STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Kate Giard, Chairman Dave Harbour Mark K. Johnson Anthony A. Price James S. Strandberg

In the Matter of the Gas Sales Agreement between ENSTAR Natural Gas Company, a division of SEMCO ENERGY, INC. and Marathon Oil Company.	)	TA 139-4

COMMENTS OF THE ATTORNEY GENERAL

Pursuant to AS 44.23.020(e), and the Commission's Notice of Utility Contract Filing, the Attorney General submits these comments in response to Enstar's application for approval of a gas supply contract ("GSA") with Marathon Oil Company ("Marathon").

I. SUMMARY OF COMMENTS

The Attorney General respectfully requests the Commission suspend Tariff Advice 139-4 ("TA 139-4") for further investigation and a hearing. The record before the Commission is inadequate for approval of the GSA. The proposed GSA raises significant public policy issues, and will, if adopted, impact all of Enstar's captive ratepayers. The Attorney General's comments are preliminary given the limited time and record available for review of the GSA.

The Attorney General has identified six principal areas of concern in his preliminary review of this GSA that require further investigation. These issues are:

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(1) whether the price of gas under the GSA is reasonable, including:

(a) whether it is appropriate to use the Henry Hub index ("HHI") as a pricing proxy under the facts presented for this GSA;

(b) whether this GSA's use of a twelve month HHI average would be prudent given HHI market volatility and the resulting potential for consumer rate shock;

(c) whether the price floor ($4.75/Mcf) and price cap ($15.00/Mcf) in the GSA are reasonable;

(2) whether the term of the GSA is reasonable;

(3) whether arbitrage opportunities that exist under the GSA are fair, just and reasonable;

(4) whether the "peaking" fee under the GSA ($2.50/Mcf) is reasonable;

(5) whether inclusion of the transportation fee proposed ($0.25/Mcf) in Enstar's Gas Clause Adjustment ("GCA") is consistent with Commission regulations and precedent; and

(6) whether the transportation fee proposed is arbitrary or otherwise unreasonable.

This list is not meant to be exclusive. Rather, the Attorney General reserves the right to identify other provisions of the GSA that warrant investigation and comment as they are discovered.

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II. STANDARD OF REVIEW

In Order U-01-07(8), the Commission articulated the standard of review it uses to review Enstar's gas supply contracts:

> In deciding whether to approve the GSA we are guided by our obligation to act in the public interest. . . . Our primary concern is to ensure reliable and reasonably priced utility service. We will determine whether the GSA is fair as a whole and we make modifications only to protect the public.

Evident from the Commission's language in Order U-01-07(8), is that there are two components to be addressed in the review of Enstar's proposed gas supply agreements. First, to be consistent with the public interest, any proposed GSA must help provide Enstar with a reliable supply of gas. And second, gas sold under the GSA must be "reasonably priced." Order U-01-07(8), at pages 4 and 14. Both requirements must be met, and a finding of reliability does not trump the need for Enstar to also show any proposed GSA is "reasonably priced."

The AG respectfully suggests that any proposed GSA cannot be found to be reasonably priced under this standard of review if it subjects captive ratepayers to an unreasonable or unmitigated risk of paying for gas at prices that present a potential for awarding windfall profits to gas suppliers. Sufficient safeguards must be contractually required to avoid this risk.

III. INADEQUATELY SUPPORTED PORTIONS OF THE GSA

The record presented by Enstar is inadequate to allow for Commission approval of this GSA. For the reasons set forth below, TA 139-4 should be suspended for investigation and a hearing.

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A. The Record Presented Does Not Support the GSA's Pricing Provisions.

The GSA prices gas using a twelve month daily average of the Henry Hub natural gas futures index ("HHI"). The GSA also contains a price floor and a price cap. The price floor is $4.25/Mcf adjusted for inflation, which comes into play if the price of gas using the HHI falls below this floor.[1] The price cap is $15/Mcf, also adjusted for inflation.[2] The record contains inadequate support for use of HHI as a pricing index, or for either the floor or ceiling price for gas.

