



## Memorandum

**TO:** Antony Scott  
**FROM:** Kenneth M. Minesinger  
**DATE:** March 20, 2007  
**RE:** Examples of New Pipeline Projects That Have Used Negotiated Rates To Allocate the Risk of Potential Cost Overruns

cc: Donald C. Shepler

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### Introduction and Summary of Conclusions

This memorandum provides a summary of how a number of pipelines and their shippers have agreed contractually to share or otherwise allocate the risk of cost overruns for new pipeline projects and expansions. Reported decisions of the Federal Energy Regulatory Commission (“FERC” or “Commission”) contain several examples of risk-sharing agreements, although relatively few that expressly address the risk of increases in the price of steel and other specific factors that can affect the cost of constructing a new pipeline. Thus, in addition to reviewing relevant FERC orders, we also reviewed open season notices, precedent agreements, and other publicly available materials. Our review disclosed a number of examples of pipeline/shipper risk sharing agreements, enabling us to reach the following conclusions:

- The recent Rockies Express project gave shippers several contracting options, including the option of negotiating a contract that required the pipeline and shipper to share the risk of cost overruns with a certain range, or a contract that required either the pipeline or the shipper to bear the risk of overruns above or below a fixed rate level.

- The Alliance project also negotiated a cost sharing arrangement with its shippers, with the pipeline agreeing to bear the risk of cost overruns that would have reduced its return on equity to 10 percent if fully realized.
- In the early 1990s, the Mojave Pipeline project, constructed contemporaneously with Kern River to serve customers in south-central California, negotiated contracts with its shippers that, prior to the in-service date, were linked to the price of steel, and capped shippers' exposure to cost overruns above a fixed rate ceiling.
- As discussed in our prior memorandum dated March 12, 2007, FERC strongly encourages pipelines to negotiate agreements with their shippers allocating the risk of cost overruns for major construction projects. There are a number of examples where pipelines and shippers have negotiated *fixed rate contracts*, which allocate the risk of cost overruns above a rate cap to the pipeline, thereby insulating the shippers from the risk of cost overruns above the agreed-upon rate cap. The prevalence of situations where shippers bear the risk of cost overruns, by agreeing to pay whatever FERC ultimately approves based on the final costs of a particular project, has significantly diminished in recent years.

## **Discussion**

### **1. Rockies Express**

The recent Rockies Express ("REX") project provides an interesting, timely insight into how pipelines and shippers can choose to allocate the risk of cost overruns on a major new pipeline

project. REX is a “Greenfield” project that will ship growing supplies of Rockies gas to markets in the Eastern U.S., from receipt locations in Wyoming and other Rockies supply areas to the terminus of the pipeline in Ohio, where it will interconnect with downstream interstate pipelines. Upon completion of the western and eastern segments of the pipeline, REX will have a capacity of approximately 2 Bcf/day, and more than 1,600 miles of pipeline facilities. It is estimated that REX will cost approximately \$4 billion.<sup>1</sup> In terms of capacity, length, and cost, REX is probably the single largest new long-haul, natural gas pipeline project constructed in the U.S. since the Alliance project. Thus, while it is not nearly the size of an Alaska natural gas pipeline to Canada or Chicago, the REX project offers some interesting points of comparison.

In its open season posting, REX offered all open season bidders the opportunity to elect from three rate options, which would apply for the entire term of the service agreement, with a minimum term of ten years. First, shippers could elect to pay the maximum recourse rate determined by FERC, under which the shippers would essentially bear the risk of any prudently incurred cost increases. Under this first option, and unlike the other two rate options, REX would have the discretion to propose changes in this rate at FERC during the term of a shipper’s contract, based on the actual cost of the project. In its open season materials, REX estimated that the initial recourse rate to go to the furthest downstream delivery points on REX would be \$1.427 Dth/day.

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<sup>1</sup> Information available on Kinder Morgan’s website at: [http://www.kindermorgan.com/business/gas\\_pipelines/rockies\\_express/](http://www.kindermorgan.com/business/gas_pipelines/rockies_express/); *see also* February 28, 2006 Press Release of Kinder Morgan available at [http://www.kindermorgan.com/business/gas\\_pipelines/rockies\\_express/NewsRelease\\_0228\\_REX\\_Commitments.pdf](http://www.kindermorgan.com/business/gas_pipelines/rockies_express/NewsRelease_0228_REX_Commitments.pdf).

Second, for this same end-to-end service, REX offered Anchor shippers a fixed negotiated rate of \$1.074 Dth/day.<sup>2</sup> This is significantly less than the estimated recourse rate of \$1.427, indicating REX was willing to take a lower return on equity than that approved by FERC in order to attract sufficient load for its project, and that REX's estimated recourse rate may, from REX's standpoint, have been conservative by building in some projected increases in the cost of construction. REX also may be gambling that in future years its recourse rate will decline below the level of its negotiated rates, providing it with the opportunity to earn a higher effective rate of return on its negotiated rate service in future years.

