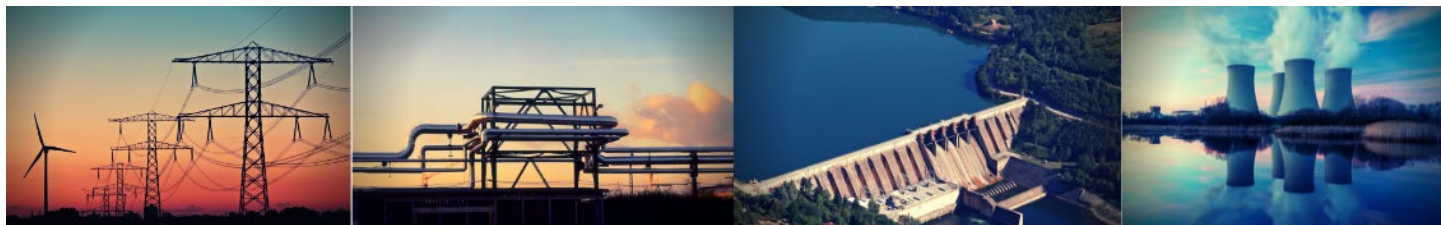


EBA BRIEFTM

A Quarterly Publication of the Energy Bar Association



INTRODUCTION FROM EBA PRESIDENT & PRESIDENT-ELECT

February 2021 brought record-shattering Arctic weather to much of the central United States and as far south as Mexico, stressing three major U.S. energy markets and resulting in massive blackouts on the Electric Reliability Council of Texas (ERCOT) system. The blackouts affected millions of Texans, many of whom were left without heat and water for days during freezing temperatures and amid a resurgent COVID pandemic. It was among the largest blackouts in U.S. history at a time like few others for many. The fallout still is being assessed, but includes tragic and preventable deaths, billions of dollars in property damage, and massive defaults and bankruptcies. In short, the system failed catastrophically.

What went wrong? Even as the crisis was evolving, opinions came fast and furiously. Was it a flaw in the market's structure that led to inadequate resources being available in a time of crisis? Was it the loss of gas supply or West Texas wind or both during the freeze? Or was it inadequate requirements to "harden" key generating equipment to withstand extreme weather events?

One of the Energy Bar Association (EBA)'s greatest strengths has always been the ability to provide a forum for thoughtful debate

ON THE DOCKET

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of legal and policy issues, where scholars, business leaders and policy makers in the energy industry can come together from across the political spectrum and industry sectors to give voice to ideas and spark solutions. The catastrophic events in ERCOT demand no less from us now.

That is why EBA is hosting a symposium on the Texas blackouts in summer 2021 that will bring together leaders in energy to discuss, debate, and isolate what went wrong and what solutions are necessary to prevent recurrence. With the great benefit of hindsight and time to gather and sort the evidence of what happened, EBA is designing an analytical, nuanced, and solutions-based approach to this symposium.

We are planning for this marquee event to be held in Austin, Texas with a virtual component available nationally. As such, we hope the symposium will be our first major in-person event since the start of the pandemic. It will introduce attendees to the newly minted Texas Chapter of EBA, which was formed this year as an expansion of the existing Houston Chapter. And it will showcase EBA and our organization's 75 years of service nationally to energy practitioners, professionals, and the people they serve.

Keep an eye out for more details in the coming weeks - we look forward to seeing you there! In addition, if you are looking for a good way to help people in need in Texas, please be on the lookout for a message soon from the Charitable Foundation of EBA linking you to charities in need of assistance. Our hearts go out to those still reeling from the blackouts and freezing weather.

Sincerely,



Jane E. Rueger
EBA President



Mosby G. Perrow IV
EBA President-Elect

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A MODEST PROPOSAL ON FEDERAL TRANSMISSION POLICY REFORM

— BY THE HONORABLE JOSEPH T. KELLIHER

Electric supply in the United States is undergoing a remarkable change—the most dramatic supply change in U.S. history. Over the past 20 years, coal generation as a share of total supply declined from 51% to 23%, natural gas generation increased from 17% to 38%, and wind and solar generation surged from less than 2% to 11%.¹ There is every reason to expect the growth of clean energy to continue, since it is driven by market fundamentals, technology improvements, corporate commitments, and customer preference. If anything, clean energy growth may accelerate as storage technology improves and federal and state policy support strengthens.

“The electric power grid is a delivery system that was designed in the past to deliver yesterday’s power supply.”

The electric power grid is a delivery system that was designed in the past to deliver yesterday’s power supply. It was configured by local utilities to deliver power from local, rather than distant, power plants. But we need a different grid to deliver tomorrow’s electricity. If we do not modernize the transmission

grid so it can support the transition to cleaner energy, that transition will be hampered, and we will be forced to retain uneconomic power plants that should retire, and develop more costly, lower quality clean energy resources instead of our best renewable resources.

Need for Federal Transmission Policy Reform

The landmark Federal Energy Regulatory Commission (FERC) Order 1000 (Order 1000), issued in 2011, was designed to strengthen regional transmission development, requiring regional plans and inter-regional planning and directing that planning to focus not just on reliability, but also on economic and public policy needs such as state renewable energy standards.² Order 1000 was a major undertaking and FERC should be commended for taking that bold step to promote the development of a clean energy grid.

Nearly a decade later, it is apparent that transmission development is not meeting the vision of Order 1000. Not one inter-regional project has been developed and most transmission development within regional transmission organizations (RTOs) is limited to local rather than regional projects. The grid is increasingly being built out through network upgrades funded by generation interconnections. This approach is inefficient and costly, causing fully contracted

renewable projects to be cancelled because of wildly unpredictable network upgrade and affected system costs. Overall, investment levels are inadequate to deliver the best clean energy resources, and to assure resilience and cyber security.

The need for an accelerated pace of regional transmission development will be even greater under the Biden Clean Energy Plan (Biden Plan), which envisions a carbon-free electricity sector by 2035.³ The Biden Plan recognizes the need to greatly expand the power grid to achieve this goal.⁴ A recent study by Princeton University projects the increase in power grid capacity necessary to enable the United States to achieve net zero carbon greenhouse gas emissions economy-wide by 2050.⁵ The study estimates that, to meet that target, power grid capacity would need to increase 60–78% by 2030 and would need to at least double by 2050.⁶

There is no prospect that the Biden Plan's transmission development requirement can be achieved under current federal transmission policy.

There are various reasons why development of regional and inter-regional transmission is falling short:

- ***Transmission Competition:*** One of the goals of Order 1000 was to encourage competition for major transmission projects, including creative solutions to transmission expansion, speeding deployment of new technology, and containing cost. However, pursuant to Order 1000: (1) competition is limited to transmission projects

whose costs are allocated on a regional basis, (2) there is an exclusion for local projects whose costs are not allocated regionally, (3) there is a “need” exclusion for projects that are required for reliability within a three-year window, and (4) there are exclusions for upgrades to existing facilities or that involve facilities that are below certain voltage levels. I commend FERC for including competitive processes in Order 1000. Indeed, competition has been effective in controlling cost; new transmission projects developed in RTO/ISO regions have seen costs lowered by 20–30% on average and lowered in some cases by as much as 50%.⁷ But in order to protect their business interests, incumbent utilities have been able to avoid competition by structuring their projects as local projects, projects falling within a need window, or upgrades to existing facilities. This behavior is perfectly rational for such utilities under regulatory economics, but it has resulted in planning focused on smaller, short-term projects that don't significantly contribute to needed grid modernization.

- ***Industry Structure:*** Most countries have either a single grid owner or a handful of owners; it is rare for a country to have ten or more grid companies. By contrast, the United States has nearly 500 grid owners; we have the most disaggregated grid in the world. This is not a source of strength. Very few U.S. grid owners have scale at a time when

there is a need to develop regional and inter-regional transmission projects to serve large markets. In addition, a third of the U.S. grid and half of the Western grid is owned by government utilities and rural electric cooperatives that are nonresponsive to market needs. Most transmission is owned by vertically integrated utilities that build to meet the needs of their retail and distribution customers rather than serving regional or market needs. The contrast between the structure of the electric and natural gas pipeline industry is striking—there are about two dozen large pipelines with regional or multi-regional scale, and some are national or North American in scale. There is nothing comparable with respect to U.S. electric transmission companies. While much of the electric grid is owned by government and non-profit corporations, all interstate pipelines are owned by corporations or other for-profit entities. Also, pipeline companies are not vertically integrated. They are dedicated to interstate gas transportation, quick to develop large projects to meet an emerging market need, and much faster at doing so than cumbersome regional transmission planning processes allow. Pipeline companies are aided, of course, by the federal eminent domain authority under the Natural Gas Act (NGA).⁸ As a result of such structural differences, the pipeline network is more robust than the power grid, an ironic contrast when

considering the objective of reducing carbon emissions.