By way of background, it should be noted that Enstar is largely – if not completely – economically indifferent to price fluctuations in its gas supply contracts.[3] Unlike its other operating expenses, Enstar's natural gas costs under its supply contracts are unique in that they are recouped through its Gas Cost Adjustment clause.[4] Under this clause of Enstar's tariff[5], Enstar passes through to its ratepayers all of its gas costs, including any increases (or decreases) that result from price fluctuations in its supply contracts. Enstar proposes to recover its gas costs under this GSA in the same manner.[6] Because Enstar has no financial incentive to ensure the price of gas it negotiates in its

1. GSA § 3.3, TA Letter page 5.

2. GSA § 3.4, TA Letter, page 5.

3. The Commission observed this fact in Order U-01-07(1) at page 16. More recently, Commissioner Giard reached the same conclusion in her dissenting opinion to Order U-03-84(10) at page 5, lines 15 – 20.

4. Enstar's Gas Cost Adjustment clause is one of a variety of automatic adjustment clauses permitted by the Commission which allow utilities to recover their fuel costs directly from its customers. *See* 3 AAC 52.501, *et. seq*.

5. Section 708.

6. GSA § 10.1.1; TA letter, page 1.

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supply contracts is reasonable, the Commission must closely scrutinize the provisions of this GSA to ensure ratepayers are adequately protected.

1. Use of Henry Hub Indexing to Price Gas Under this Contract is Patently Unreasonable.

This is the third time Enstar has presented a gas supply contract to the Commission since 2001 proposing to use HHI as a pricing index. The first to do so was the Unocal/Enstar gas contract ("Unocal GSA"), approved by the Commission in Order U-01-07(8) on October 25, 2001.[7] Under the Unocal GSA, gas is priced using a rolling three year average of the HHI to price gas, rather than a twelve month average proposed under this Marathon GSA.[8]

The second time the Commission allowed the use of HHI as a pricing index was in the NorthStar GSA, approved by the Commission in Order U-03-84(7) on March 23, 2004.[9] Like the Unocal GSA, the NorthStar GSA priced gas using a rolling three year average of the HHI.

Most notable for purposes of the Commission's review of this Marathon GSA is that both the Unocal and NorthStar GSAs purported to be "exploration"

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7. The Unocal GSA was approved over the objections of both the Public Advocacy Section and Marathon Oil Company.

8 TA Letter, page 4; GSA § 3.2.

9 The NorthStar GSA was approved over the objections of the Attorney General. In particular, the Attorney General argued in both the Unocal and NorthStar dockets that use of HHI pricing for Enstar's GSAs would be unjust, unreasonable, and contrary to the public interest. The Attorney General's opinion on this issue is unchanged, and no statement made herein should be construed, in any way, as an endorsement of the use of HHI for pricing on any Enstar GSA, or for any gas supply agreement subject to the Commission's jurisdiction.

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contracts, and each company relied on this characterization as a justification to use HHI as a pricing index. *See* Order U-01-07(8) at pages 8 – 9 and Order U-03-84(10) at pages 5 – 6. But the Marathon GSA is not an exploration contract. And remarkably Enstar admits this, but nonetheless claims use of HHI pricing in this GSA is prudent because it is "based on proven reserves" and therefore "avoid[s] exploration risk." TA Letter page 5 - 6. Other than this reference, Enstar makes no attempt to justify use of HHI for pricing purposes in this GSA.

Enstar's attempt to have the Commission accept the use of HHI pricing in this GSA is unprecedented and unreasonable for a gas supply agreement based on proven reserves. Moreover, Enstar's claim that it would be prudent to allow HHI pricing here is patently inconsistent with its own past rhetoric in the Unocal and NorthStar dockets. In each of these earlier dockets, Enstar claimed a pricing premium in the form of HHI price indexing was necessary in order to entice producers to use their worldwide exploration funds here in the Cook Inlet.[10] Indeed, it was precisely because the Commission found those GSAs **did not** involve the exploitation of proven reserves that the Commission allowed such an extraordinary gas pricing scheme to be thrust on Enstar's captive ratepayers.

