UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Management	)	Docket Nos. AD22-8-000
	)	
Joint Federal-State Task Force on Electric Transmission	)	AD21-15-000

Post-Technical Conference Comments of WIRES

Pursuant to the Notice Inviting Post-Technical Conference Comments issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") on December 23, 2022,[1] WIRES submits the following comments along with supporting material on the October 6, 2022 technical conference convened by the Commission to discuss transmission planning and cost management for transmission facilities developed through local or regional transmission planning processes ("October 6 technical conference").[2]

I. Introduction

WIRES is a non-profit trade association of investor-, publicly-, and cooperatively-owned transmission providers and developers, transmission customers, regional grid managers, and equipment and service companies. Our members include many of the largest transmission owners in the country. WIRES promotes investment in electric

[1] *Notice Inviting Post-Technical Conference Comments*, Docket Nos. AD22-8 & AD21-15 (Dec. 23, 2022) ("Notice").

[2] This filing is supported by the full supporting members of WIRES but does not necessarily reflect the views of the RTO/ISO associate members of WIRES.

transmission and consumer and environmental benefits through development of electric transmission infrastructure.[3] Since its inception, WIRES has focused on supporting investment in needed and beneficial transmission infrastructure – investments that Congress and the Commission have recognized are critical to establish a resilient, reliable, cost-effective~~,~~ modern, and clean bulk power system. As a result, WIRES is uniquely positioned to address many of the issues the Commissions seeks comment on stemming from the October 6 technical conference.

Electric transmission investment in the United States remains critical to realizing the benefits of efficient and reliable electric service while enabling the ongoing transition to new generating sources to power an increasingly electrified economy. As the Commission has recognized, there are numerous drivers underlying the need for new transmission infrastructure including the need to help ensure the ability of the transmission system to reliably serve firm transmission, the evolution in the nation's generating resource mix, an increase in the number of new resources seeking transmission service, shifts in load patterns, the impact of increasing extreme weather events on the bulk power system, the increasing electrification of the economy, and growing cyber and physical security threats. Numerous studies show the tremendous benefits transmission investment provides and that the need for new transmission has

[3] For more information about WIRES, please visit www.wiresgroup.com.

never been greater.[4] For these reasons, it is critical that the Commission adopt and implement policies designed to promote and facilitate transmission investment that is needed for the future energy needs of customers, and of the nation.

While the Commission's past efforts to encourage investment in and development of needed and beneficial transmission are to be commended, the fact remains that substantial additional transmission infrastructure is greatly needed to meet the future needs of customers, bolster the resilience of the grid, and interconnect the large quantities of location-constrained renewable resources needed to meet ambitious renewable energy mandates and goals. Several WIRES-sponsored studies on the continuing need for transmission investment, and the corresponding benefits from such investment, support this claim.[5]

For instance, in a 2019 report prepared for WIRES, the Brattle Group estimated that $30 billion to $90 billion of incremental transmission investments will be necessary in the United States by 2030 to meet the changing needs of the system due to electrification, with an additional substantial investment needed from 2030 to 2050.

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[4] *See e.g.*, The Brattle Group, *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, at 33 (May 2011) ("Brattle Report"); London Economics International, Inc. ("LEI"), *How Does Electric Transmission Benefit You?* (Jan. 2018) (LEI Report).

[5] *See*, *e.g.*, London Economics International, Inc. LLC, *How Does Electric Transmission Benefit You?: Identifying and Measuring Life-Cycle Benefits of Infrastructure Investment* (Jan. 2018); London Economics International, Inc. LLC, *Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process* (Oct. 2014); The Brattle Group, *Recognizing the Role of Transmission In Electric System Resilience* (May 2018); The Brattle Group, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments* (July 2013).

These investments are in addition to the investments needed to maintain the existing transmission system, replace aging assets, and integrate renewable generation built to meet existing load. Brattle explained that this level of investment is equivalent to $3 billion to $7 billion per year on average through 2030, a 20-50% increase over annual average spending on transmission during the past ten years, and $7 billion to $25 billion per year on average between 2030 and 2050, a 50-170% annual increase in transmission investment.[6] Even if a future scenario does not ultimately require this amount of investment, the expected changes in how energy is produced will require strong support for new transmission investments.

These findings were further reinforced in a report released by ScottMadden, Inc. in January 2020 demonstrating the pressing need for more transmission investment in all regions of the country to meet the challenges posed by changing energy resources, increasing electrification, and a greater need and preference for location-constrained renewable generation, in addition to addressing ever-growing concerns about the risks to the resilience of the North American electric power system.[7] Despite the well-documented evidence that more transmission is needed across the country to provide the benefits of both greater resilience and integration of renewable resources, the

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[6] The Brattle Group, *The Coming Electrification of the North American Economy, Why We Need A Robust Transmission Grid* (March 2019) ("2019 Brattle Report").

[7] ScottMadden, Inc., *Informing the Transmission Discussion: A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States* (Jan. 2020) (ScottMadden Report).

ScottMadden Report found that the evolution of policy has failed to support this growing need and that financial incentives to developers of transmission which drove significant investments through the 2000s are being reduced.[8] Moreover, time is of the essence, as state-mandated renewables goals with targets as early as 2030 are fast-approaching.

Despite the growing need for increased transmission to meet the challenges highlighted in the 2019 Brattle Report and the ScottMadden Report, builders of transmission continue to face significant uncertainty in the current regulatory and economic climate. Investment in transmission is a long-term proposition, and investors require certainty that they will recover their investment and earn a reasonable return. The current unstable economic climate with above-average inflation, uncertain regulatory environment, long-lead times for construction of transmission infrastructure, and long depreciable life of transmission assets necessitate Commission policies that reflect stable ratemaking processes and clearly and unambiguously incentivize investment in transmission.

Against a background of demonstrated need for significant growth in transmission investment, the Commission initiated various proceedings to reexamine regional transmission planning, cost allocation, and interconnection processes to fully account for the future energy needs of customers, and of the nation.[9] Following these efforts, the

[8] *Id*. at 19 and 295.

[9] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 (2021) ("ANOPR"); *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022) ("NOPR"); *Improvements to Generator*

Commission held a technical conference on October 6, 2022, to discuss transmission planning and cost management for transmission facilities developed through local and regional transmission and planning processes. While WIRES has supported and participated in the Commission's initiatives to review and improve its processes to better meet the nation's future transmission infrastructure needs, WIRES has urged the Commission to avoid trying to fix what is not broken or, notwithstanding the best of intentions, establishing policy that is inadvertently counterproductive or leads to unintended consequences.

I. General Comments

The Commission convened the October 6 technical conference to examine the transparency and effectiveness of local and regional transmission planning decisions and to address "potential approaches to providing enhanced cost management measures and greater transparency and oversight ***if needed*** to ensure just and reasonable transmission rates."[10] By emphasizing the question of whether there is a need for greater transparency and oversight, the Commission implicitly acknowledged that it can only impose a new requirement for transmission owners or transmission providers to establish new or "enhanced" cost management or transparency requirements if it meets the dual burden of section 206 of the FPA; in other words, the Commission must show both (1) that existing

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Interconnection Procedures and Agreements, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 (2022) ("Interconnection NOPR").

[10] *Supplemental Notice of Technical Conference*, Docket No. AD22-8 (Sept. 8, 2022) ("Supplemental Notice") at 1 (emphasis added).

tariffs or rules are unjust, unreasonable, unduly discriminatory or preferential and (2) that any new requirements it directs to be put in place are just and reasonable.[11] To date, no such record has been established that would meet either prong of this two-part test.

While the October 6 technical conference failed to identify any specific flaws or gaps in any of the existing, Commission-approved transmission planning oversight or transparency processes that have been in place for years, or in the implementation of those processes, the concern of the overall effort appears to be rooted in the general notion that if more transmission facilities get built, consumers will have to pay for the costs of those new facilities.[12] However, simply because more transmission infrastructure may be built to meet the needs of a changing resource mix,[13] and customers will pay the costs of these new transmission facilities (as the case has always been), it does not by any means follow that that additional transmission is more likely to result in unjust and unreasonable rates. Nor does it necessarily follow that increasing spending in order to build more transmission will make current, adequate oversight processes unjust and unreasonable. To the contrary, by the Commission's own reckoning, any transmission that results from the potential reforms to regional transmission planning, cost allocation, and generator interconnection should be <u>more</u> efficient and cost-effective

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[11] *See South Carolina Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 64-65 (D.C. Cir. 2014).

[12] ANOPR at P 160 ("[I]n light of potential costs of new transmission infrastructure that may be needed to meet the needs of the changing resource mix, we seek comment on whether additional measures may be necessary to ensure that the planning processes for the development of new transmission facilities, and the costs of those facilities, do not impose excessive costs on "consumers.")

[13] ANOPR at P 159.

than before and provide greater protection to customers, thereby making the need for any new transparency or oversight requirements even less necessary and more superfluous.[14] The facts bear out the Commission's theory, as a recent independent study confirms that transmission owners in RTO/ISO regions have a well-established track record of developing projects generally in line with baseline cost estimates, with final and updated project cost estimates falling between -2.9% and 7.0% of initial estimates.[15] The fact of the matter is, there is no evidence that existing processes have not been implemented appropriately such as to warrant any generic action or that the existing Commission-approved processes are producing unjust and unreasonable outcomes.

II. Local Transmission Planning Under Order No. 890 and Planning for Asset Management Projects

The Commission's Notice raises questions regarding the adequacy of the transparency in existing local transmission planning processes and the planning for asset management projects.[16] While local transmission planning can have different meanings within different RTOs/ISOs, in general it is the "transmission planning process that a public utility transmission provider performs for its individual retail distribution service territory or footprint pursuant to the requirements of Order No. 890."[17] As used in the

[14] *Id*.

[15] See https://ceadvisors.com/wp-content/uploads/2019/06/CEA_Order1000report_final.pdf at page iii.

[16] *Id*. at P 398.

[17] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011) at P 55, *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

Notice, asset management projects refers to projects and activities that "encompass the maintenance, repair, and replacement work done on existing transmission facilities as necessary to maintain a safe, reliable and compliant grid based on existing topology."[18]

Efficient local transmission and asset management planning processes are vital to ensuring that transmission owners can continue to provide reliable service to their customers, particularly retail customers in their distribution service territories, while also supporting regional planning process goals and objectives. Local planning and asset management processes are also critically important in efforts to accommodate state policies, such as promoting the development of distributed generation and increased electrification, as well as providing transmission owners the ability to develop and deploy innovative solutions to local needs, including non-wires alternatives. In addition, local transmission and asset management projects address local customer needs and demands for electricity, equipment condition performance, and risk management. It is often the case that upgrades to local, lower-voltage facilities are needed on a relatively fast timeframe to meet changing system conditions, including customer demand. As such, in order to maintain system reliability, it is important that public utilities have the ability to exercise control over their local systems. This is particularly true given that utilities are accountable for the outcomes of the decisions they make in fulfilling their obligation to provide customers with reliable and cost-effective service.

[18] Notice at p. 3, fn.3.

The Notice poses questions regarding transparency and the opportunity for input from various stakeholders in the local transmission planning and asset management process. The Commission should not lose sight of the fact that transmission providers were required to make filings to comply with Order No. 1000 transmission planning requirements which built on the Order No. 890 planning principles. The Commission-approved compliance filings provide extensive processes for stakeholders to receive information and participate in the planning processes for local projects.[19] To date, there has been no demonstration that these FERC-approved processes have not been adhered to or have been implemented improperly.

In fact, a recent study focusing on the value of local transmission projects evaluated various regional and local transmission planning processes and concluded that established RTO/ISO processes provide opportunities for stakeholders to participate and weigh in on proposed local projects.[20] The report observed that "[v]arious meetings that occur during established development stages of the local transmission solutions allow for an open and transparent forum for affected parties to voice their input while reviewing the data provided by the transmission owners."[21] As to state review processes for local transmission projects, the report determined that:

> The ISO/RTO stakeholder participation process has allowed state staff to participate in the development of the local plans more actively than in the past. Given the composition of

[19] See e.g., Order No. 1000 at PP 78-82, 148-58.

[20] *See* Charles River Associates, *Value of Local Transmission Planning Report*, (Dec. 2021) at pp. 14-20 (attached).

[21] *Id*. at p. 20.

> local projects – small and in large amounts – the ISO/RTO participation process allows for a more efficient review by the state staff.[22]

Thus, contrary to any generalized concerns, there is already ample transparency and opportunity for state commission and other stakeholder input in existing local planning processes.

III. Project Implementation and Variance Analysis

In the Notice, the Commission observes that in response to Order No. 1000's requirement for transmission providers to describe the circumstances and procedures for reevaluating a regional transmission plan in response to delays, some transmission providers voluntarily adopted a variance analysis process tied to changes in cost estimates.[23] The Notice asks several questions about the experience with these variance analysis processes, including whether such processes should be required and expanded.

At the outset, it is important to note that the Commission has not determined that transmission providers' currently approved processes do not comply with the requirements of Order No. 1000 or that those Commission-approved processes have been implemented incorrectly. While it might be commendable that some regions have voluntarily adopted processes that extend above and beyond the requirements of Order No. 1000, so far there has been no demonstration that voluntary measures adopted by

[22] *Id*.

[23] Notice at 6.

some regions should necessarily be required on a generic basis. To date, each region has determined whether or not to adopt a variance analysis based on its particular circumstances and needs, and for those regions that adopted a variance analysis, it has been structured in a manner appropriate to the region. To the extent the Commission views these efforts as a positive development, it should refrain from substituting its judgment for that of each region in favor of a one-size-fits-all generic approach.

Moreover, as the Notice acknowledges, Order No. 1000 limits the requirement for reevaluation to regional transmission planning and projects. Extending a reevaluation requirement or variance analysis to local transmission planning and projects would not be appropriate. Efficient, time-conscious local transmission planning is vital to ensuring that transmission owners can maintain reliable service to their customers, particularly retail customers in their distribution service territories, while also supporting broader regional planning process goals and objectives. It is often the case that upgrades to local, lower-voltage facilities are needed on a relatively fast timeframe to meet changing system conditions. As such, subjecting local projects to a regional entity's variance analysis process could potentially threaten the reliability and resiliency of transmission owners' systems.

IV. Independent Transmission Monitor

The Notice observes that there was disagreement at the October 6 technical conference as to the basis for requiring, need for, and scope of an Independent

Transmission Monitor (ITM).[24] WIRES maintains that there are fundamental legal, evidentiary, and policy issues with the notion of requiring transmission providers to establish an independent entity to monitor the planning and cost of transmission facilities in the region.

At the outset, there is a critical threshold legal question as to whether establishing a requirement of an ITM conflicts with the subdelegation doctrine which prohibits an agency from delegating its core statutory functions to private entities.[25] The FPA charges the Commission, not any outside party, with responsibility for ensuring the justness and reasonableness of transmission rates, and the proposed creation and authorization of an ITM would constitute an illegal subdelegation of the Commission's authority under FPA sections 205 and 206.[26] The Notice suggests a host of potential ITM activities that could include reviewing and assessing transmission plans, evaluating transmission facilities and their costs, participating in proceedings before the Commission, monitoring cost estimates, assessing need for transmission projects, accessing planning and cost information, including critical energy infrastructure information, and reviewing and evaluating costs.[27] In many instances, these are tasks that must be performed by the Commission itself, not a private entity, and to the extent the Commission were to confer

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[24] Notice at pp. 7-9.

[25] *See U.S. Telecom Assoc. v. FCC*, 359 F.3d 554, 555-56 (D.C. Cir. 2004).

[26] WIRES ANOPR Comments, p. 23.

[27] Notice at p. 8.

these types of ratemaking functions on an ITM, it would be impermissibly exercising delegated authority.[28] In contrast to existing market monitoring functions which involve referrals to the Commission of possible market inefficiencies or market manipulation, many versions of the role contemplated by the ITM would necessarily involve assessing the justness and reasonableness of particular transmission costs—functions that are vested with the Commission by statute.[29]

In order for FERC to satisfy its burden under FPA section 206 and impose such a remedy, there must be substantial evidence both that (1) there is a "practice" affecting rates that is unjust, unreasonable, unduly discriminatory or preferential, and (2) the remedy imposed is just and reasonable.[30] So far, no one has provided the necessary substantial evidence on either count. Instead, other than generalized concerns that customers will need to pay the potential costs of new transmission built to meet the needs of a changing resource mix, there is no evidence that the existing processes are failing to implement tariffs appropriately or produce unjust and unreasonable outcomes.

On the other hand, there is already a well-developed record of the potential problems with creating an ITM. These include:

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[28] *See* ANOPR Comments of the New York Independent System Operator, Inc., p. 54.

[29] *See also* ANOPR Motion to Intervene and Comments of the National Association of Regulatory Utility Commissioners at p. 21, RM21-17 October 12, 2021 (questioning the Commission's legal authority to impose an independent transmission monitor in areas that are not in an RTO/ISO).

[30] *See South Carolina*, 762 F.3d at 64-65.

- concerns that such an entity would add cost and a level of bureaucracy when there is no record of dysfunction;[31]
- confusion as to how an independent transmission monitor's review role would be preferable to the Commission conducting the contemplated review itself;[32]
- duplicate oversight already provided by RTOs/ISOs, the North American Electric Reliability Corporation, state commissions, and even the Commission itself, resulting in increased costs and delays;[33]
- increased administrative and legal costs of transmission planning with no commensurate benefits to customers;[34]
- could lead to "[a]dditional costs and burdens [as a result of] the unavoidable inefficiencies of adding another layer of review;"[35]
- in the case of RTOs/ISOs, would simply create "another independent entity to review an independent entity;"[36]

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[31] ANOPR Comments of the Large Public Power Council at p. 35, ANOPR Docket October 12, 2021.

[32] ANOPR Comments of the National Association of State Utility Consumer Advocates at p. 7, October 12, 2021.

[33] ANOPR Comments of the National Rural Electric Cooperative Association at p.31, October 12, 2021.

[34] ANOPR Comments of New York Independent System Operator, Inc. at pp. 52-53, October 12, 2021.

[35] ANOPR Comments of the Midcontinent Independent System Operator, Inc. at p. 4, October 12, 2021.

[36] ANOPR Comments of PJM Interconnection L.L.C. at p. 78, October 12, 2021.

- “would significantly harm, not facilitate transmission planning” and “would create an entirely new set of friction points within the process, resulting in unnecessary delays, costs, and litigation;”[37]
- “would duplicate work already performed by the CAISO, disrupt and add uncertainty to the transmission planning process, and create potential delays;”[38] and
- “could weaken the process and potentially introduce further delays and risks into transmission development where there are already substantial challenges, at the expense of getting infrastructure built to meet identified needs reliably and timely.”[39]

Not only is there no demonstration in the record of this proceeding sufficient to satisfy the burden under FPA section 206 that existing oversight has or will lead to unjust and unreasonable rates or preferential or discriminatory treatment, the fact of the matter is that current oversight is substantial and adequate, and additional regulatory processes in this area will only create additional burdens and frustrate the ability to get needed transmission infrastructure planned, developed, and in service in an efficient and timely manner.

[37] ANOPR Comments of the Sponsors of the Southeastern Regional Transmission Planning Process at p. 24, October 12, 2021.

[38] ANOPR Comments of the California Independent System Operator, Inc. at p. 115, October 12, 2021.

[39] ANOPR Comments of ISO New England Inc, at p. 34, October 12, 2021.

V. Commission's Formula Rates and Prudence Practices

In the Notice, the Commission poses questions relating to the adequacy of the transparency of transmission formula rate (TFR) protocols.[40] Current TFR processes use a formulaic approach that consists of two key components: (1) templates outlining the rate calculation; and (2) protocols that set out procedures for stakeholder participation and access to information. With respect to protocols, utilities using TFRs are required to submit annual updates and supporting documentation with the Commission for interested parties to review. Through these protocols, interested parties can submit discovery requests to review, verify, and challenge these annual updates on a defined annual timeline.

A recent Primer on TFRs prepared by London Economics International provides a thorough description of how TFR protocols establish the parameters of stakeholder discovery, review, interaction with the transmission owners, and oversight of updates, including timelines for review, requesting information, and raising challenges.[41] As the report explains, TFR protocols typically cover the following elements:

- **definitions** of key terms, such as "Interested Party," which is the designation for entities that have the right to review and challenge a utility's calculations under its TFR template;
- provisions for calculating the **revenue requirement** each year (and **true-up** for utilities operating under a forward-looking TFR), including how the

[40] Notice at 9-11.

[41] *See* London Economics International LLC, *Primer on Transmission Formula Rates*, (Feb. 2023) (attached).

calculations will be performed, how and when the **informational updates** with results will be posted (in both draft and final form), how and when notice of publication will be provided, the contents of the annual update, provisions for any meetings convened by the utility to discuss the filings, and requirements for filing annual updates with the Commission;

- procedures for **information exchange**, including rules as to which interested parties can submit information requests, the deadlines for submitting these requests, specifications regarding which aspects of a TFR filing the requests can address, the utility's duties in responding to the same, and any requirements for providing details of requests publicly;

- procedures for filing **informal and formal challenges** to an annual update, including filing deadlines, the information that must be provided as part of a challenge, procedures for responding to a challenge on the part of the utility, and steps to follow if the issue(s) cannot be resolved;

- procedures for **making corrections to annual updates**, including how such corrections will apply to current and future rate years; and

- other **legal issues**, such as the procedure for challenging and/or modifying the formula itself, how information provided through information requests may and may not be used, and more.[42]

In addition, the Commission already requires TFR protocols to address a lengthy set of criteria, including stakeholder participation, information dissemination, accounting and organizational changes, information requests, annual informational filings, and challenge procedures.[43] As particularly relevant here, the Commission further requires that the protocols specify that interested parties can obtain information regarding the utility's cost control methodologies and procurement practices so they can assess whether costs were prudently incurred.[44] Thus, many of the cost containment concerns reflected in the

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[42] *Id*. at p.15.

[43] *Id*. at 16-17.

[44] *Id.* at 16.

Commission's questions relating to TFRs are already fully and adequately addressed in the existing requirements relating to TFR protocols. As a result, there is no demonstrated need for the Commission to modify current formula rate protocols meeting these existing requirements or in any way restrict current use of TFRs.

