|  |  |
| --- | --- |
| **State of California** | **Public Utilities Commission** |
|  | **San Francisco** |
|  |  |
| **M E M O R A N D U M** |  |
|  |  |

**Date: March 13, 2023**

**To: The Commission**

**(Meeting of March 16, 2023)**

**From: Jonathan Pais Knapp**

**PU Counsel IV, Legal Division**

**Pouneh Ghaffarian**

**PU Counsel IV, Legal Division**

**Christine Jun Hammond**

**General Counsel, Legal Division**

**Elaine Sison-Lebrilla**

**Program Manager, Energy Division**

**Simon Hurd**

**Program and Project Supervisor, Energy Division**

**Subject: Staff request Commission Approval to File Post-Technical Conference Comments following October 6, 2023 Technical Conference on *Transmission Planning and Cost Management***

**(FERC Docket Nos. AD22-8-000, AD21-15-000)**

**RECOMMENDATION:** Legal Division and Energy Division Staff (collectively, Staff) recommend that the California Public Utilities Commission (CPUC) file comments in response to the Federal Energy Regulatory Commission’s (FERC) Notice Inviting Post-Technical Conference Comments in Docket Nos. AD22-8-000 and AD21-15-000.[[1]](#footnote-1) Staff also seek authority to join other parties’ comments that are consistent with the CPUC’s positions. Post-Technical Conference comments are due on March 23, 2023.

BACKGROUND:

On October 6, 2023, FERC convened a technical conference to discuss transmission planning and cost management for transmission facilities developed through local and regional transmission planning processes (Technical Conference).[[2]](#footnote-2) The Technical Conference addressed whether existing cost management practices for local and regional transmission projects are adequate and sought recommendations for potential reforms. The Technical Conference addressed transmission planning and cost management reforms that FERC originally proposed in the Advance Notice of Proposed Rulemaking (ANOPR) issued on July 15, 2021,[[3]](#footnote-3) and the Notice of Proposed Rulemaking (NOPR) issued on April 21, 2022.[[4]](#footnote-4) Following the Technical Conference, the Joint Federal-State Task Force on Electric Transmission (Joint Federal-State Task Force) addressed regulatory gaps and challenges in the oversight of transmission development at its fifth meeting on November 15, 2023.[[5]](#footnote-5)

FERC’s Notice Inviting Post-Technical Conference Comments (Notice) poses detailed questions regarding potential reforms to address, among other topics:

* whether FERC should establish independent transmission monitors in each region to provide transmission planning and cost oversight;[[6]](#footnote-6)
* whether FERC should require transmission owners to disclose information regarding asset management and replacement projects;[[7]](#footnote-7)
* whether FERC should consider requiring transmission owners to adopt any aspects of Pacific Gas and Electric’s Stakeholder Transmission Asset Review (STAR) Process or Southern California Edison’s Stakeholder Review Process (SRP);[[8]](#footnote-8)
* whether stakeholders have adequate information and opportunities to fully participate in local transmission planning processes;[[9]](#footnote-9)
* whether FERC should require grid operators to conduct variance analyses as part of regional transmission planning processes;[[10]](#footnote-10)
* whether FERC should alter the rebuttable presumption of prudence in certain circumstances;[[11]](#footnote-11)
* whether FERC’s approach for addressing regulatory gaps that may exist for local and/or asset management and replacement projects should depend on the underlying state regulatory framework, *e.g*., the comprehensiveness of the state’s certificate of public necessity and convenience (CPCN) process;[[12]](#footnote-12) and
* whether FERC should revise any standard formula rate protocols that FERC requires under the MISO Protocol Orders[[13]](#footnote-13) and other precedent.[[14]](#footnote-14)

Importantly, commenters are not limited to the topics or questions posed in the Notice.[[15]](#footnote-15)

DISCUSSION

Staff recommend that the CPUC file post-technical conference comments to reiterate support for transmission planning and cost management reforms that the CPUC has previously proposed, and to make additional recommendations, including the following.

