UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

High Island Offshore System, L.L.C. Docket Nos. RP03-221-000
RP03-221-002

ORDER ON INITIAL DECISION AND SETTLEMENT OFFER

(Issued January 24, 2005)

1. This order rejects a proposed settlement of this High Island Offshore System, L.L.C. (HIOS) rate case and reviews the Initial Decision issued on April 22, 2004.[1] The order generally affirms the findings of the Initial Decision, with some modifications, and rejects the settlement offer HIOS filed August 5, 2004. The order benefits the public interest by adopting just and reasonable rates effective on the date of this order, and ordering refunds of excess amounts collected while the proposed rates were in effect.

I. Background

2. HIOS is an interstate pipeline company that operates a three-pronged pipeline in the Gulf of Mexico that delivers gas from the High Island and West Cameron production areas to a point where the three 40-50 mile long segments converge at High Island Block A-264. From this point, HIOS operates a 42 inch mainline that extends northward for 66 miles where it interconnects with other pipelines. HIOS has been in service since 1978.[2]

[1] *High Island Offshore System, L.L.C.*, 107 FERC ¶ 63,019 (2004).

[2] *High Island Offshore System*, 55 FPC 2674 (1976).

3. HIOS has no employees of its own and is fully owned by GulfTerra Energy Partners, L.P. (GulfTerra),[3] a Master Limited Partnership (MLP). GulfTerra is owned ultimately by El Paso Corporation. GulfTerra provides operating services for HIOS through GulfTerra Operating Company, L.L.C., which in turn, is a subsidiary of GulfTerra and uses employees contracted from El Paso Field Services, L.P., which is also ultimately owned by El Paso Corporation, to supply operating services.

4. HIOS currently provides three transportation services to shippers: (1) firm, long haul service under Rate Schedule FT-2; (2) an interruptible long haul service under Rate Schedule IT; and (3) an interruptible short haul service also under Rate Schedule IT. HIOS also has a Rate Schedule FT in its tariff that provides for a traditional firm transportation service, with long and short haul rates, but currently has no customers for this service. HIOS' FT-2 service is available to those shippers with estimated proven recoverable reserves of 40 Bcf and features a one-part, volumetric rate, instead of the two-part rate, with reservation and usage charges, traditionally associated with firm service. If the FT-2 shippers fail to maintain an average daily throughput on HIOS equal to at least 80 percent of their nominated contract volume (Maximum Daily Quantity or MDQ), during a running three month period, then they are subject to billing under two-part rates. HIOS' short haul service only applies to volumes received by HIOS downstream of High Island Block A-264 and is a component of the FT, FT-2, and IT Rate Schedules.

5. On December 31, 2002, HIOS filed revised tariff sheets proposing to increase its rates pursuant to section 4 of the Natural Gas Act (NGA).[4] This was HIOS' first rate filing since 1994. HIOS made this rate filing to comply with the requirement of the 1995 settlement of its last section 4 rate case that HIOS file a general rate proceeding three years from the date of the Commission order approving the settlement.[5] On October 8, 1998, the Commission granted an uncontested motion to extend the date by which HIOS was required to file a new rate case to January 1, 2003.

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[3] GulfTerra is also referred to in some of the exhibits as El Paso Energy Partners. The name was changed to GulfTerra in the summer of 2003, after this matter had been set for hearing. Similarly, GulfTerra Operating Company, L.L.C. changed its name from El Paso Energy Partners Operating Company, L.L.C. on May 15, 2003. Exhibit ALJ-1 provides a flowchart of HIOS' ownership structure and history. *See also* Exh. HIO-75 at 12 describing HIOS ownership history.

[4] *High Island Offshore System, L.L.C.*, 102 FERC ¶ 61,088 (2003).

[5] Settlement Order dated Sept. 18, 1995 in Docket No. RP94-162-003.

6. Before this rate case, HIOS' long-haul volumetric rate under Rate Schedule FT-2, as well as its Rate Schedule IT rate, were 12.44 cents per Dth. The short haul volumetric rate was 4.99 cents per Dth. In this rate case, HIOS proposed to increase the Rate Schedule FT-2 long haul volumetric rate and authorized overrun rate to 16.16 cents per Dth and the IT long haul rate to 17.59 cents per Dth. These proposed rates were based on an overall cost-of-service of $35.6 million. HIOS developed these rates using a test period comprised of actual experience during the twelve-months ending September 30, 2002 (base period), as adjusted for known and measurable changes through June 30, 2003 (adjustment period).[6] HIOS stated that the proposed rates reflected: (1) a reduced rate of depreciation for the HIOS transmission system plant investment; (2) an increased rate of recovery for the negative salvage provision; (3) an increased cost of capital which results in an overall rate of return of 12.45 percent; (4) a management fee of $9.6 million to cover the cost of operating the HIOS system and to provide an incentive for efficient operation; and (5) declining levels of transportation volumes. In addition to the $9.6 million management fee, HIOS requested $5.2 million for federal taxes related to the proposed management fee.

7. HIOS also proposed changes to the way it designs its rates for services provided under Rate Schedules FT-2 and Rate Schedule IT. Currently, FT-2 shippers are billed a volumetric rate equivalent to the 100 percent load factor of the reservation charge, as long as delivered volumes remain at a level between 80 percent and 100 percent of the Maximum Daily Quantity (MDQ) for a rolling three month period. Because FT-2 service requires a dedication of long term supply that is beneficial to the system, HIOS proposed to decrease the FT-2 rate in relation to the FT rate by setting it at a level equal to 95 percent of the FT rate.

8. Currently, the rate charged for services provided under Rate Schedule IT is set at the 100 percent load factor equivalent of the FT rate. HIOS proposed to revise the design of the IT rate so that it is set at a 96.5 percent load factor equivalent of the FT rate. HIOS argued that because of the excess capacity on its system, interruptible service is the equivalent of firm service. HIOS proposes to increase the IT rate in relation to the FT rate to provide incentives for shippers to contract for firm capacity.

9. On January 30, 2003, the Commission accepted and suspended the tariff sheets to be effective July 1, 2003, subject to refund and the outcome of the hearing. Following

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[6] Under Rate Schedule FT, the maximum reservation charge would be $5.1077 per Dth, the commodity charge would be $0.0021 per Dth and the maximum authorized overrun charge would be $0.1759 per Dth. The maximum rate under Rate Schedule IT would be $0.1759.

the hearing, the ALJ issued an Initial Decision on April 22, 2004. The ALJ's decision would result in a rate for long haul service under both Rate Schedules FT-2 and IT of 8.56 cents per Dth. Briefs on exceptions were filed by HIOS, Indicated Shippers and ExxonMobil. Replies to exceptions were filed by HIOS, Indicated Shippers, ExxonMobil and Commission Staff.

10. On August 5, 2004, HIOS submitted an offer of settlement supported by Indicated Shippers. Under the settlement proposal, HIOS would, prospectively after the approval of the settlement, return its rates to their level before it filed this rate case. HIOS would also make a payment of $3 million to Indicated Shippers, but would not make refunds to any other parties in this proceeding. The settlement proposal is opposed by Exxon Mobil and Staff.

11. For the reasons discussed below, this order rejects the settlement proposal. Since the settlement is rejected, the order then proceeds to address the exceptions to the ALJ's Initial Decision. The Commission generally affirms the ALJ, but does modify her decision on a few issues, including the issue of an appropriate management fee in light of HIOS' zero rate base.

II. <u>Settlement</u>

12. Article II of the settlement provides for HIOS' rates to be reduced to the level they were at before the filing of the instant rate case. That article further provides that the settlement rates are based on a "black box" settlement without itemization of rate components. Article 2.2 provides that HIOS will make no refunds for periods the rates proposed in this rate case were in effect prior to the effective date of the settlement. However, in recognition of the fact that Indicated Shippers were the only parties to have litigated the full range of issues in this rate case, Article 2.3 provides that HIOS shall make a payment to Indicated Shippers of $3 million. That article further provides that this payment shall not be treated as a discount for future transportation by the Indicated Shippers.

13. Article 2.4 provides that, within one year of the approval of the offer, HIOS will install any needed measurement facilities on its pipeline at West Cameron Block 167, to measure deliveries to ANR Pipeline Company (ANR), Enbridge Offshore Pipeline, L.L.C. (UTOS) and Tennessee Gas Pipeline Company (TGP) pipelines. Article 2.5 provides that, until the earlier of December 1, 2004, or such time as the new measurement facilities are operational, HIOS will cap its retention percentage for Lost and Unaccounted for Gas (LAUF) at 0.75 percent. If the facilities are not installed by December 1, 2004, the LAUF percentage will be capped at 0.50 percent until the new measurement facilities are installed. After installation, no cap will apply, but HIOS will implement an annual fuel tracker for the recovery of fuel and LAUF beginning in

March 2005. The tracker mechanism would include a provision for a true up of under- or over-collections.

14. Article 3.3 would require HIOS to file a new section 4 rate case three years after the effective date of the settlement. Article IV of the settlement provides for it to become effective on the first day of the month following thirty days after issuance of an order approving the settlement without material modification.

15. Article V of the settlement permits the Commission to sever any contesting party from the settlement and approve the settlement as uncontested for consenting parties. Article 5.3 provides that if the contesting party has a negotiated rate, its negotiated rate shall control. Otherwise, rates for contesting parties will be resolved by further litigation, except that contesting parties will be subject to the provisions of the settlement concerning fuel and LAUF. HIOS believes the settlement is not contested because ExxonMobil pays a negotiated rate and will not be paying additional revenues as its negotiated rate agreement will be in effect during the settlement term and extends beyond the term of the settlement offer. HIOS argues that the Commission Staff's opposition to the offer does not make this a contested settlement because Staff is only a participant, not a party. Further, HIOS argues Staff's position has no merit because it assumes that the Commission and ultimately the Court of Appeals would uphold the Initial Decision, which HIOS claims is unlikely as it allows only a $0.7 million management fee on a $22 million cost of service.

A. <u>Comments on Settlement</u>

16. The Commission's Staff and ExxonMobil filed comments opposing the settlement proposal. Staff argues that the offer is contrary to the public interest and should be rejected. Staff states it is a representative of the public interest and non-active shippers who traditionally rely on the Staff to represent their interests, other than the Indicated Shippers. Staff states that, while the settlement may represent a reasonable bargain from the viewpoint of Indicated Shippers, those shippers account for less than 20 percent of HIOS' total throughput.[7] Staff contends that the settlement is unreasonable and unduly discriminatory with respect to the remaining shippers, who account for over 80 percent of the throughput on HIOS. While Indicated Shippers receive a payment of $3 million, the settlement denies the remaining shippers any share of refunds for the period during which HIOS' proposed rate increase was in effect. Staff calculates that those refunds would amount to about $15.6 million. Staff also points out that the ALJ's Initial Decision suggests that a just and reasonable rate for HIOS would be in the range of 8 to 9 cents per

[7] Affidavit of Staff witness Vladimir Ekzarkhov (submitted with Staff comments).

Dth, but the settlement provides for a rate of 12.44 cents per Dth, approximately 50 percent above the ALJ's determination of a just and reasonable rate. Staff claims that there is no merit to HIOS' argument that the Commission should treat the offer as uncontested even if Staff opposes the offer. Staff urges that, based on Rule 602(g), a settlement may only be considered uncontested, if it is not contested by any "participant," and section 385.102(b) defines "participant" as including litigation staff. Additionally, Rule 602(h) defines for the ALJ a situation where an offer may be contested by any participant, such as the Staff. Staff urges there are genuine issues of material fact and the record lacks substantial evidence upon which to base a reasonable decision on the offer of settlement.

17. ExxonMobil also filed comments opposing the settlement. ExxonMobil is one of the only two firm shippers on HIOS. ExxonMobil pays a negotiated rate for its firm service[8] and does not contest HIOS' assertion that, as a result, it will not be affected by the firm rates established by the settlement during the three years before HIOS is required to file another rate case. However, ExxonMobil states that it may obtain interruptible service from HIOS during the term of the settlement and, in that event, could be required to pay the settlement's interruptible rates. Like Staff, it contends that the settlement is not in the public interest as it would set rates at an excessive level compared to the rates indicated by the Initial Decision.

18. ExxonMobil also states that beginning in November 2002, HIOS increased the fuel and LAUF rates from one percent to 1.25 percent and higher levels up to 2.18 percent without explanation. ExxonMobil contends that the settlement fails to address its contentions that these actions resulted in HIOS improperly overcollecting its fuel charges during past periods. It notes that HIOS has suggested it could file a complaint regarding past fuel charges, but ExxonMobil believes an investigation by the Commission is needed and is not addressed in the settlement. ExxonMobil also argues that the settlement's proposed fuel tracker needs substantial modification or clarification and would conflict with existing section 1.9 of HIOS' tariff. ExxonMobil claims the settlement offer's proposed fuel tracker would not be consistent with section 154.403(d)(1) of the Commission's regulations.

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[8] ExxonMobil's negotiated rate agreement provides that ExxonMobil will pay the lesser of HIOS' maximum rate on file, or 15 cents/Dth, plus surcharges and fuel and LAUF. The 15 cents/Dth cap is an aggregate cap that also covers the rate ExxonMobil pays for gathering service on HIOS' affiliate, East Breaks Gathering System (East Breaks).

B. Reply Comments

19. HIOS and Indicated Shippers both filed reply comments. HIOS asserts that the settlement offer must be considered as uncontested notwithstanding the opposition of ExxonMobil and the Staff. HIOS contends that the Commission held in *Stingray Pipeline Co.*,[9] that, since Staff is a participant and not a party in hearing proceedings,[10] its opposition to a settlement does not render the settlement contested for purposes of §§ 385.602(g) and (h) of the Commission's settlement rules. HIOS also points out that the *Stingray* settlement was similar to the proposed settlement at issue here, in that it provided for Stingray to make a $4.5 million payment to Indicated Shippers, who accounted for about 25 percent of throughput on Stingray, provided for a prospective only rate decrease, and did not require Stingray to make refunds, which could have totaled $10 to 12 million, to any other shipper. While Staff opposed the Stingray settlement on the same grounds as it opposes the instant settlement, the Commission nevertheless treated that settlement as uncontested and approved it as fair and reasonable and in the public interest.

20. HIOS also contends that ExxonMobil's comments on its settlement do not justify a different result than the Commission reached with respect to the *Stingray* settlement. HIOS asserts the rates ExxonMobil pays for its firm service are not affected by the settlement. HIOS explains that ExxonMobil has contracts for service on both HIOS and its gathering affiliate, East Breaks, which delivers ExxonMobil's gas to HIOS. ExxonMobil's agreements with HIOS and East Breaks provide that it will never pay more than 15 cents per Dth in the aggregate for its service on both HIOS and East Breaks. HIOS recognizes that its negotiated rate with ExxonMobil provides that ExxonMobil will pay the lesser of HIOS' filed rate or 15 cents per Dth for the service on HIOS. However, HIOS states that the rates for service on the non-jurisdictional East Breaks system are such that, even if the Commission were to approve the ALJ's decision in its entirety, ExxonMobil would continue to pay the 15 cent per Dth rate for its overall service on both HIOS and East Breaks. HIOS also states that ExxonMobil in its comments did not claim that the settlement would affect the rates it pays for its firm service on HIOS.

21. HIOS further argues that ExxonMobil's unsupported claim that it might contract for interruptible service on HIOS in the future, without any explanation of new production prospects that would require it to enter into a new transportation agreement,

[9] 101 FERC ¶ 61,365 (2002).

[10] *Citing* 18 C.F.R. § 385.102(b)(2) (2004).

renders this assertion of an interest in HIOS' settlement rate too attenuated to justify treating ExxonMobil as a contesting party on this ground.

22. With respect to issues concerning HIOS' recovery of fuel, which do affect ExxonMobil, HIOS states that the settlement provides ExxonMobil with the annual fuel tracker mechanism it advocated in the hearing, and HIOS is willing to agree to all the clarifications concerning that proposal which ExxonMobil sought in its comments. With regard to prior period fuel and LAUF levels, HIOS argues that the offer does not prejudice ExxonMobil's rights to pursue the issue as a complaint, even though HIOS believes it has in the past under-collected its fuel and LAUF costs. In any event, HIOS would be willing for the Commission to sever that issue and address it in further proceedings in this docket.

23. HIOS concludes that the offer is properly an uncontested settlement and should be approved under the fair, reasonable and in the public interest standard. HIOS states that the benefits of certainty of rates for three years and the cessation of litigation, HIOS' agreement to the implementation of a tracking mechanism for the recovery of its fuel and LAUF costs, its agreement to install new gas measurement facilities and to cap its recovery of LAUF costs pending completion of those facilities should all lead the Commission to conclude the offer is in the public interest.

24. Indicated Shippers argue that the Commission should approve the offer of settlement because it provides a three-year moratorium on rate increases, which would not be the result of a litigated outcome. Severance of the contesting parties permits them to obtain the benefits of the evidentiary record and the proposed tariff changes will benefit them. Approval of the offer will also provide rate certainty and minimize litigation costs for Indicated Shippers and Indicated Shippers states that HIOS accepts the risk that rates set through settlement and litigation process would differ. Other benefits to shippers who did not file an objection are the reduction of the rate to 12.44 cents per Dth. The offer benefits all shippers by improvements promised in the measuring facilities for fuel charges and a new annual fuel tracker, whereas at present HIOS simply posts the charge monthly without any supporting data. Indicated Shippers notes Staff's position on rates is based on the Initial Decision becoming a final decision and overlooks that it is not a finding by the Commission. If HIOS is not satisfied with the outcome of the hearing process, it can file another rate case, where under the offer it must wait three years. Indicated Shippers state that the $3 million payment it would receive under the settlement offer involves various rate and non-rate issues and argues that a settlement can provide special benefits to those parties who negotiate a settlement and deny those benefits to other shippers.

C. Commission Decision

25. For the reasons discussed below, the Commission rejects the proposed settlement. Even assuming the settlement may be treated as uncontested, the Commission finds that the settlement has not been shown to be fair and reasonable and in the public interest, and thus does not satisfy the standard in Rule 602(g)(3) of our settlement rules for approval of uncontested settlements.

26. Before explaining our holding that the settlement is not fair and reasonable, the Commission will first clarify the treatment under our settlement rules of comments filed by its litigation staff opposing an offer of settlement. For the reasons explained below, the Commission finds that its settlement rules give the Commission broad discretion as to the significance it gives comments filed by Staff, regardless of whether or not those comments are considered to render the settlement contested.

27. Under Rule 102(b)(2),[11] Staff is a "participant" in proceedings set for hearing, not a "party." The settlement rules distinguish between the treatment of comments depending upon whether they are submitted by "parties" or "participants," and also depending upon whether they are transmitted to an ALJ in a case not yet certified to the Commission or are submitted directly to the Commission, as here. As Staff points out, if comments are transmitted to an ALJ, Rule 602(g)(1) provides that the ALJ may only certify the settlement to the Commission as uncontested, if the ALJ finds that no "participant" opposes the settlement. Thus, an ALJ may not certify a settlement to the Commission as uncontested, if Staff, which is a participant, files comments opposing the settlement. However, where, as here, comments are transmitted directly to the Commission, Rule 602(g)(2) provides that "the Commission will determine whether the offer is uncontested," without any express requirement that the Commission treat opposing comments by participants, such as Staff, as rendering the settlement "contested." This suggests that the Commission, unlike an ALJ, has discretion to treat a settlement opposed only by Staff as nevertheless uncontested so that, pursuant to Rule 602(g)(3) the settlement can be approved upon a finding that it is "fair and reasonable and in the public interest."

28. Consistent with this interpretation, the settlement rules only require that there be substantial evidence in the record in order for the Commission to decide genuine issues of material fact if such issues are raised by parties, thereby not by Staff.[12] Thus, the

[11] 18 C.F.R. § 385.102(b)(2)(2004).

[12] Procedures for Submission of Settlement Agreements, FERC Stats. & Regs. ¶ 30,061 at 30,432 (1979).

settlement rules prohibit an ALJ from certifying to the Commission a settlement contested by a party unless (1) there is no genuine issue of material fact, (2) the record contains substantial evidence from which the Commission can make a reasoned decision on the merits, or (3) the parties agree to certification. Rule 602(h)(2)(ii) and (iii). However, the ALJ is free to certify a settlement contested only by a "participant," such as Staff, even if there are material issues of fact and the record is insufficient to resolve those issues on the merits. Rule 602(h)(2)(i). Also, Rule 602(h)(1)(i) provides that if the Commission finds that a settlement is contested by "any party," the Commission may decide the merits of the contested settlement issues, "if the record contains substantial evidence upon which to base a reasoned decision or the Commission determines that there is no genuine issue of material fact." There is no comparable rule concerning merits decisions, if the Commission were to find that a settlement is contested only by a "participant," such as Staff. Finally, Rule 602(h)(1)(iii) contemplates that the Commission may sever contesting "parties" or issues and then approve the settlement under the "fair and reasonable and in the public interest" standard applicable to uncontested settlements under Rule 602(g)(3). However, there is no requirement that the Commission sever contesting "participants" in order to render the settlement uncontested.