“...the pipeline network is more robust than the power grid, an ironic contrast when considering the objective of reducing carbon emissions.”

- ***Short-Term RTO Transmission Planning and Regional Inconsistencies.*** RTO transmission planning is relatively short-term in nature, generally focusing on local projects and projects that fall within the need exclusion from competitive processes. Development of regional and inter-regional transmission that unlocks our best clean energy resources requires a longer-term focus. RTOs have little incentive to engage in such consideration. Projects that span more than one RTO raise thorny questions of cost allocation, complicated by stark regional differences. Efforts to develop regional and inter-regional transmission are undermined by variances among the RTOs’ transmission planning, system impact studies, affected system analysis, identification of network upgrades, as well as cost allocation. These inconsistencies present obstacles to the development of both regional and inter-regional transmission, but particularly hinder inter-regional projects. FERC has long had a “let a thousand flowers bloom” approach to RTOs, allowing a high degree of regional variation,

leading FERC to reflexively defer to RTO requests for variances and shy away from both standardization and active oversight of RTO transmission planning. FERC's readiness to accept RTO regional differences is rooted in the view that an RTO was less likely to use its control to engage in an unduly discriminatory manner than vertically integrated utilities.⁹

"Unfortunately, FERC has refused to take steps to produce greater consistency and predictability and lower those barriers."

That may be true, but when it established the independent entity variation, FERC did not consider whether the effect of unbridled regional variation could be unjust and unreasonable. I believe we have reached that point, and unrestrained inconsistencies raise significant barriers to regional and inter-regional planning and development. Unfortunately, FERC has refused to take steps to produce greater consistency and predictability and lower those barriers.¹⁰

A Proposal for Federal Transmission Policy Reform

Reforms that seek to accelerate development of regional and inter-regional transmission must address the factors described above. Significantly, such reforms can be adopted by FERC, acting under current law, with an assist from the U.S. Department of Energy

(DOE). These proposed reforms rely on fundamental regulatory economics and are rooted in the belief that regulated entities will act rationally if given the proper incentives.

- ***Sunset Transmission Competition:*** I believe competition has resulted in creative and lower cost solutions. However, the exclusions granted by FERC have nearly swallowed the whole, and only 3% of RTO transmission investment has been subject to competition since Order 1000 was adopted; the other 97% avoided competition.¹¹ There was a moment in 2019 when it appeared that FERC might limit these exclusions through Federal Power Act (FPA) section 206 investigations of competitive exclusions in multiple RTOs, but the agency ultimately balked.¹² At this point, there seems to be little prospect that FERC will act to expand the scope of transmission competition. Since the prospect of competition leads economically rational utilities to focus on local projects at the expense of regional projects, there is a need to choose between competing policy goals: (1) controlling cost, or (2) encouraging development of regional and inter-regional transmission. If the latter is more important, then transmission competition should be abandoned. That would make regional projects more attractive to incumbents and, in turn, result in an increased focus on long-term planning. FERC could establish effective prudence review mechanisms to police potential

excessive costs that might be collected through RTO transmission rates.

- ***Incent Development of Regional and Inter-Regional Transmission:*** FERC has the authority to use its ratemaking discretion to “encourage the orderly development of plentiful supplies of electricity . . . at reasonable prices.”¹³ FERC can set rates based *entirely* on policy considerations, and increasing supply is a valid, non-cost consideration in setting rates.¹⁴ If FERC were to conclude it was necessary to encourage development of regional and inter-regional transmission and promote the development of stand-alone transmission companies (transcos) with scale, it could establish incentive rates for regional and inter-regional projects, perhaps limiting the incentives to transcos—both affiliated and independent. The incentive could take the form of a return-on-equity (ROE) adder or a standard initial ROE that is high enough above the level produced by its current base ROE methodology to attract investment. FERC has allowed a standard initial 14% ROE for new gas pipelines since 1996 and has set a 13.5% incentive ROE for particular electric transmission projects, an approach that was upheld by the courts.¹⁵ The ROE adder or standard ROE for inter-regional projects could be higher than regional projects if FERC were to deem the former more important and needed to spur development. If FERC concluded that transcos are a better vehicle for

developing regional and inter-regional transmission, it could limit incentives to affiliated and independent transcos. Transcos could rationalize and achieve greater scale in transmission ownership.



- ***Effective Federal Transmission Siting:*** Interstate gas pipelines are sited by FERC under exclusive NGA siting jurisdiction, while electric transmission is sited by state and local governments. Certain states lack a state siting body, and transmission in those states is sited by each unit of local government along the proposed transmission path. Congress established limited federal siting authority in the Energy Policy Act of 2005,¹⁶ but that legislation was flawed, in part because it bifurcated the federal role between FERC and DOE. Whereas FERC has been siting energy infrastructure for 100 years,¹⁷ DOE has no experience siting infrastructure. Both DOE and FERC suffered setbacks in the courts on implementation of this new authority. While an in-depth discussion of those court decisions is

beyond the scope of this article, it is my view that those decisions are grossly misunderstood and actually have very limited effect. DOE's 2011 defeat in *California Wilderness Coalition v. Dept. of Energy*,¹⁸ was purely procedural, based on a failure to consult with states on corridor designation, and FERC's 2009 loss in *Piedmont Environmental Council v. Federal Energy Regulatory Commission*, was limited geographically to five states.¹⁹

"In short, federal siting remains intact and can be reimplemented in a manner to make it effective."

In short, federal siting remains intact and can be reimplemented in a manner to make it effective. The bifurcated federal role could be remedied by DOE delegation of its role to FERC,²⁰ allowing FERC to establish a consolidated proceeding wherein developers could propose narrow route-specific corridors for project siting, rather than DOE designation of very large corridors followed by a subsequent FERC siting proceeding. These proposed changes can be accomplished under current law, without new legislation.

- ***Standardization and Active Oversight of RTO Transmission Planning:*** In my view, a policy that results in a generator paying 0% of network upgrade costs in one region and 90% or 100% of costs in another region to interconnect identical facilities cannot be considered "just and

reasonable" or reasoned decision-making. Legally, FERC cannot delegate its ratemaking authority to RTOs, but unbridled deference can be indistinguishable from delegation. Instead of allowing unrestrained RTO differences that erect barriers to regional and inter-regional transmission development, FERC could adopt a different approach and more actively manage RTO planning, exercising its FPA section 206 authority to require longer-term planning and more standardization in planning and analysis, network upgrades, affected system studies, and cost allocation. This would require a significant dedication of FERC staff resources and the Commission's attention. It is possible FERC's aversion to standardization and embrace of variances without limit is a legacy of its painful experience with the Standard Market Design rulemaking.²¹ If so, perhaps after nearly twenty years the time has come to look at the merits of standardization with unjaundiced eyes.

I have limited my proposed reforms to those FERC and DOE could adopt without the need for legislation or aggressive exercise of current FERC regulatory authority. Some other reforms would require Congressional action or aggressive FERC action. For example, in order to encourage greater scale in transmission ownership FERC could require public utilities to functionally unbundle transmission and issue a FPA section 203 blanket authorization for transco consolidation and Congress could sell the federal utility

transmission systems.²² However, given new FERC leadership and an ongoing 60% change in agency composition, as well as doubts about the ability of Congress to legislate, these ideas seem beyond the pale.

Conclusion

In my view, federal electric transmission policy is falling short of the vision of Order 1000 and is beginning to impede the clean energy transition. We are not building enough regional transmission to unlock our best renewable resources, and we are not developing any inter-regional transmission. If transmission policy is not meeting current system needs, it will certainly fail to meet the dramatic capacity expansion required to achieve the goals of the Biden Plan. Transmission development is important, not only to accommodate our changing electricity supply, but also to assure resiliency and physical and cyber security.

In order to modernize the power grid so that it can support the clean energy transition FERC should adopt a mix of reforms that incent investment by incumbents in regional and inter-regional transmission, and that incent formation of transcos with scale. At the same time, FERC should assert a more active role in transmission planning, requiring greater standardization of RTO transmission planning, system impact studies and affected system analysis, network upgrades, and cost allocation.