Third, for end-to-end service REX also offered Anchor shippers an adjustable negotiated rate. While the starting rate under this option was \$1.074 Dth/day, it was subject to a floor rate of \$1.024 and a ceiling rate of \$1.124. Adjustments were tied to fluctuations in the price of steel. In an appendix to the draft precedent agreement included in its open season posting, REX described this option as follows:

The Adjustable Negotiated Rate Option recognizes that the steel costs of the Project could change substantially between the time of execution of this Precedent Agreement and the time when the Project is placed in-service. The following rate adjustment mechanism ("Steel Price Adjustment") shall apply to Shippers electing the Adjustable Negotiated Reservation Rate Option. Any adjustment that results from this formula shall be communicated to Shipper by Transporter when all steel related Project costs have been determined.

Shipper's Adjustable Negotiated Reservation Rate will be adjusted to reflect actual total steel related project costs by using the Steel Price Adjustment and is subject to the rate floors and rate caps set forth in the tables below. The negotiated rates for

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<sup>2</sup> For each of the three options, "Anchor" shippers – shippers who agreed to firm contracts for 200-500 MMcf/day, and "Foundation" shippers – shippers who agreed to firm contracts of more than 500 MMcf/day – received slightly lower rates than non-Anchor shippers, and somewhat more favorable contract rights (such as contractual right-of-first-refusal and rollover rights).

Certificate Segments, 1, 2, and 3, including Interim Service rates, may be increased or decreased from the Starting Rate as described in the formula below:

Steel Price Adjustment =

$$\frac{(\text{actual realized steel cost per ton} - \$ 1,275 \text{ per ton}) * (\text{actual tons of steel}) / \$ 1,000,000 * \$ 0.0002}{\text{Dth}}$$

The Steel Price Adjustment will be added to or subtracted from the Starting Rate(s), however the final adjusted rate will be neither higher than the Ceiling Rate nor lower than the Floor Rate ....

Thus, REX's adjustable rate option offered some protection to shippers if the price of steel went below \$1,275/ton, and also gave some protection to REX if the price went above \$1,275/ton. The adjustable rate option also required REX to assume the risk of steel price increases in excess of the ceiling rate, and shippers to assume the risk of steel price decreases below the floor rate. Between those levels, however, the adjustable rate option effectively results in a sharing of the risk between the pipeline and the shipper. The open season materials do not explicitly address whether either REX or its customers could void the precedent agreement if steel prices either increased above or decreased below the ceiling and floor rates, respectively. However, it appears that the parties agreed to assume the risk of changes in steel prices above and below the ceiling and floor rates.

The REX project also provides an example of how the three major producers in Alaska -- BP, Conoco, and Exxon ("Producers") -- have been able to insulate themselves, in whole or in part, from the risk of construction cost overruns on other pipeline projects. Both BP and Conoco have entered into long-term, negotiated rate precedent agreements with Rockies Express. While the agreements themselves are not publicly available, some of the key terms of the agreements are reflected in the Statement of Negotiated Rates contained in the tariff filed with the initial

application for the REX-West part of the project.<sup>3</sup> The BP and Conoco contracts both provide for a reservation rate of \$23.5425/Dth/month, for the duration of their respective agreements. Although the tariff sheets are silent on whether BP and Conoco elected a fixed or adjustable negotiated rate (the second and third options discussed above), it would appear that they choose the fixed rate option. In either case, this rate helps to protect BP and Conoco from cost overruns above the fixed rate, which also represents a significant discount from the otherwise applicable maximum recourse reservation rate of \$27.4297/Dth/month. A chart reflecting the BP and Conoco fixed rate contracts with REX, and examples of other fixed rate contracts held by the Producers, is attached to this memorandum at Appendix A.<sup>4</sup>

## **2. Alliance**

The Alliance pipeline project was built in the late 1990s with a capacity of approximately 1.5 Bcf/day from supply areas in British Columbia to delivery points near Chicago, Illinois. Although the subject of steel prices was not explicitly discussed either by Alliance in its certificate application or by FERC in its orders authorizing construction of the project, a risk sharing arrangement tied to Alliance's construction costs is described in the certificate application. The Alliance case thus provides another example of how a major pipeline project and its shippers have allocated the risk of cost overruns.

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<sup>3</sup> See Rockies Express Pipeline LLC, FERC Gas Tariff, Pro Forma Second Revised Volume No. 1, Original Sheet Nos. 8-9A.

<sup>4</sup> We forwarded this same chart to you yesterday along with a separate cover memo, but are including it here as well because it lists various fixed rate contracts held by the Producers on the REX and Alliance projects discussed herein.

