

NATURAL GAS COMMITTEE REPORT

This report summarizes policy developments and legal decisions that occurred at the Federal Energy Regulatory Commission (FERC or the Commission), the Pipeline and Hazardous Materials Safety Administration (PHMSA), and the United States Courts of Appeals in the area of natural gas regulation between July 1, 2022, and June 30, 2023.*

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I. Rulemaking Actions

A. Order Nos. 884 and 884-A, Revised Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs

On November 17, 2022, the Commission issued its Final Rule, Order No. 884, in Docket No. RM21-18-000, *Revised Filing and Reporting Requirements for Interstate Pipelines*.[1] Order No. 884 followed the Notice of Proposed Rulemaking ("NOPR") issued on May 19, 2022,[2] as well as a number of industry comments.[3] The Final Rule adopted the revised rules in the NOPR, and required that natural gas pipelines submit all supporting statement, schedules and workpapers accompanying Section 4 rate case filings with "all links and formulas included."[4] The Commission noted that existing regulations require live links and formulas for certain schedules (I, J and a portion of H), to preempt burdensome discovery and permit better comments on filings.[5] The NOPR proposed expanding this requirement to all statements, schedules and workpapers, citing the need to remove ambiguity, eliminate an existing information gap, allow participants to manipulate

1. Order No. 884, *Revised Filing and Reporting Requirements for Interstate Pipelines*, 181 FERC ¶ 61,121 (2022), *order on reh'g*, Order No. 884-A, 182 FERC ¶ 61,144 (2023).

2. Final Rulemaking, *Revised Filing & Reporting Requirements for Interstate Nat. Gas Co. Rate Schedules & Tariffs*, 87 Fed. Reg. 31,783 (2022) (to be codified at 18 CFR Parts 154, 260, and 284**)**.

3. Order No. 884, *supra* note 1, at P 7.

4. *Id.* at P 1.

5. *Id.* at P 3.

and test the data without creating their own rate models,[6] allow more prompt analysis of rate filings,[7] and better reflect improved technologies.[8] The Final Rule adopted the proposed regulation on the same grounds articulated in the NOPR.[9]

The Commission considered and rejected several objections to the proposed rule. The Commission found that the revised regulations would not unfairly burden pipelines for the benefit of a few parties, noting as well that pipelines could recover in their rates any increased costs stemming from the rule.[10] At the same time, the Commission clarified that the new rule did require pipelines to create links to show the calculations underlying the filing, even if the links might have been absent previously.[11] The Commission also disagreed that the rule was unneeded because the data was already present, because the absence of links created barriers to parties' ability to assess and manipulate the data, inhibiting comments and settlement progress.[12] The Commission found inapposite the absence of evidence that pipelines were severing links in their filings, concluding that the need for intact formulas and links was "imperative."[13] The Commission rejected contentions that the Final Rule did not provide sufficient notice because it did not propose specific regulations, finding instead that the revised obligations were adequately described.[14] The Commission declined to adopt a proposal by some commenters that the links and formulas required by the rule be presumed public, to prevent confidentiality claims and requirements burdening parties assessing the filings.[15] The Commission found that pipelines could seek confidential treatment and that such requests would be addressed on a case-by-case basis under existing standards, albeit that pipelines would have the burden of proof in justifying such treatment.[16] The Commission also clarified that the new obligations did not extend to links between filing materials in different other rate cases or to materials not part of the filing,[17] and that the requirements did not extend to Statements O and P.[18] The Commission declined to extend the requirements of the rule to filings by other parties in Natural Gas Act section 5 or section 4 proceedings,[19] or to expand the reporting requirements of pipelines.[20]

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6. *Id.* at P 4.
7. Order No. 884, *supra* note 1, at P 5.
8. *Id.* at P 6.
9. *Id.* at P 8.
10. *Id.* at P 12.
11. Order No. 884, *supra* note 1, at P 13.
12. *Id.* at P 15-16.
13. *Id.* at P 17.
14. *Id.* at P 20.
15. Order No. 884, *supra* note 1, at P 24.
16. *Id*.
17. *Id.* at P 27.
18. *Id.* at P 28.
19. Order No. 884, *supra* note 1, at P 30.
20. *Id.* at P 32.

In response to a joint request for rehearing and clarification filed by certain parties, the Commission issued Order No. 884-A on March 1, 2023. Those parties requested rehearing as to the Commission's decision not to apply a blanket presumption that the links and formulas required by the Final Rule would be public; the Commission demurred, concluding that the comments had indicated potential grounds for seeking confidential treatment.[21] In addition, the Commission noted that pipelines were required to accompany confidential filings with protective agreements, and any parties seeking access could obtain it within five days by providing executed agreements. Further, the Commission could act to address disputes over confidentiality as necessary.[22] The Commission also declined a requested clarification that the Commission deemed to require information to be filed by pipelines in excess of the information required by Part 154, subpart D.[23]

II. SIGNIFICANT FEDERAL MATTERS (PENDING) – FEDERAL LEGISLATION

A. Fiscal Responsibility Act of 2023 – Mountain Valley Pipeline

On June 3, 2023, President Biden signed the Fiscal Responsibility Act of 2023 (FRA) into law.[24] Section 324 of the FRA made a determination that the "timely completion of and construction and operation of the Mountain Valley Pipeline is required in the national interest."[25] The law "ratifies and approves authorizations, permits," and other approvals necessary to complete construction of the pipeline and allow it to begin operation.[26] The law also requires the "Secretary of the Army, the Federal Energy Regulatory Commission, the Secretary of Agriculture, and Secretary of the Interior, and other agencies as applicable" to issue and maintain all "authorizations, permits, verifications, extensions, biological opinions, incidental take statements, and any other approvals orders" necessary to complete project construction and allow for initial operation "at full capacity" of Mountain Valley's pipeline.[27] The law also removes judicial review of any actions taken by the various federal and state agencies and moves legal jurisdiction for challenges to FRA section 324 to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit).[28]

B. Fiscal Responsibility Act of 2023 – NEPA Reform

The FRA also amends the National Environmental Policy Act (NEPA):

21. Order No. 884-A, *supra* note 1, at P 9.
22. *Id.* at P 10.
23. *Id.* at P 11.
24. Fiscal Responsibility Act of 2023, Pub. L. No. 118-5, 137 Stat. 10 [hereinafter FRA].
25. *Id.*, § 324(b).
26. *Id.*, § 324(c).
27. *Id.*, § 324(c)(2)-(d).
28. FRA § 324(e).

- The FRA amends section 102(2) of NEPA[29] to establish the basic requirements for an environmental impact statement (EIS) to consider the "reasonably foreseeable adverse environmental effects" of a proposed agency action and analyze "a reasonable range of alternatives" that are "technically and economically feasible" and "meet the purpose and need" of the proposed action.[30]
- The FRA amends section 106 of NEPA to add circumstances when an agency is not required to prepare an environmental document; as well as establishing when an EIS and EA should be prepared. An EIS is prepared when a proposed agency action "has a reasonably foreseeable significant effect on the quality of the human environment"; and an EA is prepared when a proposed action "does not have a reasonably foreseeable significant effect on the quality of the human environment."[31]
- The FRA amends section 107 of NEPA[32] to address the preparation of an EIS or an EA. The law requires that an agency complete an EIS no later than two years after determining that an EIS is required and complete an environmental assessment (EA) no later than one year after determining that an EA is required.[33] The FRA also clarifies the appointment of a lead agency if more than one agency is involved in the preparation of the environmental document and imposes page limits.[34]
- The FRA amends section 108 of NEPA[35] to state that when a programmatic environmental document was prepared "for which judicial review was available," an agency may rely on that environmental document for five years after the document was prepared.[36]
- The FRA amends section 109 of NEPA[37] establishes a process for federal agencies to use another agency's categorical exclusions.[38]
- The FRA amends section 110 of NEPA to require the Council on Environmental Quality (CEQ) to conduct a study of online and digital technologies to help provide for efficient reviews and improve public accessibility and transparency.[39]

29. National Environmental Policy Act of 1969, Pub. L. No. 91-190, 42 U.S.C. § 4332.
30. FRA § 321(b); 42 U.S.C. § 4332(C).
31. FRA § 321(b); 42 U.S.C. § 4336(b).
32. 42 U.S.C. § 4336a(g).
33. FRA § 321(b); 42 U.S.C. § 4336a(g)(1).
34. FRA § 321(b); 42 U.S.C. §§ 4336a(a) and (e).
35. 42 U.S.C. § 4336b.
36. FRA § 321(b); 42 U.S.C. § 4336b.
37. 42 U.S.C. § 4336c.
38. *Id.*
39. 42 U.S.C. § 4336d.

- The FRA amends section 111 of NEPA to define key terms, including categorical exclusion, cooperating agency, environmental document, lead agency, major Federal action, participating Federal agency, programmatic environmental document, and special expertise.[40]

III. ENFORCEMENT

A. BP America Inc. v. FERC, 52 F.4th 204 (5th Cir. 2022).

BP America Inc. and several of its affiliates (collectively, "BP") appealed a FERC order finding that BP's Southeast Gulf Texas Team's physical, next-day fixed price natural gas trading for the period of September 18 to November 30, 2008 violated the NGA, section 4A[41] in the aftermath of Hurricane Ike because BP traded physical, next-day fixed price natural gas with the intent to depress the Platts Gas Daily index prices at Houston Ship Channel to benefit larger financial spread positions held by BP that settled off index prices.[42] FERC's BP Order assessed a civil penalty of $20.16 million and disgorgement of $207,169, which BP paid under protest.[43]

BP challenged the BP Order on grounds that the FERC exceeded its jurisdiction, erred in finding market manipulation and in its penalty assessment, and violated the Administrative Procedure Act (APA).[44] The Court rejected the majority of BP's claims, finding that BP's argument against finding manipulation "amount[ed] to disagreements with FERC's permissible interpretation of the evidence and reasonable resolution of conflicting expert testimony," and that FERC did not violate the APA's rule separating agency investigative and prosecutorial functions.[45]

The Court held, however, that FERC exceeded its jurisdiction by considering intrastate transactions in the market manipulation finding.[46] NGA section 4A prohibits manipulation "in connection with" transactions subject to FERC's jurisdiction.[47] The Court, based on longstanding precedent that only interstate transactions are subject to FERC jurisdiction, rejected FERC's attempt to use the "in connection with" language to claim authority over intrastate transactions that may affect prices.[48] The Court emphasized that jurisdiction cannot be expanded through "a subtle reading of an otherwise non-jurisdictional provision."[49] The

40. 42 U.S.C. § 4336e.
41. *BP America Inc.*, 156 FERC ¶ 61,031 (2016).
42. *Id.*
43. *Id.*
44. BP Am. Inc. v. FERC, 52 F.4th 204, 213-14 (5th Cir. 2022).
45. *Id.* at 219-26.
46. *Id.* at 215-17.
47. *See* 15 U.S.C. § 717c-1.
48. *BP Am. Inc.*, 52 F.4th at 215-17.
49. *Id.* at 216.

Court remanded the case to FERC for reassessment of the civil penalty levied on BP in light of the Court's holding.

B. BP America Inc., 184 FERC ¶ 61,016 (2023).

Following the Fifth Circuit's October 20, 2022 ruling, neither the FERC nor BP sought rehearing or filed a cert petition. FERC subsequently approved a Stipulation and Consent Agreement between the FERC Office of Enforcement ("Enforcement") and BP. Pursuant to the consent agreement, BP agreed to pay a civil penalty of $10,750,000 and agreed not to seek return of the $207, 169-disgorgement amount that it had previously paid under protest. Enforcement in return agreed not to object to BP seeking the return of the excess civil penalty payment of $13,606,686, including interest. FERC approved the agreement.

C. Pacific Summit Energy LLC, 183 FERC ¶ 61,236 (2023).

FERC approved a Stipulation and Consent Agreement between the FERC Office of Enforcement (Enforcement) and Pacific Summit Energy LLC (PSE). Enforcement brought an action against PSE for violation of NGA section 4A related to engaging in a series of 2017 trades where "PSE suffered a loss on these physical trades but realized a net profit on its related financial basis positions that were tied to the Transco Zone 6 (NY and NNY) IFERC indexes."[50] Enforcement concluded that PSE's physical trading had the "effect of inflating physical natural gas prices in Transco Zone 6, resulting in increases in the value of PSE's existing financial basis positions."[51] PSE agreed to pay a civil penalty of $360,000, disgorge $154,623, and submit annual compliance filing reports to Enforcement for two years.

D. Civil Monetary Penalty Inflation Adjustments, 182 FERC ¶ 61,002 (2023).

On January 6, 2023, FERC issued a final rule amending its regulations governing the civil monetary penalties assessable for violations of statutes, rules, and order within the Commission's jurisdiction. This final rule was required by the Federal Civil Penalties Inflation Adjustment Act of 1990.[52] That act required the head of each Federal agency to issue a rule that adjusts each civil monetary penalty within the agency's jurisdiction for inflation and to make further inflation adjustments on an annual basis every January 15 thereafter.[53] The rule increased the civil monetary penalties for a number of statutory and rule violations, including penalties assessed under NGA, section 22 and Natural Gas Policy Act of 1978, section 504(b). The rule increases the maximum penalty under both sections from $1,388,496 per violation, per day to $1,496,035 per violation, per day.

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50. *Pacific Summit Energy LLC*, 183 FERC ¶ 61,236, (2023).
51. *Id.* at P 8.
52. *Civil Monetary Penalty Inflation Adjustments*, 182 FERC ¶ 61,002 (2023).
53. *Id*. at P 2.

IV. Rates, Terms, and Conditions of Service

A. Abandonment

1. Stingray Pipeline Company, L.L.C.

On June 15, 2023, FERC granted Stingray Pipeline Company, L.L.C.'s ("Stingray") applications pursuant to section 7(b) of the Natural Gas Act ("NGA") and Part 157 of the regulations for authorization to abandon variously by removal, in-place, and sale to Triton Gathering LLC (Triton), all of its FERC-jurisdictional interstate pipeline facilities located in federal waters offshore Louisiana and Texas (West Cameron 509 System).[54] FERC also confirmed that upon acquisition by Triton, the facilities will function as non-jurisdictional gathering facilities exempt from Commission regulation, pursuant to section 1(b) of the NGA.[55] FERC further granted Stingray's requests to abandon: (1) its NGA section 7 certificate of public convenience and necessity for the operation of its pipeline system; (2) its Part 157, Subpart F blanket certificate; and (3) its Part 284, Subpart G blanket certificate. FERC accepted Stingray's cancellation of its FERC Gas Tariff and its rate schedules.

FERC applied its long-standing abandonment criteria, including: "(1) the needs of the affected natural gas systems and the public markets they serve; (2) the economic effect on the pipelines and their customers; and (3) the presumption in favor of continued service."[56] FERC noted that "[c]ontinuity and stability of existing service are the primary considerations."[57]

Although FERC's recent policy requires that purchasers of pipeline facilities that desire a formal determination of non-jurisdictional status, must do so through a petition for declaratory order,[58] FERC reviewed the primary function of the facilities in Stingray's abandonment application because Stingray requested the non-jurisdictional determination before FERC announced the new policy. FERC then determined in the abandonment order that the facilities sold to Triton will perform a gathering function exempt from FERC's jurisdiction.[59]

2. LA Storage, LLC

On June 12, 2023, FERC authorized LA Storage, LLC (LA Storage) to abandon by transfer to Gillis Hub Pipeline, LLC (Gillis) LA Storage's certificated interstate natural gas pipeline and to abandon its firm and interruptible cost-based

54. *Stingray Pipeline Co.*, 183 FERC ¶ 61,201 (2023).

55. *Id.* Triton also will convert certain of the facilities to crude oil transportation service. *Id.* at n.4.

56. *Id.* at P 35 (citing *Trunkline Gas Co.*, 147 FERC ¶ 61,041 (2014); *Transwestern Pipeline Co.*, 140 FERC ¶ 61,147 (2012).

57. *Id.* (citing *Texas Eastern Transmission, LP*, 168 FERC ¶ 61,037 at P 41 (2019); *National Fuel Gas Supply Corp.*, 160 FERC ¶ 61,050 at P 17 (2017).

58. *Gulf States Transmission LLC*, 176 FERC ¶ 62, 070 at P 2 n.5 (2021).

59. 183 FERC ¶ 61,201, at P 69.

transportation rate schedules and services. Gillis will provide transportation service to shippers of LA Storage's Hackberry Storage Project under the same rates, terms, and conditions provided by LA Storage. After abandonment, LA Storage will no longer have facilities with which to provide transportation services, and thus will not provide any transportation service, but will only provide market-based storage and hub service.[60]

3. Wyoming Interstate Company

On June 12, 2023, FERC authorized Wyoming Interstate Company, LLC (WIC) to abandon in place its Diamond Mountain Compressor Station. Due to declining production and no forecasted growth, WIC had stopped operating this compressor station. WIC stated in its application that since 2016, it has only run the compressor for preparedness and emissions testing. After abandonment, WIC can continue to meet its transportation demand on the lateral connected to the Diamond Mountain Compressor with no degradation in service to existing customers.[61]

4. Columbia Gas Transmission, LLC

On February 16, 2023, FERC authorized Columbia Gas Transmission, LLC (Columbia) to plug and abandon four existing injection/withdrawal wells and to abandon 5,178 feet of associated pipeline at the Coco B Storage Field.[62] Columbia identified these facilities for abandonment under the Department of Transportation's Pipeline and Hazardous Materials Safety Administration's (PHMSA) Underground Storage Final Rule, requiring storage operators to assess well-integrity risk and implement appropriate mitigation and prevention measures to reduce risk.[63] FERC agreed with Columbia that the four wells proposed for abandonment are aging and inefficient and therefore, abandoning these wells and their associated pipelines will minimize risk to the public. The proposed abandonments will not affect Columbia's ability to maintain current service to its storage customers and the project will enable the storage field to operate more efficiently, as well as improve service to existing customers.[64]

60. *LA Storage, LLC*, 183 FERC ¶ 62,138 at P 8 (2023); *see also Port Arthur Pipeline, LLC*, 183 ¶ FERC 62,107 (2023) (abandonment authority to transfer an LNG terminal's transportation and hub facilities).

61. *Wyoming Interstate Gas, LLC*, 183 FERC ¶ 62,141 at P 13 (2023); *see also Great Lakes Gas Transmission, LP*, 183 FERC ¶ 62,007 (2023) (temporarily abandonment in-place for a 36-month period three obsolete compressor units that had not been utilized since 2018 and would cost between $10 and $50 million to repair or replace); *Texas Gas Transmission, LLC*, 181 FERC ¶ 61,049 (2023) (temporarily abandonment in-place for one inactive, unreliable compressor unit and placing two other units on standby to use during maintenance or unplanned outages).

62. *Columbia Gas Transmission, LLC*, 182 FERC ¶ 61,089 at P 2 (2023).

63. *Id.* at P 5 n.9 (citing *Pipeline Safety: Safety of Underground Natural Gas Storage Facilities*, 85 Fed. Reg. 8104 (Feb. 12, 2020)).

64. *Id.*

5. Great Basin Gas Transmission

On February 16, 2023, FERC authorized Great Basin Gas Transmission to abandon and replace 20.4 miles of aging pipeline in order to maintain existing transportation services while improving the integrity of its pipeline system.[65]

6. Northern Natural Gas Co.

On February 1, 2023, FERC authorized Northern Natural Gas (Northern) to abandon certain segments of its A-line pipeline and replace the 340 million cubic feet per day (MMcf/day) of lost capacity by extending the C-line. The project is designed to minimize safety risks on Northern's system while maintaining existing service. The Commission held that Northern has not proposed any changes that will adversely impact the operations of its system or continuity of service.[66]

7. National Fuel Gas Supply Corp.

On January 26, 2023, FERC authorized National Fuel Gas Supply Corp. (National Fuel) to abandon the Corry Storage Field, including the base gas, the Carter Hill Compressor Station, land rights, and all associated facilities to KC Midstream. The Commission determined that the abandonment is appropriate because the Corry Storage field will be used by KC Midstream Solutions LLC (KC Midstream) for gas production and which, accordingly, will not alter the primary function of KC Midstream's non-jurisdictional natural gas gathering system. The Commission also confirmed that National Fuel will not abandon service to any customer or alter the operation of its jurisdictional facilities.[67]

8. Ohio River System, LLC

On December 6, 2022, FERC granted abandonment of a limited jurisdiction certificate held by otherwise exempt gatherer Ohio River System to transport gas to Rockies Express Pipeline.[68] The limited term certificate, granted in 2017, had a four-year term, which was due to expire.[69] In its abandonment application, Ohio River System explained that it no longer has any customers that use its jurisdictional transportation service and therefore no longer requires the limited jurisdiction certificate.[70] The Commission agreed that the abandonment of the limited-term certificate is appropriate and that no customers will be harmed by the abandonment of the transportation service. [71]

65. *Great Basin Gas Transmission Co.*, 182 FERC ¶ 61,088 at P 1 (2023).
66. *Northern Natural Gas Co.*, 182 FERC ¶ 62,065 at P 11 (2023).
67. *National Fuel Gas Supply Corp.*, 182 FERC ¶ 61,052 (2023).
68. *Ohio River System, LLC*, 181 FERC ¶ 62,135 at PP 1-2 (2022).
69. *Id.* at P 6.
70. *Id.*
71. *Id.* at P 10.

9. Columbia Gas Transmission, LLC, and KO Transmission Co.

On November 18, 2022, FERC authorized KO Transmission (KOT) to abandon by sale to Columbia all of its interests in its 88.81-mile interstate natural gas pipeline system and the associated capacity of 884,058 Dth per day. KOT's facilities will be integrated into Columbia Gas's pipeline system with pre-authorized rolled-in rates.[72]

B. Capacity Release

1. Fundare Resources Operating Company

FERC granted a 120-day temporary and limited waiver of its capacity release regulations and tariff provisions to Fundare and Moonrise Midstream, LLC ("Moonrise") on June 28, 2023.[73] The waiver was jointly requested by Fundare and Moonrise to "facilitate the assignment and permanent release of capacity under a long-term firm natural gas transportation service agreement between Fundare and [the] Trailblazer [Pipeline Company]."[74] Fundare further specified that the waiver would support its corporate reorganization in allowing Moonrise, Fundare's wholly owned subsidiary, to assume ownership and operation of one of its facilities that utilizes the Trailblazer pipeline capacity.[75] FERC applied its four-factor test and found good cause to grant the waiver since "(1) the applicant acted in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties."[76] FERC further noted that "the request is adequately supported and appears consistent with previous waiver requests the Commission has granted to permit the release of capacity under similar circumstances," concluding that good cause had been shown to grant the waiver.[77] This was just one of many temporary and limited capacity release waivers granted this year for facilitation of transportation agreements.[78]

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72. *Columbia Gas Transmission and KO Transmission Co.*, 181 FERC ¶ 62,107 at P 1 (2022).

73. *Fundare Resource Operating Co.*, 183 FERC ¶ 61,223 at P 1 (2023).

74. *Id.*

75. *Id.* (The specific waivers that were requested, and subsequently granted, were the Commission's: "(a) capacity release posting and bidding regulations; (b) capacity release applicable maximum rate requirement; (c) shipper-must-have-title policy; (d) prohibition against buy/sell arrangements; . . . (e) prohibition against tying arrangements in capacity releases," and "waiver of the related capacity release provisions in the General Terms & Conditions of Trailblazer's tariff.").

76. *Id.* at P 4.

77. 183 FERC ¶ 61,223, at P 9.

78. *See Red Willow Offshore, LLC*, 180 FERC ¶ 61,035 at P 1 (2022); *Chesapeake Energy Marketing, LLC,* 180 FERC ¶ 61,061 at P 1 (2022); *BASF Corp.*, 180 FERC ¶ 61,133 at P 1(2022); *Seneca Resources Co.*, 180 FERC ¶ 61,166 at P 1 (2022); *Calhoun Power Co.*, 180 FERC ¶ 61,202 at P 1 (2022); *Leucrotta Exploration Inc.*, 180 FERC ¶ 61,201 at P 1 (2022); *Tampa Electric Co.*, 180 FERC ¶ 61,221 at P 1(2022); *Van Buren Energy Production, LLC*, 181 FERC ¶ 61,052 at P 1 (2022); *MP Gulf of Mexico, LLC*, 181 FERC ¶ 61,073 at P 1 (2022); *Tampa Electric Co.*, 182 FERC ¶ 61,018 at P 1 (2023); *Florida Public Utilities Company*, 182 FERC ¶ 61,130 at P 1 (2023); *Macquarie Energy, LLC*, 182 FERC ¶ 61,140 at P 1 (2023); *K2 Commodities, LLC*, 182 FERC ¶

2. Venture Global Plaquemines LNG, LLC

In August 2022, FERC granted a limited waiver of the Commission's buy/sell prohibition and related relevant capacity release regulations to enable Plaquemines LNG to purchase domestic natural gas, liquefy it, and sell it as liquified natural gas (LNG) pursuant to NGA section 3 authorization granted by the Commission in 2019.[79] Plaquemines LNG is in the process of building the Plaquemines LNG Export Terminal and associated facilities in Plaquemines Parish, Louisiana and is planning to begin its first phase of LNG export by the end of 2024.[80] Plaquemines LNG requested a waiver of the buy/sell prohibition in July 2022 in order to facilitate its export transactions, "explain[ing] that it is responsible for procuring natural gas from a wide range of suppliers in the U.S. gas commodity markets and transporting the gas to its Export Terminal for liquefaction before the LNG is sold to the contracted customers."[81] It further clarified that "although none of its gas suppliers are expected to be its affiliates, the gas suppliers could potentially include Plaquemines LNG's Sales and Purchase Agreement (SPA)-counterparties or their affiliates," which could be found to be contrary to the Commission's buy/sell prohibition.[82]

FERC found good cause to grant the requested waivers:

As the Commission found in [four similar proceedings[83] noted by Plaquemines LNG in which the waiver was granted], we continue to find value in fostering a robust marketplace for LNG and agree that the instant request for waiver may help provide Plaquemines LNG with assurance and the capability to manage varying demands and conditions in its portfolio of supply and transport capacity.[84]

The Commission therefore granted the waiver, "limited to transactions which enable the capacity to be used for the same purpose for which Plaquemines LNG originally purchased that capacity: to transport natural gas to its LNG terminal for export."[85] Plaquemines LNG also noted that in these similar proceedings, in approving the waiver the Commission has required certain reporting requirements for the annual volumes of gas purchased from sellers who also buy the LNG; it further stated that it had no objection to such requirements.[86] In response, the Commission imposed such requirements: "To monitor the impact of the waiver

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61,174 (2023); *Talen Energy Marketing, LLC*, 182 FERC ¶ 61,214 (2023); *EOG Resources, Inc.*, 183 FERC ¶ 61,002 at P 1 (2023); *BP Energy Co.*, 183 FERC ¶ 61,175 at P 1 (2023).

