UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	**Docket No. RM21-17-000**

REPLY COMMENTS OF
MASSACHUSETTS ATTORNEY GENERAL MAURA HEALEY

Pursuant to the Federal Energy Regulatory Commission's ("Commission" or "FERC") Notice of Proposed Rulemaking entitled *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022) ("NOPR"), issued by the Commission on April 21, 2022, the Office of Massachusetts Attorney General Maura Healey ("Massachusetts AGO") submits these reply comments for the limited purpose of addressing three arguments raised in the initial comments:[1] (1) the Massachusetts AGO agrees that the Commission cannot rely on section 309 of the Federal Power Act ("FPA") to invalidate portions of the Commission's Order No. 1000 findings with respect to the federal right of first refusal ("ROFR"); (2) the Commission should reject unfounded claims that competition in transmission development does not benefit ratepayers; and (3) the Commission should reject the Louisiana Public Service Commission's ("Louisiana PSC") erroneous argument that proposed long-term regional transmission planning reforms violate federalism principles.

[1] The Massachusetts AGO has also separately joined the Reply Comments of the State Agencies submitted herein.

I. COMMENTS

A. The Commission's Proposed Use of Federal Power Act Section 309 to Partially Reverse Its Order No. 1000 Findings that Elimination of the Federal ROFR Is Just and Reasonable Is Improper.

In the NOPR the Commission proposes to "use the discretion afforded by FPA section 309 … to amend Order No. 1000's findings and mandates in part,"[2] specifically with respect to the Commission's Order No. 1000 finding requiring elimination of all federal rights of first refusal. Section 309 of the FPA authorizes the Commission to "prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this chapter…."[3] The Commission's proposed use of section 309 to partially reverse its Order No. 1000 findings made pursuant to FPA section 206 is legally unsound and should be abandoned. As another commenter concisely explained, section 309 does not "provide[] the Commission substantive latitude to 'amend Order No. 1000s findings and mandates' as proposed in the NOPR and declare just and reasonable that which the Commission had previously declared under Section 206 to be both unjust and unreasonable as well as causing 'severe harm to the public.'"[4]

As the Massachusetts AGO argued in initial comments on the NOPR,[5] the Commission's proposal to allow conditional exercise of federal ROFRs cannot be squared with the Commission's findings in Order No. 1000 regarding the benefits of competition and the undue

[2] NOPR at P 351.

[3] 28 U.S.C § 825h.

[4] Initial Comments of LS Power Grid, Docket No. RM21-17 at 57 (Aug. 17, 2022) (citing Order No. 1000 at P 253; *Emera Maine v. FERC*, 854 F.3d 662, 671 (D.C. Cir. 2017).

[5] Massachusetts AGO Initial Comments at 41-45 (Aug. 17, 2022).

discrimination and unjust and unreasonable rates caused by exercise of federal ROFRs.[6] The Commission's conclusion in Order No. 1000 that it must eliminate exercise of all federal ROFRs for new regional transmission facilities to ensure just and reasonable rates was reasonable and grounded in a robust record.[7] The Massachusetts AGO found no authority, and the Commission cited none on point, for the proposition that the Commission may now use section 309 of the FPA to allow conditional exercise of federal ROFRs without revising its prior findings in accordance with section 206 of the FPA.

The primary case cited by the Commission, *American Public Power Association v. Federal Power Commission,* does not support the Commission's proposed action.[8] The Commission characterizes *Am. Public Power* as "affirming Commission action taken under FPA section 309 to change rules regarding cost basis for wholesale electric power rates, observing in part that 'ratemaking methodologies perceived to produce just and reasonable results in the past may be scrapped in favor of other methodologies now perceived to be preferable.'"[9] Nonetheless, scrutiny of *Am. Public Power* reveals it does not provide the basis for the Commission to scrap its former Order No. 1000 findings and substitute others that are "preferable" where the proposed new remedy directly contradicts the Commission's prior findings under section 206. *Am. Public Power* involved appeal of a Commission order issued pursuant to section 309 that amended a regulation governing data requirements for calculating

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

[7] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[8] 522 F.2d 142, 144 (D.C. Cir. 1975).

[9] NOPR at P 351, n. 571.

test years to include estimates of future costs as well as past actual costs, rather than past actual costs alone. The Court held that the amendment was a "reasonable exercise of the Commission's rulemaking authority under the Federal Power Act" because Section 309 empowered the Commission to "prescribe rules for the performance of its duties."[10] *Am. Public Power* does not hold, either expressly or implicitly, that section 309 may be used to reverse prior findings of a fully litigated section 206 proceeding to avoid the requirements of section 206 and the Administrative Procedure Act. Tellingly, since the opinion issued in 1975, the Massachusetts AGO is not aware of any other instance where a federal Court or a Commission order cited *Am. Public Power* as authority for the proposition advanced by the Commission in this NOPR.

The D.C. Circuit Court of Appeals has made clear that section 309 is "of an implementary rather than substantive character,"[11] and has explained that "while these provisions must be read in a broad expansive manner, they can only be implemented consistently with the provisions and purposes of the legislation, and . . . they authorize an agency to use means of regulation not spelled out in detail, provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act."[12] In construing the analogous and identical section of the Natural Gas Act,[13] the Supreme Court held that it "obviously does not vest authority in the Commission to set unjust and unreasonable rates" or "to set at naught an explicit provision of the Act."[14] Here the Commission's proposed use of section

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[10] *Am. Public Power*, 522 F.2d at 145.

[11] *New England Power Co. v. Fed. Power Comm'n*, 467 F.2d 425, 430 (1972).

[12] *Id.* (cleaned up); *cf. TNA Merchant Projects, Inc. v. FERC*, 857 F.3d 354, 359 (D.C. Cir. 2017) ("[A]ny actions that FERC takes under § 309 must conform with the purposes and policies of Congress and cannot contravene any terms of the Act." (cleaned up)).

[13] 15 U.S.C. § 717*o*.

[14] *FPC v. Texaco, Inc.*, 417 U.S. 380, 394 (1974).

309 would ignore and "set at naught" section 206's explicit requirements and arbitrarily result in precisely the same practices that the Commission found to cause unjust and unreasonable rates in Order No. 1000.

As a number of commenters pointed out, only section 206 may be used to set aside a prior section 206 finding that elimination of the federal ROFR resulted in just and reasonable rates. Accordingly, a section 206 proceeding that satisfied the findings required by that section would be necessary to set aside the Commission's prior Order No. 1000 findings in whole or in part. In such a case the Commission would be required to provide a "reasoned explanation . . . for disregarding facts and circumstances that underlay its . . . prior policy"[15] as well as a reasoned explanation for reinstating practices that it previously found created unduly discriminatory barriers to entry for non-incumbent transmission developers and created unjust and unreasonable rates.