By way of background, Alliance was one of the first pipelines constructed after the implementation of the Commission's negotiated rate policy in 1996. We will provide a detailed explanation of the origin of and rationale for negotiated rates in a subsequent memorandum. Importantly, negotiated rates, as authorized by FERC, permit pipelines and shippers to agree to rates that, either now or in future years, may exceed the maximum rate approved by FERC, or differ from the rate design approved by FERC.<sup>5</sup> Negotiated rates gave pipelines and shippers the ability to craft creative rate agreements that, among other things, allocated the risk of cost overruns in a way that would not be possible if they were required simply to pay the maximum FERC-approved recourse rate.

Alliance and its shippers contractually agreed to negotiated rates that were predicated on a 12 percent return on equity ("ROE") for the life of the shippers' contracts. The core of the risk sharing agreement was that the 12 percent ROE was subject to adjustment for changes in construction costs. The base ROE of 12 percent was subject to an incentive mechanism under which each 10 percent deviation from the estimated capital costs to construct the pipeline would result in a 0.5 percent inverse adjustment to the base ROE. The incentive adjustment was limited to a plus or minus 2.0 percent (200 basis points) adjustment in the 12.0 percent base ROE.<sup>6</sup> In

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<sup>5</sup> *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines: Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076, *order on clarification*, 74 FERC ¶ 61,194, *reh'g denied*, 75 FERC ¶ 61,024 (1996) ("1996 Negotiated Rate Policy Statement").

<sup>6</sup> *See* Alliance certificate application, FERC Docket No. CP97-168, at p. 20 (filed December 24, 1996); *Alliance Pipeline L.P.*, 80 FERC ¶ 61,149, at 61,592 (1997).

essence, therefore, Alliance assumed the risk of a two percent reduction in its ROE due to steel price increases, from the base ROE of 12 percent to a floor ROE of 10 percent.<sup>7</sup>

### **3. Mojave**

Not surprisingly, efforts by pipelines and shippers to allocate the risk of constructing new projects predated the advent of negotiated rates at the Commission in 1996. Perhaps the best reported example involves the construction of the Mojave Pipeline Company facilities in the early 1990s. Mojave was constructed at the same time as Kern River Gas Transmission Company. Both Kern River and Mojave were built largely to serve enhanced oil recovery loads located near Bakersfield, California. Mojave constructed a 400 MMcf/day pipeline originating at the Arizona/California border at interconnections with two upstream pipelines, where Mojave receives gas produced in the southwestern U.S. Kern River's original facilities had a capacity of 700 MMcf/day, and originate in Rocky Mountains production areas. The facilities of Kern River and Mojave, which each commenced service in early 1992, merge at a point near Daggett, California to form a common, "undivided interest" pipeline which ships a commingled stream of gas to each pipeline's customers near Bakersfield. Although they share the same, common pipeline facilities downstream of Daggett, both pipelines compete for customers just as if they operated physically separate pipeline facilities.

FERC's orders certificating the Mojave project discuss how Mojave and its shippers contractually allocated the risk of cost overruns, including potential increases in the price of steel,

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<sup>7</sup> It also should be noted that Alliance agreed to calculate the negotiated rates based on a 70/30 debt/equity ratio, regardless of the actual capitalization of the project or the capital structure approved by FERC for purposes of calculating recourse rates. See Alliance certificate application, FERC Docket No. CP97-168, at p. 20; *Alliance Pipeline L.P.*, 80 FERC ¶ 61,149, at 61,592 (1997).

providing an example of how a pipeline and its shippers addressed this issue in the pre-negotiated rate era. Although not required to do so, Mojave submitted its executed firm transportation service agreements (“TSAs”) to the Commission for approval. In order to secure financing, Mojave had to know whether the Commission would approve or object to the agreements. *Mojave Pipeline Co.*, 56 FERC ¶ 61,282, at 62,097 (1991).

Mojave had six firm shippers, including Texaco (now part of ChevronTexaco), Meridian Oil (which became Burlington Oil, which was recently acquired by Conoco), and Mobil Natural Gas Inc. (now part of ExxonMobil). To allocate the risk of cost overruns, Mojave and its shippers agreed to discounted rates that were linked to the price of steel. As summarized by the Commission:

Mojave negotiated a cap on its transportation charge with each customer in order to allocate the risk of construction cost overruns. In general, Mojave negotiated a cap with each customer that then would escalate pursuant to an index intended to reflect increases in the price of steel, which is expected to be the chief variable in the cost of construction of the pipeline. The exact cap and escalation factor that Mojave negotiated with each customer varies somewhat, but all are expressly subject to the maximum rate levels prescribed by the Commission.

*Id.* at 62,100.

Later in the order, the Commission describes Mojave’s firm TSAs in more detail. For example, Meridian Oil’s rate was subject to a monthly adjustment based on the applicable increase, if any, in the Pipe and Oil Country Tubular Goods, Carbon Index of the Producer Price Index, calculated from the March 1, 1990 through the date Mojave’s facilities were placed in service. Texaco’s rate cap could be adjusted by between 3 and 5 percent annually but no less than 3 percent

based on the applicable increase in the Steel Pipe and Tubes, Line Pipe sub-index of the Producer Price Index. Mobil's rate cap appears to have been subject to similar adjustment. *Id.* at 62,102.

