reject the alternative based on tiny differences from the TO project(s) identified for possible displacement, must be successfully completed. [27] As a result, the potential benefits of alternative projects never get considered at all, short circuiting projects that could have produced savings for Floridians. In 2017, FPL's then-Senior Director, Development, provided detailed documentation of this fundamental defect, which he summarized as follows:[28]

> FPL strongly asserts that its six CEERTS projects are equal to their base case counterparts. The projects resolve any identified NERC failures, and do not introduce any new un-mitigatable failures that are not already present in the base case regional plan. FPL's CEERTs projects are therefore at least equal for purposes of this stage of Planning Committee review. In addition, the projects resolve some issues identified in the base cases and offer the possibility of saving Florida's transmission customers tens-of-millions of dollars in project capital costs, making them a superior choice – or at least one that should be considered in a cost-benefit review. The results that [the independent consultant] provided offer a mixed analysis of positive and negative attributes, degrees of failure, and mitigation of low-probability contingency scenarios that are fundamentally economic questions and deserve to go through a cost-benefit analysis.

These examples illustrate that in non-RTO regions, the Order 1000 process is not advancing the important objective of selecting the more efficient and cost-effective

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[27] We understand the approach to be quite different from how a TO analyzes potential projects internally.

[28] S. Miller, Florida Reliability Coordinating Council 2 (Nov. 27, 2017), https://www.frcc.com/order1000/Shared%20Documents/Archive/Announcements%20and%20Meeting%20Materials/2017/2017%2011%2027%20Open%20Stakeholder%20Meeting%20Documents/FPL%20Comments%20Regarding%20Independent%20Evaluator%20Report%2027%20NOV%202017.pdf. Florida utilities use the Florida Reliability Coordinating Council in the implementation of their tariffs' Order 1000 compliance obligations.

projects. A key reason is the absence of meaningful independent oversight, allowing the process to be effectively controlled by TOs that do not want to face competition.

To fulfill its obligations reflected in Order 1000's reforms and make effective new reforms that may be adopted in this rulemaking, the Commission should direct modifications to regional processes in non-RTO regions, including:

(i) *Require an independent transmission monitor in non-RTO regions.* This measure, which the ANOPR (PP 163-174) identifies as a possible reform, is essential for non-RTO regions. Robust independent monitors to oversee non-RTO regional planning processes are crucial to making those processes capable of achieving Order 1000's goals as well as those envisioned in the current ANOPR process. How the independent monitor is selected and its authority will be important in making this oversight meaningful.

(ii) *Require production cost savings to be considered as a metric for economic projects.* While some non-RTO regions use production cost savings modeling as an Order 1000 metric for evaluating benefits,[29] others do not.[30] Today, production cost savings modeling is well-accepted. For example, the Commission has proposed its use in granting incentives for economic projects in both RTO and non-RTO regions.[31] Given the absence of regional projects to address congested non-RTO areas, it's time to revisit the Commission's 2014 declination to impose use of production cost modeling "at this time."[32]

(iii) *Direct development and consideration of process reforms to allow for a more open, collaborative, and effective regional process that would help identify more efficient and cost-effective projects*. TAPS urges the Commission to require more collaborative, interactive joint planning processes that invite input from affected stakeholders at all stages, allow stakeholders to participate in decision-making, and assure that stakeholder views are considered on a non-discriminatory basis.[33] In addition, the process deficiencies described above warrant a close evaluation of non-RTO planning processes to identify reforms to make them work as Order 1000 intended. Such reforms could include providing for a high-level assessment of claimed economic benefits of alternative

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[29] *See Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206, PP 314, 317 (2013), cited in First Compliance Order P 254 n.404.

[30] Florida's metrics were modeled on those of the Southeastern Regional Transmission Planning region, as directed in its Second Compliance Order. *Tampa Elec. Co.*, 151 FERC ¶ 61,013, PP 76, 90 (2015) ("Third Compliance Order").

[31] 2020 Incentives NOPR P 48 (proposing use of adjusted production cost savings "or similar measures of congestion reduction or certain other quantifiable benefits that are verifiable and not duplicative").

[32] Second Compliance Order P 425.

[33] *See* Part II.D.1 below.

projects before completion of the lengthy technical assessment, to allow for a more meaningful and timely consideration of alternative projects.[34] Other potential reforms could address timing issues and the mismatch between TO flexibility to amend their base case plans and the inability of third parties to revise alternative proposals to respond to such modified plans.

### 3. Need to Better Incorporate "Quick Fixes," including Grid-Enhancing Technologies, into the Planning Process

The ANOPR evinces a sense of urgency in adopting reforms to support our resource transformation. As detailed in Part II.B below, to enable identification of the most appropriate resource-rich zones and selection of the right transmission projects in a proactive planning process, TAPS member experience points to the need for a broad consensus-building process, which unfortunately is not likely to be fast. To reduce costs to consumers by providing some immediate relief while those processes are underway, TAPS urges the Commission to consider, as part of this ANOPR process, changes to facilitate inexpensive solutions that can be implemented in a relatively short time.

For example, non-wires solutions, such as GETs, can reduce costs to consumers by enabling more efficient use of the existing system or enhancing new projects. The ANOPR mentions such non-wires solutions with respect to consideration in long-term planning scenarios (P 48(7)) and studying interconnections (P 158), as well as in its oversight questions (PP 169, 177), but makes no suggestions for reforms to better ensure their timely consideration in a regional planning context. At the same time, the Commission appears to be considering "shared savings incentives" for GETs.[35]

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[34] While fine-tuning economic benefits analysis can be deferred, making the technical and economic evaluations entirely sequential prevents a more holistic assessment of an alternative.

[35] Shared savings incentives for GETS was the topic of the September 10 Workshop in Docket Nos. RM20-10-000, AD19-19-000, Notice of Workshop (Apr. 15, 2021), eLibrary No. 2021-415-3094; Second Supplemental Notice of Workshop (Sept. 9, 2021), eLibrary No. 20210909-3059. Steve Leovy criticized the shared savings proposal under consideration, the Shared Savings Proposal of WATT

TAPS has serious concerns that offering shared savings incentives to individual developers and TOs threatens to transform inexpensive solutions into projects that are very costly to consumers.[36] But TAPS strongly supports consideration of GETs through regional planning processes, which would be a much better approach to reducing barriers to GETS, avoiding adverse interactions among GETs, and making sure we are selecting the more efficient and cost-effective solutions from a consumer perspective.

Efficient deployment of GETs requires the broad view afforded by a regional planning process. Piecemeal assessment by individual TOs could be problematic. At the 2019 GETs Workshop, Dr. Anjan Bose (Washington State University) described how more widespread adoption of a single technology or the implementation of multiple technologies could cause GETs to "fight each other."[37] AEP witness Bradish explained that this type of conflict is happening today even without widespread adoption, and "it gets harder to operate the grid with more [GETs] on it."[38] Operational interaction concerns were echoed at the September 10, 2021 Workshop,[39] with panelists also

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Coalition and Advanced Energy Economy ("AEE") (Sept. 3, 2020), eLibrary No. 20210903-5088 ("WATT/AEE Proposal"), when he appeared at that Workshop on behalf of TAPS member WPPI Energy ("WPPI") and TAPS. He also appeared for WPPI and TAPS at the November 5-6, 2019 Workshop in Docket No. AD19-19-000.

[36] *See* Written Statement of Steve Leovy, Docket No. AD19-19-000 (Oct. 31, 2019), eLibrary No. 20191112-4023. *See also Grid-Enhancing Technologies*, Post-Workshop Comments of TAPS, Docket No. AD19-19-000 (Feb. 14, 2020), eLibrary No. 20200214-5154.

[37] 2019 GETs Tr. Day 1, 80:6-12, 114:17–115:3, Docket No. AD19-19-000 (Nov. 5, 2019), eLibrary No. 20200106-4004 (Bose, WSU).

[38] 2019 GETs Tr. Day 1, 90:18-23, Docket No. AD19-19-000 (Nov. 5, 2019), eLibrary No. 20200106-4004 (Bradish, AEP).