79. *Venture Global Plaquemines LNG, LLC*, 180 FERC ¶ 61,115 at P 1 (2022).

80. *Id.* at P 2.

81. *Id.* at PP 1, 3.

82. *Id.* at PP 4-5.

83. *See Venture Global Calcasieu Pass, LLC*, 175 FERC ¶ 61,142 at P 10 (2021); *Cheniere Energy, Inc.*, 169 FERC ¶ 61,148 at P 10 (2019); *Golden Pass LNG Terminal LLC*, 172 FERC ¶ 61,252 at P 15 (2020); *Driftwood Holdings LLC*, 174 FERC ¶ 61,041 at P 8 (2021).

84. 180 FERC ¶ 61,115, at P 10.

85. *Id.* at P 13.

86. *Id.* at P 8.

granted by this order," it has required that Plaquemines LNG report to the Commission the total annual volume of every third year of natural gas purchased from sellers who also purchase LNG from Plaquemines LNG.[87]

3. Florida Public Utilities Company

In July 2023, FERC extended a capacity release waiver for Florida Public Utilities Company (FPUC) initially granted in February 2023.[88] FPUC explained that Gulfstream Natural Gas System, L.L.C. (Gulfstream), with whom FPUC had a firm natural gas transportation service agreement to facilitate a corporate reorganization, "require[d] additional time to accommodate the permanent release of capacity" granted by the February order.[89] FERC found, since the request was adequately supported and no party objected to the request, that good cause was shown, and therefore granted the sixty-nine-day extension request.[90]

C. Cost Trackers

1. Sea Robin Pipeline Company, LLC

In 2021, FERC approved, as part of a prior settlement, tariff records filed by Sea Robin to replace its stated fuel rate with a tracker mechanism.[91] In May 2023, Sea Robin filed revised tariff records proposing new fuel surcharges under section 27 of the General Terms and Conditions (GT&C) of its tariff, in part calculated using an adjusted time period.[92] It also requested a waiver of section 27.4 of its GT&Cs "to use a different time period to compute its estimated deferred reimbursement account balance," stating that it would provide "a more accurate estimate."[93] The Producer Coalition filed a protest, arguing that the throughput projections for the time period Sea Robin is using for its calculations reflect lower throughput due to system leaks, which is leading to higher fuel reimbursement percentages.[94] Sea Robin's answer to this protest stated that the Producer Coalition had not shown that such fluctuations were abnormal or that Sea Robin was not in compliance with its tariff. The Commission accepted Sea Robin's answer and rejected the Production Coalition's request for a technical conference on this issue.[95] FERC then evaluated the request for the waiver under its four-factor test,

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87. *Id.* at P 14.

88. *Florida Public Utilities Co.*, 184 FERC ¶ 61,031 at P 1 (2023).

89. *Id.* at PP 2, 3.

90. *Id.*; *see also Anadarko US Offshore LLC*, 182 FERC ¶ 61,164 at P 6 (2023) (FERC similarly granted a capacity release waiver extension after finding good cause).

91. *Sea Robin Pipeline Co.*, 183 FERC ¶ 61,230 at P 2 (2023).

92. *Id.*

93. *Id.* at P 4.

94. *Id.* at PP 5, 6 (The Members of the Producer Coalition include Arena Energy, LLC, Cox Operating, LLC, Energy XXI GOM, LLC, EPL Oil & Gas, Inc., GOM Shelf LLC, QuarterNorth Energy, LLC, M21K LLC, Talos Energy Offshore LLC, Talos ERT LLC, Talos Resources, LLC, Talos Third Coast LLC, W&T Offshore, Inc., and Walter Oil Corporation).

95. 183 FERC ¶ 61,230, at PP 14, 16.

finding that "(1) the applicant acted in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties."[96] It therefore waived the section 27.4 tariff provision regarding the time period and concluded "that Sea Robin's annual fuel tracker filing correctly follows its tariff, as waived, and is otherwise just and reasonable."[97] The revised tariff records were accepted and effective July 1, 2023.[98]

2. Transwestern Pipeline Company, LLC

In July 2022, Transwestern filed revised tariff records for a general rate case under section 4 of the Natural Gas Act pursuant to a 2015 settlement.[99] In the filing, it proposed rate and tariff changes that included adding two sections to its GT&C implementing a fuel reimbursement adjustment mechanism and a Capital Cost Recovery Mechanism (CCRM).[100] The proposed CCRM would include a one-time cost recovery for modernization of five outdated compressor stations on its system and for a separately tracked surcharge "to recover its capital revenue requirements incurred to modernize its system, to improve system integrity, to enhance service reliability and flexibility, to satisfy emerging legal/regulatory requirements, and to improve safety and reduce risk."[101] FERC found that the filing had "not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful," and therefore accepted and suspended the tariff records to establish a hearing to address several specific issues it and protestors identified in the filings.[102] After several settlement conferences, Transwestern proposed a settlement on April 5, 2023, that, among other things, removed the proposed CCRM.[103] FERC found that "the uncontested Settlement appears to be fair and reasonable and in the public interest," and therefore approved the settlement as proposed.[104]

D. Fuel

1. Texas Eastern Transmission, LP

On November 30, 2022, the Commission issued its "Order Accepting Tariff Records on Annual Tracking Filing," *Texas Eastern Transmission, L.P.*[105] In

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96. *Id.* at P 14.
97. *Id.* at P 6.
98. *Id.* at P 14.
99. *Transwestern Pipeline Co.*, 180 FERC ¶ 61,065 at P 1 (2022).
100. *Id.*
101. *Id.* at P 14.
102. *Id.* at P 18.
103. Letter from Michael T. Langston, Transwestern Pipeline Company, LLC to Kimberly D. Bose (Apr. 6, 2023) (Re: Transwestern Pipeline Company, LLC, Docket No. RP15-23-000 Refund Report).
104. *Transwestern Pipeline Company*, 183 FERC ¶ 61,213 at P 5 (2023).
105. *Texas Eastern Transmission, LP*, 181 FERC ¶ 61,165 (2022).

Texas Eastern, the Commission accepted, without modification, an annual Applicable Shrinkage Adjustment (ASA) tracking filing by the pipeline that was protested by a shipper challenging the increase affecting an incremental service, in the ASA percentage (23%) and in the applicable ASA surcharge (180%).[106] The protesting shipper raised several challenges to the filing: that the filing improperly applied the fuel percentage against received rather than delivered volumes;[107] that the LAUF calculation wrongly used legacy contract data rather than all throughput and wrongly used a seven-year average in light of recent efforts by the pipeline to invest in projects that should reduce fugitive emissions;[108] that the filing failed to include sufficient information to allow a determination that legacy contracts were not being subsidized by incremental shippers;[109] and more general assertions of flawed support.[110] The pipeline filed an answer responding in detail to the protesting party's points, including assertions that the methodology was the same as in prior approved filings.[111]

The Commission found that the ASA, as an annual tracker filing, appeared to be supported by the pipeline's accompanying, extensive supporting information, did not recover costs outside of normal pipeline operations, and applied the same methodology as has been applied by the pipeline for decades.[112] The Commission found further that, to the extent that the protesting shipper raised arguments for revisions to the underlying ASA mechanism, the Commission would decline to institute a section 5 investigation.[113] The Commission noted that the protesting shipper could more appropriately address such revisions in a section 5 complaint.[114] The Commission also stated that the ASA mechanism would not result in any over-collection of costs by the pipeline, due to its true-up features,[115] and the Commission did not find merit in other challenges to the accuracy of the filing[116] and to the adequacy of its supporting information.[117] Consequently, the Commission accepted the filing.[118]

2. Sea Robin Pipeline Company, LLC

On September 26, 2022, the Commission issued its "Order Addressing Arguments Raised on Rehearing," (*Sea Robin II*)[119] addressing its earlier denial of

106. *Id.* at PP 6, 23.
107. *Id.* at P 7.
108. *Id.* at P 8.
109. 181 FERC ¶ 61,165, at P 9.
110. *Id.* at P 10.
111. *Id.* at PP 11-14.
112. *Id.* at P 19.
113. 181 FERC ¶ 61,165 at P 20.
114. *Id.* at P 20 n.20.
115. *Id.* at P 20.
116. *Id.* at P 21.
117. 181 FERC 61,165, at P 22.
118. *Id.* at P 23.
119. *Sea Robin Pipeline Co.*, 180 FERC ¶ 61,199 (2022) [hereinafter *Sea Robin II*].

rehearing by operation of law regarding its "Order Accepting Tariff Records and Granting Waiver" (*Sea Robin I)* issued on June 30, 2022.[120]

In *Sea Robin I*, the Commission had accepted the pipeline's first annual fuel tracker mechanism, following a long period of reliance (prior to 2021) on fixed rates for LAUF and fuel use.[121] In the filing at issue in *Sea Robin II*, the pipeline proposed a new tracker with new, and higher, surcharges to recover LAUF and fuel, varying between in its West Area and East Area.[122]

In *Sea Robin I*, the Commission had found that the proposed percentages were just and reasonable and that the pipeline had followed its tariff and Commission policy in recovering only costs due "to normal pipeline operations."[123] On rehearing, parties raised two points. One shipper contended that the Commission failed to inquire into the pipeline's "sudden, substantial unexplained increase in LAUF volumes compared to" past experience.[124] All parties seeking rehearing argued that the Commission should have made its acceptance of the new tariffs on the outcome of the cash-out proceedings in which LAUF tracking was also being litigated, contending that those issues included whether the pipeline was treating LAUF and imbalances "interchangeably."[125]

On rehearing, the Commission declined to change its earlier ruling, but amended its stated rationale. In denying the first contention—regarding the increased level of LAUF—the Commission explained its fuel tracker policy, which is to limit review of tracker filings to determining compliance with the mechanism, though noting that the tracker may only recover normal operational losses, not "abnormal occurrences – such as complete failure of" a segment or losses requiring filing of a safety report.[126] Claims of abnormal losses cannot, however, be based solely on losses higher than other pipelines' losses, but on specific operational events; parties in this proceeding had not shown that the higher losses in question arose from "extraordinary occurrences."[127] The Commission noted as well that historical comparisons were not reliable in this case, because prior to 2021, the pipeline set its loss rates using a different methodology, and other historical figures were from a settlement.[128] The party seeking rehearing also raised in its rehearing petition, for the first time, evidence of a leak from a particular segment that came to light only late in the proceeding; the Commission did not find this ground sufficient to change the outcome, citing its general policy against allowing new evidence in rehearing requests except when there is a "compelling showing of good cause," and because the timing of the losses suggested that the

120. *Sea Robin Pipeline Co.*, 179 FERC ¶ 61,234 (2022) [hereinafter *Sea Robin I*].
121. *Sea Robin I*, *supra* note 120, at P 15.
122. *Sea Robin II*, *supra* note 119, at PP 7-8.
123. *Id*. at P 9.
124. *Id*. at P 10.
125. *Id.* at P 11. The other proceeding involved Docket Nos. RP21-937-000 and RP22-476-000.
126. *Sea Robin II, supra* note 119, at P 13.
127. *Id*. at P 14.
128. *Id*.

increased losses at issue were not driven by the leak.[129] The Commission also found that the pipeline had submitted all data required to support the filing.[130] The Commission also denied rehearing as to the assertion that the outcome should be conditioned on the other proceeding. The Commission stated that its policy was to condition acceptance of a fuel tracker on another proceeding only when all of the costs sought in the tracker were at issue in the other proceeding, or when there was a "significant overlap of issues"—neither of which, it concluded, existed here.[131]

E. Force Majeure

1. Eastern Gas Transmission and Storage, Inc.

On July 20, 2022, the Commission issued an order (Order) requiring Eastern Gas Transmission and Storage (Eastern) to change the reservation charge crediting provision in its section 45 of the GT&C of its tariff.[132] After Eastern filed a general NGA rate case, parties protested Eastern's reservation charge credit procedures.[133] Included in Eastern's GT&C section 45 there was a provision that stated that in order for a customer to qualify for reservation charge credits, customers were required to nominate service during a pre-announced *force majeure event* after the tenth day of the *force majeure event.*[134] The Commission found this provision to be unjust and unreasonable because it is not possible for a pipeline to simultaneously announce a total outage on a given segment and also provide reasonable assurance that it can meet its firm obligations on the segment.[135] As a result, the Commission ordered Eastern to amend section 45 of the GT&C of Eastern's tariff to clarify that it owes credit to shippers when it announces a total *force majeure event* outage on a given portion of its system, regardless of whether the affected shippers nominate to the closed portion of its system.[136] The Commission also found that the section as written did not contain a provision that would address what would happen if Eastern habitually scheduled maintenance outages on the same day of the year, which is reasonable, but would end up rewarding Eastern for past outages without awarding credits to customers.[137]

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129. *Id*. at P 15.
130. *Sea Robin II, supra* note 119, at P 16.
131. *Id*. at P 17.
132. *Eastern Gas Transmission & Storage, Incorporated*, 180 FERC ¶ 61,014 (2022).
133. *Id*. at P 3.
134. *Id*. at PP 12 and 39.
135. *Id*. at P 42.
136. 180 FERC ¶ 61,014, at P 44.
137. *Id*. at P 47.

F. Gas Quality

1. Florida Gas Transmission Co., LLC, 182 FERC ¶ 61,204 (2023)

On February 1, 2021, Florida Gas Transmission Company (Florida Gas) filed revised tariff records with FERC proposing to modify the definition and gas quality sections of its GT&C to allow for the receipt and transportation of renewable natural gas (RNG).[138] Over thirty parties intervened, commented, or protested.[139] On January 18, 2022, and May 16, 2022, Florida Gas filed settlements with some (but not all) protestors.[140] Thereafter, Trial Staff and five shippers filed comments opposing the settlement.[141] On February 27, 2023, Florida Gas withdrew the settlement and filed a revised tariff, the subject of this order.

The new "filing amends the tariff to describe the variety of sources of RNG that could be delivered into Florida Gas' pipeline system" and provides detailed gas quality standards.[142] Florida Gas asserts its RNG Quality Specifications Table is consistent with the specifications the Commission accepted in *Great Basin*.[143] On March 13, 2023, seven shippers submitted protests arguing the tariff records are unjust and unreasonable, discriminatory, and preferential.[144] Four parties submitted comments. The Commission determined that "the filing had not been shown to be just and reasonable" and set the case for hearing in Docket No. RP23-466-000. Further, the Commission accepted and suspended the tariff records, to be effective August 27, 2023, subject to refund and the outcome of hearing procedures.[145] The Commission also directed Commission Staff to convene a technical conference to discuss the pipeline's justification and support for its RNG quality standards, the concerns raised by the participants, and the technical, engineering, and operational support for the proposed tariff revisions. Commission Staff committed to reporting the results of the technical conference by August 26, 2023.

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138. *Florida Gas Transmission Co.*, 182 FERC ¶ 61,204 at P 3 (2023).

139. *Id*.

140. *Id*. at PP 3, 5.

141. *Id*. at P 5.

142. 182 FERC ¶ 61,204, at P 6.

143. *Id*. at P 7; *see also Great Basin Gas Transmission Co.*, 178 FERC ¶ 61,071 (2022); *Great Basin Transmission Co.*, Docket No. RP22-432-001 (Mar. 24, 2022).

144. 182 FERC ¶ 61,204, at PP 9-10.

145. *Id*. at PP 20, 26(A).

G. *Jurisdiction*

1. Jurisdictional Status of Facilities

a) Equitrans, L.P.

On April 30, 2020, Equitrans, L.P. (Equitrans) filed an application with FERC requesting authority to abandon "its existing certificated and non-certificated gathering facilities."[146] The facilities in question were approximately 932 miles of low-pressure pipelines, eleven compressor stations, and appurtenant facilities in West Virginia and Pennsylvania (Gathering System). Equitrans proposed a two-step process, under which FERC would authorize the abandonment, effective on the date of FERC's order, but would defer implementation of the abandonment authorization conditioned on "Equitrans submitting an abandonment implementation plan within one year."[147] Equitrans also requested the authority to remove Appalachian Gathering Service (AGS) from its tariff Rate Schedule.[148]

On May 28, 2020, Peoples Gas WV, LLC and Peoples Natural (together, Peoples), Hope Gas, Inc. (Hope), and the Independent Gas & Oil Association of West Virginia (IOGA), later merged with the West Virginia Oil and Natural Gas Association (together, GO-WV) filed protests.[149] The protestors argued that the proposed abandonment did not meet the public interest standard under Section 7(b) of the NGA pertaining to "continuity and stability of existing service."[150] Protestors asserted that the abandonment would impact the continuity of gas service to local distribution company customers with no alternative means of receiving service.[151] They further argued that FERC lacked authority to grant the abandonment without prior approval of the West Virginia Public Service Commission, based on prior agreements by Equitrans' predecessor.[152] Peoples. GO-WV further questioned whether certain Gathering System facilities properly functioned as gathering.[153] Peoples pointed to backflow transactions that occurred on Equitrans' Gathering System and stated that Equitrans may have engaged in jurisdictional transportation on the gathering facilities. "GO-WV stated that the Commission should undertake a new primary function analysis based on data it should require Equitrans to provide."[154]

In March 2021, Equitrans made a supplemental filing notifying FERC "that it had entered into a purchase and sale agreement" (PSA) with Peoples Natural Gas Company (Peoples Natural) for it to acquire one of the certificated gathering

146. *Equitrans, LP*, 179 FERC ¶ 61,204 at P 1 (2022).
147. *Id.*
148. *Id*.
149. *Id.* at P 36 n.46.
150. 179 FERC ¶ 61,204, at P 42.
151. *Id.* at P 41.
152. *Id.*
153. *Equitrans, LP*, 181 FERC ¶ 61,235 at P 8 (2022).
154. *Id*.

lines set out in the application.[155] In June 2021, Equitrans filed a notice in Docket No. RP21-882-000 "of its intent to terminate gathering service on certain" segments of non-certificated gathering facilities due to safety reasons associated with third-party longwall mining activity.[156] In September 2021, Equitrans filed a supplement to its application, notifying FERC that it had entered into a PSA with Big Dog Midstream, LLC (Big Dog Midstream), under which Big Dog Midstream would acquire nearly all remaining facilities set forth in the Equitrans application, with the remaining facilities to be abandoned in place.[157]

On June 17, 2022, the Commission granted Equitrans' request for abandonment, in part, and accepted Equitrans' notice filing in Docket No. RP21-882-000 to terminate gathering service on non-certificated facilities (the latter for informational purposes).[158] The Abandonment Order refused to take action regarding the abandonment of Equitrans' non-certificated gathering facilities, explaining that Equitrans does not need Commission approval to abandon gathering facilities for which a certificate was never issued or is not currently in effect. The Commission also found that a portion of Equitrans' non-certificated gathering facilities in West Virginia occasionally receives backflows of natural gas from Equitrans' jurisdictional pipeline system. As a result, the Commission gave Equitrans three options, to: (1) "show cause why it is not required to" seek a certificate from the Commission, (2) seek a certificate for the facilities, or (3) file information supporting the abandonment of the Taylor County Field facilities by sale to Big Dog Midstream (Option Three).[159] On July 18, 2022, Equitrans filed a timely request for rehearing and clarification.

On August 12, 2022, Big Dog Midstream filed an application for a limited jurisdiction certificate to provide interstate transportation service on the Taylor County Field facilities so that it could continue receiving backflows from Equitrans' interstate pipeline system.[160] Big Dog Midstream also sought a determination by the Commission that its status as non-jurisdictional would not change and provided information on the transaction. In an August 15, 2022 filing, Equitrans stated that Big Dog Midstream's filing satisfied Option Three by demonstrating the abandonment by sale is permitted by the public convenience or necessity, even if the Taylor County Field facilities were functionalized as providing interstate transportation service.[161]

On December 16, 2022, the Commission agreed with Big Dog Midstream and Equitrans that the requirements of Option Three are satisfied.[162] The Commission then applied the primary function test and granted a limited jurisdiction

155. *Id.* at P 10.
156. *Id.* at P 6.
157. 181 FERC ¶ 61,235, at P 10.
158. 179 FERC ¶ 61,204, at PP 110-11.
159. *Id*. at P 97.
160. *Id*. at P 14.
161. 181 FERC ¶ 61,235, at P 29.
162. *Id.* at P 32.

certificate for those facilities to Big Dog Midstream, granted Equitrans permission to abandon those facilities by sale, and confirmed that Big Dog Midstream's non-jurisdictional status would not be changed by these actions.[163]

b) Limetree Bay Terminals, LLC

On August 31, 2022, Limetree Bay Terminals, LLC (Limetree) requested that FERC declare it has no jurisdiction under sections 3 or 7 under of the NGA[164] over a plan to use Limetree terminals in St. Croix, U.S. Virgin Islands for ship-to-ship transfer of liquified natural gas (LNG). The proposed plan would be limited to Limetree's existing berthing facilities, maritime vessel bunkering, and related marine support to increase safety, and would not include any offloading of LNG onto St. Croix.

Under section 3(e)(1) of the NGA, FERC has "exclusive authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal," which the Commission determines on a case-by-case basis evaluating three factors.[165] The Commission considers "(1) whether an LNG terminal would include facilities dedicated to the import or export of LNG; (2) whether the facility would be located at or near the point of import or export; and (3) whether the facility would receive or send gas out via a pipeline."[166] For LNG terminals operating in interstate commerce, FERC considers a fourth criterion: (4) "whether, after leaving the facility, the LNG is reintroduced into a pipeline such that the terminal facilitates the interstate transportation of gas by pipeline."[167]

In evaluating this case with respect to the Commission's section 3(a) NGA authority, the Commission applied the precedent of *The Gas Company*,[168] a case which denied jurisdiction over a proposal to transport LNG in International Organization of Standardization (ISO) containers between Hawaii and the continental United States. The Gas Company's existing equipment, which would handle the ISO containers of LNG, would be used to handle containers with products other than LNG, so there would be "no identifiable natural gas facilities that would constitute an LNG terminal as contemplated by Congress."[169]

Following the reasoning of *The Gas Company*, the Commission determined that Limetree's plan would not include facilities dedicated to the import or export of LNG, as Limetree would use its existing berths for other vessels and shipping activities.[170] Limetree's marine support would similarly be multi-purpose and general-use and the terminal would facilitate the transport of other non-LNG products. Limetree's facility would neither be located at or near the point of import or

163. *Id*. at PP 32, 44.
164. 181 FERC ¶ 61,041, at P 1; 15 U.S.C. §§ 717b, 717f.
165. 181 FERC ¶ 61,041, at P 7; 15 U.S.C. § 717b(e)(1).
166. 181 FERC ¶ 61,041, at P 8.
167. *Id.*
168. *The Gas Company, LLC*, 142 FERC ¶ 61,036 (2013).
169. 181 FERC ¶ 61,041, at P 9.
170. *Id.* at P 10.

export, nor would the facility receive or send gas out via a pipeline. Failing to meet the necessary factors under section 3 of the NGA, the Commission determined that Limetree's terminal would not be an LNG terminal or an import or export facility subject to its jurisdiction.

In considering jurisdiction under section 7 of the NGA, the Commission has determined that it "only applies to the transportation in interstate commerce of gas by pipeline and does not apply to gas transported by other means, including by truck, train, or waterborne vessel."[171] As Limetree's proposed plan does not include connection to any natural gas pipeline, but instead a general port facility for LNG transfers between maritime vessels, the Commission determined that it would also not be subject to the Commission's jurisdiction under section 7 of the NGA.

c) ETC Texas Pipeline, Ltd.

On July 5, 2022, ETC Texas Pipeline, Ltd. (ETC Texas), filed a petition for declaratory order "requesting that the Commission issue an order stating that upon ETC Texas' acquisition" from Enable Gas Transmission, LLC (EGT) of pipeline facilities in Bienville and Webster Parishes, Louisiana, ETC Texas would be exempt from Commission jurisdiction under section 7 of the NGA.[172]

The Commission applied "the primary function test" in which it considered:

> (1) the length and diameter of the pipeline; (2) the facilities' geographical configuration; (3) the extension of the facilities beyond the central point in the field; (4) the location of compressors and processing plants; (5) the location of the wells along all or part of a facility; and (6) the operating pressures of the pipeline.[173]

The Commission also considered the purpose, location, and operation of the facilities; the general business activities of the facility owner; and whether the jurisdictional determination is consistent with the NGA and the Natural Gas Policy Act of 1978.[174]

The Commission found that the 10.1-mile-long pipeline with a web-like configuration and no compression facilities was consistent with a gathering function.[175] The Commission found the "central point in the field test" inapplicable, because of the pipeline's backbone-type structure.[176] The location of wells, low operating pressure, and ETC Texas' primary business activities weigh additionally towards the primary function being gathering.[177] Accordingly, the Commission granted ETC Texas' petition for declaratory order and found the facilities that ETC

171. *Id.* at P 11.
172. *ETC Texas Pipeline, Ltd.*, 180 FERC ¶ 61,178 at P 1 (2022).
173. *Id*. at P 7.
174. *Id*. at P 8.
175. *Id*. at PP 9-11.
176. 180 FERC ¶ 61,178, at P 12.
177. *Id*. at PP 13-16.