In sum, while the Mojave contracts varied somewhat according to each individual shipper, the Mojave case provides another example how a pipeline and its shippers allocated the risk of cost overruns, with the parties sharing the risk within the range of certain floor and ceiling rates. *See also Mojave Pipeline Co.*, 57 FERC ¶ 61,300, at 61,958-59 (1991).

#### **4. Other Pipelines**

Our prior memorandum dated March 12, 2007 (a copy of which is attached hereto as Appendix B), discussed several pipelines that have agreed to negotiated rates pursuant to the Commission's policy which strongly encourages pipelines and shippers to negotiate cost-sharing agreements that allocate the risk of cost overruns. As discussed in our March 12 memo, pipelines which have agreed to bear the risk of cost overruns above a negotiated rate cap, with the shipper bearing overruns below the cap, include: (1) Millennium; (2) Iroquois; (3) Cheyenne Plains; (4) Rockies Express (also discussed above); (5) Gulfstream; and (6) Guardian. Several other pipelines have also negotiated cost sharing arrangements, including North Baja, which also entered into negotiated rates with its shippers.<sup>8</sup> We also found two instances -- the Empire and Islander East pipelines -- which had not negotiated cost sharing agreements at the time of the Commission's

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<sup>8</sup> *North Baja Pipeline, LLC*, 95 FERC ¶ 61,259, 61,916 (2001) ("North Baja entered into long-term precedent agreements with its six shippers. All of the shippers have elected to pay negotiated rates. North Baja has filed copies of the agreements but redacted the rate information as commercially sensitive. North Baja states that it will disclose these terms through posting on its Internet web site on the first day of service, in keeping with section 284.13 of the Commission's regulations. To comply with the Alternative Pricing Policy Statement, North Baja is being required, as discussed below, to file additional information on its negotiated rates when it begins providing such service."). (Internal citations omitted).

certificate order.<sup>9</sup> Clearly, however, the trend is for pipelines and shippers to negotiate how to allocate the risk of cost of overruns as part of the process of entering into a firm transportation agreement.

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<sup>9</sup> See *Empire State Pipeline*, 116 FERC ¶ 61,074, P 116 (2006) (“The Certificate Policy Statement found that the responsibility for cost overruns should be apportioned between the pipeline and the new customers that have subscribed for the new capacity, so that the overruns will not become the responsibility of the existing shippers. EPI admits that its agreement with KeySpan does not contain this risk-sharing provision. In the application, however, EPI reserves the right to revise its initial rates prior to the commencement of service to reflect the changes in construction costs, unless the parties agree otherwise.”) (Internal citations omitted); *Islander East Pipeline Co.*, 97 FERC ¶ 61,363, P 105 (2001) (“The Policy Statement asserts that the risks of construction cost overruns should be apportioned between the pipeline and the new customers in their service contracts. Thus, in pipeline contracts for service on newly constructed facilities, pipelines should not rely on standard “Memphis clauses,” but should reach agreement with new shippers concerning who will bear the risks of underutilization of capacity and cost overruns associated with the new construction. Islander East’s precedent agreements do not contain any risk-sharing language on construction costs. If the parties agree to risk sharing agreements, Islander East must file those agreements with the Commission as non-conforming service agreements with negotiated terms and conditions. The Commission will review those agreements to ensure that they are not unduly discriminatory or preferential.”). (Internal citations omitted).

# Appendix A

**Examples of Fixed Rate Firm Capacity Agreements**  
**Held by BP, Conoco, and Exxon<sup>1</sup>**

<b>Producer</b>	<b>Pipeline/Project</b>	<b>Term<sup>2</sup></b>	<b>Negotiated Rate</b>	<b>Capacity</b>
<b>BP</b>				
BP Energy Company	<b>Cheyenne Plains Gas Pipeline Co.<sup>3</sup></b> Contract No. 21002000 Rate Sched: FT (New Pipeline)	12-1-04 to 1-31-15	\$10.3417/Dth/month	40,000 Dth/d
BP Energy Company	<b>Rockies Express Pipeline<sup>4</sup></b> Contract No. Unknown Rate Sched: FT (New Pipeline - "REX-West")	1-1-08 to 12-31-17	\$23.5425/Dth/Month	100,000 Dth/d <sup>5</sup>
BP Energy Company	<b>Tennessee Gas Pipeline Company<sup>6</sup></b> Contract No. 40102 Rate Sched: FT-A	7-1-02 to 6-30-07	\$3.07/Dth/month	4,700 Dth/d
BP Energy Company	<b>Transwestern Pipeline<sup>7</sup></b> Contract No. 100050 Rate Sched: FTS-1	6-15-02 to 6-14-17	\$0.3800/MMBtu/d	15,000 MMBtu/d
BP Energy Company	<b>Transwestern Pipeline<sup>8</sup></b> Contract No. 100926 Rate Sched: FTS-4 (San Juan Lateral 2005 Expansion)	5-1-05 to 4-30-15	Yrs 1-3 \$0.2620 MMBtu/d Remainder of term: Max rate capped at \$0.2370 MMBtu	100,000 MMBtu/d