For these reasons, the Commission cannot use section 309 to avoid section 206 procedures. The Commission's proposal to do so here is legally unsupported and would not weather judicial review. Further, the Commission should abandon the deeply flawed conditional ROFR proposal in its entirety for the reasons the Massachusetts AGO cited in its initial comments.

B. Incumbent Transmission Owners' Attempts to Challenge the Benefits of Competition Are Unpersuasive.

As the Massachusetts ratepayer advocate, the Massachusetts AGO maintains, as the Commission found in Order No. 1000, that "federal rights of first refusal in favor of incumbent transmission providers deprive customers of the benefits of competition in transmission development, and associated potential savings …."[16] Without competition, incumbent

[15] *FCC v. Fox Television Stations*, 556 U.S. 502, 515-16 (2009).

[16] Order No. 1000 at P 285.

transmission owners have no incentive to offer cost saving provisions to ratepayers and to more evenly share the risks of cost overruns and delays. The Massachusetts AGO shares the concerns of the Department of Justice (DOJ) and the Federal Trade Commission (FTC) that with reinstatement of even a conditional ROFR, "consumers will lose the many benefits that competition can bring, including lower rates, improved service, and increased innovation, leading to a more efficient, reliable, and resilient grid."[17] As noted by the DOJ and the FTC, "[c]ompetition is a core organizing principle of the American economy, and vigorous competition gives consumers the benefits of lower prices, higher quality goods and services, increased access to goods and services, and greater innovation."[18]

The Massachusetts AGO has no doubt that if forced to compete, incumbent New England transmission owners, either individually or jointly, will participate in solicitations for lucrative regional projects. And they may well prevail over other competitors given the advantages they enjoy from existing rights-of-way and facilities. However, the difference from an incumbent monopoly or the joint ownership arrangement that the Commission envisions in its conditional ROFR proposal is that if incumbents are awarded a transmission project through competition, it will be via a fair and transparent process and the pressure of competition will result in the cheapest and most beneficial solution available to ratepayers.

It remains unclear from the initial comments to what extent there is competent evidence in the record supporting the Commission's concern that "perverse financial incentives"[19] are resulting in incumbent utilities avoiding competition for regional projects and instead gold

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[17] Comment of United States Department of Justice and Federal Trade Commission, Docket No. RM21-17, at 1 (Aug. 17, 2022).

[18] *Id*. at 3-4 (citing *N.C. State Bd. of Dental Exam'rs v. FTC*, 135 S. Ct. 1101, 1110 (2015); *Standard Oil Co. v. FTC*, 340 U.S. 231, 248 (1951)).

[19] NOPR at P 350.

plating their transmission distribution systems. As the Massachusetts AGO explained in its initial NOPR comments, there is no evidence in New England supporting the Commission's concern.[20] Further, there is no persuasive evidence in the initial comments supporting the proposition that a partial or total monopoly over transmission development by incumbent transmission owners, either with or without a joint ownership requirement in lieu of competition, will result in benefits to consumers such as cheaper or more quickly completed regional transmission projects.

Incumbent transmission owners and their affiliated trade organizations have great nostalgia for the pre-Order No. 1000 regime when utility monopolies allegedly "collaborated" and supposedly built transmission more cheaply and quickly than competitively bid projects are built today.[21] They argue that the lack of a federal ROFR inhibits open communication and collaboration both between transmission owner monopolies and with transmission planners and that this adversely impacts transmission development in the form of uncertainties and delays.[22] They urge the Commission to go further than reinstating a conditional ROFR and to completely restore the federal ROFR. But reliable data on the benefits of such alleged historical collaboration or on the alleged current lack thereof, or how those results might compare to the performance of competitively bid projects, with their widely acknowledged benefits including cost caps and innovative risk sharing proposals, is hard to come by in the record. In contrast, the

[20] Massachusetts AGO Initial Comments at 46-48 (Aug. 17, 2022).

[21] *See, e.g.*, Initial Comments of Developers Advocating Transmission Advancements; Initial Comments of the Edison Electric Institute at 30-31; Initial Comments of Eversource at 35-36.

[22] As aptly noted in an affidavit in support of a competitive transmission developer, if, as incumbent transmission owners contend, "collaboration among incumbents to develop projects results in the greatest benefits for consumers, which suggests that collaborative projects are the least-cost," then incumbents are incentivized to collaborate in competitive transmission solicitations under the current no-ROFR regime rather than risk losing to a more competitive bid. NextEra Initial Comments, Att. A (Affidavit of Dr. John R. Morris), at 25.

record is replete with data on competitively bid transmission projects and their benefits to ratepayers.[23]

The Massachusetts AGO highlights one attempt by incumbent transmission owners to provide data-based evidence in support of their arguments because it is so flawed and unpersuasive. Two incumbent New England transmission owners, Eversource and National Grid, commenting with others as "Developers Advocating Transmission Advancement" (DATA), submitted a report by Concentric Energy Advisers ("Concentric Report") purporting to demonstrate the ills of transmission competition for consumers, in the form of cost overruns and delays, and the contrasting benefits of transmission development monopolies.[24] However, this report does not withstand the slightest scrutiny. As demonstrated in the affidavit of Massachusetts AGO Analyst James Donovan (Donovan Affidavit), provided as Attachment A, the Concentric Report suffers from a variety of methodological flaws that render its conclusions meritless. Among these flaws are the lack of an objective and coherent selection methodology, resulting in an arbitrarily small sample (6) of competitively bid projects, the absence of a control group or basis for comparison and a mischaracterization of the intended purpose and effect of cost caps, cost inflators and other cost provisions commonly used in competitive transmission development projects.[25] As Mr. Donovan finds, the Concentric Report starts with a list of competitive transmission projects and subjectively and arbitrarily removes solicitations awarded

[23] *See, e.g.,* Initial Comments of LS Power Grid, App. II, SUMMARY OF COMPLETED COMPETITIVE PROCESSES (Aug. 17, 2022); Initial Comments by the Electricity Transmission Competition Coalition in Opposition to Certain Aspects of the Proposed Rule, Docket No. RM21-17, at 4-7 (Aug. 17, 2022); Initial Comments of NextEra at Att. D & E.

[24] *See* Concentric Energy Advisors, *Competitive Transmission: Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits* (Aug. 2022) (prepared for the Developers Advocating Transmission Advancement ("DATA") Coalition (Ameren Services, Eversource Energy, Exelon Corp., ITC Holdings Corp., National Grid USA, Public Service Electric and Gas Company, and Xcel Energy).