FERC Should Convene a Technical Conference on Competition Reform Followed by a Focused Discussion of the Joint Federal-State Task Force.

In the NOPR, FERC proposed two new federal right of first refusal (ROFR) provisions. First, FERC proposed a ROFR for regionally cost allocated transmission projects conditioned on an incumbent utility entering a joint ownership arrangement with any other unaffiliated entity, including other incumbent utilities (Conditional ROFR).[[16]](#footnote-16) Under the Conditional ROFR, Pacific Gas and Electric Company (PG&E) could thus partner with Southern California Edison (SCE) and/or San Diego Gas & Electric (SDG&E) on the development of regional transmission projects and thereby circumvent competitive procurement requirements. FERC also proposed a ROFR that would apply in conjunction with a new “right-sizing” proposal in the NOPR (Right-Sizing ROFR).[[17]](#footnote-17) The proposed Right-Sizing ROFR would apply where an RTO/ISO determines that there is a more efficient and cost-effective solution than an incumbent utility’s planned in-kind replacement of an existing facility that would increase the facility’s transfer capability.[[18]](#footnote-18) FERC’s proposal would improperly grant an incumbent utility a monopoly over the development of a “right-sized project” that would otherwise be subject to competition, such as a regionally cost allocated transmission project.[[19]](#footnote-19)

The CPUC, in its comments in response to the NOPR, explained that the proposed ROFRs represent a regulatory step backwards and, if adopted by FERC, would significantly increase the cost of the required transmission buildout needed to facilitate the clean energy transition.[[20]](#footnote-20) The CPUC is concerned that if FERC ultimately retreats from competition, thus forgoing significant project cost savings,[[21]](#footnote-21) the resulting increases in already high transmission rates may prove unsustainable, and potentially undermine the implementation of FERC’s other, critical proposed transmission policy reforms in the NOPR.[[22]](#footnote-22)

Although Docket No. RM21-17-000 contains numerous comments that express serious concerns with FERC proposed ROFRs, including, as noted, extensive comments by the CPUC, neither the purported justification for, or potential ramifications of, these fundamental proposed changes in federal policy, nor the states’ perspective on these proposals, has been comprehensively discussed in an open public forum convened by FERC.[[23]](#footnote-23) There has also been no opportunity for a public discussion and exploration of alternative approaches to improve and expand the use of competitive processes to procure transmission projects. For all these reasons, FERC should convene a technical conference on competition reform followed by a focused discussion of the topic by the Joint Federal-State Task Force.

## FERC Should Establish Independent Transmission Monitors Charged with Specific, Core Functions.

The concept of an Independent Transmission Monitor (ITM) was introduced by FERC in the ANOPR[[24]](#footnote-24) and a central subject of discussion at the October 6, 2022 Technical Conference on Transmission Planning and Cost Management, and the November 15, 2022 meeting of the Joint Federal-State Task Force. The CPUC has recommended the establishment of ITMs and set forth a comprehensive vision for the role ITMs should play and the benefits they would provide in comments submitted in Docket No. RM21-17-000.[[25]](#footnote-25) Most recently, CPUC Commissioner Houck presented a specific and detailed proposal for an ITM consistent with the CPUC’s prior comments in her remarks at the November 15, 2022 meeting of the Joint-Federal State Task Force.[[26]](#footnote-26)

In short, the CPUC urges FERC to require RTOs/ISOs to establish ITMs that provide oversight of transmission planning and spending and specify certain responsibilities to ensure that the transmission investment needed to accommodate the future needs of the grid will be cost-effective and targeted to realize the maximum benefit for consumers.

FERC should charge ITMs with six core oversight functions that would apply to regional, local, and asset management and replacement projects:

* + - * Develop benchmark cost estimates;
      * Monitor actual project costs compared to estimates;
      * Monitor progress and assess continued need for incomplete projects;
      * Assess the prudency of selected projects as compared to alternatives;
      * Monitor compliance with planning requirements, e.g., compliance with application of Order 890 transparent planning principles and Order 1000 competitive procurement requirements; and
      * Periodically issue public reports that describe the state of transmission spending and compliance with planning requirements within its region or state, including the cost and efficacy of incentives.