Texas plans to acquire will be exempt from the Commission's NGA jurisdiction under section 1(b) of the NGA.[178]

d) Hummel Generation, LLC, UGI Sunbury, LLC

Hummel Generation, LLC (Hummel) filed a complaint requesting that the Commission (1) find UGI Sunbury, LLC's (Sunbury) pipeline (Sunbury Pipeline) exempt from the Commission's jurisdiction under section 1(c) of the NGA,[179] and (2) vacate its 2016 order issuing a certificate of public convenience and necessity for the pipeline.[180] After a 2015 open season, Sunbury had entered into binding precedent agreements with Hummel for a thirty-year term at a negotiated rate and with UGI Energy Services, Inc. (UGI Energy) for a fifteen-year term at the recourse rate. The Commission issued the Certificate Order authorizing Sunbury to construct and operate the Sunbury Pipeline on April 29, 2016. Sunbury placed the pipeline into service in early 2017.[181]

In its Complaint, Hummel argued that Sunbury Pipeline was exempt from FERC's jurisdiction under NGA section 1(c), the Hinshaw exemption, and was instead subject to the jurisdiction of the Pennsylvania Public Utility Commission (PaPUC) because Sunbury satisfied the Hinshaw exemption criteria.[182] Hummel asserted that (1) "the pipeline receives all gas within or at the boundary of a state because it is located entirely within five counties in Pennsylvania and that Sunbury does not receive gas from an interconnected affiliate system[;]" (2) "all of the gas passing through the Sunbury Pipeline is consumed in Pennsylvania, either at Hummel's generation facility in Snyder County or by local distribution customers in Pennsylvania[;]" and (3) Sunbury would be subject to regulation by the PaPUC.[183] Both Hummel and Sunbury agreed that Sunbury met the first two criteria, as all of Sunbury Pipeline was located in Pennsylvania, all gas was received from a receipt point in Pennsylvania, and all gas was transported for end-use consumption within the state of Pennsylvania.[184] However, Sunbury disagreed with Hummel on the third requirement because there was no evidence that Sunbury Pipeline's rates and services were subject to regulation by the PaPUC.[185]

The Commission found that the record did not support Hummel's assertion that the Sunbury Pipeline was exempt from the Commission's jurisdiction under NGA section 1(c) because it did not satisfy the third requirement of NGA section

178. *Id*. at PP 17-18.

179. 15 U.S.C. § 717(c).

180. *Hummel Generation v. UGI Sunbury*, 180 FERC ¶ 61,187 at P 1 (2022); *UGI Sunbury, LLC*, 155 FERC ¶ 61,115 (2016) ("Certificate Order").

181. *Id*. at PP 3-4.

182. The three requirements under section 1(c) of the NGA are: (1) the company receives all gas "within or at the boundary of a State;" (2) "all the natural gas so received is ultimately consumed within such State;" and (3) the relevant service is "subject to regulation by a State commission." 15 U.S.C. § 717(c).

183. 180 FERC ¶ 61,187, at PP 7-10.

184. *Id.* at P 13.

185. *Id.*

1(c). In particular, relying on *KN Wattenberg* and *Pinnacle Pipeline Co.*, the Commission found that unless and until the PaPUC certifies that it would have regulatory jurisdiction over Sunbury's rates and services, its certificate remains valid.[186] The Commission explained that while it was not necessary for the state regulatory agency to affirmatively assert jurisdiction, the state regulatory agency must have the "authority to regulate the pipeline's rates and services, even when the authority is not exercised."[187] Both Hummel and Sunbury requested the Commission to interpret Pennsylvania law to determine whether the pipeline was subject to state regulation. FERC declined to do so, explaining that the record of the proceeding demonstrated that the PaPUC acknowledged Sunbury's proposed pipeline and "did not offer any further analysis or reach its own conclusions regarding the PaPUC's jurisdiction over the pipeline."[188] The PaPUC also had not commented on the proceeding. Therefore, FERC declined to reverse its earlier finding that the Sunbury Pipeline was subject to Commission jurisdiction under NGA section 7.[189]

e) Owen Stanley Parker v. Permian Highway Pipeline

The Permian Highway Pipeline is a 430-mile natural gas pipeline extending from Reeves County, Texas, along the Texas Gulf Coast, all the way to its terminus near Sheridan, Texas.[190] The pipeline was constructed in 2020 and began transporting natural gas on November 1, 2020.[191] After providing intrastate service for more than a month, the pipeline began providing interruptible and then firm service pursuant to section 311 of the Natural Gas Policy Act (NGPA).[192] On January 7, 2021, PHP filed a petition with the Commission for section 311 rate approval. The Commission approved PHP's petition, effective December 8, 2020.[193]

On April 22, 2022, Owen Stanley Parker (Owen Stanley) filed a complaint against PHP, Kinder Morgan Texas Pipeline LLC, Kinder Morgan Inc., Eagle Claw Midstream Ventures LLC, Altus Midstream Energy, and ExxonMobil Permian Highway Pipeline LLC (collectively, Respondents), alleging that the Respondents violated section 7(c) of the NGA by failing to obtain a certificate of public convenience and necessity to construct and operate the Permian Highway Pipeline, which Owen Stanley claimed was an interstate pipeline instead of an intrastate pipeline.[194]

186. *KN Wattenberg*, 90 FERC ¶ 61,321 (2000), *reh'g denied*, 93 FERC ¶ 61,041 (2000); City of Fort Morgan v. FERC, 181 F.3d 1155, 1162 n.10 (10th Cir. 1999); *Pinnacle Pipeline Co*., 105 FERC ¶ 61,051 (2003).

187. 180 FERC ¶ 61,187, at P 30.

188. *Id.* at P 32.

189. *Id.* at P 33.

190. *See Owen Stanley Parker*, 180 FERC ¶ 61,179 at P 1 (2022).

191. *Id.*

192. *Id*.

193. *Id*. at P 2.

194. 180 FERC ¶ 61,179, at P 3.

To support its assertion that the pipeline is interstate and subject to Commission jurisdiction, Owen Stanley argued that all but one of the twelve pipelines supplying the Permian Highway Pipeline transports interstate gas, all seven of the direct connect delivery points receiving gas from the pipeline transport interstate gas, and all of the pipeline's market area delivery points either store, handle, or transport interstate gas.[195] Owen Stanley also argued that interstate gas does not need to cross a state border to be considered such. Rather, if the gas' destination is across a state line, then it becomes interstate gas as soon as it enters the pipeline system, and if intrastate gas is commingled with interstate gas, all the gas is considered interstate gas under both the NGA and NGPA.[196]

Accordingly, Owen Stanley asked that the Commission declare the Permian Highway Pipeline subject to its jurisdiction under the NGA and to require the Respondents to obtain a certificate of public convenience and necessity before continuing to operate the pipeline.[197] The complaint also asked the Commission to declare that Respondents deprived landowners of their rights under the NGA, that Respondents had no legal right to condemn property for the pipeline, to order Respondents to pay attorneys' fees and damages up to $1 billion, and to enjoin Respondents from continuing with any condemnation actions.[198]

The Commission published notice of the complaint on May 18, 2022. On May 31, 2022, PHP filed an answer on behalf of all Respondents, explaining that the Permian Highway Pipeline was properly constructed and operates as an intrastate pipeline with limited interstate transportation service under NGPA section 311.[199] PHP also argued that it is a gas utility, as defined by Texas Utility Code section 101.003(7), regulated by the Railroad Commission of Texas; that it owns and operates the Permian Highway Pipeline, which transports approximately 2.0 billion cubic feet per day of gas produced in the Permian Basin to Texas Gulf Coast markets and provides service to and from numerous intrastate pipelines and local distribution companies that service end-users in Texas. PHP also asserted that the Permian Highway Pipeline is not subject to NGA section 7 merely because it interconnects with an interstate pipeline. Rather, the pipeline operates under NGPA section 311, and NGPA section 601(a)(2) expressly exempts section 311 pipelines from NGA jurisdiction.[200]

On September 22, 2022, the Commission denied Owen Stanley's complaint.[201] The Commission explained that PHP is an intrastate pipeline providing service on behalf of interstate pipelines under section 311 of the NGPA and is therefore not subject to the Commission's jurisdiction under the NGA.[202] The

195. *Id*. at P 4.
196. *Id.*
197. *Id*. at P 4.
198. 180 FERC ¶ 61,179, at P 4.
199. *Id*. at P 7.
200. *Id*. at P 8.
201. *Id*. at P 14.
202. 180 FERC ¶ 61,179, at P 4.

Commission found that PHP did not need to obtain a certificate of public convenience and necessity before constructing or operating because NGPA section 311 authorizes intrastate pipelines to transport gas on behalf of interstate pipelines without doing so or becoming subject to the Commission's NGA section 7 authority.[203]

The Commission also explained that the Permian Highway Pipeline meets the definition of an intrastate pipeline because: (1) it is located entirely within Texas and delivers gas produced in the Texas Permian Basin to consumers within Texas; (2) the pipeline interconnects with 19 intrastate pipelines; further, there is an abundance of Texas-sourced natural gas to supply the pipeline, and when the pipeline began operating, it operated solely as an intrastate pipeline; (3) the number of interconnections with interstate pipelines and the comingling of intra- and inter-state gas is irrelevant to the Commission's analysis; and (4) the transportation of interstate gas the Permian Highway Pipeline had provided since December 8, 2020, was in compliance with the NGPA section 311, and NGPA section 601(a)(2) expressly exempts section 311 pipelines from NGA jurisdiction.[204]

2. FERC's Jurisdiction Under the NGA

a) Gulfport Energy Corp. v. FERC

Gulfport Energy Corporation (Gulfport) and Rover Pipeline (Rover) executed Transportation Service Agreements (TSAs) whereby Rover agreed to transport Gulfport's natural gas via its pipelines according to the rates set out in the TSAs. In 2020 as the COVID-19 pandemic "crushed demand for energy, and with it, the price of oil and natural gas," Gulfport's financial outlook suffered.[205] If Gulfport entered bankruptcy, it might reject the TSAs with Rover and, being insolvent, pay Rover cents on the dollar for what otherwise would have been due under those contracts. Anticipating Gulfport's inability to continue operating based on Gulfport's quarterly financial filing, Rover petitioned FERC seeking a declaratory judgement that FERC had exclusive jurisdiction over the TSAs.[206] Rover also requested that the agency hold an expedited paper hearing to determine whether continued performance under the TSAs would harm the public interest.[207]

FERC granted Rover's petition for declaratory order, noting that the TSAs are filed-rate contracts and asserting "parallel, exclusive jurisdiction" over them.[208] FERC declared that "rejection" of a filed-rate contract "in bankruptcy court alters the essential terms and conditions" of that contract and that Gulfport would need FERC's approval before rejecting any TSA during bankruptcy.[209] In

203. *Id*. at PP 9, 14.
204. *Id*. at P 3.
205. Gulfport Energy Corp. v. FERC, 41 F.4th 667, 673 (5th Cir. 2022).
206. *Id*. at 673-74.
207. *Id.*
208. *Id.* at 674.
209. *Gulfport Energy Corp.*, 41 F.4th at 674.

the paper hearing, FERC issued an order finding that "the public interest does not presently require the modification or abrogation of the Gulfport TSAs," because the rates "currently on file and in effect remain just and reasonable" under the Mobile–Sierra standard.[210] FERC required Gulfport to continue performing the TSAs. FERC denied rehearing of both the declaratory order and the order on paper hearing. Gulfport filed for bankruptcy and moved the bankruptcy court to allow it to reject the TSAs. Gulfport petitioned the U.S. Court of Appeals for the Fifth Circuit (Court) for review of FERC's initial declaratory order, order on paper hearing, and FERC's orders denying rehearing of each.

The Court explained that the issue of the case rested on two legal regimes, those of the Bankruptcy Code and the Natural Gas Act, and how such regimes interact. The Court reasoned that "rejection" of a contract by the bankruptcy court "does not change or cancel a contract; it *breaches* that contract."[211] Thus, neither the contract itself nor the filed rate change under such rejection. The Court found that FERC had the authority to issue its orders, but that because FERC's orders rested on an inexplicable misunderstanding of rejection, the Court vacated all four orders.[212] The Court held that each FERC order "rests on the premise that rejecting a filed-rate contract in bankruptcy is something more than a breach of contract."[213] The Court explained that premise is wrong, that rejection is just a breach and does not modify or abrogate the filed rate, which is used to calculate the counterparty's damage.[214] Thus, the Court clarified, FERC cannot prevent rejection, cannot bind a debtor to continue paying the filed rate after rejection, and cannot usurp the bankruptcy court's power to decide Gulfport's rejection motions.[215]

b) BP America, Inc. v. FERC

Following Hurricane Ike's landfall over southeastern Texas, FERC brought an enforcement action against BP America, Inc. (BP) for allegedly capitalizing on the hurricane-induced chaos in commodities markets by manipulating the natural gas market. BP petitioned the U.S. Court of Appeals for the Fifth Circuit (Court) for review of the FERC order finding that BP's financial traders violated an NGA anti-manipulation provision and imposing a $20 million civil penalty.

BP argued that FERC did not have jurisdiction over certain of its conduct because (1) FERC's jurisdiction extends only to interstate transportation activity pursuant to the NGA, and (2) none of the transactions at issue involved interstate natural gas transportation regulated by the FERC.[216] In response, FERC argued

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210. *Id.*
211. *Id.* at 672.
212. *Id.* at 681.
213. *Gulfport Energy Corp.*, 41 F.4th at 682.
214. *Id.* at 685.
215. *Id.*
216. BP Am., Inc. v. FERC, 52 F.4th 204, 213 (5th Cir. 2022).

partition between intrastate and interstate transactions was nullified for purposes of the anti-manipulation rule by the Energy Policy Act of 2005.[217]

The Court rejected FERC's argument because the NGA says it "shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas," which forbids FERC from exercising jurisdiction over intrastate transactions.[218] The Court further reasoned that "where Congress has decided to expand FERC's jurisdiction, it has done so explicitly and unambiguously" and the Energy Policy Act of 2005 does not unambiguously expand FERC's jurisdiction.[219]

After rejecting FERC's broad jurisdictional argument, the Court analyzed and accepted FERC's alternative basis for jurisdiction over BP's sales: "once gas is sold or transported in interstate commerce, it remains interstate gas thereafter."[220] As support, FERC pointed to eighteen of BP's allegedly manipulative sales of natural gas that had been transported under a contract which stated in its title: "UNDER SUBPART G OF PART 284 OF THE FERC'S REGULATIONS."[221] Although BP did not dispute that the natural gas had been transported under contract, it attempted to argue that the contracts were actually under section 311 of the Natural Gas Policy Act (NGPA). The Court, however, upheld FERC's assertion of jurisdiction finding it was supported by substantial evidence because BP did not present any evidence to overcome the "unambiguous language on the face of the contract to the contrary."[222] Therefore, the Court found, FERC had jurisdiction over the eighteen subject BP natural gas sales.

c) Center for Biological Diversity v. FERC

On May 21, 2020, FERC granted the Alaska Gasline Development Corporation (Corporation) authorization to build and operate a system of natural gas facilities (Project) in Alaska's North Slope under section 3 of the NGA.[223] FERC authorized the Corporation's project subject to 165 environmental conditions pursuant to its NEPA review of the project and resulting EIS.[224] The Center for Biological Diversity (CBD) petitioned for rehearing of the Commission's authorization, arguing that the EIS was deficient, and that FERC had not adequately determined the Project was in the public interest. On September 11, 2020, FERC denied rehearing and CBD then petitioned the United States Court of Appeals for the District of Columbia (Court) for review of the authorization and rehearing orders for failure to comply with NEPA and its implementing regulations. Among

217. *Id.* at 215-16.
218. *Id.* at 214-16.
219. *Id.* at 216.
220. *BP Am., Inc.*, 52 F.4th at 217.
221. *Id.*
222. *Id.* at 217-18.
223. Ctr. for Biological Diversity v. FERC, 67 F.4th 1176, 1179-80 (D.C. Cir. 2023).
224. *Id.* at 1180-81.

other things, CBD argued that FERC violated NEPA and its implementing regulations by refusing to consider the Project's indirect greenhouse gas emissions.

In its May 16, 2023 decision, the Court dismissed CBD's petition for review in part and denied it in part.[225] The Court explained that the Department of Energy has exclusive jurisdiction over whether to approve natural gas exports. Therefore, FERC "does not have authority over, and need not address the effects of, the anticipated export of the gas."[226] The Court explained that FERC is "forbidden to rely on the effects of gas exports as a justification for denying permission to an LNG project."[227] Further, the Court explained that because FERC lacks jurisdiction over export approvals, FERC also has no NEPA obligation stemming from the effects of export-bound gas.[228]

The Court also found that FERC properly cabined its NEPA analysis according to its delegated statutory authority. While CBD argued that agencies must consider the environmental impacts of closely related actions, the Court held that the governing regulations "do not, and cannot, expand FERC's jurisdiction."[229] Therefore, the Court declined to adopt CBD's reading of 40 C.F.R. § 1508.25 because it conflicts with the Court's precedent and "would require the Commission to consider the indirect effects of actions beyond its delegated authority."[230]

d) Adorers of the Blood of Christ United States Province v. Transcontinental Gas Pipe Line Co. LLC

In 2014, Transcontinental Gas Pipe Line Company (Transco) notified the Adorers of the Blood of Christ (Adorers), a centralized religious group "opposed to the extraction, transportation, and use of fossil fuels,"[231] that Transco intended to install a 183-mile-long, forty-two-inch diameter interstate gas pipeline that would run through the Adorers' property in eastern Pennsylvania.[232] "The Adorers explained to Transco's right-of-way agent that this pipeline would violate their religious beliefs," that they objected to the pipeline's construction, and that they would not engage in negotiations for the purchase of a right-of-way for the pipeline.[233] In 2015, Transco filed an application with FERC to obtain a certificate of public convenience and necessity. As part of the pipeline approval process and as required by the NGA and FERC regulations, FERC published several public notices over the course of more than two years and contacted the Adorers directly to inform them of the planned pipeline route and to solicit their feedback.[234] The

225. *Id*. at 1179-80.
226. *Id.* at 1185.
227. *Ctr. for Biological Diversity*, 67 F.4th at 1185 (internal quotations omitted).
228. *Id.*
229. *Id.*
230. *Id.*
231. Adorers of the Blood of Christ U.S. Province v. Transcon. Gas Pipe Line Co., 53 F.4th 56, 57 (3d Cir. 2022).
232. *Id.* at 58.
233. *Id.*
234. *Id.* at 58-59.

Adorers did not respond to the notices or formally oppose the proposed pipeline for the thirty months during which FERC oversaw and reviewed Transco's proposed pipeline. On February 3, 2017, FERC issued a certificate authorizing Transco to build, operate, and maintain the pipeline which would run through the Adorers' property and to use eminent domain to obtain rights-of-way from those property owners who refused to voluntarily sell a right-of-way to Transco.

In April 2017, Transco filed a complaint in federal court seeking a condemnation order to permit it to take title to the rights-of-way in the Adorers' property as was necessary to build and operate the pipeline. The Adorers failed to answer or otherwise respond to the complaint despite proper service. One week after the federal district court granted Transco default judgement on its entitlement to rights-of-way, the Adorers filed a separate suit in the U.S. District Court for the Eastern District of Pennsylvania (District Court), claiming for the first time that FERC and Transco violated their rights under the Religious Freedom and Restoration Act (RFRA). The Adorers claimed that under RFRA, they had "the right to institute an action in federal court rather than proceed before FERC" and "sought an injunction permanently enjoining Transco from completing its project."[235] The District Court held that "'RFRA did not allow the Adorers to circumvent the specific procedure prescribed [by Congress] under the NGA for challenging a FERC order' and '[b]ecause the Adorers had failed to seek FERC rehearing . . . it was foreclosed from hearing their claims.'"[236]

After the completion of the pipeline, the Adorers filed suit again in the District Court seeking money damages from Transco for violating their rights under RFRA. The District Court applied the holding of the first case, holding that the Adorers' failure to take part in the formal process before FERC precluded a judicial review of their RFRA claims. The Adorers' appealed.

The Court of Appeals applied the same principle as the Supreme Court did in *City of Tacoma v. Taxpayers of Tacoma*,[237] finding that exclusive review schemes like that of the NGA "necessarily preclude de novo litigation between the parties of all issues inhering in the controversy, and all other modes of judicial review."[238] The Court explained that the NGA's exhaustion provision made "clear Congress' intent to confer exclusive jurisdiction to the NGA by a highly reticulated statute nullifying any procedural alternatives an aggrieved party may otherwise have."[239] The Court found that the Adorers' allegation that the presence and operation of a pipeline on their property violated their rights under RFRA "could and should have been contested before FERC during the certification proceedings where such issues were to be resolved."[240] The Court held that the Adorers' claim is now barred as an impermissible collateral attack.

235. *Adorers*, 53 F.4th at 60.

236. *Id. (*quoting *Adorers I,* 897 F.3d at 193).

237. City of Tacoma v. Taxpayers of Tacoma, 357 U.S. 320 (1958).

238. Adorers of the Blood of Christ v. FERC, 897 F.3d 187, 197 (3d Cir. 2018) (quoting *City of Tacoma*, 357 U.S. at 336, 341).

239. *Adorers*, 53 F.4th at 60.

240. *Id.* at 65.

H. *Market-Based Rates*

1. Pine Prairie Energy Center, LLC, 182 FERC ¶ 61,103 (2023).

On February 17, 2023, FERC approved Pine Prairie's request to implement the following services: "(i) firm wheeling service; (ii) enhanced storage service; (iii) enhanced parking service; and (iv) enhanced loan service," and charge market-based rates pursuant to Pine Prairie's preexisting market-based rate authority.[241] In response to a customer request, Pine Prairie requested to add additional services to its tariff because these new services are needed to meet ever-changing market conditions and changes precipitated by Winter Storm Uri.[242] Specifically, the new services were proposed to provide customers with enhanced, non-interruptible service with higher scheduling and curtailment priority equal to all customers.[243] The Commission approved the new services and proposed market-based rate treatment. The Commission also granted Pine Prairie's request for waiver of the requirement that Pine Prairie "provide details and information related to costs and revenues associated with services provided by Pine Prairie," as Pine Prairie will no longer be charging cost-based rates.[244]

On October 27, 2022, FERC granted Transco's petition for a declaratory order requesting market-based rate authority for firm storage service at Transco's Washington Storage Field located in St. Landry Parish, Louisiana.[245] WSS Customer Group protested the issuance of the declaratory order arguing that Transco failed to provide sufficient support for its proposed market area and price estimate, and that Transco failed to demonstrate that it lacks market power as required for market-based rate authorization.

In its Market Power Study, Transco identified the Gulf Coast Production Area as the relevant geographic market area because it is the market for Transco's firm and interruptible services. The Commission determined that this area is appropriate because the Washington Storage Field is connected to other interstate pipelines and facilities that the "Commission has determined are physically located in the Gulf Coast Production Area" and the area provides customers with competitive alternatives to Transco's services.[246]

With regard to price, the Commission found that Transco demonstrated that the price of local production is less than the price of storage, consistent with the Commission's Alternative Rate Policy Statement, and that Transco's peak price premium adjustment is reasonable.[247] Lastly, the Commission determined that Transco lacks market power and is unlikely to be able to exercise market power in

241. *Pine Prairie Energy Ctr., LLC*, 182 FERC ¶ 61,103 at PP 1, 8 (2021).
242. *Id.* at P 3.
243. *Id.* at PP 6-8.
244. *Id.* at P 14.
245. *Transcon. Gas Pipe Line Co.*, 181 FERC ¶ 61,079 (2022).
246. *Id.* at P 22.
247. *Id.* at PP 42-44.

the Gulf Coast Production area.[248] On November 28, 2022, WSS Customer Group filed a request for rehearing of the Declaratory Order.

On March 16, 2023, the Commission addressed WSS Customer Group's arguments raised on rehearing and request for clarification of the Declaratory Order.[249] On rehearing, WSS Customer Group argued that the Commission failed to address its arguments in the underlying order. The Commission stated it was not persuaded by WSS Customer Group's arguments and sustained the result of the Declaratory Order.[250] The Commission further declined to provide clarification on whether the WSS Customer Group can purchase base gas at the same price regardless of their status as customers because the same rate schedules applies "regardless of whether Transco charges cost-based or market-based rates."[251] The Commission further refused to provide clarification on "issues regarding the implementation of market-based rates within the scope" of tariff proceedings because such issues are better addressed in tariff proceedings, rather than in the context of a declaratory order proceeding.[252]

I. Rate Cases

1. Panhandle Eastern Pipe Line Co., LP

On December 16, 2022, the Commission issued its "Order on Initial Decision," Opinion No. 885, in *Panhandle Eastern Pipe Line Co.*[253] affirming in part and reversing in part the Initial Decision.[254] The background[255] of the proceeding included the commencement of section 5 investigations by the Commission involving Panhandle Eastern Pipe Line Company, LP (Panhandle)[256] and its affiliate Southwest Gas Storage Company (Southwest).[257] The Southwest proceeding ended in a settlement, reserving one issue for litigation,[258] Panhandle filed a section 4 case,[259] and the Commission consolidated the outstanding Southwest issue, the section 5 investigation, and the Panhandle section 4 filing for hearing.[260] The consolidated proceedings went to hearing and briefing and ultimately resulted in the Initial Decision. In Opinion No. 885, the Commission summarized the issues

248. *Id.* at P 55.
249. *Transcon. Gas Pipe Line Co.*, 182 FERC ¶ 61,168 (2023).
250. *Id.*
251. *Id.* at P 38.
252. *Id.* at P 39.
253. *Panhandle E. Pipe Line Co.*, 181 FERC ¶ 61,211 (2022).
254. *Panhandle E. Pipe Line Co.*, 174 FERC ¶ 63,026 (2021).
255. The Commission also briefly noted that the last rate case of the pipeline was settled in 1996 and discussed briefly the changes to the system in the intervening years. 181 FERC ¶ 61,211, at PP 4-5.
256. *Panhandle E. Pipe Line Co.*, 166 FERC ¶ 61,032 (2019).
257. *Sw. Gas Storage Co.*, 166 FERC ¶ 61,078 (2019).
258. *Id*.
259. *See Panhandle E. Pipe Line Co.*, 168 FERC ¶ 61,208 (2019).
260. *Id*.

addressed on exceptions as including: "(1) Rate Base, (2) ADIT, (3) Cost of Capital, (4) Depreciation, Negative Salvage, and Terminal Decommissioning, (5) Billing Determinants, (6) Cost Classification, Cost Allocation and Rate Design, (7) Storage, (8) Miscellaneous Fuel Costs, and (9) the Trunkline OBA," noting that no exceptions were filed as to the cost of service, rate design of Rate Schedule SCT (Small Customer Transportation), or the SCT daily scheduling variance.[261] Each of the holdings addressed in Opinion No. 885 are discussed sequentially below.