BP Energy Company	<b>Transwestern Pipeline<sup>9</sup></b> Contract No. 101079 Rate Sched: FTS-4	6-1-05 to 5-31-08	\$0.2620/MMBtu/d	8,000 MMBtu/d
<b>ConocoPhillips</b>				
ConocoPhillips Company	<b>Alliance Pipeline<sup>10</sup></b> Contract No. US5024P-01 Rate Sched: FT1	11-1-06 to 11-30-16	15.4864/Dth/month	75 MMcf/d
ConocoPhillips Company	<b>Alliance Pipeline<sup>11</sup></b> Contract No. US5010P-01 Rate Sched: FT1	11-1-06 to 11-30-16	15.4864/Dth/month	51.1 MMcf/d
ConocoPhillips Company	<b>Alliance Pipeline<sup>12</sup></b> Contract No. US5014 Rate Sched: FT1	12-1-00 to 11-30-15	15.4864/Dth/month	50 MMcf/d
ConocoPhillips Company	<b>Questar Pipeline Co.<sup>13</sup></b> Contract #2419 Rate Sched: T-1	8-1-00 to 7-31-15	\$2.96045/Dth/month	5,000 Dth/d
ConocoPhillips Company	<b>Rockies Express Pipeline<sup>14</sup></b> Contract No. Unknown Rate Sched: FT (New Pipeline)	1-1-08 to 12-31-17	\$23.5425/Dth/month	400,000 Dth/d
ConocoPhillips Company	<b>Transwestern Pipeline<sup>15</sup></b> Contract No. 100922 Rate Sched: FTS-4 (San Juan Lateral 2005 Expansion)	5-1-05 to 4-30-15	Yrs 1-3: \$0.2620 MMBtu/d Remainder of term: Max rate capped at \$0.2370	100,000 MMBtu/d

ConocoPhillips Company	<b>Transwestern Pipeline<sup>16</sup></b> Contract No. 100925 Rate Sched: FTS-4	6-1-05 to 5-31-09	\$0.2620 MMBtu/d through 5-1-08	8,000 MMBtu/d
<b>ExxonMobil</b>				
ExxonMobil Gas & Power Marketing Company	<b>Alliance Pipeline<sup>17</sup></b> Contract No. US5011 Rate Sched: FT1	12-1-00 to 11-30-15	\$15.4864/Dth/m	30 MMcf/d
Mobil Natural Gas, Inc.	<b>Mojave Pipeline Co.</b> Rate Sched: FT-1	12-19-90 to 12-19-05	\$0.3075/MMBtu <sup>18</sup>	20,000 MMBtu/d

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- <sup>1</sup> The information contained in this chart was compiled from a variety of publicly available sources. The principal sources of information were each listed pipeline's most recent Index of Customers Report filed with the Federal Energy Regulatory Commission (report information current as of the last quarter of 2006) and the relevant pipeline's currently effective FERC Gas Tariff. Additional information was obtained from the listed pipelines' certificate applications, FERC certificate or rate orders and other pipeline rate or tariff filings. A more detailed description of the source for the information contained in each chart entry is included in the endnotes that follow. The information in the chart reflects a review of material concerning about 20 of more than 150 FERC-regulated natural gas pipelines. It is also important to note that the producers considered here have entered into fixed discount rate agreements with various pipelines that are not contained in this chart, except when specifically noted.
- <sup>2</sup> Information concerning Contract Term was taken from the pipeline's Index of Customers Report or as it is currently listed in the pipeline's FERC Gas Tariff. The contracts described herein may have been terminated or the Contract Term altered from as it is listed in the original contract or precedent agreement. Review of the actual contracts or precedent agreements between the producer and pipeline was limited, as they are typically treated as confidential and not made available to the public. *See, e.g.*, 18 C.F.R. § 388.112.
- <sup>3</sup> Transportation Service Agreement, Rate Schedule FT, between Cheyenne Plains Gas Pipeline Co. and BP Energy Co., as contained in Cheyenne Plains Gas Pipeline Company's Implementation of Tariff filing, FERC Docket No. CP03-302-004 (filed Sept. 23, 2004). Much of this information is also included in Cheyenne Plains' most recent Index of Customers Report form January 2007.
- <sup>4</sup> Information derived from the Original FERC Gas Tariff included with the Rockies Express Pipeline certificate application filed on May 31, 2006, in FERC Docket CP06-354-000. Rockies Express Pipeline, FERC Gas Tariff, Pro Forma Second Revised Volume No. 1, Original Sheet Nos. 8-9A. As noted in the chart, the contract does not become effective until January 2008.
- <sup>5</sup> BP Energy Company's commitment on the Rockies Express Pipeline will increase to 300,000 Dth/day as of the in-service date of the REX-East portion of the pipeline. This agreement to ramp up its capacity resulted in BP being classified as an Anchor Shipper on the Rockies Express system. *See* Rockies Express Pipeline LLC, Certificate Application, Vol. 1, Docket No. CP06-354-000, page 51 (filed May 31, 2006).
- <sup>6</sup> Gas Transportation Agreement between Tennessee Gas Pipeline Company and BP Energy Company, included in Negotiated Rate Tariff filing, FERC Docket No. RP96-312-072 (filed May 30, 2002). Information also contained in TGP's 1/1/07 Index of Customers.
- <sup>7</sup> Transwestern Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, First Revised Sheet Nos. 6-7, Second Revised Sheet Nos. 8-13.
- <sup>8</sup> Transwestern Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, First Revised Sheet Nos. 6-7, Second Revised Sheet Nos. 8-13.
- <sup>9</sup> Transwestern Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, First Revised Sheet Nos. 6-7, Second Revised Sheet Nos. 8-13.
- <sup>10</sup> Alliance Pipeline L.P., FERC Gas Tariff, Original Volume No. 1, Twelfth Revised Sheet No. 11, Sixth Revised Sheet No. 12-14.
- <sup>11</sup> Alliance Pipeline L.P., FERC Gas Tariff, Original Volume No. 1, Twelfth Revised Sheet No. 11, Sixth Revised Sheet Nos. 12-14.
- <sup>12</sup> Alliance Pipeline L.P., FERC Gas Tariff, Original Volume No. 1, Twelfth Revised Sheet No. 11, Sixth Revised Sheet Nos. 12-14.