ITMs would be funded through transmission rates. Therefore, they must provide a direct benefit to ratepayers. ITMs must be independent from RTOs/ISOs and accountable to state commissions, other relevant government agencies, and ratepayers and their advocates. Thus, ITMs should be responsive to reasonable requests by the applicable state commission(s), other relevant government agencies, and ratepayers and their advocates for information and analysis and, where necessary, to conduct investigations.

## FERC Should Implement Reforms to Provide for Enhanced Transparency, Stakeholder Review, and Approval of Asset Management and Replacement Projects in Independent Transmission Planning Processes.

As NARUC,[[27]](#footnote-27) the CPUC,[[28]](#footnote-28) and many other commenters have recommended, FERC should apply Order 890 transparent planning principles to asset management and replacement projects. All *transmission* projects, *i.e*., regional, local, and asset management and replacement projects, should be reviewed and approved in independent transmission planning processes.

At a minimum, however, FERC should mandate that transmission owners conduct stakeholder review processes for asset management and replacement projects that include requirements for disclosure of transmission planning and cost data at all stages of the transmission planning and develop processes for such projects, commencing with the inputs and assumptions stage. This would help ensure that the most efficient and cost-effective solutions are developed to address identified transmission needs.

California’s stakeholder review processes conducted by PG&E and SCE have demonstrated that such processes are feasible and can result in significant ratepayer savings.[[29]](#footnote-29) There are important lessons that can be learned from California’s experience. For example, FERC should require utilities to disclose the detailed project and capital expenditure data provided in PG&E’s STAR process. In addition, FERC should improve upon the California stakeholder processes by requiring disclosure of transmission owners’ inputs, assumptions, and needs data that support their asset management and replacement project proposals early in the planning stages – not merely in retrospect after a project has already been developed without any stakeholder input.[[30]](#footnote-30)

Importantly, FERC should charge ITMs with independently analyzing whether there are other, potentially more efficient and cost-effective alternative transmission solutions to meet identified transmission needs, as compared to the incumbent utilities’ proposal(s) and making a recommendation to the grid operator.

## FERC Should Require Improvements to Local Planning Processes to Ensure Stakeholders Have Adequate Information and Time to Analyze Proposed Local Transmission Projects in Relation to Potentially More Efficient and Cost-Effective Alternatives.

The CPUC recommends that FERC require improvements to local planning processes to ensure stakeholders are provided with sufficient planning and cost data to replicate local planning studies, as required by Order 890,[[31]](#footnote-31) and the time and resources necessary to analyze such data, including:

* Increased disclosure requirements

Transmission owners should provide information about the inputs and assumptions that support the need for their proposed local projects and prioritization decisions, an assessment of the benefits of each proposed solution, all potential drivers of local projects, a list of forecasted local projects looking forward several years, and overall sufficient information to enable stakeholders to understand whether proposed alternative solutions could account for and resolve developing drivers of local projects and why the transmission owner selected their proposed local project over other potential alternative solutions;

* Increased procedural requirements for stakeholder review processes

Stakeholders should be provided adequate time to review the information, and meaningful opportunities to provide feedback on local transmission planning; and

* Support of ITMs

FERC should charge ITMs with providing technical expertise to help assess whether there are other potentially more efficient and cost-effective alternatives, and, more broadly, to address transmission engineering expertise asymmetries between stakeholders and utilities in local transmission planning processes.