About the Author



Mr. Kelliher served as Chairman of the U.S. Federal Energy Regulatory Commission (FERC) from July 2005 to January 2009, and as FERC Commissioner from November 2003 to July 2005. From May 2009 to October 2020, he served as Executive Vice President-Federal Regulatory Affairs for NextEra Energy, Inc., the largest electricity company in the U.S., a company comprehensively regulated by FERC.

¹ U.S. ENERGY INFO. ADMIN., Elec. Data Browser, <https://www.eia.gov/electricity/data/browser/> (click “Annual”).

² *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 F.E.R.C. ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 F.E.R.C. ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 F.E.R.C. ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

³ The Biden Plan to Build a Modern, Sustainable Infrastructure and an Equitable Clean Energy Future, JoeBiden.com, <https://joebiden.com/clean-energy/>, (last visited July 14, 2020).

⁴ *Id.*

⁵ ERIC LARSON, ET AL., NET-ZERO AMERICA: POTENTIAL PATHWAYS, INFRASTRUCTURE, AND IMPACTS, (Princeton Univ., interim report, Dec. 15, 2020), https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.

⁶ *Id.* at 7, 14, 34, 106, 155.

⁷ JOHANNES P. PFEIFENBERGER, ET. AL, COST SAVINGS OFFERED BY COMPETITION IN ELEC. TRANSMISSION 1 (Brattle Group 2019).

⁸ See 15 U.S.C. § 717(f)(h) (2020).

⁹ The legal basis for FERC's deference to RTO regional differences is the independent entity variation in Order 2003, the Standard Generator Interconnection Rule. *Standardization of Generator Interconnection Agreements and Procedures*, 172 F.E.R.C. ¶ 61,049 at PP 822, 826 (codified at 18 CFR Part 35) (2003) (Order 2003), *order on reh'g*, Order No. 2003-

A, 106 F.E.R.C. ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 F.E.R.C. ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 F.E.R.C. ¶ 61,401 (2005), *aff'd sub nom.*

¹⁰ For example, in a complaint proceeding initiated by EDF Renewable Energy, Inc. (EDF) against certain RTOs, FERC denied EDF's request for an order requiring the RTOs to establish more coordinated affected system study methodologies. FERC denied this relief despite a strong showing of harm arising from the RTOs' practices. *EDF Renewable Energy, Inc. v. Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc., and PJM*

Interconnection, L.L.C., 168 F.E.R.C. ¶ 61,173 (2019). That failure to act resulted in the cancellations of multiple fully contracted renewable energy projects in western MISO due to large, unpredictable affected system costs. See e.g., Keri Lydersen, Grid Congestion a Growing Barrier for Wind, Solar Developers in MISO Territory, Energy News Network (Sept. 29, 2020), <https://energynews.us/2020/09/29/grid-congestion-a-growing-barrier-for-wind-solar-developers-in-miso-territory/>.

¹¹ PFEIFENBERGER, *supra* note 7, at 19.

¹² *ISO New England Inc., PJM Interconnection, L.L.C., Southwest Power Pool, Inc.*, 169 F.E.R.C. ¶ 61,054 (2019). FERC initiated FPA section 206 proceedings but terminated them a few months later, requiring modest changes in PJM's implementation of the need exclusion; FERC otherwise took no action to expand the scope of transmission competition. *ISO New England Inc.*, 171 F.E.R.C. ¶ 61,211 (2020) (terminating proceeding), *reh'g*

denied, 172 F.E.R.C. ¶ 61,293 (2020); *PJM Interconnection, L.L.C.*, 171 F.E.R.C. (2020) ¶ 61,212 (requiring changes in need exclusion and terminating proceeding), *reh'g denied*, 172 F.E.R.C. ¶ 61,292 (2020); *Southwest Power Pool, Inc.*, 171 F.E.R.C. ¶ 61,213 (2020) (terminating proceeding).

¹³ *NAACP v. FPC*, 425 U.S. 662, 670 (1976).

¹⁴ *Permian Basin Area Rate Cases*, 390 U.S. 747, 791, 815 (1968); *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1503 (D.C. Cir. 1984); *Interstate Nat. Gas Ass'n of Am. v. FERC*, 285 F.3d 18, 33–34 (D.C. Cir. 2002); *Consumers Union v. FPC*, 510 F.2d 656, 660 (D.C. Cir. 1974).

¹⁵ *Cal. Pub. Util. Comm'n v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004).

¹⁶ See 16 U.S.C. § 824(p) (2020).

¹⁷ The 1920 Federal Water Power Act granted the Federal Power Commission (FPC), FERC's predecessor, exclusive siting authority over certain hydropower projects and authorized licensees to exercise eminent domain authority. 16 U.S.C. § 814 (2020). The 1938 Natural Gas Act granted the FPC exclusive authority to site interstate natural gas pipelines and certificate holders have been authorized to exercise eminent domain since 1947. Natural Gas Act § 7; P.L. 80-245 (amending 1938 Natural Gas Act § 7) (codified at 15 U.S.C. § 717(f)(h)).

¹⁸ *Cal. Wilderness Coal. v. Dept. of Energy*, 631 F.3d 1072, 1095 (9th Cir. 2011).

¹⁹ *Piedmont Envtl. Council v. FERC*, 558 F.3d 304 (4th Cir. 2009). The Solicitor General opposed a petition for certiorari in part on the grounds that FERC was free to apply its interpretation outside the Fourth Circuit. Brief for the U.S. Fed. Energy Regulatory Comm'n on Petition for Cert., *Edison Elec. Inst. v. Piedmont Envtl. Council*, 558 F.3d 304 (4th Cir. 2009) (No. 09-343).

²⁰ *U.S. Telecom Ass'n v. U.S. FCC*, 359 F.3d 554, 565 (D.C. Cir. 2004) (holding federal agencies don't need express authorization to delegate functions to other federal agencies).

²¹ Notice of Proposed Rulemaking, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, F.E.R.C. Stats. & Regs. ¶ 32,563, 67 Fed. Reg. 55,452 (2002), terminated by FERC Docket No. RM01-12-000 (July 19, 2005).

²² This proposal is different from the federal power marketing administration privatization proposals that have consistently failed going back to the 1980s. Those proposals failed due to concerns about losing regional and public preference to the output from federal hydropower projects. The proposal here would limit privatization to the transmission assets and retain federal ownership of the hydropower projects.

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CAN FERC AND THE BANKRUPTCY COURTS HAVE CONCURRENT JURISDICTION OVER THE REJECTION OF FERC-JURISDICTIONAL CONTRACTS IN BANKRUPTCY?

- BY JOHN PAUL FLOOM & SHEREEN JENNIFER PANAH

Introduction

The natural gas industry experienced a period of unprecedented demand reduction and depressed commodity prices during 2020. As a result, several companies that hold contracts for service on interstate natural gas pipelines regulated by the Federal Energy Regulatory Commission (FERC or Commission) have recently filed, or have publicly disclosed the possibility of filing, a petition for corporate reorganization under Chapter 11 of the United States Bankruptcy Code (Code) with the United States Bankruptcy Courts.¹ This increase in bankruptcy activity from customers of interstate pipelines that operate under the Natural Gas Act (NGA)² has given rise to growing concern among pipeline owners over their customers' continued performance under existing firm transportation service agreements once a bankruptcy proceeding has been initiated. Specifically, the concern lies in the tension between, on the one hand, the jurisdiction of U.S. Bankruptcy Courts to allow rejection of executory contracts pursuant to the Code,³ and the Commission's exclusive jurisdiction over filed rates approved pursuant to the NGA and subject to the longstanding *Mobile-Sierra* doctrine.⁴

Recent Commission orders⁵ related to shipper bankruptcy proceedings have highlighted this tension,

leading pipeline owners to conjecture that "rejection" of an executory contract in bankruptcy constitutes abrogation and/or modification of a "filed rate," which FERC has the authority to abrogate or modify under the *Mobile-Sierra* doctrine. The Commission's recent affirmations of its concurrent jurisdiction over jurisdictional transportation agreements paves the way for discord between FERC and bankruptcy courts,⁶ and may undermine the efficacy and efficiency of the bankruptcy process. This article describes the purpose of Chapter 11 proceedings and the Commission's NGA jurisdiction. Next, it challenges the notion that rejection amounts to abrogation and demonstrates that the Commission's recent decisions are inconsistent with federal appellate court and FERC precedents. Finally, this article describes the role that FERC can, and must, play when a shipper seeks to reject a FERC-jurisdictional agreement in bankruptcy court.