29. Thus, the settlement rules clearly contemplate that the Commission may approve a settlement, despite the fact Staff has raised material issues of fact which the record is insufficient to resolve. Since the Commission could not resolve the merits of such factual issues without a record, the Commission's approval of a settlement in these circumstances would have to be pursuant to the standard in Rule 602(g)(3), under which the Commission may approve an uncontested settlement if it is fair and reasonable and in the public interest. Thus, the Commission reaffirms its holding in *Stingray* that, despite the fact Staff has submitted comments opposing a settlement, the Commission has discretion to approve the settlement as fair and reasonable and in the public interest, without a finding on the merits that the settlement is just and reasonable.

30. However, consistent with the decision of the U.S. Court of Appeals for the District of Columbia in *Tejas Power Corp.*, 908 F.2d 998, 1003 (D.C. Cir. 1990), the Commission only approves uncontested settlements if, in its independent judgment, the settlement is in the public interest. Since "the public interest that the Commission must protect always includes the interest of consumers in having access to a reasonable supply of gas at a reasonable price,"[13] the mere fact the active parties to a proceeding have agreed to a settlement is not necessarily sufficient to justify a finding that an uncontested

[13] *Id.*

settlement is in the public interest. In carrying out its obligation to make an independent determination of the public interest:

> The Commission wishes to emphasize the importance it places on the role of Commission Staff in representing the public interest in proceedings before the Commission. The Staff performs an important public function in developing the records and testing the case presented by other parties.[14]

Thus, while the Commission may at times have a different view of the public interest than its litigation Staff, the Commission will not lightly ignore its Staff's opposition to an uncontested settlement.

31. We now turn to the issue of whether to approve the settlement filed in this case. Here, the settlement is opposed not only by Staff but also by a party, ExxonMobil. The Commission recognizes that ExxonMobil has not seriously contested HIOS' contention that ExxonMobil will not be significantly affected during the term of the settlement by the settlement's provisions concerning HIOS' base transportation rates. Also, while ExxonMobil is affected by the settlement's provisions concerning fuel and LAUF, the settlement, as clarified in HIOS' reply comments, contains the fuel tracker that ExxonMobil has sought. Nevertheless, in the circumstances of this case, even assuming HIOS has adequately justified treating the settlement as uncontested despite ExxonMobil's opposition, the Commission finds that the settlement does not satisfy the requirement that an uncontested settlement be fair and reasonable and in the public interest.

32. First, as Staff points out, the transportation rates provided by the settlement are approximately 50 percent higher than those the ALJ found would be just and reasonable in her Initial Decision. As discussed in detail below, while we reverse the ALJ's decision in part concerning the management fee, we generally affirm the ALJ and find on the merits that just and reasonable rates for HIOS are substantially below the level of the settlement rates. This contrasts with the situation in *Stingray*, where the settlement rates were slightly lower than the rate the ALJ's decision found would be just and reasonable.

33. Second, when the Commission approves an uncontested settlement, the Commission relies in part on the fact that the interests of the active parties in the case are

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[14] Procedures for Submission of Settlement Agreements at 30,432. The Commission made this statement when it revised its settlement rules to permit an ALJ to certify a settlement contested by Staff despite the lack of substantial evidence on which to reach a merits decision.

generally similar to the interests of the inactive parties and consumers. Thus, the agreement of the active parties to a settlement generally suggests that the settlement is also in the interests of the inactive parties, who may not have the resources to participate. Here, however, the only active parties that support the settlement, the Indicated Shippers, are receiving special consideration not being given to any other party, in the form of the $3 million payment. In the meantime, the inactive parties will receive no refunds for the period of about a year and half when rates were in effect that are substantially in excess of the level that we find to be just and reasonable. The fact the Indicated Shippers demanded greater benefits than the settlement provides HIOS' other customers undercuts any assumption that the Indicated Shipper's agreement to the settlement shows that it is in the interest of other affected parties and consumers generally.[15] We recognize that we approved a similar settlement provision in *Stingray*. However, upon further reflection, the Commission is increasingly concerned about the unduly discriminatory nature of such arrangements. In any event, the Commission is unwilling to sanction such an arrangement in the circumstances of this case, where we find that the settlement rates are substantially higher than just and reasonable rates, and the settlement provides no refunds to the other parties who have paid rates at twice the just and reasonable level for a significant period.

34. The Commission concludes that the benefits claimed for the offer do not offset the detriments to the shippers by imposition of rates in excess of just and reasonable levels and the refusal to make refunds of excess charges collected subject to refund.

35. The issue of severance of non-consenting parties has been raised by Indicated Shippers, stating that the objecting shippers can be severed from the settlement.[16] Staff noted it had no objection to the settlement applying only to HIOS and the three Indicated Shippers. However, HIOS stated that such severance would constitute an unacceptable modification of the offer. Accordingly, the non-consenting shippers cannot be severed from the offer. Finally, we find that the offer is not fair and reasonable and in the public interest.

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[15] *See also Tejas Power Corp. v. FERC*, 908 F.2d 998 at 1003, holding that the Commission may not merely assume without analysis that settling parties' protection of their own interests will inure to the benefit of consumers.

[16] *See* Rule 602(h)(iii).

III. Order on Initial Decision

A. Operation and Maintenance Expenses (O&M)

36. HIOS has no employees of its own and signed an Operating Agreement in September of 1999 with an affiliate, GulfTerra Operating Company, L.L.C. (GTOC), to operate the HIOS system. The Operating Agreement consists of three components: (1) the fixed monthly fee of $806,382, referred to as the turnkey fee, that HIOS pays to GTOC for routine services performed by GTOC to operate, maintain and administer HIOS' pipeline system on a daily basis;[17] (2) additional expenses incurred by GTOC on behalf of HIOS for non-routine operation and maintenance services, which include a ten percent premium paid to GTOC for providing the service; and (3) direct flow-through expenses, paid to parties other than GTOC, for liquids separation at the Grand Chenier and Cameron Meadows facilities, as well as costs imposed by governmental authorities (including taxes and FERC-related costs). The Operating Agreement provides that the direct flow-through costs shall be billed to HIOS as a direct charge, separate from the turnkey fee, and no overhead fees or other charges shall be applicable thereto.

37. In this proceeding, Staff proposed O&M expenses of $19,638,018 based on actual data through the end of the test period, June 30, 2003, with an adjustment regarding regulatory commission expense. On rebuttal, HIOS proposed O&M expenses of $19,698,676. HIOS accepted Staff's use of actual data through the end of the test period but disagreed with Staff's proposed three-year amortization of regulatory expenses. Indicated Shippers proposed an O&M expense level of $14,367,838, asserting that a large part of HIOS' O&M expenses are unjustified fees charged to HIOS by its affiliated operator GTOC. Indicated Shippers developed its proposed O&M expenses by taking the six-year trend line from 1996 through 2001 of other offshore pipelines operating in 1996 and applying it to HIOS' O&M expenses for 1996.

38. In the Initial Decision, the ALJ adopted Staff's level of O&M expenses of $19,638,018. The Commission affirms the ALJ finding that Staff's level of O&M expenses of $19,638,018 is just and reasonable.

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[17] Although the Operating Agreement has an inflation adjustment clause, the turnkey fee did not change until May of 2003, when it was increased to $828,612. (*See* Tr. 581 and HIOS brief opposing exceptions (RB) at 16.)

Initial Decision

39. The ALJ held that Staff's proposed O&M expenses of $19,638,018 is just and reasonable and is the appropriate level of O&M expenses in this proceeding. She rejected Indicated Shippers' argument that this amount was excessive because it included unsupported costs under the Operating Agreement.

40. The ALJ rejected Indicated Shippers' contention that HIOS had failed to support the turnkey fee. She noted that the monthly fee results in an annual amount that is lower than the routine cost to HIOS in 1998-1999 when the contract was negotiated. Assuming generally rising costs since 1999, she recognized the possibility that HIOS may have made a good bargain in fixing its costs in 1999. She dismissed Indicated Shippers' contention to the contrary that there was a general decline in operating costs for several offshore pipelines from 1996-2001, in contrast to a general increase for HIOS. The ALJ found that there were flaws in Indicated Shippers' methodology, including the failure to account for the differences in size and type of facilities of the other offshore pipelines. She concluded that not all offshore pipelines will have equal operating expenses and that it would be highly speculative to compute HIOS' O&M expenses based on an average of these pipelines' O&M expenses.

41. For these reasons, the ALJ found that, although the turnkey fee lacks transparency, HIOS minimally supported such costs. The ALJ, however, held that the Operating Agreement raises concerns about affiliate transactions, how the costs are justified, and what records are kept.

Briefs on and opposing exceptions

42. Indicated Shippers assert that HIOS failed to provide adequate support for the inclusion of the O&M costs charged to HIOS by its affiliate and that the ALJ erred in recommending recovery of an excessive O&M expense level, including: (1) an excessive and unsupported turnkey fee paid to an affiliate for routine operation services; (2) the ten percent premium on non-routine operation services fees paid to an affiliate; and (3) an excessive level of direct charges for dehydration and measurement services at the Grand Chenier and Cameron Meadows Stations paid to an affiliate. According to the Indicated Shippers, a more reasonable estimate of the actual costs of operating HIOS can be determined from a review of the O&M costs of other similar OCS pipelines.

43. Indicated Shippers assert that the turnkey fee should be rejected because HIOS did not provide invoices for its support or any other justification for the level of the turnkey fee. Indicated Shippers argue that rejection of these unsubstantiated operating expenses is especially compelling because of the affiliation between HIOS and the operator at the time the agreement was negotiated, arguing that such affiliation created an

undue risk that excessive costs would be imposed on HIOS. Noting that the Commission scrutinizes affiliate transactions, Indicated Shippers assert that before HIOS executed the contract with its affiliate, HIOS did not attempt to determine a market price for the services provided by its affiliate, or determine whether comparable services were available from non-affiliates, or show what it would have cost for HIOS to provide theses services on its own.

44. Indicated Shippers maintain that a comparison of the operating costs of HIOS and other similar pipelines makes it clear that the operating fee paid by HIOS under the turnkey fee are excessive. In this regard, Indicated Shippers assert that HIOS' average operating costs of $17.93 million were significantly higher than the average operating costs of $7.16 million of a sample of six other Gulf Coast pipelines.

45. Indicated Shippers also assert that the ALJ failed to recommend whether HIOS should be able to recover the ten percent premium it pays to GTOC for non-routine operation services. Indicated Shippers argue for rejection of the premium because it gives GTOC an incentive to incur excessive costs and provide these services inefficiently. Indicated Shippers assert this same principle has been rejected by the Commission in *Tarpon Transmission Company*,[18] where the pipeline proposed a management fee based on a percentage of its O&M expenses and the Commission stated such a method of calculating a management fee creates incentives for inefficiency rather than efficiency, since the higher the pipeline's cost of service, the greater its management fee.

46. In addition, Indicated Shippers assert that the ALJ did not address the recovery of the third party dehydration and measurement services provided at the Grand Chenier and Cameron Meadows facilities and contend that HIOS has not justified these excessive charges. Indicated Shippers assert that although HIOS' rebuttal testimony suggests that these expenses have increased, they must be reduced to no more than the $3,384,924 reflected in Account No. 857. Indicated Shippers also question the appropriateness of the level of costs expended for the relatively minor amount of liquids separation. Indicated Shippers argue HIOS has not justified this portion of O&M costs or provided any explanation as to why it would continue a contract for dehydration services that are far in excess of the actual services needed.

47. Because of these alleged flaws in the O&M expense sought by HIOS, the Indicated Shippers advocate computing an O&M allowance by adjusting the last known

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[18] *Tarpon Transmission Company*, 57 FERC ¶ 61,371 (1991), *order on reh'g*, 58 FERC ¶ 61,354 (1992), *order on reh'g*, 59 FERC ¶ 61,241 (1992).

actual O&M expenses for HIOS by reference to the percentage change in O&M expenses incurred by other offshore pipelines. Indicated Shippers assert their methodology for determining O&M expenses was not addressed, and argue such methodology is a reasonable estimate of prudently incurred O&M costs for HIOS. They also assert this approach is similar to the Commission's use of proxy groups for determining the dividend yield-plus-growth component of equity return or the capital structure of a pipeline if neither the capital structure of the pipeline or the parent is appropriate.[19]

48. HIOS responds that Indicated Shippers failed to support their challenge to HIOS' O&M expenses and that the ALJ correctly rejected Indicated Shippers' proposal to use other pipelines' costs to determine HIOS' O&M expenses. HIOS argues that the challenge was not based on evidence, but instead on misguided speculation, and that the ALJ correctly found the turnkey fee to be just and reasonable. HIOS asserts that Indicated Shippers has failed to show that HIOS' costs are imprudent. HIOS argues that Indicated Shippers' approach is inconsistent with Commission precedent requiring a pipeline's rates to be based on its own cost of service. HIOS also argues that Indicated Shippers' challenge to certain fees for non-routine and dehydration services conflicts with the record.

Commission Decision

49. The Commission affirms the use of actual end-of-test-period data for O&M expenses, and affirms the ALJ's finding that HIOS has supported the inclusion of O&M costs charged to HIOS under the Operating Agreement. The use of actual test period figures is consistent with Commission policy and precedent.[20]

50. The Commission rejects Indicated Shippers' contention that HIOS has not supported the turnkey fee. HIOS explained why it elected to rely on GTOC to provide routine services rather than perform these services itself. HIOS contends that, if it were to operate its own system, it would have to hire its own staff of operational, maintenance, and administrative employees, which would sacrifice the efficiencies inherent in GTOC's operation of several pipelines and thereby increase HIOS' routine operating expenses above the level represented by the fixed fee.[21] Further, HIOS notes that an Operating

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[19] *Citing Enbridge Pipelines*, 100 FERC ¶ 61,260 (2002); *Williston Basin Interstate Pipeline Co.*, 104 FERC ¶ 61,036 (2003).

[20] *See Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 315 (2002) (citing *Trunkline Gas Co.*, 90 FERC ¶ 61,017 at 61,048-49 (2000)).

[21] *See* Exh. HIO-104 at 9-10.

Agreement can typically take advantage of economies of scale and efficiencies and avoid duplication of employees, resulting in a more efficient allocation of labor. HIOS states that it is not uncommon for one company to provide these types of services to affiliated companies, given the efficiencies that are achieved for the entire corporate entity.[22] Indicated Shippers provided no evidence in this case to show that the Operating Agreement is an inefficient way of operating HIOS' system.

51. In addition, the evidence shows that the turnkey fee was initially based on HIOS' historical operating costs. HIOS' total operating costs in 1988-89 were $10,006,126, as compared to the turnkey fee that was negotiated of $9,676,584, for a savings of $329,542.[23] HIOS' historical operating cost data was provided to Indicated Shippers by HIOS during the discovery process.

52. Although the Commission agrees that affiliate transactions should receive close scrutiny, it finds that even though the turnkey fee involves affiliate transactions in the present, it is properly viewed as an arm-length transaction negotiated between ANR and Leviathan Operating Company (Leviathan) in 1999. At that time, ANR owned fifty percent of HIOS, while Leviathan, which was not affiliated with ANR then, owned the other fifty percent. Because fifty percent of the money paid by HIOS under the Operating Agreement effectively came directly out of ANR's pocket, ANR had an interest in negotiating the lowest fixed fee possible, as well as an incentive to keep HIOS' rates and underlying cost structure at a competitive level since a portion of the gas flowing through HIOS also flowed through ANR's pipeline's system.[24]

53. The Commission also finds that Indicated Shippers has not supported its claim that the ten percent premium paid by HIOS to GTOC for non-routine services encourages GTOC to incur excessive costs. Non-routine operating services that GTOC performs for HIOS, such as major maintenance projects or equipment overhauls, are billed directly to HIOS and do not otherwise include any charge for the processing of those services, including administrative work such as the initial determination of the need for the non-routine service, the contracting or assignment of such services, and the processing and payment of all invoices related to the service. The Operating Agreement provides for a ten percent processing or administrative fee only on non-routine billings. Thus, the ten percent charge serves as a reimbursement for the time and expense incurred by GTOC to

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[22] *Id.*

[23] *See* Exh. IND-24.

[24] *See* HIOS brief opposing exceptions (RB) at 13-14 and Exh. HIO-104 at 10.

provide these additional administrative services, which is not otherwise recovered through the turnkey fee.[25] The Commission finds that because the ten percent charge is based on the actual costs of providing this service, the fee is not a cost-plus arrangement whereby GTOC earns a profit by providing this service, and is thus distinguishable from *Tarpon* cited by Indicated Shippers. Thus, the record does not support Indicated Shippers' contention that the fee encourages GTOC to incur excessive costs.

54. Similarly, the Commission finds that Indicated Shippers has provided no support in the record for its claim that HIOS has not justified recovering the fees it pays for third-party dehydration and measurement services, and that these fees are excessive. The Operating Agreement provides that dehydration and measurement services at the Grand Chenier and Cameron Meadows facilities will be billed to HIOS as a direct charge.[26] In affirming the ALJ's determination that the use of actual end-of-test-period data for O&M expenses is appropriate, the Commission finds that test period actual amounts should be used for Account No. 857, or $4,228,281.[27] The Commission has previously approved these direct flow-through charges rendered for HIOS, *i.e.*, the Cameron Meadows facilities by Enbridge Offshore Pipelines (UTOS) L.L.C. pursuant to Rate Schedule X-1, and the Grand Chenier facilities by ANR pursuant to Rate Schedule X-64.[28] Thus, the Commission finds Indicated Shippers' assertion to be speculative because they failed to offer evidence demonstrating that these costs are imprudent.

55. Indicated Shippers' assertion that the ALJ did not address their proposal to base the level of HIOS' O&M expenses by reference to other offshore pipelines is unfounded and ignores the ALJ's findings on the issue. She specifically addressed the proposal and rejected it, finding that it would be speculative to base O&M expenses on an average of other offshore pipelines' costs, and that it is flawed because it failed to account for the differences in size and type of facilities of the other offshore pipelines.[29] She found this approach ignores material differences between HIOS and the other pipelines in terms of the amount of plant in service for each pipeline, the amount of throughput transported by each pipeline, the number of offshore platforms on each pipeline system, the age of each

[25] *See* HIOS RB at 16-17 and Exh. HIO-104 at 17-18.

[26] *See* Exh. S-21, p. 7, § 3.2.3.

[27] *See* S-2, p. 8.

[28] *See* Tr. 435.

[29] *See* Initial Decision, 107 FERC ¶ 63,019 at P 24.

pipeline system, and whether the other pipelines, like HIOS, incur liquids separation charges that increase operating expenses.[30]

56. We affirm this ruling. In addition, section 154.303 of the regulations provides that when a pipeline files for a change in rates or charges it is required to base the filing on cost and revenue data reflecting what the pipeline itself actually experienced, as adjusted for known and measurable changes.[31] Thus, Commission policy is to base a pipeline's rates on its own costs, not those of other pipelines.[32]

57. Indicated Shippers advocate computing an O&M allowance by adjusting the last known actual O&M expenses for HIOS by reference to the percentage change in O&M expenses incurred by other offshore pipelines. Indicated Shippers' methodology and the cases cited in support of their approach are inapposite. The Commission uses proxy groups to derive equity returns for gas pipeline companies because gas pipelines are not publicly traded and the data necessary to perform a discounted cash flow (DCF) analysis is not existent. Similarly, the Commission's preference is to use the capital structure of real entities that obtain financing for the pipeline, the pipeline itself, or its parent and uses a hypothetical capital structure only if the capital structure of the entity obtaining the financing is anomalous. In this proceeding, however, it is not appropriate to use a proxy group of other offshore pipeline companies for O&M expenses, as Indicated Shippers has done, because O&M data is available for HIOS, and Indicated Shippers has not demonstrated use of this data is inappropriate.

B. Depreciation and Negative Salvage

Negative Salvage Allowance

58. Negative net salvage refers to the cost of removal of an asset at the time of its retirement from service over the revenue realized from the sale of the retired asset. Pipelines may be allowed to include in their cost of service a charge for negative net salvage to compensate for costs to be incurred in the future retirement of facilities. HIOS

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[30] *See* HIOS RB at 8.

[31] *See* 18 C.F.R. § 154.303 (2004).

[32] *See Mojave Pipeline Co.*, 79 FERC ¶ 61,347 at 62,485 (1997). The Commission stated that to determine one pipeline's rates based on other pipelines' costs would be contrary to the Commission's traditional method of determining cost-based rates for pipelines, where each pipeline's rates are determined based on its own costs.

proposed a negative salvage allowance based on estimated total costs of $27,504,881 which was supported by a study performed by HIOS witness Mr. Byrd.[33] Staff accepted HIOS' negative salvage cost proposal.[34] Indicated Shippers argued that HIOS' study is flawed and HIOS should not be permitted to collect a negative salvage allowance.