- <u>Rate Base – Account No. 117.2</u>. The disputed rate base issue concerned how to determine the proper level of System Balance Gas, Account No. 117.2, which had increased sharply during the period in which Panhandle filed its rate case. The Initial Decision rejected the thirteen-month period proposed by Panhandle as well as the thirty-six-month period proposed by Trial Staff, and chose a twenty-four-month period ending in January 2020 instead.[262] The Commission reversed, adopting instead a twenty-one-month period ending January 2020.[263] The Commission found that normalization of the storage balances in Account No.117.2 was appropriate, given the significant ("seven-fold") rise and the absence of an explanation as to why such balances should be representative of future levels.[264] The twenty-one-month period selected was intended to encompass data from the test period, whereas the Initial Decision's twenty-four-month period included data from before the test period.[265] The Commission rejected Panhandle's arguments that the recorded balances should be used as having been prudent, used and useful and recorded in accordance with the accounting regulations; the Commission cited the appropriateness of normalizing to account for significant fluctuations.[266] The Commission also rejected Trial Staff's rationale that a longer, thirty-six month period was appropriate to prevent the potential that Panhandle might have inflated the balances in anticipation of the rate case, noting an absence of evidence to support that concern.[267]
- <u>Rate Base – AFUDC Equity Cost Rate</u>. The Initial Decision sought to apply the standard in Part 201 of the Commission's regulations, which requires use of the "rate granted common equity in the last rate proceeding," or absent that, the average rate actually earned in

261. 181 FERC ¶ 61,211, at P 12.
262. *Id*. at PP 14-17.
263. *Id*. at P 22.
264. *Id*. at P 23.
265. 181 FERC ¶ 61,211, at P 24.
266. *Id*. at PP 25-26.
267. *Id*. at P 27.

the prior three years.[268] The two options submitted by the parties were 12.13%, the ROI approved in the last Commission merits decision (Opinion No. 404,[269] in 1996) (Trial Staff), or 13.25%, the implicit rate Panhandle contended, (1) was used in the 1996 rate settlement following Opinion No. 404, (2) was used in Panhandle's subsequent Form 2 reports and (3) was noted without adverse action in a Commission audit of Panhandle. The Initial Decision selected 13.25%, concluding that Panhandle's evidence created a prima facie case for this level, given the nature of the settlement, the continued use of the figure in reports, and the audit—a showing not rebutted by Trial Staff.[270] The Commission reversed, finding that the "rate granted" in the last rate proceeding was 12.13%.[271] The Commission concluded that the 13.25% figure was not stated and thus not granted in the 1996 settlement,[272] and further that the fact that Panhandle's rates were never effective using the 12.13% level was not controlling, because the 12.13% figure was the one "granted."[273] The Commission further noted that percentages reported in Form 2 are not Commission approved,[274] that the audit's acceptance of the percentage does not represent a finding by the Commission in a rate context,[275] and concluded that the long public use of the percentage by Panhandle without objection was not pertinent to this ratemaking determination.[276]

- <u>Rate Base – Accumulated Depreciation, Depletion and Amortization</u>. The figures for accumulated depreciation, depletion and amortization were broadly agreed-upon by the parties, except for the AFUDC equity cost;[277] consistent with the discussion above, the Commission reversed on this issue and required an AFUDC equity return of 12.13%.[278]
- <u>ADIT and EDIT</u>. The Commission reviewed the nature, sources and ratemaking roles of Accumulated Deferred Income Taxes (ADIT, typically deducted from rate base)[279] and Excess Deferred Income Taxes (EDIT, typically flowed back to ratepayers),[280] as

268. *Id*. at P 28.
269. Opinion No. 404, *Panhandle E. Pipe Line Co.*, 74 FERC ¶ 61,109 (1996).
270. 181 FERC ¶ 61,211, at P 30.
271. *Id*. at PP 35, 44.
272. *Id*. at P 36.
273. *Id*. at P 39.
274. 181 FERC ¶ 61,211, at P 40.
275. *Id*. at P 41.
276. *Id*. at P 42.
277. *Id*. at P 45.
278. 181 FERC ¶ 61,211, at P 46.
279. *Id*. at P 47.
280. *Id*. at P 48.

> well as recent legislation affecting both ADIT/EDIT amounts and decisions affecting recoverability by pass-through entities (such as Panhandle).[281] Panhandle itself experienced ownership changes, changing from being owned by a corporation to being owned by a master limited partnership (MLP) in July 2019; following that change, Panhandle excluded an income tax allowance in its rate filing, but also removed ADIT balances (thereby increasing rate base for ratemaking purposes) and removed its EDIT regulatory asset (ending the potential for flow-back of EDIT to ratepayers).[282] The Initial Decision found, based on appellate precedent, that Panhandle properly removed ADIT and EDIT balances as a result of its restructuring.[283] The Commission affirmed the ADIT holding but reversed the EDIT holding,[284] for the reasons discussed below.

Regarding elimination of ADIT, the Commission found the Initial Decision to have properly relied on Commission and court precedents,[285] and addressed in detail why the conclusion comports with tax normalization principles and rebutting three principal arguments raised by participants contending that Panhandle should not be permitted to eliminate its ADIT balances.[286]

On the tax normalization issue, the Commission concluded that when a tax allowance is no longer recovered in rates, there is no longer a "matching" function of normalization, and no therefore liability for the deferred taxes in the ADIT balances.[287] The Commission rejected the analogy, raised by Trial Staff, to changes in the tax code, on the grounds that while changes in tax rates may require changes in EDIT amortization rates, that is not comparable to the complete elimination of the tax allowance resulting from the change in Panhandle's tax status.[288] The Commission stated that in contrast to a hypothetical reduction in current tax rates to zero,[289] with a continuing right to seek a tax allowance in the future, here Panhandle's complete elimination of a future tax liability is fundamentally unlike a change in tax levels.[290] The Commission also rejected arguments attempting to distinguish prior tax allowance cases.[291]

In response to arguments that elimination of ADIT balances is unfair or inappropriate, the Commission affirmed the applicability of prior Commission and court decisions holding that ratepayers have "no equitable interest or ownership

281. 181 FERC ¶ 61,211, at P 49.
282. *Id*. at P 51.
283. *Id*. at P 52.
284. *Id*. at P 61.
285. 181 FERC ¶ 61,211, at P 62.
286. *Id.* at P 63.
287. *Id*. at P 64.
288. *Id*. at P 65.
289. 181 FERC ¶ 61,211, at P 66.
290. *Id.* at P 67.
291. *Id*. at PP 68-69.

claim in ADIT," because ADIT reflects simply the normalized impact of tax timing differences,[292] and rejecting (citing past decisions) the contention that elimination of ADIT in these circumstances is a "windfall."[293] The Commission also specifically affirmed the ID's conclusion that requiring the return of ADIT to shippers would constitute retroactive ratemaking, in violation of the Natural Gas Act's reliance on prospective rate changes,[294] noted that this principle had been applied by the courts,[295] and further found that it also accorded with the fact that ratepayers in prior years had paid allocated costs for the service being provided in those years.[296] The Commission again rejected arguments that prior cases supporting this conclusion could be distinguished[297] and found that in all cases the issue has been whether the pipeline's future costs are to be recovered in its future rates, which would not be the case with deferred taxes in Panhandle's case or as to other pipelines whose ADIT was reviewed in similar circumstances.[298] The Commission also found irrelevant whether the deferred taxes were actually being paid to the IRS,[299] rejected the contention that elimination of ADIT would result in double-recovery,[300] and did not change the decision in light of the theory that pipelines might "toggle between a corporation and an MLP to manipulate the Commission's ADIT policy."[301]

Regarding EDIT, the Commission reversed the Initial Decision and required that the pipeline's EDIT balances that had been recorded in Account No. 254 following the Tax Cuts and Jobs Act were to be flowed back to ratepayers.[302] The Commission noted that the fact pattern at issue – a pipeline subject to a statutory tax change that subsequently converted to an MLP corporate form – had not been addressed in prior Commission or court precedents. However, the Commission concluded that consistent with existing policy and related precedents, companies with EDIT balances following a tax rate change must amortize that EDIT balance in rates.[303] The Commission distinguished between ADIT balances (in Account Nos. 190, 282 and 283) reflecting timing differences and EDIT balances created (for a tax-paying entity) by a specific statutory change, in an Account (No. 254) for regulatory liabilities, whose provisions specifically require amortization on a prospective basis.[304] In 2018, the pipeline had recorded its EDIT amounts as a

292. *Id*. at P 70.
293. 181 FERC ¶ 61,211, at P 71.
294. *Id.* at P 72
295. *Id*. at P 73.
296. *Id*. at P 74.
297. 181 FERC ¶ 61,211, at P 75.
298. *Id.* at P 76.
299. *Id*. at P 77.
300. *Id*. at P 78.
301. 181 FERC ¶ 61,211, at P 79.
302. *Id.* at P 80.
303. *Id*. at P 81.
304. *Id*. at P 83.

regulatory liability in Account No. 254, making it subject to the flow-back obligations of Account No. 254, as recognized by the Commission's ADIT Policy Statement[305] at that time; the Commission found that Account No. 254 pertains to a regulatory asset, not to deferred taxes, and that it "is not subject to the same normalization restrictions that ADIT balances have and need not be extinguished under these circumstances."[306] The Commission noted similar prior applications of Account 254's effects, as to other regulatory liabilities,[307] and rejected Panhandle's citation to other pipeline precedents with differing outcomes, because those cases involved pipelines that were MLPs at the time of the statutory tax change.[308] The Commission also disagreed with Panhandle's contention that the ruling involved retroactive ratemaking, arguing that because Panhandle was a tax-paying corporation at the time of the tax changes, its recorded EDIT amounts in Account No. 254 were subject to the flow-back obligation, prospectively, which does not involve retroactive ratemaking.[309] The Commission further noted that even as to the application of this rule to EDIT recovered in past rates as a credit to future rates, which might be viewed as a change to the past rates, it was not retroactive ratemaking because the pipeline has been on notice because Commission policies on this matter have been in place since 1993, putting Panhandle on notice of the effect of a later tax change.[310] The Commission also rejected Panhandle's retroactivity argument on practical grounds, contending that if the rule had to be applied while the pipeline was still a corporation, pipelines could defeat application of the rule by changing corporate form during the pendency of an investigation.[311]

- <u>Cost of Capital – Capital Structure</u>. The Commission affirmed the ID's decision to use Panhandle's own capital structure, and to update the percentage as of the end of the test period,[312] but reversed the ID's decision to include ADIT and EDIT balances in calculating the equity percentage.[313] Regarding the basic question of whether to use the pipeline's own capital structure, the Initial Decision found that Panhandle met all three tests to justify use of its own capital structure (issuing its own debt, having its own bond rating, and showing the equity ratio is not excessive in light of precedents).[314] The Initial Decision also concluded that it was appropriate to include in the capital structure the equity from ADIT and EDIT as

305. *Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset*, 165 FERC ¶ 61,115 (2018).

306. 181 FERC ¶ 61,211, at P 84.

307. *Id*. at P 85.

308. *Id*. at P 86.

309. *Id*. at P 87.

310. 181 FERC ¶ 61,211, at P 88.

311. *Id*. at P 89.

312. *Id*. at P 100.

313. *Id*. at P 97.

314. 181 FERC ¶ 61,211, at PP 91, 92.

retained earnings.[315] The Commission agreed with the use of Panhandle's own capital structure without discussion, but required that ADIT be removed from the equity portion of the capital structure, consistent with eliminating it from the cost of service,[316] and that having reversed the write-off of EDIT, required that EDIT be removed from retained earnings as well,[317] in accordance with its ADIT and EDIT rulings.[318]

- <u>Cost of Capital – Return on Equity</u>. The Commission provided an overview of its policy and methodology regarding determination of a reasonable return on equity.[319] The Initial Decision had found an ROE of 11.43% to be appropriate,[320] with the use of a proxy group composed of TC Energy Corporation (TC Energy), Williams Companies, Inc. (Williams), Enbridge, Inc. (Enbridge) and National Fuel Gas Co. (National Fuel).[321] The Commission adopted an ROE of 11.25%, based on a proxy group composed of the four companies selected in the Initial Decision, plus Kinder Morgan.[322] The disputed issues underlying this ROE are summarized below.

Regarding the appropriate data period for the determination, the Initial Decision had chosen May 2020 as the most recent (rejecting Panhandle's proposal to use January 2020 due to COVID factors), citing precedent.[323] On exceptions, the Commission affirmed use of May 2020 as being the most recent data in the record,[324] The Commission rejected Panhandle's argument that the pandemic significantly affected May 2020 data on several grounds, concluding that May 2020 had not been shown to be "anomalous" so as to justify use of January 2020.[325]

As to the appropriate composition of the proxy group, the Commission first reviewed its policies as to proxy group purpose and applicable criteria[326] and then made specific findings regarding the inclusion, or exclusion of the selected proxy group members, as well as two suggested companies that were not selected (TC

315. *Id*. at P 93.

316. *Id*. at P 98.

317. *Id*. at P 99.

318. 181 FERC ¶ 61,211, at P 97.

319. *Id*. at PP 101-06.

320. *Id*. at P 109. Participant recommendations ranged from 14.67% (Panhandle), to 12.01% (Trial Staff) to 11.17% (Michigan PSC) to 10.10% (Panhandle Municipal Defense Group). *Id*. at P 109.

321. 181 FERC ¶ 61,211, at P 107.

322. *Id.* at P 110.

323. *Id*. at PP 111-12.

324. *Id*. at P 117.

325. 181 FERC ¶ 61,211, at PP 120-24. The Commission found that short-term effects of COVID were not controlling, given the 3-5 year expectations found in the May 2020 data (P 120), disagreed with the effect on Panhandle's stock prices (P 121), rejected the relevance of a precedent that involved truly anomalous costs of capital (P 122), declined to exclude data showing any impact of COVID (P 123), and found the later date appropriate even though it affected the selection of the proxy group members (P 124).

326. *Id.* at PP 125-28.

Pipelines and Dominion). The Commission affirmed inclusion of National Fuel Gas Supply Corporation, despite its pipeline assets falling below 50% of income or assets, by applying the *Kern River*[327] three-part criteria, which permit use of a company if its combined gas pipeline and distribution equal at least equal 50% of its total business, the natural gas pipeline business is at least equal to the distribution business, and the firm's riskier exploration or other businesses are no greater than the distribution business.[328] The Commission found that the company met the first two criteria[329] and that although it fell slightly short of meeting the third, that the criteria were applied "flexibly" and that flexibility was appropriate in order to meet the Commission's preferred proxy group size.[330] The Commission rejected Panhandle's arguments that the *Kern River* rule should be applied rigidly (and that it had not been so applied in the past),[331] that use of a three-year average (rather than one-year period) was inappropriate,[332] and that the company's involvement in an asset acquisition should disqualify it from inclusion (the "M&A screen"), because the data did not indicate any significant distortions in National Fuel's data.[333] The Commission also stated that National Fuel was "sufficiently comparable" to Panhandle.[334]

The Commission affirmed the finding and rationale of the Initial Decision that TC Pipelines should be excluded because it had a negative short-term growth rate during the applicable period.[335] Regarding the Initial Decision's exclusion of Kinder Morgan from the proxy group on grounds of having a negative growth rate as of the end of May 2020, the Commission reversed. The Commission found reasoned that the most recent data—as of June 3, 2020—showed positive growth, and that Kinder Morgan met the other proxy group criteria.[336]

The Initial Decision had excluded Dominion from the proxy group, citing its classification by Value Line as an electric utility and its growing focus on that role, as well as its falling well short of having 50% of its assets be composed of gas transmission and storage.[337] The Commission affirmed, citing the same grounds as the Initial Decision, as well as the fact that with Kinder Morgan's inclusion, the number of proxy group companies would be adequate.[338]

Regarding Enbridge, the Initial Decision had included Enbridge in the proxy group, citing its classification as a gas pipeline and the tracking of its publicly

327. *See* Opinion No. 486-C, *Kern River Gas Transmission Co.*, 129 FERC ¶ 61,240 at P 71 (2009) (citing Opinion No. 486-B, 126 FERC ¶ 61,034, at PP 91-92, 94, 97-99).

328. 181 FERC ¶ 61,211, at P 138.

329. *Id*. at PP 139-40.

330. *Id*. at P 141.

331. *Id*. at P 142.

332. 181 FERC ¶ 61,211, at P 143.

333. *Id*. at P 144.

334. *Id*. at P 145.

335. *Id*. at PP 146, 149.

336. 181 FERC ¶ 61,211, at P 154.

337. *Id*. at P 155.

338. *Id*. at P 158.

traded stock by Value Line, despite its failing to meet the third Kern River criterion, given the small number of potential proxy group members.[339] The Commission affirmed, noting the small number of eligible proxy group companies, finding its risk profile comparable to Panhandle's, and rejecting claims that its acquisition of Spectra had created demonstrated distortive effects.[340]

The Initial Decision had adopted Trial Staff's recommended DCF analysis and conclusion, including a median ROE of 11.88% and range of reasonableness from 11.26% to 15.18%.[341] Regarding the appropriate dividend yield, the Commission affirmed the ID's dividend yield for four of the five proxy group companies, but reversed the adoption of Trial Staff's dividend yield for TC Energy, and instead adopted a dividend yield of 4.75% for TC Energy.[342] The Commission's DCF results were a median ROE of 11.26%, a low ROE of 7.56% and a high ROE of 12.27%.[343]

The Initial Decision had adopted Trial Staff's CAPM analysis, which produced a median ROE of 10.98%, and a range of reasonableness from 9.91% to 16.47%.[344] This finding was not the subject of exceptions, and the Commission adopted it.[345]

Regarding the weighting of DCF and CAPM, the Commission adopted the Initial Decision's decision to give equal weight to the two, and, consistent with the Commission's finding that Panhandle was of average risk, resulted in setting the ROE at the median of the proxy group, 11.25%.[346] The Initial Decision had determined that Panhandle was not higher than average in risk, based on its investment grade ratings and debt/equity ratio,[347] evidence that it was of average business risk,[348] and lack of evidence that the proxy group was more diversified than Panhandle.[349] The Commission affirmed, finding that no party had overcome the presumption that the ROE should be set at the median of the proxy group by demonstrating an anomalously "high or low risk level."[350] The Commission rejected Panhandle's argument that its discounting showed high risks and further that denial of a discount adjustment would support a higher level of risk for ROE purposes; the Commission noted that it was allowing a discount adjustment, and hence the discounts did not justify deviating from the median ROE.[351]

339. *Id*. at P 159.
340. 181 FERC ¶ 61,211, at P 162.
341. *Id*. at P 163.
342. *Id*. at P 167.
343. *Id*. at P 168.
344. 181 FERC ¶ 61,211, at P 169.
345. *Id*. at P 170.
346. *Id*. at P 172.
347. *Id*. at P 173.
348. 181 FERC ¶ 61,211, at P 174.
349. *Id*. at P 175.
350. *Id*. at P 179.
351. *Id*. at P 180.

- Depreciation – remaining economic life of the pipeline. The Initial Decision used a forty year economically useful life, finding gas supplies available for 76.6 to eighty-eight years, and sufficient demand for forty years.[352] The Commission reversed this finding, adopting instead Panhandle's recommended thirty-five year economic life.[353] The Commission found that the underlying demand studies on the record supported only thirty-five years,[354] and that it had adopted thirty-five years in other cases.[355] The Commission further rejected Trial Staff's recommended fifty year economic life as unsupported, and rejected the argument that Panhandle was required to conduct its own supply analysis.[356]
- Appropriate depreciation rates and interim salvage rate. The Commission affirmed several findings in the Initial Decision regarding depreciation, including the conclusion that Panhandle had not justified its proposed increased depreciation rates for General Plant,[357] that for Account 368 Panhandle failed to meet its burden to show that it should reflect the shorter life of gas turbines, under applicable precedent,[358] and found the Initial Decision's use of "three-years of near-term plant additions" as being consistent with precedent, and that the record did not justify a departure.[359]

The Initial Decision had denied Panhandle's proposal to establish a "negative salvage rate" for interim retirements of long-lived assets; in Opinion No. 885, the Commission referenced this proposal as "interim negative salvage," to distinguish it from traditional "negative salvage," which Panhandle was seeking to address via its "terminal decommissioning rate."[360] The Initial Decision found that collection of interim negative salvage was a new charge for which Panhandle bore the burden of proof, and that Panhandle's proof, chiefly in the form of six years of actual retirement data and forty-eight years of Form 2 data, was insufficient under the Commission's established triple criteria for negative salvage, and in light of the NARUC standard for twenty-thirty years of retirement data, as well as Panhandle's failure to meet the evidentiary requirements established in prior precedent.[361] The Commission affirmed, agreeing that Panhandle failed to provide sufficient data,

352. 181 FERC ¶ 61,211, at P 182.
353. *Id*. at P 189.
354. *Id*. at P 190.
355. *Id*. at P 191.
356. 181 FERC ¶ 61,211, at P 192.
357. *Id*. at P 199.
358. *Id*. at P 200.
359. *Id*. at P 201.
360. 181 FERC ¶ 61,211, at P 202 n.434.
361. *Id*. at P 202.

particularly in light of NARUC guidelines, and that six years of data was insufficient in the context of a new charge.[362] The Commission agreed with the conclusion that the prior evidentiary standard in precedent had not been met, that a contrary case cited by Panhandle pre-dated the NARUC manual that has been relied upon in later Commission orders,[363] and that the Form 2 data was not sufficient to cover for absent, detailed retirement data.[364]

- <u>Terminal Decommissioning Rate (TDR)</u>. Panhandle had proposed a TDR for revenues to pay the costs of removing the pipeline from service at the end of its useful life, based on a decommissioning study of its current assets,[365] and the Initial Decision approved the recovery of part of those costs via a TDR, subject to certain conditions.[366] Although the Initial Decision found that the decommissioning was valid as a basis for the TDR, it was necessary to reduce the total plant to be recovered by the amount of plant that would be retired but not replaced in the future, as required in a prior Commission order authorizing a similar recovery mechanism.[367] The Initial Decision also suggested that the Commission consider disallowing a portion of the recovery to alleviate the potential intergenerational inequity resulting from having the cost of decommissioning borne only by customers during the remaining period of Panhandle's operation; the Initial Decision also required that the funds be kept in a "dedicated account" to prevent their being used for other purposes and that Account 108 be used to record the funds, to ensure transparency.[368] The Commission affirmed the Initial Decision's determination allowing the TDR, and its decision to remove those assets to be retired before the end of operations, but rejected the requirement of a dedicated trust and rejected the suggestion to disallow a portion of the recovery on intergenerational equity grounds.[369] The Commission agreed with the Initial Decision that the decommissioning study adequately provided the detailed information needed to support reliable and reasonable estimates, and that the mechanism accorded with prior precedent.[370] The Commission rejected Trial Staff's contention that it was imposing a burden of proof on Trial Staff, and rejected criticisms of the decommissioning study, concluding that in addition to the adequacy of the study, it had not

362. *Id*. at PP 206-07.
363. *Id*. at P 208.
364. 181 FERC ¶ 61,211, at P 209.
365. *Id*. at P 210.
366. *Id*. at PP 211-12.
367. *Id*. at P 212 (citing *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at PP 286-87 (2002)).
368. 181 FERC ¶ 61,211, at P 213.
369. *Id*. at P 218.
370. *Id*. at P 219.

been challenged "on a substantive basis."[371] Consistent with prior precedent, the Commission adopted the requirement that Panhandle remove from the TDR the costs of assets to be retired prior to the end of the pipeline's useful life, noting that Panhandle could file to recover other decommissioning costs via section 4 filings "as they arise."[372] The Commission did not accept the suggestion that costs be disallowed on intergenerational grounds, given that there was no supporting precedent and given the length of the remaining life—thirty-five years.[373] The Commission rejected the Initial Decision's conclusion that a dedicated trust be established, as being unprecedented for a gas pipeline and without a demonstrated basis, although it did require use of a sub-account of Account 108 to provide transparency.[374]

- <u>Billing Determinants</u>. Determinants had been stipulated, except as to Rate Schedule GPS.[375] The Initial Decision accepted Panhandle's proposal that costs not be allocated to Rate Schedule GPS, but set at zero, with a revenue credit for Rate Schedule GPS revenues.[376] The Commission affirmed the Initial Decision, for reasons discussed below in the section regarding rate design and cost allocation, but in large part because Rate Schedule GPS is an ancillary service whose volumes derive from line pack use rather than transportation.[377]
- <u>Contracts qualifying for discounted rate treatment</u>. The participants had stipulated to allowing discount adjustments for all but eleven contracts, and only eight of those were the subject of exceptions.[378] Disputes regarding these contracts included whether Trial Staff had raised a sufficient challenge to the showing of competition by Panhandle, whether Panhandle had supported the competitive need for the contracts, and whether contracts should contribute to discount adjustments when the discounts would expire following the test period. The Commission found that contracts whose discounts expired following the test period should contribute to the discount adjustment, consistent with Commission precedent disregarding changes following the test period,[379] noting that after the test period other discounts might be required, raising the risk of under-recovery

371. *Id*. at P 220.
372. 181 FERC ¶ 61,211, at PP 221-22.
373. *Id*. at P 223.
374. *Id*. at P 224.
375. *Id*. at P 225.
376. 181 FERC ¶ 61,211, at P 226.
377. *Id*. at PP 229-30.
378. *Id*. at P 231.
379. *Id*. at P 246.

if the discount adjustments were disallowed.[380] With respect to two of the contracts challenged for lack of sufficient evidence of competition, the Commission affirmed the Initial Decision's conclusion that the pipeline had failed to meet its initial burden of supporting the discount; the pipeline had not provided specific testimony or other evidence of competitive need, and the record contained only data responses from the customer, but no contemporaneous evidence from the formation of the contract or a specific justification from Panhandle as to why a discount was provided, only vague general references to competition not related to specific contracts.[381] With regard to another contract, the Initial Decision had found that Trial Staff did not meet its burden to raise a reasonable concern as to the competitive need for the contract; the Commission reversed, finding that the Initial Decision "overstated" the Trial Staff's burden, which Trial Staff had met by noting the great length of time granted to the discount without explanation;[382] the Commission went on to find that Panhandle failed to meet its own burden, once the challenge was properly made by Staff, by relying only on general statements of competition and a specific statement that the customer had numerous pipeline alternatives.[383] The Commission affirmed the Initial Decision's conclusion that another contract was unsupported by any specific evidence,[384] and as to another that Panhandle's specific supporting evidence that the customer needed the discount for rate "certainty" was not sufficient in the absence of a showing that the discount was required by competition.[385]