[39] Several speakers on the Technical and Reliability panel raised concerns about interactions among GETs. Yachi Lin of New York Independent System Operator, Inc. ("NYISO"), pointed to real-world examples where the increase of transfer limits in one area resulted in an inadvertent decrease to another area. Her comments were echoed by Eric Hsia (PJM), who emphasized the potential for interactions among GETs.

stressing the need to understand how the grid operator will apply GETs in order for them to be effectively evaluated.

GETs should be considered in conjunction with other alternatives, rather than through a separate process created to determine the savings to be shared via incentives.[40] All proposed system improvements—conventional and otherwise—must be considered simultaneously to yield efficient decisions and proper benefit/consumer cost calculations. A conventional project, potentially with some GET enhancements, may be the better bet than a stand-alone GET proposed to secure incentives.

Incorporating GETs into the planning process does not mean they should only be considered in an Order 1000 process. To take advantage of the potentially shorter deployment time for GETs, as well as shorter construction times associated with some conventional solutions, existing planning processes could be expanded to focus on "quick fixes." They could build off MISO/PJM Targeted Market Efficiency Projects ("TMEPs"), which are intended to provide relatively inexpensive and readily implementable solutions to address congestion along the MISO-PJM seam.[41] The aim is to identify near-term, high-value interregional projects to alleviate historical congestion, using a simplified approach based on actual historical day-ahead and real-time congestion, in contrast to the forward-looking production cost models used in each region's regional transmission planning processes. If expanded to other regions and regional projects, a quick fix

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[40] In the WATT/AEE Proposal, GETs projects that cost between $2.5 million and $25 million would be considered in the regional planning process ahead of conventional economic projects. As proposed, neither small GETS projects (under $2.5 million) nor TO GETs programs would be considered in the planning process. WATT/AEE Proposal at 8-12.

[41] *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,005, P 1 (2017).

process could provide a good vehicle for open and transparent regional consideration of GETs along with quickly implementable conventional projects, producing more efficient and cost-effective approaches to provide timely congestion relief for consumers.[42]

TAPS urges consideration of reforms to better integrate consideration of GETs into planning processes, and better accommodate prompt consideration of solutions (conventional and/or GETs) that can be evaluated and implemented on a short timeline:

(i) *Make more explicit the mandate to consider GETS as part of regional planning processes.* While Order 1000 requires consideration of non-transmission alternatives, that directive appears insufficient to ensure robust consideration of GETs in the planning process. More explicit Commission guidance could ensure such consideration is real.

(ii) *Provide for regional "quick fix" planning processes*. Extending the MISO/PJM "quick fix" process to other regions and to regional projects could relieve consumers of high congestion costs on a more timely basis, and enable open and transparent regional evaluation of GETs and conventional solutions. At the September 10, 2021 Workshop, PJM's Director of Strategic Initiatives and Interregional Planning pointed to the TMEP process as a mechanism for considering GETs that could be extended to the regional planning process, noting "certainly we have the tools that we could do that today."[43]

To the extent the deployment timeline is even shorter and where appropriate to a particular technology (e.g., grid optimization), GETs could be considered in the operational planning process (along with planning for outages) if such process is transparent and includes a broad view of potential benefits and other impacts. The Commission should also consider, as an adjunct to the various planning processes, making available a transparent process where stakeholders that identify efficiencies to be gained from GETS can get those regionally considered on a timely basis.

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[42] In conditionally accepting TMEPs, the Commission required greater transparency. *Id.* PP 41-43.

[43] Workshop to Discuss Certain Performance-Based Ratemaking Approaches at 5:42:32-5:42:40, *Elec. Transmission Incentives Policy Under Sec. 219 of the Federal Power Act*, Docket Nos. RM20 10-000, AD19-19-000 (Sept. 10, 2021), *available at* http://ferc.capitolconnection.org/ (comments of Suzanne Glatz, Dir., Strategic Initiatives & Interregional Planning, PJM Interconnection, L.L.C., Panel 4).

4. Local Planning Processes Require More Attention

The ANOPR describes Order 890's[44] requirements for local transmission planning[45] and how "local transmission plans are incorporated into regional transmission plans as inputs, with minimal opportunity for stakeholder review in the regional transmission planning process," because that review is limited to a combined reliability analysis.[46] Aside from asking "whether and how to better coordinate between regional and local transmission planning processes to identify more efficient or cost-effective solutions,"[47] and posing several questions about oversight of local processes, the ANOPR focuses almost entirely on regional and interconnection processes.[48] To ensure local planning processes are providing the essential foundation for non-discriminatory transmission service and to protect consumers from excessive charges, TAPS urges the Commission to take a closer look at them.

The local planning process is a key forum for consideration of TDU load-serving needs. It is where the rubber meets the road on whether and how a TDU can secure reliable service for its load, and whether it must bear high congestion costs (or be required to run more expensive local generation) because of constraints in delivery of

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[44] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 ("Order 890"), *order on reh'g and clarification*, Order No. 890-A, 121 FERC ¶ 61,297 (2007) ("Order 890-A"), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[45] ANOPR P 6.

[46] *Id.* P 17

[47] *Id.* P 5(8).

[48] *See*, *e.g.*, *id.* P 4.

designated network resources to its load. It could also be an opportunity for joint ownership of transmission projects developed to meet TDU needs.

But too often TDUs find themselves in load pockets or otherwise receiving service inferior to the service the TO provides to its own loads. As described above in Part I.B.1 (n.17), TAPS member OMPA has struggled since 2007 to improve reliability for two member municipal utilities, Duncan (50 MW) and Marlow (11.5 MW), that are each served by a single radial line, exposing them to extended outages in weather events. Even joint efforts with GridLiance have not enabled a resolution that would reliably serve these towns, much less provide service comparable to the service provided by the surrounding investor-owned utility to its own loads.[49] GridLiance efforts to bolster the local planning process were rejected as inconsistent with Order 890.[50]

At the same time, TOs have made significant investment in local upgrades without regional planning process review beyond testing for reliability. Not only is there no evaluation for more efficient and cost-effective alternatives, but important aspects of the local planning process—"asset management projects and activities [that] do not expand the grid"—are not subject to Order 890 requirements.[51] Given growing concerns about aging infrastructure, exclusion of such projects from a full Order 890 process, with

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[49] This type of under-investment has been well-documented by expert testimony. *See* Pardikes Affidavit quotes as described in Part I.B.1 and at page 13 nn.18-19, *supra*.

[50] *GridLiance* PP 46-47; *see id.* Clements, Comm'r, concurring.

[51] *See S. California Edison Co.*, 164 FERC ¶ 61,160, P 31 (2018) ("SCE"), *reh'g denied*, 168 FERC ¶ 61,170 (2019); *California Pub. Util. Comm'n v. Pac. Gas. & Elec. Co.*, 164 FERC ¶ 61,161, P 66 (2018) ("PG&E"), *reh'g denied* 168 FERC ¶ 61,171 (2019). Even where the Commission enforced an RTO-specific requirement that individual TOs planning for such "Supplemental Projects" adhere to Order 890 requirements, no RTO review of those TO plans was required. See *Monongahela Power Co.*, 162 FERC ¶ 61,129, P 72 (2018), *reh'g denied*, 164 FERC ¶ 61,217, P 117 (2018).

regional review, cannot be justified on the ground that "Order No. 890 [reforms] were intended to address concerns regarding undue discrimination in grid expansion,"[52] ignoring the impact of such projects on just and reasonable rates to consumers and the potential for discrimination.

TAPS urges the Commission to consider reforms to the local planning process:

*(i) Provide opportunities for TDU planning and joint ownership as a feature of the local planning process*. *See* third proposal in Part I.B.1. Among other things, the Commission should revisit and revise existing tariff restrictions on TDU planning to ensure the necessary foundation for non-discriminatory open access service.[53]

(ii) *Provide for a more interactive and transparent local planning process, with regional and independent oversight*. *See* TAPS suggestions for enhancing the role of stakeholders in planning processes and with regard to the role of an Independent Transmission Monitor. *See* Part II.D.1 below. Exclusions from Order 890 processes and regional review need to be reexamined given their impact. Such reforms are essential to make sure the right local transmission gets built and to avoid excessive costs to consumers.