## FERC Should Require Grid Operators to Implement Variance Analyses.

FERC should require grid operators to implement variance analyses for *all* interregional, regional, and local transmission projects to determine whether projects continue to be needed and still represent the most efficient and cost-effective solution for addressing an identified transmission need. There should not be any categorical exclusions from the variance analysis requirement—economic, reliability and public policy projects should all be subject to the variance analysis. Thus, FERC should establish threshold criteria for when a variance analysis is triggered, *e.g*., if a project’s actual costs exceed its estimated costs by a certain threshold percentage, or the benefit-cost ratio upon which a project has been approved declines by an identified threshold percentage, the project is significantly delayed, or the project is simply no longer needed. Once the variance analysis is triggered, provided that the project is still, in fact, needed, then the RTO/ISO will consider remedial action and sponsors of identified projects which have exceeded one or more threshold criteria will be permitted to present stakeholders with mitigation plans. FERC should require that mitigation plans for projects that have already experienced cost overruns beyond a threshold percentage include cost caps to prevent further cost escalation. The RTO/ISO will solicit stakeholder input on the sufficiency of such mitigation plans. If the RTO/ISO moves forward with a mitigation plan over the objections of stakeholders, stakeholders should be provided with procedural remedies, including the ability to petition FERC to: (1) cancel interregional or regional cost allocation for the project; or (2) for a declaratory judgment that the project is an imprudent use of ratepayer funds. FERC should grant such petitions unless it determines that the public interest is adversely affected.

FERC should charge ITMs, among other specific functions, with developing benchmark cost estimates, assessing the continued need for projects, and determining whether proposed mitigation plans/project modifications will be cost-effective as compared to alternative solutions.

## FERC Should Adopt a Supplemental Prudence Policy.

In the CPUC’s Comments in response to the ANOPR, the CPUC urged FERC “to reverse its longstanding adoption of the presumption that all transmission capital expenditures are prudent and replace it with a presumption that only capital costs associated with projects that have been approved in an independently administered transmission planning process are prudent.”[[32]](#footnote-32) The existing prudence standard, which FERC adopted as a procedural mechanism to facilitate case management, provides little scrutiny of costs because, as a practical matter, except in a handful of instances, challengers have been unable to clear the initial hurdle of establishing “serious doubt” regarding the prudency of capital costs to overcome the presumption.[[33]](#footnote-33)

In addition, utilities should be required to prove prudence using cost-benefit analyses and/or evaluations of project alternatives. If a quantitative cost-benefit analysis is infeasible, FERC should consider qualitative assessments. In the absence of any such analysis, FERC cannot determine whether capital expenditures are reasonably incurred to provide service for the ratepayers. By contrast, the current legal standard for assessing prudence is essentially a business judgment rule that is far too deferential to decisions by utility management.[[34]](#footnote-34)

Importantly, if FERC adopted this supplemental prudence policy, then transmission owners in California would be required to affirmatively show that proposed asset management and replacement projects do, in fact, represent a prudent use of ratepayer funds.

Based on its detailed knowledge of transmission network and capital expenditures in its region, the ITM could help assist FERC and stakeholder review of transmission owner rate filings with its own independent analysis.

## FERC Should not Rely on States to Investigate the Prudence of Transmission Expenditures Recovered Through FERC-Jurisdictional Rates.

As the Harvard Electricity Law Initiative has cogently explained, “[FERC] may not abdicate its ratemaking duties, and it should not rely on states to investigate the prudence of expenditures recovered through [FERC-jurisdictional] rates.”[[35]](#footnote-35) During the Technical Conference and the November 15, 2022 meeting of the Joint Federal-State Task Force, FERC and State Commissioners and other panelists addressed whether existing regulatory gaps, *e.g*., the lack of federal, state, or RTO/ISO approval of asset management and replacement projects in many regions of the country, including California, depend on the underlying state regulatory framework,[[36]](#footnote-36) and, relatedly, whether the optimal forum for scrutinizing the prudence of FERC-jurisdictional transmission facilities is in state CPCN proceedings.[[37]](#footnote-37)

State CPCN proceedings, however, do not obviate the need for FERC to adopt enhanced transparency, oversight, and cost containment reforms for *FERC-jurisdictional* transmission facilities. Further, state CPCN processes are subject to certain limitations. Most fundamentally, state CPCN processes occur far downstream *after* the planning process has been completed. While states can review transmission costs when CPCNs are required, “that is an isolated evaluation of a single project rather than a more comprehensive assessment of transmission investments by the utility or for the region as a whole.”[[38]](#footnote-38) In addition, CPCNs are not required for many types of transmission projects, including, as a general matter, for asset management and replacement projects[[39]](#footnote-39) in different regions of the country.[[40]](#footnote-40)