[25] Donovan Affidavit at 3.

to incumbent transmission owners, projects at an early development stage and projects below an arbitrary total estimated cost threshold.[26] This screening process results in such a small sample size that Concentric cannot credibly apply its conclusions beyond observations about these individual projects.[27]

Beyond the small sample size, there are issues with consistency in the way data are collected and assembled for the projects selected. Concentric does not offer a valid benchmark or comparison group that could potentially allow it to compare competitive projects with traditionally-developed transmission projects by incumbent transmission owners.[28] Finally, Concentric mischaracterizes the intended role and effectiveness of cost caps and cost inflators in competitive transmission development projects, and wrongly attributes any cost increase to the failure of these cost control provisions.[29] Taken together, these flaws render the Concentric Report without evidentiary value and lead to the conclusion that its opinions are primarily result-oriented, naked advocacy that is backed up only by unsupported assertion. For these reasons the Commission should disregard the conclusions of the Concentric Report.

The Massachusetts AGO, as well as many others, made the point in its initial comments that if "perverse financial incentives" actually exist with respect to regional transmission projects, those incentives can and should be abolished *not* by partial elimination of competition, but by means of better transmission planning practices that reduce those incentives and the influence of incumbent transmission owners. For these reasons, and the reasons set forth in its initial comments, the Massachusetts AGO respectfully urges the Commission to adopt

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[26] *Id*. at 3-6.

[27] *Id*. at 6-10.

[28] *Id*. at 10-12.

[29] *Id*. at 12-14.

transmission planning solutions rather than partial reinstatement of the federal ROFR to address any shortcomings of Order No. 1000 in spurring regional transmission development.

C. The Proposed Long-Term Regional Planning Reforms Are Consistent with Federalism Principles and Squarely Within the Commission's Legal Authority.

As described in the Massachusetts AGO's initial comments,[30] the Commission's proposed long-term regional transmission planning and cost allocation reforms "fit[] comfortably within the Commission's authority" under FPA section 206 to respond to changes in the power industry and facilitate regional transmission planning.[31] The Louisiana PSC argues in its initial comments that the NOPR would violate federalism and separation of powers principles.[32] But the facts before the Commission in this proceeding do not support the Louisiana PSC's claims. The robust record overwhelmingly demonstrates that the power sector is indeed changing and that the proposed reforms are needed to ensure just and reasonable transmission rates.[33]

The Louisiana PSC makes various arguments that the Commission lacks legal authority to adopt the reforms in the NOPR; all are grounded in the incorrect premise that the Commission is attempting to "tip the scales in favor of certain renewable resources, primarily those that are located . . . a far distance from load centers."[34] Nowhere in the NOPR does the Commission claim "authority to determine what type of generating resources should be transmitted from

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[30] Massachusetts AGO Initial Comments at 5-6.

[31] *S.C. Pub. Serv. Auth.*, 762 F.3d at 90.

[32] *See* Comments in Opposition of the Louisiana Public Serv. Comm'n, Docket No. RM21-17, at 3-12 (Aug. 17, 2022) [Louisiana PSC Comments].

[33] *See* NOPR at PP 24-46.

[34] Louisiana PSC Comments at 3; *see also id.* at 5, 6, 12. The Louisiana PSC cites *West Virginia v. EPA*, 142 S. Ct. 2587 (2022), for the proposition that the Commission lacks authority to determine the nation's electricity generation portfolio and usurp states' traditional role in determining their generation mix. *Id.* at 6.

where in the United States," as the Louisiana PSC alleges.[35] The NOPR is clear that the proposed long-term regional planning and cost-allocation reforms respond to broadly identified failures in current planning processes, which are not implemented "on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in resource mix and demand,"[36] "resulting in piecemeal transmission expansion" and "relatively inefficient investments."[37] In other words, the NOPR appropriately recognizes macro industry trends that predate the NOPR and that would persist whether or not the Commission finalizes its proposed reforms.

The Commission's recognition of extant industry trends and evidence of the benefits of long-term regional transmission planning does not infringe on the powers of Congress or the states.[38] Rather, it is critical to the Commission's rational exercise of its authority to ensure just and reasonable rates. Indeed, many states, including the Commonwealth of Massachusetts, implement clean energy and climate change policies that drive changes in resource mix and demand.[39] Any federal transmission planning order that failed to appropriately consider the long-term effects of state clean energy and climate change policies would be arbitrary and capricious and unlawful.

II. CONCLUSION

The Massachusetts AGO appreciates the Commission's solicitation of public input on the important issues raised in the NOPR. We respectfully urge the Commission to consider the

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[35] *Id.* at 12.

[36] NOPR at P 24.

[37] *Id.* at 25.

[38] *Cf.* Louisiana PSC Comments at 9.

[39] *See* Massachusetts AGO Initial Comments at 8-9.

above reply comments and recommendations, in addition to the Massachusetts AGO's initial comments in this docket, as the Commission considers potential reforms to improve electric regional transmission planning, cost allocation, and generator interconnection processes.

Respectfully submitted,

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September 19, 2022

CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010 I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Boston, Massachusetts this 19th day of September, 2022.

/s/Christina Belew
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ATTACHMENT A

AFFIDAVIT OF JAMES M. DONOVAN, JR.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT OF JAMES M. DONOVAN, JR. ON BEHALF MASSACHUSETTS ATTORNEY GENERAL MAURA HEALEY

1 **1. Statement of Qualifications**

2 My name is James M. Donovan, Jr. I am an Energy Analyst for the Massachusetts Attorney
3 General's Office ("Massachusetts AGO") in the Office of Ratepayer Advocacy. My business
4 address is One Ashburton Place, Boston, MA, 02108. The Massachusetts AGO represents the
5 Commonwealth of Massachusetts, the public interest, and the people of the Commonwealth with
6 respect to electricity industry matters that affect consumers.

7 My responsibilities at the AGO include providing qualitative and quantitative analysis of
8 proposals by ISO New England, New England Power Pool ("NEPOOL") stakeholders, and the
9 Federal Energy Regulatory Commission ("FERC" or "the Commission"). I am a voting member
10 at the NEPOOL Transmission and Reliability Committees, and an alternate member at the
11 NEPOOL Markets, Participants, and Planning Advisory Committees.