## II. CONSIDERATION OF POTENTIAL REFORMS

### *A. Reforms that are not the Focus of the ANOPR*

TAPS asks the Commission to include in this rulemaking various reforms not included in the ANOPR but which are essential to make effective any reforms developed in this process. *See* Part I.B above

### *B. Planning and Cost Allocation*

#### 1. Holistic Transmission Planning

TAPS generally supports better integrating the transmission planning and interconnection processes. Keeping them in separate silos undermines the goal of producing more efficient and cost-effective solutions to support ongoing resource

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[52] *SCE* P 31.

[53] *Id.*

changes, while maintaining affordable and reliable service to customers. There could be significant value in better aligning them and their assumptions.

Any reforms should build on existing interconnection and Order 1000 planning processes; one-size-fits-all will not work. Substantial changes—and more prescriptive Commission directives—may be needed in non-RTO regions where TOs have designed and run their planning processes in a way that all but ensures projects will never be selected for regional cost allocation. Greater flexibility may be appropriate in RTO regions, some of which are already working toward a more integrated approach.

Addressing the major challenges identified in the ANOPR will require regional consensus that can only be achieved through robust, bottom-up, collaborative processes involving all stakeholders and states in the planning region. State involvement is important to keeping cost to consumers a front-burner issue. Broad buy-in by states and stakeholders will be needed to work out thorny siting and cost allocation issues that may become even more difficult if a more proactive planning approach is adopted. As recently recognized when the Commission announced the new Joint Federal-State Task Force on Electric Transmission, federal and state regulators share authority over a host of transmission-related issues, and may have "different priorities . . . (e.g., reliability, customer protection, environmental considerations)."[54]

Collaborative, joint planning processes will take time; but based on experience, shortcuts may prove counter-productive—saddling consumers with hefty costs of facilities that prove to be unnecessary or stranded, fueling state and stakeholder resistance

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[54] *Joint Federal-State Task Force on Elec. Transmission*, 175 FERC ¶ 61,224, P 2 (2021).

to siting, or causing other unintended consequences that could thwart intended objectives. To avoid those outcomes, the Commission should look for ways to foster and support ongoing regional consensus-building efforts, rather than supplant them. Requiring regions that have made significant progress to dismantle those processes and start over could significantly delay durable solutions and the changes the ANOPR contemplates.

a) Planning for Anticipated Future Generation

The ANOPR's potential proposal (PP 54-60) to use the planning process to identify renewable-rich areas within regions, and transmission solutions to deliver the output of those areas, may have some merit. If it is to be useful, however, such an analysis cannot be merely a technical exercise. States have different approaches to meeting renewable requirements, with some strongly favoring local resources and others preferring to rely on remote generators with higher capacity factors.[55] The criteria for identifying the areas for which transmission should be proactively planned must be informed by those state policies, highlighting the need for a broadly inclusive process with state involvement to develop consensus plans the whole region can support.

In crafting reforms, the Commission should learn from previous proactive regional planning efforts. As the ANOPR correctly recognizes (PP 55-56), the MISO and California Independent System Operator Corporation ("CAISO") regions have had experience with initiatives to identify geographic zones with the potential for significant amounts of renewable resources, and transmission expansions to facilitate integration of resources from those zones.

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[55] *See*, *e.g.*, Part II.B.3, below, describing the different approaches to achieving renewable energy goals adopted by states within ISO New England Inc. ("ISO-NE").

MISO's Multi-Value Projects ("MVPs") were the product of at least three concurrent planning processes conducted by overlapping groups of TOs, TDUs, stakeholders, states, and transmission planners: CapX2020; the Upper Midwest Transmission Development Initiative ("UMTDI"); and MISO's Regional Generation Outlet Study ("RGOS"). The first of those efforts, CapX2020, began in 2004.[56] Eleven investor-owned, municipal, and cooperative utilities in Minnesota, North Dakota, South Dakota, and Wisconsin jointly planned transmission to support the changing generation mix, and had opportunities to jointly own those upgrades. After evaluating various scenarios, they selected upgrades common to many to create a "no regrets plan"; in 2006, CapX utilities began the process of obtaining state regulatory approvals for those lines.

Meanwhile, UMTDI was started in 2008 by the governors of Wisconsin, Iowa, Minnesota, South Dakota, and North Dakota.[57] It sought to "build upon and unite" existing regional planning efforts "into a plan that we all can support and implement."[58] UMTDI's 2010 final report identified wind zones and renewable energy transmission corridors to deliver power from those zones to state load centers.[59]

RGOS, which expanded on analyses performed as part of earlier MISO Transmission Expansion Plans, was also conducted during 2008-2010. The RGOS process was run by MISO, but broadly inclusive. It featured: monthly meetings of a

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[56] CapX2020, now called "Grid North Partners," is discussed in Part I.B.1 above and in TAPS 2021 White Paper. *See also* Grid North Partners, *Media*, https://gridnorthpartners.com/media/.

[57] Minnesota Public Utilities Commission, http://mn.gov/puc/about-us/news/index.jsp?id=14-11723.

[58] Upper Midwest Transmission Development Initiative Stakeholder Letter 1 (Oct. 28, 2008).

[59] Upper Midwest Transmission Development Initiative, *Executive Committee Final Report* (Sept. 29, 2010), https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=218112 (last visited Oct. 5, 2021).

Technical Review Group that included regulators, TOs, renewable energy developers, and market participants, as well as MISO transmission planners; bi-weekly Design Subteam meetings that included representatives of CapX2020; and consultation with UMTDI and regular reports to MISO working groups.[60] RGOS identified: (1) renewable energy requirements in the region; (2) renewable energy zones to meet those requirements; (3) the relative cost of alternative transmission solutions to deliver from those zones; and (4) candidate MVPs for near-term development.[61] It evaluated trade-offs between remote and local renewable areas, ultimately focusing on a group of near-term candidate MVPs that would improve access to a mix of such areas.[62]

These overlapping initiatives resulted in the CapX utilities successfully proposing, siting, and building nearly $2 billion in 800 miles of new transmission including four 345 kV lines and a 230 kV line—the largest new transmission development in the upper Midwest in forty years. Inclusive planning processes and joint ownership were key to developing consensus plans for these facilities and getting them built.[63] Several of the facilities built by the CapX utilities were designated as MVPs by MISO.

In California, the Renewable Energy Transmission Initiative ("RETI") was started in 2008. The California Public Utilities Commission, California Energy Commission, CAISO, and a broad range of stakeholders were brought together in an effort to reach consensus on where potential renewable resources are located and where transmission

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[60] *See* Midwest ISO, RGOS Regional Generation Outlet Study (Nov. 29, 2010), https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf ("RGOS").

[61] *Id.*

[62] *Id.* at 29-33, 91-96.

[63] *See* Part I.B.1 above.

should be built to deliver those resources to the market and customers. The initial RETI process resulted in identification of competitive renewable energy zones and high-level transmission concepts.[64]

In 2015, RETI 2.0 was initiated in response to new California clean energy goals—a 50 percent Renewables Portfolio Standard and a 40 percent statewide greenhouse gas emission reduction from 1990 levels by 2030. It identified Transmission Assessment Focus Areas and potential constraints in California and along major import-export paths that could limit delivery of additional renewable energy.[65] RETI 2.0 was not "[a] projection or goal for any level of additional transmission," nor "[a]n endorsement of any specific development proposal, plan, or project."[66]

These proactive planning experiences provide important lessons. First, any rule requiring proactive planning for anticipated future generation should foster and leverage the type of broadly inclusive, collaborative planning processes used in the MISO and CAISO regions, rather than mandate top-down plans. In both regions, proactive concept plans—and in the case of MISO, the MVPs—were *not* the result of RTO transmission planners applying technical criteria in isolation. They were the product of multiple collaborative processes that brought together and helped build consensus among TOs, TDUs, states, regulators, transmission planners, and other stakeholders and decision-makers. As noted above, joint ownership enhanced the planning process.

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[64] California Energy Commission, *RETI – Documents, Reports, and Other Materials*, https://web.archive.org/web/20160831074602/http://www.energy.ca.gov/reti/documents/index.html (last visited Oct. 5, 2021).