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- <sup>13</sup> Questar Pipeline Company, FERC Gas Tariff, First Revised Volume No. 1, Fortieth Revised Sheet No. 7, Twelfth Revised Sheet No. 7A.
- <sup>14</sup> Information derived from the Original FERC Gas Tariff included with the Rockies Express Pipeline certificate application filed on May 31, 2006, in FERC Docket CP06-354-000. Rockies Express Pipeline, FERC Gas Tariff, Pro Forma Second Revised Volume No. 1, Original Sheet Nos. 8-9A. As noted in the chart, this contract does not become effective until January of 2008.
- <sup>15</sup> Transwestern Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, First Revised Sheet Nos. 6-7, Second Revised Sheet Nos. 8-13.
- <sup>16</sup> Transwestern Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, First Revised Sheet Nos. 6-7, Second Revised Sheet Nos. 8-13.
- <sup>17</sup> Alliance Pipeline L.P., FERC Gas Tariff, Original Volume No. 1, Twelfth Revised Sheet No. 11, Sixth Revised Sheet Nos. 12-14.
- <sup>18</sup> Because Mobil's contract on Mojave predated the advent of FERC's "negotiated rate" policy, the rate for Mobil on Mojave was more accurately described as a discounted rate and was subject to escalation up to the maximum recourse rate (with special "banking provisions"). Mobil's rate cap was approximately \$0.30 prior to full in-service, but increased to \$0.35/MMBtu (subject to the pipeline's maximum recourse rate) once the pipeline was fully in-service. Historical contract information derived from Mojave Pipeline Company Index of Customers Report for the quarter ending April 1, 1996. Other information obtained from *Mojave Pipeline Co.*, 56 FERC ¶ 61,282, at 61,099 and 61,102 (1990). *See also Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069, at 61,152 (1990).

# **Appendix B**

**Memorandum**

**TO:** Donald C. Shepler  
**FROM:** Kenneth M. Minesinger  
**DATE:** March 12, 2007  
**RE:** Cost Overruns

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**Introduction and Summary of Conclusions**

This memorandum responds to a question posed yesterday by the State about responsibility for cost overruns on major pipeline construction projects. The question is whether, as suggested by the three major producers (Exxon, BP and Conoco, hereinafter the “Producers”), shippers would be expected to bear the risk of any cost overruns that occur in constructing an Alaska natural gas pipeline, if the project were constructed by an independent pipeline company instead of by the Producers. Specifically, the Producers have suggested that the initial shippers will bear all of the project risk, including the risk of cost overruns, and that an independent pipeline company is 100 percent indifferent regarding project cost. In other words, cost overruns mean nothing to the pipeline because they are passed through completely to the shipper.

