REPORT OF THE GAS, OIL AND LIQUIDS STEERING COMMITTEE

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 Oil and Liquids regulation between December 31, 2022 and December 31, 2023.*

I. TARIFF AND RATEMAKING ISSUES

A. Enerplus Resources (USA) Corp. v. Targa Badlands LLC, 181 FERC ¶ 61,208 (2022).

On December 16, 2022, the Commission issued its "Order Denying Rehearing, Initiating an Investigation and Establishing Hearing Procedures" in *Targa*

* The Gas, Oil & Liquids Steering Committee thanks Chris Barr, Dean Lefler, Joseph Hainline, Joseph Hicks, Randy Rich, and Laura Swett for their contributions to this report.

Badlands II,[1] regarding an earlier order, *Targa Badlands I*.[2] Targa Badlands LLC (Targa Badlands) operates the Targa Badlands System, a crude oil gathering system that links Bakken formation production wells and downstream pipelines and storage facilities; Targa Badlands operates subject to a "temporary waiver" of certain provisions of the Interstate Commerce Act (ICA),[3] which relieves it of various obligations, including that of filing a tariff. The Commission grants such waivers upon a showing of certain criteria, including 100% ownership by the pipeline or its affiliates of product moved through the pipeline and no current or likely third-party interest in transportation on the line.[4] The complainant had filed a complaint in early 2021 asserting that it had a contract with Targa Badlands to sell all of its attached crude oil production to Targa Badlands at origin points and to buy it back at destination points, and that its fees for the buy/sell transactions exceeded the fees paid by competing producer, in violation of the non-discrimination provisions of the ICA.[5] In *Targa Badlands I*, the Commission dismissed the complaint; the Commission found that although a temporary waiver did not "absolve Targa of its remaining common carrier obligations under the ICA (including the non-discrimination provisions in sections 2 and 3(1)," such obligations only applied to "transportation service," which the complainant had not requested or received (the complainant did not challenge the continued existence of the temporary waiver) – hence the complaint lacked "coherence" and did not state a claim under the ICA.[6]

The Commission denied rehearing, continuing to find that in the absence of transportation, the requirements of the ICA do not apply[7] and rejecting the complainants' claim that it was forced to enter into the buy/sell contract on both procedural and substantive grounds.[8] However, *sua sponte*, the Commission commenced an investigation into whether Targa Badlands continued to meet the criteria for its temporary waiver,[9] particularly the two criteria requiring that: there be no demonstrated third-party interest in transportation,[10] and that it is unlikely that third-party interest in transportation would occur.[11] In addition, the Commission commenced an investigation into whether the pipeline might be providing ICA jurisdictional transportation without meeting the ICA's obligations, given the nature of the buy/sell arrangements. The Commission observed that "at least in some instances, it appears that there may be no difference between the purchase and sale price except for a fee for transportation on the Pipeline System," raising

1. *Enerplus Resources (USA) Corporation*, 181 FERC ¶ 61,208 (2022).
2. *Enerplus Resources (USA) Corporation*, 174 FERC ¶ 61,241 (2021).
3. Interstate Commerce Act, 49 App. U.S.C. §§ 1, *et seq*. (1988).
4. *See*, *e.g*., *Whiting Oil & Gas Corporation*, 131 FERC ¶ 61,263 at P 4 (2010).
5. 181 FERC ¶ 61,208, at P 4.
6. *Id.* at P 5.
7. *Id.* at PP 9, 10.
8. *Id.* at P 11. The Commission found, *inter alia*, that the complainant could have avoided the "forced contract" by seeking common carrier service, which Targa Badlands would have been obligated to provide. *Id*.
9. 181 FERC ¶ 61,208, at PP 12, 13.
10. *Id.* at P 14.
11. *Id.* at P 15.

concern that the service might be jurisdictional transportation.[12] The Commission found a need for further factual development[13] and set the issues for hearing before a presiding Administrative Law Judge. The investigation has subsequently proceeded through hearing and briefing.

B. Epsilon Trading, LLC v. Colonial Pipeline Co., 185 FERC ¶ 61,125 (2023).

On November 16, 2023, the Commission issued part one of a two-part Order on Initial Decision (Order) addressing the complaints filed by numerous parties against Colonial Pipeline Company (Colonial) challenging Colonial's cost-of-service (COS) rates, market-based rates (MBR), and product loss allowance (PLA).[14] This first part of the Order concerned the Initial Decision's rulings on Colonial's MBRs and PLA charge. The Commission affirmed in part and reversed in part.

In terms of Colonial's PLA charge, the Commission found that the charges assessed by Colonial are jurisdictional.[15] The Commission then found that Colonial's PLA charge was unjust and unreasonable because it: (1) gave Colonial sole discretion over how and when Colonial adjusts the PLA charges; (2) allowed Colonial to manage the PLA charges with insufficient transparency or accountability to Colonial's shippers and the Commission; and (3) assigned different charges for short- and long-haul movements without sufficient justification as to why.[16] However, the Commission reversed the Initial Decision finding that a cent-per-barrel charge with a tracker and annual true up would be a just and reasonable way to administer the PLA mechanism.[17] The Commission also found that it was reasonable for Colonial not to assess a PLA charge on intrastate deliveries.[18] Further, the Commission found that reparations for shippers' payment of Colonial's PLA charge was not warranted under the circumstances.[19] Finally, the Commission directed Colonial to modify its tariff to reflect the approved cents-per-barrel PLA charge approved in the Order provide annual explanations for Colonial's assessment of PLA charges.[20]

As for the Initial Decision's treatment of Colonial's MBRs, the Commission affirmed the Initial Decision's determination that Colonial should retain market-based rate authority in the Gulf Coast origin market, but reversed the Initial Decision on the finding that Colonial's market-based rate authority in the Alabama origin market should be revoked.[21] In reaching this conclusion concerning the Gulf Coast market, the Commission (1) rejected Colonial's argument that shippers must