[65] California Natural Resources Agency, Renewable Energy Transmission Initiative 2.0 Plenary Report (2017), https://efiling.energy.ca.gov/getdocument.aspx?tn=216198.

[66] *Id.* at 1.

The MISO region experience with CapX2020 illustrates the value of subregional collaborative processes that can draw on the collective and deep system knowledge of a subregional TO group, to develop both a consensus vision plan and more specific plans for transmission projects based on that vision. Engaging in a collective planning process that included TDUs and other stakeholders produced a different and better product than simply having each TO submit its individual plan to MISO, for MISO planners to integrate and use to develop MISO's regional plan.

Participation by policymakers was also important.[67] In MISO, UMTDI brought together representatives of the governors and public service commissions of five states to help select wind zones for potential future transmission development. UMTDI's Executive Committee compared a "local option" calling for using resource areas closest to the load that needs renewable energy to fulfill state mandates, and a "remote option" focused on selecting resource areas with the greatest potential to generate the most energy. It determined that "[a] middle option was appropriate, with a combination of wind from both remote and local zones."[68]

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[67] *See* ANOPR P 64. *See also* Tr. at 129:1-130:14 (testimony of Robert Ethier, Vice Pres., Sys. Planning, ISO-NE), *Offshore Wind Integration in RTOs/ISOs*, Docket No. AD20-18-000 (Dec. 7, 2020), eLibrary No. 20201207-4002:

> [T]hese are the sort of decisions that are probably best made in the public policy arena and [less by] somebody like ISO who's not -- who doesn't control the purse strings, it's not our money. So if folks who are really speaking for those folks who are spending the money are the ones who should have a big role in the decision-making. I certainly think we have a large role in the technical aspects of it and helping think through options. But you know, we are unlikely to have the determinative role in pulling the trigger on these projects unlike where we really are today with the reliability projects where a lot more of the responsibility rests on us to make those determinations."

[68] Upper Midwest Transmission Development Initiative, *Executive Committee Final Report* 6 (Sept. 29, 2010), https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=218112. *See also* RGOS at 16-17 (describing survey to identify renewable requirements of individual states and portion of that requirement expected to be met by wind generation).

MISO and CAISO region experiences also highlight how collaborative working relationships developed by joint planning processes can facilitate future proactive planning. The initial RETI process was followed by RETI 2.0, five years later. And according to the CAISO, "RETI has . . . spurred a new level of commitment among energy agencies and utilities to work together to make improvements to planning and permitting processes in California."[69] Future proactive planning efforts in the northern Midwest should likewise be easier, given the subregion's earlier experience with CapX2020; in fact, the CapX utilities—now called Grid North Partners—are involved in efforts to proactively plan transmission for the subregion to meet 2050 goals.

Second, the MISO region experience illustrates the importance of having a process and adequate time to convert jointly developed transmission concept plans into specific project proposals. In the MISO region, transmission concepts were translated into specific projects by the CapX2020 process. If we want proactive planning to be more than just a costly and resource-intensive academic exercise, regions must have adequate mechanisms and time to develop and implement those plans. And if we want those plans to set regional priorities, opportunities for individual market participants to end-run the regional planning process must be limited.

Additional factors to be considered, should the Commission adopt reforms incorporating a requirement to identify and plan for renewable-rich areas, include:

- Identification of and transmission planning for renewable-rich areas may make more sense in large regions where there are significant differences in renewable potential

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[69] Memo from Laura Manz, Vice President of Market & Infrastructure Development, CAISO, to CAISO Board of Governors, regarding RETI Update (July 15, 2009), http://www.caiso.com/Documents/090720InformationalReport-RenewableEnergyTransmissionInitiativeUpdate.pdf.

across the footprint—e.g., regions with areas where the load factor of wind or solar generators is much higher, or where abundant geothermal resources are concentrated.

- Any such planning process should expressly encompass transmission solutions to deliver the output of existing, as well as anticipated generation. Consistent with FPA § 217(b)(4), both generation *and* load pockets should be remedied, so that LSEs are not burdened with congestion and receive the benefits of renewable generation for which they contracted.[70]

- Regions must consider the potential reliability impacts of placing the bulk of certain types of resources in only particular areas. Especially for types of generation that are dependent on weather conditions, there is a value in geographic diversity. Higher average load factors must be balanced against potential system impacts from both extreme weather events and normal weather systems that may simultaneously affect a large number of geographically concentrated renewable generators.

- The Commission should ensure that any such planning requirement does not inadvertently encourage gaming (e.g., rewarding generation developers for packing the queue or manipulating project timing to gain an advantage). Modifications to interconnection processes may be needed to avoid such outcomes.

2. Benefits to Be Considered in Project Selection

In response to the ANOPR's questions (PP 90-91) regarding portfolio approaches and the benefits that should be taken into account when planning for anticipated future generation, it makes sense to allow for considering multiple types of benefits in project selection in appropriate circumstances. Economic and reliability benefits, for example,

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[70] For example, TAPS member WPPI Energy has Power Purchase Agreements ("PPAs") for 80 MW (nameplate) from two wind resources in north-central Iowa. Despite having either 100% Network Resource Interconnection Service or Energy Resource Interconnection Service plus designated source-to-sinks NITS, these generation pocket-located resources face significant congestion. In 2020, about 19% of the annual production capability from the first resource, and 31% of the annual production capability from the second, was curtailed in response to down-dispatch instructions from MISO. TAPS understands that many other wind resources experience similar down-dispatches. In addition, there are a substantial number of hours each year during which wind resources are dispatched by MISO at low locational marginal prices within the generation pocket that do not cover off-takers' PPA costs.

Congestion and down-dispatching of existing wind resources located in generation pockets has consequences: it increases costs to consumers. MISO's Independent Market Monitor has documented increasing congestion due to increased wind generation. David Patton, Ph.D., *IMM Quarterly Report*: *Spring 2021, MISO Independent Market Monitor* 2-4, Potomac Economics (June 15, 2021), https://cdn.misoenergy.org/20210615%20Markets%20Committee%20of%20the%20BOD%20Item%2007%20IMM%20Quarterly%20Report559554.pdf; *see also id.* at 21-22 (additional congestion information).

can be viewed as two ends of a continuum. Today's economic project, if not implemented, could become tomorrow's reliability project. Reliability projects can have economic benefits and vice-versa.

Order 1000 Public Policy Projects are treated very differently for purposes of project selection (and have different implications for cost allocation); so it may be appropriate to consider such Public Policy Project benefits separately from economic and reliability benefits for project selection. Some RTOs have already provided for considering multiple types of benefits, including Public Policy Project benefits, from a single project for purposes of project selection. In the case of the MISO MVPs, however, MISO has not attempted to reduce the various types of benefits to a single, common metric; its MVP selection criteria consider whether certain proposed projects address at least two of the three different types of Order 1000 transmission needs.

While TAPS recognizes that projects may have additional difficult-to-quantify benefits (*see* ANOPR 95-96), introducing those into the project selection process could be counter-productive to Order 1000's directive, which TAPS supports, to select the more efficient and cost-effective projects. That directive is consistent with FPA § 217(b)(4)'s requirement that the Commission facilitate planning and expansion to meet the reasonable needs of LSEs to meet their load-serving obligations. If anything, it is even more important given the substantial transmission build-out anticipated.

Adding difficult- or impossible-to-quantify benefits could effectively homogenize projects, making it harder to evaluate and compare them for project selection. Particularly if regions are also required to plan for anticipated future generation, inclusion of difficult-

to-quantify benefits that parallel the policies driving the changing resource mix will simply cloud analyses evaluating specific projects.

This does not mean that the set of quantifiable benefits for project selection should be limited to those currently used. The Commission should allow regions to develop and propose by section 205[71] filing additional quantitative metrics that reflect increasing knowledge of the impacts of our transition to reliance on renewable resources, as those factors and the mechanisms to quantify them emerge with increasing experience. This would allow individual regions to propose metrics to quantify attributes that, based on their particular circumstances, appear significant. For example, for a region whose renewables are concentrated in particular areas, transfer capability to and from other regions could be an important and potentially quantifiable attribute to enable the region to reliably meet load under a range of conditions.