The record in the Unocal docket is replete with evidence that the use of HHI to price Enstar's GSAs was required by the Commission to be tied to an

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10. TA Letter 125-4 (NorthStar GSA), at pages 3-4: "Competition for drilling capital is worldwide. In order to attract capital, Enstar (and other gas users) must provide a return that is competitive with what the producers and financiers receive elsewhere. Enstar believes that the NorthStar Contract fairly balances the price that will be paid by consumers and the returns that are necessary to attract exploration capital."

exploration commitment. First, the Unocal GSA contained an express provision requiring Unocal to conduct an "aggressive exploration program in the Cook Inlet," spending in excess of $11 million to do so, and conducting this new exploration "in new areas outside of gas fields presently identified with a Field or Pool Code by the Alaska Oil and Gas Conservation Commission." Exhibit A, at § 2.1 and § 2.2.[11]

Second, in testimony presented to the Commission in support of the Unocal GSA, both Enstar and Unocal told the Commission that use of HHI as a pricing proxy was necessary in order for Unocal to justify the use of its exploration budget in Alaska. And both claimed that use of HHI pricing represented a price equal to the risk imposed on Unocal in committing to explore for new gas fields. For example, Unocal's counsel claimed:

> This [Unocal] contract was designed to directly address Cook Inlet's diminishing natural gas reserves, and Unocal has stepped up to the plate and has committed to look for new sources of natural gas, and its committed to do so without an assurance of any success, and without any assurance of recovering its costs.
>
> . . . [T]his contract is in most respects similar to contracts you've approved in the past, but there's one major difference. The contracts you've approved in the past are traditional supply contracts. **This is an exploration contract. Traditional supply contracts involve the sale of gas that already exists. Its there. An exploration contract is a contract where you have to go out and you have to find it**. Traditional contracts won't solve Cook Inlet's problem, because if you simply use up existing reserves, you're simply accelerating the date when there's no more gas to sell, and that sort of approach has not produced large reserves since the 1960's. **So here, rather than sell**

[11] Exhibit A is a copy of selected portions of the Unocal GSA.

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> **existing reserves, we're going to go out and find new sources of gas.** [Emphasis added].[12]

During the Unocal hearing, Patrick Coughlin, presented by Unocal as an expert in this area echoed this exploration theme, and the risk that accompanies it, as the only justification to use HHI pricing:

> "The program contemplated by the [Unocal] Contract is to find undiscovered resources, or to use the colloquial term used by the PAS, wildcatting. . . It is precisely this risk that justifies a higher return on the investment in drilling a wildcat well than in the drilling [of] a development well."[13]

Enstar's own witnesses also supported the use of HHI pricing because it was tied to exploration, and not to the development of proven reserves. Enstar's former president, Dick Barnes[14], testified that Unocal's obligations under its GSA were to explore in new areas that had very little, if anything, known about them, "unlike Moquawkie which had a discovery well in place."[15] In fact, Enstar claimed that use of the Henry Hub pricing was only necessary because Unocal was *promising* to continue to drill exploration wells in untested areas in the Cook Inlet prospectively "again, and again, and again." As Mr. Barnes explained:

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12 Exhibit B, attached, is a copy of the transcript of selected portions of the Unocal hearing. The quoted passage may be found on Tr. page 43, lines 3 – 22.

13 Exhibit C, attached, is a copy of selected pages from the prefiled testimony of Mr. Coughlin filed in U-01-07. At pages 2 and 27 of that prefiled testimony, Mr. Coughlin goes to great lengths in his attempt to justify use of HHI pricing for the Unocal GSA precisely because it was an exploration contract, and not a contract based on proven reserves.

14 Dick Barnes was Enstar's President for about 13 years, retiring in 2000, but remaining an Enstar consultant. He was a principal player in the negotiation of many of Enstar's GSAs, including the Unocal GSA.

15 Exhibit D, at page 4 (marked as Tr. 80), lines 17 – 21. Exhibit D is a copy of selected portions of the transcript of the U-01-07 hearing held before the Commission on August 14, 2001.

> Henry Hub Futures prices track what Cook Inlet producers can expect to sell gas for in the lower 48, if they choose to spend their drilling budget in that area. The producers do have the choice, and until now, that is exactly what they have been doing with their **exploration** dollars. The budgets have not gone into Cook Inlet gas **exploration**, because of low prices and because of not knowing whether there will be a market. It is difficult to get corporate capital budgets committed to **speculative** drilling where the price is low or unpredictable and where there is no market. The price term [HHI] is designed to endure over a long period at market prices that are obtainable elsewhere by major producers. [Emphasis added].[16]

It was based on this record in Docket U-01-07 that the Commission took the unique step of allowing a shift of "the risk for future Cook Inlet gas exploration [from producers] to the Enstar ratepayer."[17] And in doing so, the RCA specifically noted:

> Exploration is needed in order to ensure an adequate supply of gas for Enstar ratepayers. The risk associated with exploration must be compensated or exploration will go elsewhere. While the HHI price structure is higher than previously approved contracts, we weigh the risk that Enstar will not have an adequate natural gas supply in the future against a higher exploration price.