12 I have more than 15 years of experience as an economic and strategy consultant and analyst,
13 primarily in the energy, infrastructure, technology, and financial industries, and including more
14 than a decade working in the energy, infrastructure, and climate sectors. Prior to joining the AGO
15 in May 2022, I was a Principal and Affiliate at Monument Economics Group, LLC, an economic

1 and strategy consulting firm, where my area of focus was energy, infrastructure, and climate issues
2 in the United States and internationally. Prior to that position, I had roles as Founder and Principal
3 of energy consultancy Plum Island Analytics, Principal Consultant at International Planning and
4 Research, Principal Economist at Quantitative Economic Solutions, Senior Regulatory Analyst at
5 NSTAR and Northeast Utilities, and Manager and Senior Economist in the energy practice at
6 Compass Lexecon. I hold an M.B.A. from Northeastern University in Boston, MA, and a B.A.
7 from Middlebury College in Middlebury, VT. My CV is attached as Appendix A.

8 My energy sector consulting experience includes litigation, international arbitration,
9 regulatory proceedings, and economic studies in the electricity, natural gas, and petroleum markets
10 in the United States and internationally. My electricity work includes analysis of economic and
11 financial issues in the electricity generation, transmission, and distribution sectors. I was
12 previously disclosed as an expert witness on the issue of damages in a breach of contract dispute
13 in Massachusetts Suffolk County Superior Court.[1]

14 **2. Scope and Summary of Affidavit**

15 I am submitting this affidavit on behalf of the AGO in response to an August 2022 report
16 by Concentric Energy Advisors ("CEA" entitled *Competitive Transmission: Experience-to-Date*
17 *Shows Order No. 1000 Solicitations Fail to Show Benefits* ("CEA Report"),[2] included as
18 Attachment A to the August 17, 2022 initial comments of Developers Advocating Transmission
19 Advancements ("DATA")[3] ("DATA Comments") in response to the Commission's Notice of

[1] *Columbus US, Inc. vs. UMA Enterprises, Inc.,* C.A. No. 3084CV000905 (filed April 28, 2020).
[2] *See,* Concentric Energy Advisors [CEA], *Competitive Transmission: Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits* (August 2022), https://ceadvisors.com/publication/competitive-transmission-experience-to-date-shows-order-no-1000-solicitations-fail-to-show-benefits/ [CEA Report].
[3] Comments of Developers Advocating Transmission Advocates [DATA], Docket No. RM21-17 (Aug. 17, 2022) [DATA Comments].

1 Proposed Rulemaking entitled Building for the Future Through Electric Regional Transmission
2 Planning and Cost Allocation and Generator Interconnection, 179 FERC ¶ 61,028 (2022), issued
3 by the Commission on April 21, 2022 ("NOPR").

4 The CEA Report's main conclusion is that "a review of competitive projects that are now
5 in service or in advanced stages of development clearly demonstrates that Order No. 1000
6 competitive solicitations have not been successful in driving cost savings and have added delays
7 to the development of transmission infrastructure."[4] As I discuss below, however, serious flaws in
8 CEA's methodology, assumptions, and evidence undermine the credibility of that conclusion.
9 These flaws include the lack of objective and coherent selection criteria, the resulting small and
10 potentially unrepresentative sample size used in the analysis, the absence of a valid benchmark or
11 comparison group, and mischaracterizations of the intended role and effects of cost caps and other
12 cost provisions in competitive transmission development contracts.

13 **3. CEA's selection criteria lack objectivity and coherence**

14 CEA's "review of competitive projects that are now in service or in advanced stages of
15 development"[5] ultimately considered only six projects,[6] selected based on a selection methodology
16 described in the CEA Report.[7] However, this selection methodology is incoherent, and relies on
17 flatly incorrect, subjective, and arbitrary selection criteria.

18 CEA starts with a list of 25 competitive solicitations, subject to certain footnoted
19 limitations and qualifications of the projects included in this list,[8] which it refers to as "a complete

[4] *Id.*, at 1.
[5] *Id.*
[6] *Id.*, at 4.
[7] *Id.*, at 13.
[8] *Id.*, at tbl. 3.

1 list of Order No. 1000 competitive solicitations."[9] These footnotes contain criteria that appear to
2 be internally contradictory or arbitrarily chosen. For example, CEA notes that its list "[i]ncludes
3 PJM open window projects that resulted in a non-incumbent winner,"[10] but "does not include the
4 numerous PJM open window solicitations."[11] CEA also indicates that "SPP's Butler-Tinga project
5 has been excluded [from the list] due to the withdrawal of the project prior to submission of
6 proposals,"[12] while nonetheless including three projects ("Greg to Gates", "Wheeler Ridge
7 Junction Sub.", and "North Liberal to Walkeneyer")[13] that "have been withdrawn or put on hold
8 since selection."[14]

9 CEA screens this initial list of 25 projects to select "(1) [p]rojects awarded to non-
10 incumbent transmission developers;" "(2) [p]rojects that are in-service or under construction;" and
11 "(3) projects with an estimated total capex greater than $50 [million]."[15] However, as noted above,
12 these selection criteria are incorrect, subjective, and arbitrary, and serve to limit CEA's sample
13 size arbitrarily and unnecessarily.

14 First, by examining only competitive projects awarded to non-incumbent transmission
15 developers, CEA misconstrues both the economics of competition, and the purpose of the
16 Commission's elimination of federal rights of first refusal ("ROFR") in Order No. 1000. As
17 described in the NOPR, in Order No. 1000, "[t]he Commission found that administering
18 transmission planning processes with federal ROFRs 'may result in the failure to consider more
19 efficient or cost-effective solutions to regional needs' and thus their [ROFR] elimination may give

[9] *Id.*, at 13.
[10] *Id.*, at n. 16.
[11] *Id.*, at n. 19.
[12] *Id.*, at n. 17.
[13] *Id.*, at tbl. 3.
[14] *Id.*, at n. 18.
[15] *Id.*

1 'customers . . . the benefits of competition in transmission development, and associated potential
2 savings.'"[16] The intent was to allow non-incumbent *participation* in the competitive process, not
3 to award all or particular projects to non-incumbent developers. The competitive solicitation
4 process forces incumbents to compete with non-incumbents' proposals, which should encourage
5 them to be more cost-effective or otherwise competitive than they would have been with the
6 protection from competition afforded by a ROFR. In a competitive solicitation, if an incumbent
7 transmission owner's proposal wins, it means that the proposal was selected as the best among the
8 proposals submitted (according to the solicitation's particular selection criteria). As such, CEA
9 should have looked at outcomes of *all* competitive solicitations, *regardless* of the winner.