Similarly, TAPS is concerned about extending the time horizon for assessing project benefits. RTOs typically use a time horizon of 15-20 years. Benefit calculations made over a longer time horizon will be highly assumption-driven, and we are unlikely to get those assumptions right, even with stakeholder vetting. The resulting more speculative benefits analyses will undermine the effectiveness of planning processes in selecting the more efficient and cost-effective projects, eroding trust in those analyses and support for transmission plans and siting.

Finally, TAPS urges caution with regard to establishing a minimum list of benefits to be considered in project selection. *See* ANOPR P 94. Such a list could be

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[71] 16 U.S.C. § 824d.

problematic, especially if it fails to leave room for variation among RTOs. Regions differ significantly, for example, in the types of renewable resources available. They will need flexibility to respond and establish priorities as technology and public policies evolve, and as they develop quantitative metrics for benefits that are not currently quantified.

3. Benefits to Be Considered for Cost Allocation

a) Cost Allocation Challenges

Finding a cost allocation approach that meets FPA requirements and is consistent with achieving buy-in by those required to bear those costs—LSEs (including TDUs), states, and retail customers—will be very difficult. As regions move toward more proactive planning, those already knotty issues may become even harder.[72]

To be lawful under the FPA, costs allocated by the Commission must be "roughly proportionate" to benefits.[73] While "'exacting precision'" is not required, benefits must be at least "roughly commensurate" with allocated costs;[74] and if the Commission concludes that quantifying benefits is infeasible, "it must explain why that is so and what the alternatives are."[75] Courts have also rejected a cost allocation that would "shift a grossly disproportionate share" of the costs of new facilities to loads that will receive "only future, speculative, and limited benefits" from those facilities.[76]

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[72] As discussed above in Part I.B.1, inclusive joint ownership can ease some of these cost allocation challenges and both reduce cost to consumers and act as at least a partial hedge against increasing transmission costs.

[73] *Ill. Com. Comm'n v. FERC*, 721 F.3d 764, 770 (7th Cir. 2013).

[74] *Ill. Com. Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) (quoting *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1369 (D.C. Cir. 2004)); *Ill. Com. Comm'n v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014).

[75] 756 F.3d, at 564.

[76] *Id.* at 565.

Any rule addressing cost allocation will also need to address some fundamental tensions. First, even in regions where there is broad agreement that proactive planning for the anticipated future resource mix is necessary and appropriate, differences among the various states' renewable energy and climate change strategies can make cost allocation very challenging. In New England, for example, Massachusetts and Connecticut are very focused on new larger-scale generation resources such as additional imports from Canada and off-shore wind that will require major transmission investment. Massachusetts has already made significant commitments to off-shore wind that will require $2 billion of transmission upgrades. In contrast, Vermont hasn't pursued that new resource; and the state is actively debating the extent to which the 100% carbon-free or renewable electric portfolio standard now being designed must be met by in-state resources.[77]

As ISO-NE tries to plan and build a transmission system that accommodates varying state approaches,[78] cost allocation is becoming increasingly contentious, with the issue of who will pay for upgrades needed to deliver off-shore wind the elephant in the room that will have to be addressed by the states and stakeholders if that resource is to move forward. Other multi-state RTOs may face analogous challenges.[79] Any cost

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[77] *See* Vermont Climate Council, *Building the Climate Action Plan, Initial Suite of Actions, Cross-Sector Mitigation Subcommittee – Electricity*, Slide 6 (Oct. 5, 2021), https://outside.vermont.gov/agency/anr/climatecouncil/Shared%20Documents/Electricity%20Section%20Actions%20Presentation.pdf. The Vermont Climate Council, created by Vermont Act 153, is responsible for drafting the state's Climate Action Plan by December 2021. 2020 Vt. Acts & Resolves no. 153 (H. 688).

[78] According to NESCOE's Advancing the Vision Report, "The New England states and ISO-NE's transmission planning staff are actively working to identify inputs and assumptions for the 2050 Transmission Study, as well as discussing other potential applications of the long-term planning studies. ISO-NE has agreed that proactive system planning is necessary and useful to support the states' policy directions." NESCOE, *New England Energy Vision Statement, Report to the Governors, Advancing the Vision* 11 (2020), https://nescoe.com/resource-center/advancing_the_vision. *See also* ISO-NE, *Winter Energy-Security Initiatives Key Projects*, https://www.iso-ne.com/committees/key-projects/winter-energy-security-initiatives (last visited Oct. 6, 2021).

[79] Similar issues—albeit at a smaller scale—may occur with respect to small LSEs that have adopted a

allocation system will need to recognize such differences and cost causation principles, so that ratepayers are not unduly burdened with costs incurred to meet other states' mandates.

Any rule emerging from this ANOPR will also need to address the tension between renewable-rich areas that may have limited load, versus loads expecting to rely on remote renewable generation. This is especially a problem in RTOs with zonal rates where under existing zonal cost allocation methodologies, renewable-rich zones would bear a large share of the cost of the facilities needed to deliver to remote loads, without receiving revenue from those remote off-takers to offset those costs.[80] If states believe they are being assigned costs disproportionate to the benefits they receive, this issue has the potential to trigger RTO withdrawals that would fragment the broad RTO markets that are so important to integrating renewables and ensuring just and reasonable rates.

b) Overarching Principles for Cost Allocation

TAPS urges the Commission to keep in mind some basic principles as it considers alternative approaches for allocating costs of proactively planned projects. First, broadly spreading costs should not be the default. As a legal matter, proactive planning does not excuse the Commission from meeting its FPA obligation to determine benefits and assign associated costs accordingly. Broadly spreading costs also faces significant practical obstacles. Even in RTOs that previously constructed significant upgrades with broad cost allocation, there may not be consensus to use the same approach in the future. For

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different approach to meeting renewable goals from other larger utilities in the same region.

[80] If located outside of an RTO, such a TO would be able to charge remote off-takers a point-to-point transmission rate, and those revenues could be used to offset the transmission revenue requirement charged to load within the TO's footprint.

example, there have been no new MISO MVPs since the initial 2011 portfolio; and issues associated with that RTO's expanded footprint (i.e., the addition of MISO South) may make it even more difficult to reach consensus on broad cost allocation. In SPP, notwithstanding approval of the region's initial Balanced Portfolio, there have been significant concerns about trying to assemble another package of projects that would benefit all or most zones. In its recent draft recommendations, the Strategic and Creative Re-engineering of Integrated Planning Team ("SCRIPT") of the SPP Board stated that SPP should "[d]evelop a simplified methodology for the Balanced Portfolio cost allocation for future upgrades, or eliminate it if the methodology is not simplified."[81]

Second, because any rule addressing cost allocation must be grounded on basic cost causation principles, every effort must be made to identify particular beneficiaries of proactively planned facilities.[82] For example:

- As an initial step, to the extent project beneficiaries can be identified, those beneficiaries should bear costs for the benefits they receive. Assessment and quantification of benefits, and the associated identification of beneficiaries, should be based on the benefits included in the project selection process—current factors, augmented by the addition of other quantifiable benefits as may be identified and proposed by the various regions and accepted by the Commission.

- Next, if proactively planned facilities costs remain to be allocated after this initial step, some consideration of load zones expected to rely on the generation that the proactively planned transmission is designed to support could be appropriate.[83] Such an allocation would be consistent with the Commission's FPA section 217(b)(4)

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[81] SPP SCRIPT, *Report and Recommendations* CS4 (Sept. 24, 2021), https://spp.org/Documents/65423/20210924%20SCRIPT%20Report%20of%20Recommendations%20as%20Revised%20and%20Approved%20During%20the%20Meeting.docx.

[82] To fairly allocate interconnection-related network upgrade costs, it may be appropriate to take a close look at the specific network upgrade's characteristics to better identify the scope of its benefits—e.g., benefits of facilities under 345 kV may be more localized than those of Extra High Voltage facilities.