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[16] Exhibit E, attached, is a copy of selected pages from the Prefiled Reply Testimony of Richard Barnes filed in Docket U-01-07. The quoted section is on page 28 of that reply testimony. *See also*. Exhibit D, at transcript page 82, lines 15 – 20 ("But go out in the future, how do you pick a price that will cause the producer to drill at a future date and have some certainty. Well, the way you do that is you pick a price that they will be able to get in their largest market to do the same thing, to – drill for gas.") This is also exactly how Enstar's counsel characterized Unocal's ongoing commitment to continue to explore in the Cook Inlet in docket U-01-07: "This deal is good for the community only if Unocal finds gas and develops it and delivers it, ***and then does it again and again and again. This is a long-term deal.*** There are all sorts of things we can do in the short term to have a little gas. But the point of the deal is to create a strong financial incentive for Unocal to continue to explore for and develop and deliver the gas to Enstar." Exhibit B, at Tr. page 33, lines 9 – 15. *See also* Exhibit B at Tr. page 30, lines 7 – 9 ("You see Unocal . . . beginning to put together an exploration program, the first real exploration program for a utility ever put together in Cook Inlet.")

[17] Order U-01-07(8), page 6, lines 10 – 11.

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. . .

> The evidence persuades us that Enstar must pay a competitive price to attract necessary capital and encourage exploration in Cook Inlet. The **HHI price is necessary to attract exploration capital**. We find that a price tied to the HHI, with a floor of $2.75 is a reasonable balance of the **risks associated with gas exploration** and the need to assure an adequate supply of gas for Enstar's ratepayers. [Emphasis added].[18]

In Docket U-03-84, the Commission approved use of HHI for a second time as a pricing index for an Enstar GSA, this time with NorthStar, who was promising to make natural gas available for service to Homer. Again, as with the Unocal GSA, both Enstar and NorthStar claimed that the NorthStar GSA was an exploration contract – not a contract to supply gas from proven reserves. Indeed, both claimed that NorthStar's risks were even greater than those facing Unocal. And it was only because of this that the Commission ruled (in a 3 to 2 decision) that use of HHI as a pricing index was justified:

> NorthStar must explore for and find two distinct wells, each of which is separately and independently capable of providing all of Homer's needs, both in terms of daily deliverability (which is at least 6.5 Mcf per day) and a total deliverability of 14.5 billion cubic feet (Bcf). Because proven reserves stand at 12 Bcf, NorthStar has a performance guarantee that can only be satisfied by successful exploration efforts. Both ENSTAR and NorthStar state that NorthStar's risks are much greater than Unocal's. ENSTAR offered discussion of why the Moquawkie situation is markedly different.
>
> We have considered arguments from the parties on this issue. We find that there is adequate record to find this

[18] Order U-01-07(8), page 8, line 15, through p. 9, line 7.

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> pricing provision in the public interest. NorthStar's and ENSTAR's explanations of the investment required and the risks associated with developing the requisite gas supply convince us that the pricing provisions are reasonable for the specific circumstances surrounding this contract. Furthermore, no ENSTAR customer will be affected and terms of the Agreement will not be activated absent NorthStar's successful exploration requirements and performance.[19]

The evidentiary record that formed the foundation for the Commission's conclusions for the Unocal and NorthStar GSAs in Orders U-01-07(8) and U-03-84(10) is totally absent in the case of this Enstar/Marathon GSA:

- The Marathon GSA requires no exploration[20];
- There is no evidence whatsoever that performance of Marathon's duties under the GSA will require it to make any materially significant capital expenditures;
- The Marathon GSA will do nothing to increase Cook Inlet's natural gas reserves; and
- Marathon faces no material risk whatsoever under this GSA.

Risk and the need for new gas exploration in Cook Inlet were the drivers that the Commission relied on in deciding to approve the use of HHI pricing for Unocal and NorthStar. Neither of these elements is present for Marathon, and there is simply no rational basis offered in this record upon which the Commission can approve this

19 Order U-03-84(10), at pages 5 – 6.

20 TA Letter 139-4, page 5.

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GSA using HHI pricing, regardless of how it is structured. TA 139-4 should be suspended for investigation and a hearing to address this issue in detail.