VI. Federal and State Regulation of Transmission Facilities

The Notice poses questions relating to whether there is a regulatory gap with regard to ensuring a cost-effective mix of local, asset management, and regional reliability transmission projects.[45] It also raises questions regarding the adequacy of state, regional, and federal scrutiny of project need and prudency.[46]

To the extent the Notice seeks input as to the appropriate "mix of local, asset management, and regional reliability transmission projects," the question raises concerns about the Commission's lack of authority to direct the building of transmission facilities. Any FERC process that is directed toward determining the appropriate "mix" of transmission projects could either explicitly or implicitly require certain types of transmission facilities be constructed and could potentially intrude upon or impermissibly interfere with state-jurisdictional processes contrary to section 201 of the FPA.[47] Indeed, in Order No. 1000, FERC expressly declined to impose obligations to build transmission,

[45] Notice at 11.

[46] *Id.*

[47] 16 U.S.C. § 824.

and to determine what transmission needs to be built.[48] As FERC lacks authority to require what the appropriate investment in transmission should be, the Commission should refrain from any effort to require a particular "mix" of local, asset management, or regional transmission projects.

With respect to the adequacy of state scrutiny of project need in the context of siting proceedings, it is clear from the October 6 technical conference that those processes vary from state to state.[49] What is less clear is whether anyone, other than the states themselves, has the authority to evaluate the adequacy of individual state needs evaluation processes. In the absence of any clear authority vested in FERC to evaluate, judge and remediate the adequacy of state siting processes and needs evaluation processes, the Commission should refrain from taking any action.

[48] Order No. 1000 at P 159. *See also* Order No. 1000-A at 32,215 ("Order No. 1000's transmission planning reforms are concerned with process" and "are not intended to dictate substantive outcomes.")

[49] Outside of state Certificate of Public Convenience and Necessity (CPCN) siting jurisdiction, states do not have "prudency" authority over FERC jurisdictional transmission rates. States can bring prudence challenges to FERC pursuant to section 206, but FERC has ultimate responsibility for determining just and reasonable transmission rates.

VII. Conclusion

WIRES respectfully submits these comments for consideration by the Commission as it considers whether further action, if any, is warranted on these matters.

Respectfully submitted,

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Disclaimer

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1. Executive Summary

Charles River Associates (CRA) was engaged by WIRES to produce a report that provides a comprehensive review of the value of local transmission planning. In this report, we define local transmission planning as the "transmission planning process that a public utility transmission provider performs for its individual retail distribution service territory or footprint pursuant to the requirements of Order No. 890".[1] The product of the local transmission planning processes is local solutions that are critical to the integrity of the transmission system. Local projects enable the continued reliable operation of the transmission system by enhancing grid resilience and operational flexibility, addressing transmission asset health and replacing of aging infrastructure.

While we recognize the importance of regional and interregional transmission planning, our report focuses on documenting the value of local transmission planning as a key facilitator of local and regional energy transfer. Analogous to our national road network, local roads and off-ramps are equally important as interstate highways in providing transportation access.

Similar to local roads, local transmission is valuable to access important services in a reliable manner. Meeting reliability requirements is critical for the operation and design of the local and regional power system and ensure access to affordable and reliable electricity to all consumers. The standards and guidelines developed and enforced by all reliability entities, national and regional, provide a basis for reliable design and operation of the transmission system. However, their generic nature does not fully account for differences between local systems. While meeting the established regional reliability standards, local planners with their extensive system experience, also ensure that the local system is designed to accommodate locational system needs documented in their local reliability procedures. Our comprehensive review of the reliability needs assessment planning of six transmission asset owners within three Independent System Operators and Regional Transmission Operators (ISO/RTOs) confirms this complementary nature of local planning.

Local transmission planning is critical to regional planning since it ensures foundational system needs are met. The regional planning process complies with reliability, economic criteria, and public policy initiatives. However, it fails to address additional system needs related to resiliency, interconnecting customers, and replacing aging infrastructure among others that are the primary focus of local planning. In the ISO/RTOs reviewed, the local solutions are incorporated into the regional plan to produce a framework that captures the entire spectrum of the transmission investment benefits. A recent study by Exelon Transmission also shows that local planning projects do not affect or usurp the need for regional reliability projects. This indicates that local project needs are often unique and distinct from regional system issues and solutions. While regional planning processes can be expanded to account for a greater number of benefits, local system development will still be needed to support an expanded regional system.

All three examined regional planning processes offer an open and transparent review of the local projects to their stakeholders. Various stakeholder meetings allow for the review and discussion of local project-related information such as assumptions, drivers for the local solution need and proposed upgrades. The forums also ensure that the feedback provided is considered by the local planners ultimately resulting in modifications to needs, design, and implementation of the transmission solutions. These meetings also allow state commission staff to actively participate in an efficient manner to promote state goals related to clean

1 Order No. 1000, 136 FERC ¶ 61,051 at P 55

energy and grid modernization. Local planning is subject to robust transparency requirements in many regions.

Comments at recent FERC proceedings[2] proposed the consideration of a centralized entity – comparable to ISO/RTO - to oversee both local and regional planning. Even though a full examination of this structure is not within the scope of this report, it is important to inform the discussion regarding the challenges of such a change. Significant additional staffing resources and expertise would be required along with significant data exchange from local to regional planners. Currently ISO/RTOs lack the subject matter experts and local presence to analyze the local system and identify needs related to asset management, resilience, customer impact and other local needs.

In addition, to maintain a fair and transparent local planning oversight, a centralized entity would have to rely on a process that would require the collection, analysis and reporting of all local transmission solution data - activities that could be costly considering the number of local planning projects. Also, since the current coordinating agreements between transmission asset owners and ISO/RTOs do not include such a framework, legal challenges would arise.

To achieve federal and state clean energy goals, both regional and local planning are needed. Clean energy goals require efficient transmission solutions for the integration of renewable resources while maintaining system integrity. Though regional solutions are needed to facilitate the integration of new clean resources and provide for regional reliability and resilience, local planning will continue to offer crucial benefits and support for the regional grid. For instance, grid modernization and distributed energy resources (DER) integration initiatives are supported by local planning since they mostly affect the distribution system connected to local transmission. It would be challenging to expect a non-local entity to design local transmission solutions that enable the decentralization of generating resources and their participation in the wholesale market in accordance with the objective of FERC Order 2222.[3]

For the reasons discussed in this report, local transmission planning provides significant benefits and is foundational to the success of the regional planning process. Combining proximity to the local system with important expertise, local planners design cost-efficient transmission solutions that serve their customers while maintaining system integrity.

The report is organized as follows:

Section 2 summarizes and compares reliability standards and their application in the evaluation of the power system needs in both regional and local transmission practices. The section presents key takeaways compiled from a detailed review of the reliability standard application on local and regional planning practices.

Section 3 explains more broadly the local and regional selection and review processes. The discussion includes information on the results of those processes and their complementary nature.

Section 4 details the challenges associated with a potential consolidation of the local and regional planning activities in one centralized location. This section provides the basis for future discussions.

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

[3] FERC Order 2222 (RM18-9-000) was the result of discussion around the efficient integration of distributed energy resources

Lastly, Section 5 summarizes the local planning value in achieving various electric industry goals. The section is not exhaustive but provides a sound basis to inform related discussions.

2. Overview of Local and Regional Planning Criteria

Reliability is at the core of the transmission planning practices codified by well-documented reliability standards and guidelines. In identifying the value of local planning, it is critical to understand the incremental benefits realized from the development and application of more localized planning reliability criteria. Local standards not only comply with the regional and national reliability standards but offer a complementary layer of localized system security not inherently captured by regional planning.

In this section of the report, we compare the applicable reliability standards at the regional and local levels followed by a review of the processes for their application to transmission system studies. Before we proceed with that discussion, we offer a brief background on the development of the reliability standards in the US.

2.1. History of Transmission System Reliability in the US

The codified use of reliability standards and criteria in transmission planning and operations has been an important part of the electric power industry. Their importance dramatically increased during the grid expansion and the emergence of new technologies and grid applications. Initially the power systems were relatively simple, whereby a major system disturbance only affected a small area that in turn did not require the development of uniform reliability standards. However, as the power system expanded with the introduction of high voltage alternating current technology, the need for effective and consistent reliability standards became apparent.

The 1965 Northeast Blackout accelerated the development of unified reliability standards throughout North America. At the time, PJM was already enforcing a uniform set of reliability criteria throughout its footprint, with the rest of the regions following. Utilities across North America formed their own regional reliability councils with the objective to maintain, update, and enforce a regionally unified set of reliability criteria. At the time, regional differences in terms of topology and generation mix for example prevented the development of a coordinated set of standards throughout North America. Over time, each regional council developed its own reliability criteria and established procedures for evaluating compliance. Following suit, individual systems and power pools often maintained their own detailed or more stringent criteria in addition to the regional criteria as a minimum. In 1968, the regional reliability councils formed the North American Electric Reliability Council (NERC)[4] to coordinate reliability standard activities across the entirety of North America and to develop collective reliability guidelines.

In 2003, the blackout of the Midwest and Northeast United States and Ontario caused major industry changes that were enacted in the 2005 Federal Power Act. Under Section 215, FERC's authority expanded to include oversight of mandatory reliability rules. The Commission was authorized to designate an Electric Reliability Organization (ERO) to administer the rules and enforce penalties up to a million dollars per day for reliability standard compliance failures. Ultimately, the NERC was designated as the ERO. Currently, the NERC is comprised of six regional entities or councils that support various regions in North America.

[4] Later renamed to North American Electric Reliability Corporation

Exhibit 1 NERC Regional Entities

5

Lastly, pursuant to Section 215 of the Federal Power Act, states may disseminate and enforce reliability standards that are more specific than NERC and its regional entities if they don't affect reliability outside of the specific state. For example, New York has the New York State Reliability Council (NYRSC) that is within the Northeast Power Coordinating Council (NPCC) territory and develops and enforces requirements that are more stringent and specific than that of NERC or NPCC.

2.2. Reliability Standards and Criteria

The terms "standards" and "criteria" are often confused when used in the industry. Based on our review, mandatory requirements developed and enforced by NERC are considered "standards" while "criteria" are requirements independently maintained and enforced by the regional reliability entities. Occasionally, the term "guidelines" is used and refers to general requirements addressed by the regional councils through their own criteria. NERC standards are applicable to the Bulk Electric System (BES)[6].

The development of the reliability standards occurs through a NERC process that allows for industry participation throughout the entire process - beginning with the initial creation of a new standard up to its final approval. The NERC Board, residing under FERC's authorization, reviews and approves the proposed standards after a super-majority of registered entities

5 https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

6 The definition of the BES has been a controversial topic over the past several years. FERC has argued for applicability of NERC standards to all transmission facilities 100 kV and higher with approved exceptions. The existing BES definition generally applies to facilities rated at 200 kV or higher but could include some lower voltage facilities that may impact the overall system.

throughout the energy sector is obtained. The regional entities have a similar process for developing and approving reliability criteria within their areas. Any materially affected entities or individuals can initiate the review and approval process. At the state level, state reliability councils, like the New York Reliability Council in New York State, can modify or create new reliability rules that apply only within that state.

The established reliability criteria developed at NERC and its regional councils apply to all entities accountable for reliability in a specific geographical area, such as the regional operators, transmission owners, and generating companies. Additionally, transmission owners have local transmission planning criteria – beyond the regional standards - that are tailored to meet their specific system and area needs. The exhibit below depicts the documents that include all NERC standards.

Exhibit 2 NERC Reliability Standards Documents[7]

Reliability Area	**Definition**	**NERC Reliability Documents**
Supply and Demand Balance	Maintains the supply and demand balance of the system under business-as-usual conditions and emergencies	BAL – 001 through 006
Transmission Operations	Ensures that all Reliability Standards are followed by grid operators, that coordinators and operators have the resources needed to address grid issues, and procedures are in place to resolve threats to the system	TOP – 001 through 010
Transmission Planning	Ensures that new transmission facilities are resilient to threats and emergencies	TPL – 001 through 007
Communication	Maintains proper communication and coordination between reliability coordinators and operators of the grid	COM – 001,002
Critical Infrastructure	Ensuring that the grid's critical assets are protected from cyber and physical threats	CIP – 001 through 014
Emergency Preparedness	Ensures that grid operators are prepared for emergencies and have the resources and authority to restore operations if there is a disruption	EOP – 001 through 011
Facilities Design, Connections and Maintenance	Ensures that transmission operators have properly rated their transmission equipment and that adequate maintenance is performed to maintain grid reliability	FAC – 001 through 014, 501
Interchange Scheduling	Ensures that electricity transmission between balancing authorities does not pose a threat to the grid	INT – 001 through 011
Interconnection Reliability	Ensures that reliability coordinators have the authority to enforce reliability by directing grid operators to take necessary action when a threat is perceived	IRO – 001 through 018
Data Analysis	Ensures that grid operators are using accurate and consistent data for the use of transmission planning and reliability	MOD – 001 through 033
Nuclear Operations	Ensures that there is proper coordination between nuclear plant and transmission operators	NUC – 001
Personnel Training	Ensures that grid operations personnel are properly trained and qualified to meet the Reliability Standards	PER – 001 through 006
Protection and Control	Ensures that protection systems that protect the grid are operating as designed	PRC – 001 through 027
Voltage	Ensures that reactive power sources operate within their limits and maintain adequate voltage levels	VAR – 001, 002 and 501

7 https://www.nerc.com/pa/Stand/Pages/USRelStand.aspx

The transmission planning process is mostly structured around compliance with Transmission Planning (TPL) and Facility Ratings (FAC) reliability standards. The first provides an analysis of power system conditions and guidance on measuring performance, while the latter describes information related to the output potential of the analyzed transmission system under specified conditions.

The reliability standards are primarily focused on maintaining reliability during both steady state and dynamic conditions. More specifically, steady state refers to a state when load and generation are in balance and the power system is relatively stable. A common steady state analysis is a contingency analysis, which is used to verify whether the power system is secure after the occurrence of a contingency such as a failure of a line, transformer, generator, or facility for reactive compensation. Besides a single failure, commonly referred to as an 'N-1 contingency,' a contingency analysis may also extend to an N-2 contingency- i.e., the simultaneous loss of two generators or transmission lines.

Stability refers to the ability of a system to return to a steady state following a disturbance. According to the CIGRÉ-IEEE[8] task force technical brochure on stability terms and definitions, the following stability phenomena must be investigated during both normal and contingency conditions: (i) Frequency Stability, (ii) Voltage Stability and (ii) Rotor Angle Stability.

Lastly, short circuit analysis – also part of the reliability evaluation - investigates the impact of different types of short circuits on the power systems, including minimum and maximum single-phase or symmetric (three-phase) short circuits or multi-pole short circuits with/without earth contact.

Planners evaluate the system's responsiveness under various conditions and use established metrics to evaluate the need for specific enhancements.[9]

2.3. Review of ISO/RTO and Local Transmission Reliability Standards

In this report, our objective is to provide different perspectives from a non-technical review of transmission planning standards for regional and local entities.

In total, we examined three RTOs (i) ISO-New England (ISO-NE), (ii) PJM, and (iii) Midcontinent ISO (MISO) and six local transmission owners located within the ISO/RTO areas: (i) Central Maine Power (CMP), (ii) National Grid, (iii) Commonwealth Edison (ComEd), (iv) PPL Electric Utilities (PPL), (v) Great River Energy (GRE) and (vi) Northern Indiana Public Service Company (NIPSCO).

The reviewed documents are provided in the exhibit below.

8 Definition and classification of power system stability IEEE/CIGRE joint task force on stability terms and definitions, IEEE Transactions on Power Systems, August 2, 2004

9 TPL-001-5 Transmission System Performance Requirements

Exhibit 3 Transmission Planning Criteria Review

Entity	Reviewed Documents
ISO-NE	Transmission Planning Technical Guide Reliability Standards for the New England Area Pool Transmission Facilities (ISO-NE Planning Procedure No. 3) PP3
MISO	BPM – 020-r24 Transmission Planning
PJM	PJM Manual 14B: PJM Region Transmission Planning Process
National Grid	Transmission Group Procedure TGP28 National Grid Planning Guide
CMP	Technical Manual TM 1.2.00 Electric Transmission Planning
ComEd	Exelon Transmission Planning Criteria Applicable to ComEd, PECO, Baltimore Gas and Electric, Potomac Electric Power Company, Atlantic City Electric and Delmarva Power and Light Company
NIPSCO	NIPSCO Transmission Planning 2018 FERC Form 715 Part VI[10]
PPL	Practices Transmission Planning, All PPL EU BES and Non-BES PJM Tariff Facilities
GRE	PLG-CR-0001 System Planning and Strategic Projects

CRA reviewed and compared the documents, and we provide our key conclusions below.

2.3.1. Key Conclusions

The consideration of the applicable reliability requirements is at the core of both local and regional transmission planning practices. The review presented in this report suggests the following conclusions for policy makers and transmission planners to consider when evaluating proposals to merge local and regional planning processes.

- Local planning ensures that the underlying local transmission system is reliable and resilient and provides an important foundation for the regional planning practices to build on. Local planning is not performed in isolation but in coordination with neighboring and regional planning practices. The complementary expertise of the regional planner and the local planner allow for a more robust analysis to mitigate system issues that can cascade from regional to local transmission systems. All reliability standard documents

[10] Document was part of the 2018 NISPCO IRP Appendix F redacted

include information related to coordinating with neighboring local and regional entities to better mitigate intra-regional reliability issues.[11]

- Local planning criteria consider locational needs that are difficult to capture under the broader uniform regional reliability requirements. They also consider the NERC Reliability standards with applicable exceptions related to system differences like geography, configuration, and others. Such exceptions are permitted by the established national criteria and are not considered a violation given the appropriate risk level. For example, varying levels of load shedding are allowed in different jurisdictions, with more stringent requirements seen at the local level. This is reasonable given the available local transmission system modeling detail that allows local planners to have a better understanding of potential issues in the system and design their mitigation. To this point, the facility ratings utilized in various jurisdictions were specific, rather than uniform, to each region to account for geographical and other differences.
- Lastly, the national and regional planning reliability standards primarily focus on compliance with NERC and regional requirements excluding system needs that arise from asset management, resilience, customer impact and other local needs. These critical system needs are assessed through parallel local processes, which are not required by the national and regional standards.

2.4. Structure and Features of the Reliability Needs Assessment

The evaluation of the power system based on the applicable reliability standards occurs in the commonly referred to *reliability needs assessment*. To further understand the complementary nature between regional and local planning, it is important to review how reliability assessments are performed at the regional and local level and describe their differences.[12]

In the reliability needs assessment, transmission planners use transmission system modeling analysis tools to perform steady state load flow, system stability and short circuit analysis to determine any potential violations to planning criteria.

The scope and focus of a reliability assessment dictate the configuration of the load flow models and their input data. In general terms, the input data required in the load flow studies are described as follows:

- System data that includes the overall system topology, technical parameters of the system like transmission line ratings, line and transformer impedances, and location
- Information related to generation dispatch levels and load based on specific assumptions such as season, specific time of day, weather, upcoming resource retirements or additions, generation technology, and others

The process for performing transmission system analysis is as follows:

- *Developing a model of the power system*

This stage includes the gathering and evaluation of the elements within the power system that include transmission lines, transformers, etc. The transmission planner also gathers

[11] Due to the non-technical nature of this report, we did not fully compare criteria such as voltage distortion limits and harmonics. Based on our review, all the technical requirements included in the local and regional reliability standard documents were adequately documented and referenced by well-established entities like IEEE and CIGRE.

[12] In this section, we focus on the reliability component of the transmission planning process excluding others like the economic and environmental impact evaluations.

information related to the system resources that include changes to generation and load. The estimated point demand produced in load forecasting is also a critical component of this effort.

- *Utilize this model to measure the performance of the system for a range of operating conditions and contingencies*

The reliability criteria are applied to evaluate the performance of the system, and the planners identify areas of need after they apply various standard mitigation techniques like generation re-dispatch and others. Lately, enhancements to this stage have included the introduction of stochasticity, which will be needed for the evaluation of future uncertainties.

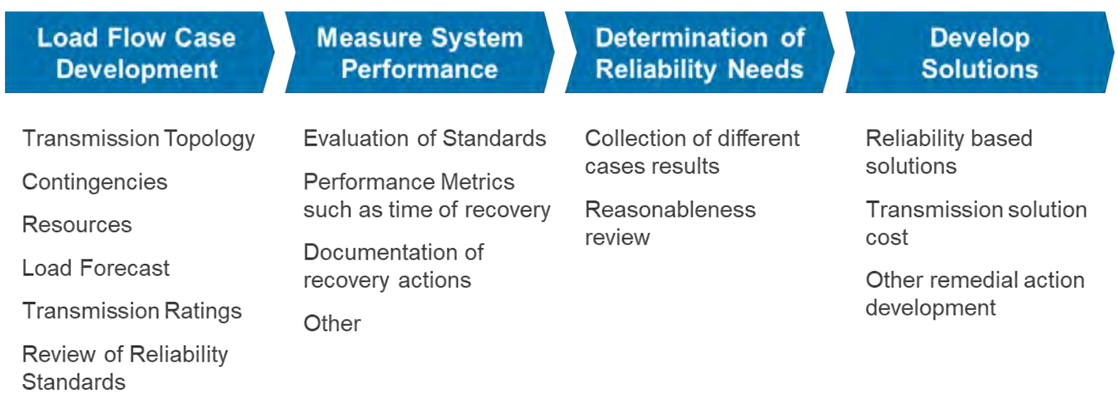
- *Determining those operating conditions and contingencies that have an undesirable reliability impact and result in criteria violations*

Results of the different load flows are organized to assess the complete spectrum of system impacts and the system reliability needs. Planners apply their expertise and system knowledge to assess the reasonableness of the different model outcomes.

- *Developing and evaluating a range of solutions and selecting the preferred solution, taking into account the time needed to place the solution in service*

During this phase, planners use the developed load flow cases to evaluate different solutions to mitigate identified reliability events. The objective is the most cost-effective solution. During this phase, planners coordinate internally with operations, project management and other affected groups.

Exhibit 4 Reliability Assessment Process



Similar to the reliability standard review, we gathered information related to the reliability assessment process performed by entities mentioned in Section 2.3. Our review on the aspects related to the reliability assessment is provided in the exhibit below.