Initial Decision

59. The ALJ found that HIOS meets the three criteria for receiving a negative salvage allowance articulated by the Commission in *Williston Basin Interstate Pipeline Company*.[35] These three criteria are: (1) the pipeline has a clearly discernable end-of-life; (2) the evidence is persuasive that interim retirements have been taken into account in computing negative salvage costs: and (3) sales and salvage values of abandoned or retired equipment are fully proven. With respect to the first criteria, the ALJ found that HIOS had a discernable end of life, namely an estimated economic life of 17.5 years. On the second criteria, while noting that HIOS did not present evidence of any historic retirement, the ALJ found this was insufficient reason to reject the study. This was because there was no record evidence that HIOS had any historic costs or that HIOS had previously retired any of its offshore facilities. She also found that it was logical that HIOS would retire its facilities all at once at the end of their economic life because the pipeline's economic life is tied directly to the recoverable supply in the Gulf of Mexico. Finally, as to the third criteria, she found that Mr. Byrd's study is sufficient to prove the "sales and salvage values of abandoned or retired equipment," particularly since there was no record evidence refuting the study.

Briefs on and opposing exceptions

60. Indicated Shippers assert that the ALJ overlooks several flaws in HIOS' negative salvage study.[36] They assert that the proposed salvage expense includes a 6 percent allowance for delays due to weather, a 15 percent allowance for work contingencies and an 8 percent allowances for project management, supervision and inspection services that is only supported by a statement that these percentages were developed over years of on-site experience with decommissioning projects. Indicated Shippers also maintain that

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[33] Exh. HIO-83.

[34] Exh. S-7 at 5-6.

[35] 95 FERC ¶ 63,008 at 65,104-05 (2001).

[36] IS BOE at 22-25.

HIOS' study failed to take into account the salvage value of the HIOS system. Finally, to the extent HIOS is allowed to collect a negative salvage allowance, Indicated Shippers requests the Commission find that if actual salvage costs turn out to be less than the salvage revenues, HIOS must refund the difference to shippers.

Discussion

61. The Commission affirms the ALJ on this issue. While Indicated Shippers raise issues with certain cost assumptions in Mr. Byrd's testimony and his assumption that there would be no salvage value, there is simply no evidence in the record to support their objections. As found by the ALJ, HIOS submitted a study that details the facilities and cost of retirement of HIOS' pipeline as a known and measurable event and this study was not substantially challenged at hearing.[37] For the reasons articulated by the ALJ, we find that HIOS has justified a negative salvage allowance based on estimated costs of $27,504,881 under Commission policy articulated in *Williston*.

62. We also reject Indicated Shippers' request for the Commission to make a finding in this proceeding that to the extent any salvage revenues exceed actual salvage costs in the future, HIIOS should be required to refund these overcollections. Indicated Shippers cites no record evidence or Commission precedent to support its request.

Reserve Life

63. HIOS proposed to base its depreciation rate for transmission plant and its annual level of negative salvage expense on a remaining economic life of its pipeline of ten years as of June 30, 2003 (the end of the test period).[38] Staff determined a 17.5-year remaining life for HIOS, as of June 30, 2003.[39] Indicated Shippers contended that 20 years from the end of the test period was the appropriate economic life for HIOS, but unlike Staff and HIOS, did not submit an independent depreciation study.

64. Although different methods were used by Staff witness Mr. Pewterbaugh and HIOS witness Mr. Jenkins to forecast the length of time HIOS' <u>existing</u> fields could be expected to produce sufficient gas, HIOS' vintage method and Staff's least squares

[37] Initial Decision, 107 FERC ¶ 63,019 at P 84.

[38] Exh. HIO-76.

[39] Exh. S-4.

method did not produce significantly different results.[40] However, HIOS and Staff disagreed over the amount of gas reserves that HIOS could potentially attach in the future to estimate potential future volumes of gas that might be accessible to HIOS. Indicated Shippers supported Staff's analysis but modified it to include increased gas supplies that are accessible to HIOS and did not submit their own study.

65. Staff used an area-wide approach to calculate a range for the supply life based on the number of years that different levels of production would exhaust both remaining reserves and future reserves, taking into consideration, among other things, competition and the distance of the pipeline from reserves.[41] Staff combined information from the Minerals Management Service (MMS), which provides information on existing production and reserves by planning area, and the Potential Gas Committee (PGC). Using an area designated by the MMS as the Western Planning Area (WPA), Staff adjusted estimates of undiscovered reserves in the Gulf of Mexico to reflect areas that he determined HIOS could potentially attach in the future: Alaminos Canyon, Keathley Canyon, Galveston and Garden Banks areas. Using a PGC report dated December 31, 2002,[42] Staff calculated a range of 11 to 30 years of gas supply to support HIOS' operations, based on the number of years that various levels of production would exhaust the total reserve amount (remaining and future reserves). Using the mid-range, Staff supported a 20-year gas supply life as of December 31, 2000, which equates to 17.5 years as of June 30, 2003.

66. In making his estimate of gas reserves that HIOS could potentially attach in the future, Mr. Jenkins projected "Deepwater future volumes" using an El Paso Corporation proprietary data base that estimates active deepwater prospects in the Gulf of Mexico.[43] However, unlike Staff's study which relied on estimates of reserves for the whole WPA, Mr. Jenkin's study was limited to the portion of the WPA he determined to be accessible to HIOS. Risk components were then factored in by means of downward adjustments to the unrisked resource potential. In conclusion, Mr. Jenkin's estimated future expected deepwater gas prospects could add approximately four years to his existing field

[40] *Compare* Exh. HIO-119 at 5 with Exh. S-4 at 13-16 (8 years or less using the vintage method vs. 0-11 years using the least squares, respectively).

[41] Exhs. S-4 at 19-21, 27; and S-14 at 9-10.

[42] Potential Supply of Natural Gas in the United States. Report of the Potential Gas Committee (December 31, 2002).

[43] Exh. HIO-76 at 6-7.

remaining production of eight years, and determined ten years to be the point when operations reach HIOS' economic level.

Initial Decision

67. The ALJ adopted Staff's recommended remaining life of 17.5 years that was based on Mr. Pewterbaugh's reserve study. She rejected HIOS' assertions that there were several weaknesses in Staff's study. She found that WPA was not an unreasonably large portion of the Gulf of Mexico to determine available gas reserves finding that, among other things, HIOS overlooks the significant growth in estimates of reserves in the Gulf of Mexico. She disagreed that Mr. Pewterbaugh failed to take sufficient account of declining production trends from existing sources, noting that HIOS' throughput had not exhibited a constant decline and that Staff witness Mr. Ekzarkhov's testimony indicates that near-term future trends predict slightly increased throughput. She also rejected HIOS' argument that Staff's depreciation study was flawed because it did not reflect projections of remaining reserves for the HIOS fields, stating that the *Memphis* decision[44] did not endorse a particular methodology. Finally, she found that HIOS' assertion that Mr. Pewterbaugh did not take sufficient account of the existence of competitive pipelines in the vicinity of HIOS was unsupported because the risks associated with exploration and production along with economic and regulatory risks are already taken into account by considering only the estimates in the "most likely" category estimates of the PGC "probable" and "possible" categories.

68. The ALJ rejected HIOS' gas supply study for several reasons. She found that HIOS' deepwater Gulf of Mexico reserve estimates were derived from El Paso's proprietary database, which is based on information that was not offered by HIOS and is not supported by the record in this proceeding. She also faulted Mr. Jenkins' study because the estimates were also limited to the portion he determined to be accessible to HIOS, which incorrectly excluded potential production from deep gas in the shallow Outer Continental Shelf (OCS) waters. Further, the ALJ found that HIOS' study, which includes only active deepwater leases, erroneously excluded consideration of unleased prospects in the Gulf of Mexico that are not currently active or have yet been discovered. The ALJ found that HIOS also failed to consider the ramifications of the rapid growth in demand for gas. Finally, the ALJ found that HIOS incorrectly made a downward adjustment to its resource estimates to account for the risks associated with the development of these resources, because the Commission already takes into account the risks associated with exploration and production, along with economic and regulatory

[44] *Memphis Light, Gas & Water Division v. FPC*, 504 F.2d 225 (D.C. Cir. 1974).

risks, by considering only the estimates in the “most likely” category estimates of the PGC “probable” and “possible” gas reserve categories.

Briefs on and opposing exceptions

69. On exceptions, HIOS claims the ALJ erred in adopting Staff’s reserve study because it uses reserve estimates for existing and potential fields in the entire WPA, regardless of whether the reserves could be transported over HIOS. HIOS asserts this 200 by 300 mile area contains gas fields in which the reserves are not economically accessible for transportation due to distance and/or competition. HIOS maintains a fundamental flaw in Mr. Pewterbaugh’s study was his failure to utilize historic data from the various fields actually accessible to HIOS. According to HIOS, what is most troubling is that the Staff witness actually undertook an examination of the historic data and did make reserve life projections for the specific fields serving HIOS, but then disregarded those projections in calculating his depreciable life estimate, choosing instead to rely only on aggregated data for the entire WPA. Thus, HIOS alleges his study did not take into consideration important factors such as production rates in the areas near HIOS, distance from reserves, or competition HIOS faces from other pipelines.

70. HIOS also claims that the ALJ erroneously rejected HIOS reserve study, finding that there were serious flaws in Mr. Jenkins’ approach. According to HIOS, the record supports Mr. Jenkins’ inclusion of only active deepwater development prospects in the Gulf of Mexico because the large prospects have already been identified and leased. Similarly, HIOS asserts that Mr. Jenkins was correct in not taking into account potential production from deep gas in shallow waters because only twelve deep shelf wells have been drilled near HIOS and only two are producing. If deep shelf wells near HIOS were really considered good prospects, HIOS asserts there would have already been more activity.

71. Indicated Shippers state that, although it believes the 17.5-year remaining life is a low estimate of the gas supplies available to HIOS, and should be at least 20 years, the ALJ correctly rejected the ten-year estimate proposed by HIOS, which did not take into account all viable deepwater supplies (not just supplies covered by existing leases) and deep gas in the shallow OCS. Stating that pipelines and their affiliates have strong financial incentives to attach new supplies (such as HIOS’ East Breaks Pipeline), Indicated Shippers reiterate that the WPA is the proper focus to determine the total supply available to HIOS, not just the economically viable portion attainable as determined by Mr. Jenkins. Moreover, Indicated Shippers claim Staff was overly conservative and understated HIOS’ available supply.

72. Regarding attaching supplies, Indicated Shippers state that because HIOS is the only pipeline in the Aliminos Canyon area and has already recovered virtually its entire

investment via depreciation expense, it has a big rate advantage over any future pipeline competitor. Also, HIOS only added four years to its remaining life for deepwater prospects stating that large areas of the Gulf remain unleased (as 85 percent of all leases, active and inactive, have never been drilled).[45] Indicated Shippers claim that as of October 17, 2003, MMS had approved 123 leases in the OCS and is planning more for the western Gulf of Mexico. Finally, Indicated Shippers state that substantial new deepwater gas supplies are flowing due to the East Breaks Pipeline, HIOS has not satisfied Indicated Shippers' concerns regarding its supply study model, and HIOS does not offer any discounts to increase throughput or aggressively market its transportation. Therefore, Indicated Shippers agree with the ALJ that the near-term future trend indicates that throughput on HIOS will climb.[46]

73. Briefs opposing exceptions were filed by Staff, HIOS and Indicated Shippers.

Commission Decision

74. The Commission affirms the ALJ's holdings, based on Staff's study that the economic life of HIOS can reasonably be extended 17.5 years, as of June 30, 2003. The ALJ extensively addresses the arguments raised by the parties on exceptions, and we adopt her findings.

75. We find the record and Commission precedent clearly support a reserve life based on the entire WPA. The ALJ noted that the determination of whether the record better supports a ten-year remaining life from the end of the test year, as recommended by HIOS, or Staff's recommended 17.5-year remaining life, really boils down to a question of whether the WPA-wide reserve estimates utilized by Mr. Pewterbaugh or the HIOS-specific reserve estimates utilized by Mr. Jenkins provide the better evidence of HIOS' remaining life.[47]

76. To support her adoption of Staff's area-wide reserve estimate, the ALJ relied on *Trunkline Gas Company*,[48] where the Commission held:

[45] HIOS BOE at 66.

[46] IS BOE at 23.

[47] Initital Decision, 107 FERC ¶ 63,019 at P 74.

[48] 90 FERC ¶ 61,017 at 61,055 (2000).

> The Commission's depreciation decisions are made in the context of gas ratemaking proceedings. They consider the foreseeable future of the pipeline and its supply areas and must be based on long-term forecasts of supply over large areas. They are based on the resources available within whole gas supply provinces. The full universe of available supplies must be considered in determining the remaining life of the pipeline as an active operation and its corresponding depreciation rates.

77. In his testimony, Mr. Jenkins relies on estimates for only a portion of the WPA, namely, only those he determined to be accessible to the HIOS system, claiming the entire WPA area is too large an area to consider. He makes this claim despite the fact that HIOS currently receives, or has the potential to receive gas from the High Island, East Breaks, West Cameron, Alaminos Canyon, Keathley Canyon, Galveston and Garden Banks areas of the WPA. These areas represent approximately two-thirds of the WPA's total area. In addition, as conceded by HIOS, HIOS either actually accesses gas supplies or can access supplies in each region of the WPA.[49] Also, the ALJ noted that HIOS identified over 57 drilling prospects in various stages of development that could be connected to HIOS and that HIOS conceded that six prospective gas supplies are within the WPA and some supply areas extend beyond the WPA.[50] As noted by Staff, HIOS also has the ability to attach significant new reserves to its 200-mile, multi-pronged system such as the increased throughput provided by its East Breaks lateral.[51] Finally, the record shows that that the demand for gas is expected to rise from 22.3 trillion Btu (TBtu) in the year 1999 to 32.498 TBtu in the year 2020.[52]

78. Based on these factors, the Commission finds that it is not credible that HIOS could not obtain gas supplies from the entire WPA region, which includes potential production from deep gas in the shallow OCS waters and unleased prospects in the Gulf of Mexico that are not currently active or have not yet been discovered, excluded from Mr. Jenkins' study. Therefore, the Commission rejects as unpersuasive and unreasonable HIOS' study and its conclusion that it has an economic life of ten years.

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[49] Exhs. S-4, 16:7-13, & 20:1-3 (Pewterbaugh).

[50] IS BOE at 13.

[51] Staff RB at 47.

[52] Staff Exh. S-4 at 26:9-15.

79. Therefore, we find Staff's gas supply estimate most persuasive in the record and consistent with Commission policy for estimating the potential recoverable natural gas and for developing estimates within a zone of reasonableness.[53] Also, we find Indicated Shippers' arguments to be conclusory, and without any evidence in the record to support their claimed adjustments to Staff's study. Accordingly, the ALJ's findings in the Initial Decision concerning HIOS' depreciation rates, amortization expense and negative salvage allowance are affirmed.

C. Management Fee

80. The original cost of HIOS' gas plant in service is $385,510,921. Its accumulated depreciation is $372,105,125, leaving net plant of only $13,405,796. HIOS has collected through its past rates deferred tax revenue of $1,093,882 and negative salvage revenue of $13,256,294. When these two amounts are subtracted from HIOS' net plant, it is left with a negative rate base.[54] This has raised the issue whether HIOS should be allowed a management fee in lieu of the return on net rate base that the Commission ordinarily includes in a pipeline's rates, and, if so, what the level of the management fee should be.

Initial Decision

81. The ALJ found that this case is similar to *Tarpon Transmission Co.*,[55] in which the Commission approved a management fee for a pipeline whose transmission plant was fully depreciated. In so doing, the Commission found that a management fee could provide a better incentive for efficiency for a pipeline that has fully depreciated its transmission plant.[56] The ALJ accordingly found that HIOS should be awarded a management fee based on the same formula that was used to calculate the management fee in *Tarpon.*

82. The ALJ rejected Indicated Shippers' contention that no management fee should be awarded. Indicated Shippers contended that this case is distinguishable from *Tarpon*, since HIOS' transmission plant, unlike Tarpon's, is not fully depreciated. The ALJ,

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[53] *South Dakota Utilities Commission v. FERC*, 668 F.2d 333, 345 (8th Cir. 1981).

[54] *Citing* Exh. HIO-106.

[55] 57 FERC ¶ 61,371 (1991).

[56] *Id.*

however, found that the absence of a positive rate base on which a return can be based is the critical factor in determining that a management fee is appropriate, not whether the transmission plant has been fully depreciated. The ALJ also rejected Indicated Shippers' proposal that, rather than subtracting negative salvage revenues from rate base, those amounts be placed in a separately designated, interest bearing trust account. The ALJ held that, while the Commission did endorse such a separate account for negative salvage in *Tarpon*, it has not required a trust account in all cases where a negative salvage allowance has been granted.[57] In fact, the Commission has approved HIOS collection of negative salvage amounts in the past without placing them into a trust account. The ALJ accordingly concluded that, given the potential difficulties involved in altering these arrangements now, application of negative salvage to reduce rate base is just and reasonable. The ALJ concluded that, as in *Tarpon*, a management fee is appropriate as an alternative for HIOS since a traditional cost of service rate methodology cannot apply with a negative rate base.

83. Having concluded that a management fee is appropriate, the ALJ turned to the calculation of the amount of the fee. She pointed out that, in *Tarpon*, the Commission calculated the management fee by applying the current pretax cost of capital to 10 percent of the pipeline's historical average rate base. *Tarpon* stated that "this should provide an incentive for increased throughput and efficiency without providing a fee that would be so high that competitors would enter the market in the absence of significant barriers to entry."[58] The ALJ accordingly concluded that HIOS' management fee should be calculated using the same formula as in *Tarpon.*

84. The ALJ held that Staff's proposed management fee of $680,802 followed the *Tarpon* formula, and therefore should be approved. Staff arrived at this number by calculating HIOS' average rate base for the period from 1979-2002 ($54,691,713).[59] Staff then took 10 percent of this number ($5,469,171) and multiplied that by a 12.448 percent pretax rate of return for a total management fee of $680,802.[60] Staff developed

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[57] *See Kansas Pipeline Co.*, 96 FERC ¶ 63,014 at 65,100-01 (2001) (permitting negative salvage in a separate account, but denying request for a separate trust account), *aff'd in pertinent part, Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 292-95 (2002), *order on reh'g*, 102 FERC ¶ 61,310 (2003).

[58] *Tarpon,* 57 FERC ¶ 61,371 at 62,241.

[59] Exhs. S-2 at Sch. W(2), S-11.

[60] Exh. S-2 at 17, Sch. W(2).

its pretax rate of return by computing an overall rate of return of 9.6 percent based on a hypothetical capital structure of 50.8 percent long term debt and 49.2 percent common equity and applied a debt cost of 8.04 percent and an equity cost of 11.22 percent.[61] Staff computed the pretax return by applying a 34 percent federal tax rate to the equity component of the capital structure, which produced the pretax rate of return of 12.448 percent.[62] The ALJ rejected HIOS' proposed management fee of $9,323,608 as not being consistent with *Tarpon*.

85. Both Indicated Shippers and HIOS have excepted to the ALJ's holdings concerning the management fee. Indicated Shippers primarily contend that the ALJ should not have allowed any management fee at all. HIOS, by contrast, contends that the ALJ should have approved its much higher proposed management fee of over $9 million, or at least an amount significantly above the $680,802 proposed by Staff. Below, we first address the issue whether HIOS should be awarded any management fee. Finding that the ALJ correctly determined that HIOS should be awarded a management fee, we then turn to the issue of how that fee should be calculated.

(1) Whether HIOS should be awarded a management fee

Briefs on and opposing exceptions

86. Indicated Shippers contend that, on the facts of this case, there is no justification for a management fee. They first argue that a management fee represents a departure from the principle that rates should be based on the pipeline's costs. Indicated Shippers assert that to justify such a departure, there must be a reasonable explanation of the need for the non-cost component in HIOS' rates.[63] Indicated Shippers contend that there has been no showing that HIOS needs a management fee to continue its operations or as an incentive to reduce costs, increase throughput, or construct new facilities. Indicated Shippers argue that, if the Commission permits HIOS to include in its cost of service the entirety of the fees HIOS pays to GTOC to operate its system, then HIOS would already have recovered the full cost of operating the system plus some unspecified fee profit for GTOC.

87. Indicated Shippers contend that, in view of the fact that a management fee

[61] Exh. S-12, Schedule A, page 1.

[62] Exh. S-2, Schedule W(2), part 2.

[63] IS BOE at 32.

represents a departure from rate principles, such a fee is "justified only in situations where the pipeline has no net plant and is facing imminent financial distress, and all of the *Tarpon* criteria are satisfied."[64] Indicated Shippers state that HIOS has recouped most of the capital that it invested in its facilities and paid this money out in partnership distributions and, as a result, a management fee is not necessary to give HIOS a return on capital for its investments. Consequently, Indicated Shippers contend HIOS' investors have already more than met their expectations regarding return of capital and have no need for a special management fee to protect against financial distress.