Bankruptcy Principles

The Code provides U.S. District Courts—and the bankruptcy courts—with "original and exclusive jurisdiction of all cases under title 11."⁷ Bankruptcy itself represents a fundamental public policy goal of providing "the prompt and effectual administration and settlement of the [debtor's] estate."⁸ To do so, it is

critical “to centralize disputes . . . in one forum, thus protecting both debtors and creditors from piecemeal litigation and conflicting judgments.”⁹ Hence, “[e]ase and centrality of administration are . . . foundational characteristics of bankruptcy law.”¹⁰

Embedded into the framework of the Code are the bankruptcy court’s powers of equity and law.¹¹ Guided by equitable doctrines,¹² bankruptcy courts may “grant or deny relief upon performance of a condition which will safeguard the public interest.”¹³ In this regard, bankruptcy courts are not merely ministerial registers for security holders. Rather, they are responsible for scrutinizing creditor claims, and confirming reorganization plans only after independently balancing debtor and creditor equities.¹⁴ Even so, bankruptcy courts may not “enforce [their] view of sound public policy at the expense of the interests the Code is designed to protect.”¹⁵



As part of the Chapter 11 process, the Code authorizes bankruptcy courts to allow debtors-in-possession (DIP) to assume (reaffirm) or reject (breach) executory contracts.¹⁶ Assumption allows DIPs to

continue performance under the agreement after curing all outstanding pre-bankruptcy defaults.¹⁷ Rejection allows DIPs to stop performance under an unfavorable contract.¹⁸ If rejected, the counterparty’s recourse is limited to filing an unsecured claim for damages arising from the pre-petition amounts owed and from rejection.¹⁹ Like other unsecured creditors of the estate, such counterparties may receive only a fraction of the value of their claim. Exceptions to the bankruptcy court’s sole authority over rejection exist, but neither FERC, nor FERC-approved contracts, are included in the Code’s list of limitations on the bankruptcy court’s authority.

NGA Principles

The NGA declares that “Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate . . . commerce is necessary in the public interest.”²⁰ NGA sections 4, 5, and 7 “reveal a single coherent design,” under which the Commission determines just and reasonable rates for regulated entities consistent with maintaining adequate service in the public interest.²¹

Sections 4 and 5 grant FERC authority over the rates, terms, and conditions of service that an interstate pipeline may apply to service on its system. Sections 4(c) and 4(d) require that the rates, terms, and conditions be filed with the Commission and require prior approval to change the filed rates. Section 5 authorizes FERC to determine that a rate is no longer just and reasonable and to determine a new just and

reasonable rate. Sections 4 and 5 are silent as to shipper responsibilities under transportation service agreements.

FERC's recent orders on shipper bankruptcies rely on FERC's authority and obligations under the *Mobile-Sierra* doctrine.²² This doctrine holds that FERC may only abrogate or modify a jurisdictional contract if the public interest requires FERC to do so (*i.e.*, if the contract rate "seriously harms the public interest").²³ Commission and court precedent allows the Commission to abrogate contracts where the contract rate may: (1) impair the financial ability of the public utility to continue its service; (2) cast excessive burdens on other consumers; or (3) be unduly discriminatory.²⁴ This authority is necessarily limited because contracting parties are deemed to be sophisticated businesses "enjoying presumptively equal bargaining power," that can "negotiate a 'just and reasonable' rate as between the two of them."²⁵

"The U.S. appellate courts have similarly indicated that rejection does not implicate FERC's jurisdiction under the filed rate doctrine."

Is Rejection Abrogation (i.e., Does Rejection Implicate the Filed Rate Doctrine)?

The simple and straightforward answer to the question is, "No." Rejection is merely a breach of an executory contract, which allows the non-breaching party to file an unsecured claim against the bankruptcy estate for an amount equal to the damages from the

breach.²⁶ The Supreme Court has held that "a debtor's rejection of an executory contract in bankruptcy has the same effect as a breach outside bankruptcy. Such an act cannot rescind rights that the contract previously granted."²⁷ "[B]ecause rejection 'constitutes a breach' the same consequences follow in bankruptcy. The debtor can stop performing its remaining obligations under the agreement."²⁸

The U.S. appellate courts have similarly indicated that rejection does not implicate FERC's jurisdiction under the filed rate doctrine.²⁹ In *In re FirstEnergy Sols., Corp.*, the Sixth Circuit determined that FERC-jurisdictional contracts, once they become part of a bankruptcy proceeding, "are not de jure regulations but, rather, ordinary contracts susceptible to rejection in bankruptcy."³⁰ The practical effect of this determination is that the trustee or DIP may reject FERC-jurisdictional contracts "subject to proper bankruptcy court approval and FERC cannot independently prevent it."³¹ Indeed, the Sixth Circuit held that "the public necessity of available and functional bankruptcy relief is generally superior to the necessity of FERC's having complete or exclusive authority to regulate energy contracts and markets."³²

The Fifth Circuit, in *In re Mirant Corp.*, reached a similar conclusion when it held that "FERC must rely upon the provisions of the Bankruptcy Code to limit Mirant's ability to reject the [FERC-jurisdictional contracts]. The structure of the Bankruptcy Code, however, indicates that Congress did not intend to limit the ability of utility companies to reject an executory

contract.”³³ Moreover, FERC has previously held that mitigation, which reduces the amount a debtor might have otherwise owed under a contract, “does not change the filed rate; it only changes the net amount owed as an equitable remedy for the *breach* of contract.”³⁴

“FERC would have no ‘rate change’ to approve in a reorganization plan that includes a rejection of a FERC-jurisdictional contract.”

In contrast, FERC’s current position is that rejection implicates the filed rate doctrine because it necessitates contract modification and/or abrogation.³⁵ But the courts and the Code have answered differently, finding that rejection merely allows for an orderly and efficient mechanism for creditors to recover value for their debts without rescinding the rights that the contract previously granted.³⁶

If rejection is merely a breach,³⁷ and debtors can stop performing under the agreement following rejection,³⁸ then rejection cannot implicate the *Mobile-Sierra* doctrine. To implicate the doctrine, debtors would need to be seeking modification or abrogation of a FERC-jurisdictional contract. By seeking rejection, however, debtors seek to breach that agreement and place the creditor (*i.e.*, the FERC-jurisdictional pipeline) in the same queue as other unsecured creditors to recover contract damages.

In addition, FERC’s supplemental argument that section 1129(a)(6) of the Code allows FERC to approve a reorganization plan does nothing to advance the notion that rejection alters the filed rate.³⁹ If, following approval of a request to reject an executory contract, the “debtor can stop performing its remaining obligations under the agreement,”⁴⁰ there is no rate modification under the contract that must be approved. The remedy for breach is mitigation, which, again, “does not change the filed rate; it only changes the net amount owed as an equitable remedy for the breach of contract.”⁴¹

Thus, FERC would have no “rate change” to approve in a reorganization plan that includes a rejection of a FERC-jurisdictional contract.

The Policy Implications of FERC’s Recent Decisions

FERC’s above-noted conflation of “modification and/or abrogation” with “rejection,” and its assertion of concurrent jurisdiction with bankruptcy courts has wide-ranging implications for customers of interstate gas pipelines. Bankruptcy proceedings will become inefficient because shippers will exit bankruptcy “[h]ampered by the pressure and discouragement of preexisting debt.”⁴² Under FERC’s view, FERC would be required to opine whether the shipper-debtor could reject, abrogate, or modify its jurisdictional contracts in each bankruptcy proceeding. This could lead to the creation of an extra-statutory super-class of pipeline creditors that would have their debts paid first, or not extinguished, ahead of all other creditor classes defined in the Code.

In addition, requiring assumption of FERC-jurisdictional contracts significantly increases the possibility that a shipper will exit bankruptcy as a refinanced business, only to face insufficient cashflows from other remaining assets to pay for the charges incurred under such contracts.

Conclusion

The implications of the Commission's recent orders go far beyond the statutory limits that the Code and the NGA impose on FERC. Thus, FERC should reconsider its approach to shippers entering bankruptcy and allow the bankruptcy courts to manage the bankruptcy process as Congress intended.

About the Authors



Mr. Floom has over 20 years of experience representing natural gas producers and marketers in proceedings at the FERC. With the recent spate of bankruptcy proceedings concerning FERC-jurisdictional contracts, Mr. Floom has developed an interest in the interplay between the FERC's authority to allow abrogation of a filed rate contract and the bankruptcy courts' exclusive jurisdiction over rejection of executory contracts in bankruptcy.