Transmission Planning Component	Examined Regional Transmission Planning Provider	Examined Local Transmission Planning Provider
Source of Power Flow Case	Power flow cases are developed by independent entities. For example, for the Eastern Interconnection, power flow Cases derived primarily from the Modelling Working Group (MMWG)	Provide related data to construct the ISO/RTO case. The result is then used as for local planning including locational details
Source of Load Data Assumptions	All ISO/RTOs rely primarily on stakeholder-driven internal load forecasts for load assumptions	Local planners provide data to ISO/RTO load projections. The finalized information is considered as input to the local process with appropriate locational modifications
Source of Transmission Topology	PJM and MISO use topology assumptions from MMWG and data furnished by member entities. ISO-NE uses topology assumptions from the Regional System Planning Process and Interconnection study processes for internal facilities and the MMWG for facilities external to its system.	Local planners provide the ISO/RTO transmission topology information (ratings etc).
Generation Assumptions	For existing resources, all ISO/RTOs rely primarily on respective stakeholder-driven internal resource studies and regional modeling databases.	In-house generation assumptions shared via the stakeholder process with the ISO/RTO
Stressed Case Conditions	Most ISO/RTOs develop base case(s) with expected generator outages. Additional scenarios and cases are developed to test the system under stressed conditions	Similar framework with additional analysis that incorporates harmonics, etc.
Resolution to Load Flow Violations	Most ISO/RTOs develop transmission solutions as a mitigation measure. These include resource investment (like Demand Response, special protection schemes, and others).	Transmission solutions, special protection schemes, and non-transmission solutions in some cases

2.4.1. Key Conclusions

Overall, the reliability assessment between the two processes is similar. Although performed during different time frames, they appear to be complementary since they evaluate the system from different perspectives. Below we summarize our key takeaways:

System Models: While the basis of the utilized system models is similar between the two processes, local planners consider impacts to the distribution system extending the granularity of the load flow models. Similar to the development of the regional model, local planners incorporate the input of different stakeholders affected by local transmission operations. Coordination with local operations is used to develop practices that better represent the system and how it will respond to various system contingencies. Based on our review, this practice is included in all six local transmission owner planning documents.

Load Scenarios: Our review indicates that local transmission owners analyze more detailed load scenarios applicable to multiple weather patterns compared to the regional process that analyzes mostly only pre-determined forecasts. For example, while CMP refers to the ISO-NE load forecast case as its basis for the load flow development, it also relies on adjustments based on customer needs. Additional sensitivities and scenarios are becoming increasingly important as the grid becomes more dynamic in the changing energy landscape. These types of local studies help to ensure there is adequate transmission capacity to reliably serve load all hours of the year.

Stressed System Evaluation: Experience with their system allows local planners to evaluate more extensive system conditions at the local level. Since the RTO/ISO planers are generally focused on compliance with NERC and regional entity criteria, local planners - where applicable - can examine the needs of the system beyond those guidelines. System familiarity also serves well when interpreting the results of more complex analysis, such as assessing equipment end of life.

3. Transmission Benefits from Local Planning

Apart from meeting the standardized reliability requirements described in the previous section, local transmission solutions deliver additional system benefits related to resilience, operational flexibility, and others. In this section of the report, we briefly describe the full spectrum of the drivers for transmission solutions and their benefits. We also provide an overview of the regional process and how it incorporates local transmission solutions in PJM and MISO. Lastly, we describe the process for reviewing transmission projects at the state level.

Our objective is to inform the discussion around the value of local transmission planning. Our review indicates that:

- Local transmission planning delivers critical benefits not captured under the current regional planning practice.
- The regional process allows for an extensive review of local solutions by the ISO/RTO stakeholders.
- There is adequate review of local transmission solutions to prevent transmission owners from favoring local transmission over regional.

3.1. Transmission Investment Benefits

Originally, transmission planning occurred at the public utility level, often as a component of the local utility's integrated resource planning. Initially, transmission projects rarely crossed state borders as they were designed to deliver electricity from power plants to load centers within a locality. The rapid development of the power grid necessitated the construction of longer transmission projects to interconnect with neighboring utility systems to increase reliability and to access potentially lower priced electricity. The increased complexity of the system required a more extensive selection process for new transmission investments that examined a wider spectrum of reliability, economic, and public policy drivers for transmission enhancements.

The benefits of transmission investment have been categorized and analyzed extensively over the years both in industry and academia. The table below depicts the most mentioned transmission benefits.

Exhibit 5 Transmission Investment Benefits

Area	Transmission Benefit
Energy Production Savings	Congestion reduction, extreme event impacts, reduce wear on generation fleet, and others
Public Policy	Efficiently integrate public policy goals
Market Efficiency	Enhanced competition and market access
Clean Energy	Reduce cost of implementing emission regulations, facilitate integration of renewable technologies, meet climate and energy goals
Reliability/Resource Adequacy	Avoided future generation and transmission investment, allows retirement of high-cost generation, lower planning reserve requirement
Resilience	Storm hardening, system flexibility, and others

Notably, transmission benefits beyond reliability are usually analyzed via a cost-benefit analysis, where the cost of a proposed project is compared with the quantifiable benefits and, in some instances, qualitative benefits which are important but not easily defined. While production cost savings are determined via production cost models, planners have limited analytical tools to evaluate a variety of other benefits like the impact of a proposed solution to the system's storm hardening level.

Although currently conducted by different entities, the local and regional planning processes are complementary, because they capture different sets of benefits produced by different needs. While RTO planning is generally focused on bright line criteria designed to address NERC TPL standards, market congestion, and generation interconnections/deactivations; local planning extends to resilience, asset management, and customer impact. With most of the current transmission system developed in the early part of the 20^{th} century, the benefits from updated infrastructure are significant. The exhibit below provides an overview of various local transmission solution drivers and their benefits.

Exhibit 6 Local Transmission Project Drivers and Benefits[13]

Local Planning Driver	System benefit
Degraded equipment, equipment failure, obsolescence	Enhanced equipment material condition, minimization of performance risk
Minimization of outages, optimal system configuration, increased element restoration capability	Increased Operational flexibility and efficiency
Need to Improve system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather, geo-magnetic disturbances, physical and cyber security challenges, critical infrastructure reduction	Improved Infrastructure Resilience
Service to new and existing customers. Interconnect new customer load. Address customer transmission & distribution load growth, outage exposure, and equipment loading.	Enhanced Customer Service
New Government/State regulations, new industry standards on transmission, pilot projects and other	Addressed other system needs

3.2. Regional Transmission Planning Process Overview

Understanding the involvement of local planning in the regional process requires an overview of the current planning structure at the ISO/RTO level. In the three reviewed regional areas, local solutions are included in the regional and inter-regional transmission planning that occurs at the ISO/RTO level. We concentrate on PJM and MISO planning processes that are similar to ISO-NE and other regional operators.

PJM Regional Planning Process

In PJM, the regional transmission process is performed during the Regional Transmission Expansion Plan (RTEP) process. The RTEP process facilitates planning updates and seeks to resolve issues through open and transparent engagement with members, stakeholders, regulatory agencies, and other parties.

According to PJM, there are three types of transmission planning projects, and are briefly described as follows:

- *Baseline projects* that address national and regional reliability standards. These include projects that mitigate overloads, bus voltage drops, generator instability, and others. They

13 PJM M-3 Process Presentation by Exelon Transmission

also address generation deactivation, market efficiency criteria, public policy, and PJM's operational performance.

- *Network upgrades* required to interconnect new customers seeking long-term transmission service and connection to the grid.
- *Supplemental Solutions* identified by local transmission owners required for local reliability, resilience, aging, and condition.

Several committees support the process of reviewing recommended planning strategies and policies, as well as planning and engineering designs. The Transmission Expansion Advisory Committee (TEAC) provides a forum for stakeholders and PJM staff to exchange ideas, discuss study assumptions and review results before their approval. Subregional RTEP committees also address lower voltage planning concerns.

Under the established process described in Attachment M-3 of the PJM tariff, the PJM transmission owners provide for an extensive stakeholder participation during various development stages of the local transmission solutions. Throughout this process, stakeholders can provide comments for consideration by the local transmission asset owner for all proposed supplemental solutions. In a recent order by the FERC,[14] the M-3 attachment was revised to incorporate enhanced transparency towards the review of aging infrastructure replacement projects. As a result, increased opportunity to review and provide feedback was provided to PJM's stakeholders related to asset management activities.

At first, TEAC and subregional RTEP Committees coordinate stakeholder meetings to review the proposed assumptions, criteria and models provided by the transmission Owners that will be used to identify local transmission solutions. The models used in the M-3 Process are the load flow, short circuit, and/or stability models required to review the impacts of potential solutions. Notably, the local transmission solution discussions occur in parallel with the discussions related to other types of transmission solutions such as baseline and network upgrades to ensure consistency.

Following the Assumptions meeting, in the needs meetings transmission owners and other stakeholders can present the identified system needs and their drivers, based on the application of the previously discussed assumptions and criteria. The review of the potential solutions occurs in a subsequent meeting after the needs have been identified and discussed. The proposed projects and evaluated alternatives are presented to the forum for further commenting and feedback.

[14] PJM Interconnection, L.L.C., 172 FERC ¶ 61,136 (August 2020 Order)

Exhibit 7 PJM's Transmission Stakeholder Participation Process

Lastly, local projects are finalized and submitted to the local plan which is incorporated to the RTEP process with the baseline and, network upgrades. PJM planning engineers study the impact of the finalized local projects to the baseline – a process called "no harm"- and other projects and provide feedback to the transmission owners and stakeholders. This process also ensures that local projects do not displace regional transmission enhancements.

In 2020, the PJM Board approved 43 new baseline projects at an estimated cost of $413 million to meet fundamental system reliability across the grid, with a majority costing upwards of $20 million per solution. Based on our review, the number of these projects is not great due to limited regional and national reliability needs over the past few years.

Although the total supplemental projects cost was close to $3.2 billion, it is important to understand their cost composition. Since PJM does not provide detailed cost data for individual supplemental projects, we relied on historical data provided to PJM by its transmission owners. Based on the available information, most of the approved projects in the RTEP process have been supplemental, with the majority costing less than $10 million dollars, dwarfed by the regional project average cost of more than $50 million.

Exhibit 8 Overview or Approved Supplemental Projects included in the RTEP process[15]

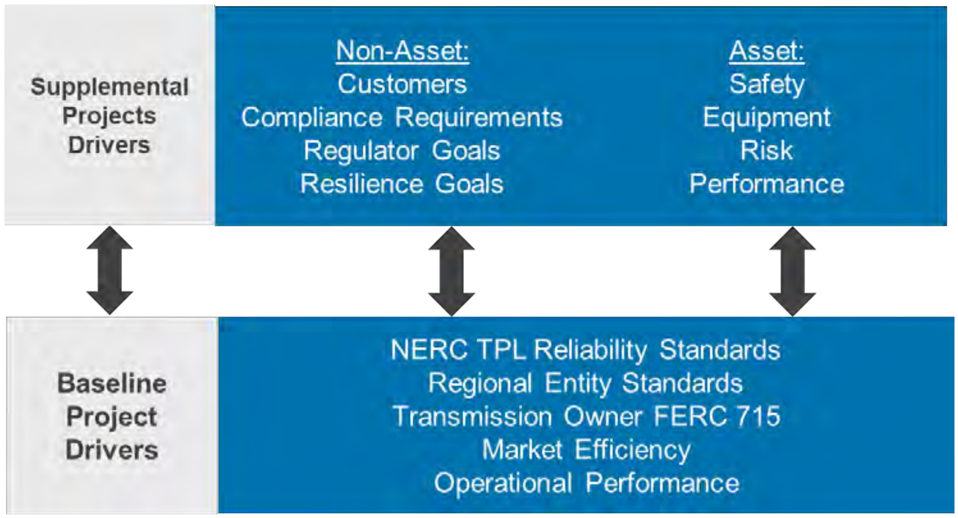
Individual Project Cost ($millions)	Count of projects	%
Less than 0.5	1151	28
Between 0.5 and 4	1420	34
Between 4 and 10	663	16
More than 10	896	22

15 https://www.pjm.com/planning/project-construction

The supplemental projects are categorized by their drivers related to asset and non-asset needs. There exists a sub-set of the supplemental projects that is required to meet reliability requirements – similarly to the baseline projects – but the majority of the transmission solutions are needed to alleviate issues around customer service, asset performance and resilience among others. This confirms the foundational nature of the supplemental projects since they ensure that the local transmission system can support regional projects.

Our review of the supplemental project descriptions did not indicate any overlap with regional projects. The exhibit below indicates the relationship between the two categories and how local projects supplement the limitations of the current regional planning practice at PJM.

Exhibit 9 Transmission Benefits for Supplemental and Baseline Projects



Since the transmission benefits captured by the two processes are not the same, there is no deliberate overlap between the produced transmission solutions.

A recent example provided by Exelon in the FERC ANOPR[16] proceeding reinforces the complementary benefit nature of the supplemental projects. In October 2020, Exelon Transmission[17] performed a transmission study to understand the impact of supplemental projects. The study removed the 72 ComEd supplemental projects from the 2025 PJM model and mimicked the reliability and market efficiency analysis done by PJM. The results demonstrated that the none of the 72 supplemental projects served to alleviate PJM reliability or market efficiency drivers. This result confirmed the concept that supplemental projects do not supplant market efficiency or projects driven by reliability.

MISO Regional Planning Process

The MISO Transmission Expansion Plan, or MTEP, is at the core of MISO's regional planning process, integrating the results of MISO members' local planning processes with the advice and guidance of its stakeholders obtained through multiple meetings. The typical planning cycle occurs over an 18-month period that commences with transmission developers submitting their proposed projects – usually in September. MISO planners evaluate the proposed projects during a multi-month period before sending for approval to the MISO Board. All projects – regional and local – are evaluated through an open and transparent

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

[17] Parent Company of various transmission owns in North America included ComEd

stakeholder process similar to the process described above for PJM. For local projects, this review largely occurs during sub-regional planning meetings which are open to interested stakeholders in each MISO sub-region. In consultation with stakeholders and the regional planner, transmission owners such as ITC review all proposed projects and potential alternatives at these meetings. This process informs which projects are included in MISO's MTEP.

The projects listed in Appendix A of the MTEP Report constitute the essential transmission projects recommended to the MISO Board of Directors for review and approval on a bi-annual basis. MISO distinguishes between different types of projects and evaluates them based on reliability, economic, and public policy criteria.

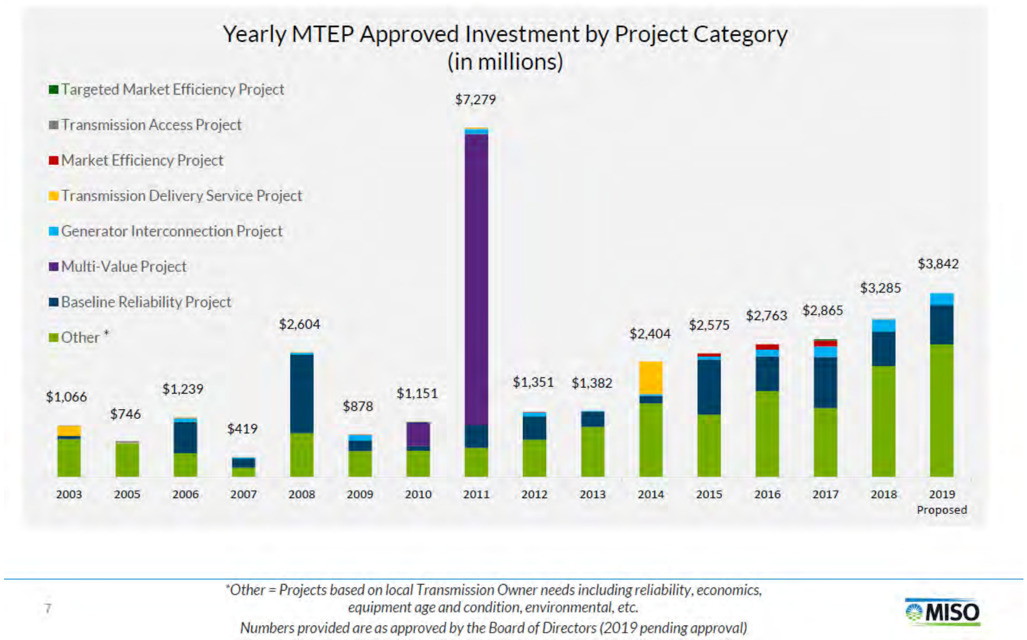
Exhibit 10 Types of MISO Transmission Projects and their drivers[18]

MISO Transmission Projects	Driver
Multi-Value	Provides regional benefits and addresses energy policy laws
Baseline Reliability Projects	NERC Reliability Criteria
Market Efficiency Project	Reduce market congestion when benefits are 1.25 times in excess of costs
Participant Funded (Other)	Transmission owner identified projects that does not qualify for other cost allocation mechanisms
Transmission Delivery Service Project	Transmission Service Request
Generation Interconnection Project	Interconnection Request

Historically, most transmission enhancements in MISO have been developed by local transmission owners. These transmission solutions have been categorized as required to meet load growth, aging infrastructure, and local reliability needs.

18 MISO – Transmission Planning Business Practices Manual BPM-020-r25

Exhibit 11 Historical Approved MTEP investment



Other than 2011, most of the transmission investment has been classified as "other," defined as being identified and developed by local transmission owners. Looking at the latest MTEP 2020, the "other" composition is as follows:

Exhibit 12 MTEP20 'Other Project' Composition

Individual Project Cost ($millions)	Count of Projects	%
Less than 0.5	611	28
Between 0.5 and 4	834	39
Between 4 and 10	409	19
More than 10	311	14

3.3. Key Conclusions from the Regional Process Review

Our review of the regional planning process as it relates to local projects identified two major themes. First, the current regional planning framework does not evaluate transmission benefits from areas such as aging infrastructure replacement and local resilience and other local needs. The evaluation of those needs occurs at the local level, where planners have the expertise and capabilities to identify and develop plans for their solution. If the current planning framework is modified and the regional reliability category becomes more expansive, it may or may not impact local planning since regional planners will still lack the expertise and proximity to evaluate needs tied to local resilience, new load integration, and aging infrastructure. While the amount of local transmission investment is large compared to regional, that does not indicate a regional project displacement by the local projects as supported by the Exelon analysis.

The second relates to stakeholder participation during the regional planning process. Both ISO/RTOs reviewed have established processes, where stakeholder can weigh in on the proposed local projects. Various meetings that occur during established development stages of the local transmission solutions allow for an open and transparent forum for affected parties to voice their input while reviewing the data provided by the transmission owners.

3.4. State Review Process for Local Transmission

The discussion around the benefits of the value of local planning fails to adequately describe the well-established transmission solutions review at the state level. States have maintained authority over their transmission facilities due to policy principles, as well as design and operation activities. This authority is primarily concentrated on siting of new projects and their impact to the public needs. State commission staff is sensitive to T&D design and operations, due to their responsibilities for coordinating state-policy goals. Other more traditional responsibilities like setting electricity rates, enforcing reliability requirements, and mitigating environmental effects have motivated the staff to thoroughly review new transmission plans within their jurisdictions and at the ISO/RTO level. The ISO/RTO stakeholder participation process has allowed state staff to participate in the development of the local plans more actively than in the past. Given the composition of local projects – small and in large amounts – the ISO/RTO participation process allows for a more efficient review by the state staff.

For larger projects – usually long transmission lines or major transmission infrastructure enhancements – states have relied on more extensive reviews. Through legislation, various states have developed broad selection criteria that are usually applied during the Certificate of Public Convenience and Necessity (CPCN) process. To provide an example of the CPCN process, we focused on two states located within the examined ISO/RTOs: (i) Maine, as part of ISO-NE and (ii) Wisconsin, as part of MISO.

Both CPCN processes are well established and include a lengthy review process that allows multiple stakeholders to examine proposed local transmission projects. It primarily focuses on larger projects with various thresholds in place like miles or voltage level.

The transmission project evaluation standards include, but are not limited to, the following:

- Impact to ratepayers
- Allowing open market access
- Economic impact to the region and economics of the project route
- Compliance with state laws and requirements

In Maine, the process also includes the review of non-transmission alternative solutions and provides the opportunity for stakeholders to propose substitutions for the transmission owner solution.

There are many examples where the CPCN process has provided a sound review and approval of large transmission solutions at the state level. One example is the Cardinal-Hickory Creek project in Wisconsin.[19] During this proceeding, the state commission evaluated the proposed solution based on both qualitative and quantifiable benefits including:

[19] Final Decision Public Service Commission of Wisconsin Docket 5-CE-146, September 26, 2019

energy cost savings, capacity cost savings, insurance value, and avoided reliability and asset renewal benefits.[20]

4. Challenges of Centralized Local Planning

The FERC-issued ANOPR[21], relating to transmission planning reform, raised the possibility of expanding the ISO/RTOs functions – via the creation of an independent monitor- to include local transmission planning oversight. Specifically, FERC stated the following:

"…it would be appropriate for the Commission to require that transmission providers in each RTO/ISO, or more broadly, in non-RTO/ISO transmission planning regions, establish an independent entity to monitor the planning and cost of transmission facilities in the region."

Under a centralized entity, local projects will be subject to regional oversight and open to competition. In our view, a more extensive and comprehensive analysis is required to assess the impacts of such a transition in the future. The analysis would focus on various risks of such transition such as implementation cost and risk of transferring responsibilities from an organization with local planning experience to one that does not and other among other. The analysis should also review potential competitive structures that enable competition at a cost-effective and non-discriminatory manner. As depicted in Section 3.2, the number of local projects at MISO and PJM is significantly greater than the number of regional projects making the development of a cost-competitive framework difficult to manage and having questionable benefits for customers.

In this report, we identify a sub-set of potential areas to further investigate the expected impacts of such transition.

4.1. Staffing

Expanding the transmission planning and engineering responsibilities and oversight from the regional level to the local level will impact the availability of current ISO/RTO planners and require significant additional resources with very different skill sets related to asset management, resilience and other. Based on our review, currently regional transmission planning in both ISO/RTO and non-ISO/RTO regions relies on one of the following[22]:

- In-house standing body of planning staff supported by external consultants. Regional planners focus on modeling and simulation to identify the reliability needs and potential solutions.

[20] Energy Cost Savings: The Energy Cost Savings represent the project's ability to lower overall energy costs for Wisconsin customers. Capacity Loss Savings: These are the savings resulting from the reduction in capacity costs as a result of the project operation. Insurance Value: The Insurance Value is the reduction in the economic impact of severe generation or transmission outages. Avoided Reliability Project Benefits: These are the benefits from avoiding the need to construct future reliability projects if the project constructed. Asset Renewal Benefits: These are the benefits associated with avoiding the need to renew and replace existing transmission lines if each alternative is constructed.