12. *Id.* at P 18.
13. 181 FERC ¶ 61,208, at PP 19, 20.
14. *Epsilon Trading, LLC*, 185 FERC ¶ 61,125 (2023).
15. *Id.*at P 16.
16. *Id*. at PP 23-26.
17. *Id.* at PP 42-51.
18. 185 FERC ¶ 61,125, at P 55.
19. *Id.* at PP 63-67.
20. *Id.* at P 67.
21. *Id.* at P 73.

show changed circumstances to warrant revocation of MBRs;[22] (2) affirmed the Initial Decisions findings on geographic markets;[23] (3) largely affirmed the initial decision on competitive alternatives[24] but reversed the Initial Decision's rejections of waterborne shipments as competitive alternatives;[25] and (4) affirmed the Initial Decision on finding that Colonial lacks market power in the Gulf Coast origin market.[26]

In the Alabama origin market, the Commission reversed the Initial Decision and found that Colonial lacked market power in that market. In doing so, the Commission found that (1) the decision was a close call that required evaluation of secondary competitive factors;[27] (2) Colonial's pro-competitive factors were unpersuasive;[28] and (3) Trial Staff's anti-competitive factors were unpersuasive.[29] Since there were no persuasive pro- or anti-competitive factors, the Commission found that Trial Staff failed to carry its burden of proof, given that Colonial's Herfindahl-Hirschman Index ("HHI") was under 2,500 and its market share was below 50%.[30] Therefore, the Commission reversed the Initial Decisions revocation of Colonial's MBR authority in the Alabama origin market.

C. Epsilon Trading, LLC v. Colonial Pipeline Co., 185 FERC ¶ 61,126 (2023).

On November 16, 2023, the Commission issued part 2 of a 2-part Order addressing the complaints filed by numerous parties against Colonial challenging Colonial's COS rates, MBRs, and PLA. The second part of the Order concerned the Initial Decision's rulings on Colonial's COS rates. The Commission affirmed in part and reversed in part.

The Commission affirmed the Initial Decision's finding that the test period should be measured on actual volumes on Colonial's pipeline system from October 1, 2017, through September 30, 2018, and the Initial Decision's rejection of an adjustment to the test period throughput volumes.[31] The Commission affirmed the Initial Decision's return on equity (ROE) and proxy group findings, but it modified the capital structure proxy group by adding Enbridge and Phillips 66 (P66) to that group, producing a capital structure of 53.45% debt and 46.55% equity for the proceedings.[32]

In terms of carrier property, the Commission affirmed the Initial Decision's determination that Colonial is entitled to recover deferred earnings in its cost of service, but the Commission reversed the Initial Decision's holding regarding the

22. 185 FERC ¶ 61,125, at P 78.
23. *Id.* at PP 92-93.
24. *Id.* at PP 113, 117-29.
25. *Id*. at P 115.
26. 185 FERC ¶ 61,125, at P 133.
27. *Id.* at P 140.
28. *Id.* at PP 141-43.
29. *Id.* at P 144.
30. 185 FERC ¶ 61,125 at P 145.
31. *Epsilon Trading, LLC*, 185 FERC ¶ 61,126 at PP 64-67 (2023).
32. *Id.* at PP 69-72, 140-42.

appropriate methodology for calculating the amortization rate.[33] Instead, the Commission found that Colonial should use the composite depreciation method, which divides depreciation expense by gross plant in service.[34] The Commission reversed "the Initial Decision's holding that Colonial should derive the amortization rate for deferred earnings based upon the remaining useful life method, as advocated by Trial Staff . . .[and the Commission found] that Colonial should use the composite depreciation method, as advocated by Colonial."[35]

In terms of cost of capital, the Commission affirmed the Initial Decision on (1) Colonial's parent company capital structure;[36] and (2) the use of Colonial's expert's proxy group and ROE calculations.[37] However, the Commission modified the Initial Decision by adopting "a 2017 calendar year capital structure of 51.18% debt and 48.82% equity in this proceeding based on a proxy group of Buckeye, Enterprise, Magellan, and Enbridge, as proposed by Citgo witness Mr. Ashton."[38] The Commission agreed with the Initial Decision that it was "appropriate to impute a debt-to-equity ratio from a proxy group analysis, . . . [and the Commission also affirmed] the Initial Decision's rejection of Colonial's proposed capital structure proxy group."[39] The Commission also affirmed "the inclusion of Enbridge in the base period capital structure proxy group."[40]

On the issue of Accumulated Deferred Income Tax (ADIT) and excess ADIT (EDIT), the Commission modified the Initial Decision and found "that (1) [ ]ADIT and EDIT balances should be calculated based on Colonial's approach using vintages and carrier property groups, subject to certain modifications; and (2) Colonial should have begun amortization of the pre-1974 unfunded ADIT balance in 1974."[41] The Commission modified the Initial Decision and adopted "Colonial's methodology based upon specific carrier property groups and vintages for determining ADIT and EDIT balances."[42] The Commission also modified the Initial Decision and found "that Colonial should have begun amortization of the pre-1974 unfunded ADIT balance in 1974."[43]

On Accumulated Funds Used During Construction (AFUDC) and AFUDC amortization, the Commission reversed: "the Initial Decision and f[ound] that Colonial should amortize AFUDC using the composite depreciation method."[44] On accrued depreciation, the Commission affirmed the Initial Decision and found

33. *Id.* at P 155.
34. *Id.*
35. 185 FERC ¶ 61,126, at P 160.
36. *Id.* at P 173.
37. *Id.* at PP 177-78.
38. *Id.* at P 179.
39. 185 FERC ¶ 61,126, at P 184.
40. *Id.* at P 187.
41. *Id.* at P 201.
42. *Id.* at P 202.
43. 185 FERC ¶ 61,126, at P 204.
44. *Id.* at PP 219-22.