Ms. Panahi joined Floom Energy Law in September 2020 following her two-year tenure as an attorney-advisor to FERC Administrative Law Judges. Ms. Panahi has prior experience with Chapter 13 bankruptcy proceedings as well as FERC ratemaking under the Natural Gas Act. As the landscape for both fields has changed throughout an unprecedented 2020, Ms. Panahi is keeping a close eye on the emerging trends in regulatory response affecting the wholesale electric and natural gas sectors.

¹ 11 U.S.C. §§ 101–1532 (2018).

² 15 U.S.C. §§ 717–717z (2018).

³ 11 U.S.C. § 365(a).

⁴ See *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956); *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956).

⁵ *Rockies Express Pipeline LLC*, 172 F.E.R.C. ¶ 61,279 (2020); *ETC Tiger Pipeline, LLC*, 171 F.E.R.C. ¶ 61,248 (2020).

⁶ *Rockies Express*, 172 F.E.R.C. ¶ 61,279 at P 27 (recognizing concurrent jurisdiction under sections 4 and 5 of the NGA and the Bankruptcy Code, while asserting that the Bankruptcy Code does not displace the Commission's jurisdiction over filed rate contracts), citing *ETC Tiger*, 171 F.E.R.C. ¶ 61,248 at P 22.

⁷ 28 U.S.C. § 1334(a)(2018).

⁸ *Moses v. CashCall, Inc.*, 781 F.2d 63, 72 (4th Cir. 2015) (quoting *Katchen v. Landy*, 382 U.S. 323, 328 (1966); *Celotex Corp. v. Edwards*, 514 U.S. 300, 308 (1995)); *Ex parte City Bank of New Orleans*, 44 U.S. 292, 312 (1845).

⁹ *Moses*, 781 F.2d at 72 (citing *Phillips v. Congelton, L.L.C.* (In re *White Mountain Mining Co.*), 403 F.3d 164, 169–70 (4th Cir. 2005); *A.H. Robins Co. v. Piccinin*, 788 F.2d 994, 998 (4th Cir. 1986)).

¹⁰ *Id.*

¹¹ *Celotex Corp.*, 514 U.S. at 328 (citing 28 U.S.C. § 1481 (1982 ed.)).

¹² *SEC v. U.S. Realty & Improvement Co.*, 310 U.S. 434, 455 (1940).

¹³ *Id.*

¹⁴ *American United Mut. Life Ins. Co. v. Avon Park*, 311 U.S. 138, 145 (1940).

¹⁵ *Midlantic Nat'l Bank v. New Jersey Dep't of Envtl. Prot.*, 474 U.S. 494, 514 (1986) (prohibiting expenditure of resources to further environmental agency's goals) (Rehnquist, J. dissenting); *U.S. Realty*, 310 U.S. at 455.

¹⁶ 11 U.S.C. §§ 365(a), 1107.

¹⁷ See *id.* § 365(b); *In re Washington Capital Aviation & Leasing*, 156 B.R. 167, 173 (Bankr. E.D. Va. 1993); Jay Westbrook, *A Functional Analysis of Executory Contracts*, 74 MINN. L. REV. 227, 231 (1989) ("Assume" and

'reject' are merely bankruptcy terms for the decision to perform or to breach, an election open to any party to a contract outside of bankruptcy.>").

¹⁸ See *Aslan v. Sycamore Inv. Co.*, 909 F.2d 367 (9th Cir. 1990).

¹⁹ *NLRB v. Bildisco and Bildisco*, 465 U.S. 513 (1984). The creditor has (1) a damage claim for breach of contract, and (2) an administration expense claim for benefits received by the DIP prior to rejection. See, e.g., *In re Bridgeport Plumbing Prods., Inc.*, 178 B.R. 563 (Bankr. M.D. Ga. 1994).

²⁰ 15 U.S.C. § 717(a).

²¹ *N. Nat. Gas Co. v. FERC*, 827 F.2d 779, 787 (D.C. Cir. 1987).

²² See, e.g., *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty.*, 554 U.S. 527, 547–48 (2008).

²³ *Id.*; see also *NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165, 167 (2010).

²⁴ *Sierra*, 350 U.S. at 354–55.

²⁵ *Morgan Stanley*, 554 U.S. at 545 (quoting *Verizon Commc'ns. Inc. v. FCC*, 535 U.S. 467, 479 (2002)).

²⁶ *In re Mirant Corp.*, 378 F.3d 511, 520 (5th Cir. 2004).

²⁷ *Mission Prod. Holdings v. Tempnology, LLC*, 139 S. Ct. 1652, 1666 (2019).

²⁸ *Id.* at 1662–63.

²⁹ See *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 579 n.9 (1981); *In re FirstEnergy Sols., Corp.*, 945 F.3d 431, 452 (6th Cir. 2019); *In re Mirant Corp.*, 378 F.3d at 520; *Gulf States Utils. Co. v. Ala. Power Co.*, 824 F.2d 1465, 1471–73 (5th Cir. 1987). Notably, in a case involving PG&E Corp., the Ninth Circuit vacated as moot two FERC orders and one bankruptcy court order that dispute FERC's FPA jurisdiction over PG&E's power purchase agreements in PG&E's bankruptcy proceeding without opining on the merits of the jurisdictional claims. *PG&E Corp. v. FERC* (In re PG&E Corp.), 603 B.R. 471 (Bankr. N.D. Cal. June 7, 2019), *amended and direct appeal certified*, 2019 WL 2477433 (Bankr. N.D. Cal. June 12, 2019),

permission to appeal granted, No. 19-71615 (9th Cir. Sept. 17, 2019), vacated as moot, D.C. No. 3:19-bk-30088 (9th Cir. Oct. 7, 2020).

³⁰ *In re FirstEnergy Sols., Corp.*, 945 F.3d at 446.

³¹ *Id.*

³² *Id.* at 445–46.

³³ *Mirant*, 378 F.3d at 521.

³⁴ *U.S. Gen. New England, Inc.*, 116 F.E.R.C. ¶ 61,285 at P 32 (2006) (emphasis added).

³⁵ See, e.g., 171 F.E.R.C. ¶ 61,248 at P 23 (citing *NextEra Energy Inc. v. Pac. Gas & Elec. Co.*, 166 F.E.R.C. ¶ 61,049 at P 29 (2019); *Exelon Corp. v. Pac. Gas & Elec. Co.*, 166 F.E.R.C. ¶ 61,053 at P 26 (2019)).

³⁶ See, e.g., *Mission Prod.*, 139 S. Ct. at 1661–63, 1666 (holding that rejection of trademark licensing agreement could not revoke the license or deprive creditor-licensee of its rights to use the trademark, so licensee may continue to do whatever the license authorizes); *Mirant*, 378 F.3d at 520–21 (finding rejection is merely a breach and does not implicate the “filed rate”).

³⁷ *Mirant*, 378 F.3d at 520.

³⁸ *Mission Prod.*, 139 S. Ct. at 1666.

³⁹ Section 1129(a)(6) states that the bankruptcy court may only confirm a reorganization plan if “[a]ny governmental regulatory commission with jurisdiction, after confirmation of the plan, over the rates of the debtor has approved any rate change provided for in the plan, or such rate change is expressly conditioned on such approval.” 11 U.S.C. § 1129(a)(6).

⁴⁰ *Mission Prod.*, 139 S. Ct. at 1666.

⁴¹ 116 F.E.R.C. ¶ 61,285 at P 32. This conclusion is also supported by *Mission Products*, where the Supreme Court’s analysis found that “breach” has the same meaning in the Code as it does in contract law outside of bankruptcy. *Mission Prod.*, 139 S. Ct. at 1661 (citing *Field v. Mans.*, 516 U.S. 59, 69 (1995)). From there, the Court turned to non-bankruptcy contract law to evaluate the effects of breach. *Mission Prod.*, 139 S. Ct. at 1661–62. Applying its own analysis, the Court arrived at the same conclusion as the Bankruptcy Appellate Panel, which found that “outside of bankruptcy, breach of contract does not eliminate the rights the contract had already conferred on the non-breaching party, so neither could a rejection of an agreement in bankruptcy have that effect.” *Id.* at 1659. The Court went on to hold that rejection of “any contract” in bankruptcy “operates not as a rescission but as a breach.” *Id.* at 1659, 1661. Applied here, the right to damages for breach of contract is measured by the value of the would-be performed contract, or the *filed rate*. Whether the pipeline decides to “continue the contract or walk away” while suing for breach of contract damages in response to a shipper’s rejection does not disturb the pipeline’s right to charge the filed rate or enjoy any other rights granted to it under the contract. *Id.* at 1662. Indeed, one cannot simultaneously exercise the contractual right to receive damages based on the filed rate while at the same time claiming that abrogation or modification by rejection has terminated *that same contractual right* to charge the filed rate.