[83] In crafting this element of any cost allocation requirement, the Commission and each region may want to consider interactions, and the need to coordinate, with the region's existing cost allocation methodology for Order 1000 Public Policy Projects, to the extent there continues to be a distinct treatment of those projects.

obligation to facilitate planning tailored to meeting the reasonable needs of LSEs. Consideration of sharing the costs of proactively planned transmission with new generators—another mechanism to allocate costs to the specific loads served by those generators—may be warranted. Such an approach could be appropriate if it could be structured in a way that does not create a disincentive for generators to locate in areas to be served by proactively planned lines. Any such cost assignment to generators should be designed to work in tandem with TAPS' proposed sharing of costs for interconnection-related network upgrades, discussed below in Part II.C.

- As a final step, broad cost allocation may have a role in limited circumstances. Because of the tensions associated with it, that approach should be used sparingly.

Third, cost allocation for proactively planned and interconnection-related network upgrades should be considered together. For example, if the Commission requires RTOs to move away from 100% direct assignment of interconnection-related network upgrades, it may be appropriate to allocate all or a portion of the share of interconnection-related network upgrade costs borne by load in the same way as proactively planned regional projects. For the reasons discussed above and in Part II.C, below, assigning such costs only to the zone where the facilities are located could heighten the tension between renewable-rich zones that may have limited load, versus zones with large loads that are expected to rely on remote generators to meet their renewable energy requirements.

### *C. Participant Funding and Crediting*

#### 1. Changes to RTO Flexibility to Require Participant Funding of Network Upgrades Associated with Generator Interconnections

While Order 2003 generally requires interconnection customers to fund network upgrades up front, with repayment through crediting, the Commission allowed RTOs to directly assign such costs to the IC as an "independent entity variation," finding that just and reasonable.[84] The ANOPR seeks comment on whether to eliminate or reduce

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[84] ANOPR PP 29, 110. Direct assignment is not available outside of the RTO context because of the

participant funding of interconnection-related network upgrades in RTOs, and whether proposed changes allocate costs in a manner roughly commensurate with benefits, and do not unreasonably shift costs to customers of LSEs.[85]

TAPS appreciates that some relief from 100% direct assignment may be consistent with fundamental cost allocation principles in order to recognize benefits received by load beyond those received by the IC and the LSE that owns or has contracted for the output of the newly interconnected generation. Thus, TAPS supports partially restricting the flexibility of RTOs to directly assign up to 100% of those costs in conjunction with reforms to improve regional transmission planning processes, while maintaining appropriate price signals to generators to site wisely.[86]

However, TAPS does *not* support complete elimination of the direct assignment of network upgrades associated with generator interconnection. Retention of a meaningful degree of direct assignment correctly recognizes the significant benefits those upgrades afford those generators and the LSEs that have contracted to purchase their output. These beneficiaries both cause the upgrades to be undertaken and reap rewards far more tangible than those enjoyed by other users of the transmission system, making it appropriate for them to continue to bear a significant share of those costs.

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significant risk that the transmission provider ("TP") will favor its own generation and load. *Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 104 FERC ¶ 61,103, PP 695-96 (2003) ("Order 2003"), *on reh'g* Order No. 2003-A, 106 FERC ¶ 61,220, P 691 (2004), *on reh'g,* Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

[85] ANOPR P 19.

[86] TAPS supports continued 100% direct assignment to ICs of the cost of Interconnection Facilities (i.e., facilities that would not be needed but for the request, and which are not network upgrades), consistent with the *pro forma* large generator interconnection agreement ("LGIA") and current practice. The ANOPR (P 124) expressly excludes changes to that treatment from the scope of potential reforms.

Failure to allow at least partial direct assignment to ICs would be particularly problematic in RTOs with zonal pricing.[87] Elimination of participant funding could leave loads in renewable-rich pricing zones bearing costs disproportionate to their benefits. At the same time, broadly shifting substantial cost responsibility to remote loads other than the off-taking LSE may impose disproportionate cost responsibility on those loads.[88]

Another key reason not to completely or substantially relieve ICs of cost responsibility for network upgrades they cause is the need for generators to have skin in the game, so that they make reasonable development and siting decisions. Order 2003 found that allowing RTOs to directly assign interconnection-related network upgrade costs provides ICs an incentive to make efficient siting decisions, taking account of transmission costs and consistent with promoting competitive markets. That finding remains true today.[89] Because directly assigned network upgrade costs factor in pricing the unit's output, generators must consider those costs as they seek buyers for PPAs, providing competitive discipline to location decisions. While some areas are more conducive to certain renewable generators than others, there are tradeoffs to be made among possible locations, including some that may have a lower capacity factor but are closer to load. Eliminating price signals could invite a free-for-all, unreasonably increasing overall costs of interconnection-related network upgrades and shifting those costs away from those in the position to make decisions that contain those costs. Such

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[87] *See id.* P 128.

[88] *See* Part II.B.3 above.

[89] ANOPR P 116 (seeking input on Order 2003, PP 695, 702).

elimination would also apply to non-renewable generators (*e.g.*, gas-fired) not subject to the same locational constraints.

The importance of allowing RTOs to continue requiring ICs to bear a meaningful share of cost responsibility is heightened as we move toward more proactive planning. Planned transmission lines to renewable-rich zones may well spur increased land costs in the areas to be served by those lines, inducing generators to seek sites in cheaper locations. It would be unjust and unreasonable for load to bear primary responsibility for the cost of both proactively planned transmission additions that end up being underutilized *and* network upgrades for generators that choose to connect far away from the proactively planned lines.

To prevent such unintended consequences, it is essential that ICs be subject to higher costs if they choose to site far from proactively planned regional upgrades and instead choose a location that would require substantial interconnection-related network upgrades. To promote siting that takes advantage of proactively planned lines, it would be wise (as TAPS discusses more fully in Part II.C.2. below) to partially reduce the level of participant funding before a proactive planning process associated with this rulemaking could affect generation location decisions, and permit a higher level of participant funding once those major upgrades to integrate new renewables can be considered by generators in siting generation.

Another consideration is how elimination of most or all direct assignment will impact the scope of interconnection-related network upgrades and the process by which they are planned. The ANOPR raises questions as to whether participant funding creates an incentive on the part of ICs to keep associated network upgrades to the minimum

necessary.[90] As discussed in Part II.B, TAPS shares the goal of planning and constructing right-sized upgrades that can deliver needed transmission capacity efficiently and cost-effectively, avoiding both overbuilding and the minimalist approach currently used for project-specific interconnection-related network upgrades. But if IC incentives to minimize network upgrades costs are substantially removed and the interconnection process is used to trigger major (rather than minimalist) upgrades, load would bear significant costs for large facilities that are selected and built without an open, transparent, and collaborative planning process. Only the RTO, the affected TO(s), and the IC now participate in the interconnection process; other stakeholders have no voice in that process, which is intended to be streamlined to support prompt interconnection. If project-specific interconnection processes are to be a driver of substantial expansions needed to address our changing resource mix, then the interconnection process must be expanded to satisfy the requirements of Orders 890 and 1000, and to provide stakeholders a meaningful role in planning those facilities. The imperative for prompt interconnection that the ANOPR evinces[91] will be difficult to satisfy while meeting these essential requirements.

Given these considerations, TAPS urges *against* adoption of ANOPR reforms that would eliminate participant funding.[92] Such approaches would send no price signal to the IC, and fail to recognize the benefits to the IC as well as its contractual off-taker.

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[90] *Id.* P 115.

[91] *Id.* PP 41, 153-58.

[92] The ANOPR poses the question of eliminating or reducing participant funding in the context of retaining the *pro forma* LGIA's upfront funding and crediting policies. *Id.* P 124. The concerns raised in this section become even more acute if the Commission were also to eliminate or reduce those requirements.

Similarly, TAPS is skeptical of ANOPR proposals that would substantially reduce participant funding. Of particular concern are proposals that do so in a way that fails to send ICs a price signal for efficient siting of their proposed generation.

For example, the ANOPR (PP 135-136) suggests requiring ICs to contribute to the upfront funding of interconnection-related network upgrades by applying the same non-refundable fixed fee to each interconnection request, irrespective of the resource's capacity or location. If high enough, such a fee might decrease duplicative applications or projects that are not viable in the queue; but it would create no incentive to site wisely. The ANOPR's suggestion of a variable fee tied to the resource's capacity[93] may be a step in the right direction, but does not necessarily send the right price signal either.