"that Trial Staff's derivation of the accumulated depreciation balance of $1.57 billion" was "reasonable after adjustment for the corrections required to conform with" their "findings related to ADIT."[45] The Commission also affirmed the Initial Decision on the issue of depreciation of carrier property, finding "that Colonial's existing depreciation rates, using a thirty-year remaining economic life, are just and reasonable," and "Colonial's existing depreciation rates are supported by the record."[46] On Dismantlement, Removal and Restoration ("DR&R") costs, the Commission affirmed "the Initial Decision's finding that Colonial failed to adequately support its proposed DR&R costs."[47]

In terms of operating expenses, the Commission adopted "Trial Staff's proposal to exclude the costs for the CR-91 and CR-251 incidents and normalize the remaining costs over the three-year period 2015 to 2017."[48] The Commission found "that Trial Staff witness' [] analysis appropriately compared the magnitude and costs of Colonial's incidents over a historical period as well as analyzed other factors bearing on whether the incidents were extraordinary and non-recurring."[49] However, the Commission declined "to adopt the Initial Decision's alternative recommendations to exclude all incident response costs over a threshold of $1 million."[50]

The Commission affirmed "the Initial Decision's finding that Colonial's surcharge for litigation expenses in this proceeding should be offset by unpaid reparations to non-complaining shippers, consistent with Commission policy that has been affirmed by the D.C. Circuit."[51] The Commission affirmed "the Initial Decision's use of annualized 2018 legal expenses from the first nine months of 2018."[52] However, the Commission agreed with Joint Shippers that certain expenses should be removed.[53]

In terms of system integrity program management costs, the Commission found that the "Initial Decision errored in finding that mitigation and remediation SIPM costs should be capitalized."[54] Instead, the Commission found "these costs should be expensed."[55] The Commission affirmed "the Initial Decision's holding that normalized the SIPM costs from January 1, 2015, through September 30, 2018."[56] "Because participants agreed to remove Line 25 from carrier property and accrued depreciation during the test period," the Commission found "that the operating expenses associated with Line 25 should be removed from test period

45. *Id.* at P 227.
46. *Id.* at PP 233-34.
47. 185 FERC ¶ 61,126, at P 244.
48. *Id.* at P 258.
49. *Id.* at P 259.
50. *Id.* at P 264.
51. 185 FERC ¶ 61,126, at P 273.
52. *Id.* at P 280.
53. *Id.*
54. *Id.* at P 286.
55. 185 FERC ¶ 61,126, at P 286.
56. *Id.* at P 294.

for cost of service."[57] However, the Commission reversed the Initial Decision and found that it was "not appropriate to impute potential property tax refunds to Colonial's FERC Account No. 580 test year balance in the cost of service."[58]

As to cost allocation, the Commission reversed "the Initial Decision and adopted the Trial Staff's method for allocating costs related to merchant storage, blending, PTO and the Alliance lease,"[59] but the Commission affirmed "the Initial Decision's determination regarding the Nashville lease."[60] Finally, the Commission declined "to adopt the Initial Decision's recommendation that Colonial make a limited one-time filing with updated costs, revenues, and going-forward cost allocations for all activities under Accounts 250 and 260, no sooner than thirty-six months from the Commission's final order."[61]

D. Colonial Pipeline Co., 185 FERC ¶ 61,209 (2023).

On April 21, 2023, Colonial filed FERC Tariff No. 98.58.0, which cancelled FERC Tariff No. 98.57.0 (Tariff). The Tariff contained changes to Colonial's procedures regarding product testing and specifications as well as related scheduling procedures. Colonial's Tariff revised Items 10(a) of the Tariff to (1) discontinue the process of testing all product tendered to its system, instead retaining discretion whether to test or rely on certification from shippers; and (2) declare that Colonial's product testing regime will always control over testing conducted by shippers.[62] Colonial's Tariff revised Item 10(b) to require (1) shippers to submit Certificates of Analysis assessing whether petroleum products tendered for shipment on Colonial meet the Tariff's quality standards; and (2) shippers to bear all liability for damaged caused to Colonial by off-specification jet fuel if that fuel can be linked to a particular shipper.[63] Additionally, "Colonial proposed to revise Item 25(d) of the Tariff to require product to be in tankage at the origin station within at least eight hours prior to scheduled lifting."[64] Colonial's Tariff revisions were protested by ExxonMobil Oil Corporation ("EMOC"), Castleton Commodities Merchant Trading L.P. (CCMT), Airlines for America, American Airlines, Inc., Epsilon Trading, LLC, Southwest Airlines Co., United Aviation Fuels Corporation, and United Parcel Service, Inc. (collectively, the Airlines), and P66 (entire group collectively, the Protestants).[65]

The Protestants challenged Colonial's revisions of Item 10(a) as inconsistent with industry standards and sought the Commission to require Colonial to utilize ASTM D3244, which requires that a third-party lab be selected to conduct additional testing in the event of conflicting test results between the shipper and the

57. *Id.* at P 300.
58. *Id.* at P 306.
59. 185 FERC ¶ 61,126, at P 307.
60. *Id.* at P 307.
61. *Id.* at P 360.
62. *Colonial Pipeline Company*, 185 FERC ¶ 61,209 at PP 6-7 (2023).
63. *Id.* at P 19.
64. *Id.* at P 38.
65. *Id.* at P 3.