⁴² *Local Loan Co. v. Hunt*, 292 U.S. 234, 244 (1934).



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SECTION 45Q TAX CREDIT FOR SECURE GEOLOGICAL STORAGE OF CO₂: HISTORY, STATE OF PLAY, AND AN EYE TO THE FUTURE

- BY PHILIP M. MARSTON

In 2018, Congress adopted the Bipartisan Budget Act (BBA)¹ which, among many other things, amended the 26 U.S.C. § 45Q investment tax credit (§ 45Q Credit or Credit), originally adopted in 2008.² This Credit is available to taxpayers who use qualifying captured carbon dioxide (CO₂)³ in certain ways, including as a tertiary injectant in the enhanced recovery of oil or natural gas, usually referred to as enhanced oil recovery (CO₂-EOR). It is an oil recovery technique that has been used commercially for nearly fifty years.⁴ To qualify for the § 45Q Credit for CO₂ use in CO₂-EOR operations, taxpayers must meet certain requirements, including that the qualified captured CO₂ must be “disposed of by the taxpayer in secure geological storage.”⁵ Rather than define the term “secure geological storage,” the 2018 statute, like the original 2008 law, directed the Secretary of the Treasury to “establish regulations for determining adequate security measures for the geological storage . . . such that the qualified carbon dioxide does not escape into the atmosphere.”⁶

“It is particularly important to have a final rule with clear definitions and implementation procedures...”

Following enactment of the Credit in 2008, the Internal Revenue Service (IRS) did not issue the required regulation, but instead issued interim guidance for the term in Notice 2009-83 (2009 Guidance).⁷ In June 2020, however, a proposed rule was published to formally define the term, as well as to implement various other statutory provisions,⁸ and a final rule was published in the Federal Register on January 15, 2021 (Final Rule).⁹ It is particularly important to have a final rule with clear definitions and implementation procedures because of the very large capital commitments required to design and construct facilities for capturing CO₂ at qualifying facilities and for integrating the captured CO₂ into planning and operation of long-lived CO₂-EOR operations.

While the Final Rule is complex and addresses many aspects of implementing the statutory Credit, this article addresses the narrow question of how to define and implement the statutory term “secure geological storage” over the last decade. The article seeks to clarify the legal and historical record regarding IRS implementation of the “secure geological storage” requirement, as interpreted by the 2009 Guidance and IRS reporting forms. Understanding this history may facilitate public discussion of what is required to qualify for the § 45Q Credit in light of changes resulting from the recently issued Final Rule.

November 2009: the 2009 Guidance is issued. The 2009 Guidance provided “interim” guidance for claiming the § 45Q Credit. It directed taxpayers to use the “methodology, inputs, and equations” in the Environmental Protection Agency’s (EPA) greenhouse gas (GHG) reporting rule “or any successor rule.”¹⁰ The 2009 Guidance explicitly recognized that geological sequestration was occurring “at active EOR facilities” and noted that EPA had, in 2009, indicated its intention to develop GHG reporting rules for CO₂ injections, specifically including CO₂ injections that were “geologically sequestered at active EOR facilities.”¹¹ The 2009 Guidance also reiterated that when EPA completed that work, such rules would apply “to the extent applicable.”¹² Pending the EPA rulemaking, taxpayers were guided to comply with guidelines published by the Intergovernmental Panel on Climate Change (IPCC).¹³

2009-2015: IRS Form 8933 relies on the 2009 Guidance. Following issuance of the 2009 Guidance, the IRS began to implement the § 45Q Credit by promulgating the applicable form, Form 8933, to claim the Credit. Beginning in 2009, the instructions to Form 8933 defined the term “secure geological storage” by citing “such conditions as the IRS may determine under regulations”—which had never been issued. Pending such regulations, the instructions pointed taxpayers back to the 2009 Guidance, stating:

Secure Geological Storage

This includes storage at deep saline formations, oil and gas reservoirs, and unminable coal seams under such conditions as the IRS may determine under regulations.

See Notice 2009-83, 2009-44 I.R.B. 588, for more information on secure geological storage. Notice 2009-83 is available at www.irs.gov/irb/2009-44_IRB/ar11.html.¹⁴

Identical instructions were repeated on Form 8933 for the next seven years, from 2009 through and including 2015.¹⁵ As noted above, the 2009 Guidance referred the reader to the IPCC guidelines or the EPA rules “to the extent applicable.”¹⁶

*April 2010: EPA Subpart RR is **proposed** for CO₂-EOR and non-CO₂-EOR injections.* In the spring of 2010, EPA began to develop rules applicable to CO₂ injections. It proposed a rule to bring all geologic injections of CO₂ within its GHG emission reporting framework.¹⁷ EPA proposed to establish “subpart RR” of the GHG reporting categories, which would apply to “all” injections of CO₂ in the subsurface.¹⁸ Thus, the proposed rule included injections for CO₂-EOR operations (where CO₂ is “inherently stored” as an intrinsic part of the oil recovery operation)¹⁹ as well as injections without such hydrocarbon recovery (where there is no offsetting withdrawal of production fluids to balance CO₂ injections and maintain a subsurface pressure equilibrium).²⁰ As proposed, subpart RR applied to all CO₂ injections in the subsurface for any

purpose, while reporting obligations were divided into a “Tier 1” and “Tier 2.” Tier 1 reporting applied to all CO₂ injections, while Tier 2 imposed additional requirements—including an EPA-approved monitoring, reporting and verification (MRV) plan—for “geological sequestration facilities”, and only applied to CO₂-EOR injections if the operator voluntarily chose to do so. The additional MRV requirement for Tier 2 reflected the higher subsurface pressures and greater areal extent expected in such non-EOR operations.²¹

*December 2010: **Proposed** subpart RR is **finalized** as subparts UU and RR of the final rules.* The final rule adopted in December 2010 preserved the distinction between pressure-balanced enhanced oil recovery operations and higher-pressure, non-EOR based injections.²² But rather than keep both types of geological injections in a single subpart with differing requirements, the final rule split proposed subpart RR into two separately designated subparts.

- *Subpart UU:* Newly designated subpart UU was adopted for CO₂ that is injected and incidentally stored in association with EOR operations. Due to the pressure balancing of CO₂-EOR, where fluid injections of CO₂ are balanced with fluid withdrawals, and the now-50 years of operating experience of safe, secure associated storage of CO₂ through EOR under Class II well permitting regulations, EPA did not require submission

and EPA approval of MRV plans under subpart UU.

- *Subpart RR:* The initially proposed subpart RR was reconfigured and designated for reporting CO₂ injections in higher pressure, non-EOR storage operations (e.g., saline aquifers) where fluid injections of CO₂ are not offset by fluid withdrawals of production fluids.²³ However, EOR operators were given the option of electing to report under subpart RR (with the requirement for an EPA-approved MRV plan), if they so choose.²⁴

“The net effect of EPA’s rulemaking in 2010 was to create two subparts that are applicable to geologic injections of CO₂, but to different types of injections.”

The net effect of EPA’s rulemaking in 2010 was to create two subparts that are applicable to geologic injections of CO₂, but to different types of injections. The applicable reporting rule for injections with associated storage of CO₂ in active EOR facilities is subpart UU. The subpart UU reported data fits into EPA’s broader GHG reporting framework for reporting emissions from other aspects of CO₂-EOR operations: subpart PP (for CO₂ supply), subpart W (surface equipment leakage and venting of CO₂), and subpart C (stationary fuel combustion sources on site, if any). Reporting under subpart RR is an option for CO₂-EOR, but not a requirement.²⁵

The above timeline demonstrates that the 2009 Guidance did not—and indeed could not—have conditioned availability of the Credit exclusively on subpart RR reporting for the simple reason that the rule would not even be proposed until April 2010, or adopted until December 2010, thirteen months after publication of the 2009 Guidance. Those final rules applied to CO₂ injections for *both* CO₂-EOR, where EPA has separately recognized that CO₂ storage associated with the operation is a “common occurrence” and such “[g]eologic storage of CO₂ can continue to be permitted” under UIC Class II,²⁶ as well as injections for storage that is not associated with CO₂-EOR. Subpart UU is for the former and subpart RR for the latter, with a voluntary option for CO₂-EOR operators to elect subpart RR if they so choose. And as repeatedly recognized by EPA, geologic storage of CO₂ occurs in both types of injection operation.

“The new requirement was unannounced, unexplained and unforeseen.”