10 Instead, CEA's assumption "that whether or not a project developed by an incumbent TO
11 was awarded as part of a competitive solicitation, it would experience the same outcome related
12 to cost and schedule adherence as compared to had it been constructed pursuant to a ROFR"[17]
13 ignores the fact that the effects of competitive solicitation act on all participants, both incumbent
14 and non-incumbent. Even if this implausible assumption were somehow to be true, CEA should
15 have examined competitive solicitations won by incumbents as a control or comparison group for
16 its six-member test group. CEA's failure to examine all competitive solicitations regardless of the
17 winner, either under a standard competitive economic framework, or, alternatively, under its own
18 novel assumption that the competitive solicitation process would have no effect on the cost of
19 projects undertaken by incumbent transmission owners (alone or under joint ownership), distorts
20 and limits the projects chosen for its analysis and undermines CEA's conclusions.

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[16] NOPR at P 340 (citing Order No. 1000, 136 FERC ¶ 61,051 [Order No. 1000] at PP 284-286, 291). "[In Order No, 1000,] [t]he Commission reasoned, in part, that '[g]reater participation by transmission developers in the transmission planning process may lower the cost of new transmission facilities, enabling more efficient or cost-effective deliveries by load serving entities and increased access to resources.'" *Id.*, citing Order No. 1000, at P 291.
[17] CEA Report at 13.

1 Second, while CEA is correct in assuming project costs can be estimated with increasing
2 certainty as a project progresses toward completion, CEA's choice to select both in-service or
3 under-construction projects draws an arbitrary line, since full cost certainty is only achieved when
4 a project is completed and placed in-service.

5 Third, CEA's election to examine only projects with estimated costs of at least $50 million,
6 is based on a "belie[f] that the results of competition are more transparent and easier to observe
7 across projects of a certain size, scope, and length of construction … ."[18] This is an arbitrary
8 threshold that does not appear to be based on any identified empirical evidence or standard
9 practice.

10 **4. CEA's arbitrarily and unnecessarily small sample size**

11 For the six projects it selected, CEA examined what it termed "cost overruns" as the
12 difference or percentage difference between the "final cost or current cost estimate" and the
13 "winning bid cost estimate,"[19] and measured what it terms "schedule adherence" as the "days
14 between need identification and selection" and as the difference between the actual or current
15 estimated "in-service date" and the "ISO required in-service date."[20] CEA apparently relied on
16 these measures, as well as some background information it compiled on each of the six projects,
17 to conclude that competitive solicitations have led to cost increases and project delays.[21] However,
18 the data CEA assembled in this report is insufficiently robust to credibly reach any of the
19 conclusions that CEA makes about project costs or schedules.

[18] *Id.*, at 14.
[19] *Id.*, at tbl. 9.
[20] *Id.*, at tbl. 7.
[21] *Id.*, at 35.

1 The high degree of variability of the values of individual projects in the various metrics
2 CEA adopts for solicitation process and construction "schedule adherence" is illustrated in Table
3 1 below.

Table 1.
Schedule Metrics of the Competitive Solicitations Studied in the CEA Report

	Project	Days Between Need ID and Selection	In-Service Date	ISO-Req. In-Service Date	In-Service Date Minus ISO-Req. In-Service Date
		[A]	[B]	[C]	[D]=[B]-[C]
		(days)			(months)
[1]	Empire State	820	Jul-22	Jun-22	1
[2]	Artificial Island	950+	May-20	Apr-19	13
[3]	Suncrest	287	Feb-20	Jun-17	32
[4]	Delaney to Colorado	360	Jan-23 - Dec-23	May-20	32 - 43
[5]	Duff Coleman	385	Jun-20	Jan-21	-7
[6]	Harry Allen to Eldorad	544	Aug-20	May-20	3
	Average	558			13
	Median	465			8
	Minimum	287			-7
	Maximum	950			43

Source:
CEA Report Table 7.

4 In Table 1, Column A shows the number of days between need identification and selection,
5 as a measure of the length of the solicitation process. According to this measure, the solicitation
6 process lasted as little as 287 days (Suncrest), and as much as 950+ days (Artificial Island). The
7 Artificial Island solicitation process was a complex outlier. By CEA's own account, the need for
8 what would become the Artificial Island solicitation was identified in 2012,[22] and an initial
9 solicitation process was initiated on April 28, 2013,[23] with the project awarded to LS Power in
10 2015.[24] In CEA's words, however, "PJM underestimated the cost of integration work at the

[22] *Id.*, at 19.
[23] *Id.*
[24] *Id.*, at 20.

terminus [Public Service Electric and Gas Company ("PSE&G")] substation. PJM's revised estimates raised the estimated total cost, and this cost increase, in part, led the PJM Board to suspend the project in August 2016 and direct PJM staff to conduct a more comprehensive analysis."[25] The PJM Board lifted this suspension on April 26, 2017, "and approved PJM staff's recommendation to retain LS Power as the developer … under the revised project scope and route.".[26] CEA goes on to explain that "[t]he LS Power project that was ultimately awarded was substantially different from both the PSE&G project that was initially recommended by PJM Staff in 2014 and the PJM Board-approved project in 2015 that was awarded to LS Power."[27] After acknowledging the highly unusual solicitation process for Artificial Island, CEA failed to adjust solicitation times appropriately or eliminate this data point from its analysis. CEA instead holds up this data point as "exemplif[ying] many of the ways that competitive solicitations can slow down and otherwise complicate the development of transmission infrastructure."[28] CEA's characterization notwithstanding, this data point instead exemplifies the potential perils of inconsistent or biased data collection and of basing analysis on a small sample. The inconsistency of the data and resulting wide distribution of values and small sample size preclude any credible conclusion by CEA about the length of the solicitation process in competitive solicitations.

Column D of Table 1 shows the "In-Service" Date (Column B) minus the ISO-Required In-Service Date (Column C), in months, as a measure of construction delay. According to this measure, projects in CEA's study ranged from 7 months *ahead* of schedule (Duff-Coleman), to 32+ months *behind* schedule (Delaney to Colorado). The wide range and small sample size of

[25] *Id.*, at 19-20.
[26] *Id.*, at 20.
[27] *Id.*
[28] *Id.*

these data cannot credibly be used to determine *anything* conclusive about competitive transmission projects related to construction delay.

Table 2 shows the cost data presented by CEA for the projects it studied (Columns A through C) and calculates three metrics for cost increase available from CEA's data.