pipeline.[66] Colonial countered that using this standard would be impractical and time-consuming.[67] The Airlines challenged Colonial's revisions to Item 10(b) claiming changes were unsupported by data, allowed Colonial to indemnify itself for flawed testing results, that holding shippers liable where they did not directly tender product to the pipeline was unjust and unreasonable, and that liability shifting violates section 20(11) of the ICA.[68] Additionally, CCMT argued that the provision was vague and should be revised to include a reference to Item 25(d), which concerns Colonial's tariff waiver requirements.[69] Colonial argued that shippers who control the product tendered are in the best position to ensure that off-specification product is not delivered to the pipeline and that allowing Colonial to recover for damages related to the delivery of off-specification product is reasonable.[70] Finally, Protestants argued that Colonial's revisions to Item 25(d) are unsupported and too strict to be commercially feasible, urging FERC to limit the provision to a "best commercial efforts basis."[71] Colonial argued that the requirement was reasonable and in the best interest of shippers.[72]

Ultimately, the Commission largely rejected the protestants' arguments. However, the Commission ordered that Colonial make a number of changes to its tariff, including: (1) adding that Colonial "will only use certified laboratories to Item 10(a);" (2) "remove the proposed "or granted an exemption" language from Item 10(b);" (3) made "the proposed additions to Item 25(d) as described in Colonial's Initial Comments, along with clarifying that requests for exemptions under Item 10(b) will be evaluated according to the waiver criteria listed in Item 25(d)."[73] Colonial was ordered to submit a compliance filing within 21 days of order, which it did submit.

E. Bayou Bridge Pipeline LLC, 185 FERC ¶ 61,229 (2023).

On December 28, 2023, the FERC suspended for the full seven-month period allowed under the ICA[74] and set for paper hearing, tariff proposals by eight affiliated common carrier pipelines[75] to establish identical Nomination Shortfall

66. 185 FERC ¶ 61,209, at PP 10-11.

67. *Id.* at P 14.

68. *Id.* at PP 21-24.

69. *Id.* at P 26.

70. 185 FERC ¶ 61,209, at PP 27-29.

71. *Id.* at P 40.

72. *Id.* at PP 41-43.

73. *Id.* at P 48.

74. 49 U.S.C. app. §15(7)*; see also Buckeye Pipe Line Co.,* 13 FERC ¶ 61,267, at pp. 61,595-96 (1980) (FERC has long held that, as a general rule, a one-day suspension is appropriate in common carrier rate increase tariff filings under the ICA. However, in the same order, FERC stated: "It is conceivable that there will now and then be a situation in which there is good reason to believe that: (1) The particular unadjudicated oil pipeline rate increase there involved may have significant anticompetitive effects or impose undue hardship on a shipper or a group of shippers. (2) A suspension for the maximum period permitted by the Interstate Commerce Act might well have sufficient mitigative effect to render such a suspension worthy of consideration.").

75. *Bayou Bridge Pipeline LLC*, 185 FERC ¶ 61,229 at P 2 (2023).

Charges.[76] In order to address alleged adverse impacts of over-nominations and under-deliveries by shippers, the carriers proposed tariff records that would permit them to charge a shipper that tenders a volume of product that is less than its binding nomination,[77] a Nomination Shortfall Charge equal to "the positive difference between the shipper's binding nomination for a transportation month and the actual volumes delivered out to a shipper in that month, multiplied by" the applicable rate.[78] The carriers contend that over-nominations and under-deliveries (1) result in potential disruption of system flow rates and unexpected delivery delays for shippers, (2) "limit the capacity available to other shippers and may put a pipeline into allocation unnecessarily, stranding capacity that would have been available to other shippers and resulting in inefficient use of the system", and (3) limit the carriers' "ability to schedule supplemental nominations" (i.e., requests for additional capacity after the nomination deadline).[79]

Several shippers of crude oil on the pipelines protested the tariff changes, arguing that the proposed Nomination Shortfall Charge is unsupported by specific data to establish that the proposed revisions are necessary and that the charge would address the alleged impact of over-nominations rather than merely provide additional revenue to the carriers.[80] Further, protestors contend that the proposed Nomination Shortfall Charge improperly applies when the pipeline is under-utilized or in *force majeure* situations and fails to include a tolerance or threshold mismatch between nominations and deliveries.[81] One shipper proposed that the FERC require the carriers to credit any revenues to non-offending shippers to avoid the pipelines receiving enhanced revenues in excess of their cost of service.[82]

FERC found that the tariff filings "raise issues of material fact that cannot be resolved based on the record" and established a paper hearing providing for additional comments and reply comments on all issues.[83]

II. MARKET BASED RATES

A. *West Texas Gulf Pipe Line Co., 184 FERC ¶ 61,128 (2023).*

On April 30, 2019, West Texas Gulf Pipe Line Company LLC (WTG) filed an application for authorization to charge market-based rates for the interstate "transportation of crude oil from the Permian Basin production region to the Gulf Coast and East Texas region surrounding Tyler, Texas."[84] Husky Marketing and

76. *Id.*

77. *Id.* at P 3 ("Under the proposed tariff language, a binding nomination is any timely initial nomination submitted by a shipper and accepted by the carrier plus any incremental nomination submitted by a shipper after the initial nomination due date and accepted by the carrier.").

78. *Id.*

79. 185 FERC ¶ 61,229, at P 4.

80. *Id.* at P 7.

81. *Id.* at P 8.

82. *Id*. at P 9.

83. 185 FERC ¶ 61,229, at PP 17-18.

84. *West Texas Gulf Pipe Line Company*, 184 FERC ¶ 61,182 at P 4 (2023).