2016: The sub silentio revision of Form 8933 purports to limit the EOR Credit to those reporting non-EOR associated storage under subpart RR and those “opting in.” In August 2015, IRS issued public notice to promulgate Form 8933 for the 2016 tax year, stating that “[t]here are ***no changes being made*** to this form [Form 8933] at this time.”²⁷ Contrary to this public representation, however, IRS did revise the instructions to impose

subpart RR reporting as a requirement, retroactive to 2010.²⁸ The new instructions for “secure geological storage” read:

Secure Geological Storage: This includes storage at deep saline formations, oil and gas reservoirs, and unminable coal seams under such conditions as the IRS may determine under regulations.

After 2010:

- Secure geological storage requires approval by the EPA of a Monitor, Report and Verify Plan (MRV Plan) submitted by the operator of the storage facility or tertiary injection project.
- The annual amount of carbon dioxide claimed for the credit must be reconciled with amounts reported to the U.S. Environmental Protection Agency (EPA) under its Greenhouse Gas Reporting Program, subpart RR.

See the EPA website at www.epa.gov and Notice 2009-83, 2009-44 I.R.B. 588, for more information on secure geological storage. Notice 2009-83 is available at www.irs.gov/irb/2009-44_IRB/ar11.html.²⁹

In short, after seven years of consistently instructing taxpayers to follow the 2009 Guidance on “secure geological storage”—which pointed to the IPCC framework or to subsequent EPA reporting rules “to the

extent applicable”—the revised Form 8933 purported to require subpart RR reporting, together with an EPA-approved MRV plan.³⁰ The new requirement was unannounced, unexplained and unforeseen.

2019-2020: The Treasury admits that Form 8933 has imposed “additional” requirements. In 2019, the Treasury explicitly recognized that “IRS Form 8933 *adds regulatory requirements* for Class II UIC permit holders (enhanced oil recovery operations) who are not currently required to get an EPA-approved MRV plan.”³¹ The Department repeated this recognition in its 2020 proposed rule to implement the Credit by stating that Form 8933 imposed an “*additional burden*” on Class II CO₂-EOR operators.³² The IRS has not, however, recognized that this “additional burden” of subpart RR reporting beginning with the 2016 form was also contrary to the Form 8933 instructions that had been in place for the seven prior years. IRS also did not recognize that the 2016 revisions had been adopted contrary to its prior express representation that “no changes” were being made to the form. Yet the IRS cannot change a regulation, modify an officially published notice, or “add regulatory requirements” by means of unannounced, *sub silentio*, revisions to the instructions on a tax form.³³

Where Do We Go from Here?

The 2009 Guidance instructed taxpayers seeking to claim the § 45Q Credit that they must comply with future EPA reporting and UIC permitting rules “to the extent applicable” or “as required” under EPA rules.”³⁴

It is now equally clear that EPA has established *two parallel reporting paths* for geological injections of CO₂. Both reporting paths arose from a common source: the subpart RR rule proposed in April 2010. For seven years, the applicable IRS Form 8933 reflected this regulatory disposition and instructed taxpayers to comply with the EPA rules “to the extent applicable.”³⁵ Then, in 2016, and contrary to its public notice, IRS sought to impose what it has itself recognized as an “additional regulatory requirement”³⁶ or burden that EOR operators *must* comply with an EPA regulatory provision that EPA quite explicitly has left voluntary. It is not surprising that regulatory implementation of the § 45 Credit has created considerable confusion and uncertainty.

The recent Final Rule states repeatedly that IRS is “contemplating making additional changes to the Form 8933” to account for various provisions in final regulations.³⁷ It is hoped that these anticipated revisions will resolve the confusion and correct the errors introduced by the earlier revisions to the Form. CO₂-EOR has the potential to geologically store large quantities of captured CO₂ as an inherent part of the process of recovering otherwise stranded hydrocarbons, thus serving the dual public interests in reducing CO₂ emissions while simultaneously maximizing resource extraction from already-developed oil fields. Congress sought to incentivize such operations by providing the § 45Q Credit in 2008 for using qualified CO₂ and extending and enhancing it on a bipartisan basis in 2018 through the Bipartisan Budget Act. Experience in

implementing the Credit over the last dozen years has revealed difficulties in achieving the congressional objective, in particular due to the lack of a clear, consistent, and well-founded definition of the statutory term “secure geological storage.” The recent Final Rule has at last promulgated the regulation originally mandated by Congress when it created the § 45Q Credit some thirteen years ago. Hopefully, a better understanding of the evolution of the intertwined regulations of the IRS and the EPA, and a more accurate understanding of the applicable law, may facilitate future regulatory implementation of this important bipartisan tax legislation.

About the Author



Philip M. Marston is an internationally recognized expert in energy regulation and policy with four decades of experience. He founded Marston Law in 1998. His practice now focuses on CO₂ capture, transport, and use, including the ISO 27916 standard for documenting and quantifying associated storage of CO₂ in enhanced oil recovery. The views expressed here are personal. He has written widely on energy regulatory issues and can be reached at pmarston@marstonlaw.com.

The author wishes to thank former EBA President Fred Moring for teaching him to be an energy lawyer and introducing him to EBA in 1976

¹ Bipartisan Budget Act of 2018, Pub. L. No. 115–123, § 41119, 132 Stat. 64, 162 (Feb. 9, 2018).

² Energy Improvement and Extension Act of 2008, Pub. L. No. 110–343, § 115, 122 Stat. 3829 (Oct. 3, 2008), *amended by* American Recovery and Reinvestment Tax Act of 2009, Pub. L. No. 111–5, § 1131, 123 Stat. 115 (Feb. 17, 2009).

³ The 2008 statute applied to “carbon dioxide.” *See id.* The 2018 BBA applies to all “carbon oxides.” *See* Bipartisan Budget Act of 2018, *supra* note 1. The focus of this article is only on carbon dioxide or “CO₂.”

⁴ For an overview of the CO₂-EOR process, *see* *Introduction to CO₂-EOR*, informative Annex A to CSA/ANSI ISO 27916:19 (“Carbon dioxide capture, transportation and geological storage — Carbon dioxide storage using enhanced oil recovery (CO₂-EOR)” (ISO 27916:2019, IDT)) [hereinafter ANSI/ISO 27916].

⁵ 26 U.S.C. § 45Q(a)(4)(B)(i).

⁶ Bipartisan Budget Act of 2018, *supra* note 1. The 2008 statute required that the regulation be adopted in consultation with the Secretary of Energy and the EPA Administrator. The 2018 BBA included the Secretary of Interior in the required consultation.

⁷ Internal Revenue Service, Notice 2009–83: “Credit for Carbon Dioxide Sequestration Under Section 45Q”, 2009–44 I.R.B. 588, 590 (Nov. 2, 2009) [“2009 Guidance”].

⁸ Notice of Proposed Rulemaking, *Credit for Carbon Oxide Sequestration*, 85 Fed. Reg. 34,050 (June 2, 2020) [“Proposed 45Q Rule”].

⁹ Final Regulation, *Credit for Carbon Oxide Sequestration*, 86 Fed. Reg. 4728 (January 15, 2021) [“Final 45Q Rule”]. The Final 45Q Rule has an effective date of January 13, 2021 and provides several applicability dates for particular provisions.

¹⁰ 2009 Guidance, *supra*, note 7, at 590.

¹¹ *Id.* at 591. Section 5.02 (b)(iii), entitled “Proposed Geologic Sequestration Rules”, states that “such rules (or any successor rules) will apply in addition to the final [Underground Injection Control] program rules (to the extent applicable)” (emphasis added).

¹² *Id.* (emphasis added).

¹³ *See id.* at 590. The referenced IPCC guidelines generally require: (1) a site characterization; (2) a leakage risk assessment to evaluate the potential

for leakage; and (3) monitoring potential leakage pathways, measuring leakage at those pathways as necessary, monitoring current and future behavior of the CO₂ and the storage system, and using the results of the monitoring plan to validate and/or update models as appropriate.

¹⁴ INTERNAL REVENUE SERVICE, Form 8933 (2009–2015), <https://apps.irs.gov/app/picklist/list/priorFormPublication.html?resultsPerPage=200&sortColumn=sortOrder&indexOffFirstRow=0&criteria=formNumber&value=8933&isDescending=false>.

¹⁵ *Id.*

¹⁶ 2009 Guidance, *supra*, note 7, at 591.

¹⁷ Proposed Rule, *Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide*, 75 Fed. Reg. 18,576 (2010).

¹⁸ *Id.* at 18,593 and 18,600 (proposing new § 98.440(a)).