Table 2.
Cost Metrics of the Competitive Solicitations Studied in the CEA Report

	Project	Cost Estimate			Winning Bid v. Region		Final / Current v. Region		Final / Current v. Winning Bid	
		Region	Winning Bid	Final / Current						
		[A]	[B]	[C]	[D]=[B]-[A]	[E]=[D]/[A]	[F]=[C]-[A]	[G]=[F]/[A]	[H]=[C]-[B]	[I]=[H]/[B]
		($M)	($M)	($M)	($M)	%	($M)	(%)	($M)	(%)
[1]	Empire State		181	249					68	38%
[2]	Artificial Island		146	150					4	2%
[3]	Suncrest	59	50	54	-9	-15%	-5	-8%	4	9%
[4]	Delaney to Colorado	325	300	389	-25	-8%	64	20%	89	30%
[5]	Duff Colemean	50 to 75	42	53	-8 to -33	-15% to -44%	3 to -22	6% to -29%	11	25%
[6]	Harry Allen to Eldorado	120	144	202	24	20%	82	69%	58	41%
	Average	142	144	183	-8	-5%	33	22%	39	24%
	Median	91	145	176	-15	-12%	30	13%	35	27%
	Minimum	59	42	53	-33	-44%	-22	-29%	4	2%
	Maximum	325	300	389	24	20%	82	69%	89	41%

Source:
CEA Report Table 8.

Columns D and E compare the winning bid cost estimate to the "regional cost estimate" (in dollars (Column D) and as a percentage (Column E). CEA's "regional cost estimate" is the relevant regional transmission organization's pre-solicitation project cost estimate. CEA only included regional cost estimates for four projects. Once again, the range of values among projects and the small sample size of four precludes any credible conclusions about cost increases for competitive solicitations that can be drawn from these data.

Columns F and G compare the final cost or current cost estimate to the regional cost estimate (in dollars (Column F) and as a percentage (Column G)). Two of four projects' final cost

or current cost estimate is less than the regional cost estimate, meaning the project cost *less* than the RTO's original projections. Again, no credible conclusions can be drawn.

Columns H and I compare the final cost or current cost estimate with the winning bid cost estimate for all six projects (in dollars (Column H) and as a percentage (Column I). In the interim, costs increased by as little as 2% and by as much as 41%. Once again, the variability in values and the limited sample size preclude any credible conclusions regarding cost increases for competitive solicitations.

The small project sample size makes CEA's conclusions about project costs and schedules of competitive transmission solicitations untenable. In contrast, other studies consider a significantly broader range of projects than those chosen by CEA and reach opposing conclusions to those of CEA.[29]

5. CEA provides no benchmark or basis for comparison

CEA compounds the weakness of its sparse data by failing to provide any basis for comparison. CEA measures "cost increases" and "schedule adherence" for the six projects in its study in a vacuum. CEA's measures of cost and schedule, summarized in Tables 1 and 2 above, do not offer any context or benchmark with which to understand whether, for example, the 287-day solicitation process for Suncrest is a short or a long time, only that it is the shortest among the few projects CEA studied. Because there is no context or benchmark against which to measure CEA's findings, there no way to interpret these data.

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[29] *See*, *e.g.*, Johannes P. Pfeiffenberger, *et al*., The Brattle Group , *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value* (April 2019), https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf [Brattle Report]; Paul L. Joskow, MIT Center for Energy and Environmental Policy Research [CEEPR] WP 2019-004, *Competition for Electric Transmission Projects in the U.S.: FERC Order 1000* (March 2019), https://ceepr.mit.edu/wp-content/uploads/2021/09/2019-004.pdf,

1 Similarly, CEA's failure to provide a valid control group, for example, of traditionally
2 developed transmission projects, or even competitively solicited projects won by incumbent
3 transmission owners, makes it impossible for CEA to credibly ascribe a "cost increase" or "delay"
4 to the competitive solicitation process itself, or to the award of projects to non-incumbent operators
5 (depending on the control group considered). CEA appears to understand the weakness of its
6 evidence, as it concedes that "[i]ncumbents and non-incumbents alike can be subject to project
7 delays for various reasons,"[30] and that "[n]ot all projects will exceed their cost caps, as evidenced
8 by the Duff Coleman example."[31]

9 Rather than providing a valid basis for comparison in the CEA Report itself, CEA relies
10 on a previous report by CEA ("2019 CEA Report")[32] that it maintains "showed that incumbent
11 transmission owners have successfully controlled costs for transmission projects that they have
12 undertaken."[33] The 2019 CEA Report was in large part a critique of an April 2019 report ("Brattle
13 Report") by The Brattle Group ("Brattle").[34] In an August 2019 response, however, Brattle
14 answered CEA's three main criticisms.[35] Brattle also explains that "the Concentric authors'
15 reliance on updated project costs instead of using a common reference point of the initial cost
16 estimates accounts for most of the difference between our and the Concentric authors' estimates
17 of cost escalations associated with traditionally-developed transmission projects. By using the

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[30] CEA Report at 32.
[31] *Id.*, at 34.
[32] *See,* Emma Nicholson et al., CEA, *Building New Transmission: Experience To-Date Does Not Support Expanding Solicitations* (June 2019), https://ceadvisors.com/publication/building-new-transmission-experience-to-date-does-not-support-expanding-solicitation/ [2019 CEA Report].
[33] CEA Report at n. 1.
[34] *See*, Brattle Report.
[35] *See*, Judy W. Chang, et al., Brattle, *Response to Concentric Energy Advisors' Report on Competitive Transmission* (August 2019), https://www.brattle.com/wp-content/uploads/2021/05/16873_response_to_concentric_energy_advisors_report_on_competitive_transmission.pdf [Brattle Response].

updated cost estimates, which are generally higher than initial cost estimates, as the reference point for cost comparisons, the Concentric authors' calculated cost escalations for traditionally-developed projects are much lower than our estimates."[36] In other words, CEA underestimated cost inflation in incumbent projects by using an updated cost estimate, which was higher than the initial cost estimate it used for non-incumbent projects (and that Brattle correctly used for both incumbent and non-incumbent projects).

In this case, the CEA Report uses the initial cost estimate (the "winning bid cost estimate") as the starting point to measure cost escalation to the final cost or current estimated cost of competitively solicited projects awarded to *non-incumbents* only. Because the two comparison methodologies use such materially different starting points, the results of this study and their 2019 report are not comparable. Initial cost estimates used by CEA for non-incumbent transmission projects are almost always lower than the updated cost estimates used by CEA for incumbent-owner transmission projects. In effect, CEA uses a methodology that leads to a higher cost increase for non-incumbent projects, and a different methodology for incumbent projects that leads to a lower cost increase, all else equal. CEA therefore intentionally distorts the relative cost escalations of non-incumbent and incumbent transmission projects to make non-incumbent project cost increases look larger than incumbent-owner project cost increases. Without a similar cost calculation methodology, there is no way to compare the cost and schedule performance of competitive solicitations of incumbents and non-incumbents using the data presented by CEA.

6. CEA mischaracterizes the role and effect of cost caps and other cost provisions

[36] *Id.*, at 6.