88. Indicated Shippers propose an alternative, namely, reducing the negative salvage balance by one-half, which would produce a rate base of $5.6 million, and using the ALJ's overall rate of return of 9.6 percent, would result in a return of $0.54 million.[65]

89. HIOS responds that its proposed management fee is in fact based on the costs imbedded in the historical rate base computation, or in the original cost of facilities rate base it proposes to be used in the *Tarpon* formula, *i.e.*, gas plant investment by HIOS, contrary to Indicated Shippers' assertions that a management fee is not cost based. Thus, HIOS urges that Indicated Shippers' argument that the management fee must be justified as a non-cost charge lacks merit.[66] Regarding Indicated Shippers' claim that a management fee must have operating or efficiency goals or serve to reduce costs or increase throughput, HIOS argues that the existence of a management fee has no bearing on a pipeline's incentive to increase throughput or reduce costs as it already has that incentive in seeking to generate greater earnings between rate cases.[67]

90. HIOS also argues that there is no requirement that a pipeline commit to expand its operations as a prerequisite to obtaining a management fee, as a management fee is a substitute for a traditional return on investment.[68] HIOS attacks Indicated Shippers' position that no management fee can be granted when there remains depreciable plant. In *Tarpon*, the Commission held that absent an owners' fee, Tarpon would have only limited incentives to manage the operations on an efficient basis once the plant has been

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[64] *See Tarpon*, 57 FERC ¶ 61,371 at 62,240 (1991).

[65] IS BOE at 37.

[66] HIOS RB at 18.

[67] HIOS RB at 18-19.

[68] HIOS RB at 19.

fully depreciated.[69] It is correct that Tarpon had little or no undepreciated plant in its rate proceeding, however, the situation here is effectively the same as HIOS' situation as rate base is determined by deducting negative salvage from net plant to apply to a rate of return.[70] Without a rate base, it is not possible to compute a return.

91. Finally, HIOS urges that Indicated Shippers' alternative solution to manufacture a small rate base by crediting only one-half of negative salvage to rate base reduction would produce a meager management fee less than that adopted by the ALJ, and HIOS argues that it should be rejected as a contrived and arbitrary approach.

Discussion

92. We affirm the ALJ's holding that a management fee is appropriate here where HIOS has no traditional rate base on which to earn a return. Indicated Shippers is incorrect in its contention that HIOS should not be granted a management fee absent a showing that it is in imminent financial distress. In *Tarpon,* the Commission approved a management fee without any showing of financial distress. Rather, the Commission held that a management fee was appropriate, once there was no longer a rate base on which to earn a return, "to compensate Tarpon's owners for the risks of continuing to operate the pipeline and to provide an incentive for efficient operations."[71] Since HIOS no longer has a rate base on which to earn a return, it is appropriate to include a management fee in its cost of service.

93. Indicated Shippers argue HIOS has failed to show that it needs a management fee to continue operations, or as an incentive to reduce costs, increase throughput or construct new facilities. We find that establishing rates for HIOS that would only recover its projected costs of continuing to operate the pipeline without any allowance for earning a profit would leave HIOS' owners with "only limited incentives to manage the operations of the pipeline on an efficient basis."[72] Giving HIOS an opportunity to earn a modest profit through a management fee should be an effective means of encouraging efficient operations, including reducing costs and increasing throughput and maintaining needed transportation facilities.

[69] HIOS RB at 21, citing 57 FERC ¶ 61,371 at 62,240.

[70] HIOS RB at 22.

[71] *Tarpon*, 57 FERC ¶ 61,371at 62,240.

[72] *Id.*

94. Indicated Shippers argue that HIOS' cost of service includes fees paid to its affiliate GulfTerra Operating Co., which includes a profit on non-routine billings, and that should satisfy the demand for a profit. We disagree because the allowed O&M expenses have been found to be reasonable on their own as a re-imbursement for the time and expense incurred to provide these additional administrative services, and these actual costs are not a profit.[73] Here, we are dealing with a management fee as a substitute for the traditional return on invested capital as an incentive for the management to continue to operate the pipeline to serve the needs of the ratepayers.

95. Finally, as an alternative to allowing a management fee, Indicated Shippers proposes to create a rate base of $5.6 million on which a traditional return may be allowed, by reducing the negative salvage balance by one-half. We reject this proposal as arbitrary and contrary to established rate base methodologies. Further, Indicated Shippers provided no rationale for its arbitrary reduction of the negative salvage balance by 50 percent, other than to reduce the management fee to $0.54 million. Accordingly, we agree with HIOS that Indicated Shippers' alternative proposal is without merit because it is inconsistent with ratemaking principles addressing deductions from net plant to derive rate base and return and produces an unreasonably low fee compared to the magnitude of the enterprise.

(2) Calculation of the Management Fee

96. HIOS contends that the ALJ should have approved its proposed management fee of over $9 million. At the hearing, HIOS proposed, in essence, a modification of the *Tarpon* formula for calculating a management fee. Under the *Tarpon* formula, the management fee is calculated by multiplying the overall pre-tax return allowed for the pipeline by ten percent of the pipeline's average historical rate base. HIOS proposed to use a much higher rate base figure to calculate its management fee, contending that there should be a floor on the rate base figure used in the formula equal to 20 percent of HIOS' gross investment in plant. This floor would apply, even if the pipeline's rate base were positive. Thus, a pipeline would always be guaranteed a return on at least 20 percent of its original rate base, through a return on any positive rate base and a management fee on any amount by which 20 percent of the pipeline's original investment in its facilities exceeds the positive rate base. HIOS proposed to multiply this substitute rate base by the overall return approved for the pipeline.[74] In contrast to the *Tarpon* formula, which

[73] *See also Tarpon*, finding that the fact the pipeline's rates include an allowance for the owners' salaries for the daily management of the pipeline does not justify providing no management fee. *Id.*

[74] Exhs. HIO-19 and 67.

uses the overall *pretax* return, *i.e.*, the return adjusted upward to account for taxes, HIOS proposed simply to use the overall return, without any upward adjustment for taxes.

97. In subsequent sections of this order, we will address issues concerning the appropriate overall return to be used in calculating the management fee and the treatment of taxes. In this section, we address only the issue of what substitute rate base to use in determining the management fee.

98. Twenty percent of HIOS' $385.5 million investment in plant is $77 million. Since HIOS' rate base is negative, it proposed to use this amount as the substitute rate base for purposes of calculating its management fee. Multiplying $77 million by its proposed overall return of 12.08 percent produced a proposed management fee of $9.3 million. By contrast, under the *Tarpon* formula adopted by the ALJ, the management fee is calculated by multiplying 10 percent of HIOS' average historical rate base of $54.7 million, or only $5,469,171, by HIOS' pre-tax rate of return. HIOS argues that the ALJ's Initial Decision ignored its arguments in favor of setting a floor on the rate base used to calculate the management fee and gave no reasons for rejecting its proposal.

99. HIOS' primary argument in favor of its proposal is that a floor is necessary to eliminate any disincentive for it to invest in new facilities. HIOS contends that under the management fee adopted by the ALJ, it would lose its management fee if it made investments that created a positive rate base, no matter how small. Moreover, it asserts that if it makes plant additions of up to $15 million, the return on rate base it would receive would be less than the forfeited management fee. However, under HIOS' proposal, while creation of a positive rate base would reduce the management fee to the extent of the return yielded by the positive rate base, it would not completely eliminate the management fee unless HIOS makes a sufficient investment in facilities to create a rate base of at least 20 percent of its original investment.

100. HIOS also attacks the management fee of $680,602 approved by the ALJ on a number of grounds. HIOS argues that the *Tarpon* method used to calculate that fee is not appropriate for HIOS because it uses the average rate base over the life of the pipeline. Tarpon's depreciation was constant over time, whereas HIOS' early accelerated depreciation and variations in ADIT skewed the average rate base. In Tarpon's case, the average rate base was approximately 50 percent of investment, whereas in HIOS' case the average is less than ten percent.[75] As shown in its testimony, HIOS had negative rate bases starting in 1998 and these figures further distort the computation of average rate

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[75] In Exhibit HIO-65, HIOS' net rate base at midpoint was $22 million, less than 10 percent of total gross plant of $385 million.

base and may in the future make the average a negative, which would produce no Tarpon method management fee. HIOS states that a normal average rate base over the life of its pipeline would be about $180 million, based on total investments in plant, and that would produce an annual management fee of $2.2 million.[76]

101. HIOS argues that the $680,602 management fee approved by the ALJ would give it insufficient cash reserves to manage fluctuations in revenues or expenses, creating an unacceptable risk that HIOS could become insolvent.[77] HIOS argues that the ALJ's management fee would only cover a four percent swing in its annual operating expenses of $18.3 million. HIOS also argues it would add to business risk, because HIOS has no assurance of a firm revenue stream to support its cost structure since only five percent of its capacity is firm and throughput has declined from 341 MMDth in 1998 to 270 MMDth in 2003, and it projects a continuing decline.[78]

102. HIOS also argues that such a low management fee provides no incentive for HIOS to compete for new gas supply with new capital and capital to continue operating the existing system (HIOS estimates approximately $2.7 million in annual additions to plant are required, and $6.6 million was expended in the test period).[79] Without such incentives, owners would have no incentive for future investments in the system.[80] Further, negative salvage increases in the future would wipe out any net rate base.

103. Finally, HIOS contends that there is no need to limit its management fee to the low level produced by the *Tarpon* formula in order to assure that HIOS has an incentive to operate efficiently. HIOS contends that, under the Commission's traditional test-period ratemaking methodology, all pipelines have an incentive to operate efficiently, since they may earn more than their allowed return if they can reduce costs below, or increase throughput above, the levels projected based on test period data.[81] HIOS also argues that *Tarpon* can be distinguished because it had a cost of service tariff and was allowed

[76] Exh. HIO-64 at 15.

[77] HIOS BOE at 20.

[78] HIOS BOE at 34; Exh. HIO-64 at 22.

[79] HIOS BOE at 17; Exh. HIO-64 at 11-13.

[80] Exh. HIO-64 at 8.

[81] HIOS cites *Canyon Creek Compression Co.*, 99 FERC ¶ 61,351 at P 14 (2002).

windfall profits by paying extraordinarily high salaries for its executives who were the owners of the company, as well as high travel expenses and other perks.[82]

104. Staff, Indicated Shippers, and ExxonMobil all oppose HIOS' exception on this issue. They contend that the ALJ correctly found that the *Tarpon* methodology for calculating the management fee provides an appropriate amount for HIOS and that the amount requested by HIOS was excessive. They contend that the ALJ's management fee does not create a disincentive for investment in pipeline infrastructure or create a risk of insolvency for HIOS. They also assert that the ALJ's management fee appropriately gives HIOS an incentive to act efficiently. They further argue that the ALJ's decision does not penalize HIOS for its use of accelerated depreciation and oppose HIOS' alternative suggestion that its management fee be calculated as if it had used straight line depreciation.

Discussion

105. The Commission finds that HIOS has not satisfied its burden under NGA section 4 to show that its proposed management fee of over $9 million is just and reasonable. However, the Commission will modify the management fee adopted by the ALJ. In the circumstances of this case, the average rate base used in the *Tarpon* formula should be one half of HIOS' gross investment in plant, rather than the average of HIOS' net rate base at the end of each year of its life. This change in the calculation of HIOS' management fee (together with changes in the return calculation discussed below) results in a fee of just under $2,000,000.

106. The Commission held in *Tarpon* that a management fee should compensate the owners of a pipeline with a negative rate base for the risks of continuing to operate the pipeline once the original investment has been recovered and provide an incentive for efficient operations.[83] The Commission also stated, "Thus, the purpose of the management fee is to encourage Tarpon to take actions to prevent an injurious loss of throughput by more aggressively marketing its gas supplies, pricing its services to increase volume, and to minimize costs. The Commission believes that the size of the management fee should be high enough to encourage such activities, but not so high that it would be equivalent to a monopoly return unavailable to a firm operating under competitive conditions." [84] The Commission finds that the revised management fee

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[82] HIOS BOE at 29.

[83] 57 FERC ¶ 61,371at 62,240

[84] *Id*. at 62,241.

approved in this order is fully sufficient to accomplish these purposes, and the much higher management fee proposed by HIOS is unjustified.

107. The management fee we approve here is fully adequate to compensate HIOS' owners for the risks of continuing to operate the pipeline. In the first place, we believe HIOS overstates its business risks. HIOS transports gas from the High Island and West Cameron offshore production areas to major interstate pipelines. Its two major firm shippers have contractually committed to transporting production from their gas reserves in those areas through HIOS. Moreover, the record shows that even the large volumes of gas transported on an interruptible basis through HIOS are in fact captive to HIOS, since shippers would face high hookup costs in order to access a different pipeline.[85] While HIOS claims that it suffers from a lack of additional accessible gas reserves, the record shows that it recently invested $80 million to build the non-jurisdictional East Breaks Gathering System in order to attach additional reserves to its system.[86] Also, as discussed above in the depreciation section of this order, we find that substantial additional accessible reserves also exist. HIOS also has received all of its investment in the pipeline, and thus it has no financial risk.[87]

108. We also find that HIOS has not shown that a management fee of the level we approve in this order would leave it with insufficient cash reserves to manage fluctuations in revenues or expenses or create an unacceptable risk that HIOS could become insolvent.[88] HIOS' operating costs, depreciation, and negative salvage totaling over $20 million are already included in the allowed cost of service and should provide the cash flow HIOS requires to continue to be solvent.[89] HIOS' proposed $9.3 million management fee, if approved, would amount to nearly one third of HIOS' cost of service, even without any additional allowance for taxes. Thus, HIOS' proposed management fee would be of comparable magnitude to the management fee of almost half the pipeline's cost of service proposed by the pipeline in *Tarpon*. In that case, the Commission

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[85] Exhs. S-11 at 15, S-4 at 27, and IND-1 at 12. *See also* the map in Exh. HIO-28 showing the absence of other nearby pipelines.

[86] Exh. HIO-76 at 3, 6; Tr. 209, 210, 238.

[87] IS RB at 33.

[88] HIOS BOE at 20.

[89] Staff RB at 22-24.

described a management fee of such magnitude as “huge,”[90] and rejected it as contrary to its policy of permitting a “modest management fee” to encourage efficiency.[91]

109. HIOS suggests various reasons why it might not be able to collect the full cost of service approved in this case. For example, it states that its throughput has declined from 341 MMDth in 1998 to 270 MMDth in 2003, and it projects a continuing decline. However, if HIOS determines it cannot recover its cost of service through the rates approved in this rate case because of a change in circumstances, it is free to file a new rate case proposing higher rates. HIOS suggests that the ALJ’s management fee would leave it with such a “razor-thin” 3.5 percent margin over operating expenses,[92] that it might not have time to prepare a new rate case and place the new rates into effect after a five month suspension before being forced into bankruptcy. However, the increased management fee we approve in this order would provide a greater operating margin. In any event, it is the responsibility of prudent management to maintain cash on hand necessary to weather downturns in its business. HIOS has made distributions to its partners of $23.2 million in 1998, $15.3 million in 1999, $23.9 million in 2000, and $25 million in 2001.[93] The Commission sees no reason to approve a management fee of $9.3 million, providing a margin of nearly 50 percent over operating expenses, to a pipeline that has been able to make such large cash distributions to its partners in the recent past.

110. HIOS suggests that using the *Tarpon* methodology to calculate a management fee creates a disincentive to invest in pipeline infrastructure, because if the pipeline continues to make the investments necessary to maintain its system and thereby creates a small positive rate base it will lose its management fee. HIOS seeks to avoid this result by its proposal to place a floor on the rate base used to calculate its management fee/return of twenty percent of its original investment. The Commission rejects this contention. First, HIOS assumes that the Commission would refuse to allow any management fee, if the pipeline had a positive rate base regardless of how small and regardless of whether that rate base was less than the portion of the pipeline’s original investment that would be used to calculate a management fee. The Commission has never been faced with a case where the pipeline had such a small positive rate base, and has thus never addressed the question whether to permit a management fee in such circumstances. However, as a

[90] 57 FERC ¶ 61,371 at 62,241.

[91] *Id*. at 62,240.

[92] HIOS BOE at 20-21.

[93] Exh. S-22.

general matter, the Commission believes that the policy underlying its allowance of a management fee where there is no rate base would support allowing a sufficient management fee in the situation of a very small positive rate base, such that a pipeline in that situation would not be worse off than if it had a negative rate base. Thus, HIOS' concern about the complete loss of its management fee is without basis. Moreover, HIOS' proposal to set a floor of 20 percent on the rate base used to calculate the management fee/return would actually provide less incentive for HIOS to invest in additional facilities, as additional rate base investments up to this higher level would only serve to reduce the management fee by an equivalent amount.

111. Most of HIOS' arguments seeking to distinguish *Tarpon's* holding concerning the substitute rate base to be used in calculating the management fee are unavailing. HIOS suggests that the Commission set the management fee in *Tarpon* at a relatively low level because Tarpon had a cost of service tracker. However, contrary to HIOS' argument, the Commission took section 5 action to eliminate Tarpon's cost of service tracker.[94] HIOS' claim that Tarpon's executives and employees received high salaries is also wrong as the record shows they were not paid extraordinarily high salaries, whereas HIOS made high cash distribution to its owners.[95] Also, the Commission reaffirmed *Tarpon* in the *Natural* case.[96]

112. However, there is one respect in which we agree with HIOS that an adjustment to the *Tarpon* calculation of substitute rate base is appropriate in the circumstances of this rate case. As discussed above, under *Tarpon*, the substitute rate base is determined by multiplying the pipeline's average rate base over the life of the pipeline by ten percent. In *Tarpon*, the pipeline had used straight-line depreciation, and the Commission expressly noted that its average rate base was approximately 50 percent of gross investment.[97] This meant that the management fee approved in *Tarpon* was equal to providing the pipeline a return on five percent of its original investment.

113. Here, however, HIOS used a high initial depreciation rate of 8.33 percent in the early years of the project and credited additional transportation revenues to accumulated

[94] IS RB at 37 citing *Tarpon*, 57 FERC ¶ 61,371 at 62,229-30.

[95] IS IB at 38.

[96] IS RB at 39, *citing Natural Gas Pipeline Co. of America,* 105 FERC ¶ 61,383 at P 19 (2003).

[97] 57 FERC ¶ 61,371 at 62,241.

depreciation, recorded as Supplemental Depreciation.[98] HIOS also had negative rate bases starting in 1998. As a result, calculating HIOS' average rate base in the same manner used in *Tarpon* results in an average rate base of $54.7 million, and ten percent of that amount is only $5,469,171, which is only slightly more than one percent of HIOS original rate base. In short, while in *Tarpon*, the Commission allowed a management fee equal to a return on about five percent of the pipeline's original investment, using the same formula in this case would lead to allowing HIOS a management fee equal to a return on only about one percent of its original investment. HIOS computed a substitute average rate base over the life of the project of $180 million, based on investments in plant, which would produce an annual management fee of $2.2 million.[99]

114. The unique historical circumstances of HIOS' depreciation of plant investment over the life of the project, as reflected in the record and as described above, persuade us to make a modification. As discussed above, the purpose of allowing a management fee is to compensate the owners of a pipeline with a negative rate base for the risks of continuing to operate the pipeline once the original investment has been recovered and provide an incentive for efficient operations. We do not believe that differences in the timing of the pipeline's past recovery of its original investment in order to arrive at its current situation of a negative rate base should have a major effect on a fee whose purpose is to provide the pipeline modest compensation for future activities in operating the pipeline. Indeed, in *Tarpon* the Commission rejected the use of past returns in calculating the management fee so that the management fee would be "less subject to the influence of past performance."[100] Having found that a management fee equal to a return on about five percent of the original investment was appropriate in *Tarpon,* we see no reason to limit HIOS to a significantly lower management fee.

115. HIOS computed a normal average rate base over the life of the project of $180 million, based on total investments in plant.[101] Mr. Porter testified that this calculation assumes HIOS' average cost of facilities as an average rate base at the midpoint of the pipeline's useful life, as assumed in *Tarpon*.[102] Accordingly, we concur with this

[98] Exh. HIO-64 at 5-6; *High Island Offshore System, L.L.C.*, 5 FERC ¶ 61,267 at 61,580 (1978).

[99] Exh. HIO-64 at 15. HIOS assumed a rate of return of 12.45 percent.

[100] 57 FERC at ¶ 61,371 at 62,241.

[101] Exh. HIO-64 at 15.

[102] Exh. HIO-64 at 15.

testimony and exhibit that the actual average rate base of HIOS applied to the *Tarpon* formula is inappropriate and produces an unreasonable result. Therefore, we find that the substitute rate base to be used in calculating HIOS' management fee should be 10 percent of its average rate base of $180,625,854.[103] We now turn to the issues of the return to be used in the management fee calculation and the treatment of taxes.

D. Rate of Return

116. The various management fee proposals presented at the hearing in this case all use HIOS' overall rate of return, including both its debt costs and its return on equity as an element in the management fee formula. The parties are in agreement that HIOS' debt cost is 8.04 percent. Thus, we must consider three rate of return issues in this order: (1) the appropriate proxy group to be used both in evaluating whether to use a hypothetical capital structure and in determining the range of reasonable returns under the DCF model; (2) the capital structure; and (3) the return on equity, particularly the appropriate projection of long-term growth in dividends and where to place HIOS in the zone of reasonableness.