¹⁹ ANSI/ISO 27916, *supra* note 4 at 20 (quoting Carbon Sequestration Leadership Forum, *Final Report by the CSLF Task Force on Technical Challenges in the Conversion of CO₂-EOR Projects to CO₂ Storage Projects* 58 (2013), https://www.cslforum.org/cslf/sites/default/files/documents/CO2-EORtoCCS_FinalReport.pdf).

²⁰ For an explanation of the pressure equilibrium typical of CO₂-EOR, the significantly smaller areal extent of the injected CO₂, and other differences between the two types of CO₂ injections, *see* ANSI/ISO 27916, *supra* note 4 at 29–30. *See also* Carbon Capture and Storage: Emerging Legal and Regulatory Issues, at 269–72 (Havercroft et al. eds., 2d ed. 2018).

²¹ *See* *Mandatory Reporting of Greenhouse Gases*, *supra* note 17, at 18,579.

²² Final Rule, *Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide*, 75 Fed. Reg. 75,060 (2010) (codified at 40 C.F.R. pts. 72, 78, 98) [“Final RR/UU Rule”].

²³ *See* ANSI/ISO 27916, *supra* note 4. *See also* Philip M. Marston, *Pressure profiles for CO₂-EOR and CCS: Implications for regulatory frameworks*, 3 GREENHOUSE GAS SCI. TECH., 165, 165–68 (2013), <http://onlinelibrary.wiley.com/doi/10.1002/ghg.1348/full>.

²⁴ *See* 40 C.F.R. § 144.19. In its Underground Injection Control (UIC) rules, EPA has listed a number of operational factors that might materially alter the risk profile of a traditional CO₂-EOR operation, such as increases

in reservoir pressure or injection rates, decreases in production rates, and various other site-specific risk factors. *See id.*

²⁵ *See* 40 C.F.R. § 98.440(c). Subpart RR does not include CO₂ injections for EOR unless, *inter alia*, owner or operator “has chosen” to submit and obtain approval of an MRV plan from the EPA.

²⁶ Final Rule, *Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, 80 Fed. Reg. 64,510, 64,585 (2015). EPA explained there that CO₂ that remains in the reservoir during CO₂-EOR operations “is not mobile and becomes sequestered,” *id.* at 64,579, and CO₂ injected via Class II wells “becomes sequestered by the trapping mechanisms” described in the rule, *id.* at 64,588. Thus, “[g]eologic storage of CO₂ can continue to be permitted under the UIC Class II program.” *Id.* at 64,590. EPA further noted that “[g]eologic storage options [under that emission standard rule] include use of CO₂ in EOR operations” and indeed that “of the [carbon capture and storage] projects under construction or at an advanced stage of planning, 70 percent intend to use captured CO₂ to improve recovery of oil in mature fields.” *Id.* at 64,566.

²⁷ Notice and Request for Comments, *Proposed Collection; Comment Request for Form 8933*, 80 Fed. Reg. 46,648, 46,649 (August 5, 2015) (emphasis added).

²⁸ INTERNAL REVENUE SERVICE, Form 8933, INSTRUCTIONS FOR 2016, <https://www.irs.gov/pub/irs-prior/f8933--2016.pdf>.

²⁹ *Id.*

³⁰ *Id.*

³¹ Request for Comments on Credit for Carbon Oxide Sequestration, Notice 2019-32, 2019-21 I.R.B. 1187, 1189 (May 20, 2019) (emphasis added) (https://www.irs.gov/irb/2019-21_IRB) (*see esp.* section 3.01).

³² Proposed 45Q Rule, *supra* note 8, at 34,055 (recognizing that Form 8933 requirement to receive an approved MRV Plan for purposes of the section 45Q credit “creates an additional burden” on Class II permit holders) (emphasis added).

³³ The IRS “Oil and Gas Handbook” asserts that the preamble to EPA’s reporting rule states that “operators of facilities that are sequestering CO₂ in geologic storage must comply with Subpart RR regardless of whether the CO₂ is currently used as a tertiary injectant in an EOR project.” *See* INTERNAL REVENUE SERVICE, OIL AND GAS HANDBOOK, https://www.irs.gov/irm/part4/irm_04-041-001 (emphasis added). This statement is simply wrong. As detailed above, the Final RR/UU rule requires subpart UU reporting for *all* CO₂-EOR injections unless the operator voluntarily elects to file under subpart RR. *See* 40 C.F.R. § 98.440(c). *See also* Final RR/UU Rule, *supra*, note 22, 75 Fed. Reg. at 75,064. It is simply incorrect to say otherwise. In any event, the Oil and Gas Handbook is part of the IRS Manual and, thus, does “not have the force and effect of law.” *See* U.S. v. Horne, 714 F.2d 206, 207 (1st Cir. 1983).

³⁴ 2009 Guidance, *supra*, note 7, at 591.

³⁵ PRIOR YEAR PRODUCTS, Form 8933, (2009-2015) INTERNAL REVENUE SERVICE, <https://apps.irs.gov/app/picklist/list/priorFormPublication.html?sessionId=AFQdYcmNabFwBIzb1ZVcXSDh.20?value=8933&criteria=formNumber&submitSearch=Find>.

³⁶ Proposed 45Q Rule, *supra*, note 8, 85 Fed. Reg. at 34,055.

³⁷ Final 45Q Rule, *supra*, note 9, 86 Fed. Reg. at 4756 and 4757.



EBA IS CELEBRATING 75 YEARS!!

of advancing the professional excellence of those engaged in energy law, regulation and policy through professional education, exploring diverse viewpoints and building connections. #75YearsofEBA

Diversity and Inclusion Policy

Adopted 2017, Amended 2021

The Energy Bar Association (“EBA”), the Charitable Foundation of the Energy Bar Association (“CFEBA”), and the Foundation of the Energy Law Journal (“FELJ”) (jointly referred to as the “Associations”) are committed to the goals of fostering an inclusive and diverse membership and increasing diversity across all levels of the Associations. Attorneys, Energy Professionals and Students with varied and diverse characteristics practicing in the energy field are welcome to join our ranks and are encouraged to become active participants in the Associations’ activities.

For all purposes within this Policy and its application across the Associations, “diversity” and “diverse characteristics” will include but not necessarily be limited to differences in race, creed, color, ethnicity, Native American, Alaska, or Hawaiian Native tribal membership or descentance, gender (including gender identity or expression), sexual orientation, family and marital status (including pregnancy), family responsibilities, religion, national origin, age, personal appearance, political affiliation, veteran status, disability, source of income (government, solo, corporate, or firm practices), or place of residence or business (geographic diversity).

The Associations recognize that the goals of increasing membership diversity and ensuring that diversity is reflected across all levels of the Associations cannot be achieved without the unequivocal support of, and sustained effort by, the Associations’ leadership. Therefore, the Associations’ leadership and all members holding positions with powers of appointment must be mindful of this Diversity and Inclusion Policy and are expected to the best of their ability to work actively to promote diversity and inclusion within the Associations. Active promotion of diversity and inclusion within the Associations shall include, but not be limited to, making good faith efforts to:

- Periodically review EBA’s methods for soliciting members, undertaking outreach efforts, and structuring membership benefits with the aim of appealing to as broad and diverse a group of eligible professionals as possible.

- Extend high-visibility opportunities such as speaking engagements and panel participation to individuals reflecting diverse characteristics, in order to encourage the membership of, and the active engagement of broadly diverse groups.

- Consider in connection with appointment decisions (such as board memberships, officer positions, committee or chapter leadership, speaking/panel opportunities, or publishing and editing opportunities), individuals who possess diverse characteristics, as identified in the EBA definition of Diversity, that are underrepresented in these positions in order to: (1) actively welcome and encourage all persons to contribute and participate; and (2) strive for diversity across such positions.

- Encourage pro-diversity policies in the many companion and sub-groups of the Associations, including Committees, Chapters, and Councils and in particular by the Professional Education Council.

- Present this Policy in all orientation and training materials; presentations, and meetings; and to candidates under consideration by the Nominating Committee.

- Include in the Associations’ programming, from time to time, programming, training, and materials that promote diversity in the energy sector.

To advance this Policy, there will be an annual presentation of a report by each Association’s Diversity and Inclusion Facilitator to the EBA Board of Directors detailing all initiatives and efforts taken over the course of each year to foster diversity and inclusion within the Association, and outlining any newly recommended measures for the Board’s consideration.

In furtherance of this Policy, all the Associations’ Officers and Directors shall submit a signed statement once per year indicating that they have received, read, understand and acknowledge the Diversity and Inclusion Policy.