On the other hand, the potential proposal of a variable fee tied to the cost of the interconnection-related network upgrades,[94] perhaps combined with consideration of the location of those upgrades with respect to the renewable-rich zones identified by the regional planning process, could create an incentive to site wisely, but only if fees are large enough. If imposed early in the interconnection process, such fee would likely be insufficient to incent IC siting decisions that minimize network upgrade costs. A fee that escalates through the process[95] would be a better approach, supplementing queue management reforms already instituted to deter excessive and duplicative interconnection requests. TAPS' concept for partial participant funding relief (discussed below), with continued direct assignment at a level sufficient to reflect the IC's benefits and to

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[93] ANOPR P 137.

[94] *Id.*

[95] *See id.* P 138.

influence siting, could be viewed as a variation on the ANOPR's non-refundable variable fee concept.

2. Possible Approaches to Partially Reducing RTO-Required Direct Assignment of Interconnection-Related Network Upgrade Costs

TAPS offers, for consideration, the following possible concept for partial relief from participant funding. In the limited time available, TAPS has not tried to flesh out all aspects of the concept and is open to adjustments. TAPS suggests one approach during what we have termed an "interim period" (i.e., the period between the effective date of a final rule in this rulemaking process and before the first plans for proactively planned additions have been identified through a reformed planning process), and a modified longer-term approach to be used once the first proactively planned additions are identified and thereafter. For discussion, we have used as the point of transition between the interim and the longer-term approach, the date one year after a region's first regional plan identifying proactively planned upgrades is adopted. This cut-off is intended to separate the projects that could be siting with knowledge of the long-term plan.[96]

a) *Interim Period*: If an IC requests service *prior* to a date one year after the adoption of the region's first regional plan that includes proactive planning for future generation, the following rules would apply:

1. Continue the independent entity exception to the *pro forma* LGIA, but restrict IC direct assignment to no more than, e.g., 50% of network upgrade cost.

2. Remaining network upgrade cost would be paid by load through a crediting mechanism (as provided in the *pro forma* LGIA), and allocated in a manner consistent with Part II.B.3 above.

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[96] In determining the cut off, it may be appropriate to consider potential adverse impacts on the proactively planned lines if that process were overtaken by ICs requiring network upgrades in that same area, e.g., by complicating the siting process for the proactively planned line.

b) *Long-Term*: If an IC requests interconnection *after* a date one year after the adoption of the region's first regional plan that includes proactive planning for the future generation mix, thereby enabling the IC to consider that plan in proposing to site its generation, the following rules would apply:

1. Continue the independent entity exception to the *pro forma* LGIA, but restrict direct assignment to IC to no more than, e.g., 75% of network upgrade cost.

2. Remaining network upgrade cost would be paid by load through a crediting mechanism (as provided in the *pro forma* LGIA) and allocated in a manner consistent with Part II.B.3 above.

By allowing RTOs to continue to directly assign a share of interconnection-related network upgrade costs to the IC, TAPS' concept would assure that ICs have sufficient skin in the game to promote efficient generation siting, reflect the considerable tangible benefits received by the IC and its off-taker, and otherwise address the considerations identified above. A higher direct assignment percentage *after* adoption of proactive regional plans is appropriate because:

- Proactively developed transmission facilities should dramatically reduce network upgrade costs for ICs that site in the areas targeted by the proactive regional plans;
- A higher potential direct assignment percentage is needed to dis-incent generator development in areas with neither existing nor planned transmission capacity.

TAPS' concerns could be addressed, and its objectives achieved, through other mechanisms. For example, the ANOPR asks questions about the appropriateness of making interconnection-related network upgrade costs that are directly assigned to the initial IC subject to reallocation to subsequent generators that use those upgrades.[97] Such cost-sharing is logical and facially reasonable. Experience with other transmission cost reallocation schemes (such as SPP's Attachment Z2) cautions that the process could be

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[97] ANOPR P 150.

resource-intensive and highly contentious.[98] But it could be a useful mechanism if the cost reallocation process can be implemented in a clear and simple way in this context.

3. Changes to Crediting Policies in all Regions

The ANOPR poses questions regarding potential changes to upfront funding and crediting policies. Under the *pro forma* LGIA, which is applicable in non-RTO regions, the IC initially funds 100% of interconnection-related network upgrade costs. The TP repays that amount over time with interest, through credits against charges for transmission service from the generator, and a balloon payment of any remaining uncredited amounts 20 years after the generator's commercial operation date.[99] A project that does not achieve commercial operation receives no reimbursement except to the extent a later-constructed generating facility uses network upgrades the first IC funded.[100]

Eliminating or significantly reducing ICs' upfront funding obligation would transfer to load all or most risk for network upgrades associated with generators that never reach commercial operation. Generators and LSEs with whom they enter into long-term PPAs—not load, in general—are the only entities that can make choices that manage that commercial risk. It is inappropriate to remove the safeguard that IC upfront funding provides to protect consumers from bearing stranded network upgrade costs.

Nor is the *pro forma*'s upfront funding an unreasonable barrier to new generation.[101] That requirement has been in place for almost two decades; and where a

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[98] See *Okla. Gas & Elec. Co. v. FERC*, 2021 U.S. App. LEXIS 25892, at *5 (D.C. Cir. 2021), ("implementation of the upgrade crediting process proved to be complex").

[99] LGIA section 11.4.1.

[100] *Id.*

[101] ANOPR P 120.

proposed generator is supported by a long-term PPA, the necessary capital should be readily available. Support by renewable generation groups for proposed *pro forma* LGIA reforms that would have limited the right of TOs to initially fund network upgrades, in lieu of IC upfront funding, belie any concern that the upfront funding requirement is a substantial drag on new development.[102]

And while life cycle costs to consumers are not likely to be significantly different, eliminating or substantially reducing upfront funding will place a more immediate cost burden on load. Instead of those costs being gradually added to the TP's ratebase as it provides credits to the IC (or its assignee) against transmission charges from the generator over the crediting period, the full interconnection-related network upgrades cost would be added to ratebase and earn a ROE once the facilities go into commercial operation. These costs would aggravate the rate impact of the major build-out anticipated to be required to support the industry's resource transformation.

Finally, it is far from clear that doing away with crediting would eliminate "phantom" interconnection requests. And doing so would aggravate concerns discussed in Parts II.C.1 and II.C.2 above with regard to eliminating participant funding.

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[102] *Reform of Generator Interconnection Procs. & Agreements*, Order No. 845, 163 FERC ¶ 61,043, P 121 (2018) ("Order 845"), *on reh'g & clarification*, Order No. 845-A, 166 FERC ¶ 61,137 (2019). In this proceeding, the Commission proposed modifying the *pro forma* LGIA/LGIP to eliminate the TO's unilateral right to initially fund interconnection-related network upgrades, instead of requiring IC upfront funding. Order 845, P 118. Although the Commission ultimately decided to withdraw that proposal, it noted that American Wind Energy Association and Joint Renewable Parties (i.e., Community Renewable Energy Association and Renewable Energy Coalition) both argued in favor of making that change. *Id.* PP 120 n.197, 122.

### *D. Enhanced Transmission Oversight and Cost Containment*

#### 1. Potential Oversight and Cost Containment Mechanisms

TAPS agrees with the ANOPR (P 159) that, particularly given the anticipated significant transmission investment, enhanced oversight of transmission planning and spending is needed to protect consumers from excessive costs. A consumer-protection focus as the Commission considers defining benefits and planning scenarios, cost allocation methodologies, and changes to the generator interconnection process will be crucial to ensuring just and reasonable transmission rates. Any rule should also include measures, such as the Independent Transmission Monitors ("ITM") described in the ANOPR (PP 164, 170), to ensure those processes are designed and implemented appropriately and prevent imposition of unnecessary costs on consumers.

As discussed above in Part I.B.2, an ITM should be required in non-RTO areas where planning is not performed by an independent entity.[103] With respect to RTO areas, it is important to avoid unnecessary duplication; but an ITM could be useful, particularly with respect to local plans developed by non-independent TOs, which RTOs typically evaluate only for reliability impacts.[104] In RTOs with formula transmission rates, an ITM could also provide valuable review and oversight of TO implementation of those rates to the extent the RTO does not do so.[105]

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[103] *See* ANOPR PP 170-171 (including "Supplemental Projects," i.e., asset management projects and activities that do not expand the grid).