By contrast, as summarized above, there are many reforms that FERC can readily implement that would materially improve transmission planning and enhance cost containment for transmission facilities that are squarely under its jurisdiction. For example, to comprehensively address the regulatory gap concerning asset management and replacement projects, FERC could, as a threshold matter, apply Order 890 transparent planning principles to such projects. Short of this, FERC could adopt, as outlined above, the supplemental prudence policy in combination with increased disclosure requirements applicable to asset management and replacement projects, stakeholder review processes for such projects, and the establishment of regional ITMs to provide expert technical analysis of the prudence of such investments as compared to potentially more efficient and cost-effective alternatives.

## FERC’s Office of Administrative Litigation Staff Should Participate in Annual Update Filings.

FERC’s Office of Administrative Litigation (OAL) staff should not only participate in the proceedings establishing the transmission owner’s formula rates, but OAL staff should also engage in the annual update process, so they can use their technical expertise to review the actual costs that subsequently flow through the formula rate. States’ abilities to fully participate in the annual update process vary widely and all states would benefit from OAL staff’s participation in the process.

## Improvements to Formula Rate Protocols.

FERC should revise and broadly apply the MISO Protocol Orders to require transmission owners in their annual update filings to explain differences from the previous year’s forecasted capital additions and identify whether, and, if so, how such differences are reflected in the transmission owners’ annual update filings.

CONCLUSION

Staff seek the Commission’s approval to file post-technical conference comments in response to the Notice consistent with the positions outlined above, and authority to join other parties’ comments that are consistent with the CPUC’s positions.

**ASSIGNED STAFF:** Legal Division, Christine Hammond (415) 703-2682; Pouneh Ghaffarian (415) 703-1317; Jonathan Knapp (415) 703-1626,; Energy Division: Elaine Sison-Lebrilla (916) 823-4808; Simon Hurd (415) 703-2503.