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

[22] Lawrence Berkeley National Laboratory, A Review of Recent Regional Transmission Plans, September 2016. https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf

- Third party evaluator/s responsible for various analyses of proposed projects, including cost-benefit analysis. An example of this approach is the Florida Reliability Coordinating Council.
- Collaboration between the public state commission staff and regional transmission planning entity. This mostly occurs in non-RTO regions with NTTG as example.[23]

A potential shift to a centralized regional planner for local transmission planning will affect all three practices in various degrees. For the ISO/RTO, any extension on planning responsibilities will require the need for larger planning groups including resources with skills outside the traditional reliability planning like asset management. It is unclear whether planning engineers from the local transmission owner would be able to support a regional entity. Third party evaluators that currently support non-ISO/RTO centralized planners would also require incremental skills that can add to planning costs for a particular area. Without a detailed study, it is difficult to determine whether such a structure is more cost-effective and would enable more robust local planning.

In addition, in most transmission owner organizations, transmission planning is performed in coordination with distribution planning to design and operate the system in an efficient manner. Moreover, in areas like the Midwest, local planners have expertise tied to system intricacies like contractual agreements between smaller transmission owners with infrastructure connected to their system that is not part of the Bulk Electric System. It is unclear how a centralized entity will effectively manage these arrangements to the benefit of the local network customers.

Lastly, local projects related to asset management rely to a decision-making process that has evolved over time and cannot be replicated at the regional level. Even though local engineers deploy software tools and monitoring devices to assess the estimated life of field electrical equipment, they also rely on experience developed over time to conclude on their replacement. Maintaining a balance between replacing an old asset on time and not replacing too soon is a decision making process not easily replicated with a uniform decision making approach at a centralized entity.

4.2. Centralized Entity Infrastructure Needs

The formation of an independent monitor would require enhancements in data sharing and additional infrastructure investments.

In transmission planning, information sharing is critical. Currently, the regional planning process requires a significant amount of confidential data to be transferred related to various transmission system elements collected from local transmission owners and other entities. An expansion of the ISO/RTO planning with the addition of evaluating transmission enhancements driven by asset management, resilience, customer service and other will require the transfer of significantly more critical infrastructure data. This data transfer could amplify the risk of a potential cyber breach event. NERC has instituted the critical infrastructure protocols that provide standards for preventing such an event, but the need to modify or enhance the current standards may be required adding cost to the affected parties.

Larger planning groups would also require supporting infrastructure such as buildings, servers and other that can increase implementation cost with limited benefit. Recent ISO/RTO formation studies can offer insights on the investment cost, but we expect it to differ under different regional oversight structures (greater oversight will require larger infrastructure development).

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[23] https://www.nwcouncil.org/sites/default/files/2016_0510_7.pdf

4.3. Project Selection Administrative Cost

Under a centralized entity, we expect the local projects to be subject to regional oversight and open to competition. Maintaining fair and competitive local transmission selection would require the expansion of competitive selection process.

Currently there are two approaches for selecting competitive transmission projects subject to Order No. 1000 bidding requirements in North America: sponsorship and project-based solicitation. Under the sponsorship approach, the competition for a transmission solution includes both the selection of the project and the developer. Under the project-based solicitation approach, the planning process determines the project based on set criteria, while the developer is selected by solicitation.

Regardless of the approach, the ISO/RTOs have in place a robust and resource intensive process designed to meet established criteria propagated by FERC Order 1000 for the selection of both projects and developers – per their selection approach. Even though direct ISO/RTO administrative costs for given competitive processes are recovered via a proposal fee, it is uncertain how this fee will evolve if there are significant numbers of needs or proposals. General and administrative expenses for RTOs/ISOs, including staffing needs to oversee competitive processes, would likely increase significantly. Besides the analytical component, the ISO/RTO staff will have to evaluate the financial status of the developers, administer the solicitation process, report and process the results, and potentially track the status of completion of these solutions more actively.

On the developer side, initial participation costs can take the form of ISO/RTO membership, access to the solicitation process, and others. Our industry experience indicates that the development of a project proposal can be at significant cost and may negatively affect smaller developers. As an example, SPP reported a $500,000 cost for the competitive process for the North Liberal–Walkemeyer 115 kV project.[24]

As described in the previous section, most of the supplemental projects in PJM are less than $4 million. The impact of the developer proposal costs and the ISO/RTO fee on these projects' total budgets is greater, compared to a multi-million-dollar regional project. In order to maintain a competitive bid, compared with an experienced merchant developer, small developers may elect to not participate in the solicitation process for smaller projects.

5. Energy Industry Goals and Local Transmission Planning

Local transmission planning has an important role in the coordination and reliable implementation of emerging policy initiatives since it acts as a bridge between distribution and regional systems.

In this section of the report, we detail how an effective local transmission planning process can address various challenges that stem from these initiatives. The discussion focuses on the importance of local transmission planning in advancing grid modernization efforts, integrating Distributed Energy Resources (DER) into the electric grid, enhancing resilience against severe weather, and achieving various proposed clean energy goals. We recommend policy makers and planners use this section to communicate a comprehensive "business case" for local transmission projects that focus not only on reliability like the previous section but as complementary to achieving state and federal government policy goals.

[24] Prepared Statement of Paul Suskie, Executive Vice President and General Counsel, Southwest Power Pool, Inc., Before the Federal Energy Regulatory Commission, Docket No. AD16-18-000.

5.1. Grid Modernization

Transmission planning benefits related to system resilience and grid modernization have gained more visibility. Recent capital expenditure on grid infrastructure, apart from maintaining and expanding current T&D networks, has also begun to enter the territory of grid modernization to transition the current electric grid into a more dynamic system. Focused on the local level, various utilities and transmission owners are at different stages of incorporating elements of a modern grid into their T&D networks. A general understanding is that a more automated and modernized grid will be the best response to a rapidly changing electric system and world.

Distributed Energy Resources (DERs) have also been driving the modernization of the electric grid. As utilities start to ramp up their investments in DERs, they can be viewed as an almost simultaneous investment in elements of a more modernized grid to improve grid reliability, resiliency, and recovery time. Commonwealth Edison (ComEd), for instance, has successfully prevented over 4.8 million customer interruptions since 2012 with its Energy Infrastructure Act. The Act included the deployment of 2,600 smart switches and 4 million smart meters throughout its service territory.[25]

Additionally, recent investments in the T&D industry show a preference for a more digitized T&D system.[26] National Grid, for example, has begun to digitize substations to create a more dynamic network, which the utility believes provides cost savings for customers and significantly improves flexibility and safety.[27]

These examples of modernizing the electric grid show that this process has thus far been spearheaded by local transmission owners who are closer to the T&D network interface and understand intimately what will best serve their customers. This makes a strong case for why transmission planning needs to be fostered at the local level, as it is likely that those who are most familiar with particular T&D systems are the ones who can make the most informed decisions on what is needed to develop a truly resilient and modernized grid.

5.2. DER Integration and DER Planning

In the U.S. and abroad, households and small businesses are utilizing the grid when adopting technologies that allow them to influence their energy bills and carbon emissions. In parallel, more and more utilities are pivoting towards an increasing adoption of Distributed Energy Resources (DERs) to serve the emerging needs of their consumers while simultaneously meeting state clean energy targets.

Exhibit 13, below, shows in various shades of green the leading states in installed DER capacity, ranging from about 1 GW to 8 GW. Efficient local planning is critical in ensuring that periods of intermittency – particularly from renewable DERs – is addressed by a modernized network.

Local planning ensures that the integrity of T&D networks in terms of reliability and resilience are maintained whilst also decentralizing the energy generation, increasing penetration levels of DERs, and putting some control in the hands of consumers.[28]

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25 Henderson, I. M et al. Electric Power Grid Modernization Trends, Challenges and Opportunities. 2017. Pg. 5

26 2020 Black & Veatch Strategic Directions Electrical Report. Pg 11

27 https://www.tdworld.com/substations/article/20971018/national-grid-advances-digital-substations

28 Henderson, I. M et al. Electric Power Grid Modernization Trends, Challenges and Opportunities. 2017. Pg. 5

Exhibit 13 DER Adoption in the U.S.[29]

Federal and state policy makers have realized that local planning can more efficiently facilitate the integration of DERs. We understand that states, such as New York, are considering the adoption of enhanced local planning standards that will focus on the following principles[30]:

- *Open access:* Local planning is better suited to optimize the investment decisions of customers and third parties by identifying points on the grid where distributed resources have greatest value.
- *Reliability and Security:* Enhancements to local planning can ensure that reliability, physical security, and cybersecurity are maintained as the distribution grid changes.
- *Coordination:* Cost effectiveness is better met with local transmission and distribution plans informing and interacting with other utility planning practices, including integrated resource and capital budget plans.
- *Flexibility:* Local planning adapts faster to changing grid conditions and new technologies because they are closer to the emerging trends than the RTO/ISOs.
- *Inclusion:* Local transmission planning can better assess that all customers have opportunities to participate in grid modernization through tariffs and programs that compensate customers for the value of their distributed resources.

Even though these principles appear generic, they must be considered in a way that better apply to the local system and its stakeholders. This realization has created the need for an active discussion at the state level, where the familiarity of the local system and its complexities by the local planners can advance the enhancement of the current planning standards.

Lastly, FERC Order 2222's objective to enable DER wholesale market access continues the federal commitment for accelerated decentralization of generation. The effect of the Order on transmission planning hasn't been fully studied yet, but we expect changes to occur both in

29 The U.S. Energy Information Administration

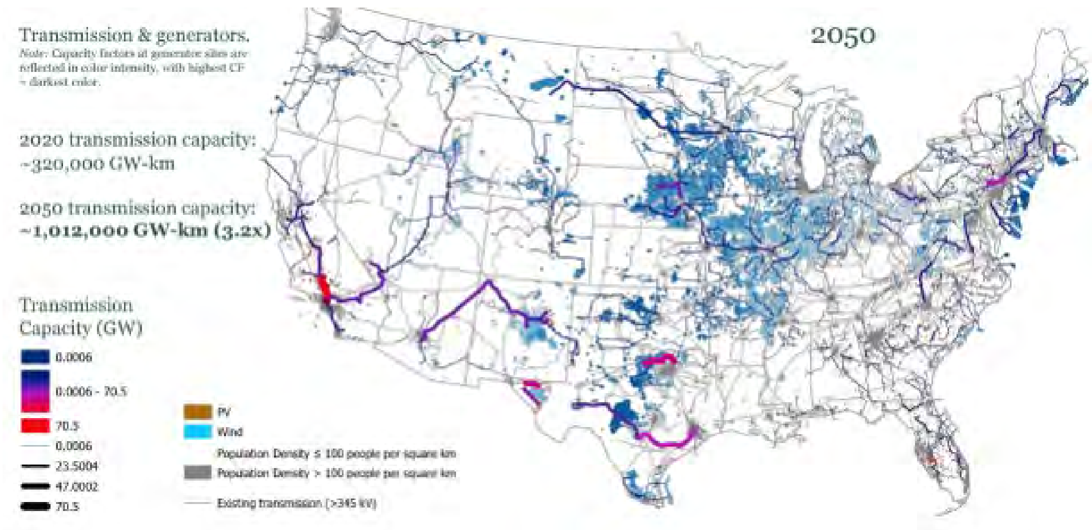
30 New York's CLCPA Transmission Policy Working Group

terms of interconnecting new assets and design and operation of the power grid. The proximity of local planning to these changes provides an advantage in the assessment of the required transmission solutions in an integrated manner with other aspects of planning like resource planning and distribution.[31]

5.3. Clean Energy Goals

The role of transmission in achieving clean energy goals is critical. The aggressive commitments to combat climate change and the growing cost-competitiveness of renewable resources have enabled the widespread adoption of clean energy goals by many U.S. states and the federal government. Notably, in January 2021, the Biden administration announced ambitious decarbonization plans that aim to reach 100% clean electricity by 2035 and net-zero emissions by 2050. Reaching these goals efficiently will require a doubling or tripling of the size and scale of the nation's transmission system. Exhibit 14 below highlights the investment need with over 1 million GW-km of incremental transmission capacity by 2050.

Exhibit 14 Required Transmission Capacity to Support Renewables by 2050[32]



Consequently, as more renewable resources are built, there are increasing demands on local transmission entities to expand their capacities to better accommodate new renewable generation facilities. Black & Veatch's 2020 Strategic Directions report highlights that transmission owning utilities and transmission organizations, particularly in the Mid-West and on the West coast, are facing increasing demand for interconnection requests, predominantly from utility scale renewable generators. There is also the expectation that the increased interest in offshore wind energy on the East Coast will lead to increased demand for local transmission expansion in this part of the country.[33]

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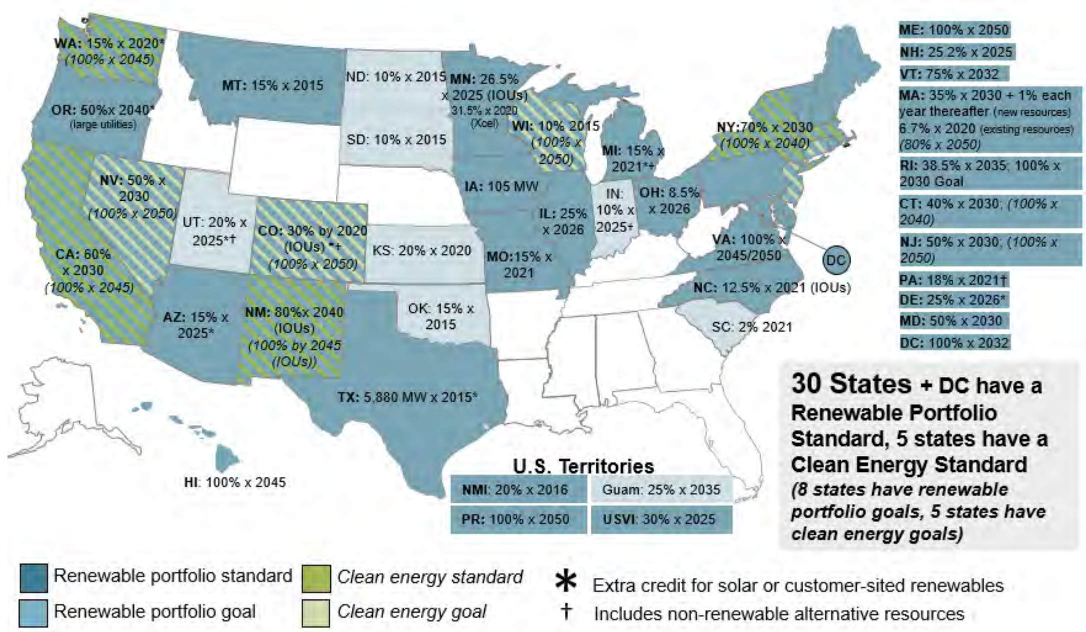
[31] CRA has been active in this area supporting various clients with conceptualizing and implementing an integrated resource, transmission, and distribution planning framework. https://www.crai.com/industries/energy/energy-advisory-and-strategy/grid-resource-planning/

[32] Larson et al. Net-Zero America. 2020. Pg. 137. https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf

[33] 2020 Black & Veatch Strategic Directions Electrical Report. Pg 11

Local transmission owners are at the forefront of planning for such demands on the T&D network as evidenced by increasing references in various utility Integrated Resource Plans (IRPs) on how they plan to expand their T&D networks. PacifiCorp, for instance, in their 2021 IRP, highlighted that they will embark on expanding their existing transmission network to enable new renewable resources they are bringing online to efficiently reach their customers.[34]

Exhibit 15 U.S. Renewable Portfolio and Clean Energy Standards by State[35]



One of the challenges that regional solutions are facing is the disparity between the clean energy goals and net-zero commitments between states. As depicted in Exhibit 15, the clean energy goals vary not only in terms of renewable targets but also in terms of compliance timelines. Large regional and inter-regional solutions are needed to support the integration of renewables, but buildout on the regional and inter-regional levels to accommodate clean energy goals necessitates more local projects, not fewer. Local transmission lines would be needed to accommodate increased renewable penetration and transmit power from the new/upgraded regional and inter-regional lines.

Local planning can improve the pathways for renewable generation to reach the regional transmission grid reducing local curtailments. This will enable more efficient regional and inter-regional transfer of renewable power even through states that have different goals than others. Local planning should be viewed as a ramp to a highway. A more efficient ramp enables a larger amount of renewable power to be integrated into the regional system

34 2021 Integrated Resource Plan. Pacific Corp. 2021. Pg. 9 https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

35 DSIRE. https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2020/09/RPS-CES-Sept2020.pdf

Primer on
Transmission Formula Rates

prepared for WIRES

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1 Executive summary

WIRES commissioned London Economics International LLC ("LEI") to prepare a primer that: (i) explores what transmission formula rates ("TFRs") are; (ii) describes how the Federal Energy Regulatory Commission (referred to interchangeably as "FERC" or "the Commission" throughout this primer) applies such rates; and (iii) assesses in an objective manner the positive ratemaking characteristics inherent in the use of TFRs for customers, regulators, transmission owners, and other industry stakeholders. This primer also provides a brief history of the inception and use of formula rates, as well as a high-level comparison of the use of the traditional stated rates approach and formula rates.

Under the TFR approach, after the utility files an initial application under the Federal Power Act ("FPA") Section 205, the Commission approves a formula for the utility to calculate its costs of service and derive its rates, and in subsequent years, the utility uses the approved formula and updated input data to calculate its new rates each year. The utility submits its annual updates and supporting documentation to the Commission on an informational basis only, and shares the updates with interested parties, who can review, verify, and challenge the inputs used in the calculations pursuant to approved protocols. In contrast, under the stated rates approach, the utility must file an application under FPA Section 205 each time it seeks to change its rates.

TFR use has become widespread across electric utilities under Commission jurisdiction, with recent estimates (as of November 2019) reporting approximately 106 utilities using TFRs, compared to only 31 utilities using transmission stated rates.[1] Based on LEI's analysis, transmission owners using TFRs have service territories encompassing every state in the continental United States.[2]

TFRs gained traction because of their characteristics that advance multiple ratemaking objectives and balance the interests of customers, regulators, transmission owners, and other stakeholders. These characteristics can broadly be grouped into three categories:

- **Transparency, oversight, and stakeholder engagement:** the annual update process provides a transparent, routine way for utilities to disclose and true-up the information and data underlying the resulting rates, while also providing multiple opportunities for significant stakeholder engagement (which can include stakeholder sessions, opportunities to submit information requests, and opportunities to raise informal and formal challenges) as well as Commission oversight (including audits of FERC Form No. 1 data and ensuring compliance with the formula rate and protocols).[3] This enables

[1] FERC. *Order No. 864.* November 21, 2019. P. 68-69. These numbers reflect only entities that are under Commission jurisdiction. Non-jurisdictional entities, such as many cooperatives and municipal power providers, are not included in these figures.

[2] Drawn from various sources, including tariffs filed with the Commission, utility service maps, and state regulators.

[3] Currently, the annual update process does not provide for all of these items in each transmission owners' TFR protocols. However, in recent years, the Commission has issued "show cause" orders seeking to align TFR protocols and requiring utilities to respond to deficiencies in the areas of: (i) the scope of participation; (ii) the

interested parties to gain a better understanding of rate calculations and the underlying inputs (costs). While meaningful participation in this process by both stakeholders and utilities requires a commitment of time, effort, and resources, with information requests and responses numbering in the hundreds and resource-intensive informal and formal challenges, the process ultimately provides a more transparent rate setting process, allowing parties to verify that the costs included in rates are reasonable and prudently incurred;

- **Timeliness of cost recovery:** the annual update process reduces the risk of rate shock (i.e., large step changes in rates) from prolonged periods between rate cases and also reduces regulatory lag, which improves the predictability of a utility's cash flows and reduces its financing costs[4] – an element of formula rates that ultimately flows through to customers in the form of lower rates. Finally, this timely cost recovery provides a supportive process for investment in transmission, which facilitates a variety of reliability, resiliency, and clean energy policy goals at the local, state, and national levels, ensuring customers receive more reliable and cleaner electric service; and

- **Reduced regulatory burden and enhanced administrative efficiency:** the avoidance of frequent and lengthy rate cases under the TFR approach leads to cost savings in terms of time, effort, and resources for all involved, including the utility, the Commission, and intervening parties – cost savings that are realized by customers.

LEI provides a high-level overview of TFRs in the context of ratemaking attributes in Figure 1 on the following page, assessed from the perspective of various stakeholder groups.

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transparency of the information exchange; and (iii) the ability to challenge the transmission owners' implementation of the formula rate as a result of the information exchange.

[4] Major credit rating agencies (Fitch, S&P, and Moody's) recognize the importance of timely cost recovery in their credit rating methodologies, acknowledging that the regulatory environment impacts the predictability of a utility's cash flows, which in turn impacts its financial stability and, ultimately, its credit rating. Countervailing Commission policies (e.g., open-ended refund obligations) diminishes rate certainty (and increasingly so, as the formula rate ages).

Figure 1. Overview of TFR characteristics from various stakeholder perspectives

Transparency, oversight, and stakeholder engagement

- **Customers**, **FERC**, and **industry stakeholders** have access to annual information filings on costs of service
- Regularly scheduled stakeholder engagement per protocols for **customers**, **industry stakeholders**, and **FERC**
- TFR protocols enable understanding of rate calculations and underlying inputs (costs) for **all parties**
- **Customers** protected by regulatory oversight, including audits under **FERC**

Timeliness of cost recovery

- Annual process means **customers** benefit from greater rate predictability and reduced risk of rate shock by avoiding prolonged periods between rate cases
- Annual true-up based on actual costs so that **customers** do not over-pay and **transmission owners** do not under-recover
- Reduced regulatory lag minimizes financing costs for **transmission owners** and flows through to **customers** through lower rates
- Facilitates transmission investments which enable reliable electric service for **customers**

Reduced regulatory burden and enhanced administrative efficiency

- Eliminates need for participation in lengthy, often litigated rate cases for **all parties**
- Lowers costs of proceedings for **all parties**, including time and resources dedicated to preparing, filing, litigating, and resolving rate cases; cost savings ultimately flow through to **customers**

Note: When referring to "customers", LEI includes transmission customers as well as their representatives, such as ratepayer advocates, state attorneys general, consumer trade associations, and transmission-dependent utilities (who may intervene in rate proceedings on behalf of their end-users). When referring to "industry stakeholders", LEI is referring to other potential stakeholders not covered under the "customer" or "transmission owner" categories, including state regulators, RTOs/ISOs, energy-related trade groups, and other interested parties.