Supply Company and BP Products North America Inc. (collectively, Joint Protestants) protested WTG's application. The FERC issued an order finding that WTG lacked market power in the origin markets and setting for hearing whether WTG had market power in the destination markets.[85] On August 16, 2019, Permian Express Partners LLC (Permian and, with WTG, the Applicants) filed for authorization to charge market-based rates from the Permian Basin, Fort Worth Basin and Haynesville production areas to the Gulf Coast and the East Texas region surrounding Tyler, Texas.[86] Permian's application was not protested.[87] The FERC issued an order finding that Permian lacked market power in the origin markets and setting for hearing the issue of whether Permian had market power in the destination markets.[88] Subsequently, the proceedings were consolidated.[89] A hearing was held from June 15 to July 23, 2021, and the Administrative Law Judge issued an Initial Decision[90] on March 18, 2022.[91] The Initial Decision found that (1) the product market should be defined as the "transportation of all grades of crude oil;" (2) the geographic destination markets are the Tyler Market, the Nederland, Texas Market and the Anchorage, Louisiana Market; (3) the HHI calculations using the FERC's trial staff's (Trial Staff) method for the Tyler market demonstrate that the "Tyler Market is highly concentrated and susceptible to the exercise of market power;" and (4) "the HHIs for the Nederland and Anchorage Markets show that Applicants are unable to exercise market power" and that Applicants should be granted market based rate authority for those markets.[92] Applicants and Joint Protestants filed briefs on exceptions to the Initial Decision.[93]

Applicants argued that the Initial Decision's decision to limit the product market to the transportation of crude oil could exclude local production in the destination market; the Commission, however, affirmed that the transportation of crude oil is the appropriate product market but clarified it has incorporated the "appropriate local production" into its defined product market and subsequent market analysis.[94] Joint Protestants challenged the Initial Decision's decision to define the Tyler Market to include the Tyler Refinery plus counties within a 100-mile radius of the Tyler Refinery and argued that the Tyler Market should be limited solely to the refinery, or alternatively, that the Commission should treat the Tyler Market as an intermediate market because most shipments to Tyler travel to downstream markets.[95]

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85. *Id.* at P 5.
86. *Id.* at P 6.
87. *Id.*
88. 184 FERC ¶ 61,182, at P 7.
89. *Id.* at P 8.
90. *West Texas Gulf Pipe Line Company*, 178 FERC ¶ 63,020 (2022).
91. 184 FERC ¶ 61,182, at P 8.
92. *Id*.
93. *Id*. at P 9.
94. *Id*. at PP 15, 17.
95. 184 FERC ¶ 61,182, at P 21.

The Commission held that it was reasonable to include counties within a 100-mile radius, which represented a reasonable trucking distance for shippers to the Tyler Refinery.[96] The Commission also ruled that Joint Protestants did not adequately support their alternative proposal to use downstream markets.[97] With respect to competitive alternatives in the Tyler Market, the Initial Decision found that one oil pipeline and local crude oil production serve as competitive alternatives and ruled that Applicants failed to show that potential new entrants are competitive alternatives.[98] Applicants challenged the exclusion of potential new entrants, but the Commission held that Applicants failed to meet their burden to support including potential new entrants.[99] Among other concerns, the Commission concluded that Applicants' analyses may have failed to account for barriers to entry into the market, were affected by Applicants' selection of the incorrect marginal supplier, and were based on subjective assumptions that improperly inflated the profitability of capital investments new entrants would need to make to enter the market.[100]

The Commission used the effective capacity method to measure market power for the Tyler Market, which produced an HHI figure of 2,870, which led the Commission to conclude that the Tyler Market is highly concentrated because it exceeds the 2,500 HHI threshold that the Commission has historically applied to determine whether a market is concentrated.[101] In so doing, the Commission rejected Applicants' proposal to deduct local production from market consumption to calculate the HHI.[102] In addition, the Commission declined to include local production outside the 100-mile radius of the Tyler Market in market statistics, finding that Applicants' proposal to include such production was an untimely proposal to expand the Tyler Market.[103]

The Commission affirmed the Initial Decision's findings that the Applicants do not have market power in the Nederland and Anchorage Markets.[104] Applicants did not oppose those findings but objected to the Initial Decision's decision to limit those markets to a 100-mile radius of each delivery point.[105] The Commission, however, concluded that, since the market statistics show that Applicants do not have market power within the markets as defined, it was not necessary to evaluate a broader Gulf Coast destination market.[106]

96. *Id*. at P 25.
97. *Id*. at P 28.
98. *Id*. at PP 29-30.
99. 184 FERC ¶ 61,182, at PP 32, 35.
100. *Id*. at PP 42-44.
101. *Id*. at PP 58-59.
102. *Id*. at P 64.
103. 184 FERC ¶ 61,182, at P 68.
104. *Id*. at P 72.
105. *Id*. at PP 73-74.
106. *Id*. at P 79.

III. QUALITY BANK

A. BP Pipelines (Alaska) Inc., 185 FERC ¶ 61,206 (2023) (OR14-6-003).

This Order[107] addresses exceptions to an Initial Decision[108] that considered and rejected claims brought by Petro Star Inc. (Petro Star) that the Trans Alaska Pipeline System (TAPS) Quality Bank undervalues Resid, which is the heaviest of nine Quality Bank components that the Quality Bank values. The FERC affirmed the Initial Decision on most issues, but reversed the Initial Decision's conclusion that the Quality Bank tariffs did not require the administrator of the Quality Bank (QBA) to update certain Resid properties that are used to value Resid.[109]

TAPS transports crude petroleum that it receives from different production fields in a common stream. The Quality Bank compensates TAPS shippers for the differences in quality of the crude petroleum they tender to TAPS compared to the quality of the crude petroleum that shippers receive on redelivery.[110] The Quality Bank uses a distillation methodology to value each crude petroleum stream tendered to TAPS.[111] Each month a laboratory performs distillation assays on each stream to divide it into nine components to which the Quality Bank then assigns values.[112]