(1) Proxy Group

117. The Commission has historically required that each company included in the proxy group satisfy the following conditions. First, the company's stock must be publicly traded. Second, the Commission has required that the company be recognized as a natural gas pipeline company and that its stock be recognized and tracked by an investment information service. Third, the Commission has required that pipeline operations constitute a high proportion of the company's business.[104] However, in recent years fewer and fewer companies have met these standards, because of mergers, acquisitions, and other changes in the natural gas industry. In a July 2003 order in *Williston Basin Interstate Pipeline Co. (Williston)*, 104 FERC ¶ 61,036 at P 35 (2003), the Commission found that only three companies remained that met the Commission's traditional standards for inclusion in the proxy group. In those circumstances, the Commission approved the pipeline's proposal to use a proxy group based on nine companies listed among the Value Line Investment Survey's group of diversified natural

[103] The management fee set out in Exh. HIO-65 using the filed for rate of return must be recalculated to be based on the rate of return resulting from our decision on other issues in this proceeding, including taxes. *See* our calculation of the management fee in P 166 *infra.*

[104] *Transcontinental Gas Pipe Line Corp.*, 90 FERC ¶ 61,279 at 61,933 (2000).

gas companies that own Commission regulated natural gas pipelines. The Commission found that, based the record in that case, those companies represented a functional proxy group to establish the pipeline's return on equity.

118. In this case, the ALJ adopted the proxy group proposed by Staff, consisting of four companies: Kinder Morgan, Inc., Equitable Resources, Inc., National Fuel Gas Company, and Questar. In developing this proxy group, Staff used as its starting point the nine companies which the Commission approved for use in the proxy group in *Williston.* However, Staff excluded five of the companies it no longer considered appropriate.[105] It excluded Columbia and Coastal Corp. because these entities were acquired by other companies and are no longer publicly traded. It excluded Enron because it was in bankruptcy, and excluded El Paso and Williams because financial difficulties have resulted in lowered dividends for these companies. The ALJ found that Staff's removal of five of the companies approved in *Williston* is reasonable and, while this leaves a relatively small proxy group of four companies, such proxy groups have been accepted by the Commission.[106]

119. The ALJ rejected the alternative proxy group proposals by HIOS and Indicated Shippers. HIOS agreed with Staff that Kinder Morgan, Inc. should be included in the proxy group. However, it contended that the remaining three companies Staff proposed to use should be excluded, because a substantial portion of their natural gas business was local distribution service, rather than interstate pipeline service. HIOS contended that, instead, four pipeline master limited partnerships (MLPs) should be included in the proxy group: GulfTerra Energy, Kinder Morgan Energy Partners, Northern Border Partners, and Enterprise Products Partners, in addition to Kinder Morgan, Inc. The ALJ was concerned that, because MLPs do not pay corporate taxes, and they can pay out substantially larger dividends than corporations, including in excess of earnings. She suggested that this would skew the result of any proxy group including both MLPs and corporations. The ALJ recognized that the Commission had permitted use of MLPs in the proxy group in *SFPP, L.P.,*[107] an oil pipeline rate case. However, she pointed out that, in that case, the Commission had relied on the fact that the record contained two to three years of

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[105] Exh. S-11 at 11-12.

[106] *See e.g., EPGT Texas Pipeline, L.P.,* 99 FERC ¶ 61,295 at 62,250 (2002) (order on Staff panel); *Williston,* 95 FERC ¶ 63,008 at 65,090-91 n.203 (2001); *Horizon Pipeline Co.*, 92 FERC ¶ 61,205 at 61,687 (2000) (using four companies in preliminary order determining non-environmental issues).

[107] *SFPP*, *L.P.*, 86 FERC ¶ 61,022 at 61,099 (2001) (Opinion No. 435).

information concerning market prices and trading patterns in oil partnership limited shares. She found that in this case the record lacked similar evidence as to the trading history of MLPs in the natural gas industry.

120. The ALJ also rejected Indicated Shippers' proposed proxy group of sixteen companies. Indicated Shippers proposed to include the four companies from the *Williston* group used by Staff. In addition, it proposed to include two other companies from the *Williston* group, El Paso and Williams, which Staff had excluded because of lowered dividends due to financial difficulties. Indicated Shippers also sought to include two other companies from the Value Line group of diversified natural gas companies, GulfTerra and ONEOK, Inc. Indicated Shippers contended that the inclusion of GulfTerra is proper, even though it is an MLP, because it is HIOS' parent. Finally, Indicated Shippers proposed to add eight large local distribution companies (LDCs) from the Value Line "Natural Gas (Distribution) Industry" grouping.[108] The ALJ found that Indicated Shippers had not demonstrated a need to expand Staff's proposed four company proxy group. She stated she was not persuaded by Indicated Shippers' contention that LDCs face risks similar to pipelines. She also rejected inclusion of GulfTerra, since it is an MLP.

Briefs on and opposing exceptions

121. HIOS argues on exceptions that the ALJ erred in accepting Staff's proxy group proposal, instead of HIOS' proposal. HIOS contends that, aside from Kinder Morgan, Inc., the remaining three companies in the proxy group approved by the ALJ earn substantially more from their LDC operations than from their pipeline operations. Therefore, they should be treated as LDCs and excluded from the proxy group for the same reasons the ALJ rejected Indicated Shippers' proposal to include an additional eight LDCs in the proxy group. HIOS also argues that the ALJ erred in excluding its proposed four MLPs from the proxy group.[109] HIOS asserts that the tax advantages of MLPs do not skew the results of the proxy group. The tax advantages of the MLPs it claims have been diminished by recent reductions in corporate dividends. HIOS also contends that MLPs are appropriate because HIOS is a limited liability company which is treated for income tax purposes as a partnership and because changes in the industry have reduced the number of suitable gas pipeline corporations.

[108] Exh. IND-3.

[109] HIOS BOE at 43.

122. Indicated Shippers, by contrast, contends that the ALJ erred in rejecting its proposal to include additional LDCs in the proxy group. It argues that the unbundling of merchant and transportation service by LDCs in many states means that LDCs are increasingly operating as transmission companies, like pipelines, and are directly competing with pipelines. It also claims there are various other similarities between pipelines and LDCs including that both tend to own and operate storage facilities and have similar dividend yields.

123. HIOS and Indicated Shippers each oppose the exceptions of the other. Staff opposes the exception of HIOS.

Commission Decision

124. We affirm the ALJ's approval of Staff's proposed proxy group. We find that, based on the record in this case, the ALJ properly rejected both HIOS' proposal to include MLPs in the proxy group and the Indicated Shippers proposal to include companies who are classified as distribution companies by Value Line.

125. The Commission finds that the proxy group proposed by Staff is the best available proxy group for use in this case, based on the record developed before the ALJ. The Commission recognizes that, in theory, it might be appropriate to compare HIOS, an L.L.C. owned by an MLP, with other MLPs whose business is made up primarily of pipeline operations. However, before the Commission could consider including an MLP in the proxy group, the record would have to contain reliable financial data concerning the MLP, comparable to that for corporations, so as to permit the Commission to determine a return on equity for the MLP under the Discounted Cash Flow (DCF). As described in more detail below, under the DCF analysis used by the Commission, return on equity is considered to equal dividend yield (dividends divided by stock price), plus the estimated constant growth in dividends. The estimated growth in dividends is based on five-year Institutional Broker's Estimate System (IBES) growth projections for the company and a projection of the long-term growth of the Gross Domestic Product (GDP). Thus, the financial data the Commission must have for any entity to be included in the proxy group includes (1) the level of its dividend payments, (2) its stock price, and (3) a five-year IBES growth projection.

126. HIOS did submit an exhibit at the hearing that purported to show this information for each of the MLPs it proposed to include in the proxy group, including stock prices for the period March to August 2003, IBES growth projections, and annual dividend

payments.[110] HIOS' exhibit stated that this information was from the "IBES Report of 8/14/03." However, it is not clear from the evidence presented by HIOS that the "dividend" figures supplied by HIOS for the MLPs it proposes to include in the proxy group are comparable to the corporate dividends the Commission uses in its DCF analysis. Partnerships make distributions to their partners, rather than pay dividends to stockholders. Those distributions may include payment to the partners of a share of the partnership's earnings; to that extent the distribution is comparable to corporate dividend payments. However, the distributions may also include a return of a portion of the partners' original investment, unlike a corporate dividend.[111] Use of a distribution payment that includes both earnings and a return of investment as an MLP's "dividend" for purposes of a DCF analysis would skew the DCF results, since the dividend yield would appear higher than it actually was.[112] Thus, the Commission will not consider including an MLP in the proxy group, unless the record demonstrates that the distribution used as the "dividend" includes only a payment of earnings and not a return of investment.

127. In the instant case, HIOS' exhibits showing its DCF analysis for the MLPs it proposes to include in the proxy group include figures labeled "annual divd" for each MLP.[113] The dividend yields calculated by HIOS for these MLPs in its proxy group based on this data range from 3.2 percent to 7.88 percent,[114] as compared to the range of dividend yields for natural gas companies from 1.59 percent to 4.70 percent.[115] Thus, the

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[110] Exh. HIO-135. HIOS also presented this information for Northern Border Partners for the period May-October 2002. Exh. HIO-87.

[111] Exh. IND-17 at 4.

[112] That the DCF results could be significantly skewed is shown by the fact that two of the MLPs in HIOS' proxy group, El Paso Energy Partners and Northern Border Partners, over the 2001-2003 time period, averaged a 301.3 percent payout ratio, which indicates that two-thirds of their payout distributions are a return of capital and not a return on capital. Exh. IND-17 at 3-4. By comparison, the payout ratios for the group of gas pipeline companies over the same period averaged 73.78 percent, demonstrating that their dividends represent a return on capital and not a return of capital. *Id.*

[113] Exh. HIO-87 and HIO-135.

[114] Exh. HIO-135 page 1.

[115] Exh. S-12 Sch. A page 2.

claimed dividend yields for the MLPs are twice the yields of natural gas companies. However, there is nothing in the record to indicate whether the dividend amounts included in HIOS' exhibits represent only that portion of the MLPs' distributions that pays earnings to the partners or also includes a return of investment.[116] Since there is nothing in the record to demonstrate that the relatively high dividend yields calculated by HIOS are based on "dividend" amounts that are, in fact, comparable to corporate dividends, the Commission finds that HIOS has not satisfied its burden under NGA section 4 to justify its proposal to include MLPs in the proxy group.

128. In discussing the appropriateness of MLPs, both Staff witness Manganello and HIOS witness Williamson cite to *SFPP, L.P.*, [117] an oil pipeline proceeding, as relevant. In *SFPP*, the Commission found that:

> there is now sufficient evidence of market prices and trading patterns in oil partnership limited shares that only oil partnership equities should be used in developing the equity cost of capital for that industry. This is reflected in the exhibits which show two to three years of information for publicly traded oil pipeline partnership interests.[118]

129. The Commission's decision in *SFPP* to employ MLPs as a comparison group is limited to oil pipelines as there no longer existed sufficient companies in that industry to provide a satisfactory reference group, so that the only entities in the oil pipeline business that could be included in the proxy group were MLPs. By contrast, here there are pipelines involved in the interstate natural gas pipeline business which can be used in the

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[116] Indicated Shippers presented evidence that Value Line, in its March 21, 2003, analysis of Northern Border Partners stated, "Because Northern Border is a limited partnership, its dividends include a return of capital and are not to be confused with regular quarterly dividends." Exh. IND-17 at 4. The Commission recognizes that HIOS' exhibits cite IBES reports as the source of their information, rather than Value Line. But without some express indication in the record that the dividend figures HIOS proposes to use have been adjusted to exclude any return of investment, the Commission is unwilling to assume that those figures in fact include only a distribution of earnings.

[117] Opinion No. 435, 86 FERC ¶ 61,022 at 61,099 (1999), *order on reh'g requests*, Opinion No. 435-A, 91 FERC ¶ 61,135 (2000), *aff'd in pertinent part*, Opinion No. 435-B, 96 FERC ¶ 61,281 at 62,069 (2001) (*SFPP*).

[118] *SFPP*, 86 FERC ¶ 61,022 at 61,099.

proxy group. Also, in *SFPP*, the issue of whether the dividend amounts used were comparable to corporate dividends was not raised.

130. In light of our finding that the record lacks evidence as to whether the dividend amounts include return of capital, we need not consider whether the various other reasons given by the ALJ for excluding MLPs from the proxy group are valid.

131. HIOS also argues on exceptions that the ALJ erred by including LDCs in the proxy group. HIOS contends that the Commission has in several previous cases disapproved the inclusion of distribution companies in pipeline proxy group. We reject HIOS' exceptions for the following reasons. The companies that the ALJ included in the proxy group are all companies listed in the Value Line Group of diversified natural gas companies whose business includes FERC-regulated natural gas pipelines. Thus, the companies are not solely in the distribution business. In *Williston*, [119] the Commission approved the use of a proxy group with the same diversified natural gas companies, as in the proxy group adopted by the ALJ.[120] We agree that each of these gas companies in the proxy group also have significant distribution functions but that does not disqualify their inclusion in a pipeline oriented proxy group. As emphasized by the ALJ, because of changes in the natural gas industry, gas companies can no longer be classified as pure transmission or pure distribution companies, and thus, the proxy companies reflect characteristics of both. While not pure transmission companies as is HIOS, these diversified gas companies are the best available proxies on the current record on which to base the DCF analysis.

132. HIOS cites various prior decisions wherein the Commission declined to include LDCs in proxy groups. However, we have found that significant changes in the natural gas industry because of mergers and acquisitions made it necessary, as found in the *Williston* decision, to revise our policy on proxy groups. Earlier cases such as *Mountain Fuel, Inc.*, 28 FERC ¶ 61,195 at 61,369-370 (1984) did not reject gas companies with distribution functions as such but declined to include a group of companies which appeared to be arbitrarily proposed for inclusion in the proxy group. In the earlier *Williston* proceeding, 87 FERC ¶ 61,264 at 62,007 (1999), the Commission rejected the inclusion of LDCs on the basis that the proxy group provided no better representation and was unnecessary to determine the equity return for Williston. We have examined the other cases cited by HIOS to support its exception and find that they have no merit.

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[119] Staff RB at 32.

[120] *Williston*, 104 FERC ¶ 61,036 (2003). Those diversified companies were Questar, National Fuel and Equitable.

Accordingly, we reject HIOS' exception to the use of Staff's proxy group for the purpose of determining HIOS' cost of equity capital.

133. The Commission also denies Indicated Shippers' contention on exceptions that a number of LDCs should be added to the proxy group. Indicated Shippers argues that its proposed inclusion of eight large natural gas distribution companies to its proxy group is justified as natural gas distribution services are more similar to the nature of HIOS' services than would be true for an oil pipeline or and electric utility.[121] We find that argument unpersuasive, as no participant proposes using oil pipeline or electric utilities in their proxy groups nor did we accept those types of companies in our decision in *Williston*. On this record, there is no need to go beyond the proxy group approved by the ALJ, consistent with the proxy group approved in *Williston*, to use companies that are less similar to HIOS, since they do not perform significant interstate pipeline business. Further, we find that Indicated Shippers has not carried its burden of proof to show that the risk profile of its gas distribution companies in its proposed proxy group sufficiently represents the risks of HIOS. Accordingly, we deny this exception.

(2) Capital Structure

134. The Commission prefers to use a pipeline's own capital structure. However, if the pipeline does not provide its own financing, the Commission looks to another entity. The Commission's policy is to use the actual capital structure of the entity that does the financing for the regulated pipeline as long as it results in just and reasonable rates. If the actual capital structure of the entity providing the financing is anomalous relative to the capital structures of the publicly traded proxy companies used in the DCF analysis, and capital structures approved for other regulated pipelines, the Commission may employ a hypothetical capital structure.[122]

135. HIOS is owned entirely by its parent GulfTerra. Accordingly, it has no publicly traded stock. Also, it issues no debt and has no bond rating. Since HIOS does not do its own financing, all parties agree that its capital structure should not be used in determining its return. At the hearing, both HIOS and Staff also opposed using GulfTerra's capital structure, which is made up of 63 percent debt and 37 percent equity. HIOS' witness Williamson testified that GulfTerra provides no debt capital to HIOS, and indeed all of GulfTerra's debt is devoted to financing GulfTerra's non-regulated

[121] Exh. IND-1 at 11.

[122] *See cases cited in Enbridge*, 100 FERC ¶ 61,260 at P 173.

activities.[123] Staff agreed that GulfTerra's capital structure should not be used, because it has a bond rating that is below investment grade. Accordingly, both HIOS and Staff proposed the use of a proxy group to determine a hypothetical capital structure for HIOS. However, they differed on the proxy group to be used.

136. Staff proposed to use the same proxy group that it also proposed to use to determine return on equity so as to assure a match between the financial risk inherent in its DCF analysis and its recommended capital structure. The average capital structure of this group was 50.8 percent debt and 49.2 percent equity. HIOS proposed to use the median capital structure of 14 gas pipelines which submitted 2001 Form 2s by July 20, 2002 and had long-term bond ratings. HIOS' proposal would result in a hypothetical capital structure of 44 percent debt and 56 percent equity.

137. In contrast to HIOS and Staff, Indicated Shippers opposed the use of a hypothetical capital structure, and instead proposed to use the capital structure of HIOS' parent, GulfTerra, which consists of 63 percent debt and 37 percent equity.[124] Indicated Shippers contended that its proposal was consistent with the Commission's policy of using the parent's capital structure if it finances the pipeline and issues its own debt and is not anomalous when compared to the equity ratios of the proxy companies used for the DCF analysis and equity ratios approved in other proceedings.

Initial Decision

138. Since HIOS is owned by GulfTerra, the ALJ deemed it appropriate to consider using GulfTerra's capital structure, as Indicated Shippers suggest, as the Commission generally prefers the use of actual entities. "To the maximum extent possible, the Commission bases capital structure on real entities, the pipeline or a company associated with the pipeline, that obtains financing for the pipeline."[125] However, in this case, the ALJ found that the use of GulfTerra's capital structure is inappropriate based on her finding that GulfTerra provides no debt capital to HIOS, and indeed all of GulfTerra's debt is devoted to financing GulfTerra's non-regulated activities. The ALJ stated that in *Enbridge*, the Commission stated that a prerequisite for using the capital structure of GulfTerra is a finding that GulfTerra actually obtains financing for HIOS. She held that

[123] Exh. HIO-133 at 3.

[124] Exh. IND-18.

[125] *Enbridge*, 100 FERC ¶ 61,260 at P 185 (2002).

the record shows that GulfTerra does not provide such financing, and accordingly concluded that GulfTerra's capital structure should not be used for HIOS.

139. The ALJ found that this left the option of a hypothetical capital structure based on an appropriate proxy group. The ALJ found that since a hypothetical capital structure requires examination of the average capital structure for comparable independent firms, an appropriate proxy group for HIOS needed to be determined to create a hypothetical capital structure.[126] The ALJ found that the same proxy group used for the DCF analysis should also be used to determine a hypothetical capital structure for HIOS. Accordingly, based on her holding that Staff's proxy group was appropriate for both purposes, the ALJ adopted Staff's proposed capital structure.

Briefs on and opposing exceptions

140. On exceptions, Indicated Shippers urge that the capital structure be based on HIOS' parent GulfTerra, consistent with the Commission's preference that, to the maximum extent possible, capital structure should be based on real entities.[127] Indicated Shippers contends that GulfTerra provides its capital to support all of HIOS' operations and therefore HIOS relies entirely on GulfTerra for its financing. Indicated Shippers also argues that it is irrelevant for purposes of determining capital structure that GulfTerra is an MLP.[128]

141. HIOS contends that the ALJ correctly found that a hypothetical capital structure should be used, but it urges that the ALJ erred in using Staff's capital structure proxy group.[129] HIOS says the ALJ should have used HIOS' hypothetical capital structure. It objects that Staff's proxy group is not comparable to HIOS, since it is made up of LDCs, while its proposed proxy group for determining capital structure is made up of other gas pipelines. HIOS also asserts that its proposed capital structure compares favorably with those the Commission has approved in other cases, citing *Williams Natural Gas Pipeline Co.*, 86 FERC ¶ 61,232 (1999), where the Commission approved a capital structure of 64 percent equity and 36 percent debt.

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[126] *Ky West*, 2 FERC ¶ 61,139 at 61,326.

[127] IS BOE at 26.

[128] Indicated Shippers would eliminate Coastal, Columbia and Enron from the group that was used in the *Williston* case.

[129] HIOS BOE at 51.

142. The Staff opposes HIOS' exception. Staff contends that the ALJ properly used the same proxy group to determine the hypothetical capital structure as she adopted for purposes of DCF analysis. Staff says that, in each case cited by HIOS, the Commission used the company's actual capital structure, and Staff is not aware that the Commission has ever approved a hypothetical capital structure that was outside the range of the proxy group, as HIOS proposes here.

Commission Decision

143. The Commission affirms the ALJ on this issue and will use the hypothetical capital structure proposed by Staff. The Commission prefers to use a capital structure of real entities that obtain financing for the pipeline, the pipeline itself or a company associated with the pipeline, such as its parent. However, the Commission may use a hypothetical capital structure if the capital structure of the entity obtaining the financing is anomalous. The Commission has recently stated that the "anomalies include circumstances where either "(a) the capital structure of the financing entity is not representative of the regulated pipeline's risk profile, or (b) the capital structure is different from the capital structure approved for other pipelines, or if a DCF analysis is performed, outside the range of the proxy group used in the DCF analysis."[130]

144. Here, HIOS' parent, GulfTerra, is the actual entity providing the financing for HIOS. HIOS itself does not issue debt or have a bond rating. GulfTerra currently owns all of HIOS' stock, having bought out the other owners of HIOS, and does issue debt and have a bond rating. As Indicated Shippers points out, when asked at the hearing what HIOS' owners do, its witness responded, "They provide their capital."[131]

145. However, we find that GulfTerra's capital structure may be found to be anomalous on the ground that it is not representative of the pipeline's risk profile. The Commission has held that such a finding may be justified where there is evidence that the parent issued its debt in order to finance non-pipeline activities that have risks different from the pipeline's risks.[132] For example, in *Transcontinental Gas Pipe Line Corp*., 71 FERC ¶ 61,305 at 62,194 (1995), the Commission held that Transco's parent's capital structure should not be used because it included long-term debt issued by another pipeline which did not finance Transco's rate base and the parent's capital structure reflected non-

[130] *Enbridge Pipelines (KPC)*, 109 FERC ¶ 61,186 at P 89 (2004).