2 Background on transmission formula rates

2.1 Overview

Electric transmission rates for interstate commerce are regulated by the Commission. Pursuant to the FPA,[5] the Commission is responsible for ensuring that electric transmission rates for interstate commerce are just, reasonable, and not unduly discriminatory or preferential.[6] Just and reasonable rates have been interpreted in North America to mean rates which provide an investor the opportunity to achieve a return consistent with that which could be received in an unregulated industry facing a similar level of risk, provided service expectations are met. Returns are not guaranteed, however. Not unduly discriminatory or preferential rates ensure that groups of customers with similar characteristics are treated in the same way.[7]

Electric utilities operating under Commission jurisdiction are generally permitted to set their transmission rates through one of two approaches – either through stated rates or TFRs. Figure 2 below lists the key features of both approaches. Notably, both approaches are meant to achieve just and reasonable and not unduly discriminatory or preferential rates.

Figure 2. Key features of stated rates versus transmission formula rates

Stated rates	Transmission formula rates
• Use historical or projected data to determine costs of service and resulting rates • Commission-approved rates are numerically fixed and stated as-is – rates are not updated as costs of service change, unless the utility files a new rate case	• Commission approves the formula – the utility inputs historical or projected data into the approved formula to calculate costs of service and resulting rates • Annual true-up mechanism reconciles projected data to actual revenues earned and costs incurred in the rate year • The utility enters input data into the approved formula each year to calculate new rates – the annual update is filed with the Commission on an informational basis and does not require submission of a new rate case • Interested parties can review, verify, and challenge the inputs used in calculations and the prudency of costs

[5] Codified in 16 U.S. Code § 824d.

[6] FERC. *Staff's Guidance on Formula Rate Updates.* July 17, 2014.

[7] FERC. *An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities.* June 2018.

Both approaches are designed to employ similar principles of cost-of-service ratemaking and accounting.[8] Rates are designed to fully recover the utility's costs of providing safe and reliable transmission service, along with a reasonable return on investment. The differences between the two approaches primarily relate to how and when transmission rates may be updated. Specifically, a utility under stated rates cannot change its rates unless it files a full Section 205 rate case with the Commission. In contrast, a utility under the TFR approach must update its rates each year using a Commission-approved formula and protocols[9] and prepare an annual informational filing; these updated rates do not require a full Section 205 rate case or a separate Commission order for approval.

Stated rates approach

The stated rates approach has been in use since the very early days of the regulated utility model. Under the stated rates approach, rates can only be updated through a Section 205 rate case filing with the Commission. As part of its rate application, the utility uses historical or projected data to calculate its transmission revenue requirement, allocate costs among its customers, and set its transmission rates.[10] If the Commission finds the proposed transmission rates to be just and reasonable, they are numerically fixed (or "stated") until the utility files its next rate application.

However, at any point, the Commission, on its own motion or that made by a party under Section 206 of the FPA, can allege that the stated rates are unjust and unreasonable, and order amendments.[11] More details on the stated rates approach are provided in Section 3.3.

Transmission formula rates approach

Formula rates were introduced by the Commission as early as the 1970s as an alternative to the traditional stated rates approach. Under the TFR approach, after a Section 205 application by the utility, the Commission approves the formula that a utility proposes to calculate its costs of service and determine its resulting transmission rates. Similar to the stated rates approach, the Commission on its own motion or that made by a party under Section 206 of the FPA, can allege that the formula itself is unjust and unreasonable, and order amendments. The formulaic approach consists of two key components: (i) templates outlining the rate calculation and underlying inputs; and (ii) protocols that set out procedures for stakeholder intervention.

Templates: The formula approved by the Commission defines the methodology and various inputs used to determine the utility's costs of service – the utility then enters updated input data

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[8] Key principles of regulated rate design, as put forth by Bonbright's primary criteria (see Section 4.2 for further details), are cost recovery (which enables utilities to recover from customers the costs of providing service) and cost causation (which dictates that rates that customers pay should reflect the costs that their usage imposes on the system); together, these two principles ensure efficient and fair rates.

[9] TFR protocols provide robust opportunities for stakeholder engagement and intervention – see Section 3.1.2 for further details.

[10] Federal Register. *Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes.* November 27, 2019.

[11] 16 U.S. Code § § 824e, 825e.

into the approved formula each year to calculate its new transmission rates.[12] Generally, the utility updates its rate base (i.e., net plant in-service plus adjustments), operation and maintenance ("O&M") expenses, income tax rate, and rates for taxes other than income taxes, and depreciation expenses each year. The return on equity ("ROE") is a fixed input to the revenue requirement and is determined in the initial Section 205 proceeding to establish the formula rate, or a separate[13] Commission proceeding.[14] Other inputs and data must either be sourced directly from the utility's annual FERC Form No. 1 filing, or be supported by additional information describing how the input was derived.[15] In the initial proceeding that establishes the TFR, the utility must choose to use either projected or historical data in setting its rates. For those utilities that use projected data in their TFR, an annual true-up mechanism reconciles estimated costs with actual costs, thus enabling full cost recovery for the utility and timely refunds to customers in the event of overcollections.[16] More details on the templates used under the TFR approach are provided in Section 3.1.1.

Protocols: Under the TFR approach, the utility is required to submit annual updates[17] and supporting documentation with the Commission on an informational basis, as well as share the filings with interested parties.[18] Through established protocols, interested parties can submit discovery and review, verify, and challenge these annual updates.[19] More details on the TFR protocols that guide stakeholder intervention procedures are provided in Section 3.1.2.

2.2 Process for transitioning from stated rates to TFRs

Commission-jurisdictional utilities have historically employed stated rates.[20] Over time, many utilities shifted to TFRs. To shift from a stated rate to a formula rate, the utility must first file an application with the Commission, pursuant to FPA Section 205 and Section 35.13 of the Commission's regulations.[21] Once the initial TFR application has been filed, stakeholders may file motions to intervene and protest with the Commission, pointing out where they believe the filing

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[12] Utilities operating under a calendar year rate do this twice a year – once as part of their true-up filing for the prior year (typically filed in June), and again for their annual update filing, which forecasts rates for the next rate year and includes the over- or under-collection from the true-up (typically filed in October). For examples, see Section 6.

[13] The ROE is either determined for the individual utility, or the RTO-wide ROE can be used.

[14] FERC. *Formula Rates in Electric Transmission Proceedings: Key Concepts and How to Participate.* July 5, 2022.

[15] FERC. *Staff's Guidance on Formula Rate Updates.* July 17, 2014.

[16] 123 FERC ¶ 61,098. Docket Nos. ER08-92-000 et al. April 29, 2008. Para. 16.

[17] As noted previously, utilities operating under a calendar year rate submit two filings per year – the true-up filing (typically filed in June) and the annual update filing (typically filed in October).

[18] 123 FERC ¶ 61,098. Docket Nos. ER08-92-000 et al. April 29, 2008. Para. 16.

[19] FERC. *Formula Rates in Electric Transmission Proceedings: Key Concepts and How to Participate.* July 5, 2022.

[20] Ibid.

[21] 18 Code of Federal Regulations § 35.13. This provision outlines the requirements for a rate filing at FERC.

is not just and reasonable and proposing modifications for the Commission to consider. The utility may also file motions to answer such protests.[22]

The Commission may then either: (i) accept the proposed formula and allow the calculated rates to enter into force; (ii) accept the proposed formula (and thus any transmission rates calculated using it) for filing, but suspend the TFR's implementation for up to five months and establish hearing and settlement proceedings, in order to allow for the resolution of issues between the utility and interested parties; or (iii) reject it.[23, 24] Once all issues have been resolved and the formula has been approved by the Commission, the utility updates input data for the approved formula each year to calculate its new transmission rates (and provides this annual update and supporting documentation to the Commission on an informational basis). Additionally, and unlike stated rates, customers and other interested parties have the opportunity to review and seek information on the implementation of the formula rates each year.

Under the TFR approach, the utility does not need to file a rate application with the Commission to update its annual transmission revenue requirement. In contrast, the stated rates approach requires utilities to file a new transmission rate application pursuant to Section 205 of the FPA every time it seeks to update its costs of service. However, similar to stated rates, if the utility wishes to amend the TFR itself (and not simply update its rates) the utility must file a Section 205 rate application.[25, 26]

2.3 Prevalence of TFRs across the US

Commission-regulated entities have used formula rates since at least the early 1970s.[27] Today, as recognized by the Commission, "*the vast majority of public utilities have transitioned from stated rates to formula rates.*"[28] According to the Commission, as of the latest count completed in November 2019, there were approximately 106 public utilities under Commission jurisdiction using TFRs,

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[22] As a technical matter, 18 Code of Federal Regulations 385.213(a)(2) prohibits any answers to protests. However, parties may still file motions to answer, which FERC may accept if they provide information that is helpful to the Commission. (Source: 165 FERC ¶ 61,194. Docket No. ER19-13-000. November 30, 2018.)

[23] For example, see FERC Docket Nos. ER19-13-000 and ER19-1816-000.

[24] Typically, the requested base ROE is a contentious item and is set for hearing and settlement judge procedures.

[25] For example, see FERC Docket No. ER20-3040-000.

[26] However, a utility's TFR protocols may specify certain exceptions, which would allow the utility to file a limited Section 205 filing in the event that it is seeking changes to certain items (e.g., amortization/depreciation rates, post-retirement benefits other than pensions ("PBOP") accruals, or extraordinary property losses), where the sole issue for examination is whether those limited changes to stated values are just and reasonable and shall not include other aspects of the formula.

[27] 42 FERC ¶ 61,307. Docket No. ER88-202-000. March 15, 1988. P. 9.

[28] Federal Register. *Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes.* November 27, 2019.

compared to only 31 utilities under Commission jurisdiction using transmission stated rates.[29] Based on LEI's analysis, transmission owners using TFRs have service territories encompassing every state in the continental United States.[30] TFRs are used across all of the Commission-jurisdictional regional transmission organizations ("RTOs") or independent system operators ("ISOs"), as described further in Appendix A (Section 6). In addition, major utilities outside of RTO/ISO regions use TFRs, such as Duke Energy Carolinas and Southern Company utilities (in the Southeast), Puget Sound Energy, PacifiCorp, Idaho Power Company (West), as well as Arizona Public Service Company and Public Service Company of New Mexico (Southwest), among others.

[29] FERC. *Order No. 864.* November 21, 2019. P. 68-69. These numbers reflect only entities that are under FERC jurisdiction. Non-jurisdictional entities, such as many cooperatives and municipal power providers, are not included in these figures.

[30] Drawn from various sources, including tariffs filed with FERC, utility service maps, and state regulators.

3 The mechanics of transmission formula rates and stated rates

The TFR approach differs from the stated rate approach in several key respects. This section first presents the mechanics of TFRs, including how TFR templates and protocols operate. We then apply this understanding to a high-level overview of the TFR process. Finally, we explore the stated rates process, which is the only alternative to formula rates and therefore critical for understanding the benefits and challenges of implementing TFRs, which we will focus on in Section 4.

3.1 Key components of the TFR approach

Under the TFR approach, the Commission approves the proposed formula as just and reasonable, rather than a specific fixed schedule of rates, recognizing that rates are a direct result of inputs (from agreed-upon sources). A TFR has two components:

- **templates**, which set forth the calculations and inputs used to determine a utility's revenue requirement and rates (see Section 3.1.1); and

- **protocols**, which set out the procedures for stakeholder intervention (see Section 3.1.2).[31]

The utility must follow the TFR template and protocols to calculate its updated revenue requirement and rates each year.[32] More details on how utilities with TFRs publish their updated rates each year are provided later in Section 3.2.

3.1.1 Templates

A TFR template is comprised of detailed worksheets in Excel format that outline step-by-step how the utility will perform its calculations and define the data sources to be used. The outputs of the template correspond to the utility's revenue requirement and associated transmission rates calculated pursuant to its Commission-approved formula.

As a first step, a TFR template calculates the utility's costs of providing transmission service, which generally includes the high-level elements shown in Figure 3 below.

The TFR template can either use historical data or projections.[33] A template using historical data relies on actual data from prior years. In contrast, projections are typically either determined using an incremental approach (which relies on historical data as a baseline and then attempts to

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[31] FERC. *Formula Rates in Electric Transmission Proceedings: Key Concepts and How to Participate.* July 5, 2022.

[32] Ibid.

[33] For an example of a TFR using projected data, see: PJM. *PJM Open Access Transmission Tariff – Attachment H-16*. For a TFR using historical data, see MISO's default formula rate template: MISO. *MISO Open Access Transmission Tariff – Attachment O.*

approximate how that data should change over the rate period)[34] or through internally generated values with supporting documentation. If a projected test year is used, rates are reconciled and subject to a true-up mechanism, wherein the amount of over- or under-collection is calculated once the actual costs of service for a rate year are known. This incremental amount is returned to or recovered from ratepayers, as required, in the next rate period.[35] True-up calculations are performed and published as part of the annual TFR process, as discussed further in Section 3.2 below.

Figure 3. Typical elements of a cost-of-service calculation

Source: Adapted from FERC.

The underlying data for the calculation elements shown in Figure 3 are typically drawn from FERC Form No. 1 or other utility sources.[36] FERC Form No. 1 is a report that electric utilities and other entities meeting certain thresholds (e.g., over 1,000,000 MWh of total sales in a year) must file with the Commission each year. FERC Form No. 1 includes financial and operational data[37] and is based on the Uniform System of Accounts ("USofA", 18 Code of Federal Regulations Part 101). The USofA provides detailed instructions on how Commission-jurisdictional public utilities and other entities must record financial information, allowing for consistent reporting and accounting. Some utilities also draw their TFR templates from generic templates, as in the MISO region; this enables a relatively standardized approach to review and oversight on the part of interested parties.

If a utility wishes to use data in its TFR template that is not explicitly listed in its FERC Form No. 1 filing, then the utility must "*support [the data] with sufficient narrative description of the steps taken and calculations performed to derive the input*" along with "*workpapers detailing the derivation of such formula input.*"[38] This means that, ideally, all inputs can be verified and cross-checked by interested parties.

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[34] For example, PG&E in California projects a portion of its revenue requirement by forecasting additions to its transmission infrastructure (known as "transmission plant") and then multiplying the incremental amount by an Annual Fixed Charge Rate ("AFCR"). The AFCR represents the additional cost that each incremental increase in transmission plant is expected to generate, and is calculated by dividing the prior year's value of transmission plant by the same year's actual revenue requirement. (Sources: PG&E. *Offer of Global Settlement. Attachment C – Revised Model – Unpopulated.* Docket Nos. ER19-13-000 et al.; PG&E. *Exhibit PGE-0004 – Formula Transmission Revenue Requirement and Wholesale Rates.* Docket No. ER19-13-000. September 13, 2018.)

[35] 123 FERC ¶ 61,098. Docket Nos. ER08-92-000, et al. April 29, 2008. P. 6-7.

[36] FERC. *Staff's Guidance on Formula Rate Updates.* July 17, 2014. P. 1-2.

[37] FERC. *Form No. 1 – Annual Report of Major Electric Utility.* June 20, 2020.

[38] FERC. *Staff's Guidance on Formula Rate Updates.* July 17, 2014. P. 1-2.

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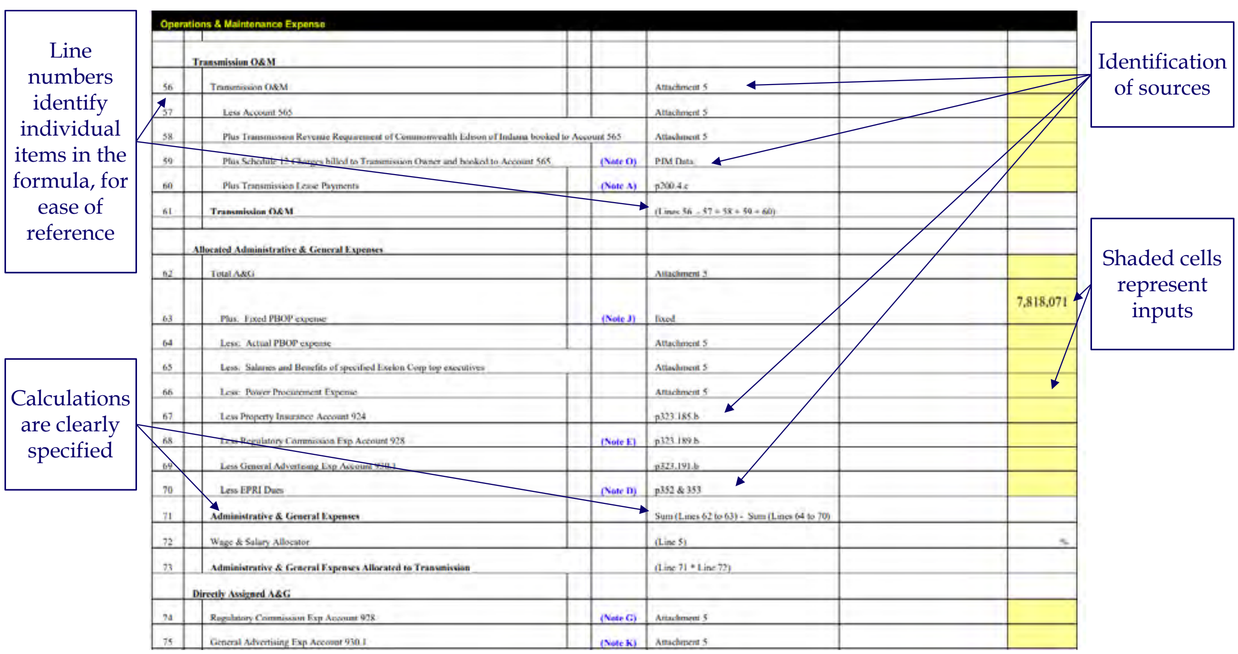
Each year, based on the timelines specified in the TFR protocols (to be discussed later in Section 3.1.2), the utility populates its Commission-approved formula rate using updated data from FERC Form No. 1 and other sources, as applicable. The updated rate must be posted to a public domain and permits interested parties to review. The purpose of this review is typically three-fold: (i) to ensure that the utility has used appropriate input data; (ii) to ensure that the utility has properly applied the approved formula in calculating its revenue requirement and resulting transmission rates; and (iii) to review whether the costs included in rates are reasonable and prudently incurred. If the input data is properly sourced, and calculations are correctly performed, the Commission presumes the resulting rates to be just and reasonable.[39] Figure 4 below shows an example of a TFR template worksheet filed with the Commission as part of PJM's OATT, along with annotations highlighting important components of the sample worksheet.

Figure 4. Annotated example of a TFR template worksheet



Note: The worksheet above is just one part of a larger TFR template.

Source: PJM. *PJM Open Access Transmission Tariff – Attachment H-13A*. February 1, 2022.

In addition to the posting referenced above, updated rate calculations must be submitted with the Commission on an informational basis, which allows Commission Staff to perform their own review of the utility's calculations. As part of these annual updates, Commission Staff have instructed utilities to provide populated TFR templates as well as any source workpapers. Utilities are required to submit these files in their native format (Excel) with formulas preserved. This measure, among others, was directed by Commission Staff to alleviate past issues that "*have impeded the ability to review the annual updates and verify that the resulting rates have been developed*

[39] FERC. *Formula Rates in Electric Transmission Proceedings: Key Concepts and How to Participate.* July 5, 2022.

consistent with the requirements of the filed rate (i.e., the formula rate)."[40] The process for preparing these annual updates is discussed in more detail in Section 3.2 below.

3.1.2 Protocols

The TFR protocols, which are a component of the filed rate, set forth the terms of stakeholder discovery, review, interaction with the transmission owners, and oversight of the annual process for updating transmission rates under the TFR approach.[41] The protocols set out the timelines and procedures through which interested parties can review the utility's TFR template calculations, ask for more information, and, if necessary, raise challenges.

TFR protocols typically cover the following elements:

- **definitions** of key terms, such as "Interested Party," which is the designation for entities that have the right to review and challenge a utility's calculations under its TFR template;

- provisions for calculating the **revenue requirement** each year (and **true-up** for utilities operating under a forward-looking TFR), including how the calculations will be performed, how and when the **informational updates** with results will be posted (in both draft and final form), how and when notice of publication will be provided, the contents of the annual update, provisions for any meetings convened by the utility to discuss the filings, and requirements for filing annual updates with the Commission;

- procedures for **information exchange**, including rules as to which interested parties can submit information requests, the deadlines for submitting these requests, specifications regarding which aspects of a TFR filing the requests can address, the utility's duties in responding to the same, and any requirements for providing details of requests publicly;

- procedures for filing **informal and formal challenges** to an annual update, including filing deadlines, the information that must be provided as part of a challenge, procedures for responding to a challenge on the part of the utility, and steps to follow if the issue(s) cannot be resolved;

- procedures for **making corrections to annual updates**, including how such corrections will apply to current and future rate years; and

- other **legal issues**, such as the procedure for challenging and/or modifying the formula itself, how information provided through information requests may and may not be used, and more.

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[40] FERC. *Staff's Guidance on Formula Rate Updates.* July 17, 2014.

[41] As FERC has stated, "*formula rate protocols … play an important role in ensuring just and reasonable rates.*" *See* 178 FERC ¶ 61,207. Docket No. EL22-27-000. March 24, 2022.

A formal challenge cannot be used to contest the TFR itself;[42] rather a formal challenge under the TFR protocols can only be used to contest the way in which the TFR is being implemented. If an interested party wishes to challenge the utility's TFR protocols (or TFR template) as unjust and/or unreasonable, it must file a complaint pursuant to FPA Section 206.[43] Over the past decade, the Commission has also issued "show cause" orders, requiring utilities to respond to certain deficiencies in their protocols that the Commission has identified. The Commission has done so on its own initiative, initiating investigations pursuant to FPA Section 206 (16 US Code § 824e).[44]

The Commission established its current policy regarding TFR protocols through a series of orders issued to the MISO transmission owners, beginning in 2012.[45] In those orders, the Commission provided a set of criteria to apply when evaluating TFR protocols, which include the following:

- **stakeholder participation:** TFR protocols must allow all interested parties to participate in information exchange and review processes, including but not limited to customers under the TFR, state attorneys general, consumer advocacy groups, and state utility regulatory commissioners;[46]

- **information dissemination:** transmission owners must post/publish their annual revenue requirement updates and associated information in various ways (including online) and hold an annual meeting open to interested parties to review the underlying calculations. These annual updates must provide "*information about the … implementation of the formula rate in sufficient detail and with sufficient explanation to demonstrate that each input to the formula rate is consistent with the requirement of the formula rate*";[47]

- **accounting and organizational changes:** transmission owners must disclose any accounting changes that occurred during the rate period that affect the underlying inputs or transmission rates, including explaining the effects of any mergers or reorganizations;[48]

- **prudency:** interested parties must be able to obtain information regarding the utility's cost control methodologies and procurement practices, to assess whether costs were prudently incurred;[49]

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42 FERC has rejected formal challenges that have attempted to do so. For example, see 156 FERC ¶ 61,209. Docket No. ER16-1169-000. September 22, 2016. In this decision, FERC rejected a formal challenge partly because it took issue with the TFR itself.