As discussed below, the short answer is that, while we of course cannot predict with certainty the precise terms of the contracts that ultimately will be agreed to between an Alaska pipeline and its shippers, it is clear that the Producers’ assertion regarding pipeline indifference to cost overruns does not reflect Federal Energy Regulatory Commission (“FERC”) policy. FERC strongly encourages pipelines to negotiate agreements with their shippers allocating the risk of cost overruns for major construction projects. There are a number of examples where pipelines and

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shippers have negotiated fixed rate contracts, which allocate the risk of cost overruns above a rate cap to the pipeline, thereby insulating the shippers from the risk of cost overruns above the agreed-upon rate cap. Several of those examples are discussed below.<sup>1</sup>

### **Introduction and Summary of Conclusions**

In the Commission's 1999 *Policy Statement Concerning Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128 (2000), *order granting further clarification*, 92 FERC ¶ 61,094 (2000), the Commission encouraged pipelines to negotiate risk sharing agreements with shippers participating in a new project regarding the rate impact of cost overruns (and underutilized capacity).<sup>2</sup> The Commission stated:

[T]he risks of construction cost overruns should not be the responsibility of the pipeline's existing customers but should be apportioned between the pipeline and the new customers in their service contracts. Thus, in pipeline contracts for service on newly constructed facilities, pipelines should not rely on standard "Memphis clauses", but should reach agreement with new shippers concerning who will bear the risks of underutilization of capacity and cost overruns and the rate treatment for "cheap expansibility."<sup>3</sup>

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<sup>1</sup> This memorandum provides an initial list of such agreements. Additional citations will be provided in a subsequent memorandum.

<sup>2</sup> See *Iroquois Gas Transmission System, L.P.*, 100 FERC ¶ 61,275, P 35 (2002) ("Under the Policy Statement, the Commission urges pipelines and project customers to apportion the risks of construction cost overruns in their service contracts. While the contracts between Iroquois and each ELI Project shipper do not currently contain the cost sharing language encouraged by the Policy Statement, Iroquois indicates that it intends to finalize its contracts with the ELI Project shippers on either January 1, 2003 or March 1, 2003, depending on the shipper. It states that at that time it will enter into a mutually agreeable cost sharing structure with the shippers that will be in a manner consistent with the Policy Statement. The Commission strongly urges Iroquois and the ELI Project shippers to enter into a cost sharing agreement on cost overruns."). (Internal citations omitted).

<sup>3</sup> 88 FERC ¶ 61,128, at 61,747 (emphasis added). A "Memphis clause" refers to contractual provision that permits the pipeline to change the rate during the term of the contract by making rate filings under Section 4 of the Natural Gas Act.

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Although this statement was made in the context of an expansion of an existing pipeline, and FERC's policy of protecting existing shippers from cost overruns, subsequent cases have cited the same principle in the concept of new, "greenfield" pipelines.

Consistent with the 1999 Certificate Policy Statement, the trend in recent years has been for pipelines and shippers to enter into negotiated rate agreements that allocate the risk of cost overruns for major construction projects, including new pipelines and pipeline expansions. Very recently, in its December 2006 order certifying the Millennium pipeline project, a new pipeline project serving the Northeast U.S., FERC addressed this precise issue. *Millennium Pipeline Co., LLC*, 117 FERC ¶ 61,319 (2006). There, FERC approved an agreement between Millennium and its shippers that allocated the risk of cost overruns above an agreed-upon rate cap to Millennium -- not to the shippers. FERC stated:

In the Certificate Policy Statement, we urged pipelines and project customers to use their business expertise and negotiating skills to apportion the risks of construction cost overruns in their service contracts, noting that the parties are in the best position to allocate such risks at the time of contracting, rather than leaving such issues for litigation at the Commission.

Millennium has addressed the issue of cost overruns, with Millennium and its shippers agreeing to rate caps over a ten-year term as set forth in an amendment to section 3 of the *pro forma* firm transportation service agreements. To the extent the negotiated rate methodology would yield a rate above the cap due to project cost overruns, Millennium will bear the cost of such overruns. When Millennium files its statement on construction costs within six months after the facilities are constructed in compliance with section 157.20(c)(3) of the regulations, Millennium will be required to compare the projected construction costs to the actual costs and explain any significant differences. Thus, we find that Millennium has adequately addressed the issue of cost overruns.<sup>4</sup>

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<sup>4</sup> *Id.* at PP 110, 111 (footnotes omitted).

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Later, in the same order, FERC found that a second pipeline (Iroquois), which was also constructing new facilities in association with Millenium's project, had also agreed to bear the risk of cost overruns:

We find that Iroquois and Consolidated Edison have addressed the issue of cost overruns in their negotiated rate agreement, since the agreement provides for a rate cap for the firm transportation service tied to the cost of the new facilities, which protects Iroquois' other customers from cost overruns. Further, if the facilities exceed a given cost, the rate charged to Consolidated Edison will not go above the cost specified in the negotiated rate agreement and Iroquois will bear the cost of the overruns.<sup>5</sup>

The Millenium and Iroquois projects are by no means the only examples where the risk of cost overruns on a major pipeline construction project has been allocated to the pipeline. The issue of cost overruns is not an issue which FERC has been required to address in a large number of orders regarding new construction projects. We have, however, researched the negotiated rate filings for several major new construction projects, and have found several instances where pipelines have agreed to negotiated, fixed rates that effectively allocate the risk of cost overruns above a rate cap to the pipeline. Examples include: (1) Cheyenne Plains, which involved the construction of a major new pipeline connecting Rockies gas supplies with Mid-Continent pipelines; (2) Rockies Express, a major new pipeline which will connect Rockies gas supplies to