1. *Notice Inviting Post-Technical Conference Comments*, Docket Nos. AD22-8-000, AD21-15-000 (Notice) (Dec. 23, 2022). [↑](#footnote-ref-1)
2. Notably, Simon Hurd from the CPUC’s Energy Division served as a panelist during the Technical Conference and filed a summary statement in advance of the Technical Conference. *See* Agenda ID # 21010 (seeking Commission ratification of Litigation Subcommittee’s Prior approval of Summary Statement of Simon Hurd on Behalf of the California Public Utilities Commission in FERC Docket No. AD22-8-000). [↑](#footnote-ref-2)
3. Advance Notice of Proposed Rulemaking to Consider Potential Transmission Reforms: *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection* (July 15, 2021) 176 FERC ¶ 61,024 (ANOPR). [↑](#footnote-ref-3)
4. *Notice of Proposed Rulemaking: Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 179 FERC ¶ 61,028 (April 21, 2022) (“NOPR”). The Technical Conference was noticed by FERC “concurrent with the issuance of this NOPR.” NOPR at P 10. [↑](#footnote-ref-4)
5. *Supplemental Notice of Meeting*, Docket No. AD21-15-000 (November 14, 2022). As the Notice was issued in Docket No. AD22-8-000 (the administrative proceeding for the Technical Conference), and Docket No. AD21-15-000 (the administrative proceeding for the Joint Federal-State Task Force on Electric Transmission), responsive comments may address both the discussions at the Technical Conference and the November 15, 2023 meeting. [↑](#footnote-ref-5)
6. Notice, Question 5. [↑](#footnote-ref-6)
7. Notice, Question 2(a). Notice at 3, fn. 3 (*citing* *See So. Cal. Edison Co*, 164 FERC ¶ 61,160 at n.55 (2018); *Cal. Pub. Util. Comm’n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161 at n.119 (2018)) (defining “Asset Management” as referring 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.’”). [↑](#footnote-ref-7)
8. Notice, Question 2(a). [↑](#footnote-ref-8)
9. *See e.g*., Notice, Questions 1(a), (b). [↑](#footnote-ref-9)
10. Notice, Question 4(c). [↑](#footnote-ref-10)
11. Notice, Questions 7(a), 9. [↑](#footnote-ref-11)
12. Notice, Question 9, 11(b). [↑](#footnote-ref-12)
13. *Midwest Indep. Transmission Sys. Operator*, *Inc.*, 139 FERC ¶ 61,127 at P 9 (2013); *see also Midwest Indep. Transmission Sys. Operator*, *Inc.*, 143 FERC ¶ 61,149 (2013); *Midcontinent Indep. Sys. Operator*, *Inc.,* 146 FERC ¶ 61,212 (2014); and *Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,025 (2015) (collectively, MISO Protocol Orders). [↑](#footnote-ref-13)
14. Notice, Question 6(a). [↑](#footnote-ref-14)
15. Notice at 1. [↑](#footnote-ref-15)
16. NOPR at P 365 (emphasis added) (the Transmission NOPR explains that “potential joint ownership partners *could include* unaffiliated public power entities, unaffiliated load-serving entities such as transmission-dependent municipally-owned utilities or electric cooperatives, other unaffiliated third parties that do not have (or are operating outside of) their retail distribution service territory or footprint, or another unaffiliated entity, *including another incumbent transmission provider*.”). Under FERC’s proposed Conditional ROFR, RTOs/ISOs—or whichever entity has section 205 filing rights in each region—would be able to decide whether to include the Conditional ROFR in their tariffs. *Id*. at PP 354-355. [↑](#footnote-ref-16)
17. NOPR at P 403 (emphasis added) (where FERC proposes to “require that, as part of each Long-Term Regional Transmission Planning cycle, public utility transmission providers in each transmission planning region evaluate whether transmission facilities operating at or above 230 kV that an individual public utility transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be “right-sized” to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning. *By ‘right-sizing’ we mean the process of modifying a public utility transmission provider’s in-kind replacement of an existing transmission facility to increase that facility’s transfer capability. Right-sizing could include, for example, increasing the transmission facility’s voltage level, adding circuits to the towers (e.g., redesigning a single-circuit line as a double-circuit line), or incorporating advanced technologies (such as advanced conductor technologies)*.”). [↑](#footnote-ref-17)
18. *Id*. [↑](#footnote-ref-18)
19. NOPR at P 409 (emphasis added) (“for any right-sized replacement transmission facility that is selected in the regional transmission plan for purposes of cost allocation to meet transmission needs identified through Long-Term Regional Transmission Planning, *we propose to require the establishment of a federal right of first refusal* for the public utility transmission provider that included the in-kind replacement transmission facility in its in-kind replacement estimates, which would extend to any portion of such a transmission facility located within the applicable public utility transmission provider’s retail distribution service territory or footprint.”). [↑](#footnote-ref-19)