43 FERC. *Formula Rates in Electric Transmission Proceedings: Key Concepts and How to Participate.* July 5, 2022.

44 FPA Section 206 gives FERC the right to find that rates filed with it, including TFR protocols, are "*unjust, unreasonable, unduly discriminatory or preferential*" and to determine how they must be changed to remedy the issue.

45 178 FERC ¶ 61,207. Docket No. EL22-27-000. March 24, 2022. P. 3-4.

46 143 FERC ¶ 61,149. Docket No. EL12-35-000. May 16, 2013. P. 15.

47 Ibid. P. 34-35.

48 Ibid. P. 35-36.

49 Ibid. P. 37.

- **information requests:** TFR protocols must specify the period during which interested parties can review information and ask for further relevant information and documentation. TFR protocols must also include a requirement that the utility respond to such information requests in good faith and within a reasonable amount of time;[50]

- **annual information filings:** transmission owners must prepare and submit annual information filings with the Commission, with contents sufficient to verify the accuracy of the underlying data and calculations and their consistency with the filed TFR. The same requirements apply to the information that transmission owners must provide to interested parties during the review period;[51] and

- **challenge procedure:** TFR protocols must provide a pathway for interested parties to raise an **informal** challenge on proposed inputs and calculations, usually directly with the utility.[52] TFR protocols must also allow interested parties to raise a **formal** challenge directly with the Commission if the dispute is not resolved through an informal challenge; in a formal challenge, the utility bears the burden to show that its TFR implementation is just and reasonable.[53] The Commission makes determinations based on the record and may, for example, require changes to accounting, disallow costs, or require refunds.

3.2 TFR process overview

The initial process for establishing a TFR was described previously in Section 2.2. Rate calculations for the first year of the TFR are typically filed alongside the utility's initial application with the Commission. Once a TFR rate case is resolved, either through a Commission order or a Commission-approved settlement, a utility's first-year rates go into effect on the effective date specified in the initial application. In subsequent years under the TFR approach, the utility calculates its new rates each year using the Commission-approved formula and, if operating under a forward-looking TFR, performs true-up calculations on an annual basis. We describe the main stages of the annual update process in the subsections below (see Figure 5 for a high-level summary).

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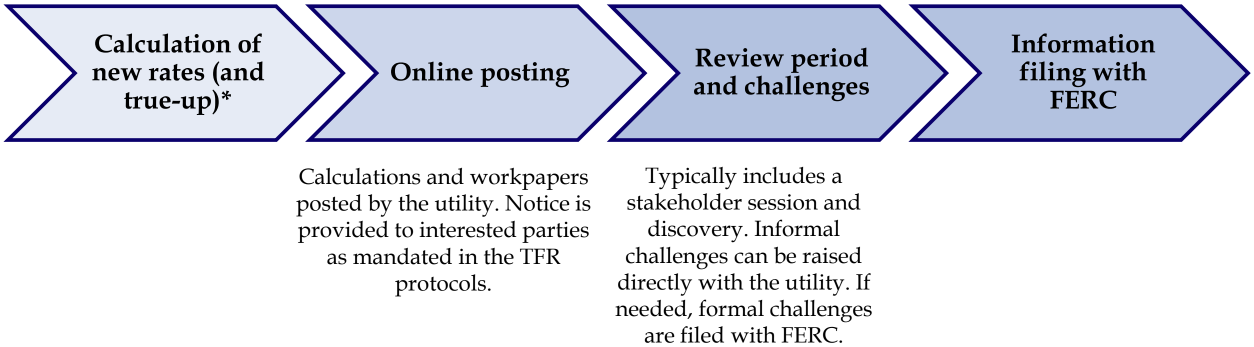
[50] Ibid. P. 37-38.

[51] Ibid. P. 38.

[52] Ibid. P. 50.

[53] Ibid. P. 50-51.

Figure 5. Key stages of the annual update process



* A true-up mechanism only applies to utilities employing a forward-looking TFR.

3.2.1 Calculation of new rates (and true-up)

Each year under the TFR approach, a utility must perform calculations to determine: (i) its new transmission rates; and (ii) if the utility is operating under a forward-looking TFR, its annual true-up for the prior rate year.

The utility's new transmission rates are calculated each year by populating its TFR template with either historical data or projections. For utilities employing a forward-looking TFR, the annual true-up is calculated by comparing the projected revenue requirement for the prior rate year against the actual revenue requirement. The interest on such over- or under-collections is determined according to Commission regulations. Adding the interest to the base excess or shortfall amount yields the total annual true-up. This true-up amount is added to the revenue requirement for the next rate period used to set rates.

3.2.2 Online posting

The new transmission rates and/or true-up calculation (for utilities employing a forward-looking TFR) must be posted on the utility's website and/or the website of its RTO by a certain deadline, usually around the middle of the year. This posting must include detailed information as to how the utility calculated its new transmission rates and/or annual true-up, including workpapers in their native format (Excel) with all formulas and links intact, supporting documentation, and anything else that an interested party would need to independently verify the calculations. The utility must also notify certain interested parties of the posting, including its customers, the applicable state utility regulatory commissions, and others. This posting triggers the review period.

3.2.3 Review period and challenges

Once the revenue requirement and/or annual true-up calculations (for utilities employing a forward-looking TFR) and associated materials have been posted, the review period begins.

The utility typically convenes a meeting with interested parties to discuss and provide an overview and walk-through of the calculations.[54] At this time, interested parties also have an opportunity to provide feedback and ask any clarifying questions. The revenue requirement and/or annual true-up calculations may be discussed in the same session, or two separate meetings may be convened.

Pursuant to the protocols, interested parties may begin submitting information requests during a specified period of time about the data used and/or the calculations performed. Information requests must be focused on certain topics, as outlined in Section 3.1.2 above. The utility must make a good faith effort to respond to information requests within a certain number of days, as outlined in its TFR protocols (e.g., 10 to 15 business days).

Also pursuant to the protocols, interested parties have a right to raise informal challenges with the utility after the review period is over. An informal challenge permits an interested party to raise its concerns directly with the utility (without Commission involvement) and requires the utility to respond within a certain time period (e.g., 20 business days). Depending on the conditions in the TFR protocols, the utility may also appoint a company representative to liaise with the interested party raising the challenge to resolve it.

If the utility and the interested party are unable to resolve the issue(s) raised through the informal challenge, then the interested party may file a formal challenge with the Commission by the prescribed deadline.[55] Formal challenges typically have prescribed information that must be included, such as the precise violations of the TFR template or protocols that an interested party claims the utility has committed, as well as the interested party's best efforts to quantify any financial impact to it as a result of the violation. During the Commission proceeding, the utility bears the responsibility to demonstrate that it has correctly applied the TFR template and protocols.

Informal and formal challenges are generally limited to the topics outlined in Section 3.1.2 above. An interested party may not attempt to challenge the TFR itself through an informal or formal challenge, because the Commission has already approved the TFR through the initial Section 205 application establishing the TFR. Furthermore, any changes to an annual update because of an informal or formal challenge are likely to be applied as components in the following year's true-up calculation – although they may still be applied to the current annual update provided that the issue is resolved early enough, either by Commission order or by an agreement between the interested party and the utility.

[54] As per FERC's order after its MISO investigation. (Source: 143 FERC ¶ 61,149. Docket No. EL12-35-000. May 16, 2013. P. 34.)

[55] However, these deadlines can be extended, which may lead to discovery and challenge obligations from one rate year spilling over and overlapping with the next rate year.

3.2.4 Information filing with the Commission

The annual information update is submitted to the Commission by a certain date, as specified in the utility's TFR protocols. The number of filings made with the Commission each year differs by utility:

- for utilities that use **historical data** to populate their TFR templates, they submit one annual update filing to the Commission which does not include a true-up;
- for utilities that use **partially projected data** to populate their TFR templates, they submit one annual informational filing to the Commission, which includes the annual update and a true-up; and
- for utilities that use **fully projected data** to populate their TFR templates, they typically submit two filings to the Commission each year – a true-up filing (typically submitted in June), and an annual update filing (typically submitted in October) that rolls in the most recent true-up over- or under-collection.[56]

The annual information update specifies the utility's revenue requirement and transmission rates for the next rate-setting period[57] and details the underlying calculations.[58] Importantly, the annual information update is not a full rate case filing, as would be required to update rates under the stated rates approach – rather, it is a formal statement of the rates that have been calculated using the approved formula for the next year.[59] Unless the Commission delays enactment of the calculated rates, these automatically go into effect at the start of the next rate year (e.g., January 1st for utilities on calendar-year cycles).

3.3 Stated rates approach

Under the stated rates approach, the utility files a rate application through which it proposes its revenue requirement and resulting rates – the application is subject to Commission approval, and if approved, the transmission rates go into effect and cannot be changed unless the utility files a new rate application.

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56 However, in MISO, both the annual update and true-up calculations are submitted together in one filing in March.

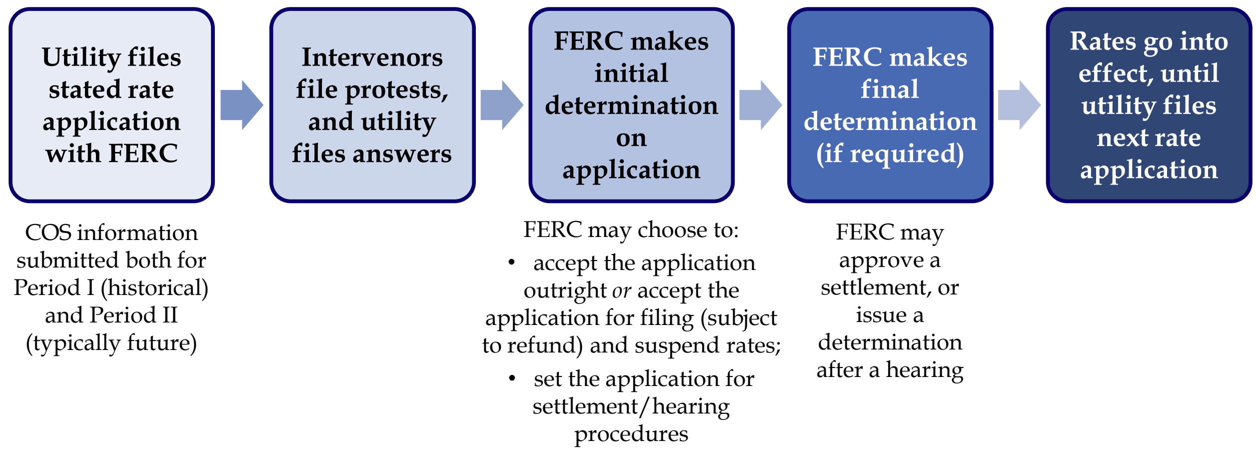
57 However, in MISO, while the annual information filing is submitted in March, the rates at that point have already been in effect since June of the prior year (for utilities using historical data) or January (for utilities using projected data).

58 These calculations may be modified pursuant to an informal or formal challenge that is resolved after the information update is submitted (see Section 3.2.3 for further details). However, the modifications are typically applied in the following year's true-up calculation.

59 As an example, PG&E in its last stated rates case (TO19, filed with the Commission on July 27th, 2017) submitted a rate application consisting of a transmittal letter and 37 exhibits totaling 2,881 pages. In contrast, PG&E's most recent draft annual update under the TFR approach (posted on its website on June 15th, 2022) consisted of a summary document and a PDF version of its TFR template totaling 50 pages, alongside an Excel version of its TFR template and a set of 20 workpapers (mostly in Excel format). *See* FERC Docket No. ER17-2154-000 and PG&E. *Draft Annual Update: Transmission Owner Tariff Rate Year 2023.* June 15, 2022, respectively.

3.3.1 Process overview

Figure 6. Stated rates case process



To establish or update a stated rate, a utility must file an application with the Commission pursuant to FPA Section 205.[60] The application sets out how the utility has calculated its costs of service and derived its proposed transmission rates. Costs of transmission service include the expenses to construct, maintain, and operate a utility's transmission assets, plus a return on investment to a utility's shareholders and debtholders that accounts for the risk of their investment.[61]

Title 18, Section 35.13 of the Code of Federal Regulations outlines 38 separate "statements" that a utility must submit alongside its rate application, including income statements, and allocation demand and capability data, among others.[62] Most of these statements must be prepared for two periods: Period I, i.e., "*the most recent twelve consecutive months, or the most recent calendar year, for which actual data are available*"; and Period II, i.e., "*any period of twelve consecutive months after the end of Period I that begins*" sometime between the nine months prior to, and the three months following, the effective date of a rate change. Given that Period II typically pertains to a future period, the utility must develop forecasts of its anticipated costs and electricity sales.[63] The Period II data is generally the test year for the rate application.[64]

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[60] 16 U.S. Code § 824d. 18.

[61] FERC. *Formula Rates in Electric Transmission Proceedings: Key Concepts and How to Participate.* July 5, 2022.

[62] These requirements apply to TFR applications as well. However, depending on the details of either the TFR or stated rates application, some statements may not need to be filed. For example, *Statement BI – Fuel cost adjustment factors*, need only be submitted if the rate filing "embodies a fuel cost adjustment clause." (Source: 18 Code of Federal Regulations § 35.13.h(34).) Furthermore, a utility may request that FERC waive filing requirements, as appropriate.

[63] PG&E. *Exhibit PGE-001 – Formula Rate Overview and Policy.* Docket No. ER19-13-000. September 24, 2018.

[64] 18 Code of Federal Regulations 35.13(d)(4).

The procedural steps once an application for stated rates has been filed with the Commission are similar to the steps for a TFR application, described previously in Section 2.2.

If a utility's application involves a rate decrease, or if a rate decrease is possible due to changes that occur during the proceeding, then an investigation under FPA Section 206 may be required.[65] Intervenors may ask the Commission to initiate such an investigation, or the Commission may do so on its own initiative. The point of such an investigation would be to safeguard customer interests if an even greater rate reduction is warranted.[66]

Once the rate case concludes, either through a Commission final decision or Commission-approved settlement, and the approved rates go into effect, a utility cannot update its rates without starting the rate filing process over again.

3.3.2 Ratemaking characteristics of stated rates

A defining feature of the stated rates approach is that rates do not change until a utility files another rate case. This provides customers with stability in their transmission rates, and the utility with relatively stable revenues. Particularly for a utility that does not experience significant changes in the various components of its costs of service year over year – including its assets and operating expenses – stated rates may be sufficient to meet its revenue requirement over extended periods of time. Under the stated rates approach, the utility does not prepare annual updates.

However, there are several challenges associated with the stated rates approach. As the Commission has observed, this approach involves "*typically lengthy, expensive proceedings … and requires[s] discovery of evidence and expert testimony – like a court trial*"[67] every time a utility needs to change its rates to reflect updated costs of service. Indeed frequent rate cases may be necessary for a utility whose costs of service demonstrate consistent growth; for example, before switching to the TFR approach, PG&E, a California utility, had to file full stated rate cases with the Commission nearly every year to ensure that its rates reflected its growing costs of service (for further background on PG&E's historical situation, please see Appendix B, Section 7).[68] The use of projections also raises the potential for under- or over-recovery of costs from ratepayers, due to discrepancies between forecast data and actual costs and sales data. As a result, stated rate cases can lead to drawn-out disputes between the utility, Commission staff, and other interested parties, thus increasing the costs associated with litigation and/or settlement negotiations.[69]

Finally, because stated rates are not updated automatically as costs of service change, prolonged periods of time between rate cases may lead to rate shock – i.e., significant and abrupt increases

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65 16 U.S. Code § 824e. This legislation grants FERC the authority to find that a rate is "*unjust, unreasonable, unduly discriminatory or preferential*" and to "*determine the just and reasonable rate … to be thereafter observed and in force.*"

66 156 FERC ¶ 61,238. Docket No. ER16-2320-000. September 30, 2016. P. 12-13; Transcript of the March 30, 2017 prehearing conference held in Washington, DC re the Pacific Gas & Electric Company under ER16-2320. P. 35.

67 FERC. *Formula Rates in Electric Transmission Proceedings: Key Concepts and How to Participate.* July 5, 2022.

68 Ibid. P. 4.

69 PG&E. *Exhibit PGE-001 – Formula Rate Overview and Policy.* Docket No. ER19-13-000. September 24, 2018. P. 3-4.

in transmission rates. For example, in a recent stated rate application filed by Portland General Electric Company (in FERC Docket No. ER22-233-000), the utility proposed a 355% increase in its annual transmission revenue requirement, after around 20 years had elapsed since its previous rate case.[70]

[70] Portland General Electric. *Rate Case Filing Letter*. FERC Docket No. ER22-233-000. October 28, 2021.

4 Ratemaking characteristics of transmission formula rates

There are many characteristics inherent in the use of TFRs that advance ratemaking objectives. These attributes lead to a ratemaking structure that balances multiple objectives and stakeholder interests that is ultimately beneficial to customers, the Commission, transmission owners, and other industry stakeholders involved in transmission rate proceedings (including interveners such as state regulators, RTOs/ISOs, and trade groups). These characteristics can be grouped into three key categories, which are discussed in turn below:

- transparency, oversight, and stakeholder engagement (see Section 4.1);
- timeliness of cost recovery (see Section 4.2); and
- reduced regulatory burden and enhanced administrative efficiency (see Section 4.3).

4.1 Transparency, oversight, and stakeholder engagement

Utilities have an obligation to appropriately charge their cost of service in compliance with Commission regulation and policy. The resulting rates under the TFR reflect this objective. In addition to the obligations held by utilities to properly calculate annual rates, under the TFR approach, review mechanisms in place serve as "safeguards" to ensure the rates calculated and charged under the TFR approach are just and reasonable. The safeguard mechanisms include:

- the **TFR protocols**, which ensure transparency in the ratemaking process and enable robust opportunities for stakeholder engagement on an annual basis (which can include stakeholder sessions, opportunities to submit information requests, and opportunities to raise informal and formal challenges). Formal challenges filed as a result of this process provide the Commission an opportunity to review and weigh issues raised and challenged by interested parties. In addition, the Commission can initiate FPA Section 206 proceedings to revise the formula rates and customers can also submit Section 206 complaints if they believe the templates have become unjust and unreasonable; and
- the **Commission's audit process**, which involves an inspection of FERC Form No. 1 data and a review and confirmation that the annual updates comply with the formula rate and protocols.

We discuss each of these mechanisms in turn below.

4.1.1 TFR protocols: facilitating transparency and stakeholder engagement

As described by Commission Staff in a 2014 guidance document on the annual update process under the TFR approach, "*[t]he Commission recognizes that the integrity and transparency of formula rates and their implementation are critically important in ensuring just and reasonable rates. Therefore, the Commission's policy is that utilities include safeguards in their transmission formula rate protocols to provide transparency in the utilities' implementation of their transmission formula rates, to ensure that the input data is the correct data and that calculations are performed consistent with the formula. Among these safeguards is a requirement for utilities to share the annual updates to their transmission rates determined* *pursuant to their formulas, with appropriate support, with all interested parties and to file such annual updates with the Commission on an informational basis.”*[71]

As discussed previously in Section 3.1.2, protocols are an important component of the TFR approach, and establish the procedures through which interested parties may review TFR template calculations, file information requests, and if necessary, raise challenges. As a result, TFR protocols enhance transparency by enabling interested parties to gain a better understanding of rate calculations and the underlying inputs (costs). Ultimately, a more transparent rate setting process benefits and protects customers, as it allows parties to verify that the costs included in rates are reasonable and have been prudently incurred.

TFR protocols also provide ample opportunities for stakeholder engagement and intervention on a regular basis (i.e., every year). Specifically, interested parties can get involved in the TFR process at the following stages of the review period (see Section 3.2.3 for further details):

- during **stakeholder sessions**, where the utility convenes meetings to discuss and walk-through the revenue requirement update and/or the annual true-up calculation;

- by submitting **information requests**, which can, among other topics (see Section 3.1.2 for a complete list), request documentation or information on the prudency of a utility’s actual costs and expenditures, request details on the recording and accounting of specific costs, or request evidence of the accuracy of certain data inputs and calculations; and/or

- by either raising **informal challenges** directly with the utility (without Commission involvement), or if the utility and the interested party are unable to resolve the issues among themselves, raising a **formal challenge** with the Commission, where the Commission directly weighs in on the issues.

The robust information exchange process and challenge provisions allow interested parties to review and assess on an annual basis whether the proposed rates are just and reasonable.

While TFR protocols importantly enable transparency in the rate setting process, they require both stakeholders and utilities to dedicate sufficient – and often significant – time, effort, and resources to ensure meaningful participation. While it is appropriate for utilities to address these issues and dedicate time and resources to the process, it can also be particularly taxing for utilities that face substantial and increasing intervenor involvement each year. For example, through a review of recent annual update processes, LEI has found TOs that have received hundreds of data requests from interested parties as well as dozens of preliminary challenges on a single annual update.

To further inform the discussion, LEI conducted a survey of transmission owners who are under TFRs.[72] LEI asked about the annual discovery process. Nearly half of the respondents reported typically receiving over 100 information requests during the annual review period, some with

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[71] FERC. *Staff’s Guidance on Formula Rate Updates.* July 17, 2014. PDF P. 3.

[72] The survey was distributed in October 2022. LEI received responses from 20 transmission owners.

multiple subparts or several rounds of follow-up. Several transmission owners responding to the survey also documented how the extent of discovery has evolved over time; all experienced an increase in the number of information requests received year over year. Indeed, in recent years, the number of information requests for those transmission owners increased by 29% per year on average. The relative volume of information requests each year shows that the TFR itself and the protocol processes are working to provide customers and regulators with timely information on costs, opportunities for customers to seek detailed data on costs, and for transmission owners to explain the basis of the costs incurred. Importantly, the extent of discovery requests has in some instances required transmission owners to agree to an extension of deadlines to avoid cutting off the flow of information to interested parties.[73] However, this impacts the efficiency of the TFR process, at times resulting in rate cycles melding, negating the benefits of a TFR process intended to provide smooth updating of rates on a regular basis, avoiding the lag or rate shock associated with stated rates.