2. Recent Events Have Shown How Use of the Henry Hub Index is Unreasonable for Pricing Gas in Alaska.

The HHI has increased sharply during the past three year period, from approximately $4.75/Mcf at the end of 2003, to a rough average of $6.00/Mcf in 2004. For 2005, prices on the HHI have been as high as $12 to $15/Mcf because of recent catastrophic events in the Gulf of Mexico (Katrina/Rita). A November 2005 study performed by Energy and Environmental Analysis, Inc.[21] projects gas prices to remain in the $13 to $14/Mcf range through the winter and gradually drop back to the $8 to $10/Mcf range later next year.[22]

The Unocal GSA is now capturing this upward trend in gas pricing with the 3 year average price of gas to Enstar in 2006 set at $6.19/Mcf. *See* Enstar's Tariff Advice Letter 138-4, filed November 4, 2005, at page 5. This average will grow substantially when Unocal's three year HHI average captures the recent sharpest upturn in HHI pricing which will undoubtedly be presented next year by Enstar to the Commission as yet another request for a substantial rate hike to consumers.

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[21] *Hurricane Damage to Natural Gas Infrastructure and its Effect on the U.S. Natural Gas Market*. A copy of this report is attached as Exhibit F.

[22] "In recent years, deliverability has declined so that all available capacity is required to meet demand. While additional gas is being supplied through imports, total North American gas production has remained relatively flat while demand has continued to grow. The US gas market is now in a very tight supply/demand balance situation, leading to high prices and high volatility." Exhibit F at page 3-1.

The potential for such dramatic impacts on consumer prices for natural gas in Alaska under HHI pricing were forecast by Commissioner Giard in her dissent to Order U-03-84(7), at page 4:

> With the decisions in Docket U-01-07 and herein, Alaska natural gas prices are utterly dependent on activities in the Lower 48. A series of events or a single dramatic event occurring in the Lower 48 could materially affect our economy. For example, if a Lower 48 pipeline is affected by terrorist acts and decommissioned, the natural gas prices in the Lower 48 would rise exponentially and hold. While the supply of natural gas in Alaska would remain unaffected by this event, our gas prices would also rise.
>
> The Lower 48 event does not have to be dire to cause irrational price increases in Alaska. As is indicated in a March 2004 press release, a single cold winter month in the Lower 48 can cause gas storage supplies to fall. When those supplies decrease, the Henry Hub price increases. The result is an increase in Alaskan prices completely unrelated to the supply or demand in Alaska.[23]

Commissioner Giard's observations just 20 months ago were quite prophetic. The effects of hurricanes Katrina and Rita on lower 48 spot market gas prices at the Henry Hub are significant, and will linger for some time.[24] While these events have created real gas supply impacts in the lower 48, Alaska is unaffected, except insofar as Enstar's supply contracts are tied to this lower 48 Henry Hub index.

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[23] *See also* Commissioner Giard's Dissent to Order U-03-84(10) at pages 2 – 3, noting that a decision to tie Enstar's gas supply agreements' pricing to HHI was an unreasonable practice, and one that would subject Enstar's "captive ratepayers [to] the mercy of a spot market for gas in the lower 48 that bears no relation to gas market conditions in Alaska."

[24] Exhibit F, at pages 3-3 and 3-4. Notably, this report also discusses how spot market pricing can differ between areas of the lower 48, with the eastern U.S. (including the Henry Hub) expected to face higher gas prices than the western U.S. "which receives gas from the Rockies, the west-Texas on-shore producers and Canada."

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Although these observations obviously call into significant question the ongoing reasonableness of continuing Commission approval of the use of HHI pricing for the Unocal GSA[25], Marathon does not even come close to standing in Unocal's shoes. Given Enstar's admission that the Marathon contract is grounded on proven reserves, there is no justification in this record to subject Enstar's ratepayers to a gas supply contract based on pricing that is tied to a lower 48 spot market index having no connection to events in Alaska.

3. Use of a Twelve Month Average HHI to Price Gas Will Subject Enstar's Ratepayers to Greater Sensitivity to Lower 48 Events.