- <u>Cost classification, cost allocation and rate design – gathering service allocation</u>. The Initial Decision found that Panhandle had not justified its removal of gathering rates from its tariff, that its recent filings in 2019 were inconsistent with its position in the rate case,[386] and that the company should be required to specify its gathering facilities in a compliance filing.[387] The Commission reversed, finding that Panhandle properly eliminated its gathering rates and supported the abandonment of its gathering facilities, and thus should not assign any costs to them, regardless of the 2019 gathering filing.[388] The Commission also held that, consistent with precedent,

380. 181 FERC ¶ 61,211, at P 247.
381. *Id*. at P 250.
382. *Id*. at PP 251-52.
383. *Id*. at PP 253-54.
384. 181 FERC ¶ 61,211, at P 255.
385. *Id*. at P 256.
386. *Id*. at P 257.
387. *Id*. at P 258.
388. 181 FERC ¶ 61,211, at P 261-63.

issues as to refunctionalization of gathering facilities were to be addressed in section 7 proceedings, not section 4 proceedings.[389]

- Cost classification, cost allocation and rate design – Field Zone versus Market Zone. Many of these issues were stipulated, but the Initial Decision found that Rate Schedule GPS volumes should not be used to allocate costs among zones, and that system storage should be 15.4 MMdth "for purposes of this proceeding;" the Commission affirmed.[390]
- Cost classification, cost allocation and rate design – Mileage-related and non-mileage related within the Market Zone. Panhandle did not propose to change its rate design for the Market Area, which involved a "100-mile block" methodology previously approved by the Commission, with an access charge for non-mileage costs and a charge for mileage costs for each one hundred miles on a shipper's contract path,[391] nor did Panhandle change the historical classification of mileage and non-mileage costs previously approved by the Commission.[392] A shipper argued that Panhandle's classification methodology was unreasonable because it classified certain costs as being mileage-related even though they did not vary with distance; the shipper specifically sought reclassification of depreciation (other than pipeline mains), O&M (other than for pipeline mains, part of ROE and revenue credits.[393] The Initial Decision found that the shipper had the burden of proof under section 5 to prove that the existing classification is unjust and unreasonable, and that its proposed alternative classification is just and reasonable.[394] The Initial Decision concluded that the shipper failed to "rebut the presumption" that the existing methodology was just and reasonable, finding that in this context the pipeline need not follow the specific physical path of gas, and that precedents cited by the shipper were inapposite due to differing characteristics of the pipelines in those proceedings; the Commission affirmed this finding.[395] Regarding the proposed reclassification, the Initial Decision found that the revenue credits in question (rental and Rate Schedule GPS) were non-distance-related, but that the shipper failed to overcome the presumption that the other costs were distance related, particularly given the absence

389. *Id*. at P 264.
390. *Id*. at P 265.
391. *Id*. at P 266.
392. 181 FERC ¶ 61,211, at P 267.
393. *Id*. at P 268.
394. *Id*. at P 269.
395. *Id*. at P 270.

of a supporting study or data (and instead only conclusory testimony by a witness).[396]

The Commission affirmed the Initial Decision as to the shipper's burden of proof,[397] and rejected the shipper's interpretation of a prior precedent, which instead supported the two-part burden imposed by the Initial Decision.[398] The Commission also rejected the shipper's arguments that it had shown the existing methodology to be unjust and unreasonable, rejecting in particular the shipper's theory that Panhandle erred in treating contract miles as reflecting physical miles, given that the Commission has found that pipelines may use contract path rather than physical path in reflecting distance in rates, citing in particular an earlier decision involving El Paso Natural Gas Company.[399] The Commission rejected in detail the shipper's arguments seeking to distinguish the El Paso decision, emphasizing the general principle that pipelines may assess distance-related costs as to contract paths, which customers acquire rights to, and pay for, rather than as to physical paths.[400] Similarly, the Commission dismissed the shipper's attempt to support its result with reference to Northern Natural Gas Company's Market Area rates, which involved a different rate design, and in any case could not by itself, even if superior, demonstrate that Panhandle's rate design was unjust and unreasonable.[401]

The Commission also affirmed the Initial Decision's findings rejecting specific reclassifications of particular costs from mileage-based to non-mileage-based, as failing to rebut the general presumption on that score in a prior decision, for failing to meet the standard mandated by precedent, which requires a "clear showing why they [the costs] do not vary with distance" (the shipper's witness only stated that the Panhandle system now operates only "predominantly" to move gas via compression long distances in the Market Zone); the Commission also faulted the shipper's lack of detailed supporting studies showing the lack of distance-related causation.[402]

- <u>Cost classification, cost allocation and rate design – allocation of A&G costs between transmission and storage</u>. The Initial Decision approved as reasonable Panhandle's proposal to allocate A&G costs between transmission and storage based on a ratio of transmission throughput and maximum storage quantity (MSQ), given Panhandle's complete reliance on third-party storage and thus its incurrence of less A&G costs arising from storage.[403] The Commission affirmed, despite its general preference for allocation based

396. 181 FERC ¶ 61,211, at P 271.
397. *Id*. at P 277.
398. *Id*. at P 278.
399. *Id*. at P 279.
400. 181 FERC ¶ 61,211, at P 280.
401. *Id*. at P 281.
402. *Id*. at P 282.
403. *Id*. at P 283.

on the Kansas-Nebraska method,[404] given Panhandle's "unique circumstances" (i.e., lack of any on-system storage),[405] also noting that the A&G costs related to the purchased third-party storage services are "embedded within" the rates charged by third parties to Panhandle.[406] Although both Panhandle's proposed method (which allocated approximately 92% of A&G to transmission) and Trial Staff's proposal (which proposed allocating approximately 50%/50% between transmission and storage) departed from the Commission's preferred method,[407] the Commission agreed with the Initial Decision that Panhandle's approach was just and reasonable, in its circumstances.[408]

- Cost classification, cost allocation and rate design – allocation of system storage costs to Rate Schedules FT and EFT/SCT. The issue addressed by the Initial Decision was whether to allocate system storage costs to Rate Schedule GPS, and the Initial Decision concluded that Panhandle properly excluded such costs.[409] The Commission affirmed, rejecting Trial Staff's exceptions and finding that system storage costs did not "rationally match" the Rate Schedule GPS service, which used "little to no storage,"[410] noting that the service was "neither clearly transportation, nor storage," and instead an ancillary service using line pack.[411] In addition, the Commission found that allocation of storage to this rate schedule would have skewed the allocation of costs, given the large relative size of Rate Schedule GPS volumes and the fact that they did not represent transportation on the system.[412] The Commission rejected Trial Staff's contention that because of its volumetric size, Rate Schedule GPS was likely to use storage, finding that the evidence showed no reliance on storage and instead that the service relied upon line pack.[413]
- Cost classification, cost allocation and rate design – Rate Schedule GPS maximum rate and crediting. Panhandle did not allocate costs to Rate Schedule GPS, but designed its rates based on a ratio of annual facility costs to annual design units, and credited the historic Rate Schedule GPS revenues to the cost of service; Trial Staff proposed, in contrast, to derive rates for the service by allocating costs

404. 181 FERC ¶ 61,211, at P 288 n.679.
405. *Id*. at P 286.
406. *Id*. at P 287.
407. *Id*. at P 288.
408. 181 FERC ¶ 61,211, at P 289.
409. *Id*. at P 290.
410. *Id*. at P 293.
411. *Id*. at P 294.
412. 181 FERC ¶ 61,211, at P 295.
413. *Id*. at P 296.

to the service.[414] The Initial Decision determined on a different approach than either Panhandle or Trial Staff, to retain the historic Rate Schedule GPS rates, while not allocating costs to the service, and crediting historic revenues to the cost of service.[415] The Commission reversed, approving Panhandle's proposed approach of not allocating costs to the service, while affirming the ID's decision to credit the resulting revenues to the cost of service.[416] The Commission found that allocation of costs to Rate Schedule GPS was inappropriate, given that its volumes (as calculated by Trial Staff) exceeded system throughput by a factor of five, while it was only an ancillary service only offered as-available, not a service using transmission facilities to the extent of other services, and because it would have seriously distorting effect on the allocation of costs to other services.[417] The Commission concluded that in light of the problems raised by Trial Staff's proposal, it should adopt Panhandle's approach to designing the rate and should credit the revenues.[418]

- <u>Cost classification, cost allocation and rate design – appropriate minimum rate for Rate Schedule GPS</u>. The Initial Decision determined that the minimum rate for Rate Schedule GPS should be zero, in the absence of evidence that the service involved variable costs; the Presiding Judge interpretated the data to mean that the service did not cause injections or withdrawals.[419] The Commission affirmed, finding that, consistent with Commission policy that minimum rates be based on the average variable costs of a service, and that there was no evidence of variable costs on the record.[420] The Commission disagreed with Trial Staff's interpretation of the record, finding that Panhandle's statement regarding injections and withdrawals did not support the conclusion that the service caused variable storage costs, noting as well that the service had been found not to involve storage.[421]
- <u>Cost classification, cost allocation and rate design – appropriate implied load factor for Rate Schedule SCT</u>. The Initial Decision found that Panhandle failed to prove as just and reasonable its proposed increase in the implied load factor of Rate Schedule SCT (Small Customer Transportation) should be changed from 52.5% to 20%;

414. *Id*. at P 297.
415. *Id*. at P 298.
416. 181 FERC ¶ 61,211, at P 302.
417. *Id*. at P 303.
418. *Id*. at P 304.
419. *Id*. at P 305.
420. 181 FERC ¶ 61,211, at P 308.
421. *Id*. at P 309.

the Initial Decision found that the result would be a rate increase of 150% for the affected customers, but that Panhandle provided "little information" to support this increase.[422] The Commission affirmed the Initial Decision, noting its historical concern for potential cost shifts to small customers as recognized in the mitigation measures of Order No. 636—indeed, the firm yet one-part rate design of this service was originally intended to benefit the small customers.[423] The Commission stated that the proposed increase would be large, as the Initial Decision found, both in absolute terms and relative to other customers, and yet the service accounted for only 1% of market area volumes and base period revenues.[424] The Commission rejected Panhandle's contentions that the actual load factor of approximately 18% justified the change to 20%, that there was no longer a need to continue the Order No. 636 transitional protections for small customers, and other justifications, noting in particular that Panhandle failed to articulate when the transition should end, and that Panhandle had not shown a change in circumstances sufficient to justify the large rate increase.[425]

- Storage. Panhandle purchases significant storage to maintain deliveries in the Market Zone when demand outstrips supply from the Field Zone, to maintain line pack and to meet the demands of customers with 1/16 maximum hourly rights (Rate Schedules EFT and SCT).[426] Panhandle's overall storage acquisition was 76.1 MMDth, with 34.4 MMDth allocated to system storage; it is the level of the 34.4 MMDth that was in dispute.[427] Panhandle supported this figure with a 2019 storage analysis sponsored by a witness.[428] The Initial Decision found that Panhandle had not supported the proposed 34.4 MMDth level, and required that system storage volume be set at the 15.4 MMDth level approved by a prior Commission order.[429] The Initial Decision criticized Panhandle for not supporting and explaining the inputs to the storage analysis,[430] found that the study appeared to use blended contract and operational data, the Initial Decision did not accept the operational experience of the sponsoring witness as sufficient support,[431] and found that Panhandle failed to support the percentage utilization attributed

422. *Id*. at P 314.
423. *Id*. at P 311.
424. 181 FERC ¶ 61,211, at P 315.
425. *Id*. at P 316.
426. *Id*. at P 318.
427. *Id*. at P 319.
428. 181 FERC ¶ 61,211, at P 320.
429. *Id*. at P 321.
430. *Id*. at P 322.
431. *Id*. at P 323.

to the Market Zone,[432] failed to supply supporting data for its estimates as to unplanned system outages and receipt outages and failed to support data as to fuel use.[433]

The Commission affirmed the Initial Decision and held that system storage should remain at 15.4 MMDth.[434] As to each of the deficiencies found by the Initial Decision, the Commission reviewed the evidence in some detail and came to the same conclusions: failure to support and explain inputs to the storage analysis,[435] failure to support the assertion that the study's 88% and 80% utilization factors were directly based on actual peak hourly demand data for January 2019,[436] use of projected rather than actual data on demand,[437] inadequate support for unplanned outages and outages of supply,[438] unfounded reliance on the operational experience of the witness,[439] inadequate support of fuel usage,[440] insufficient support of line pack loss data,[441] and over-reliance on expert recommendation rather than specific support for Panhandle's assumptions and quantified studies to meet the burden of proof.[442] The Commission agreed that the reduction in system storage to 15.4 MMDth risked loss of firm deliverability and harm to customers, but noted that Panhandle could file under section 4 to justify the higher figure in a later proceeding.[443]

- <u>Rate treatment of affiliated agreements in annualized level of storage expense</u>. Panhandle included annualized storage expenses of approximately $62.8 million reflecting contracts with affiliated and unaffiliated third party storage providers, and Trial Staff challenged recovery of a portion of those expenses.[444] The Initial Decision found that the annualized storage expense should be reduced, and the findings related to recovery of two affiliated storage providers, Southwest Gas Storage (Southwest Gas) and the Houston Pipe Line Company LP's Bammel storage with Trunkline transportation (Bammel/Trunkline), which were the subject of exceptions.[445]

Regarding Southwest Gas, the Initial Decision found that Panhandle's cost of service should reflect the Southwest Gas maximum recourse rates approved in

432. 181 FERC ¶ 61,211, at P 324.
433. *Id*. at P 325.
434. *Id*. at P 335.
435. *Id*. at P 336.
436. 181 FERC ¶ 61,211, at P 337.
437. *Id*. at P 339.
438. *Id*. at P 340.
439. *Id*. at P 341.
440. 181 FERC ¶ 61,211, at P 342.
441. *Id*. at P 343.
442. *Id*. at P 344.
443. *Id*. at P 345.
444. 181 FERC ¶ 61,211, at P 346.
445. *Id*. at P 347.

a 2019 partial settlement regarding Southwest Gas, rather than the negotiated rates agreed upon between Southwest Gas and Panhandle, and that Southwest Gas' market-based rate authority, authorized after the test period, was not pertinent to the Panhandle rate determination.[446] Panhandle had argued that the agreement could not be disregarded under the Mobil-Sierra doctrine, but the Initial Decision found that the common ownership of both Southwest Gas and Panhandle removed the presumption created by Mobil-Sierra.[447] The Commission affirmed the Initial Decision, as to both the decision not to use the negotiated rate agreement and to use the 2019 settlement rates in determining the allowable cost of Southwest Gas storage service in Panhandle rates.[448] On the issue of Southwest Gas' market based rate authority, the Commission noted that in the order granting such authority it had expressly reserved the question of pass-through of Southwest Gas costs by Panhandle, and that the authorization took place after the end of Panhandle's test period.[449]

The Commission also agreed with the Initial Decision that Panhandle had failed to carry its burden to support the pass-through of the negotiated rate, noting in particular the timing of the rate agreement, well before the end of the prior maximum recourse rate agreement and shortly before Southwest Gas' Form No. 501-G filing (which threatened a Section 5 proceeding and rate reduction); the Commission noted as well the absence of other evidence that the negotiated rate was just and reasonable.[450] The Commission also rejected Panhandle's argument that the negotiated rate was similar to rates in other negotiated storage rate agreements and thus competitive; the Commission found that while competitiveness is used in assessing discounts to affiliates, extra scrutiny is used for the contract because Panhandle had an incentive to negotiate a higher rate with its affiliate regardless of competitive alternatives, and further found that Panhandle had not offered evidence of comparable storage services at a competitive rate.[451] Given the rejection of the negotiated rate agreement, the Commission concurred with the Initial Decision that the most accurate available cost-based rate would be the maximum recourse rate in the 2019 settlement as the best approximation of Southwest Gas' costs, given that no party has provided alternative cost-based rate data for Southwest Gas.[452] The Commission also found that Mobil-Sierra was not an issue, given that the proposal was not to modify that agreement, but rather to determine what costs could be flowed through Panhandle.[453]

446. *Id*. at P 348.
447. *Id*. at P 349.
448. 181 FERC ¶ 61,211, at P 357.
449. *Id*. at P 358.
450. *Id*. at P 359.
451. *Id*. at P 360.
452. 181 FERC ¶ 61,211, at P 361.
453. *Id*. at P 362.

Regarding the Bammel/Trunkline agreement, the Initial Decision found that Panhandle failed to show that the Bammel storage costs and the Trunkline transportation costs were just and reasonable, because evidence showed that Panhandle was motivated by the benefits of the transaction for the common parent of the involved entities, Energy Transfer.[454] The Initial Decision was not convinced by Panhandle's arguments that the agreement had operational and reliability benefits that made it superior to a less costly alternative service from DTE/Washington ten – operational benefits which, the Initial Decision found, were not considered by Panhandle at the time it entered into the Bammel/Trunkline agreement.[455] The Initial Decision concluded that the lower costs of the rejected DTE/Washington ten service should be imputed in determining Panhandle's cost of service.[456] The Commission affirmed the Initial Decision's conclusions and adopted its proposed cost solution.[457]

The Commission found that the Initial Decision, though it used the term "convincingly" as a modifier for Panhandle's burden, was not raising the burden of proof imposed on the pipeline, but rather applied the "preponderance of the evidence" standard.[458] The Commission also agreed with the Initial Decision that the record contained evidence that the Bammel/Trunkline service would benefit Panhandle's affiliates and parent, and that the evidence showed that this consideration affected the decision to enter into that agreement, even if the document evidencing these motives is not the only basis for Panhandle's decision.[459] The Commission also rejected Panhandle's "primary" argument in favor of the affiliate agreement, that it provided operational and reliability benefits due to the location of the facilities, because of evidence that these considerations were not considered at the time of the contractual decision; the Commission also disagreed with the materiality of the asserted operational benefits relative to the unaffiliated alternative.[460] The Commission reviewed in more detail the operational benefits argument and found that they did not support rejection of the unaffiliated option.[461] In closing, the Commission noted, in finding the Bammel/Trunkline contract rate unjustified, that the affiliate service had a price "nearly twice as much as the DTE/Washington 10 renewal offer."[462]

- <u>Miscellaneous fuel costs</u>. The Initial Decision found that Panhandle failed to justify the inclusion of costs in certain accounts (Account Nos. 819, 823 and 833) as being recoverable in its fuel tracker, noting that such costs relate to fuel used for underground

454. *Id*. at P 363.
455. *Id*.
456. 181 FERC ¶ 61,211, at P 363.
457. *Id.* at P 367.
458. *Id*. at P 368.
459. *Id*. at P 369.
460. 181 FERC ¶ 61,211, at P 370.
461. *Id*. at P 371.
462. *Id*. at P 373.

storage, which Panhandle does not have, and that fuel costs for the Southwest Gas storage contract would be recovered in that company's separate charges, and finally that Panhandle failed to support recovery of the costs in Account No. 853.[463] The Commission affirmed.[464] The Commission rejected Panhandle's argument that the costs had already been accepted in a fuel tracker order, which the Commission found to have determined where such costs could be recovered, not whether they could be recovered.[465]

- Trunkline OBA. Certain participants challenged the existence of large imbalances in Panhandle's OBA with Trunkline, as being far larger than other OBA imbalances which allegedly contributed to Panhandle's need to contract for storage service from third parties, to the detriment of Panhandle's unaffiliated shippers.[466] Panhandle responded that the imbalances were the result of normal operations, that the Trunkline interconnection was the largest on the system and hence resulted in higher imbalances, and that the 2018 Audit Report did not fault the imbalances.[467] The Initial Decision found that the challenging participants had met their section 5 burden regarding the OBA imbalances, and that Trunkline imbalances were higher than non-affiliated OBA imbalances, and that Panhandle had not shown the imbalances to be normal for the interconnection.[468] The Initial Decision also rejected Panhandle's reliance on the 2018 Audit Report, which did not rule on the issue of preferential treatment of Trunkline OBA imbalances, and the Initial Decision further expressed concern over the potential for the Trunkline OBA balances to increase storage costs.[469] The Initial Decision found that the OBA should be reformed to remedy undue preferences, and specified that the reformed OBA would include language making the mutual waiver of the thirty-day deadline for resolving outstanding balances to be sustained only if the parties are unaffiliated or if prior Commission notice and approval have been obtained.[470]

The Commission reversed the Initial Decision as to the Trunkline OBA determinations, finding that although the participants challenging the OBA had raised "legitimate concerns," they had not met their burden under section 5 to show

463. *Id*. at P 374.
464. 181 FERC ¶ 61,211, at P 378.
465. *Id*. at P 377.
466. *Id*. at P 378.
467. *Id.* at P 379.
468. 181 FERC ¶ 61,211, at P 381.
469. *Id*. at P 382.
470. *Id*. at P 383.

that Panhandle had engaged in unduly preferential and discriminatory administration of the Trunkline OBA.[471] The Commission noted evidence that this interconnection was the largest in size and volume, and that there was no demonstration that Panhandle had failed to waive the deadline for resolution of imbalances with parties to other OBAs.[472] The Commission also noted that its other rulings limiting the pass-through of storage costs alleviated the concern over unnecessary storage costs, and further that no fees arose from the volumetrically balanced OBAs.[473]

Commissioner Danly filed a concurrence in part and dissent in part, dissenting as to the aspect of the opinion reversing the Initial Decision and allowing Panhandle to zero out its excess ADIT, disagreeing with the premises and conclusions of the majority in this respect.

Commissioner Christie filed a concurrence to emphasize his general view that, "if the company's anticipated tax liability is reduced or eliminated through legislation by the taxing authority, then the monies collected for that purpose should be returned to customers," and that the funds cannot be treated as an "interest free loan" to "be forgiven at the discretion of the company and kept as a cash windfall."

J. Rate Investigations

1. MountainWest Overthrust Pipeline, LLC, 181 FERC ¶ 61,246 (2022).

On December 20, 2022, the Commission dismissed MountainWest Overthrust Pipeline, LLC's (Overthrust) request for rehearing of the September 2022 Order opening an investigation into whether Overthrust's rates are unjust and unreasonable.[474] Using Overthrust's revenue information, the Commission found that Overthrust may be over-recovering.[475] While the Commission has not made a formal finding as to the just and reasonableness of Overthrust's leases and expansion, it estimated that if the Rockies Express Pipeline LLC lease capacity was repriced at Overthrust's existing recourse rates, Overthrust's ROE would be approximately 34.1% and 30.5% in 2020 and 2021, respectively.[476] Without the lease, the Commission estimated the 2021 ROE would be about 18%.[477]

On rehearing, Overthrust claimed that the Commission erred in initiating the section 5 investigation by including the costs and revenues of a capacity lease, and that the Commission overstepped its authority by requiring Overthrust to derive rates as part of a cost and revenues study. Overthrust further contended that the Commission exceeded its authority under sections 4 and 5 of the NGA because

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471. *Id.* at P 390.

472. 181 FERC ¶ 61,211, at P 390.

473. *Id.* at P 391; *see* 81 FERC ¶ 61,211, at n.933 (the Commission also noted that the 2018 Audit Report did not support the findings sought by Panhandle).

474. *MountainWest Overthrust Pipeline, LLC*, 181 FERC ¶ 61,246 (2022).

475. *Id.* at P 1.

476. *Id.*

477. *Id.*

under section 4, only the jurisdictional pipeline can initiate a rate change. The Commission dismissed the request for rehearing because an Investigation Order is not a final order eligible for rehearing under rule 713(b). The Commission noted that it has previously addressed and rejected the arguments raised as it has wide discretion to decide whether to initiate a section 5 investigation.[478]

2. Stagecoach Pipeline & Storage Co., LLC, 180 FERC ¶ 61,175 (2022).

On September 22, 2022, "pursuant to section 5 of the Natural Gas Act" the Commission opened an investigation into whether Stagecoach's rates were unjust and unreasonable.[479] Using 2020 and 2021 Form 2-A, the Commission calculated Stagecoach's costs to be $49 million and its ROE to be 11% and 22.6%, respectively.[480] The Commission found that this information indicates that Stagecoach may be recovering revenue in excess of its estimated costs of service.[481] To address these issues, the Commission set the matter for hearing and directed Stagecoach to prepare a revised cost and revenue study.[482]

K. Reservation Charge Credits

1. Eastern Gas Transmission and Storage, Inc.

On July 20, 2022, following the issuance of an order directing Eastern Gas Transmission and Storage, Inc. (Eastern), to show cause why the reservation charge credits in its tariff were just and reasonable,[483] the Commission found certain portions of Eastern's reservation charge crediting tariff provisions to be unjust and unreasonable, and directed Eastern to propose replacement language.[484] Eastern made a compliance filing that was accepted, and also filed a request for rehearing of the July 2022 Order. The Commission denied rehearing on November 18, 2022.[485]

As described in the July 2022 Order, the Commission requires pipelines to award reservation charge credits to compensate firm shippers when the pipeline fails to provide the promised service.[486] The Commission explained that when an outage is within the pipeline's control, the pipeline should bear the responsibility

478. 181 FERC ¶ 61,246, at P 5; *see, e.g.*, *Algonquin Gas Transmission Co*., 84 FERC ¶ 61,174 at p. 61,912 (1998).

479. *Stagecoach Pipeline & Storage Co*., 180 FERC ¶ 61,175 (2022).

480. *Id.* at P 5.

481. *Id.*

482. *Id.* at P 9.

483. *Eastern Gas Transmission & Storage, Inc.,* 177 FERC ¶ 61,064 (2021).

484. *Eastern Gas Transmission & Storage, Inc*., 180 FERC ¶ 61,014 (2022).

485. *Eastern Gas Transmission & Storage, Inc*., 181 FERC ¶ 61,141 (2022).

486. 180 FERC ¶ 61,014, at P 4.

of failing to provide service, either by not charging for such service or by providing reservation charge credits equal to the amount of service which the pipeline failed to deliver.[487]

In the July 2022 Order, the Commission determined that the existing reservation charge crediting language in Eastern's tariff was unjust and unreasonable because it required that a shipper nominate gas in order to receive reservation charge credits, even in the event Eastern had pre-announced a total outage on a given segment of its system. The Commission explained that Eastern's tariff language required shippers to nominate volumes that they could not reasonably expect would be honored.[488] However, the Commission found that the requirement to nominate was appropriate in the event Eastern had announced a *partial* outage on a given segment of its system, or a different part of the system than was relevant to the shipper, because in that circumstance the shipper could expect those nominations to be honored.[489]

The Commission also found it unjust and unreasonable that Eastern's tariff allowed Eastern, when calculating the amount of credits that it owes based on historical usage, to define the historical period to include a period in which a previous outage had occurred.[490] The Commission explained that this could allow the pipeline to habitually schedule maintenance during the same period each year, enabling it to avoid awarding credits on those annually scheduled days.[491] The Commission directed Eastern to modify its tariff to address both of these deficiencies.[492]

On rehearing, the Commission first rejected Eastern's argument that the hypothetical scenarios the Commission had posed would occur too infrequently to merit a finding that its tariff was not just and reasonable.[493] The Commission disagreed with the Eastern's implication that the Commission must only be reactive – waiting for tariff provisions to be triggered a specific number of times before finding that a provision is unjust and unreasonable as written.[494] The Commission explained that tariffs regularly allocate risk for infrequent *force majeure* events, and when those allocations are unjust and unreasonable the Commission maintains the ability to direct changes to them pursuant to its NGA section 5 authority. The Commission reasoned "even if the risk of occurrence is relatively low, the harm caused as a result of a single incident could be quite high and difficult to otherwise remedy."