[131] Tr. 239.

[132] *Enbridge*, 109 FERC ¶ 61,186 at P 91.

pipeline losses. Here, HIOS' witness testified, "GulfTerra provides no debt capital to HIOS and indeed all of the GulfTerra's debt is devoted to financing GulfTerra's non-regulated activities."[133] HIOS did not describe its non-regulated activities or provide an explanation why those activities caused the need to issue debt, as opposed to financing GulfTerra's purchase of the other owners' share of HIOS.

146. Staff, however, provided evidence that GulfTerra's bond rating is below investment grade.[134] The Commission finds that this evidence, combined with GulfTerra's assertions, is sufficient to support the ALJ's finding that GulfTerra's capital structure is not representative of HIOS' risk profile. Since HIOS has recovered almost all of its initial investment and, as discussed earlier in this order, made distributions to its owners in the range of $15 million to $25 million a year during the period 1998 to 2001, we think it reasonable to infer that the cause of GulfTerra's below investment grade bond rating is its non-jurisdictional activities, as opposed to any risks associated with HIOS. Thus, since GulfTerra's capital structure is not representative of HIOS' risk profile, the Commission will approve the use of a hypothetical capital structure.

147. The Commission also affirms the ALJ's decision to adopt a hypothetical capital structure based on the average equity ratio of the same proxy group Staff uses for its DCF analysis. As the ALJ found, this assures a match between the financial risk inherent in the DCF analysis used to develop return on equity and the hypothetical capital structure. The average capital structure of this group was 50.8 percent debt and 49.2 percent equity. The Commission rejects HIOS' assertion on exceptions that a different proxy group, made up of the 14 gas pipelines which submitted 2001 Form 2s by July 20, 2002 and had long-term bond ratings, should be used to determine a hypothetical capital structure. The Commission might consider using the capital structure of each of those pipelines in determining returns for the pipeline in question, consistent with its preference to use the capital structure of the actual company providing the financing for the pipeline. However, once the Commission moves beyond using the capital structure of the entity that provided the financing for the pipeline in question to determining a hypothetical capital structure, the Commission believes it more appropriate to use companies that meet the Commission's requirements for use in a proxy group, including having publicly traded stock.

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[133] Exh. HIO-133.

[134] Exhs. S-11 a 8-9; S-18 at 5.

(3) Return on Equity

148. We now turn to the issue of the return on equity to be used in determining a management fee for HIOS. The Commission prefers to determine return on equity based on the Discounted Cash Flow (DCF) Analysis. The DCF methodology is based on the premise that a stock is worth the present value of its future cash flows, discounted at a market rate commensurate with the stock's risk. Under the constant growth DCF formula used by the Commission, the cost of capital is equated with the dividend yield (dividends divided by market price) plus the estimated constant growth in dividends to be reflected in capital appreciation.[135] Since Opinion 414-A,[136] the Commission has used a two-step procedure to determine the projected growth in dividends of the proxy group companies, averaging short-term and long-term growth estimates. The Commission uses five-year Institutional Broker's Estimate System (IBES) growth projections for each proxy group company for the short-term growth projection. The Commission uses the growth rate of the Gross Domestic Product (GDP) as its long-term growth rate, since the Commission has found that pipeline specific projections of long-term growth cannot reasonably be developed based on available data sources. The Commission averages these growth projections, giving two-thirds weight to the short-term growth projection and one-third weight to the long-term growth projection.[137] The DCF methodology produces a zone of reasonableness in which the pipeline's rate may be set based on specific risks.[138]

149. In this case, the parties have not disputed this basic methodology. Aside from the issue of the appropriate proxy group to be used discussed above, the parties' exceptions raise only two other issues: (1) the appropriate projection of long term growth to be used and (2) where to place HIOS in the range of reasonable returns.

(a) Long-term Growth Rate

150. The ALJ adopted the DCF analysis supported by Staff. Mr. Manganello concluded that the DCF returns for the proxy group ranged from 10.53 percent to 13.51

[135] *Northwest Pipeline Corp.*, 79 FERC ¶ 61,309 at 62,378 (1997) (Opinion No. 396-B).

[136] Opinion No. 414-A, 84 FERC ¶ 61,084 at 61,423.

[137] *Enbridge*, 100 FERC ¶ 61,260 at P 215 (footnotes omitted).

[138] *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, 57 (D.C. Cir. 1999).

percent with a median of 11.22 percent.[139] For its projection of long-term growth, Staff used the average of forecasts of long-term GDP growth by three organizations: the Energy Information Administration (EIA), DRI-Wharton Economic Forecasting Associates (DRI-WEFA), and the Social Security Administration (SSA). The ALJ rejected HIOS' objection to the use of the SSA forecast. The ALJ found that the Commission had approved use of the SSA forecast in *Williston* and only limited the range to the 50-year time period used by the other forecasts of GDP growth. Accordingly, she found no reason to exclude the SSA forecast here.

Briefs on and opposing exceptions

151. HIOS argues that the ALJ erred in using the SSA growth forecasts in determining the long-term growth projection to be used in the DCF analysis.[140] Although used in *Williston*, HIOS argues that it was by the parties' agreement and SSA forecasts are conservative because they are used to pay SSA obligations and are not appropriate for determining gas pipeline long-term growth.

152. Staff responds that the ALJ properly allowed inclusion of SSA growth forecasts when the Initial Decision followed the Commission's decision in *Williston* to include SSA forecasts. Staff states that long-term forecasts of growth are required and the Commission accepted the use of SSA data in *Williston*.

Commission Decision

153. The Commission affirms the ALJ on this issue. In *Williston*, the Commission accepted the use of SSA forecasts and only limited the range to the 50-year time period used by the other forecasts of GDP growth. The Commission also approved use of the SSA GDP growth estimate in *Enbridge*.[141] The fact that no party opposed the inclusion of SSA forecasts in the calculation of long-term growth rates in those cases does not make them a less valid element of the analysis. Projecting long-term growth in GDP is an inexact science. The Commission believes that use of an average of the projections of a number of professional organizations making such projections is appropriate. While those organizations may make those projections for varying purposes, the use of a

[139] Exh. S-11 at 14 (*citing* Exh. S-12, Sch. A at 3).

[140] HIOS BOE at 50.

[141] 100 FERC ¶ 61,260 at P 236 n 232 (2002).

number of projections made from such different viewpoints may produce a more reliable projection than the use of any single projection.

(b) Placement in the Zone of Reasonableness

154. The Commission begins its risk analysis with the assumption that pipelines generally fall into a broad range of average risk, absent highly unusual circumstances that indicate an anomalously high or low risk as compared to other pipelines. While the Commission stated in Opinion No. 414-A that parties may present evidence to support any return on equity that is within the zone of reasonableness, the tools available to the Commission for determining the return on equity to be awarded a particular pipeline are blunt. Therefore, the Commission is skeptical of its ability to make carefully calibrated adjustments within the zone of reasonableness to reflect the generally subtle differences in risk among pipelines. Unless a party makes a very persuasive case in support of the need for an adjustment and the level of the adjustment proposed, the Commission will set the pipeline's return at the median of the range of reasonable returns.[142]

155. In this case, HIOS' witness Porter contended that if Staff's proposed proxy group is used, then HIOS should be placed at the high end of the zone of reasonableness,[143] because its business risk is higher than that of the companies in the proxy group. The business risks described by Mr. Porter were based on the lack of firm service on HIOS and his estimation that throughput on the HIOS system will continue to decline as reserves in the Gulf of Mexico are exhausted.[144]

Initial Decision

156. The ALJ found that HIOS has not made a very persuasive case in support of the need for an adjustment and the level of the adjustment proposed under *Transco* to support any adjustment above average risk.[145] The ALJ stated that HIOS did not propose a specific adjustment at all, but merely detailed its risks and claimed that it should be placed at the higher end of any proxy group with a lower range of reasonableness than its

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[142] *Transco*, 90 FERC ¶ 61,279 at 61,936.

[143] Exhs. HIO-64 at 22-25, HIO-91 at 15.

[144] Exh. HIO-64 at 22-25.

[145] *Transco*, 90 FERC ¶ 61,279 at 61,936.

own, based on its above-average risk.[146] Moreover, the ALJ stated that there is little risk of exhaustion of gas reserve in the Gulf of Mexico and insufficient evidence to warrant any adjustment under *Transco.* The ALJ concluded that the median of Mr. Manganello's proxy group (11.22 percent) would be the appropriate return on equity. Based on the agreed-upon debt level and the hypothetical capital structure approved above, the overall rate of return would be 9.60 percent.[147]

Exceptions

157. HIOS argues that the ALJ failed to recognize that its business risks are greater than those faced by the companies in Staff's proxy group, specifically, low load factor usage and a decline in volumes, a throughput mix of mostly interruptible volumes, a dearth of firm transportation, and barriers to attaching new gas supply in its market. Staff and Indicated Shippers oppose HIOS' exception.

Commission Decision

158. The Commission concurs in the ALJ's decision on this issue. The Commission's risk analysis assumes that pipelines generally fall into a broad range of average risk, absent highly unusual circumstances that indicate an anomalously high or low risk as compared to other pipelines. HIOS has recovered almost all of its initial investment in the pipeline, and thus it has no financial risk. HIOS also has not shown that its business risk exceeds the business risks of the diversified natural gas companies in the proxy group, all of which have significant interstate pipeline business. Even though large volumes of interruptible transportation are moving on HIOS, which would seem to increase its business risk, in fact those volumes are shipped by captive shippers who have no alternative means of transportation to bring their gas to market. If HIOS' throughput does decline, HIOS can file a new rate case to increase its rates. Accordingly, we adopt the proposed return on equity of 11.22 percent, and an overall return, without adjustment for taxes, of 9.60 percent.

E. Income Taxes

159. We now turn to the issue of the appropriate treatment of taxes in connection with our allowance of a management fee. As discussed above in the management fee .section of this order, in *Tarpon*, the management fee was calculated by multiplying the overall

[146] Exh. HIO-91 at 15.

[147] *See* Exh. S-12, Sch. B at 1.

pre-tax return allowed for the pipeline by ten percent of the pipeline's average historical rate base. A pipeline's overall pretax return is determined by adjusting the allowed equity return upward for income tax expense so that the allowed equity return received by the pipeline is equal to the return on equity approved based on the DCF analysis. After approving a management fee determined in this manner, the Commission then also appears to have allowed Tarpon an income tax allowance calculated by multiplying the approved management fee by the corporate income tax rate.

160. Staff recommended the use of this same approach in this case. Thus, in determining the overall return to be used in the management fee calculation it adjusted the equity component upward to permit recovery of income taxes on the equity component assessed at the corporate income tax rate of 34 percent. This resulted in an overall pretax return of 12.448 percent, as compared to its proposed 9.60 percent overall return unadjusted for taxes.[148] Staff also proposed that HIOS be allowed a tax allowance determined by multiplying the proposed management fee by the 34 percent corporate income tax rate, which all parties agreed was the appropriate income tax rate to be used in this case. Indicated Shippers contended that Staff's use of a pretax overall return to calculate the management fee itself provided HIOS a tax allowance, since the return on equity was adjusted upward to account for taxes. Therefore, Indicated Shippers asserted, allowing a tax allowance in addition to the management fee would, in effect, result in allowing HIOS to double recover its tax payments.

161. HIOS in its management fee proposal used its proposed overall return without any upward adjustment for taxes. It then proposed a tax allowance calculated by multiplying the 34 percent federal income tax rate by its proposed management fee.

Initial Decision

162. The ALJ approved both the Staff's use of an overall pretax return to calculate the management fee and the Staff's proposed tax allowance in addition to its proposed management fee. The ALJ held that Indicated Shippers had raised an interesting point on "double recovery," but found Staff's approach consistent with *Tarpon.* The ALJ held that, while the Commission in *Tarpon* approved a management fee that was calculated based on a formula that used the pipeline's overall pretax return, the purpose of that formula was simply to calculate the management fee, separate and apart from any calculation of income tax allowance.

[148] Exh. S-2 Sch. F.

Exceptions

163. On exceptions, Indicated Shippers reiterates its double recovery of taxes contention. HIOS responds that the allowance of income taxes is not a double recovery as the management fee is the after tax profit and was allowed in the *Tarpon* case.

Commission Decision

164. The Commission reverses the ALJ in part on this issue. The Commission finds that HIOS' management fee should be calculated based on the 9.60 percent overall return, without adjustment for taxes, which the Commission approved above. HIOS should then be awarded an income tax allowance with respect to the entire management fee thus calculated.

165. The Commission agrees with Indicated Shippers that it is anomalous both to use a pretax return in the determination of the management fee and allow a tax allowance on the resulting management fee, since this results in a double recovery of taxes. HIOS itself avoided this anomaly in its various management fee proposals, by using an overall return unadjusted for taxes, and then calculating a tax allowance based on the resulting management fee. Since, as HIOS states, the purpose of the management fee is to permit the pipeline to earn a modest profit as an incentive to operate its pipeline efficiently, it is appropriate to allow a tax allowance with respect to the full management fee.

166. Based on all of the above findings, we approve a management fee for HIOS of $1,734,008. This is calculated by multiplying the overall rate of return of 9.60 percent approved above by 10 percent of the modified average rate base of $180,625,854. We also approve an income tax allowance of $893,277, calculated by multiplying the management fee by the 34 percent corporate income tax rate. The total of the approved management fee and tax allowance is $2,627,285.

F. Billing Determinants

167. On exceptions, HIOS contends that the ALJ erred in her finding concerning the volumes associated with firm service to be used in designing its rates. HIOS argues that the firm billing determinants should be developed using its firm shippers' actual contract demand levels as of the end of the test period as the starting point. The other parties support the ALJ's holdings concerning rate design volumes. The ALJ found that HIOS must use the firm shippers' actual throughput during the last twelve months of the test period, inclusive of all overrun volumes, to determine rates. As discussed below, the Commission affirms the ALJ's decision.

Background

168. HIOS offers two firm transportation services under Rate Schedules FT-1 and FT-2. The FT-1 rates are two-part rates with a reservation and usage charge designed using the straight fixed variable (SFV) rate design consistent with section 284.7(e) of the Commission's regulations. The FT-2 service features a one-part volumetric rate, instead of a two-part rate with reservation and usage charges, that is traditionally associated with firm service. The FT-2 service is available to shippers that have rights to estimated proven recoverable reserves of at least 40 Bcf, which they have committed to shipping on HIOS. HIOS has only two firm customers, and they receive service under Rate Schedule FT-2.

169. Any party desiring transportation service under Rate Schedule FT-2 must support its maximum daily quantity (MDQ) by a life of reserves forecast. As part of its initial request for service, an FT-2 Shipper may request a separately stated MDQ for specified Delivery Periods of not less than three consecutive months, and such Delivery Points and their MDQs will be set forth in Exhibit A to its services agreement. Prior to the initiation of service under a shipper's FT-2 agreement and thereafter at least six months before each calendar year, HIOS may request a shipper to update its production profile to support its MDQs and, when available, to provide an actual production history for its committed leases and an update of its technical data. The shipper must reduce, and may increase, its MDQ as may be appropriate based on the production profile. In addition, the shipper has the right to change at any time and for any reason the MDQs for any Delivery Period set forth in Exhibit A to its FT-2 Agreement on six months prior written notice to HIOS.

170. Rate Schedule FT-2 includes a provision that, if the average throughput level for the production month being billed and the immediately preceding two months (the "three-month period") is less than 80 percent of the average of the MDQs specified in the FT-2 agreement for the three-month period, the shipper will be subject to reservation and usage charges for the second production month following the three-month period. Rate Schedule FT-2 also includes a rate for authorized overrun service in excess of MDQ which is equal to the one-part volumetric rate for service within MDQ.

171. At the hearing, HIOS proposed to use the end-of-test-period MDQs of its two firm FT-2 shippers as the starting point for determining its firm rate design volumes. The last day of the test period was June 30, 2003. On September 26, 2002, ExxonMobil had sent HIOS a letter reducing its MDQ for the three-month period April-June 2003 to 67,000 Mth per day. On October 30, 2002, BP Exploration and Production, Inc. (BP), had sent HIOS a letter reducing its MDQ for the three-month period May through July 2003 to 52,000 Dth per day. Thus, the total MDQ of the two shippers as of June 30, 2003 was 119,000 Dth per day.

172. HIOS next proposed certain adjustments to this figure, which it contended were justified by the special provisions of the FT-2 rate schedule. First, it examined the two FT-2 shippers' load factor usage of their contracts for the years 2000 through 2004, finding that their overall load factor usage (excluding overrun volumes) was 83 percent.[149] Because the load factor usage exceeded 80 percent, HIOS concluded it was reasonable to project that the two customers would pay the FT-2 one-part volumetric rate, as opposed to a two-part rate. Therefore, it proposed to design the FT-2 rate based solely on a projected annual usage volume. It arrived at the annual usage figure through a two-step calculation. First, it converted the 119,000 Dth daily MDQ into an annual entitlement figure of 43,435,000 Dth (daily MDQ multiplied by 365).[150] Second, it reduced the annual entitlement by 20 percent to 34,748,000 Dth on the ground that the FT-2 shippers were only required to maintain throughput at 80 percent of their entitlements in order to be billed on a volumetric basis.[151]

173. In contrast to HIOS' proposal, Staff used as its starting point to determine FT-2 rate design volumes, actual throughput under the FT-2 Rate Schedule for the last 12 months of the test period (July 1, 2002 through June 30, 2003) of 68,598,374 Dth. That figure included overrun volumes transported pursuant to the FT-2 Rate Schedule. It then imputed a daily MDQ of 187,941 by dividing annual throughput by 365. Staff contended that, while the Commission ordinarily uses end-of-test period MDQ as the reservation billing units to be used in designing rates, that was inappropriate in this case for several reasons. First, the FT-2 rate is a one-part volumetric rate that will be billed based on annual throughput, not daily MDQ. Second, the FT-2 shippers are able to nominate changed MDQs for three-month periods, contrary to the usual practice of MDQ being established at a fixed level for the duration of a contract. Third, the end-of-test period MDQs nominated by the FT-2 shippers were significantly below those shippers' actual usage as shown by such facts as that their load factor usage during the last month of the test period, including overrun volumes, was 144 percent.

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[149] Exh. HIO-98.

[150] Actual FT-2 throughput during the last 12 months of the test period was 68,598,374 Dth, and slightly higher during the base period. HIOS did not use this actual throughput, however, on the ground that under the MDQs in effect on the last day of the test period, the two FT-2 shippers would not be entitled to that level of service.

[151] This figure translates to a daily MDQ of 95,200 Dth.

Initial Decision

174. The ALJ agreed with Staff, finding that HIOS has failed to justify its use of the shippers' nominations as the basis for establishing reservation units for FT-2 service. The stated MDQs of the shippers, as indicated in their letters, are only a prediction of how much volume they intend to ship in that month. The ALJ found that the purpose of these periodic nominations is not, as HIOS suggests, to provide the basis for the design of rates, but rather to establish the threshold for the billing mechanism under the FT-2 rate schedule. The rate schedule allows the shippers to be billed with one-part volumetric rates if they maintain average daily throughput at or above 80 percent of their nominated MDQs, as those nominations may change from time to time.

175. The ALJ also found that a review of the two shipper letters stating their latest nominations reveals the problem with HIOS' theory. The revised MDQs are only made for three-month periods, which are different for the two shippers.[152] Also, the ALJ found that the shippers' periodic estimates of MDQ bear no relationship to their actual use of HIOS' pipeline during the test period.[153] The ALJ found that unlike other pipelines, the FT-2 shippers' MDQs do not represent a typical right to capacity in the HIOS pipeline. These nominated levels are not fixed for the life of the contract as they may fluctuate up or down (and do so) based upon the quarterly estimations of these shippers projected throughput. The ALJ found that these MDQs do not bear the relationship to contractual entitlements upon which the Commission's policy regarding the use of end of test year firm entitlements is based. The ALJ noted that the two shippers routinely exceeded their stated MDQs during the test period, and that these "overrun" volumes totaled approximately 25 percent of the firm shippers' volumes during the test period. Thus, the monthly MDQ estimate upon which HIOS proposes to base its rates significantly understate the actual use of the HIOS system by the FT-2 shippers.