4.1.2 The role of Commission audits in the context of TFRs

TFRs are subject to the Commission's oversight rules and requirements, including through established protocols which enable stakeholders to verify and challenge annual updates (described above), as well as through audits of FERC Form No. 1 data. Commission Staff within the Division of Audits and Accounting ("DAA") are responsible for reviewing FERC Form No. 1 data and ensuring compliance with the formula rate and protocols.

The FERC Form No. 1 data also has an additional layer of review and oversight from the requirement to submit a CPA Certification Statement within 30 days after filing the FERC Form No. 1. The CPA Certification Statement must attest to the conformity, in all material aspects, of the listed schedules and pages with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and be signed by an independent certified public accountant or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision.

In FY2022, the Commission's DAA "*participated in 79 rate proceedings that continued to predominately involve electric formula rate proceedings.*" Specifically, the DAA's formula rates audit branch is focused on ensuring "*compliance with the Commission's accounting and FERC Form No. 1 ... requirements for costs that are included in formula rate recovery mechanisms used to determine billings to wholesale customers.*" Among other responsibilities, the DAA audits seek to "*prevent the recovery of costs that should have been excluded from the formula rate*."

In recent years, DAA has focused on several areas that include:[74]

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[73] Many transmission owners also noted that a substantial portion of information requests are submitted close to or at the deadline, which can place a significant strain on utility resources when trying to ensure timely responses within the annual cycle.

[74] FERC. *2022 Staff Report on Enforcement (FERC Docket No. AD07-13-016).* November 17, 2022.

- understating revenue credits;
- incorrectly recording income tax overpayments for which utilities have elected to receive a refund;
- improper adjustments of accumulated deferred income taxes balances, leading to overstated rate base;
- improper accounting of internal merger costs;
- including asset retirement obligation amounts without explicit Commission approval;
- including amortized regulatory assets without explicit Commission approval;
- improper accounting of administrative and general expenses; and
- including electric vehicle charging stations as part of general plant, even though they serve a distribution function.

If audits identify areas of noncompliance and overcollections from ratepayers, utilities may be directed to issue refunds. For example, as noted in the *2022 Report on Enforcement* prepared by staff from FERC's Office of Enforcement, the DAA completed two formula rate audits in FY2022. Together, the FY2022 TFR audits identified 64 recommendations that required corrective action by the two utilities, and both utilities were required to issue refunds to customers.[75]

LEI surveyed transmission owners on their experiences with TFR audits. More than half of the survey respondents reported having undergone a formula rate audit in the last five years. With only one exception, these audits resulted in determinations that required the utility to issue retroactive refunds, sometimes going back many years. The risk of retroactive refunds as a result of these audits can be substantial and material, and may be based on the auditors' judgment and interpretations of accounting guidance. Although utilities have a right to contest audit determinations, the recourse is limited and infrequently exercised. As such, this aspect of TFR audits may undermine some of the intended goals of the TFR approach, such as stability and rate certainty.

4.2 Timeliness of cost recovery

TFRs support timely recovery of the costs of providing safe and reliable transmission service from customers, consistent with Bonbright's principles of effective regulation and ratemaking. Professor James C. Bonbright published his seminal work, *Principles of Public Utility Rates*, in 1961 and through it, established several frequently cited principles for effective rate design. We introduce here what Bonbright refers to as the "three primary criteria" of a sound rate structure for a regulated utility – these three fundamental ratemaking objectives are:

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[75] Ibid.

1. **recovery of the revenue requirement:** ultimately, rates should be effective in "*yielding total revenue requirements under the fair-return standard*";[76]

2. **fair or equitable apportionment of costs among customers:** this objective "*invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service*";[77] and

3. **efficiency:** whereby rates should be designed to "*discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received.*"[78]

Consistent with criterion (1) above, TFRs ensure timeliness of cost recovery through the annual update process and true-up mechanism. The true-up mechanism (which applies to utilities operating under a forward-looking TFR) reconciles estimated costs with actual costs of service once they are known, and ensures customers are not over-paying (by issuing refunds in the event of over-collections) and utilities are not under-recovering, ultimately ensuring that transmission rates accurately track changes in the costs of service. As noted by one observer, "*if the formula is properly designed, it helps ensure that the utility's rates do not become too high or too low as costs and loads change over time, protecting buyer and seller alike,*" adding that *"[i]f a utility is planning any significant transmission build-out, the formula rate is the most advantageous ratemaking tool available."*[79] Importantly, the annual update process and true-up mechanism also adjusts rates to account for changes in actual system usage, providing a mechanism through which transmission owners operating under TFRs are protected from under-recovery (if volumes decrease) and customers are protected from over-paying (if volumes increase).[80]

In addition, the annual update process under the TFR approach ensures that costs of service are up to date and reflected in transmission rates, thus reducing regulatory lag (or the time between when a utility's costs of service increase and when it is allowed to raise its rates). Regulatory lag is undesirable as it negatively affects full cost recovery – as rates are less than what they should be – thus negatively impacting the utility's financial health and possibly leading to increased customer costs (as credit risk, discussed below, will translate into higher borrowing costs for the utility).

Major credit rating agencies (Fitch, S&P, and Moody's) recognize the importance of timely cost recovery in their credit rating methodologies and commentary, acknowledging that the regulatory environment impacts the predictability of a utility's cash flows, which in turn impacts a utility's financial stability and, ultimately, its credit rating. For example, Moody's credit rating methodology for the "*Regulated Electric and Gas Networks*" sector (which includes companies that

[76] Bonbright, James C. *Principles of Public Utility Rates.* 1961 (Reprinted in 2005). P. 291 (PDF P. 155).

[77] Ibid. P. 292 (PDF P. 156).

[78] Ibid. P. 292 (PDF P. 156).

[79] Public Utilities Fortnightly. *FERC Formula Rate Resurgence: Transmission Cost Recovery Revisited.* July 2020.

[80] In contrast, under the stated rates approach, a utility would have to file a new FPA Section 205 application in order to change the billable units (volumes) underpinning its rates.

are "*primarily engaged in the transmission or distribution of electricity or natural gas or both*") uses a scorecard approach, where the "*Cost and Investment Recovery (Ability and Timeliness)*" sub-factor accounts for 15% of the overall score. As noted by Moody, "*[t]he ability to recover prudently incurred costs in a timely manner is extremely important because a delay in cost recovery may cause financial stress. Therefore, the predictability and supportiveness of the regulatory framework in which a network operates, as well as the legal and political framework that underpins it, are key credit considerations.*"[81]

According to Moody's methodology, a regulated transmission utility would earn a credit rating of Aaa if, on the "*Cost and Investment Recovery*" sub-factor, it is found to operate in an environment where there is "*[n]o regulatory or contractual impediment to adjust tariffs (no approval or reviews required).*"[82] The range of credit ratings for this "*Cost and Investment Recovery*" sub-factor are listed in Figure 7 on the following page. Higher credit ratings result in reduced financing costs, which ultimately flows through to customers in the form of lower rates. A strong credit rating also adds value to customers in the form of reliable electric service, as reduced financing costs enable utilities to make necessary investments in the transmission system at a lower effective cost.[83]

In fact, this positive characteristic (i.e., more timely cost recovery reducing the cost of doing business for utilities, thus aiding with financing and capital investment) was raised by a utility in its TFR application as one of the reasons why it was seeking to shift away from the stated rates approach. The utility, El Paso Electric Company ("EPE") noted: "*EPE must maintain its ability to access capital at all times to plan, construct, maintain, and operate its transmission system. To do so at reasonable cost, EPE needs to demonstrate solid capital structure ratios, predictable and stable cash flows, and a competitive and reasonable rate of return, among other factors. A formula rate will promote financial stability, enhance predictable and stable cash flows, and support [its] debt coverage and repayment, thereby enhancing EPE's ability to access credit on reasonable terms, which is favorable to both EPE and its customers.*"[84]

The annual update process in TFRs also reduces the risk of rate shock for customers (i.e., large step changes in rates) from prolonged periods between rate cases. Furthermore, because these annual updates offer utilities more timely cost recovery, there is a supportive process for utilities to invest in transmission. A stronger transmission system in turn supports a variety of reliability, resiliency, and clean energy policy goals at the local, state, and national levels, which ultimately benefits customers who are receiving cleaner and reliable electric service.

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[81] Moody's Investors Service. *Rating Methodology: Regulated Electric and Gas Networks.* April 13, 2022. P. 9.

[82] Ibid. P. 4.

[83] These investments can support service during normal operating conditions, as well as exceptional operating conditions, such as during extreme weather events.

[84] EPE. *Exhibit EPE-0002: Transmission Investment, Prepared Direct Testimony of James A. Schichtl (FERC Docket No. ER22-282-000).* October 29, 2021. P. 5-6 of 6.

Figure 7. Moody's scorecard on the "Cost and Investment Recovery" sub-factor

Credit rating	*Cost and Investment Recovery (Ability and Timeliness)* criteria
Aaa	No regulatory or contractual impediment to adjust tariffs (no approval or reviews required).
Aa	Tariff formula is expected to allow for timely recovery of operating expenditure including depreciation, electricity losses and balancing costs/shrinkage gas and a fair return on all investment. All capital expenditure is included in asset base as incurred. Unanticipated expenditure quickly reflected in allowed revenue with low, if any, efficiency assessment.
A	Tariff formula is expected to allow for recovery of operating expenditure including depreciation based on allowances set at frequent price reviews (5-yearly intervals or shorter) and a fair return on all efficient investment. Capital expenditure is included in asset base as incurred. Opex and capex subject to efficiency tests; electricity losses and balancing costs/shrinkage gas subject to efficiency test on volumes only (price is a pass through). Unanticipated expenditure generally quickly reflected in allowed revenue although this may not be until the following regulatory period and may be subject to a degree of regulatory scrutiny or sharing factor with customers. Performance is likely to be in line with regulatory expectations.
Baa	Tariff formula is expected to allow for recovery of operating expenditure including depreciation and return on investment but subject to retrospective regulatory approval or infrequent price reviews (> 5-yearly intervals); recovery of electricity losses and balancing costs/shrinkage gas is somewhat exposed to price. Some instances of revenue backloading expected (e.g. depreciation allowance set below asset consumption or operating expenditure is capitalized). Unanticipated expenditure slow to be reflected in allowed revenue or may be subject to a stringent efficiency assessment / low sharing factor. Performance may be below regulatory expectations.
Ba	Tariff formula is not expected to take into account all cost components and depreciation is set below asset consumption; recovery of electricity losses and balancing costs/shrinkage gas has large exposure to price. Revenues expected to cover most operating expenditure but investment is not clearly or fairly remunerated. Overspend either not recognized in allowed revenue or there is high uncertainty about its future recognition. Operational underperformance likely to be significantly impacting the returns achieved by the business.
B	Tariff formula is not expected to take into account all cost components and depreciation is set below asset consumption; recovery of electricity losses and balancing costs/shrinkage gas is fully exposed to price. Revenues expected to cover cash operating expenditure.
Caa	Revenues expected to only partially cover cash operating costs.

Source: Moody's Investors Service. *Rating Methodology: Regulated Electric and Gas Networks.* April 13, 2022.

4.3 Reduced regulatory burden and enhanced administrative efficiency

As discussed previously in Section 3.3, the regulatory process under the stated rates approach entails an extensive FPA Section 205 filing each time a utility wishes to update its rates, which among other things, requires the preparation and submission of a complete rate application, to be accompanied by 38 separate "statements", and often involves litigation. As recognized by the Commission, these full rate cases "*are typically lengthy, expensive proceedings overseen by an administrative law judge and require discovery of evidence and expert testimony – like a court trial*" and therefore "*[a] formula rate reduces the expense and burden for FERC and the utility to update transmission rates.*"[85]

The improved administrative efficiency achieved by requiring less burdensome regulation under the TFR approach through avoidance of frequent, lengthy rate cases ultimately leads to cost savings in terms of time, effort, and resources. These cost savings are realized for all parties involved, including the Commission, the utility, and intervening parties, and ultimately customers.

[85] FERC. *Formula Rates in Electric Transmission Proceedings: Key Concepts and How to Participate.* July 5, 2022.

5 Concluding remarks and recommendations

Overall, and as discussed throughout this primer, TFRs have characteristics that advance ratemaking objectives of transparency and oversight, timeliness of cost recovery, as well as reduced regulatory burden and enhanced administrative efficiency (particularly when compared to full, lengthy stated rate cases). These attributes result in benefits that flow through to customers, the Commission, transmission owners, and other industry stakeholders involved in transmission rate proceedings.

Having provided an extensive background on formula rates and associated processes, we close by acknowledging several criticisms of TFRs and placing them in the context of this factual framework. We also identify potential areas for improvement to the Commission's formula rate policy based on our observations and research.

Criticisms regarding TFRs suggest that:

(i) the formulaic nature of the annual update process "*put[s] ratemaking on autopilot*";[86]

(ii) avoiding full rate cases "*shrink[s] stakeholder input*";[87]

(iii) the reduced regulatory lag decreases the utility's incentive for efficiency;[88] and

(iv) there is "*[n]o meaningful opportunity to review [the] reasonableness of costs*."[89]

These criticisms are largely addressed through TFR protocols. To point (i), while the annual update process involves a relatively routine procedure of inputting data into the FERC-approved formula each year to calculate updated rates, these annual updates are not only subject to review, verification, and challenge by interested parties, but are also subject to Commission oversight through FERC's audit process.[90]

To point (ii), while full rate cases are indeed avoided under the TFR approach, the annual update process provides ample opportunities for stakeholder intervention. Interested parties can review and verify a utility's input data and calculations at various points in the review period, including during stakeholder sessions (where the utility convenes meetings to discuss and walk-through the annual update and associated calculations), by submitting information requests, and by raising concerns and issues through informal challenges directly with the utility (without Commission involvement), or through formal challenges with FERC (if the utility and interested party cannot resolve the issues among themselves).

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[86] Public Utilities Fortnightly. *FERC Formula Rate Resurgence: Transmission Cost Recovery Revisited.* July 2020. PDF P. 2.

[87] Ibid.

[88] USAID and NARUC. *Ratemaking's Impact on Investment Levels.* September 9, 2014. P. 8.

[89] Ibid.

[90] *See for example* FERC. *Staff's Guidance on Formula Rate Updates.* July 17, 2014.

Finally, to points (iii) and (iv), TFR protocols specifically allow interested parties to submit information requests and raise challenges to verify whether a utility's costs and expenditures were prudently incurred.

However, these criticisms highlight areas for improvement of the TFR process, specifically as it relates to educating stakeholders and enhancing transparency.

First, it is clear that **some stakeholders are not aware of the opportunity they have to review** the templates and information filing and informally or formally challenge. This could be addressed through increased efforts by transmission owners and the Commission to expand awareness of available data and processes.

Second, as demonstrated through the various "show cause" orders issued by the Commission over the past decade,[91] which require utilities to respond to certain deficiencies identified by the Commission, **TFR protocols do not always adhere to the Commission's current criteria**, specifically in the areas of: (i) the scope of participation; (ii) the transparency of the information exchange; and (iii) the ability to challenge the transmission owners' implementation of the formula rate as a result of the information exchange.[92] While further show cause orders may ensure that the protocols of more utilities operating under the TFR approach come into alignment with the Commission's current criteria, it does suggest that some utilities may be operating under TFR protocols that enable fewer opportunities for stakeholder intervention than others.

Third, in compiling data on the prevalence of TFR use across the country, it became clear that **a publicly available, comprehensive list of all FERC-jurisdictional utilities that use TFRs versus stated rates does not exist**. This type of resource could aid interested parties in understanding how their transmission rates are formulated and could help to identify where the opportunities for intervention lie.

Finally, based on a survey of transmission owners, LEI learned that there are **challenges in TFR administration that sometimes increase, rather than reduce, the regulatory burden and regulatory risks**. This has consequences not only for utilities, but also for customers and other interested parties. Information requests submitted during the annual review process have become more voluminous over time, and sometimes have resulted in a situation where rates are not finalized timely. It would be beneficial for the Commission to consider ways to refine the annual review and audit process to streamline and eliminate unnecessary administrative burdens. For example, to ensure utilities are able to respond to information requests adequately and within the timeframes established under their TFR protocols, interested parties should look to submit any common requests collectively and sufficiently ahead of deadlines. This would reduce instances of duplicate information requests and improve compliance with deadlines, which would ultimately enhance the efficiency of the stakeholder intervention process.

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[91] Such as the series of orders issued to the MISO transmission owners beginning in 2012, or the more recent series of orders issued to SPP in July 2022.

[92] 139 FERC ¶ 61,127. Docket No. EL12-35-000. May 17, 2012. P. 5.

6 Appendix A: Comparing TFRs across RTOs/ISOs

TFRs are used by transmission owning entities that are members of the six FERC-jurisdictional RTOs/ISOs:

- **California ISO ("CAISO")**: in the CAISO region, all three of the large investor-owned utilities ("IOUs") use formula rates – Pacific Gas and Electric Co. ("PG&E"), Southern California Edison Co. ("SCE"), and San Diego Gas & Electric Co. ("SDG&E"). PG&E transitioned to formula rates most recently in 2019;[93]

- **ISO New England ("ISO-NE"):** in the ISO-NE region, there are separate TFRs for regional and local network service. All active transmission owners listed under the ISO-NE Open Access Transmission Tariff ("OATT") use TFRs to calculate their local network service rates, while regional network service has a separate TFR, which aggregates revenue requirements from all the involved transmission owners for facilities used in providing regional network services;[94]

- **Midcontinent ISO ("MISO")**: all but one of the transmission owners in the MISO region employ formula rates;[95]

- **New York ISO ("NYISO"):** among the incumbent transmission owners in the state, only one operates under a TFR – Niagara Mohawk Power Corporation, a subsidiary of National Grid. Aside from the incumbent transmission owners, LS Power Grid New York Corporation, New York Transco LLC, NextEra Energy Transmission New York, Inc., and the Power Authority of the State of New York (or NYPA), and the Long Island Power Authority ("LIPA") also employ TFRs for projects that resulted from Order 1000 competitive procurements;[96]

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[93] 165 FERC ¶ 61,194. Docket No. ER19-13-000. November 30, 2018.

[94] Based on ISO New England's OATT as of July 28, 2022, particularly Schedule 21 and Attachment F. (Source: FERC eTariff).

[95] LEI compared the entities listed as a transmission owner under the MISO "Stakeholder Groups" webpage against the entities listed under the "Formula Rate Protocols" webpage. Michigan South Central Power Agency is the only entity to appear on the former list, but not on the latter. Based on this, LEI concluded that Michigan South Central Power Agency does not use TFRs. (Sources: MISO. *MISO Region Engagement*. Undated; MISO. *Transmission Owner Rate Data*. Undated.)

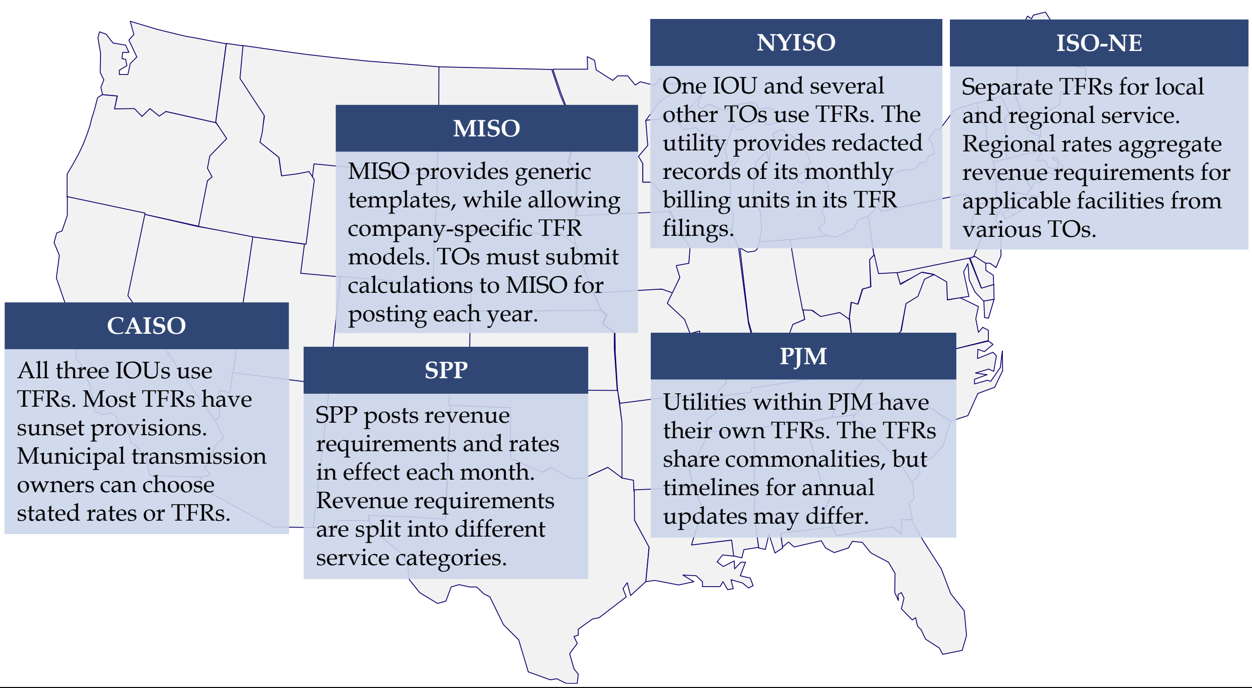
[96] NYISO OATT, Section 14, Attachment H.

- **PJM Interconnection LLC ("PJM")**: over 85% of transmission owners in PJM, including both incumbent utilities and merchant operators, use TFRs to calculate their annual transmission revenue requirements and related rates;[97, 98] and

- **Southwest Power Pool ("SPP")**: over 87% of transmission owners in SPP, including investor-owned utilities, municipal utilities, cooperatives, and non-incumbent transmission developers, use TFRs to calculate their zonal annual transmission revenue requirements ("ATRRs") and related rates.[99]

The differences in the application of TFRs across RTOs/ISOs broadly relate to how and when transmission rates are updated. Figure 8 lists notable features in each region at a high level, with more details presented below the figure. While there may be further differences between utilities within each RTO/ISO region, that is beyond the scope of this primer and therefore the description below focuses on a comparison at the RTO/ISO level.

Figure 8. Summary of high-level TFR distinctions across RTOs/ISOs



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97 Based on PJM's most recent OATT. (Source: PJM. *PJM Open Access Transmission Tariff – Attachment H*. February 1, 2022.)