1 CEA mischaracterizes the role and effect of cost caps, cap exclusions, cost inflation
2 escalators, and other cost provisions that appear in various forms in competitive transmission
3 development contracts. These types of provisions are meant to reallocate risk between parties in
4 a complex, long-term contract, and are arrived at through contract negotiations. Contract caps with
5 exclusions (which can vary widely by project), are designed to strike a balance between protecting
6 the interests of customers, who receive a degree of protection from cost inflation of scoped costs,
7 and developers, who receive protection from unforeseen costs or costs that were outside of the
8 initial scope of the project. Inflation escalation provisions balance the interests of customers and
9 developers as well. For example, a fixed escalation provision, locks in the cost inflation for
10 customers, gives developers a degree of protection against inflation (of labor costs, equipment
11 costs. etc.) and offers a way for the parties to avoid trying to predict uncertain costs with certainty
12 at the time of the contract (when there is a great deal of uncertainty surrounding the project) At the
13 other end of the spectrum of risk allocation, cost containment and escalation provisions give the
14 parties more cost certainty than, for example a "cost-plus" contract, which would ultimately attach
15 all the risk to customers. Importantly, the intent of such cost provisions is *not* to ensure that the
16 bid cost is equal to the final cost. If that was the goal, the parties would instead agree on a fixed-
17 price contract that prices all the uncertainty surrounding the project into a single price.
18 CEA attempts to paint a very different picture of the purpose and effectiveness of cost
19 provisions that stands in stark contrast to the reasons and ways these provisions are used. CEA
20 states, for example, that "in some cases, competitive project costs have escalated significantly
21 against initial estimates provided in the selected proposals, as developers utilize exceptions to cost

caps and guarantees to recover higher than expected costs," [37] and that "[i]n some instances, cost containment provisions have offered little protection against cost increases due to the use of exclusions that allow developers to recover the costs of major cost escalations."[38] CEA ignores the nature of "cost escalations," some of which would fall contractually under cost caps, while others would not. CEA contrasts these observations about competitive solicitations won by non-incumbents, with incumbent transmission operators that CEA asserts "have demonstrated the ability to manage project costs effectively even without imposed price caps."[39] However, the basis for this assertion is not disclosed. If the basis is the 2019 CEA Report, it is not comparable to the analysis presented in the CEA Report. It also belies the fact that incumbent transmission owners commonly oppose cost caps and typically do not offer them in projects that are not subject to competitive selection. If cost caps are as ineffective in containing costs as CEA claims, incumbent transmission owners might be expected to embrace them as a low- or no-cost public relations concession.

7. Conclusion

In spite of the weaknesses in the CEA Report's evidence and analysis, CEA without qualification concludes that "[b]ased on the case studies reviewed in this paper, Order No. 1000 competitive solicitations have not delivered innovation, cost savings, or timely development of transmission."[40] The lack of valid evidentiary support for this and the related conclusions in the

[37] CEA Report at 2.
[38] *Id.*, at 3.
[39] *Id.*, at 2.
[40] *Id.*, at 35.

1 CEA Report reduce this conclusion to unsupported speculation that should be given no weight in
2 the Commission's decision-making.

I declare that the information contained in this affidavit is true and correct to the best of my knowledge and belief.

James M. Donovan, Jr.
Energy Analyst
Massachusetts Attorney General's Office, Office of the Ratepayer Advocacy
Executed on September 18, 2022

APPENDIX A

CV OF JAMES M. DONOVAN, JR.

APPENDIX A. CV OF JAMES M. DONOVAN, JR.

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PROFESSIONAL SUMMARY

James Donovan has more than 15 years of experience in the areas of economic and strategy consulting and market analysis. As an energy analyst with the Massachusetts AGO, his responsibilities include quantitative and qualitative analysis of proposals put forward by ISO-NE, NEPOOL stakeholders, and FERC. As an economic consultant, Mr. Donovan provided crucial assistance to law firms and corporate clients in complex litigation, international arbitrations, and regulatory proceedings. As a strategy consultant, he helped companies and governments navigate and plan for complex and rapidly evolving business, climate, economic, and regulatory challenges. Mr. Donovan has worked extensively on contract, damages, antitrust, competition, and intellectual property disputes, and strategy projects in a range of industries, including energy and infrastructure, software and technology, and finance. His energy background includes the conventional and renewable electricity, natural gas, and petroleum industries in the United States and internationally. He has experience with a range of economic and business issues, including climate and emissions strategy, market analysis and forecasting, financial analysis, federal and state regulatory issues, and disputes involving competition, fraud and price manipulation, tolls and tariffs, royalties, breach of contract damages, and direct and indirect asset expropriation. He has worked on international arbitrations and strategy projects involving more than a dozen countries.

EMPLOYMENT

Energy Analyst, Massachusetts AGO, Boston	May 2022 –
Principal / Affiliate, Monument Economics Group, Boston, MA	2020 – 2022
Founder and Principal, Plum Island Analytics, Ipswich, MA	2018 – 2020
Principal Consultant, International Planning & Research (IPR), Waltham, MA	2016 – 2017
Senior Economist, Quantitative Economic Solutions (QES), Boston, MA	2012 – 2016
Senior Regulatory Analyst, NSTAR (Eversource Energy), Westwood, MA	2012
Senior Economist (09 – 10), Manager(04 – 08) Compass Lexecon, Cambridge, MA	2004 – 2010

EDUCATION

M.B.A., *Summa Cum Laude*, Northeastern University	1999
B.A., Molecular Biology / Biochemistry, *Cum Laude*, Middlebury College	1994

COUNTRY EXPERIENCE

Algeria, Brazil, China, Republic of the Congo, Dominican Republic, Germany, Japan, Kenya, Kyrgyz Republic, Mozambique, Mongolia, Nigeria, Peru, Venezuela, United States, Yemen

PUBLICATIONS AND PRESENTATIONS

"Investor-State Arbitration in the Energy Sector Likely as Green Transition Accelerates," Cleary Gottlieb presentation, February 2022, contributor. (Link)

"Investment Arbitration and the Green Transition" panelist, Paris Arbitration Week, September 2021.

Grant, Kenny, and Jamie Donovan, "Governments Must Balance Green Energy, Investment Treaty Duties," Law 360, June 2021.

Ipswich Committee on Energy Use and Climate Protection, "Climate Action Plan for Ipswich, MA." (2011).

Jones, Scott "Accounting for Uncertainty in Discounted Cash Flow Valuation of Upstream Oil and Gas Investments." Transnational Dispute Management (2007).

Kursh, Steven R., with James Donovan. *Minding the Corporate Checkbook: a Manager's Guide to Evaluating and Executing Investments.* FT Press (2004).