Exceptions

176. HIOS argues that contrary to the approach taken by the ALJ, the Commission typically uses actual MDQs (i.e., contract demand units) to design firm rates, instead of using imputed units that include firm shippers' interruptible overrun volumes. HIOS asserts that the Commission uses actual end-of-test-period firm MDQs to design firm rates, because such billing determinants "reflect the latest best evidence of what will exist

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[152] Exh. S-10 at 1-2.

[153] Exh. S-17 at 4.

for the pipeline once the rates go into effect."[154] HIOS argues that moreover, because overrun service is a form of interruptible service, the Commission requires pipelines to allocate costs to overrun service separately from firm service. HIOS asserts that its proposed firm billing determinants are properly based on its actual end-of-test period firm MDQs, in accordance with these precedents.

177. HIOS further argues that the ALJ's imputation of MDQs on the basis of all FT-2 throughput during the last twelve months of the test period, improperly ignores the uncontroverted decline in MDQ from 179,800 Dth/day to 119,000 Dth/Day that occurred during the test period. By ignoring this decline, the ALJ's approach directly conflicts with the Commission's goal of reflecting the latest best evidence in its rate calculation.[155] HIOS argues that the end-of-test period MDQs represent HIOS' obligation going forward based on the clear tend of declining MDQs, not the higher MDQ levels that existed during a past period. HIOS further contends that inclusion of the FT-2 overrun volumes in the annual throughput used to impute MDQs is contrary to the Commission's policy of excluding overrun volumes in designing firm rates.

178. In addition, HIOS argues that the ALJ made a number of erroneous findings in support of the decision to use imputed firm MDQs that include interruptible overrun volumes. For example, MDQs represent more than a mere "prediction" by the shippers.[156] HIOS argues that the evidence shows that the MDQs in the FT-2 contracts represent the maximum level of firm service that FT-2 shippers can demand from HIOS, whereas it is undisputed that HIOS has no obligation to provide firm transportation for any volumes, such as overrun volumes, that exceed the shippers' MDQs.

179. HIOS argues that the ALJ's attempt to justify its position by asserting that HIOS is "atypical" because it has excess capacity is irrelevant, because HIOS is not the only pipeline in the U.S. that has or had excess capacity, and the Initial Decision fails to cite any case that creates an "underutilized pipeline" exception to the Commission's policy of designing firm rates based on actual, not imputed, firm MDQs.

180. In addition, HIOS disputes the ALJ's assertion that HIOS would overcollect its costs if HIOS' proposed billing determinants were accepted. HIOS argues that its billing determinants properly account for overrun volumes. HIOS argues that in accordance

[154] HIOS BOE at 69 (*quoting Trunkline*, 90 FERC ¶ 61,017 at 61,084 (2000)).

[155] HIOS BOE at 70.

[156] HIOS BOE at 70 (*quoting* Initial Decision at P 191).

with Commission precedent holding that overrun is an interruptible service and should be treated separately from firm volumes, HIOS based its proposed interruptible billing determinants on a normal year of throughput for all interruptible services, including (1) volumes shipped by HIOS' FT-2 shippers as overrun, and (2) volumes shipped under HIOS' IT rate schedule. HIOS thus accepted Staff's use of test year interruptible throughput of 195,327,103 Dth as representative of all interruptible throughput, including overrun. HIOS argues that in this regard, the record shows that IT service has steadily declined by an average of 8.4 percent per year, and that its witness Mr. Porter was following precedent when he reduced HIOS' 2002 IT throughput by 8.4 percent to determine a projected normal year IT estimate of 185.4 MMDth. Mr. Porter then added this figure to the full 11.1 MMDth of firm service overrun volumes that HIOS actually experienced in 2002. HIOS argues that this rate design proposal fully accounts for interruptible overrun volumes, and thus would not result in HIOS overrecovering its costs.

181. HIOS also argues that it will not overrecover its costs based on the fact that it adjusted the actual MDQs to reflect the 80 percent minimum bill provisions set forth in the FT-2 contracts. HIOS argues that under its FT-2 Rate Schedule, shippers pay for service on a volumetric basis, provided that their throughput during the production month and the preceding two months is at least 80 percent of their contractual MDQ. HIOS argues that both Mr. Porter and Mr. Ekzarkhov agree that this provision can be viewed as a minimum throughput level obligation, and as a result of this minimum bill, FT-2 shippers are obligated to pay for only 80 percent of HIOS' fixed costs. Thus, in order to design rates that reflect what the FT-2 shippers are obligated to pay, HIOS utilized 80 percent of the actual MDQs to design firm reservation rates.

182. HIOS argues that the actual historical load factor of HIOS' FT-2 shippers indicates that they have been and will continue to be billed on a volumetric basis reflecting the 80 percent minimum bill. As a result, because of the commodity billing feature of the FT-2 rate schedule, if HIOS were to design rates based solely on the assumption each and every FT-2 shipper would flow at 100 percent of their MDQs, HIOS would experience an underrecovery of its cost of service. HIOS argues that the record indicates that while one FT-2 shipper frequently utilized all of the contracted MDQ, the other rarely achieves a load factor significantly higher than 80 percent. HIOS argues that the fact that the average load factor of the rate class is 83 percent (excluding overrun volumes) lends further credence to HIOS' position. While the ID would have HIOS design rates reflecting the usage of the highest load factor shipper, HIOS proposed to design rates on the load factor and cost responsibility of the rate class.

Discussion

183. We affirm the ALJ's decision. As HIOS points out, the Commission ordinarily uses contract demand on the last day of the test period as the firm billing determinants used in designing the pipeline rates.[157] However, the Commission has also stated that it "will consider other approaches to projecting long-term contract demand when the particular circumstances of a case indicate another figure may be more representative."[158] This case presents just such a circumstance. Most importantly, in the ordinary case, the pipeline charges a two-part rate for firm service, with all fixed costs recovered through a reservation charge billed on each unit of contract demand. Here, however, HIOS charges the FT-2 shippers a one-part volumetric rate so long as they maintain throughput of at least 80 percent of contract demand, which HIOS argues its FT-2 shippers will do. Thus, HIOS will recover the fixed costs allocated to FT-2 service through a volumetric rate billed based on actual usage of the system. Therefore, it makes sense to design that one-part rate based on a projection of the FT-2 shippers' actual usage of the system as opposed to their contract demand. Further, it is appropriate to include overrun throughput in that usage because the FT-2 rates includes a one-part overrun rate that is the same as the one-part rate for service within contract demand. So, FT-2 shippers pay the same rates regardless of whether their service is below or above contract demand.

184. We note that there are several flaws with HIOS' methodology. First, HIOS has failed to justify the use of shippers' nominations as the basis for establishing reservation units for FT-2 service. The stated MDQs of the shippers, as indicated in their letters, is only a prediction of how much throughout they will take in any given month. The purpose of such periodic nominations is not, as HIOS suggests, to provide the basis for the design of rates, but rather to establish the threshold for the billing mechanism under the FT-2 rate schedule. The rate schedule allows the shippers to be billed with one-part volumetric rates if they maintain average daily throughput at or above 80 percent of their nominated MDQs, as those nominations may change from time to time.

185. A review of the two shipper letters stating the latest nominations highlights the problem with HIOS' theory. The revised MDQs are only made for three-month periods, which are different for the two shippers. Exhibit No. S-10, at 3, compares the shippers' monthly stated MDQs to actual monthly throughput, showing that the FT-2 customers shipped volumes in excess of their MDQ levels virtually every month during the 12 months ended June 30, 2003. In addition, while, as HIOS points out, the shippers

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[157] *Trunkline Gas Co*., 90 FERC ¶ 61,017 at 61,084 (2000).

[158] *Id*.

gradually reduced their contract demand during that period, there was no similar decline in throughput. The two FT-2 shippers' contract demand went down from 154,500 Dth in January 2003 to 117,500 Dth in February and then varied to 102,000 Dth to 119,000 Dth for the remainder of the test period. However, the two FT-2 shippers' throughput was at 5.5 million Dth in July 2002, but above 6 million Dth for each month from September 2002 through January 2003. Throughput did go below 5 million Dth in February 2003, but then rose to 5.7 million Dth in March 2003, and remained above 5 million Dth through June 2003. The result is that the FT-2 shippers' load factor, including overruns, was above 100 percent every month but August 2002. Moreover, during the last five months of the test period when contract demand varied from 102,000 Dth to 119,000 Dth, load factor usage was always 140 percent or higher and was 173 percent in April.

186. Also, HIOS' assertion that the FT-2 shipper load factor usage averaged 83 percent was based on 2000-2003 figures rather than just the last 12 months of the test period, and excluded overruns. HIOS' number is therefore irrelevant for analyzing load factor usage during the test period. In addition, the fact that HIOS included an 11.1 MMDth of overrun in its IT projection, based on overruns during 2002, does not satisfactorily take into account overrun usage. Actual overrun usage in the last 12 months of the test period was over 16 MMDth.

187. Under these circumstances, we find that it is not inappropriate for the Commission to consider the actual use of the HIOS system by FT-2 shippers during the last twelve months of the test period, rather than rely on the constantly changing MDQs that bear no relationship to the demand for service the shipper places on the pipeline. The Commission has long recognized that a major objective of rate design is to achieve equity in the apportionment of a pipeline's cost of service among its various customers and customer classes.[159]

> The just and reasonable standard in the process of rate design has often been measured by the equitable distribution of revenue responsibility among customers *in proportion to their utilization of the pipeline system*. This principle, often termed the cost incurrence principle, requires customers to pay for the *portion of the system that is designed and utilized on their behalf*.[160]

188. Accordingly, we find that the ALJ was correct to require HIOS to base its rates on the FT-2 shippers' actual utilization of HIOS and adopt FT-2 reservation determinants of

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[159] *Texas Eastern Transmission Corp.*, 30 FERC ¶ 61,144 at 61,259.

[160] *Id*. (emphasis added).

187,941 Dth (imputed from the actual, latest 12-month use of the pipeline by the FT-2 shippers) and FT-2 commodity determinants of 68,598,374 Dth (the actual, latest 12-month use of the pipeline by the FT-2 shippers). The Commission further finds that the ALJ was correct to reject the proposal of HIOS to reduce its annual FT-2 throughput level by 20 percent to 80 percent of the FT-2 shippers' contract demand, since the 20 percent reductions in billing determinants does not reflect the FT-2 shippers' actual usage of the system, which substantially exceeds their contract demand.

G. Rate Design

Background

189. HIOS proposed two rate design changes in this case. First, HIOS proposed to establish a 5 percent price differential between the rate for FT and FT-2 service, setting the FT-2 reservation charge at 95 percent of the Rate Schedule FT reservation charge, which equates to the same as a 105 percent load factor of the FT rate. Second, HIOS proposed to set the IT rate at 103.5 percent of the Rate Schedule FT rate, that is, at a 96.5 percent load factor rate. HIOS argues that these proposals are designed to attract additional firm throughput through the dedication of new reserves under Rate Schedule FT-2 and to encourage interruptible shippers (including shippers relying on interruptible overrun service) to enter into firm contracts.

Initial Decision

190. The ALJ found that the Commission has found that the use of 100 percent load factor derivative rates for IT service imposes the appropriate level of cost responsibility on interruptible shippers.[161] The ALJ further held that HIOS had not shown the need to ration capacity for either IT or FT service. The ALJ noted that such need would argue, at least at a minimum, for increased rates for these services – relative to other services – based upon the Commission's rate design policies and corresponding regulations contained in 18 C.F.R. section 284.10. These regulations call for, generally, rates for transportation services of natural gas pipeline companies to be designed to ration capacity

[161] *E.g., Ohio Valley Hub, L.L.C.*, 100 FERC ¶ 61,238 at 61,846 (2002) (the Commission has consistently approved interruptible rates designed on a 100 percent load factor equivalent of firm rates); *Northern Border Pipeline Co.*, 39 FERC ¶ 61,104 at 61,346 (1987) (requiring the pipeline to use a 100 percent load factor rate for interruptible service will prevent firm customers from subsidizing the interruptible customers' cost of service, since at that load factor the IT per unit cost of transportation would equal the FT per unit cost).

and maximize throughput. Given the high level of IT service on the HIOS system and low overall utilization of total pipeline capacity of the same, the HIOS proposals to increase FT and IT service rates do nothing to further ration capacity and work counter to the second goal of maximizing throughput.

191. The ALJ found that HIOS failed to meet its burden with respect to changing the design of the FT-2 and FT reservation charges and with respect to deviating from longstanding Commission policy and precedent on a 100 percent load factor rate for IT service. As the proponent of the changes, HIOS bore the burden of proof under section 4(e) of the NGA.

HIOS' Exceptions

192. HIOS argues that the ALJ erred by rejecting HIOS' proposed rate design, which encourages the dedication of firm long-term gas supplies and efficient contracting while remedying a significant pricing inequity between firm and interruptible services.

193. HIOS argues that key record evidence ignored by the ALJ supports HIOS' proposals. With regard to HIOS' proposal to create a differential for service under Rate Schedule FT-2, the evidence demonstrates that but for the stable, long term revenue contribution that FT-2 shippers make to HIOS' fixed costs, IT shippers would pay significantly higher rates. HIOS argues that it showed in unrebutted testimony that the two current FT-2 shippers would not have used the HIOS system but for the FT-2 tariff. FT-2 shippers have dedicated specific gas reserves to the HIOS system. HIOS argues that the record shows that as a result of incremental revenues provided by those shippers, all shippers pay a rate that is 17 percent lower than they would otherwise pay. HIOS also argues that HIOS' rate design proposal of a FT-2 rate calculated at a 105 percent load factor of the FT rate represents an equitable way to recognize the benefits that all shippers enjoy as a result of the incremental revenues provided by FT-2 shippers – the only firm shippers on HIOS' system.

194. HIOS argues that the record also supports HIOS' modest adjustment to the IT rates. HIOS argues that it presented evidence demonstrating that the Commission should make an exception in this case to permit HIOS' very modest rate differentials, which deviate much less from a 100 load factor IT rate than prior cases where the Commission has rejected requests for an exception to its general policy.[162] HIOS argues that if all of its services were interruptible, HIOS could justify a higher return on equity, due to the increased revenue risk of a fully interruptible system.

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[162] HIOS BOE at 76 (*citing Southern Natural Gas Co.*, 99 FERC ¶ 61,345 (2002)).

195. HIOS also argues that it demonstrated that as a result of excess capacity and the extremely high proportion of IT throughput on its system, a rate design change is needed to encourage efficient contracting and address the pricing inequity that currently exists between firm and interruptible services. HIOS argues that because it has significant excess capacity, shippers have little incentive to efficiently contract or pay for firm service. HIOS argues that shippers will correctly assume that an interruption of service is unlikely, and thus contract for less MDQ than required or for interruptible service instead of firm because they can effectively receive "firm" uninterruptible service while paying the interruptible rate. HIOS argues that in this situation, HIOS' existing rate design puts firm shippers at a disadvantage, and discourages firm contracting, because although HIOS' IT rate is currently equal to HIOS' 100 percent load factor firm rate, interruptible shippers pay a lower effective unit rather than firm shippers.

Discussion

196. We affirm the ALJ's finding that HIOS has failed to carry its burden of proof under section 4(e) of the NGA. HIOS first proposes to fix the reservation charge for FT-2 service at a level equal to only 95 percent of the FT reservation charge. Historically, HIOS has set the reservation charges for these two services at the same level. Exhibit No. HIO-103 shows how HIOS effects its proposed change, by using firm FT-2 reservation allocation units of only 90,440 Dth (95 percent of 95,200 Dth), while keeping its proposed firm FT-2 reservation billing units at 95,200 Dth. HIOS has argued that its non-FT-2 customers are receiving a rate benefit due to the fact that FT-2 customers are shipping gas on HIOS, and that setting the FT-2 reservation rate at 95 percent of the level of the FT reservation rate will provide the appropriate "minimal" adjustment to HIOS' other rates.

197. However, any pipeline can argue that but for any one class of customers, other customer classes would be subject to higher rates due to the loss in throughput attributable to that class. Furthermore, HIOS has failed to provide any reasonable justification for the selection of a five percent differential between the FT and FT-2 reservation charges.

198. HIOS also proposes a change in rate design to shift costs to interruptible shippers. HIOS advocates increased IT rates by a factor of 3.5 percent, or, stated differently, the use of a 96.5 percent rather than 100 percent load factor derivative of the FT rate to establish the IT rates. HIOS' witness Mr. Porter argued that because HIOS has a large amount of unused capacity, the interruptible shippers under Rate Schedule IT get a "free ride" with little chance of interruption and no incentive to sign up for firm service. To address this problem, Mr. Porter calculates that the current IT rate needs adjustment by 3.5 percent to align it properly with respect to firm service. FT-2 shippers that qualify, and in this case both of HIOS' firm customers did qualify during the test period, also pay

100 percent load factor derivative rates. There is no substantive difference in the quality of these IT and FT-2 services that justifies a rate design change.

199. Over the years, the Commission has issued orders endorsing the use of 100 percent load factor derivative rates for IT service. It has consistently found that this rate design imposes the appropriate level of cost responsibility on interruptible shippers, although other levels may be appropriate under certain circumstances. The Commission has held that a 100 percent load factor rate strikes an appropriate balance between the interruptible transportation and capacity release. The Commission has also held that a 100 percent load factor rate strikes an appropriate balance between the rate objectives in section 284.7(c)(2) ("Rates for … interruptible service during all periods should maximize throughput" and section 284.7(c)(1) ("Rates for service during peak periods should ration capacity").[163]

200. In general, the Commission seeks interruptible rates which ration scarce capacity during peak periods, maximize throughput when capacity is available, and recognize quality of service considerations. In the instant case, HIOS has shown no need to ration capacity on its underutilized pipeline, thus making maximizing throughput to be the goal in designing HIOS' rates. In fact, given the high level of IT service on the HIOS system and low overall utilization of total pipeline capacity, the HIOS proposal to increase FT and IT service rates does nothing to further ration capacity and works counter to the second goal of increasing throughput. HIOS' rate design proposal is a disincentive to move IT volumes (the current service of choice on HIOS) and appears to be a means of extracting greater rates from these customers than is justifiable under the circumstances.

201. Also, HIOS' proposal fails to take into account quality of service. IT service on HIOS should be at a lower rate than that paid by firm shippers, because it is a lower quality of service. Although HIOS' IT customers rarely have their service interrupted, it is untrue that they are enjoying a "free ride" on HIOS. IT shippers contributed only their share to the recovery of the pipeline's fixed costs, based on the traditional 100 percent load factor derivative rates they pay.

202. Because HIOS has not shown any reason to ration capacity and has not otherwise shown why a deviation from longstanding Commission policy and precedent on 100 percent load factor rates for IT service is warranted, we find that the ALJ was correct to reject HIOS' proposals for failure to carry its burden of proof.

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[163] *See Tennessee Gas Pipeline Co*., 80 FERC ¶ 61,070 at 61,201 (1997) and *Southern Natural Gas Co*., 72 FERC ¶ 61,322 at 62,337-339 (1995).

H. LAUF Gas

Background

203. HIOS has a provision in its tariff that allows it to retain a portion of the volume of gas it receives for transportation that is attributable to its system compressor fuel and LAUF gas. Section 1.6 of the GT&C in HIOS' tariff bases the level of this retention on the ratio of HIOS' total system fuel and LAUF to HIOS' total received volumes.[164] The tariff does not, however, expressly state the fuel and LAUF retention percentage. Instead, HIOS posts the applicable percentages, as they may change from month to month, on its website.[165] HIOS' website also lists only one combined percentage that represents the charge for both fuel and LAUF. HIOS did not propose any changes to its tariff provisions concerning fuel in this rate case.

204. At the hearing, concerns were raised because HIOS had recently posted increases in its fuel retention percentage. HIOS had consistently charged its shippers a rate of 1.00 percent for more than a decade until November 1, 2002. Beginning in that month, HIOS posted an increase in its fuel retention percentage above the historical level to 1.25 percent. In January 2003 the percentage rose to 1.50 percent, and remained there until May 2003 when the percentage rose to 2.18 percent, more than double the historical level. The percentage dipped slightly to 1.97 percent in July 2003, and dipped again in August 2003 to 1.71 percent. Indicated Shippers and ExxonMobil contended HIOS should be required to implement a fuel tracker with an annual true-up of over- or underrecoveries. ExxonMobil also requested that the Commission require HIOS to complete and report on an investigation into the sudden increase in fuel and LAUF above its historic flat one percent that occurred during the test period beginning in 2002. ExxonMobil argued that its effort to modify HIOS' fuel provision under section 5 of the NGA does not prohibit refunds if HIOS overcollected in the past.

205. HIOS, a former affiliate of ANR,argued that it should retain its tariff provision concerning the recovery of fuel and LAUF. However, HIOS contended that it should be permitted to adopt a fuel tracking mechanism similar to ANR's, with each year's fuel retention percentage based on the average of the last three-years' fuel use and LAUF and no true-up mechanism. HIOS argued that its proposal would give the pipeline an incentive to reduce fuel use and thus benefit customers over the long run.

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[164] Exhs. EM-2 at 1-3, HIO-91 at 37.

[165] Exh. EM-1 at 5.