Market prices are not posted for Resid, so the Quality Bank derives a price for Resid based on the products produced by coking Resid, multiplied by the market value for each of those products, minus a cost deduction to reflect the cost of coking.[113] The cost deduction includes a 20% capital recovery factor to account for the capital investment that would be required to build a hypothetical coker capable of processing Resid.[114]

The FERC first addressed Petro Star's argument that the Initial Decision erred in rejecting Petro Star's "Anomaly Theory," which Petro Star claimed shows that the method for valuing Resid is flawed because, in some months, the market price for Alaskan crude petroleum is greater than the value the Quality Bank establishes for that crude petroleum at the post-distillation stage.[115] The FERC rejected this argument for several reasons, including that the anomaly disappears when evaluated over the long term,[116] and the anomaly could be attributable to factors other than the value the Quality Bank determines for Resid.[117]

Petro Star argued that the Initial Decision erred by rejecting Petro Star's argument that the product yields the Quality Bank assumes are obtained from coking

107. Opinion No. 588*, BP Pipelines (Alaska) Inc.,* 185 FERC ¶ 61,206 (2023).
108. *BP Pipelines (Alaska) Inc.*, 179 FERC ¶ 63,013 (2022).
109. 185 FERC ¶ 61,206, at P 2.
110. *Id.* at P 5.
111. *Id.* at P 6.
112. *Id.*
113. 185 FERC ¶ 61,206, at P 9.
114. *Id.* at P 12.
115. *Id.* at PP 21, 25-27.
116. *Id.* at P 32.
117. 185 FERC ¶ 61,206, at PP 33-36.

Resid are too low and should be based on average yields from a coker built in the year 2000, which Petro Star claimed is when the Quality Bank's hypothetical coker would have been constructed.[118] The FERC rejected this argument; the FERC declined to assume that TAPS shippers always use cokers from the year 2000 or later and found that "the proper measure for the products produced from coking Resid should be those from the typical, not the newest or most productive, cokers."[119] The FERC found that the coker yields Petro Star proposed were not based on the operating conditions of a typical West Coast coker[120] and that the current Quality Bank coker yields are consistent with yields from a typical West Coast coker.[121]

The FERC reversed the Initial Decision's conclusion that the QBA was not required to update the Quality Bank tariffs to reflect the results of tests the QBA took of Resid properties that are used to value Resid.[122] The FERC recognized that the Quality Bank tariffs gave the QBA discretion to determine whether to retest the Resid properties.[123] However, the FERC held, if the QBA tested those properties and the test results were valid, the Quality Bank tariffs required that the new Resid properties be used.[124] By failing to do so, the QBA failed to comply with the Quality Bank tariffs.[125] FERC ordered the owners of TAPS to revise the Quality Bank tariffs to require the QBA to test the Resid properties monthly and to update the Resid properties annually to reflect the averages of the monthly tests.[126]

Petro Star argued that the Initial Decision erred by rejecting Petro Star's claim that an adjustment to the value of coker products yields for the costs of transporting and handling coke should be eliminated, since the values of other eight Quality Bank components are not adjusted for the cost of transportation.[127] FERC rejected this argument, finding that the record supports the conclusion that the costs for transporting and handling coke are much higher than the costs for the other components.[128]

Petro Star argued that the Initial Decision incorrectly upheld the application of an index, the Nelson-Farrar Index for changes in refinery operating costs (NFOCI), which tracks changes in refinery operating costs, to the coker cost deduction.[129] FERC rejected Petro Star's arguments and concluded that the NFOCI should continue to apply to the coker cost deduction.[130]

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118. *Id.* at P 45.
119. *Id.* at P 53.
120. *Id.* at P 55.
121. 185 FERC ¶ 61,206, at P 54.
122. *Id.* at P 72.
123. *Id.* at P 76.
124. *Id.*
125. 185 FERC ¶ 61,206, at P 71.
126. *Id.* at P 82.
127. *Id.* at P 86.
128. *Id.* at P 91.
129. 185 FERC ¶ 61,206, at P 94.
130. *Id.* at PP 103, 113.

Petro Star argued that the 20% capital recovery factor, which is a component of the coker cost deduction, should be eliminated, or greatly reduced, for several reasons, including that 20% is excessive when compared to average equity returns for refiners.[131] FERC rejected Petrol Star's arguments.[132] Among other things, FERC found that the 20% capital recovery factor "appears to remain a reasonable (or even slightly low) approximation of the capital costs and return requirements of a West Coast coker."[133]

The FERC upheld the Initial Decision's conclusion that Petro Star is not entitled to retroactive relief for the QBA's failure to comply with the QB tariff[134] because (1) Petro Star represented that it was not asking FERC to order damages,[135] and (2) the FERC cannot order damages in this proceeding because FERC initiated the proceeding pursuant to section 13(2) of the ICA,[136] which does not allow FERC to award damages.[137]

IV. PIPELINE SAFETY

A. PHMSA Holds Gas Advisory Committee Meeting on Proposed Requirements for Leak Detection and Repair Criteria.

On May 18, 2023, PHMSA issued a Notice of Proposed Rulemaking (NPRM) that sought to amend the federal pipeline safety regulations for new and existing gas transmission pipelines, distribution pipelines, regulated (Types A, B, C, and offshore) gas gathering pipelines, underground natural gas storage facilities, and liquefied natural gas (LNG) facilities.[138] Among the proposed amendments for gas pipelines subject to the regulations contained in 49 C.F.R. Part 192 (2023) are more frequent leakage survey and patrolling requirements; performance standards for advanced leak detection programs; leak grading and repair criteria with mandatory repair timelines; requirements for mitigation of emissions from blowdowns; pressure relief device design, configuration, and maintenance requirements; and clarified requirements for investigating failures. Finally, PHMSA proposed expanded reporting requirements for operators of all gas pipeline facilities within the Department of Transportation's jurisdiction, including underground natural gas storage facilities and LNG facilities. The NPRM responded to congressional mandates in the Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2020.[139]

131. *Id.* at PP 115-16.