20. *Initial Comments of the California Public Utilities Commission*, Docket No. RM21-17-000 (August 17, 2022) (“CPUC Initial Comments”) at 80-94, 115-117. [↑](#footnote-ref-20)
21. *Id*. at 4 (emphasis in original) (explaining that based on CAISO’s cost estimates for the high-voltage bulk transmission projects in California needed to meet the State’s public policy goals, assuming projects will be phased in between 2030 and 2040, *i.e*., $30.5 billion, and The Brattle Group’s estimation that competitive processes have resulted in an average expected cost savings of 29% in the CAISO as compared to traditional project development, the elimination of competition in California “**could result in the loss of expected project cost savings from competition of over $8.8 billion in the next two decades**.”); *id*. at 63-69 (explaining that that the actual cost of two recently completed projects in the CAISO that were procured using competitive processes demonstrate cost savings of 29% and 55%, respectively, as compared to the CAISO’s initial estimates and the historical cost escalation of 41% experienced in the region for traditional project development by incumbent utilities, suggesting that expected cost savings from competition attainable in the CAISO would likely be greater than 29%). [↑](#footnote-ref-21)
22. *Id*. at 4-5. [↑](#footnote-ref-22)
23. FERC’s two proposed new federal ROFRs were not discussed at the October 6, 2022 Technical Conference, nor at the November 15, 2022 meeting of the Joint Federal-State Task Force on Electric Transmission. [↑](#footnote-ref-23)
24. For example, the ANOPR asked whether FERC should establish independent entities to monitor the planning and cost of transmission facilities in particular regions, referred to as an “Independent Transmission Monitor[s].” ANOPR at PP 163-175. As proposed in the ANOPR, ITMs would operate independently of existing RTOs/ISOs and could make referrals to FERC about problematic planning decisions, *e.g*., where “potentially excessive transmission facility costs” were identified, or where transmission projects were approved for regional cost allocation though “credible less-costly alternatives,” including non-wires alternatives, were available. *Id*. at P 164. [↑](#footnote-ref-24)
25. *See e.g*., CPUC Initial ANOPR Comments at 52-65; *see also* CPUC Initial Comments at 49-50 (recommending that FERC establish ITMs and charge them with the responsibility of ensuring that grid-enhancing technologies and non-wires solutions are fully considered as alternatives in transmission planning processes); *id*. at 111 (recommending FERC improve the stakeholder review process for local projects proposed in the NOPR by charging ITMs with evaluating stakeholder comments, independently analyzing whether there are other, potentially more efficient and cost-effective alternative transmission solutions to meet identified transmission needs, as compared to the incumbent utilities’ proposal(s), and making a recommendation to the grid operator); *id*. at 108-113 (where the CPUC explains and critiques FERC’s proposed stakeholder process for review of local projects). [↑](#footnote-ref-25)
26. Transcript, Fifth Meeting of the Joint Federal-State Task Force on Electric Transmission, Docket No. AD21-15-000 (November 15, 2022) (“Meeting Transcript”) at 53:6—58:2. [↑](#footnote-ref-26)
27. *Motion to Intervene and Comments of the National Association of Regulatory Utility Commissioners*, Docket No. RM21-17-000 (October 12, 2021), eLibrary No. 20211012-5537 (“NARUC ANOPR Comments”) at 49 (emphasis added) (“NARUC respectfully submits *that the most* *critical reform needed at this time is to apply Order No. 890’s transparent planning principles to utility* *self-approved projects*. This would eliminate incumbent utilities’ incentive to overinvest in these projects and provide the appropriate regulatory scrutiny over investments that currently comprise approximately 50 percent of transmission costs.”); *id*. at 48 (recommending that utility self-approved projects “should be evaluated in regional transmission planning processes to ensure they are needed and are the most cost-effective alternative.”). [↑](#footnote-ref-27)
28. *See* CPUC Initial Comments at 9; *see also* CPUC ANOPR Reply Comments at 14. [↑](#footnote-ref-28)
29. *Summary Statement of Simon Hurd on Behalf of California Public Utilities Commission*, AD22-8-000 (Sept. 16, 2022) (“Hurd Summary Statement”) at 6 (“By identifying project costs that should be expensed instead of capitalized, or should be eliminated from rates altogether, in the first two years of these stakeholder processes, the CPUC estimates over $400 million in long-term transmission ratepayer savings.”). [↑](#footnote-ref-29)