Enstar touts use of a twelve month average as a "buffer" to the Unocal GSA's three year HHI rolling average. It claims this twelve month average will "more quickly reflect falling prices" and it will be "more market responsive, mitigating any risk that over the term of the contract the price will be higher than the Henry Hub market price." TA Letter page 4 – 5. Enstar's discussion of this issue is both incomplete, as well as entirely inconsistent with its own prior representations to the Commission.

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[25] The law is well settled that the Commission holds ongoing jurisdiction to modify contracts between public utilities and third party vendors, which would include Enstar's GSA with Unocal. *Stepanov v. Homer Electric Ass'n*, 814 P.2d 731, 736 (Alaska 1991). *See also, United Gas Pipeline Co. v. Mobile Gas Svc. Corp.*, 350 U.S. 332 (1956). In *United Gas*, the United States Supreme Court held that the Natural Gas Act, 15 U.S.C. § 717 *et seq.* ("NGA") granted the Federal Power Commission ("FPC") authority to modify the rates in a contract between a utility and a gas supplier. The Court held the FPC retained authority to modify the terms of any contract if the public interest required. This provided, according to the Court, a "reasonable accommodation between the conflicting interests of contract stability on one hand, and public regulation on the other." The text section of §5 of the NGA relied on by the Supreme Court is virtually identical to AS 42.05.431(a).)

For example, in Docket U-01-07, Enstar's witness Daniel Dieckgraeff explained how use of the 36-month average was necessary to dampen the impact of HHI price spiking in Enstar's rates:

> Marathon apparently forgets that the Agreement [the Unocal GSA] uses a trailing 36-month average of the Henry Hub prices.[26] The \$8.00/Mcf to \$10.00/Mcf prices cited by Marathon are anomalous. . . . If in effect today, the 36-month contract price would be \$2.637 per Mcf, just \$0.005 per Mcf less that Enstar is now paying under its Beluga contract. . . .[27]

Enstar's endorsement of use of a 12-month average also fails to acknowledge that when HHI pricing jumps quickly, the Marathon GSA's pricing will rapidly follow suit subjecting ratepayers to the potential for shocking price swings from one year to the next. Catastrophic events that impact natural gas pricing on the Henry Hub, such as hurricanes Katrina and Rita, would be captured in full by ratepayers who would see little if any mitigating effects.

As these recent events on the Gulf coast demonstrate, pricing gas to consumers using a twelve month HHI average will enhance the potential for rate shock. Rate shock has historically been a result the Commission seeks to avoid – not embrace.

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[26] Remarkably, in Docket U-01-07, Marathon argued against Commission adoption of HHI pricing for the Unocal GSA in large part because it "could drive up costs exponentially to [Enstar's] ratepayers." Exhibit G, attached, is a copy of selected portions of the Comments filed by Marathon in TA 117-4 addressing the Unocal GSA. The quoted reference is found at page 14 of the Comments.

[27] Exhibit H, attached, is a copy of selected portions of Enstar witness Daniel Dieckgraeff's Prefiled Testimony in Docket U-01-07. The quoted passage can be found at page 24 of that testimony. It is also educational that in the Unocal Docket Enstar was claiming the Commission could rely on HHI pricing remaining stable at approximately \$3.50/Mcf. *See* Exhibit H, at page 24, lines 16 – 20 of Mr. Dieckgraeff's prefiled testimony.

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E.g., Re Copper Valley Electric Ass'n.. 7 APUC 26, 28 (1985); *Re Matanuska Electric Ass'n*, 7 APUC 366, 373 (1986). Enstar has presented an inadequate record on this issue to justify a Commission decision to deviate from long standing Commission policy that seeks to mitigate rate shock. As use of this twelve month HHI GSA pricing appears destined to exacerbate consumer rate shock, the Commission cannot accept it on this record.

4. There is No Record Supporting the GSA's Price Floor or Cap.

Enstar's TA Letter provides very little information as to why a price floor of $4.25/Mcf and a price cap of $15/Mcf are fair, just and reasonable. This price floor exceeds – by $1.50/Mcf – the $2.75/Mcf floor price approved by the Commission for the Unocal and NorthStar GSAs.