487. *Id.*

488. 180 FERC ¶ 61,014 PP 39-44; *see also* n.14 (citing *Rover Pipeline*, 172 FERC ¶61,103 at P 9 (2020) ("In the event of a preannounced outage in which reservation charge credits are required, a pipeline may not compel shippers to submit nominations in order to preserve their relevant reservation charge crediting rights.")).

489. *Id.* at PP 41-42.

490. *Id.* at PP 43-44.

491. *Id*. at PP 45-48.

492. 180 FERC ¶ 61,014, at P 44.

493. 181 FERC ¶ 61,141, at PP 21-22.

494. *Id.*

The Commission also rejected Eastern's argument that shippers should be required to make nominations in the event of total outages because even in this case, Eastern might have back-up methods of providing service.[495] The Commission found that to the extent that Eastern has the capability to provide "back-up methods of providing primary firm service," Eastern is not experiencing a total outage but rather a partial outage.[496]

Eastern also argued that the July 2022 Order was inconsistent with an order involving *Transcontinental Gas Pipe Line Corp.* (*Transco*), in which the Commission had found it unjust and unreasonable to require shippers to nominate to receive credits during *force majeure* outages, and had explicitly contrasted non-*force majeure* outages, for which it found nominations were not required.[497] The Commission, however, stated that the policy consideration that shippers should "not [be] compelled to submit nominations that they do not reasonably expect the pipeline to honor" is identical for non-*force majeure* and *force majeure* scenarios.[498] The Commission explained that its determination was consistent with *Transco's* reasoning because that case was based on pipelines who were providing full credits, and not because they were involved in non-force majeure scenarios.[499] The Commission also rejected Eastern's argument that the *Rover* ruling should not control because Rover is a straight-line pipeline while Eastern is a reticulated system, stating that this does not change the underlying principle that nominations should not be required in the cases of total outages.[500]

2. Range Resources-Appalachia, LLC & Columbia Gulf Transmission, LLC v. Texas Eastern Transmission, LP

On December 21, 2021, Range Resources-Appalachia, LLC (Range) filed a complaint against Texas Eastern Transmission, LP (Texas Eastern),[501] as well as a joint complaint against Texas Eastern with Columbia Gulf Transmission, LLC (Columbia Gulf)[502] (collectively, Complaints). The Complainants argued that for certain curtailment periods in 2019 and 2021, Texas Eastern failed to deliver gas at the minimum pressure necessary for delivery into the Columbia Gulf system at an interconnect in Adair County, Kentucky. Among other things, Range argued that by failing deliver gas at sufficient pressure for Columbia Gulf to receive it, Texas Eastern violated its tariff and Range's service agreement, and therefore, that Range was entitled to reservation charge credits during the curtailment periods.

495. *Id.* at P 23.

496. 181 FERC ¶ 61,141, at P 23.

497. *Id.* at P 28 (citing *Transcontinental Gas Pipe Line Co., LLC*, 175 FERC ¶ 61,085 at P 19 (2021)).

498. 175 FERC ¶ 61,085, at P 19.

499. 181 FERC ¶ 61,141, at P 9.

500. *Id.* at P 27.

501. Notice of Complaint, *Range Res.-Appalachia, LLC v. Tex. E. Transmission, LP*, FERC Docket No. RP-22-435-000 (Dec. 21, 2021).

502. Order Dismissing Complaints, *Range Res.-Appalachia, LLC & Tex. E. Transmission, LLC v. Tex. E. Transmission, LP*, FERC Docket No. RP-22-433-000 (Mar. 24, 2022).

On March 24, 2022, the Commission dismissed the complaints.[503] Range and Columbia Gulf each filed requests for rehearing of the Dismissal Order on April 25, 2022, and the Commission denied rehearing on August 5, 2022.[504]

As relevant for the issue of reservation charge crediting, Texas Eastern had declared a *force majeure* event during the 2021 curtailment period that resulted in it delivering gas at a reduced pressure to the interconnect with Columbia Gulf. Because of the pressure differential between the Texas Eastern and Columbia Gulf systems, Columbia Gulf had reduced its receipts at the interconnect. In the Dismissal Order, the Commission found that under its tariff, Texas Eastern was only required to deliver gas at the available line pressures, and that it had satisfied this obligation and therefore, had not violated any applicable requirements. The Commission further found that Texas Eastern had already provided reservation charge credits to the extent that Texas Eastern reduced Range's scheduled nominations, and that Range was not entitled to additional credits for reductions that were due to Columbia Gulf's failure to confirm volumes that Texas Eastern had scheduled for delivery.[505]

In its request for rehearing, Range contended that the Commission erred in not addressing whether Texas Eastern properly declared a *force majeure* event during the 2021 Curtailment and by concluding that Range was not entitled to additional reservation charge credits.[506] The Commission rejected this argument, finding that it did not need to resolve the question of whether Texas Eastern had improperly declared *force majeure*, because Texas Eastern had provided reservation charge credits for the reductions that resulted from its declaration of *force majeure*.[507] The Commission found that Texas Eastern was not responsible for providing reservation charge credits for volumes that it had been willing to deliver notwithstanding the *force majeure* declaration, but which Columbia Gulf had refused to confirm[508]

3. Rover Pipeline LLC

On January 5, 2023, the Commission accepted Rover's proposed revisions to its tariff to provide that for new discounted or negotiated rate service agreements, Rover will not provide reservation charge credits unless such agreements explicitly require reservation charge credits.[509] The Commission approved the tariff language over protests from two shippers who asserted that although the Commission had approved similar tariff provisions in other cases, the Commission should not accept Rover's proposed language. Protestors claimed modernization and mainte-

503. *Range Res.-Appalachia, LLC v. Tex. E. Transmission, LP*, 178 FERC ¶ 61,217 (2022).
504. *Range Res.-Appalachia, LLC v. Tex. E. Transmission, LP*, 180 FERC ¶ 61,079 (2022).
505. 178 FERC ¶ 61,217, at PP 64-65, 68-69.
506. 180 FERC ¶ 61,079, at P 6.
507. *Id*. at P 16.
508. *Id.*
509. *Rover Pipeline LLC*, 182 FERC ¶ 61,001 (2023).

nance costs, as a result of the Pipeline and Hazardous Materials Safety Administration's (PHMSA) three-part "Mega Rule,"[510] have increased significantly since the precedent was set in 2013, requiring firm shippers to pay for "a service that they are not receiving more often now than they were 10 years ago."[511]

The Commission explained that it has previously approved, and encouraged the clarification of, similar tariff provisions allowing for reservation charge credits to be a subject of negotiation in discount and negotiated rate agreements.[512] Citing a previous order, the Commission stated, "[a] shipper can decide whether it is willing to trade limits on reservation charge credits for a lower rate. If not, the shipper has the right to take service at the maximum rate and receive reservation charge credits in a manner that is consistent with Commission policy."[513]

The Commission rejected shippers' arguments that Rover's currently effective tariff language provides sufficient implicit flexibility to exclude reservation charge credits on an individual basis from discounted or negotiated rate contracts ,and that by making it the default position that such contracts will *not* provide reservation charge credits, Rover's tariff language flipped Commission precedent on its head.[514] The Commission found this argument "groundless," as the tariff language would not prevent shippers from negotiating these rights.[515]

The Commission also rejected arguments that the proposal would put Rover's shippers at a disadvantage in all future negotiations for reservation charge credits, since most of Rover's firm customers have negotiated rate agreements.[516] The Commission stated that protestors provided no evidence demonstrating that approval of Rover's proposed changes would hamper discount and negotiated rate shippers from obtaining reservation charge credits rights as a component of their transportation agreements.

Finally, the Commission rejected the arguments that the Commission should change its policy in response to heightened pipeline safety requirements.[517] The Commission stated nothing in the protestor's argument regarding changed circumstances compelled it to reject Rover's revisions over established precedent.

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510. 182 FERC ¶ 61,001, at P 9 (citing *Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments*, 86 Fed. Reg. 63,266 (2021)).

511. *Id.* at P 6.

512. *Id. (*citing *CenterPoint Energy Gas Transmission Co., LLC,* 144 FERC ¶ 61,195 at P 77 (2013); *Algonquin Gas Transmission, LLC*, 153 FERC ¶ 61,038 at n.112 (stating that the Commission has "permitted pipelines to include in tariff provisions offering reservation charge credits a provision exempting shippers with discounted or negotiated rates from such credits unless the pipeline agrees to include a reservation charge crediting provision in the discounted or negotiated rate agreement.")).

513. *Id.* (citing 144 FERC ¶ 61,195, at P 78).

514. 182 FERC ¶ 61,001, at P 12.

515. *Id.*

516. *Id*. at P 13.

517. *Id*.

V. INFRASTRUCTURE

A. Pipelines

1. Sabal Trail Transmission, LLC v. 18.27 Acres of Land

Sabal Trail Transmission, LLC (Sabal Trail) challenged a district court determination that the measure of compensation for its condemnation of private lands to construct a new pipeline was governed by a Florida law that requires "full compensation" (which included attorneys' fees and costs), rather than the U.S. Constitution's "just compensation" standard.[518] The U.S. Court of Appeals for the Eleventh Circuit found that the NGA does not specify whether state law or federal law applies, leaving the issue to the federal judiciary to decide. The Court found that *Georgia Power Co. v. Sanders*, governed its analysis, and that the facts and administrative scheme involved in that case were very similar to the case before it, such that "it's almost like we are deciding the same case again—only this time we are bound by precedent."[519] In *Georgia Power*, the court held that state law governs the valuation of property taken by eminent domain for water projects constructed under the FPA.

The Court noted that the original enactment of the NGA did not include an eminent domain provision, but, in 1947, FPA then-existing eminent domain provision was added to the NGA. On this basis, the Court found that Congress intended the eminent domain rights of these two acts to be "coextensive," meaning that the same law on compensation should apply, and in *Georgia Power*, state law was found to apply. Consistent with *Georgia Power*, the Court found that applying state law to the narrow determination of the amount of compensation did not result in a conflict with the federal program under the NGA. The Court found that the need for uniformity in calculating compensation bore no more relation to the aims of the NGA than it did to those of the FPA. The court also noted that the NGA specifically authorizes "reasonable differences in rates, charges, service, facilities, or in any other respect . . . as between localities,"[520] meaning that it accounts for differences between states that affect costs and rates.

2. City of Oberlin v. FERC

This case concerned whether the Commission properly granted NEXUS Gas Transmission, LLC (NEXUS) a certificate of public convenience and necessity to construct and operate a pipeline from Ohio to Michigan, when, as evidence for the need for the pipeline, the Commission relied on agreements to transport gas ultimately bound for export to Canada.[521] In an earlier case on a petition for review from the City of Oberlin (City), the D.C. Circuit had remanded the Commission's

518. Sabal Trail Transmission, LLC v. 18.27 Acres of Land, 59 F.4th 1158, 1161 (11th Cir. 2023).
519. *Id.* at 1160.
520. *Id.* at 1171 (quoting 15 U.S.C. § 717c(b)).
521. *City of Oberlin v. FERC,* 39 F.4th 719, 721 (D.C. Cir. 2022).

approval of the project, instructing the Commission to explain whether it was lawful to credit NEXUS's contracts with foreign shippers serving foreign customers as evidence of market demand.[522] On remand, the Commission explained its decision and clarified that it would have granted the certificate even without considering the export agreements.[523] The City again petitioned for review, contending that the explanation was arbitrary and contrary to law and violative of the Takings Clause of the U.S. Constitution.

The Court upheld the issuance of the certificate. The Court rejected the City's claim that the Commission cannot consider benefits of exports when determining whether there is a need for a project under NGA section 7. The Court recognized that the NGA only confers the right of eminent domain to pipelines operating in interstate commerce and does not confer eminent domain authority to developers of import/export facilities. Notwithstanding, the Court found that even though some of the gas transported on NEXUS ultimately is exported, NEXUS was indisputably using its pipeline to transport in interstate commerce, and in analyzing whether a project is in public convenience and necessity under NGA section 7, the Commission must evaluate all factors, which may include the benefits of exports. The Court disagreed with the City's assertion that gas bound for export is not part of interstate commerce, explaining that gas comingled with gas flowing in interstate commerce becomes interstate gas.

The Court also rejected the City's argument that crediting the export precedent agreements as a benefit runs afoul of the Takings Clause because shipping gas for export "does not serve a public use." The Court found that Congress has determined that pipelines that are certified as being in the public convenience and necessity serve a public purpose. The Court found that so long as the Commission's crediting of export agreements is consistent with the NGA, the agreements further a public purpose consistent with the Takings Clause.

The Court also upheld the Commission's finding that the NEXUS project was in the public convenience and necessity, even if it did not consider the precedent agreements to transport gas bound for export. Although precedent agreements with domestic shippers accounted for only 42% of the project's capacity, the Court found that the Commission's approval of the project based on these precedent agreements was supported because existing pipelines lacked capacity to ship the gas transported by NEXUS.

3. Spire STL Pipeline LLC

Spire STL Pipeline LLC (Spire) is a sixty-five-mile greenfield pipeline serving customers in greater St. Louis that was constructed and placed into operation in 2019, pursuant to a certificate that was vacated by the D.C. Circuit in June 2021.[524] The certificate was supported only by a single precedent agreement with Spire Missouri, a local distribution company that was affiliated with Spire. In

522. *City of Oberlin v. FERC,* 937 F.3d 599, 606 (D.C. Cir. 2019).

523. NEXUS Gas Transmission, 172 FERC ¶ 61,199 at P 30 (2020), *reh'g denied;* 174 FERC ¶ 62,068 (2021).

524. Env't Def. Fund v. FERC, 2 F.4th 953, 963 (D.C. Cir. 2021).

vacating the certificate, the court had found that the Commission had failed to support its finding that the Project was needed and failed to show that the Project's benefits outweighed its potential adverse effects. The Court stated that protestors had provided "'plausible evidence of self-dealing'" between the affiliates such that the Commission should have looked behind the precedent agreements to determine if there was market need.[525]

After issuing a temporary certificate allowing the pipeline to remain in operation while the Commission responded to the Court's vacatur,[526] the Commission reissued Spire's permanent certificate.[527] The Commission conceded that in the original certificate order, it had erred in relying solely on a single precedent agreement among affiliated entities to find need given the particular facts, particularly because the already-existing pipeline systems had been sufficient to meet the vast majority of Spire Missouri's current and anticipated demand.[528] However, the Commission found that in light of economic, operational, and other public benefits that were demonstrated during the three years of the project's operation, the project was required by the public convenience and necessity.

The Commission found that due to events that had occurred since the pipeline's placement into service, the project now was needed to meet Spire Missouri's current and future demand. Specifically, the Commission found that Spire Missouri had allowed contracts on its previous transportation provider to expire, and that capacity had been remarketed to other shippers and was no longer available. In addition, Spire Missouri had retired compressors at its storage field and decommissioned propane peaking facilities, such that additional transportation capacity was needed. The Commission also found numerous other benefits of the pipeline, including that another interstate pipeline, MoGas Pipeline LLC, could take advantage of the high pressure on Spire to interconnect with Spire to serve new markets without having to spend an estimated $100 million to construct additional facilities that would otherwise be needed. The Commission also determined that Spire was able to provide Spire Missouri with a lower total cost of delivered gas than delivery by other pipelines, and provided Spire Missouri with greater security of supply by providing access to diversified supply sources that were previously inaccessible. As a result of these benefits, the Commission explained that it did not need to determine what, if any, weight it should accord the precedent agreement between Spire and Spire Missouri; because need for the project had been demonstrated by the operational facts on the ground.

The Environmental Defense Fund sought rehearing, claiming that the remand order was procedurally defective because the Commission did not convene a notice-and-comment process to address the deficiencies the Court identified in

525. See *Eastern Shore Nat. Gas Co.*, 181 FERC ¶ 61,233 at PP 14-16 (2022) (for discussion of "self-dealing" between affiliates).

526. *Spire STL Pipeline LLC*, 177 FERC ¶ 61,147 at P 73 (2021).

527. *Spire STL Pipeline LLC*, 181 FERC ¶ 61,232 at P 118 (2022), *reh'g denied;* 183 FERC ¶ 61,048 (2023).

528. 181 FERC ¶ 61,232, at P 25.

Spire's original certificate order, and to allow for responses to Spire's request that the Commission reissue its certificate. On April 20, 2023, the Commission issued an order addressing the rehearing requests.[529] The Commission stated that vacatur did not require it to reinitiate notice and comment proceedings, and that while the Commission had erred in the original certificate order by failing to address questions in the record about self-dealing and the need for the project, the Court did not identify any deficiencies in the Commission's development of the record that would require additional procedural steps.

4. Transcontinental Gas Pipe Line Co.

On July 31, 2023, the Commission granted a certificate of public convenience and necessity authorizing Transcontinental Gas Pipe Line Company, LLC (Transco) to construct a new compressor station, install a new compressor unit, and make modifications to its existing system to provide up to 423,400 dekatherms per day of firm transportation service along two paths on its pipeline system, all of which was subscribed to in a precedent agreement with Piedmont Natural Gas Company, Inc.[530] Although all four Commissioners voted to approve the project, each of the Commissioners signed on to separate statements concerning the Commission's analysis of the project's greenhouse gas (GHG) emissions, with particular disagreement concerning GHG emissions downstream of the project.

The Commission found that downstream GHG emissions associated with the project were reasonably foreseeable and quantified those emissions using the full-burn of the project's design capacity.[531] The project's Environmental Impact Statement also provided the Social Cost of GHG (SC-GHG) statistic of these emissions for informational purposes, but the order did not include the SC-GHG value or address the significance of the downstream emissions. The Commission did not estimate upstream GHG emissions, finding that "[t]he environmental effects resulting from natural gas production are generally neither caused by a proposed pipeline project nor are they reasonably foreseeable consequences of our approval of an infrastructure project[.]"[532] The Commission contextualized the project's GHG emissions in light of relevant state emissions reductions targets and recent federal and state emissions.

Commissioners Phillips and Christie issued a joint concurrence outlining their preferred method of evaluating GHG emissions, which they called the "*Driftwood* compromise."[533] Under the *Driftwood* compromise, the Commission would not characterize GHG emissions associated with a project as "significant or not significant." Instead, the Commission would estimate the SC-GHG calculation associated with construction, operation, and downstream emissions "for informational purposes," and state that the SC-GHG calculation does not enable the Commission to determine the significance of a project's GHG emissions in terms of

529. *Spire STL Pipeline LLC*, 183 FERC ¶ 61,048 (2023).
530. *Transcontinental Gas Pipe Line Co.*, 184 FERC ¶ 61,066 at PP 3-4 (2023).
531. *Id*. at P 53.
532. *Id*. at P 55.
533. *Id.* at P 2 (Phillips & Christie, concurring).

their impact on climate change, nor is there any accepted way of doing so. Commissioners Phillips and Christie noted that the language used in the *Driftwood* compromise was removed from the Transco order only to move the project forward.

Commissioner Clements issued a concurrence, explaining her disagreement with the *Driftwood* compromise. Commissioner Clements stated that by including the *Driftwood* language, "the Commission was (1) effectively deciding key issues raised in the draft GHG Policy Statement docket[534] without ever having seriously studied those issues, and (2) departing from precedent without reasoned explanation in violation of the Administrative Procedure Act." Commissioner Clements stated that she "do[es] not know whether the [SC-GHG] protocol or another tool can or should be used to determine [the] significance of GHG emissions or otherwise assess their environmental effects," but, "[w]hat I do know is that the Commission's failure to come to grips with the difficult questions surrounding the assessment of GHG emissions is fraught with legal risk."

Commissioner Danly issued a partial dissent, stating that the Commission had failed to explain why it was accurate to use a full-burn analysis to estimate reasonably foreseeable downstream emissions, given that Transco had estimated that the project's expected utilization rate would be only 38.6 percent. Commissioner Danly disagreed with the Commission's establishment of "a new policy, *sub silento*," in which the Commission would28 use a full burn estimate to analyze downstream emissions to the extent projects are subscribed by LDC shippers. Commissioner Danly also highlighted his belief that when shippers are LDCs, downstream emissions are not reasonably foreseeable impacts of interstate pipeline projects. Commissioner Danly stated that downstream emissions of LDC-driven projects are not reasonably foreseeable because "[t]he Commission has no jurisdiction over the LDCs" and the Commission is not "the legal proximate cause of the emissions of the gas that their consumers may ultimately use."

5. Transcontinental Gas Pipe Line Co.

On January 11, 2023, the Commission issued a certificate of public convenience and necessity authorizing Transcontinental Gas Pipe Line Co. (Transco) to construct and operate new pipeline and compressor facilities to provide 829,400 Dth/day of firm capacity in New Jersey, Pennsylvania and Maryland.[535] The Commission considered three studies of market need in its analysis: one sponsored by Transco (Transco Study), another by the New Jersey Board of Public Utilities (NJ Agencies Study), and a third by the New Jersey Conservation Foundation (Skipping Stone Study). Several parties sought clarification and/or rehearing of the Commission's order, particularly its consideration of project need and market studies, and on March 17, 2023, the Commission granted clarification and denied rehearing.

534. 184 FERC ¶ 61,066, at P 2 (Clements, concurring).

535. *Transcontinental Gas Pipe Line Co.*, 182 FERC ¶ 61,006 at P 1 (2023); *clarification granted and reh'g denied, Transco*, 182 FERC ¶ 61,148 (2023).

The Commission determined that there was a need for the project based on Transco's execution of precedent agreements for 100% of the project's firm capacity. The Commission also considered market studies. Transco's study concluded that local distribution companies (LDCs) in New Jersey and Southeastern Pennsylvania would experience shortfalls in firm capacity during the 2022/2023 winter heating season and in future heating seasons. The NJ Agencies Study, on the other hand, concluded that there was no need for new pipeline capacity in New Jersey, based on projected efficiency reflected in policy goals of the State of New Jersey and assumptions about the future penetration of non-pipeline alternatives. The Commission stated that both of these studies provided valuable information, but concluded that the record did not support a conclusion that non-pipeline alternatives would eliminate the need for the project.[536] The Commission also noted that while the State of New Jersey had a policy goal to achieve certain environmental targets, there was "no requirement under New Jersey law that LDCs adopt non-pipeline alternatives," and LDCs could decline to adopt non-pipeline alternatives that were non-economic.[537]

The New Jersey Agencies[538] sought clarification that the Commission's discussion of the NJ Agencies Study would not override any factual determinations the New Jersey Agencies might make in state-level proceedings, based on the same NJ Agencies Study, regarding New Jersey LDCs' need for additional capacity or their prudence in purchasing project capacity. The Commission granted these requests for clarification, explaining that the New Jersey Agencies were free to use the NJ Agencies Study to support their own determinations within their own jurisdictions, and further stated that the Commission had no intention—or authority to—constrain state reviews of non-jurisdictional purchases of capacity.[539]

Several project opponents sought rehearing of the Commission's determination that there was a need for the project, asserting that the Commission overweighed the Transco Study and under-weighed the NJ Agencies and Skipping Stone studies. The Commission denied rehearing, reiterating its conclusion that both the Transco Study and the NJ Agencies Study provided valuable information, but disagreeing with certain findings of the NJ Agencies Study. The Commission stated that both studies supported the conclusion that demand for capacity would continue to grow in New Jersey through 2030. The Commission also noted that the NJ Agencies Study failed to account for certain "potentially offsetting effects that may undercut its claim that gas demand will increase," specifically, that with increasing electrification, gas demand could be transferred from LDCs and third-party suppliers to gas-fired generators.[540] While finding some fault with the Transco Study, the Commission concluded that despite some shortcomings, the

536. 182 FERC ¶ 61,006, at P 31.

537. *Id*.

538. NJ Agencies included the New Jersey Board of Public Utilities and the New Jersey Division of Rate Counsel. *Id.* at P 11.

539. 182 FERC ¶ 61,148, at P 28.

540. *Id.* at P 37.

study was consistent with accepted traditional LDC supply planning practices and appropriately balanced interests in reliable service and reasonable rates. The Commission reiterated its finding that the project was needed, emphasizing the precedent agreements for 100% of the project's firm capacity, and conclusion that those agreements were not outweighed by other record evidence. As of this writing, the Commission orders are under review at the U.S. Court of Appeals for the D.C. Circuit.[541]

6. Mountain Valley Pipeline, LLC

On June 28, 2023, the Commission issued an order authorizing all construction activities on the Mountain Valley Pipeline's (MVP) new interstate pipeline system, which had been stalled by numerous Fourth Circuit Court decisions invalidating federal permits.[542] The Commission had granted MVP a certificate of public convenience and necessity October 13, 2017, authorizing MVP to construct and operate a 2,000,0000 Dth/day pipeline from Wetzel County, West Virginia, to Pittsylvania County, Virginia. Although substantial portions of the pipeline were already built, the Commission halted construction because of the Fourth Circuit's orders invalidating various federal permits.

On June 3, 2023, President Biden signed into law the Fiscal Responsibility Act of 2023.[543] Section 324 of the Act ratified and approved all authorizations issued pursuant to Federal law necessary for the construction and operation of the MVP Project, and superseded any other provisions of law, statute, regulation or judicial decision that were inconsistent with the issuance of any authorization or other approval for the project. Accordingly, the Commission determined that MVP had all necessary authorizations to proceed with the remaining construction. The Commission also noted that its "Order No. 871, which precludes construction while the Commission considers certain requests for rehearing, [was] not implicated" by the instant order, and therefore, construction could commence immediately and would not be halted by any rehearing request.[544]

7. Columbia Gulf Transmission, LLC

On March 22, 2022, the Commission issued an order approving Columbia Gulf Transmission, LLC's (Columbia Gulf) East Lateral Xpress Project (Project),

541. New Jersey Conservation Found. v. FERC, 2023 U.S. App. LEXIS 7888 (D.C. Cir. 2023); *New Jersey Conservation Foundation, et al. v. FERC*, FERC (Oct. 10, 2023), https://www.ferc.gov/media/new-jersey-conservation-foundation-et-al-v-ferc-0.