132. *Id.* at P 140.

133. 185 FERC ¶ 61,206, at P 141.

134. *Id.* at P 191.

135. *Id.*

136. *Id.* at P 192.

137. 185 FERC ¶ 61,206, at P 192.

138. Notice of Proposed Rulemaking, *Pipeline Safety: Gas Pipeline Leak Detection and Repair*, 88 Fed. Reg. 31,890 (2023).

139. *Id.*

From November 27 through December 1, 2023, PHMSA held its statutorily mandated public meeting of the Gas Advisory Committee (GPAC), which is made up of five representatives each from industry, the public, and the government.[140] During the meetings, the GPAC and the public had the opportunity to discuss the proposed regulations contained in the NPRM and to make nonbinding recommendations to PHMSA for what should be included in the final rule. PHMSA scheduled additional meetings to complete review of the NPRM during the final week of March 2024. The following topics were discussed and voted on during the GPAC meetings.

1. Operations and Maintenance and Venting

One of the proposed regulatory changes from the NPRM is a requirement for operators to minimize emissions from gas transmission pipeline blowdowns. In response to the proposal, the GPAC voted to recommend that PHMSA create an exception to the blowdown requirement for non-emergency blowdowns with a *de minimus* volume release, including during the following activities: blowdowns of launchers and receivers that may not be within the confines of a compressor station; blowdowns from work on measurement and regulation stations; blowdowns from maintenance work on compressor units and associated equipment including relief systems and filter separators; blowdowns to conduct an immediate anomaly repair and excavation; and emergency shutdown testing as relevant.

The GPAC further recommended that PHMSA create another exception for when a blowdown would result in a significant negative impact to customers, and to limit sole use of flaring when other options are impractical, unsafe, or result in lower emissions abatement.

Regarding the proposed requirements for repairing pressure relief devices, the GPAC voted to recommend that PHMSA clarify in the final rule that the repair timeline is thirty days unless that timeline is impracticable, in which case the repair should be completed as soon as practicable (beyond the thirty days).

2. Leak Surveys and Patrols

The second topic of discussion related to patrolling and leakage surveys of transmission lines. The GPAC voted to recommend that PHMSA revise the patrol frequency from the proposed twelve times each calendar year at intervals not to exceed forty-five days to six times/year at intervals not to exceed seventy-five days for Class 3 and 4 locations, and four times per year in Class 1 and 2 locations. In addition, the GPAC supported the proposal, as written in the NPRM, to require operators to perform periodic leakage surveys pursuant to an advanced leak detection program required by 49 C.F.R. § 192.763, except that operators should be permitted to rely on human or animal senses in lieu of equipment for offshore transmission or gathering lines below the waterline, or in Class 1 or 2 locations with advance notice to, and no objection from,- PHMSA.

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140. *Pipeline Safety: Meeting of the Gas Pipeline Advisory Committee*, 88 Fed. Reg. 64,518 (2023); PHMSA, *Technical Pipeline Safety Standards Committee (GPCA)*, https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=167 (last visited Apr. 3, 2024).

Regarding the frequency of leak surveys on odorized lines, GPAC recommended that PHMSA alter the proposal from the NPRM to the following schedule:

- Outside of a high consequence area (HCA): one time per calendar year with intervals not to exceed 15 months;
- Class 1, 2, and 3: two times per calendar year with intervals not to exceed 7.5 months;
- Class 4: at least four times per calendar year with intervals not to exceed 4.5 months;

For non-odorized lines, GPAC recommended the following leakage survey schedule:

- Class 3: two times per calendar year, at intervals not exceeding 7.5 months;
- Class 4: four times per calendar year with intervals not to exceed 4.5 months;

Valves, flanges, and certain other facilities:

- Class 1, 2, and 3: two times each calendar year, at intervals not exceeding 7.5 months;
- Class 4: four times each calendar year, at intervals not exceeding 4.5 months.

For Distribution Systems, GPAC recommended the following leakage survey schedule:

- Three-year external leak survey interval is required with consideration for the opportunity to use leak data from DIMP (distribution integrity management program) to extend the interval up to five years with appropriate agency approval. When considering approval, the appropriate agency will evaluate whether a five-year interval would provide an equivalent or greater level of safety and environmental protection; and
- PHMSA should consider an alternative interval frequency for indoor piping.

3. Advanced Leak Detection Program Elements and Performance Standards

The GPAC voted to recommend that PHMSA include in the final rule the following thresholds for the advanced leak detection program requirements proposed in the NPRM:

- Pipelines – Screening Standard:
    - 10 kg/hr flow rate standard for screening surveys; follow-up investigation of leak indications with handheld equipment (5 ppm, 5 ppm-m, or 1% LEL) to pinpoint the source of the leak; or leakage survey with handheld or mobile equipment (5 ppm, or ppm-m);
    - Recommend Probability of Detection standard for all flow-rate based advanced leak detection technology of 90%; and

    - Aboveground appurtenances: allow for use of Optical Gas Imaging (consistent with EPA).
- Pipelines — Performance Standard:
    - 0.5 kg/hour screening survey and follow-up investigation of leak indications with handheld equipment (5 ppm, 5 ppm-m, or 1% LEL), or leakage survey with handheld or mobile equipment (5 ppm or 5 ppm-m);
    - PHMSA should consider an alternative standard for inside piping;
    - Recommend Probability of Detection standard for all flow-rate based advanced leak detection technology of 90%; and
    - Recommend requiring operator to conduct evaluation of the Advanced Leak Detection Program every three years (instead of the one year proposed in the NPRM).