30. *Id*. at 7 (emphasizing that the California stakeholder processes “are no substitute for an ISO-driven, holistic planning approach that more comprehensively addresses the planning, prioritization, and development of projects on the CAISO-controlled grid. These negotiated processes typically provide transparency of projects only after they have already been self-approved by the utility or approved by the CAISO. Therefore, these processes occur downstream of the identification, planning, authorization, and prioritization processes, and at times, after construction is well underway.”). [↑](#footnote-ref-30)
31. *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266, 12,318 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 at P 471 (2007) (Order 890), *on reh’g*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *on reh’g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *clarified*, Order No. 890-C, 74 Fed. Reg. 12,540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *clarified*, Order No. 890-D, 74 Fed. Reg. 61,511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009) (emphasis added) (“The Commission adopts the NOPR’s proposal and will require transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans. . . . *This information should enable customers, other stakeholders, or an independent third party to replicate the results of planning studies* and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion.”). [↑](#footnote-ref-31)
32. CPUC Initial ANOPR Comments at 47. [↑](#footnote-ref-32)
33. *See e.g.,* *Indiana Mun. Power Agency v. FERC*, 56 F.3d 247, 253 (D.C. Cir. 1995) (citations omitted) (emphasis added) (explaining that under FERC’s prudence standard, a complainant alleging that some aspect of a utility’s rate or practice is unjust or unreasonable is required “*to present evidence sufficient to raise serious doubt* that a reasonable utility manager, under the same circumstances and acting in good faith, would not have made the same decision and incurred the same costs. *If the petitioner clears this initial hurdle, the utility has the burden of presenting evidence sufficient to dispel those doubts*. If it cannot, the complainant wins.”). [↑](#footnote-ref-33)
34. *See e.g.*, *Re New England Power Co*., 31 FERC ¶ 61,047, 61,084 (1985) (emphasis added) (“we reiterate that managers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers. In performing our duty to determine the prudence of specific costs, *the appropriate test to be used is whether they are costs which a reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and at the relevant point in time*.”). [↑](#footnote-ref-34)
35. *Comment of the Harvard Electricity Law Initiative*, Docket No. RM21-17-00 (Oct. 12, 2021) at 56. [↑](#footnote-ref-35)
36. Notice, Question 9 (emphasis added) (where FERC asks, in part, “Do you agree that there is a regulatory gap for local projects and/or asset management projects, and if so, why or why not? *Does the presence or extent of a regulatory gap depend on the underlying state regulatory framework?*”). [↑](#footnote-ref-36)
37. *See e.g.*, Transcript of Technical Conference, FERC, Docket No. AD22-8-000 (Oct. 6, 2022) (“Conference Transcript”) at 286:13-15 (emphasis added) (where Commissioner Christie states: “There is a gap at what scrutiny is taking place at the state level, *and yet that is where all these projects should be scrutinized*.”). [↑](#footnote-ref-37)
38. *Pre-Conference Comments of Maine Public Utilities Commission Chair Phillip L. Bartlett II*, Docket No. AD22-8-000 (Oct. 4, 2022) (‘Bartlett Summary Statement”) at 3; Conference Transcript at 260:7-25 (where Chair Bartlett makes the same point); *id*. at 280:17-20 (same). [↑](#footnote-ref-38)
39. Significantly, in California a CPCN is not required for “the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing power line facilities, the conversion of existing overhead lines to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built.” GO 131-D, § 3(A). Similarly, a Permit to Construct (PTC)—which is required in California for new transmission facilities that are designed to operate at any voltage between 50 kV and 200 kV, or upgraded substations that will exceed 50 kV—is not required for “the replacement of existing [transmission] line facilities or supporting structures with equivalent facilities or structures,” “the placing of new or additional conductors, insulators, or their accessories on supporting structures already built,” or minor relocations of existing transmission lines facilities. *Id*., § 3(B)(1)(b), (c), (e). [↑](#footnote-ref-39)
40. *See e.g*., Bartlett Summary Statement at 3 (“Moreover, asset condition projects—basically in-kind replacements due to age or deteriorating conditions—typically do not require any local siting review in Maine, and the costs are regionalized. This regulatory gap that exists where transmission project costs do not undergo any state-level review and only limited FERC review in a formula rate annual update proceeding is not insignificant. We have approximately $2.5 billion of installed asset condition projects in New England and another $3 billion of such projects in planning or construction.”). [↑](#footnote-ref-40)