98 Among 35 transmission owners in PJM, only five employ stated rates: (i) Allegheny Electric Cooperative, Inc., (ii) Essential Power Rock Springs, LLC, (iii) Ohio Valley Electric Corporation, (iv) Rockland Electric Company, and (v) Southern Maryland Electric Cooperative, Inc. (Source: PJM. *2022 Informational Filing (Docket No. ER19-2105-000 and -001).* December 8, 2021.)

99 Based on Attachment H of SPP's OATT, effective June 6, 2022. (Source: FERC eTariff.)

6.1 CAISO

In the CAISO region, most formula rates have sunset provisions, requiring utilities to file a new formula (or a stated rate) after three to six years. The steps for the three main IOUs (PG&E, SCE, and SDG&E) to update their base transmission revenue requirements are the same. Similar to the procedure outlined in Section 3.2, the first step involves posting a draft annual update, which sets forth the base transmission revenue requirement for the upcoming rate year and is accompanied by populated versions of all schedules comprising the formula rate. This is then followed by information requests, a draft annual update conference, and finalized annual update filings. The annual update includes the true-up calculation. The timelines for these steps, however, vary for each utility. For example, the posting date of the draft annual update is June 15th for SCE, but July 1st for SDG&E. The last day to submit information requests is October 15th for PG&E, but October 31st for SDG&E.[100]

Municipal transmission owners, serving cities such as Anaheim, Azusa, Banning, Colton, and Pasadena, are participating transmission owners ("PTOs") in CAISO. As such, they file their transmission tariffs with FERC, as well as their transmission revenue requirements. The Commission approves the revenue requirements and gross load predictions, but each municipal utility's governing body develops its own retail rates.[101] Each entity selects (on its own accord) whether to use a stated rates or a formula rate approach for its revenue requirement approved by FERC.

6.2 ISO-NE

In the ISO-NE region**,** service rates are divided into local service and regional service, both of which are calculated using TFRs. Regional service uses pool transmission facilities ("PTFs") while local service uses non-PTFs.[102] For local service, each transmission owner individually calculates its rates based on its TFR filed in the ISO-NE OATT. For regional service, there is one formula under which all regional network service revenue requirements are calculated. Each transmission owner submits its calculations to ISO-NE, and ISO-NE aggregates them to reach the total annual transmission revenue requirement.[103] ISO-NE's protocols state that the annual update and the

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100 Based on SCE, SDG&E and PG&E's OATTs, respectively.

101 California ISO. *How Transmission Cost Recovery Through the Transmission Access Charge Works Today*. April 12, 2017. P. 10.

102 PTFs are facilities at and over 69 kV (pre-2004), or at and over 115 kV (2004 and later), over which ISO-NE has operating authority under the terms of the applicable Transmission Operating Agreement. These facilities are used to provide regional network service, moving electricity out of or through the New England Balancing Authority Area. Regionalized costs associated with PTFs are apportioned to each New England region, based on the region's proportion of electricity demand. (Sources: ISO New England. *New England Control Area Transmission Services and ISO-NE Open Access Transmission Tariff General Business Practices -- Section 1: Overview of Transmission Services offered under the ISO-NE Open Access Transmission Tariff*. June 15, 2022; ISO New England. *Transmission Service Types*. Undated; ISO New England. *Transmission Cost Allocation.* Undated.)

103 ISO-NE. *Rate Development of Regional Transmission Charges*. 2022/2023 OATT Schedule 1 & 9 Rate Development Worksheets and Supporting Documents. June 15, 2022.

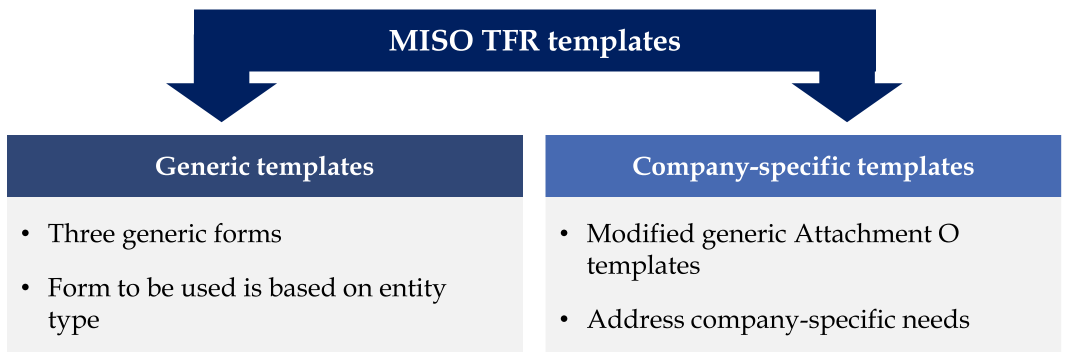
draft informational filings shall identify all system planning costs included in operating expenses by project.[104]

6.3 MISO

In the MISO region, there are two types of TFR templates included in the MISO OATT Attachment O: (i) generic templates, and (ii) company-specific templates.[105] Figure 9 provides a high-level overview of the two. The generic templates use historical data. In addition to a template based on FERC Form No. 1 data, there are two additional templates for use by cooperatives and municipal utilities. A company-specific template is a modified template that is created by a transmission owner to address its specific needs.[106]

Each transmission owner completes the appropriate formula rate template, and is responsible for providing MISO with its completed template for posting.[107] MISO will review the transmission owner's submission to ensure it complies with tariff requirements and may request further information, if necessary.[108]

Figure 9. Overview of MISO TFR templates



Source: Adapted from MISO.

6.4 NYISO

In the NYISO region, the only incumbent transmission owner with a TFR is Niagara Mohawk Power Corporation, a subsidiary of National Grid. Niagara Mohawk calculates and updates its annual transmission revenue requirement, scheduling system control and dispatch costs ("Component CCC"), and annual billing units ("Component BU") using its TFR. Except for forecasted data, the cost information used in the TFR is pulled from Niagara Mohawk's annual FERC Form No. 1 filing, its official books or record, or its annual report to the New York State

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104 ISO-NE. *OATT Att. F - Appendix C, Formula Rate Protocols (1.0.0)*. January 27, 2021.

105 Attachment O is the mechanism used by transmission owners to annually report their transmission revenue requirements to MISO.

106 MISO. *Level 100 – Transmission Pricing: Attachment O*. P. 9.

107 Ibid. P. 10.

108 Ibid. P. 16.

Public Service Commission.[109] Niagara Mohawk recalculates its annual revenue requirement and Components CCC and BU on or before June 14th of each year.[110] As part of the supporting documentation for these calculations, Niagara Mohawk provides monthly records of its billing units for the most recent concluded calendar billing year. The names and reference numbers for the entities listed in the documents are redacted to preserve confidentiality.[111]

Aside from Niagara Mohawk, LS Power Grid New York Corporation, New York Transco LLC, NextEra Energy Transmission New York, Inc., the Power Authority of the State of New York (or NYPA), and the Long Island Power Authority ("LIPA") also employ TFRs.

6.5 PJM

Each utility within PJM has its own TFR template and protocols, which may differ in terms of specific details but share some commonalities. One distinction to be noted is the procedural timeline. Some utilities have been migrating to a calendar year rate year, which involves two filing deadlines – (i) the true-up filing for the prior year, which is typically submitted in June; and (ii) the annual update filing, which is typically filed in October and forecasts the rates for the next rate year and rolls in the over- or under-recovery from the true-up filed in June. For example, AEP East Companies are required to provide their true-up calculations for the prior rate year on or before May 25th of each year, while the projections for the next rate year must be provided by October 31st.[112]

6.6 SPP

Similar to MISO, SPP has both general requirements for administering TFRs and separate TFRs in the OATT for individual transmission owners. In addition, SPP posts on a monthly basis a series of spreadsheets detailing the revenue requirements and rates in effect for that month, known as its "Revenue Requirements and Rates" ("RRR") files.[113] These files include data for utilities that use TFRs as well as those on stated rates – although over 87% of the transmission owners in SPP use formula rates to calculate their zonal ATRR.[114] Similar to ISO-NE's approach of separating facilities and service charges into different service components, an SPP utility's

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109 NYISO. *14.1 OATT Attachment H - § 14.9.1.* November 1, 2021.

110 NYISO. *14.1 OATT Attachment H - § 14.9.1.4.* November 1, 2021.

111 Ibid.

112 AEP East Operating Companies are Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company. (Source: PJM. *OATT Attachment H-14A.* January 1, 2017.)

113 See the SPP Documents page, "*Governing (Tariff, Bylaws, Articles, Criteria, Membership/Seams Agreements, Market Protocols, Business Practices)*" folder, "*RRR for Billing Documents and Link to TO Formula Rate Postings*" subfolder. While the SPP spreadsheet is updated on a monthly basis, the revenue requirements and rates do not necessarily change month-to-month.

114 LEI calculations based on Attachment H of SPP's OATT, effective June 6, 2022. (Source: FERC eTariff.)

transmission revenue requirement is subdivided into different categories, including Network Integration Transmission Service[115] and Base Plan Upgrade charges.[116]

[115] Network Integration Transmission Service is an open access provision under the SPP tariff, pursuant to which a transmission owner delivers capacity and energy from generation to load for other parties "*on a basis that is comparable to the Transmission Owner(s') use of the Transmission System to reliably serve*" its own load. (Source: SPP. *OATT Section 28.3.* July 26, 2010.)

[116] Base Plan Upgrades are "*upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the Transmission System.*" SPP utilities that must recover Base Plan Upgrade costs calculate ATRRs for these facilities, and then derive rates to be recovered per zone and regionwide. (Sources: SPP. *OATT Section 1 – Definitions B.* June 1, 2022; SPP. *OATT Schedule 11.* July 1, 2018.)

7 Appendix B: Case studies related to transitioning from stated rates to TFRs

We present below two case study examples of utilities that have recently sought to transition from stated rates to TFRs:

- Pacific Gas and Electric Company ("PG&E"), who submitted its TFR application on October 1st, 2018, which was finalized via settlement and approved by FERC on December 30th, 2020; and

- El Paso Electric Company ("EPE"), who submitted its TFR application on October 29th, 2021, and is currently undergoing settlement procedures.

These examples highlight the theoretical case for TFRs from the perspective of utilities (as well as the benefits that are expected to flow through to other stakeholders), while also representing two extreme ends of the stated rates approach. On the one hand, PG&E utilized the stated rates approach for around 21 years before seeking to transition to the TFR approach (with its first stated rate case filing in 1997), and during that time submitted 19 rate cases with FERC, equating to almost one stated rate case filed each year. In contrast, EPE utilized the stated rates approach for around 24 years before seeking to transition to the TFR approach, but only submitted the one rate case during that time.

7.1 Pacific Gas and Electric Company

PG&E is one of three IOUs operating in California, owning an extensive electric transmission and distribution system that extends across northern and central California. PG&E submitted its TFR application on October 1st, 2018 (in FERC Docket No. ER19-13-000), after having used the stated rates approach for its previous 19 transmission tariff proceedings (dating as far back as 1997).[117] PG&E sought to move away from the stated rates approach for the following reasons.

PG&E argued the TFR approach is "*consistent with Commission precedent and policy*", citing to previous FERC decisions, such as a 2008 case involving Niagara Mohawk in New York (in FERC Docket No. ER08-552).[118] There, the Commission stated that it "*[agrees] ... that having a formula cost recovery system in place should eliminate the need for frequent rate adjustment filings, ensure that rates reflect the actual cost of providing transmission service, and incent needed transmission investment. The Commission has found that the use of formula rates encourages the construction and timely placement into service of needed transmission infrastructure and has approved the use of formula rates by a number of transmission-owning utilities.*"[119]

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[117] PG&E. *Exhibit PGE-0001: Formula Rate Overview and Policy, Prepared Testimony of Lanette Kozlowski (FERC Docket No. ER19-13-000).* October 1, 2018.

[118] PG&E. *Transmittal Letter (FERC Docket No. ER19-13-000).* October 1, 2018. P. 1.

[119] Ibid. P. 2.

PG&E also highlighted that under the stated rates approach, it forecasted all elements of its base transmission revenue requirement for a future test year, which often led to protracted proceedings due to disagreements with FERC Staff and intervenors regarding the underlying assumptions, thus impacting the pace of negotiations and at times resulting in litigation. As such, PG&E argued the TFR approach "*mitigates concerns about cost and sales forecasts being different than actuals because formula rates provide a mechanism for truing up rates based on actual cost and sales information*" and similarly ensures that "*customers ... pay actual costs*", while also providing "*more predictability as inputs to the formula rate are made in accordance to the approved formula rate protocols, which will be in effect for the duration of the formula rate.*"[120]

Furthermore, PG&E argued that the TFR approach would "*reduce parties' litigation costs compared to the typical annual "stated" rate case filing*", by avoiding the need to "*[expend] significant resources evaluating PG&E's filing and participating in settlement and/or litigation processes.*"[121] PG&E noted it faced a significant cost – in terms of time, effort, and resources – to compile and file each stated rates case, due to extensive submission requirements (including testimony and the need to file around 35 separate "statements"). Recognizing that TFR filings still involve stakeholder review, PG&E contended "*it expects that over time the Formula Rate will involve less resources and effort by all concerned.*"[122]

FERC accepted PG&E's TFR filing on November 30th, 2018, and established hearing and settlement judge procedures. PG&E submitted a partial settlement to FERC resolving certain TFR template and protocol issues on March 31st, 2020 (approved by FERC on August 17th, 2020), and later filed an unopposed settlement with FERC resolving all outstanding issues on October 15th, 2020 (approved by FERC on December 30th, 2020).[123]

7.2 El Paso Electric Company

El Paso Electric Company is a vertically integrated electric utility serving approximately 446,000 retail customers across southern New Mexico and west Texas. EPE's service territory extends across a roughly 10,000 square mile area.[124]

EPE submitted its TFR application on October 29th, 2021 (in FERC Docket No. ER22-282-000), after its stated rates had not been updated since they were first established through a "black-box" settlement approved by the Commission on June 10th, 1998.[125] Given this significant lag between rate cases, EPE found that its outdated stated rates "*fail to recover [it's] costs of providing*

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120 Ibid. P. 2.

121 Ibid. P. 2.

122 Ibid. P. 2.

123 PG&E. *Summary Description of the Draft Annual Update for the Rate Year 2023.* June 15, 2022.

124 EPE. *Transmittal Letter (FERC Docket No. ER22-282-000).* October 29, 2021.

125 EPE. *Exhibit EPE-0001: Overview and Transmission Service Provided, Prepared Direct Testimony of David C. Hawkins (FERC Docket No. ER22-282-000).* October 29, 2021.

transmission service."[126] As noted in its application "*at the time EPE last filed rates for transmission service with the Commission in the mid-1990s, EPE's total transmission plant account balance was $238,822,547, and that balance has since grown to $572,495,263*" – a nearly 140% increase.[127]

Given this context, EPE argued that moving to a "*forward-looking formula rate will enable EPE to recover its capital investments in the system on a timely basis*"[128] and "*thereby avoid the regulatory lag associated with preparing, filing, litigating and resolving individual section 205 stated rate proceedings, which can be extensive and costly in both resources and time. Through a formula rate, EPE's transmission rates will more accurately and timely reflect the actual costs EPE incurs to provide transmission service.*"[129]

EPE cited other benefits of the TFR approach as reasons for the requested transition. Specifically, EPE argued that "*aligning EPE's transmission rates with its costs through an updated and projected formula rate tends to reduce "rate shock" or sudden jumps in rates that can occur when stated rate cases are filed years apart. Thus, transmission formula rates allow customers greater regulatory certainty and the ability to more accurately budget for transmission costs. A formula rate should also help EPE to minimize its financing costs, which, in turn, mitigates the costs of providing service.*"[130]

Furthermore, in contrast to the "black-box" settlement that determined EPE's stated rates, the "*proposed transmission formula rate structure incorporates transparency to transmission customers and the Commission. For example, the formula rate protocols require the submittal of annual information filings, as well procedures for data and information exchange regarding EPE's implementation of the formula*."[131]

Several EPE customers filed protests regarding EPE's proposal, citing substantial rate increases (which arose as a result of the prolonged period since the utility's last rate update). FERC accepted EPE's TFR filing on December 30th, 2021, and established hearing and settlement judge procedures.[132]

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[126] EPE. *Transmittal Letter (FERC Docket No. ER22-282-000).* October 29, 2021. P. 2.

[127] Ibid. P. 2-3.

[128] Ibid. P. 3.

[129] EPE. *Exhibit EPE-0002: Transmission Investment, Prepared Direct Testimony of James A. Schichtl (FERC Docket No. ER22-282-000).* October 29, 2021. P. 5 of 6.

[130] Ibid. P. 5 of 6.

[131] Ibid. P. 5 of 6.

[132] S&P Capital IQ Pro. *Focus on FERC – Democrat Willie Phillips sworn in; transmission issues heat up.* December 16, 2021.

8 Appendix C: List of acronyms

AEP	American Electric Power Service Corporation
AFCR	Annual Fixed Charge Rate
ATRR	Annual transmission revenue requirement
CAISO	California Independent System Operator
DAA	Division of Audits and Accounting
EPE	El Paso Electric Company
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
IOU	Investor-owned utility
ISO	Independent system operator
ISO-NE	Independent System Operator New England
LEI	London Economics International LLC
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
NYPA	New York Power Authority
O&M	Operation and maintenance
OATT	Open Access Transmission Tariff
PG&E	Pacific Gas and Electric Company
PJM	Pennsylvania-Jersey-Maryland Interconnection
PTF	Pool transmission facilities
PTO	Participating transmission owner
ROE	Return on equity
RRR	Revenue Requirements and Rates
RTO	Regional transmission organization
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SPP	Southwest Power Pool
TFR	Transmission formula rate
USofA	Uniform System of Accounts

9 Appendix D: List of works cited

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124 FERC ¶ 61,106. Docket Nos. ER08-552-000/001. July 29, 2008.

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143 FERC ¶ 61,149. Docket No. EL12-35-000. May 16, 2013.

146 FERC ¶ 61,212. Docket Nos. ER13-2379-000 et al. March 20, 2014.

148 FERC ¶ 61,035. Docket No. EL14-71-000. July 17, 2014.

156 FERC ¶ 61,209. Docket No. ER16-1169-000. September 22, 2016.

156 FERC ¶ 61,238. Docket No. ER16-2320-000. September 30, 2016.

16 U.S. Code § 824.

165 FERC ¶ 61,194. Docket No. ER19-13-000. November 30, 2018.

173 FERC ¶ 61,290. Docket No. ER21-00253-000. October 29, 2020.

178 FERC ¶ 61,207. Docket No. EL22-27-000. March 24, 2022.

18 Code of Federal Regulations § 35.13.

18 Code of Federal Regulations § 385.603.

42 FERC ¶ 61,307. Docket No. ER88-202-000. March 15, 1988.

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10 Appendix E: LEI's qualifications

10.1 Background on the firm

London Economics International LLC is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity transmission, distribution, and generation, sophisticated analysis and a suite of proprietary quantitative models that together produce reliable and comprehensible results. LEI is active across the power sector value chain and has a comprehensive understanding of the issues faced by investors, utilities, and regulators alike.

LEI's areas of expertise are briefly described in Figure 10.

Figure 10. LEI's areas of expertise

- Exhaustive sector knowledge and a suite of state-of-the-art proprietary quantitative modeling tools
  - Wholesale electricity market models
  - Valuation and economic appraisal
  - Due diligence support
  - Cost of capital database
  - Contract configuration matrices

- Market design, market power and strategic behavior advisory services
  - Electricity
  - Natural Gas
  - Water
- Incentive ratemaking
  - Quantify current and achievable efficiency levels for regulated industries
  - Convert findings into efficiency targets mutually acceptable to utilities and regulators

- Reliable testimony backed by strong empirical evidence
- Expert witness service
  - Material adverse change
  - Materiality
  - Cost of capital
  - Market power
  - Tax valuations
  - Contract frustration

- Creating detailed market simulations to identify beneficiaries and quantify costs and benefits from proposed transmission lines
  - Valuing transmission
  - Transmission tariff design
  - Procurement process and contract design

- Renewable energy policy design, procurement, modeling, and asset valuation
  - Solar, wind, biomass, and small hydro
  - Demand response
  - Cogeneration
  - Energy efficiency
  - Micro-grids
  - Emissions credits trading
  - Energy storage technologies

- Designing, administering, monitoring, and evaluating competitive procurement processes
  - Auction theory and design
  - Process management
  - Document drafting and stakeholder management

10.2 LEI's expertise related to transmission assets

LEI has extensive, in-depth experience in the transmission sector, spanning a broad array of regulatory, market, and economic topics. LEI has worked with a variety of stakeholders and institutions on electric transmission engagements including RTOs and ISOs, regulators, vertically integrated utilities and transmission owners, merchant transmission developers, independent power producers, environmental groups, and coalitions of consumers. LEI Principals have also testified on a variety of transmission related topics before policymakers, regulators, and siting organizations. LEI has advised on many facets of transmission, from rate design and regulation, to planning and investment analysis.

LEI’s key areas of work in the electricity transmission sector include:

- **transmission rate design and regulation:** LEI has extensive experience analyzing tariff designs and developing new transmission tariffs using well-established techniques for cost-of-service ratemaking, including empirically supported analysis of the cost of capital and efficient cost allocation. LEI has also performed several productivity and benchmarking studies to better understand the cost of service for RTOs and transmission owners. Furthermore, LEI has worked on policy issues related to the introduction of competition in transmission investment and the alignment of RTO practices (inter-regional planning). LEI has also examined different methods for instituting market-compatible transmission use charges and transmission congestion pricing. Finally, LEI Principals have also testified on the topic of weighted average cost of capital and appropriate risk compensation.

- **valuing transmission assets:** LEI creates meaningful simulations of transmission investment impacts using proprietary tools, conducts related cost-benefit analysis, provides advice and analysis related to the valuation of congestion contracts, and has performed several economic development studies to investigate the positive externalities of infrastructure investment on local and regional economies;

- **evaluating transmission alternatives:** LEI’s expertise includes assessing and quantifying the value of conventional and distributed energy resources as non-transmission alternatives to regulated transmission solutions, through analysis of the different generation technologies’ costs, siting requirements, generation patterns, reliability implications to the system, and practical factors related to policy compliance and alignment with timing of needs; and

- **procurement process and contract design:** LEI applies fundamental economic principles and an exhaustive knowledge of electricity markets to help governments, regulators, and private companies create effective, rational, and transparent procurement processes, including competitive solicitations for transmission capacity, and independent management of open seasons and open solicitations.