4. Leak Grading and Repair

GPAC voted to recommend that PHMSA modify the proposals in the NPRM regarding how an operator grades, and thus respond to and repair leaks of different grades (severity), as follows:

Grade 1 Leak Criteria:

- Leaks equal to or greater than 100 kg/hr.

Grade 2 Leak Criteria:

- *Distribution Lines*:
    - Ten standard cubic feet per hour (scfh) and leak extent criteria; or
    - The leak is of sufficient magnitude to pose significant harm to the environment, considering one of the following characteristics:
    - estimated leakage rate of ten scfh or more as indicated by suitable technology; or
    - For below-grade and subsurface leaks, estimated leak extent (land area affected by gas migration) of 2,000 square feet or greater; or
    - an alternative method demonstrated to meet the capability of identifying a minimum leakage rate of ten scfh consistent with Method A with a notification to PHMSA in accordance with 49 C.F.R. § 192.18.
- *Transmission and Gathering*:

    Modifying Grade 2 leak requirements to include:

    - Any reading of gas that does not qualify as a Grade 1 leak that occurs in the pipe body of a transmission pipeline or a regulated gas gathering line operating at high stress (greater than 30% specified minimum yield strength); or

  - A transmission pipeline or regulated gas gathering line leak measured to be greater than an appropriate volume threshold for a transmission or regulated gathering line [such as 5-10 kg/hr].

The GPAC also recommended that PHMSA require in the final rule that repairs for Grade 2 leaks be made as soon as practicable considering impacts to customers and environmental concerns, but not to exceed one year (as opposed to the NPRM proposal of six months from date of detection), and reevaluation of the repair to every six months instead of thirty days.

The GPAC also recommended that PHMSA include an exception for distribution pipelines scheduled for replacement and replaced within two years, and that the final rule should allow for a risk-based approach for the repair of Grade 2 leaks following environmental changes that affect gas migration (e.g., freezing ground, heavy rain, flooding, or other changes).

Grade 3 Leak Criteria:

- Revise general repair timeline from twenty-four months to thirty-six months;
- HCA and Class 3+4 gas transmission lines: one year;
- Repair is required for Grade 3 gas distribution pipelines with an emissions rate greater than or equal to five scfh, or a leak extent method equivalent to five scfh, or an alternative method demonstrated to meet the capability of identifying a minimum leakage rate of five scfh with a notification to PHMSA in accordance with 49 C.F.R. § 192.18;
- Repair is required within thirty-six months, unless the pipeline is scheduled for replacement and replaced within seven years. All other Grade 3 leaks are to be re-evaluated at a one-year reinspection interval. PHMSA would evaluate where a leak extent method would be appropriate and equivalent; and
- PHMSA should consider a prioritization process for elimination of Grade 3 leaks.

- *Distribution Systems General Exceptions*

PHMSA should provide exceptions to the proposed repair schedule for:

  - Any leak that is eliminated by routine maintenance work—such as adjustment or lubrication of aboveground valves, or tightening of packing nuts on valves with seal leaks;
  - Grade 3 leaks;
  - Leaks on an aboveground pipeline facility;
  - Repairs for excavation damages;
  - Remediation of leak involving pipeline replacement or where the pipeline was abandoned; and
  - To the applicability of post repair rechecks to all subsurface leaks on a gas distribution pipeline repaired, other than by the replacement or abandonment of the affected section of

> pipe, must be reevaluated after allowing the soil to vent and stabilize but not more than thirty calendar days after the repair, unless a 0% gas reading was taken at the time the repair was complete.

PHMSA discussed the remaining topics of the NPRM at the March 2024 GPAC meetings. Those topics include the applicability of the leak detection and repair proposed regulations to gas gathering pipelines, the reporting requirements, the proposed regulations specific to LNG and hydrogen facilities, the compliance deadlines set forth in the NPRM, and the operator qualification proposals. While PHMSA is not required to accept the recommendations from the GPAC, they hold persuasive value and if the final rule departs from the GPAC recommendations, PHMSA must justify the reason(s) for doing so in the preamble of the final rule. There is no expected date for PHMSA to issue a final rule on this NPRM, and it is likely to take several months after the GPAC concludes before PHMSA provides an update on the anticipated timeline.

B. Class Location Change Requirements

On October 14, 2020, PHMSA published an NPRM seeking to amend the requirements for gas transmission pipeline segments that experience a change in class location.[141] Under the existing regulations, pipeline segments located in areas where the population density has significantly increased must perform one of the following actions: Reduce the pressure of the pipeline segment, pressure test the pipeline segment to higher standards, or replace the pipeline segment. This proposed rule would add an alternative set of requirements operators could use, based on implementing integrity management principles and pipe eligibility criteria, to manage certain pipeline segments where the class location has changed from a Class 1 location to a Class 3 location.

PHMSA held a GPAC meeting on this NPRM in March 2024 and will seek to issue a final rule soon thereafter. The issuance of a final rule on updating the class location change requirements has long been pursued by industry and a directive for PHMSA to issue a final rule on this subject in 2024 in included in a congressional draft reauthorization bill that will mandate PHMSA take certain actions, including completing this rulemaking process.

C. PHMSA CO_2 NPRM

PHMSA will publish an NPRM that includes amendments to the Federal Pipeline Safety Regulations that, for the first time, include regulations specific to the transportation of carbon dioxide by pipeline, both in a supercritical and gaseous state. The anticipated timeline for publication of this NPRM is between April and June of 2024.[142]

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141. Notice of Proposed Rulemaking, *Pipeline Safety: Class Location Change Requirements*, 85 Fed. Reg. 65,142 (2020).

142. Paul W. Parfomak, *Siting Challenges for Carbon Dioxide (CO2) Pipelines,* CONG. RSCH. SERVS. 3 (Nov. 30, 2023), https://crsreports.congress.gov/product/pdf/IN/IN12269.