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<sup>5</sup> *Id.* at P 112 (footnotes omitted). See also *Empire State Pipeline*, 116 FERC ¶ 61,074, at P 116 (2006) ("We believe that the potential exists for cost overruns here because the pipeline facilities are to be constructed more than two years after the filing date. We addressed this issue in the Certificate Policy Statement, finding that pipelines should reach an agreement with their new shippers concerning who will bear the risk of cost overruns. The Certificate Policy Statement found that the responsibility for cost overruns should be apportioned between the pipeline and the new customers that have subscribed for the new capacity, so that the overruns will not become the responsibility of the existing shippers. EPI admits that its agreement with KeySpan does not contain this risk-sharing provision. In the application, however, EPI reserves the right to revise its initial rates prior to the commencement of service to reflect the changes in construction costs, unless the parties agree otherwise. If EPI seeks to change the proposed rates prior to placing the facilities into service, it must file a section 7(c) amendment to this filing. If EPI seeks a change after the facilities are placed into service, we will require EPI to make a section 4 rate filing.") (footnotes omitted).

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pipelines in the Mideast U.S.; (3) Gulfstream, a major pipeline serving Florida, constructed in the 1990s; and (4) Guardian, a significant pipeline serving Wisconsin, also constructed in the 1990s. We expect this list will grow after further research.<sup>6</sup>

Even before FERC's 1999 Certificate Policy Statement, and well before the advent of negotiated rates, pipelines sometimes agreed to bear the risk of cost overruns. For example, in the early 1990s, Mojave Pipeline Company and its shippers entered into firm contracts with fixed rate caps that allocated the risk of cost overruns to Mojave. *See Center Point Energy Gas Transmission Co.*, 112 FERC ¶ 61,223 (2005) (discussing how Mojave entered into risk sharing agreements with its initial shippers which "provided the shippers rate certainty by capping their rates at levels which could be less than Mojave's maximum rates, depending upon its actual cost of constructing the pipeline and its cost of operating the pipeline."); *see Mojave Pipeline Co.*, 57 FERC ¶ 61,300, at 61,958 (1991) ("Mojave states that these contract rate caps provide rate certainty and protect Mojave's customers from overruns in the cost of the construction of Mojave's pipeline, as well as excesses in the cost of operation, resulting in increases beyond negotiated levels.") (emphasis added).<sup>7</sup>

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<sup>6</sup> See, e.g., *Cheyenne Plains Gas Pipeline Company, LLC*, FERC Gas Tariff, Original Volume No. 1, Effective Sheet Nos. 22 - 28A; *Rockies Express Pipeline, LLC*, FERC Gas Tariff, Original Volume No. 1, Effective Sheet Nos. 22 - 24; *Gulfstream Natural Gas System, LLC*, FERC Gas Tariff, Original Volume No. 1, Effective Sheet Nos. 8 - 8Z; *Guardian Pipeline, LLC*, FERC Gas Tariff, Original Volume No. 1, Seventh Revised Sheet No. 6.

<sup>7</sup> Although beyond the scope of this memorandum, it should be noted that, in addition to FERC's statements about allocating the risk of cost overruns, there may be other reasons why a pipeline would not be indifferent to the cost of constructing an Alaska pipeline. For example, even though it can be expected that only one pipeline will be built from Alaska to destination markets in Canada or the Lower 48 States, that pipeline will still be required to compete to some degree with other existing pipelines serving those same markets. While the level of pipeline competition in such markets may not as robust as what one would see in a highly competitive market (thus, the continued need for regulation of natural gas pipelines), nevertheless the level of competition between pipelines has increased as a result of FERC regulatory

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### Conclusion

FERC has encouraged pipelines and shippers to allocate contractually the risk of cost overruns for new construction projects. The trend in recent years has been for pipelines to agree to negotiated, fixed rate contracts that allocate the risk of cost overruns above a rate cap to the pipeline. Assuming this form of contractual arrangement is used in Alaska, the suggestion by the Producers that an independently-owned Alaska pipeline would be indifferent to cost overruns is incorrect.

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initiatives over the past two decades. This would likely provide an independently-owned Alaska pipeline at least some incentive to control costs, even in the absence of negotiated fixed rate contracts. This may be an issue which the State may wish to ask one of its economic consultants to analyze further, although based on our experience in the natural gas industry the development of increased competition among natural gas pipelines generally over the past twenty years cannot be disputed, particularly in certain parts of the U.S. A related issue is whether an independent pipeline, experienced in building pipeline projects, is better equipped than the Producers to construct an Alaska pipeline in a cost-efficient manner. That issue also is beyond the scope of this memorandum.