542. *Mountain Valley Pipeline, LLC*, 183 FERC ¶ 61,221 at PP 1, 9-10 (2023).

543. Fiscal Responsibility Act of 2023, Pub. L. No. 118-5, 137 Stat. 10.

544. *Mountain Valley Pipeline, LLC*, 183 FERC ¶ 61,221 at P 11; Order No. 871, 18 C.F.R.§ 157.23 (2020), *order on reh'g and clarification;* Order No. 871-A, 174 FERC ¶ 61,050, *order on reh'g and clarification;* Order No. 871-B, 175 FERC ¶ 61,098 at P 17, *order on reh'g and clarification;* Order No. 871-C, 176 FERC ¶ 61,062 (2021). In Order No. 871-B at P 17, the Commission stated that—"to the extent a non-initial order merely implements the terms, conditions, or other provisions of the initial authorizing order [. . .]—a request for rehearing of that order would not implicate the initial authorizing order," so that the rule temporarily staying construction would not apply.

consisting of new pipeline and compression facilities in Louisiana designed to create 183,000 Dth/day of new capacity, which would be combined with 542,000 Dth/day of existing capacity to provide 725,000 Dth/day of capacity to deliver gas to Venture Global Plaquemines LNG, LLC (Venture Global) for export at its approved LNG terminal in Louisiana. On September 29, 2022, the Commission issued an order addressing issues raised on rehearing.[545]

On rehearing, the Commission rejected arguments that because the Project would only transport gas destined for export rather than domestic consumption, the Commission should have reviewed the Project as an export project under NGA section 3, rather than an interstate pipeline project under NGA section 7. The Commission stated that Columbia Gulf is a "natural gas company" subject to Commission jurisdiction under NGA section 7, and because the Project would transport gas that has been comingled with gas bound for domestic interstate use, it would be carrying gas in interstate commerce. The Commission stated that gas transported on the Project would only enter foreign commerce upon its delivery to Venture Global, the exporter of the gas.

The Commission also rejected arguments that it had failed to support its findings that the project would support the American public given that the project would only transport gas for export. Citing *City of Oberlin, Ohio v. FERC*, the Commission stated that it can consider benefits as export as part of its analysis of the public convenience and necessity under NGA section 7, and properly did so in the underlying order.[546]

The Commission also rejected several challenges to its review of the Project under NEPA, Sierra Club asserted that the Commission should have reviewed the project in a single EIS covering numerous other "connected actions," including the certifications of the Venture Global LNG export terminal and other pipelines designed to feed gas to the LNG export terminal. Sierra Club argued that each of the several pipeline projects designed to serve the LNG export terminal were interdependent and should have been reviewed together. The Commission rejected this contention, concluding that each of the projects had "substantial independent utility," and each could proceed without the Project. The Commission explained that the other interstate pipelines serving Venture Global connect to other sources of gas, and it is not uncommon for LNG terminal operators, for a variety of reliability and business reasons, to have multiple supply options.

The Commission also rejected challenges to the Certificate Order's finding that the Commission's NEPA analysis should have considered greenhouse gas emissions and other effects of the upstream production of gas and downstream transportation, consumption, and combustion of gas. The Commission stated that the Certificate Order correctly had found that the Commission's NEPA analysis need not consider the upstream or downstream impacts because the Department of

545. *Columbia Gulf Transmission, LLC*, 178 FERC ¶ 61,198, *order on reh'g*; 180 FERC ¶ 61,206 at PP 1-2 (2022).

546. *Columbia Gulf Transmission, LLC*, 180 FERC ¶ 61,206 at P 11; *see* City of Oberlin v. FERC, 39 F.4th 719, 726 (D.C. Cir. 2022).

Energy (DOE) had made the independent decision to allow the export of LNG.[547] The Commission rejected the argument that the Commission's NGA section 7 authority is independent of and broader than its NGA section 3 authority, such that the Commission may reject a project under NGA section 7 on the basis of indirect impacts, and thereby effectively block the export that DOE approved. The Commission stated that under *Freeport*, it had no basis to intrude on DOE's authority and determination regarding the indirect impacts of the export of gas.

B. Storage Projects

1. LA Storage, LLC

On September 23, 2022, the Commission issued a certificate of public convenience and necessity to LA Storage LLC to construct and operate new natural gas storage and transmission facilities ("Hackberry Storage Project") located in Cameron and Calcasieu Parishes, Louisiana.[548] The purpose of the project is "to meet the demand for high-deliverability natural gas storage capacity in the Gulf Coast from LNG exporters, electric generation facilities, and other customers in the region."[549] The Commission found that LA Storage LLC demonstrated need for the Hackberry Storage Project, that the project would not have adverse economic impacts on existing shippers or other pipelines and their existing customers, and that the project's benefits outweighed any adverse economic effects on landowners and surrounding communities.[550]

On October 24, 2022, Sierra Club filed a request for rehearing of the certificate order for the Hackberry Storage Project.[551] Sierra Club argued that the Commission's issuance of the certificate order violated the Natural Gas Act ("NGA") and the NEPA.[552] On January 20, 2023, the Commission issued its order on Sierra Club's rehearing request which rejected Sierra Club's arguments and continued to reach the same result in the certificate order.[553]

2. Columbia Gas Transmission, LLC

On February 16, 2023, the Commission issued a certificate of public convenience and necessity to Columbia Gas Transmission, LLC (Columbia) "to abandon, install, construct, and operate certain natural gas injection and withdrawal wells,

547. See Sierra Club v. FERC, 827 F.3d 36, 47 (D.C. Cir. 2016). The D.C. Circuit found that the Commission NEPA analysis did not have to address indirect effects of the export of natural gas because DOE, not the Commission, had sole authority to license the export of gas through the Freeport LNG facilities, and therefore, the Commission, cannot be the "cause" (i.e., Commission action certifying the project is not the cause) of "indirect effects," such as the impact of additional gas production (upstream) or greenhouse gases from the burning of the exported LNG (downstream).

548. *LA Storage, LLC*, 180 FERC ¶ 61,188 at P 1 (2022) (order issuing certificate).

549. *Id.* at P 20.

550. *Id.* at P 89.

551. *LA Storage, LLC*, 182 FERC ¶ 61,026 at P 1 (2023) (order addressing arguments raised on rehearing).

552. *Id.* at P 6.

553. *Id.* at P 2.

as well as associated pipelines at its Coco B Storage Field in Kanawha County, West Virginia ('Coco B Wells Replacement Project . . . ."[554] The proposed project would enable Columbia to replace aging and inefficient wells with new, more efficient wells, which would be designed and constructed to comply with the latest PHMSA standards.[555] The Commission agreed that the Coco B Wells Replacement Project would "benefit Columbia's system as a whole by improving reliability and flexibility for existing customers and the market."[556] The Commission found that Columbia had "demonstrated [] need for the Coco B Wells Replacement Project, that the project [would] not have adverse economic impacts on existing shippers or other pipelines and their existing customers, and that the project's benefits [outweighed] any adverse economic effects on landowners and surrounding communities."[557] In the application, Columbia's stated that it intends to recover project costs through its Capital Cost Recovery Mechanism until that mechanism terminates, and that it would seek to recover any project costs remaining after the termination of that mechanism through its system rates in its next NGA section 4 general rate case.[558] The Commission granted Columbia's "request for a pre-determination that it may roll any costs of the project, not recovered upon termination of the CCRM mechanism, into its system rates in a future NGA section 4 rate case, absent a significant change in circumstances."[559]

C. LNG Projects

1. Golden Pass LNG Terminal LLC

On July 29, 2022, the Commission granted Golden Pass LNG Terminal LLC's (Golden Pass) request to amend the Commission's December 21, 2016 order granting authorizations under section 3 of the NGA, to allow for increased workforce, construction traffic and modifications to the scope of work that could be performed on a 24 hours a day, seven days a week basis.[560] Although Golden Pass' request was initially filed as a request for variance (Variance No. 15), the Commission determined that "the magnitude and potential impacts of change requested in Variance No. 15 constitute a proposed amendment to the NGA section 3 approvals" in the December 21, 2016 order.[561] The Commission concluded that

554. *Columbia Gas Transmission, LLC*, 182 FERC ¶ 61,089 at P 1 (2023) (order issuing certificate and approving abandonment).

555. *Id.* at PP 5-6.

556. *Id.* at P 69.

557. *Id.*

558. 182 FERC ¶ 61,089, at P 33.

559. *Id.* at P 35.

560. *Golden Pass LNG Terminal LLC*, 180 FERC ¶ 61,058 at P 1 (2022) (order amending authorization under Section 3 of the Natural Gas Act).

561. *Id.* at P 2.

Golden Pass' amendment "would not constitute a major federal action significantly affecting the quality of the environment" and would not be inconsistent with the public interest.[562]

2. Delfin LNG LLC[563]

On November 18, 2022, the Commission granted Delfin LNG LLC's (Delfin) request for a one-year extension of time, until September 28, 2023, "to construct and place into service the onshore metering, compression, and piping facilities . . . intended to interconnect with Delfin's planned deepwater LNG" export terminal, subject to the jurisdiction of the U.S. Maritime Administration (MARAD).[564] Delfin stated that, similar to its previous requests for an extension, that delays were caused by difficulties resulting from the COVID-19 pandemic, including difficulty securing agreements with potential customers of the deepwater port.[565] Several environmental groups intervened in the proceeding, and challenged Delfin's request and argued that the project was no longer needed, that the environmental analysis was no longer valid, and that good cause to grant the extension did not exist.[566] The Commission rejected the environmental groups' arguments and found good cause to grant Delfin's request. Additionally, the Commission found that Delfin had made good faith efforts to meet the deadline in its certificate and that Delfin made progress in the commercialization and design of the deepwater port.[567]

3. EcoEléctrica, L.P.

On July 28, 2022, the Commission issued an order addressing arguments raised by EcoEléctrica, L.P. (EcoEléctrica) in its request for clarification of the Commission's April 22, 2022 Order on Initial Brief, which rejected EcoEléctrica's request to temporarily increase the operating level of its LNG storage tank following the Commission's decision to lower the maximum liquid level of EcoEléctrica's LNG storage tank to sixty-three feet in response to the January 7, 2020 6.4 magnitude earthquake in Puerto Rico.[568]

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562. *Id.* at PP 9, 60.

563. The Commission granted several requests for extensions of time to LNG companies this past year, along substantially similar grounds. *See Rio Grande LNG, LLC,* 181 FERC ¶ 61,032 (2022); *see also Freeport LNG Development, L.P., et al.*, 181 FERC ¶ 61,023 (2022); *see also Port Arthur LNG, LLC, et al.*, 181 FERC ¶ 61,024 (2022). Similarly, the Commission issued rehearing orders upholding extensions of time that provided substantially similar discussions. *See Corpus Christi Liquefaction Stage III*, *LLC, et al.,* 181 FERC ¶ 61,033 (2022); *see also Freeport LNG Development, L.P., et al*; *see also* 182 FERC ¶ 61,112 (2023); *Rio Grande LNG, LLC,* 182 FERC ¶ 61,027 (2023).

564. *Delfin LNG LLC*, 181 FERC ¶ 61,144 at P 1 (2022) (order granting extension of time).

565. *Id.* at PP 4, 9.

566. *Id.* at P 7.

567. *Id.* at P 11.

568. *EcoEléctrica, L.P.*, 180 FERC ¶ 61,054 at PP 1, 4 (2022) (order addressing arguments raised on rehearing and establishing technical conference).

Although the Commission recognized that the structural analyses performed by EcoEléctrica after the January 7, 2020, earthquake indicated the tanks were not damaged, the Commission noted that the tank was operating at a liquid level of 63 feet at the time of the January 7, 2020 earthquake, as opposed to its maximum allowable liquid height of 104 feet.[569] The Commission stated that the 6.4 magnitude earthquake exceeded the Safe Shutdown Earthquake ground motions and design specifications of the LNG storage tank.[570] The Commission further affirmed its request for the use of the 5,000 and 10,000-year mean seismic recurrence intervals (as set forth in the 1996 edition of NFPA 59A) as a means to help inform its decision-making on a maximum safe tank liquid level for foreseeable seismic events being projected for the area.[571] Finally, the Commission found that, considering the ground motions experienced during the January 7, 2020, earthquake and the recent seismic activity near the EcoEléctrica LNG terminal, there was not enough evidence in the record to support safe operation up to the 91 feet requested by EcoEléctrica.[572] The Commission's order also granted EcoEléctrica's request for a technical conference to discuss its structural analysis with Commission staff.[573]

On June 9, 2023, Commission staff issued a letter order authorizing EcoEléctrica, L.P. to increase the liquid height limit of 63 feet to a liquid level of eighty-four feet.[574] The letter order indicated that the structural analyses filed by EcoEléctrica, L.P. indicated that the maximum safe liquid level of the tank would be eighty-four feet based on U.S. Geological Survey projections and seismic data. Commission staff's authorization was without prejudice to EcoEléctrica to support further increases in tank liquid levels in the future.[575]

4. Nopetro LNG, LLC

On July 29, 2022, the Commission issued an order addressing arguments raised on rehearing by Public Citizen, Inc. with respect to the Commission's conclusion that Nopetro LNG LLC's proposed facility in Port St. Joe, Florida was not an LNG terminal subject to the Commission's jurisdiction under section 3 of the NGA.[576] The Commission rejected Public Citizen, Inc.'s argument that it impermissibly interpreted the term "onshore" in the definition of LNG terminal in NGA section 2(11) as applying to facilities located on or near the water or the coast such

569. *Id.* at P 12.
570. *Id.*
571. *Id.* at P 14.
572. *EcoEléctrica, L.P.*, 180 FERC ¶ 61,054 at P 16.
573. *Id.* at P 17.
574. *EcoEléctrica, L.P.*, 184 FERC ¶ 61,114 at P 3 (2023).
575. Id. at PP 2-3.
576. *Nopetro LNG, LLC*, 180 FERC ¶ 61,057 at P 1 (2022) (order addressing arguments raised on rehearing).

"that LNG terminals must be capable of transferring LNG onto waterborne vessels."[577] Finally, the Commission noted that the definition of "LNG terminal" was ambiguous and, if interpreted without the context in which the statute was enacted, could include a far larger universe of facilities than Congress intended.[578] In light of that ambiguity, the Commission concluded that it reasonably interpreted section 2(11), consistent with its longstanding application of its NGA section 3 jurisdiction and evidence of congressional intent.[579]

5. Cameron LNG, LLC

On March 16, 2023, the Commission issued an order granting Cameron LNG, LLC's application pursuant to section 3 of the NGA "to amend its authorization to site, construct, and operate certain additional facilities for the liquefaction and export of domestically-produced natural gas at its existing [] LNG terminal in Cameron and Calcasieu Parishes, Louisiana (Amended Expansion Project)."[580] Cameron LNG, LLC proposed to modify the Commission's 2016 order authorizing Cameron LNG, LLC to construct two additional liquefaction trains (Train 4 and Train 5) and a fifth LNG storage tank, as well as appurtenant facilities (Expansion Project).[581] Specifically, Cameron LNG, LLC requested authorization to enhance the design of Train 4 and partially vacate its authorization with respect to Train 5 and the fifth LNG storage tank.[582] With removal of Train 5, the overall maximum production capacity of the Expansion Project would be reduced from 9.97 metric tonnes per annum (MTPA) to 6.75 MTPA.[583] The Commission found that the Amended Expansion Project would not constitute a major federal action significantly affecting the quality of the human environment and was not inconsistent with the public interest.[584]

6. Corpus Christi Liquefaction, LLC

On May 18, 2023, the Commission granted Corpus Christi Liquefaction, LLC's (CCL) application pursuant to section 3 of the NGA and Part 153 of the Commission's regulations to acquire, as part of its currently-operating LNG terminal (Liquefaction Project), approximately 3,700 linear feet of existing, operating forty-eight-inch and thirty-six-inch diameter natural gas pipeline segments and ancillary facilities (the Terminal Supply Line), which connects the outlet of the existing pipeline and metering and regulating station, operated by Cheniere Corpus Christi Pipeline L.P., to the existing feed gas inlet for the LNG terminal and

577. *Id.* at PP 9, 21.

578. *Id.* at P 24.

579. *Id.* at P 25.

580. *Cameron LNG, LLC*, 182 FERC ¶ 61,173 at P 1 (2023) (order amending authorization under Section 3 of the NGA).

581. *Id.* at P 3.

582. *Id.* at PP 4-5.

583. *Id.* at P 5.

584. 182 FERC ¶ 61,173, at PP 25, 59.

reclassify the facilities and their operations to the Commission's NGA section 3 jurisdiction.[585] The Commission found that the proposed acquisition and reclassification, which involved the transfer of authority to operate the specified facilities from one jurisdictional entity to another, would not require any new construction, modification, or operation of any facilities and would not result in any environmental impacts.[586] Therefore, the Commission found that the proposal was not inconsistent with the public interest.[587]

On the same day, the Commission also approved CCL's request to vacate, in part, the Commission's November 22, 2019 order authorizing CCL to site, construct, and operate additional facilities for the liquefaction and export of domestically-produced natural gas at CCL's existing LNG terminal on the northern shore of Corpus Christi Bay in San Patricio and Nueces Counties, Texas (Stage 3 LNG Project).[588] Specifically, the Commission vacated its authorization with respect to the 160,000 m^3 full-containment LNG storage tank and appurtenant facilities proposed as part of the Stage 3 LNG Project.[589] CCL stated that it no longer intended to build the LNG storage tank because it determined, after beginning operation of its existing facilities, that it can accommodate the storage needs of the Stage 3 LNG Project with its three existing storage tanks.[590]

7. Freeport LNG Development, L.P., et al.

On July 29, 2022, the Commission granted an application by Freeport LNG Development, L.P., FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC, and FLNG Liquefaction 3, LLC (Freeport LNG) pursuant section 3 of the NGA and part 153 of the Commission's regulations to increase the authorized liquefaction production capacity at Freeport LNG's terminal from 782 billion cubic feet per year (Bcf/y) to 870 Bcf/y (Capacity Amendment Project).[591] Freeport LNG requested the production capacity increase to reflect the "maximum quantity of LNG that can be produced in a particular year when operating the Liquefaction Project at an annualized rate of 2.38 Bcf per day."[592] The Capacity Amendment Project did not require any new facilities, construction activities, or modifications to previously authorized facilities and would not require additional LNG vessel transits beyond those previously considered by the Commission and reviewed by the U.S. Coast Guard.[593] The Commission, in conjunction with PHMSA and the U.S. Department of Energy, Office of Fossil Energy performed an Environmental Assess-

585. *Corpus Christi Liquefaction, LLC*, 183 FERC ¶ 61,126 at PP 1-2 (2023).
586. *Id.* at P 8.
587. *Id.* at P 9.
588. *Corpus Christi Liquefaction, LLC, et al.*, 183 FERC ¶ 61,127 at P 1 (2023).
589. *Id.* at P 3.
590. *Id.*
591. *Freeport LNG Development, L.P., et al*., 180 FERC ¶ 61,055 at P 1 (2022).
592. *Id.*
593. *Id.* at P 7.

ment to analyze "air quality, climate change, safety, environmental justice, cumulative impacts, and alternatives"[594] After review of the application and Environmental Assessment, the Commission determined that Freeport LNG's application adequately support the requested increase to the maximum authorized LNG production capacity at the Liquefaction Project.

8. Commonwealth LNG, LLC

1.On November 17, 2022, the Commission granted Commonwealth LNG, LLC's (Commonwealth) application pursuant to section 3 of NGA and Part 153 of the Commission's regulations for authorization to site, construct, and operate a natural gas liquefaction and export facility, including an NGA section 3 natural gas pipeline, in Cameron Parish, Louisiana (Commonwealth LNG Project).[595] The approved Commonwealth LNG Project consists of: six liquefaction trains; six LNG storage tanks; one marine loading berth; a 3.04-mile-long, 42-inch-diameter pipeline; and other process and support facilities.[596] The Commonwealth LNG Project has a design production capacity of approximately 390.6 Bcf/y with a peak capacity of 441.4 Bcf/y.[597] The Commission's order acknowledged that some environmental impacts from the Commonwealth LNG Project would be permanent and significant, such as impacts on visual resources for environmental justice communities, but that most impacts would not be significant or would be reduced to less-than-significant levels with the implementation of environmental conditions adopted by the order.[598] Although the Commonwealth LNG Project was heavily protested by environmental groups, the Commission concluded that the arguments raised did not amount to an affirmative showing of inconsistency with the public interest necessary to overcome the presumption in section 3 of the NGA.[599] On June 9, 2023, the Commission issued an order addressing several arguments raised on rehearing by environmental groups (Environmental Coalition). The Environmental Coalition argued that: the Commission did not perform a proper assessment of the project's adverse impacts against its benefits under NGA section 3; the Commission did not fully explore all reasonable alternatives; the Commission failed to properly consider greenhouse gas emissions or air pollution impacts, particularly on environmental justice communities; and the Commission did not adequately consider impacts to certain species, such as the bottlenose dolphin and eastern black rail.[600] The Commission determined that Commonwealth's proposal is not inconsistent with the public interest based on the entirety of the record, and determined that it properly considered the project purpose and need, the information provided during the application process and through the EIS, and agency

594. *Id.* at P 23.
595. *Commonwealth LNG, LLC*, 181 FERC ¶ 61,143 at P 1 (2022).
596. *Id.* at P 2.
597. *Id.* at P 4.
598. *Id.* at P 15.
599. 181 FERC ¶ 61,143, at P 15.
600. *Commonwealth LNG, LLC*, 183 FERC ¶ 61,173 at PP 1, 7 (2023).

and judicial precedent as it considered and approved the application, and continued to reach the same result as in the underlying proceeding.[601]

9. Rio Grande LNG, LLC, et al.

On April 21, 2023, the Commission issued its order on remand from the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) in *Vecinos para el Bienestar de la Comunidad Costera v. FERC.*[602] The Commission continued to find that its authorization of Rio Grande LNG, LLC's proposed LNG terminal project (Rio Grande LNG Terminal) was not inconsistent with the public interest.[603] On remand, the D.C. Circuit directed the Commission to (1) "explain whether 40 C.F.R. § 1502.21(c) [the Council on Environmental Quality's (CEQ) regulations implementing NEPA] calls for [the Commission] to apply the social cost of carbon protocol or some other analytical framework, as 'generally accepted in the scientific community' within the meaning of the regulation, and if not, why not;"[604] and (2) either explain why it only analyzed the project's impacts on environmental justice communities in census blocks within two miles of the project site, or analyze the project impacts on environmental justice communities within a different radius of the project site.[605] Further, the court directed the Commission to revisit its public interest determination under sections 3 and 7 (with respect to the Rio Bravo Pipeline Project) of the NGA.[606]

In its remand order, the Commission explained that although it was including the social cost of GHGs estimates associated with the reasonably foreseeable emissions (i.e., the emissions from the construction and operation of the project) for informational purposes, the Commission concluded that 40 C.F.R. § 1502.21(c) did not require the use of the social cost of GHGs tool in the proceeding because it was not developed for project level review and does not enable the Commission to credibly determine whether GHG emissions from the project are significant or not significant in terms of their impact on global climate change.[607] The Commission further stated that it was not aware of any other currently scientifically accepted method that would enable the Commission to determine the significance of reasonably foreseeable GHG emissions.[608] With respect to environmental justice, following the D.C. Circuit's remand, the Commission staff conducted a new environmental justice analysis using the Commission's current methods and determined that a fifty-kilometer radius around the Rio Grande LNG Terminal was the appropriate area of review based on a conservative estimate of the furthest possible

601. *Id.* at PP 11.
602. Vecinos para el Bienestar de la Comunidad Costera v. FERC, 6 F. 4th 3121 (D.C. Cir. 2021).
603. *Rio Grande LNG, LLC, et al*., 183 FERC ¶ 61,046 at PP 1, 208 (2023).
604. *Id.* at P 10.
605. *Id.* at P 11.
606. *Id.*
607. 183 FERC ¶ 61,046, at PP 92-93.
608. *Id.* at P 93.

extent of impacts associated with air quality.[609] The Commission's updated area of review resulted in identification of 286 environmental justice community block groups within fifty-kilometers of the Rio Grande LNG Terminal.[610]

The Commission's updated environmental justice analysis resulted in the modification of the environmental conditions in Rio Grande LNG, LLC's authorization. In its remand order, the Commission recognized that the simultaneous construction, commissioning and start-up, and operations at the Rio Grande LNG Terminal could result in exceedances of the National Ambient Air Quality Standards (NAAQS) at nearby recreational areas for periods when these emissions are taking place concurrently.[611] Therefore, the Commission's order required Rio Grande LNG, LLC to prepare a Project Ambient Air Quality Mitigation and Monitoring Plan to reduce the air quality impacts and ensure that NAAQS are not exceeded during such periods.[612] Finally, in order to further mitigate potential offsite risks, the Commission modified the environmental conditions in the authorization order regarding the preparation of an Emergency Response Plan and Cost Sharing Plan.[613]

10. Texas LNG Brownsville LLC

On April 21, 2023, in a companion order to the remand order for the Rio Grande LNG Terminal (above), the Commission issued its order on remand from the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) in *Vecinos para el Bienestar de la Comunidad Costera v. FERC*.[614] The Commission determined that its authorization of Texas LNG Brownsville LLC's (Texas LNG) proposed LNG terminal project (Texas LNG Project) was not inconsistent with the public interest.[615] On remand, the D.C. Circuit directed the Commission to (1) explain whether the Council on Environmental Quality's (CEQ) regulations implementing NEPA (40 C.F.R. § 1502.21(c)) required the Commission to apply the social cost of carbon protocol (now updated to calculate the social cost of specific GHGs) or some other analytical framework; and (2) either explain why it only analyzed the project's impacts on environmental justice communities in census blocks within two miles of the project site, or analyze the project impacts on environmental justice communities within a different radius of the project site.[616] Further, the court directed the Commission to revisit its public interest determination under section 3 of the NGA.[617]

609. *Id.* at P 118.
610. *Id.* at P 119.
611. 183 FERC ¶ 61,046, at PP 139, 141.
612. *Id.* at PP 141-42.
613. *Id.* at PP 156-57.
614. Vecinos para el Bienestar de la Comunidad Costera v. FERC, 6 F. 4th 3121 (D.C. Cir. 2021).
615. *Texas LNG Brownsville LLC*, 183 FERC ¶ 61,047, at PP 1, 85 (2023).
616. *Id.* at P 1.
617. *Id.*

In its remand order, the Commission explained that although it was including the social cost of GHGs estimates associated with the reasonably foreseeable emissions (i.e., the emissions from the construction and operation of the project) for informational purposes, the Commission concluded that 40 C.F.R. § 1502.21(c) did not require the use of the social cost of GHGs tool in the proceeding because it was not developed for project level review and does not enable the Commission to credibly determine whether GHG emissions from the project are significant or not significant in terms of their impact on global climate change.[618] The Commission further stated that it was not aware of any other currently scientifically accepted method that would enable the Commission to determine the significance of reasonably foreseeable GHG emissions.[619] With respect to environmental justice, following the D.C. Circuit's remand, the Commission staff conducted a new environmental justice analysis using the Commission's current methods and determined that a fifty-kilometer radius around the Texas LNG Project was the appropriate area of review based on a conservative estimate of the furthest possible extent of impacts associated with air quality.[620] The Commission's updated area of review resulted in identification of 279 environmental justice community block groups within fifty-kilometers of the Texas LNG Project.[621]

618. *Id.* at PP 20-21.
619. 183 FERC ¶ 61,047, at P 20.
620. *Id.* at PP 32-33.
621. *Id.* at P 34.