Initial Decision

206. The ALJ held that HIOS could use a three-year average of past fuel use to determine each year's fuel retention percentage, but also required HIOS to implement a true-up mechanism. The ALJ stated that Commission regulations on periodic rate adjustments specify details that are applicable to HIOS' retention of fuel and LAUF:

> Where a pipeline recovers fuel use and unaccounted-for natural gas in kind, the fuel reimbursement percentage must be stated in the tariff either on the tariff sheet stating the currently effective rate or on a separate tariff sheet in such a way that it is clear what amount of natural gas must be tendered in kind for each service rendered.[166]

207. The method currently set forth in HIOS' tariff is a formula that is redetermined periodically and not a fixed charge filed with the Commission. The ALJ found that while the use of a formula is not precluded by the Commission, HIOS' current existing mechanism does not satisfy the Commission's regulations because it does not state the steps used by HIOS to calculate fuel and LAUF and because the fuel retention provision is merely posted on HIOS' website, rather than being stated in the tariff. The ALJ found that requiring HIOS to modify its tariff to state the percentage in its tariff, and to file under section 4 of the NGA to justify or change the percentage will more adequately comply with the Commission's regulations. These filings would provide shippers and the Commission with a forum to review the derivation of the charge and require HIOS to support its calculations.

208. The ALJ held that HIOS' proposed changes to its fuel and LAUF provisions, would remedy many of these difficulties. HIOS' proposal would revise HIOS' fuel and LAUF fuel retention percentage on a yearly basis using a three-year average. The ALJ found that while HIOS' proposal is not a "fuel tracker" per se, it performs a similar function and has the effect of "smoothing out" fuel charges over time. *ANR Pipeline Co.*, 78 FERC ¶ 61,290 at 62,267 (1997) (*ANR*) (order after technical conference adopting mechanism based on a three-year average). While on one hand, HIOS' proposed mechanism would permit HIOS to collect higher fuel charges for several years after a high fuel use year, it also would prevent HIOS from quickly raising its expenses and, indeed, could expose the company to losses until the higher level can take effect. On balance, the ALJ found that the use of a three-year time period is just and reasonable in this case.

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[166] 18 C.F.R. § 154.403(b) (2003).

209. However, the ALJ required two changes to HIOS' proposal. First, the ALJ found that HIOS' new proposal must be modified to add a "true-up" provision. The ALJ found that a true-up mechanism is needed to prevent over or under recovery by HIOS and to add the protection needed by its shippers who will pay the fuel and LAUF percentage calculated by HIOS even as HIOS continues to investigate its system.

210. Second, the ALJ required that HIOS must separate its fuel charge from its LAUF charge. The ALJ stated that, while HIOS had protested this burden, ExxonMobil correctly noted that Exhibits EM-8 and EM-9, provided by HIOS to ExxonMobil during discovery effectively split out these numbers. Clearly HIOS is capable of tracking these costs separately without great expense and already does so. This would also bring HIOS tariff in line with the Commission's regulations on periodic rate adjustments.[167]

211. The parties also debated whether there could be any refunds for past overcollections of fuel by HIOS and an investigation to determine whether there had been overcollection. The ALJ held that because the alteration determined above is an overhaul to HIOS' previously effective fuel use and LAUF tariff mechanism and as there has been no showing that HIOS has been in violation of its previously effective gas tariff, this issue should be treated solely under section 5 and, therefore, retroactive remedies are inappropriate.[168] However, as noted by Staff, the ALJ found that if the Commission should later find some violation by HIOS in computing its LAUF charges, the Commission could order refunds as disgorgement of unjust enrichment.[169]

Exceptions to the Initial Decision

HIOS' Exceptions

212. HIOS argues that the ALJ erred in requiring that HIOS' proposed fuel mechanism contain a "true-up' mechanism. HIOS states that because trackers "true-up" over- or under-collections that occurred in the preceding year, the Commission has found that they undercut pipelines' incentives to minimize costs and maximize service.[170] It points

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[167] 18 C.F.R. § 154.403 (2004).

[168] *See ANR Pipeline Co.*, 103 FERC ¶ 61,065 (2003) (*ANR*), *appealed sub nom.*, *Texaco Exploration & Production Co. v. FERC*, No. 03-1153 (filed May 30, 2003).

[169] Staff RB at 52 (citing cases).

[170] *See Florida Gas Transmission Co.*, 105 FERC ¶ 61,171 at P 47 (2003).

out that, in *Koch* the Commission rejected a proposal by Indicated Shippers' for a fuel tracker, stating that "The fact that the settlement does not have a fuel tracker is thus consistent with Commission policy and regulations."

213. HIOS argues that in recognition of these precedents, its proposal to recalculate fuel/LAUF charges annually based on the average of actual fuel and LAUF for the prior three years is appropriate and consistent with the Commission's 1997 decision in *ANR Pipeline Co.*[171] and other cases in which the Commission has approved similar fuel redetermination mechanisms. HIOS argues that in *ANR I*, the Commission approved a similar three-year redetermination mechanism over the specific objection that a fuel tracker should be imposed.

<u>Exceptions of ExxonMobil</u>

214. ExxonMobil argues that the Initial Decision erred in not recommending that the Commission establish a procedure for determining whether past overcharges occurred. ExxonMobil argues that a formal procedural mechanism would provide ExxonMobil and other shippers a means by which to challenge HIOS' fuel and LAUF rates. ExxonMobil argues that the lack of opportunity to review the data HIOS uses to compute its fuel and LAUF charges require the Commission to establish a process to allow these data to be reviewed now.

215. ExxonMobil also argues that the Initial Decision erred in concluding that the Commission cannot require HIOS to refund fuel/LAUF overcharges for past periods. ExxonMobil argues that NGA section 4, not section 5, governs the Commission's authority to require refunds to remedy past overcharges because the issue at hand does not call for modifications of HIOS' tariff for the relevant past period.

<u>Indicated Shippers' Exceptions</u>

216. Indicated Shippers argues that HIOS should not have unlimited discretion to recover widely varying and unsupported LAUF volumes. Instead, HIOS should bear a special burden for justifying any LAUF percentage that exceeds 0.5 percent. Indicated Shippers argues that the use of a 0.5 percent cap on LAUF volume would not prevent HIOS from filing for authorization to recover a LAUF percentage in excess of 0.5 percent, but would mean that HIOS could not automatically recover any higher LAUF percentage without demonstrating that any higher percentage was just and reasonable.

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[171] 78 FERC ¶ 61,290 (1997) (*ANR I*).

Replies to Exceptions

217. ExxonMobil and Indicated shippers support the ALJ's requirement that HOIS implement a true-up mechanism to prevent under-or overrecovery HIOS. They argue that in this instance a true-up is warranted, both to ensure that HIOS does not overrecover for fuel and LAUF, and by the wide fluctuations in HIOS' posted fuel/LAUF rates during the test period.

218. HIOS also argues that the ALJ properly rejected ExxonMobil's request for refunds. As a threshold matter, HIOS argues that if ExxonMobil believed that HIOS charged more for fuel/LAUF than the rate set forth in its tariff, the ExxonMobil could have filed a complaint with the Commission at any time. HIOS also argues that ExxonMobil's assertion that HIOS must carry a section 4 burden to justify previous fuel/LAUF rate changes is an effort to modify HIOS' tariff retroactively, which the ALJ found impermissible under section 5. HIOS further argues that ExxonMobil has offered no evidence to support its allegations that HIOS may have charged more for LAUF than its tariff permits.

Discussion

219. We affirm the ALJ's decision. HIOS' proposal must be modified to add a "true-up" provision. HIOS has defended its proposal for a fuel mechanism based on a three year average without a true-up by relying on the Commission's 1997 order in *ANR I*. However, in *ANR Pipeline Co*. (*ANR II*),[172] the Commission is reversing *ANR I* and requiring ANR to revise its fuel tracker to include a fuel mechanism that includes a true-up provision. In that case, the Commission modifies its current policy to require a true-up mechanism as part of all tariff provisions permitting adjustments to cost items outside of a section 4 rate case, absent agreement otherwise by all interested parties. The Commission finds that when a pipeline is permitted to track changes in a particular cost item without regard to changes in other cost items, "there should be a guarantee that the changes in that cost item are tracked accurately. This can only be accomplished if the tracking mechanism includes a provision for truing up over and underrecoveries."[173]

220. In light of the requirement that HIOS add a true-up mechanism, HIOS may modify the fuel recovery mechanism it proposed in the hearing to use a one year average rather than a three year average of fuel use to project its future fuel use. In *ANR II*, the

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[172] 108 FERC ¶ 61,050 (2004), *reh'g denied*, Docket No. RP04-201-002 (2005).

[173] *Id*. at P 26.

Commission permits ANR to use the most recent calendar year data on the grounds that such data is likely to produce a more accurate projection of actual use during the next year than the use of three and four year average data.[174] The Commission notes that it is reasonable to believe use of the most recent calendar year data is more likely to minimize the need for substantial true-up surcharges. On the other hand, should HIOS wish to retain the smoothing effect of using multiple year averages to determine its fuel retention percentages, including spreading the true-up of averages of over and underrecoveries over a period of more than a year, it would be free to do so.

221. Lastly, we affirm the ALJ's finding that this issue should be treated under section 5 of the NGA. The modifications being made to HIOS' tariff previously effective fuel use and LAUF mechanisms are being made without any showing that HIOS has been in violation of its previously effective FERC gas tariff, which would make treating this issue under section 4 inappropriate. Accordingly, providing retroactive remedies as requested by Indicated Shippers would also be inappropriate.

The Commission orders:

(A) The Initial Decision is affirmed and modified, as discussed in the body of this order.

(B) The settlement offer filed on August 5, 2004 is rejected.

(C) HIOS is required to file tariff sheets to comply with this order within 21 days of the date this order is issued.

(D) Within 30 days of the date of issuance of this order, HIOS is directed to refund to its shippers all charges collected in this proceeding subject to refund, with interest, as specified in section 154.501 of the Commission's Regulations.

By the Commission. Commissioner Brownell dissenting in part with a separate statement attached.

(S E A L)

Linda Mitry,
Deputy Secretary.

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[174] *Id*. at P 174.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

High Island Offshore System, LLC. Docket No. RP03-221-000

(Issued January 24, 2005)

BROWNELL, Commissioner, dissenting in part:

I would have approved the offer of settlement as an uncontested settlement that is fair, reasonable and in the public interest. I am also very troubled by the merits decisions on several issues.

The Trial Staff and ExxonMobil filed comments opposing the settlement proposal. The settlement may be considered uncontested notwithstanding Trial Staff's and ExxonMobil's comments. Citing *Stingray*, the majority acknowledges that, despite Trial Staff's opposition, the Commission has the discretion to approve the settlement as fair and reasonable and in the public interest. The majority also acknowledges that, since ExxonMobil pays a negotiated rate, ExxonMobil is unaffected by the settlement, other than the provisions concerning the fuel tracker. However, the settlement, as clarified in HIOS' reply comments, contains the fuel tracker ExxonMobil has sought. Thus, ExxonMobil's opposition is also not a bar to treating the settlement as uncontested. Consequently, I would consider the settlement proposal as uncontested and find that the settlement meets the standard for approval.

The Commission's policy is to encourage settlements whenever possible.[1] When the Commission approves an uncontested settlement, the Commission relies in part on the fact that the interests of the active parties in the case are generally similar to the interests of the inactive parties. Here, the only active party, Indicated Shippers, has agreed to the settlement proposal and will receive $3,000,000 in refunds. The inactive parties will receive no refunds. The majority imputes some nefarious intent to HIOS and Indicated Shippers and concludes that the Commission can not assume that Indicated Shippers have negotiated a settlement that is in the interest of other, inactive parties. I would characterize the agreement between HIOS and Indicated Shippers as simply a good business decision between two aggressive litigants. However, no one is suggesting that the mere fact that the active parties to a proceeding have agreed to a settlement is sufficient to justify a finding that an uncontested settlement is in the public interest.

[1] *See, e.g., Transcontinental Gas Pipe Line Corporation*, 77 FERC ¶ 61,118 at 61,457 (1996).

The settlement provides shippers other than Indicated Shippers with significant benefits. This is HIOS' first rate filing since 1994. During that period, HIOS' firm volumetric and interruptible rates were 12.44 cents per Dth. The settlement would reestablish the 12.44 cents per Dth rate for the next three years, including a rate moratorium for that period. It is this type of rate certainty that is frequently the basis for determining a settlement to be in the public interest. It may also explain why the non-active parties do not contest the settlement.

The settlement requires HIOS to file a new rate case after three years and obviates the need for continued litigation. There is no obligation for a pipeline to periodically file to justify its rates. Consequently, the three year come-back provision creates a forum for all shippers to review HIOS' rate levels, even beyond the three year term of the settlement. Just as importantly, the three year come-back provision places the burden of proof to justify its rates squarely on the pipeline. This provision is a valuable safeguard to all shippers.

Although HIOS opposed the implementation of a fuel tracker in the litigation phase of the case, HIOS agreed to implement an annual fuel tracker as part of the settlement. Moreover, HIOS also agreed to include a provision for truing up over or undercollections in the fuel tracker mechanism. It is noteworthy that the Commission in an order issued concurrently today is modifying its current policy to require all fuel trackers in pipeline tariffs to include a true-up mechanism. The fuel recovery mechanism was the most contentious issue in the proceeding. Exxon Mobil's entire evidentiary presentation addressed this issue. Particularly with current gas prices at elevated levels, it is important to ensure that fuel charges accurately reflect fuel costs. In addition, this provision of the settlement would be a tool to review and assess if any additional steps need to be taken to minimize lost gas. These are meaningful benefits for all shippers.

In addition, pursuant to the settlement, HIOS agreed to install within one year measurement facilities on its pipeline at West Cameron Block 167, to measure all deliveries by HIOS to ANR, Enbridge Offshore and Tennessee pipelines. The settlement states that the new measurement facilities must be capable of electronic monitoring of gas flow on a real-time basis. The costs of these facilities can not be included in rates until HIOS' next rate case. All shippers benefit from the increase in measurement accuracy because shippers will only pay for the service they receive.

The settlement provides for substantial benefits that redound to all shippers on the HIOS system. The fact that Indicated Shippers are the only party to receive refunds is not unduly discriminatory. HIOS argues that the Commission has recognized the appropriateness of providing an additional benefit to a settling party that has shouldered the burden of litigation, as Indicated Shippers have here.[2] Indicated Shippers also assert that Commission and court precedent endorse the principle that a settlement with special provisions applicable only to active parties is not unduly discriminatory.[3] More recently, the Commission approved a similar settlement provision in *Stingray*.[4] Because the inactive shippers would realize substantial benefits from other aspects of the settlement, I find the refund payment only to Indicated Shippers an appropriate recognition of its unique role in this proceeding.

The majority is troubled that the non-active shippers will have to pay a settlement rate (12.44 cents per Dth) that is higher than a litigated rate (9.2 cents per Dth) and receive no refunds. Trial Staff calculates refunds would amount to about $15.6 million. Some context is useful. The non-active shippers are large, sophisticated producers and marketers.[5] HIOS asserts that non-active shippers have not even sought to intervene.[6] Under these circumstances, the Commission's admonition that "if a ratepayer chooses not to intervene in a proceeding, it assumes the hazard that parties may settle the dispute in a manner not to its liking" seems appropriate.[7]

Furthermore, the issue is not whether litigated rates will be lower that settled rates. The issue is whether the settled rates are just and reasonable. In *Stingray*, the settled rate of 10 cent per Dth was a 21 percent increase from the preexisting rate.[8] The Commission found the settled rate to be just and reasonable. Here, the settled rate

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[2] Citing *Williams Natural Gas Company*, 54 FERC ¶ 61,134 at 61,448 (1991).

[3] Citing *United Municipal Distribution Group v. FERC*, 732 F.2d 202, 212 (D.C. Cir. 1984); *Town of Norwood v. FERC*, 202 F.2d 392, 402 (1st Cir. 2000); and 83 FERC ¶ 61,283 at 62,174, *aff'd on reh'g*, 85 FERC ¶ 61,104.

[4] 101 FERC ¶ 61,365 (2002).

[5] Affidavit of Staff witness Vladimir Ekzarkhov (submitted with Trials Staff's comments).

[6] HIOS Reply Comments at 12.

[7] *Stingray Pipeline Company*, 66 FERC ¶ 61,202 at 61,462 (1994).

[8] The 100 percent load factor FTS rate ($2.49) is 8.25 cents per Dth including 0.07 cent commodity rate. See Eighth Revised Sheet No. 5 in Docket No. RP99-166-000.

represents no increase from the pre-existing rate. Moreover, the estimated amount of HIOS' refund obligation fails to withstand scrutiny. The underlying assumption is that HIOS charged the maximum tariff rate of 17.59 cents for every volume of gas transported and generated $45,534,935 in "actual" revenues.[9] This assumption ignores the fact that HIOS has negotiated rate transactions below that rate. Further, HIOS reported in its Form No. 2 only $31,009,000 of revenues for 2003. Inherent in settlement negotiations are trade-offs of value. The non-rate benefits, described above, are particularly valuable from the perspective of shippers. Consequently, in the context of the settlement package, the settled rates may be found to be just and reasonable.

Finally, I do not agree with the merits decisions on several issues. For example, there is no dispute that a management fee is appropriate. The issue is the level of the fee. Trial Staff calculates a management fee of $680,802 by applying the pretax cost of capital to 10 percent of the pipeline's historical average rate base (the *Tarpon* formula). Using straight-line depreciation, the average rate base would be approximately 50 percent of gross investment. This meant that the management fee under the *Tarpon* formula would be equal to a return on 5 percent of its gross gas plant (i.e., original investment). HIOS' proposal is 20 percent of gross gas plant which would yield a management fee of $9,300,000. The majority endorses the end result of the *Tarpon* formula, i.e., 5 percent of gross gas plant. Since HIOS did not use straight-line depreciation with a negative rate base since 1998, the majority adjusted the *Tarpon* formula by substituting a normalized average rate base. The use of a modified *Tarpon* formula results in a management fee of $2,200,000. The management fee should compensate the owners of a negative rate base for the risks of continuing to operate the pipeline and provide an incentive for efficient operations. The management fee should also encourage the pipeline "to take actions to prevent an injurious loss of throughput by more aggressively marketing its gas supplies, pricing its service to increase volume, and minimize costs."[10] For many of the reasons laid out in HIOS' evidentiary presentation, the management fee using the *Tarpon* formula, even as modified, is insufficient.

In establishing the depreciation rate, the issue in this case is over the amount of gas reserves that HIOS could potentially attach in the future to estimate potential future volumes of gas that might be accessible to HIOS. Trial Staff used the entire Western

[9] Affidavit of Staff witness Vladimir Ekzarkhov (submitted with Trials Staff's comments).

[10] 57 FERC ¶ 61,371 at 62,240.

Planning Area (WPA). The majority finds the gas supply from the entire WPA is appropriate. HIOS uses a subset of WPA. HIOS would exclude potential production from deep gas in the shallow OCS waters and unleased prospects in the Gulf of Mexico that are not currently active or have not yet been discovered. HIOS argues that deep gas in shallow waters is properly excluded because only twelve deep shelf wells have been drilled near its system and only two are producing. Giving the increase in demand and elevated gas prices, more activity would have been expected. Further, HIOS asserts that Trial Staff acknowledges that there are areas in WPA that HIOS would not get gas from.[11] It seems that making some adjustments to using the entire WPA has some merit.

In developing the rate of return, one issue was the appropriate proxy group to be used to determine the range of reasonable returns under the DCF analysis. To be included in the proxy group, (1) the company's stock must be publicly traded; (2) the company must be recognized as a natural gas pipeline company and its stock recognized and tracked by an investment information service; and (3) pipeline operations must constitute a high proportion of the company's business. Fewer and fewer companies meet these standards, because of bankruptcies, mergers, acquisitions and other changes in the natural gas industry.

Trial Staff recommends a proxy group consisting of four companies. The majority acknowledges that four companies is a relatively small proxy group. However, the majority adopts this group, noting that such proxy groups have been accepted in the past. I find the precedent relied upon to be unpersuasive. Two of the three cases cited were a staff panel proceeding and a certificate proceeding. The third case was an initial decision that simply noted in a footnote that a four company proxy group had been used in the aforementioned certificate proceeding. In fact, the ALJ stated "both Staff and Williston agree that the four company (soon to be three) 'Commission Group' is too small to be useful."[12] Furthermore, HIOS asserts that three of the four companies in this proxy group include distribution companies. HIOS argues that Commission precedent has uniformly rejected use of distribution companies as proxies for gas pipelines because distributors have franchised service territories and, therefore, significantly lower risks. HIOS offered the alternative to include four pipeline master limited partnerships (MLPs) in the proxy group. The Commission has permitted use of MLPs in the proxy group in

[11] HIOS Reply Brief at n.21.

[12] 95 FERC ¶ 63,008 at 65,091.

SFPP, L.P.[13] The majority acknowledges that, in theory, it might be appropriate to compare HIOS, an L.L.C. owned by an MLP, to other MLPs whose business is made up primarily of pipeline operation. Consequently, I believe the proxy group used by the majority is unrepresentative.

For these reasons, I would have approved the settlement as fair, reasonable and in the public interest. Therefore, I respectfully dissent in part.

Nora Mead Brownell
Commissioner

[13] 86 FERC ¶ 61,022 at 61,099 (2001)(Opinion No. 435).