[104] *See* Part I.B.4 above.

[105] Some RTOs (e.g., MISO) provide some oversight over formula rate inputs today, but others (e.g., SPP) provide none, leaving all the work and expense to customers.

TAPS urges consideration of additional oversight and cost containment mechanisms. SPP's Regional State Committee ("RSC"), for example, could be a productive cost containment mechanism in other regions. In comparison to other RTOs' state committees, SPP's RSC has concrete powers within the scope of its authority (resource adequacy and cost allocation) and a more robust role in RTO decision-making.[106] It has not historically monitored individual transmission planning and spending decisions along the lines contemplated for an ITM. But TAPS members report that the SPP RSC can be very effective in keeping RTO attention on consumer cost impacts; and it has not been shy about voicing consumer protection concerns in the transmission planning context.

Mechanisms to enhance stakeholder participation in transmission planning could provide added oversight. One of the most effective ways to contain costs and enable customers to monitor transmission planning and spending would be for the Commission to require TPs to implement collaborative, interactive joint planning processes. TPs should be required to invite input from affected transmission customers at all stages of the planning process (local, regional, and interregional), allow them to participate in decision-making, and assure that their views are considered on a non-discriminatory

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[106] As the ANOPR describes (P 176), "'the RSC will determine whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of [TOs] in proposing transmission upgrades in the regional transmission process'" (quoting SPP, Governing Documents Tariff, *Bylaws*, section 7.2 (Regional State Committee) (1.0.0)). In addition, if the SPP RSC reaches decisions on the methodology that will be used to address this and other issues (e.g., use of participant funding for transmission enhancements, whether the regional access charge will be a license plate or postage stamp rates, financial transmission rights allocation, where a locational price methodology is used, and resource adequacy), SPP will file the RSC's methodology pursuant to FPA section 205. SPP, *Bylaws*, First Revised Volume No. 4 (Mar. 1, 2021), https://www.spp.org/documents/13272/current bylaws and membership agreement tariff.pdf.

basis. Giving transmission customers a concrete decision-making role will provide them with both information they need to monitor and oversee transmission planning and spending, and invaluable insight into the justifications underlying expansion decisions. Order 890 took important steps in the right direction, but stopped short of requiring transmission providers to collaboratively develop transmission plans with customers on a co-equal basis.[107] Order 890's restrictions on the role of TDUs in local planning was a decisive factor in the rejection of a recent proposal to enhance that process, highlighting the need for further reforms.[108] This rulemaking provides an important opportunity to enhance these processes.

Finally, the Commission should consider whether and to what extent competition could be productively used to discipline transmission spending. Competitive transmission development was a major feature of Order 1000. Although the ANOPR does not identify it as a cost containment measure, competitive processes have significantly reduced costs in the relatively few instances in which they have been used.[109] While state ROFRs limit where such competition can be effective, the Commission should not abandon this

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[107] Order 890, P 454; Order 890-A, PP 188-189.

[108] *GridLiance* PP 46-47; *id.* Clements, Comm'r, concurring (discussed in Part I.B.1 above with regard to the need to foster inclusive joint ownership through the planning process, and noted in Part I.B.4 above with regard to the need to improve local planning processes).

[109] Johannes P. Pfeinfenberger, et al., *Transmission Competition Under FERC Order No. 1000: What We Know About Cost Savings to Date* 1, 13, 15, THE BRATTLE GROUP, (Oct. 25, 2018), https://brattlefiles.blob.core.windows.net/files/14786_brattle_competitive_transmission_wires_10-25-18.pdf. For example, the winner (NextEra Energy Transmission Midwest, LLC) of the stiff competition for MISO's Hartburg-Sabine Junction 500 kV project came in *below* MISO's scoping bid and the median bid, with an ROE fixed at 9.8% with 45% equity, foregoing construction work in progress and Allowance For Funds Used During Construction, and limiting ATRR and Operation and Maintenance costs over the first ten years. MISO, *Selection Report: Hartburg-Sabine Junction 500 kV Competitive Transmission Project* 5-6, 21 (Nov. 27, 2018), https://cdn.misoenergy.org/Hartburg-Sabine%20Junction%20500%20kV%20Selection%20Report296754.pdf.

important tool to minimize costs to consumers. Rather, it should foster this process in a manner that advances the role of inclusive joint ownership.[110]

### 2. Cost-Increasing Incentives Defeat Cost Containment and Threaten the ANOPR's Objectives

The eagerness of developers to compete for the right to build, and their willingness to sharpen their pencils to find cost savings, highlight that the Commission should *not* offer cost-increasing incentives (e.g., ROE adders) for proactively planned transmission.[111] As demonstrated in TAPS 2020 Incentive NOPR Comments at 15-22, such incentives are *not* needed to entice TOs and developers to build more efficient and cost-effective transmission solutions. Few investments assure cost recovery through formula rates with a Commission-regulated ROE. Investors have touted these investments' "recession-resistant earnings."[112] No wonder TOs highlight increasing transmission investments when communicating with investors,[113] and fight for the right to build transmission.[114] Given the keen interest in transmission investment, the Commission would be hard pressed to demonstrate that incentives are required to induce

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[110] *See* Part I.B.1 above.

[111] *See* ANOPR P 61 ("whether and, if so, how to expand or improve any incentives to incent the development of regional transmission facilities that demonstrably may offer a more efficient or cost-effective solution to an identified need than local alternatives").

[112] Warren E. Buffet, *Berkshire's Performance vs. the S&P 500*, at 12, Berkshire Hathaway Inc., (Feb. 25, 2017), http://www.berkshirehathaway.com/letters/2016ltr.pdf (essentiality of electricity service and steady demand as ensuring Berkshire Hathaway Energy's ability to service debt under all circumstances).

[113] *See* Comments of TAPS 18-19, *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, Docket No. PL19-3-000 (June 26, 2019), eLibrary No. 20190626-5264 ("TAPS Initial Incentives NOI Comments") (discussing Eversource Energy, First Energy Corp., American Electric Power Company, Inc. and Public Service Enterprise Group, Inc. investor communications).

[114] *See, supra*, n.22; TAPS 2020 Incentive NOPR Comments at 19-20, 81-82. *See also id*. at 20, 32 n.76, documenting TOs' vigorous (but unsuccessful) efforts to retain federal ROFRs.

construction of more efficient and cost-effective proactively planned projects, and are the minimum necessary to do so.[115]

By adding significantly to the already substantial costs of the anticipated build out, cost-increasing incentives will not only defeat the Commission's cost containment efforts but would impede achieving the Commission's goals. Such incentives will exacerbate cost allocation issues, create additional resistance that makes siting harder, and make it more difficult to achieve consensus around major upgrades.[116] They will do far more harm than good.

### *E. Enhanced Interregional Coordination*

TAPS has long recognized that Order 1000's interregional coordination may be insufficient.[117] As the Commission considers whether moving toward interregional planning is appropriate, it needs to take care to maintain flexibility to avoid burdening consumers with stranded transmission costs for needs that have changed. While we recognize the challenges posed when regional or interregional projects are reconsidered due to changes in loads, resources, technology, or other factors, failure to allow regions to reconsider interregional projects where there are changed circumstances could result in consumers bearing significant costs for unnecessary projects.

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[115] *City of Detroit v. Fed. Power Comm'n*, 230 F.2d 810, 817 (D.C. Cir. 1955), "[i]f the Commission contemplates increasing rates for the purpose of encouraging exploration and development . . . it must see to it that the increase is in fact needed, and is no more than is needed, for the purpose." *See also Farmers Union Cent. Exch. Inc. v. FERC*, 734 F.2d 1486, 1503 (D.C. Cir. 1984).

[116] TAPS also opposes shared savings incentives for GETs. *See* Part I.B.2 above.

[117] *See*, *e.g.*, TAPS Initial Incentives NOI Comments at 81-83 (arguing against incentives for interregional projects and explaining that the Commission should revisit the interregional processes instead).

## CONCLUSION

The Commission should consider TAPS' comments as it moves forward in this important rulemaking process.

Respectfully submitted,

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