VI. The Commission's updated environmental justice analysis resulted in the modification of the environmental conditions in Texas LNG's authorization. In its remand order, the Commission recognized that the simultaneous construction, commissioning and start-up, and operations at the Texas LNG Project could result in exceedances of the NAAQS at nearby recreational areas for periods when these emissions are taking place concurrently.[622] Therefore, the Commission's order required Texas LNG to prepare a Project Ambient Air Quality Mitigation and Monitoring Plan to reduce the air quality impacts and ensure that NAAQS are not exceeded during such periods.[623] Finally, in order to further mitigate potential offsite risks, the Commission modified the environmental conditions in the authorization order regarding the preparation of an Emergency Response Plan and Cost Sharing Plan.[624] The modified conditions require the periodic distribution of public education materials identifying "potential hazards and impacts, steps for notification, proposed evacuation routes and shelter in place locations."[625] The Emergency Response Plan must also provide for first responder training, emergency command centers and equipment, and public communication methods and devices."[626] PHMSA & Pipeline Safety

A. *Revised Federal Pipeline Safety Regulations*

1. Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments: Technical Corrections – Final Rule – Docket Number PHMSA-2011-0023

On June 13, 2022, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published in the *Federal Register* a final rule with technical corrections to incident and annual reporting requirements for offshore gathering pipelines in its November 15, 2021 final rule.[627] The 2021 final rule amended the Federal pipeline safety regulations to introduce, among other things, incident and annual reporting requirements for previously unregulated Types C and R onshore gas gathering pipelines. Type C gathering lines are in Class 1 locations, operate at higher stress levels or pressures and have outer diameters of 8.625 inches or

622. *Id.* at PP 69-70.

623. 183 FERC ¶ 61,047, at PP 70.

624. *Id.* at PP 61-62.

625. *Id.* at P 64.

626. *Id.*

627. *Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments: Technical Corrections*, 87 Fed. Reg. 35,675 (Jun. 13, 2022); *see* Final Rule, *Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments,* 86 Fed. Reg. 63,266 (Nov. 15, 2021).

greater.[628] Type R gathering lines are subject to part 191 reporting but are not designated as regulated gathering lines in part 192.[629] The preamble to the rule explicitly referenced amendment of then-existing part 191 reporting and part 192 safety requirements pertaining to offshore gas gathering pipelines.[630] In amending the regulatory language pertaining to incident and annual reporting requirements, however, "PHMSA inadvertently omitted language requiring offshore gas gathering pipelines to continue to submit the same consistent with longstanding requirements."[631] As a result, PHMSA issued corrections amending §§ 191.15(a)(1) and 191.17(a)(1) consistent with its intent to include offshore gas gathering pipelines in the original final rule.[632]

2. Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments – Final Rule – Docket Number PHMSA-2011-0023

On August 24, 2022, PHMSA published in the *Federal Register* a final rule revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines.[633] The final rule amends PHMSA's natural gas pipeline safety regulations at 49 C.F.R. part 192 to include revisions to management of change processes, revisions to integrity management processes, updates to corrosion control requirements, and requirements for inspecting pipelines following extreme weather events.[634]

- *Management of Change Processes.* Through revisions to sections 192.13 and 192.911, PHMSA expanded the applicability of Management of Change (MOC) requirements to all onshore gas transmission pipelines.[635] Prior to the final rule, such requirements applied only to pipelines that were subject to Subpart I Integrity Management Requirements.[636] The final rule also provides operators of non-HCA[637] pipeline segments with eighteen months to fully incorporate the MOC process, and the possibility of a further one-

628. Final rule, *Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments*, 86 Fed. Reg. 63,268 (Nov. 15, 2021)

629. *Id.* at 63,275.

630. *Id.* at 63,266.

631. *Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments: Technical Corrections*, 87 Fed. Reg. 35,675 (Jun. 13, 2022).

632. *Id.*

633. *Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments*, 87 Fed. Reg. 52,224 (Aug. 24, 2022) [hereinafter *Safety of Gas Transmission Pipelines*].

634. *Id.* at 52,224.

635. *Id*. at 52,233-34.

636. *Id.* at 52,235.

637. "HCA" refers to "high-consequence areas." *Safety of Gas Transmission Pipelines*, *supra* note 633, at 52,225.

year extension if a written request is submitted "at least 90 days before" the effective date of February 26, 2024.

- *Integrity Management Processes.* Through revisions to sections 192.917 and 192.935, PHMSA established new and revised requirements for identifying and analyzing threats, performing direct assessments, repairing pipelines, and implementing preventive and mitigative measures.[638]
- *Corrosion Control Requirements.* Through revisions to sections 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935, PHMSA expanded corrosion control requirements for gas transmission pipelines, including new requirements for pipe coating assessments, protective coating strength, preventative and mitigative measures, and additional mitigation of stray current.[639] PHMSA also implemented changes to its gas stream monitoring program to mitigate internal corrosion.
- *Inspections Following Extreme Weather Events.* Through revisions to section 192.613, PHMSA now requires operators, following an "extreme weather event" (*e.g.*, hurricanes, landslides, earthquakes, flooding exceeding the high-water mark), to inspect all potentially affected pipeline facilities to ensure that no conditions exist that could adversely affect the safe operation of the pipeline.[640] Upon detection of a condition that could adversely affect the safe operation of the pipeline, an operator must take prompt remedial action. PHMSA's new requirements for natural gas pipelines are largely similar to those already applicable to hazardous liquids pipelines.[641]

The final rule marks the third and final installment of the "Mega Rule" that PHMSA first proposed in April 2016, in response to congressional action following a deadly 2010 gas transmission pipeline explosion in San Bruno, California.[642]

On December 6, 2022, in response to industry petitions for reconsideration of the final rule,[643] PHMSA determined that additional agency guidance—and associated time to implement the guidance—would provide additional safety benefits to the public. As a result, PHMSA exercised its "inherent enforcement discretion to refrain from taking enforcement action alleging violations of the Final

638. *Id*. at 52,228-34.

639. *Id*. at 52,234-42. The final rule notes that "PHMSA has revised § 192.9 to exempt gathering lines from several of these requirements. PHMSA, however, may consider expanding this provision to gathering lines in the future." *Safety of Gas Transmission Pipelines*, *supra* note 633.

640. *Id.* at 52,241.

641. *See* 49 C.F.R. § 195.414.

642. *Safety of Gas Transmission and Gathering Pipelines*, 81 Fed. Reg. 20,722 (Apr. 8, 2016).

643. *Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments: Technical Corrections; Response to Petitions for Reconsideration*, 88 Fed. Reg. 24,708 (Apr. 4, 2023).

Rule's requirements (subject to certain exceptions described below) for nine additional months (i.e., from May 24, 2023, to February 24, 2024) against operators of existing onshore gas transmission pipelines in-service as of the publication date of the Final Rule on August 24, 2022."[644] During that nine-month period, PHMSA plans to prepare and issue guidance to aid operators in their compliance with the final rule. "This enforcement discretion will not apply to (1) those provisions of the Final Rule for which the Final Rule prescribed independent compliance timelines (i.e., 49 C.F.R. 192.917(b) and 192.13(d)); and (2) pipelines that are new or replaced after August 24, 2022."[645]

On April 17, 2023, PHMSA determined that the same rationale merits the exercise of enforcement discretion for other requirements in the final rule.[646] Specifically, PHMSA states that it "will exercise its inherent enforcement discretion to refrain from taking enforcement action alleging violations of the Final Rule's requirements—except for certain regulatory amendments discussed below—for nine additional months (i.e., from the effective date of the Final Rule on May 24, 2023, to February 24, 2024) against operators of onshore gas transmission pipelines that enter into service between August 24, 2022 (the publication date of the Final Rule), and the expiration of this enforcement discretion on February 24, 2024. "In addition, prior to February 24, 2024, PHMSA will not enforce updated [operations and maintenance] manuals to account for those provisions that do not otherwise require operator action before that time."[647]

> This enforcement discretion specifically excludes: (1) those provisions of the Final Rule subject to independent compliance timelines (i.e., §§ 192.917(b) and 192.13(d)); and (2) compliance with §§ 192.319, 192.461, and 192.613. Sections 192.319 and 192.461 provide important corrosion control provisions to take during construction to ensure long-term integrity of pipelines after the expiration of this enforcement discretion.[648]

3. Gas Pipeline Leak Detection and Repair – Proposed Rule – Docket Number PHMSA-2021-0039

On May 18, 2023, PHMSA published in the *Federal Register* a proposed rule updating the requirements for gas pipeline leak detection and repair.[649] On June 30, 2023, PHMSA extended the comment period on the proposed rule to August 16, 2023.[650] The proposed rule includes several updates that would enhance leak survey and patrol requirements, require operators to identify and repair leaks, and expand release reporting. The following key changes are proposed.

644. Memorandum from USDOT on Limited Enforcement Discretion for Onshore Gas Transmission Pipelines Entered into Service After August 24, 2022 Regarding Compliance with the Recently Issued Gas Transmission Final Rule (Apr. 17, 2023) [hereinafter Memo from USDOT].

645. *Id*. at 2.

646. *Id*.

647. *Id*. at 1-2.

648. Memo from USDOT, *supra* note 645, at 1-2.

649. *Gas Pipeline Leak Detection and Repair*, 88 Fed. Reg 31,890 (May 18, 2023).

650. *Gas Pipeline Leak Detection and Repair*, 88 Fed. Reg. 42,284 (June 30, 2023).

- *Enhanced leak surveys and patrolling*.[651] The proposed rule would increase leak surveys and minimum patrolling frequencies for numerous facilities, with the most frequent surveys proposed for certain gas transmission and gathering pipelines in high consequence areas. Methane leak surveys for certain LNG facilities are also proposed.
- *New leak detection performance standard.*[652] The proposed rule includes a new Advanced Leak Detection Program (ALDP) performance standard that would require operators to demonstrate that their leak detection equipment and procedures can detect all leaks above a minimum threshold.
- *New requirement to repair all leaks.*[653] If finalized, operators of gas transmission, distribution, and certain gathering pipelines would be required to identify and repair all leaks. This would significantly expand the current requirements, which are focused on public safety risks associated with ignition of large-volume, instantaneous releases and accumulated gas. The proposed rule would also require operators to classify each leak and prioritize repairs that pose the most significant risk to public safety and the environment.
- *New requirement to mitigate intentional emissions*.[654] The proposed rule would require intentional emissions, such as blowdowns, to be mitigated. Operators would also be required to reduce emissions associated with pressure relief devices.
- *Expanded release reporting.*[655] Several changes to release reporting are proposed, including a requirement to report both unintentional and (for the first time) intentional releases of 1 MMCF or more of gas from any gas pipeline facility. Updates to annual reporting requirements for certain facilities are also proposed, including new reporting on the number and grade of leaks detected and repaired as well as estimated emissions associated with each leak.

B. *Challenges in the U.S. Courts of Appeals*

1. GPA Midstream Association v. DOT, No. 22-1070 (D.C. Cir.)

On May 2, 2022, industry groups challenged, in the U.S. Court of Appeals for the D.C. Circuit, PHMSA's new gas gathering pipeline rule, which went into effect on May 16, 2022.[656] The rule amends regulations governing rural onshore

651. *Gas Pipeline Leak Detection and Repair*, *supra* note 649, at 31,891-92.
652. *Id*. at 31,892.
653. *Id*.
654. *Id*.
655. *Gas Pipeline Leak Detection and Repair*, *supra* note 649, at 31,892.
656. GPA Midstream Ass'n v. DOT, No. 22-1148, slip op. at 2 (D.C. Cir. May 16, 2023).

gas gathering pipelines and, among other things, creates a new category of regulated gathering pipelines (Type C pipelines), subjecting them to safety requirements related to corrosion control, damage prevention programs, and emergency plans.[657] Operators of existing Type C pipelines were given until May 16, 2023, to comply with these new safety requirements.

On July 8, 2022, GPA Midstream Association (GPA Midstream) and PHMSA filed a Joint Status Report informing the Court that the parties have agreed to settle the case. PHMSA agreed to exercise its enforcement discretion and refrain from taking enforcement action for one additional year (from May 16, 2023, until May 17, 2024) against operators of existing Type C gathering pipelines with outer diameters greater than or equal to 8.625 inches, but less than or equal to 12.75 inches, for violations of safety requirements identified in 49 C.F.R. § 192.9. GPA Midstream agreed to move to dismiss the case upon completion of the limited enforcement discretion period and to "offer to all operators of these lines educational and information sessions on the requirements of § 192.9."[658]

On July 8, 2022, PHMSA simultaneously issued the Notice describing how it will exercise limited enforcement discretion on this matter.[659] Notably, the Notice explains that, during the period of limited enforcement discretion, PHMSA will continue to enforce all of the rule's other regulatory deadlines and requirements as they relate to Type C pipelines. Further, PHMSA explains that upon expiration of its limited enforcement discretion, it will begin compliance inspections on Type C pipelines, "prioritizing those pipelines that have a building intended for human occupancy within its [potential impact radius]."[660]

2. GPA Midstream Association v. DOT, No. 22-1148 (D.C. Cir.)

On July 1, 2022, industry groups challenged, in the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit or Court), PHMSA's new requirement to install automatic or remotely operated safety valves on gas gathering lines.[661] The petitioners argued that PHMSA unlawfully failed to disclose the economic basis for regulating gathering pipelines when it proposed the standard, and also failed to make a reasoned determination that regulating these pipelines was appropriate.[662]

On May 16, 2023, the D.C. Circuit agreed, noting that the agency "said nothing about the practicability or the costs and benefits of the standard for gathering pipelines until promulgating the final rule."[663] The Court further explained that

657. *Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments*, 86 Fed. Reg. 63,266 (Nov. 15, 2021)

658. GPA Midstream Ass'n v. DOT, No. 22-1070 (D.C. Cir. June 1, 2022).

659. Memorandum from USDOT on Limited Enforcement Discretion for Type C Gas Gathering Pipelines with Outer Diameter Greater than or Equal to 8.625" but Less than or Equal to 12.75", as to 49 CFR § 192.9 Compliance (Jul. 8, 2022).

660. *Id*. at 2.

661. GPA Midstream Association v. DOT, No. 22-1148 (D.C. Cir. May 16, 2023); *Requirement of Valve Installation and Minimum Rupture Detection Standards*, 87 Fed. Reg. 20,940 (Apr. 8, 2022).

662. GPA Midstream Ass'n v. DOT, 67 F.4th 1188, 1191 (D.C. Cir. 2023).

663. *Id*.

"PHMSA also ultimately failed to make a reasoned determination that the benefits of regulating gathering pipelines would exceed the costs, and that doing so would be practicable, as required by law."[664] As a result, the Court "vacate[d] the rule in its entirety as it applies to gathering pipeline facilities."[665]

VII. ENVIRONMENTAL

A. *Clean Air Act*

1. EPA Issues a Supplemental Proposal Addressing New Source Performance Standards and Emissions Guidelines for the Crude Oil and Natural Gas Source Category

In November 2021, the U.S. EPA issued a proposed rule[666] in response to President Biden's January 20, 2021 Executive Order titled "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." The 2021 proposed rule comprised several actions under the Clean Air Act (CAA) aimed at reducing emissions of greenhouse gases and other air pollutants from the Crude Oil and Natural Gas source category.[667] EPA accepted comments on the 2021 proposed rule until January 31, 2022.[668]

On November 11, 2022, EPA issued a supplemental rule proposal to update, strengthen, and expand on the 2021 proposed rule.[669] The 2022 supplement incorporates input received during the public comment period on the 2021 proposed rule and includes several key changes. First, the 2022 supplement strengthens the leak monitoring system included in the 2021 proposed rule by tying monitoring requirements to the types and amount of equipment on site rather than baseline emissions calculations.[670] This approach removes routine monitoring exemptions for well sites with lower emissions (e.g., wellhead-only sites).[671] The 2022 supplement also proposes routine monitoring requirements for abandoned and unplugged wells until the well owner or operator permanently closes the site in accordance with a well closure plan.[672]

Second, the 2022 supplement includes new or more stringent requirements for certain types of equipment and activities. EPA is proposing to limit flaring of

664. *Id*.

665. *GPA Midstream Ass'n*, 67 F.4th 1188 at 1202.

666. *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 86 Fed. Reg. 63,110 (Nov. 15, 2021).

667. *Id*.

668. *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review; Extension of Comment Period*, 86 Fed. Reg. 71,603 (Dec. 17, 2021).

669. *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 87 Fed. Reg. 74,702 (Dec. 6, 2022).

670. *Id*. at 74,735.

671. *Id*. at 74,723.

672. *Id*. at 74,736.

associated gas from oil wells and require owners or operators to either route the gas to a sales line, use the gas for fuel or another beneficial purpose, or reinject the gas into the well for enhanced oil recovery.[673] EPA is also proposing a zero-emission standard for pneumatic pumps, which means that the pumps cannot be powered by natural gas unless a demonstration is made that it is technically infeasible (*e.g.*, where the site does not have access to electricity).[674] The 2022 supplement also includes standards for new and existing dry seal compressors, which had not previously been regulated.[675] As proposed, owners and operators of dry seal compressors would be required to maintain the volumetric flow rate at or below three standard cubic feet per minute to limit emissions.[676]

Third, the 2022 supplement includes new opportunities for third party monitoring. EPA is proposing a "Super-Emitter Response Program" where regulatory authorities and qualified, EPA-approved third parties may notify owners and operators of regulated facilities when a "super emitter" event is detected.[677] As proposed, a "super emitter" event is emissions of 100 kilograms (220.5 pounds) of methane per hour or more.[678] Owners or operators would then be required to conduct a root-cause analysis of the event and take corrective actions to address the source of the emissions.[679] Notices sent to owners or operators and any response would be available on a public website.[680]

The comment period for the 2022 supplement closed on February 13, 2023.[681] As of this writing, the rule remains pending.

2. EPA Updates Greenhouse Gas Reporting Requirements Relevant to the Petroleum and Natural Gas Systems Source Category

The Greenhouse Gas Reporting Program (GHGRP) requires certain sources of greenhouse gas (GHG) emissions to report GHG data annually.[682] Pursuant to its authority under CAA section 114, on May 22, 2023, EPA issued a supplemental notice of proposed rulemaking that requires reporting from new industry sectors and proposes other changes aimed at improving the quality of GHGRP data.[683] Although the changes are not specific to the Petroleum and Natural Gas Systems source category, the proposed new "Energy Consumption" source category would

673. 87 Fed. Reg. 74,702, at 74,780.

674. *Id*. at 74,770.

675. *Id.* at 74,707.

676. *Id*. at 74,790.

677. 87 Fed. Reg. 74,702, at 74,747.

678. *Id*.

679. *Id*.

680. *Id*. at 74,748.

681. 87 Fed. Reg. 74,702.

682. 40 C.F.R. Part 98 (2009).

683. *Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule*, 88 Fed. Reg. 32,852 (May 22, 2023).

apply to all sources currently required to report under the GHGRP and would require each source to report purchased metered electricity and thermal energy products to EPA.[684] This new requirement is intended to capture data on direct, onsite emissions as well as indirect, offsite emissions that result from the production of purchased energy.[685] The comment period for this rulemaking closed on July 21, 2023.[686] As of this writing, the rule remains pending.

B. National Environmental Policy Act

1. Council on Environmental Quality Issues

a) Interim Guidance on Greenhouse Gases and Climate Change

On January 9, 2023, the White House CEQ issued interim guidance to Federal agencies on how to consider greenhouse gas and climate change effects associated with major federal actions in accordance with the NEPA.[687] The interim guidance instructs Federal agencies to apply certain "best practice" to their climate change analyses, including:

- leveraging early planning to integrate GHG emissions and climate change considerations into the identification of proposed actions, reasonable alternatives (including the no-action alternative), and potential mitigation and resilience measures;
- quantifying a proposed action's projected GHG emissions or reductions for the expected lifetime of the action;
- using projected GHG emissions associated with proposed actions and their reasonable alternatives to help assess potential climate change effects;
- providing additional context for GHG emissions, including through social cost of GHG estimates;
- analyzing "reasonably foreseeable direct, indirect, and cumulative GHG emissions";
- addressing short- and long-term climate change effects;
- providing up to date examples of existing sources of scientific information;
- considering reasonable alternatives that would make the affected communities more resilient to the effects of a changing climate;
- analyzing biogenic carbon dioxide sources and carbon stocks associated with land and resource management actions;
- applying the "rule of reason"; and

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684. *Id*. at 32,887.
685. *Id*.
686. *Id*. at 32,852.
687. *National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions and Climate Change*, 88 Fed. Reg. 1196-01 (Jan. 9, 2023).

- incorporating environmental justice considerations into analyses of climate-related effects

Notably, the interim guidance instructs that agencies should "mitigate GHG emissions associated with their proposed actions to the greatest extent possible, consistent with national, science-based GHG reduction policies established to avoid the worst impacts of climate change."[688] Mitigation should "particularly" include avoidance and minimization,[689] as well as enhanced energy efficiency, renewable energy generation and energy storage, lower-GHG-emitting technology, reduced embodied carbon in construction materials, carbon capture and sequestration, sustainable land management practices, and capturing GHG emissions such as methane.[690] The interim guidance is subject to change until the rule is finalized but took immediate effect for relevant agencies, including FERC.

b) Notice of Proposed Rulemaking: Bipartisan Permitting Reform Implementation Rule

On July 31, 2023, CEQ released a proposed "Bipartisan Permitting Reform Implementation Rule" to revise regulations implementing procedural provisions of NEPA.[691] Significant modifications in the proposed rule include: (1) increasing, earlier engagement with indigenous populations;[692] (2) limiting climate change analysis for renewable energy projects, and specifically, relaxed requirements that will reduce the need to perform an exhaustive EIS; (3) providing a new "innovative" NEPA process for projects that address "extreme environmental challenges" such as climate change;[693] (4) requiring, for the first time, an analysis of reasonably foreseeable climate change impacts and consideration of disproportionate or adverse effects on environmental justice communities;[694] and (5) enhanced and more predictable interagency coordination for project review.[695] CEQ requested comments on the proposed rulemaking by September 29, 2023.

2. Center for Biological Diversity v. FERC, 67 F.4th 1176, 1180 (D.C. Cir. 2023)

On May 16, 2023, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued an opinion affirming FERC's authorization of Alaska Gasline Development Corporation (AGDC) to construct and operate LNG facilities in the North Slope of Alaska. The proposed project would transport gas out of the North Slope through an 800-mile, forty-two-inch diameter pipeline

688. *Id.* at 1197.
689. *Id.* at 1206.
690. *Id.*
691. *National Environmental Policy Act Implementing Regulations Revisions Phase 2*, 88 Fed. Reg. 49,924-88 (July 31, 2023).
692. 88 Fed. Reg. 49,924 at 49,942-43.
693. *See id.* at 49,957.
694. *Id.* at 49,984.
695. *Id.* at 49,953.

bisecting Alaska from north to south. The project would also entail construction of natural gas liquefaction facilities in southern Alaska for delivery to tanker ships.

As NEPA requires, FERC prepared an EIS for the project as part of its review and approval process. The EIS concluded that the project would cause numerous environmental impacts, but that those impacts could be mitigated by imposition of 165 environmental conditions. FERC authorized the Project as modified by such conditions. Environmental petitioners sought rehearing of the authorization, arguing that FERC failed to adequately determine that the Project was in the public interest. FERC denied rehearing, thus the petitioners sought review at the D.C. Circuit.

The D.C. Circuit denied or dismissed all petitioner claims. Petitioners claimed that FERC failed to comply with NEPA by: (1) failing to consider project alternatives; (2) not employing the "social cost of carbon" metric to estimate the significance of the project's direct GHG emissions; (3) not considering indirect GHG emissions; (4) not addressing the project's impact on a whale species; and (5) inadequately evaluating wetland impacts. Petitioners also argued that FERC violated the NGA for the same reasons. The D.C. Circuit rejected all arguments, holding that FERC's decision to authorize the project was reasonable and within the law.

Regarding GHG emissions, the D.C. Circuit held that petitioners' assertion that FERC must consider the social cost of carbon in a NEPA analysis fell short because there is no scientific consensus regarding the social cost of carbon. Further, the court held that FERC's delegated authority does not require consideration of indirect GHG effects, and that GHG effects were otherwise not reasonably foreseeable because FERC could not identify the project's end gas users.

Previously, the Commission established a default policy, through its authority under the NEPA, to require any project that would increase emissions to undergo a lengthy EIS instead of a less rigorous Environmental Assessment (EA). More recently, though, the Commission has switched three natural gas projects to an EA that were slated by former leadership to undergo an EIS. The Commission also recently approved an expansion for the Transcontinental Gas Pipeline and approved multiple liquified natural gas projects, including the Freeport LNG Export Terminal and the Texas Brownsville LNG project.