EXPERT TESTIMONY

Columbus US, Inc., Plaintiff and Counterclaim-Defendant, vs. UMA Enterprises, Inc., Defendant and Counterclaim-Plaintiff, Superior Court of Suffolk County, MA, Civil Action No.: 2084CV000905. Expert Disclosure, December 10, 2021.

SELECTED PROJECT EXPERIENCE

ENERGY, INFRASTRUCTURE, AND CLIMATE

International Arbitration

Highway Concession Tolls IA

For a South American government in a dispute over toll increases with a highway concession owner over toll increases, managed the supporting analysis and the preparation of written expert testimony and exhibits, and assisted counsel with case strategy.

Venezuela O&G IA

For a global oil and gas company whose interests in Venezuela were expropriated by the government, developed a complex financial model to determine the NPV of the 20-year Production Sharing Agreement under a range of production, price, and macro assumptions, coordinated analysis and testimony of 8 consulting firms involved in the project, and managed the preparation of written expert witness testimony and exhibits.

Yemen O&G IA

For an oil and gas company in an international arbitration dispute over the expropriation of its interests in Yemen with the state oil company, created a model to determine the value of the production sharing agreement between the parties, managed the preparation of written expert testimony and exhibits, prepared expert witness for hearing, and assisted counsel with case strategy.

LNG Long-Term Contract IA

For a US energy company in a dispute over a long-term LNG contract with the state oil company of Algeria, created a model to estimate the wellhead value of gas from production costs, LNG processing and transportation costs, and global natural gas prices, managed the preparation of written expert testimony and exhibits, prepared expert witness for hearing, and assisted counsel with case strategy.

Litigation

Electric Generation Bid Dispute

For an energy company in a dispute with a consulting firm over a bid for new generation in Latin America, managed the supporting analysis and the preparation of written expert witness testimony and exhibits, and assisted counsel with case strategy.

Natural Gas Price Manipulation FERC Action

For a natural gas firm accused of market manipulation by FERC, developed algorithms to identify complex trading behaviors by individual traders and trading desks across markets from ICE trading data, managed the preparation of written expert witness testimony and exhibits, prepared expert witness for deposition, and assisted counsel with case strategy.

Natural Gas Price False Reporting CFTC Action

For natural gas traders accused of false reporting to index publishers by the CFTC, created a methodology and model to show defendants' reported prices were within the range of market value and did not systematically benefit their positions, managed the preparation of written expert witness testimony and exhibits, and supported counsel and expert witness through trial.

Republic of the Congo Oil Dispute

For a sovereign bond investor, developed a forecast model based on benchmark crude forecasts, adjusted for quality and location differentials, to determine the value of oil cargoes to be held as collateral.

CO2 Royalties Dispute

For the operator of a West Texas CO2 pipeline used for enhanced oil recovery (EOR) in a royalty dispute, developed a model to determine the fair market value range of CO2 over a 20-year period based on the tariff/location-adjusted initial prices of more than 200 individual CO2 contracts, and managed the preparation of expert witness testimony and exhibits.

Energy Trading Desk Fraud Dispute

For a US utility in a fraudulent conveyance dispute over its purchase of an energy trading desk from a bank that concealed crucial negative information about it, developed models to value complex power agreements to determine the value of the assets given the concealed information, and managed the preparation of written expert witness testimony and exhibits.

Qui Tam Gas Royalties Dispute

For defendants in a qui tam dispute over federal gas lease royalties, analyzed lease, royalty, and GIS data, pipeline costs and tariffs, and downstream gas prices to determine the wellhead fair market value of natural gas and the amount of underpayment, managed the preparation of written expert witness testimony and exhibits, and prepared experts for deposition.

CA Energy Crisis Class Action Certification

For natural gas company class action defendants in a suit related to the CA energy crisis, assisted counsel with case strategy, assessed the certifiability of the class of retail natural gas purchasers,

quantified the effect of alleged false reporting on natural gas prices, and analyzed pipeline capacity and flows into the CA market.

Regulatory

PV/Wind Grid Tie-In Analysis

For a non-profit entity, created a financial model to estimate revenues, costs and payback times for a proposed solar PV and wind project.

Offshore Wind

For NSTAR/ Northeast Utilities, conducted research and benchmarking analysis related to proposed Cape Wind offshore wind project.

Utility Rate and Reconciliation Filings

For NSTAR/Northeast Utilities, assisted in the preparation of MA DPU compliance and reconciliation filings, including exhibits and written company witness testimony, including Capital Projects Scheduling List (CPSL), EE Reconciliation Factors (EERF), Net Metering Recovery Surcharge, NSTAR Green Rate Adjustment, Residential Assistance Adjustment Factor (RAAF) and Smart Grid Rate Adjustment.

Utility Merger

For utilities involved in a merger, conducted research, and prepared responses to utility commission interrogatories, and modeled the financial implications of settlement agreements.

Strategy and Program Review

Kyrgyz Republic Energy Reform Report

Drafted the investment and financing chapter of a report entitled "Transforming the Energy Sector of the Kyrgyz Republic: A roadmap for Reform and Priority Investments" for the Government of the Kyrgyz Republic, which delineated the investments needed to meet energy reform priorities and climate commitments and described and evaluated financing options for the portfolio of projects.

Kenya Public Expenditure Review (PER)

Developed PowerPoint presentation to accompany the PER Interim Report to the World Bank for the water sector in Kenya, covering water and sanitation services, water resource management, flood and drought management, irrigation, and hydropower.

Mozambique Public Expenditure Review (PER)

Drafted executive summary of PER Interim Report to the World Bank for the water sector in Mozambique, covering water and sanitation services, water resource management, flood and drought management, irrigation, and hydropower.

Nigeria Public Expenditure Review (PER)

Drafted executive summary of PER Final Report to the World Bank for the water sector in Nigeria, covering water and sanitation services, water resource management, flood and drought management, irrigation, and hydropower.

Natural Gas Distribution Project

For investors in a Chinese natural gas distribution project, developed a 20-year financial model combining already-existing infrastructure and planned investments.

Water System Acquisition Targets

For an investor, identified and prioritized potential New England water systems for acquisition based on analysis of rate levels, structure, and affordability, system size, water quality, financial conditions, and location-specific issues.

Climate Action Plan

For Ipswich, MA, co-authored its Climate Action Plan, which assessed and prioritized ways for government, businesses, and residents to meet emissions reductions targets through energy conservation, efficiency, and renewables.

Transmission Planning

For Idaho Power, developed a model to optimize the utility's investment across several competing large-scale transmission projects in order to efficiently meet its forecasted future demand.