The Unocal and NorthStar GSA floor price was established by looking to the Moquawkie GSA approved by the Commission on July 27, 2001 in TA 114-04, which prices gas to Enstar at a flat rate of $2.75/Mcf, adjusted for inflation.[28] Enstar's current TA Letter provides no analysis or rational justifying such a huge deviation from prior approved GSA floor pricing. And Commission precedent in the NorthStar GSA shows that where no justification is provided, or it is deemed inadequate, attempts to inflate the floor price beyond $2.75/Mcf will not be allowed.[29]

The price cap provision in the GSA is a new feature for Enstar's HHI based GSAs. However, the cap selected, $15/Mcf, is unaccompanied by any analysis or

[28] Exhibit I, attached is a copy of a selected portion of Unocal witness Dan Thomas' Prefiled Testimony, which at page 15 describes how the Unocal floor price was derived from the Moquawkie GSA.

[29] Order U-03-84(7), page 11.

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discussion as to why the cap selected is reasonable. Such a discussion is particularly significant given Enstar's admission that this GSA is based on proven reserves, where presumably Marathon faces no perceivable risk, and any capital expenditures are likely to be minimal. The record before the Commission on these price cap and floor issues is inadequate to justify their adoption.

5. The Peaking Fee of $2.50/Mcf is Unsupported.

Enstar's TA Letter also provides no explanation as to how the $2.50/Mcf Peaking fee was reached, or why it should be considered reasonable. Moreover, Enstar does not discuss why this peaking fee should be allowed to deviate from the peaking fee allowed by the Commission in the Unocal GSA. In that docket, a peaking fee of $1.00/Mcf was permitted. Order U-01-07(8) at page 9; Exhibit A, at § 4.6. On this record, the Commission cannot allow adoption of a peaking fee 250% higher than that allowed in U-01-07.

6. The Transportation Fee's Inclusion in Enstar's GCA Should be Evaluated to Ensure Consistency With Commission Regulation.

The Marathon GSA includes a fixed transportation fee of $0.25/Mcf. GSA §3.8. Enstar is requesting that this transportation fee, like the GSA's other cost components, be passed directly through to ratepayers via Enstar's GCA.[30]

Inclusion of this fee in Enstar's GCA should be investigated under 3 AAC 52.502(a). This regulation only permits cost elements to be included in adjustment clauses if three conditions are met:

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30 TA Letter, page 1; GSA § 10.1.1.

(1) The cost incurred must be subject to change at a rate that would cause financial harm to the utility;

(2) The cost incurred must be beyond the control of the utility; and

(3) The cost incurred must be easily verifiable.

Enstar has not shown how this GSA's fixed transportation fee meets the requirements of this regulation. Enstar should be required to do so.

7. The Transportation Fee is Arbitrary, Potentially Discriminatory, and Unsupported.

Enstar claims use of a fixed fee is a preferable method of addressing transportation costs, rather than "paying the actual tariff for each pipeline." TA Letter page 6. However, Enstar provides no explanation as to how a $0.25/Mcf figure was derived or why it should be considered reasonable. Without some justification, this fixed transportation fee is arbitrary and cannot be permitted.

Nor has Enstar provided an adequate justification to avoid having a transportation fee determined by tariff. In Order U-01-07(8), the Commission approved the Unocal transportation fee after observing it would be set by a tariff that the Commission would need to review and approve. As the Commission stated, by doing so, "we have an opportunity to determine if the rates are just and reasonable." Order U-01-07(8), page 11. Enstar's request for a fixed transportation fee therefore amounts to an end-run on the Commission's statutory mandate to test the fee for reasonableness. AS 42.05.381(a). Public policy cannot support this request on this record.

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Not only does Enstar's request for a fixed fee appear to be at odds with the Commission's mandate to ensure rates are reasonable, but application of this proposed fee could require Enstar's ratepayers to pay a fee at odds with that charged to others under established tariffs. Such a result could amount to unlawful rate discrimination, in violation of AS 42.05.391(a) or AS 42.06.320. *See Jager v. State*, 537 P.2d 1100, 1109 - 10 (Alaska 1975).[31]

Nor can Enstar reasonably rely on the Moquawkie GSA's approved transportation fee as precedent for two reasons. First, Enstar is agreeing to a transportation fee exceeding that allowed in Moquawkie by 60% without explanation. And second, although the Moquawkie GSA includes a fixed $0.15/Mcf transportation fee, the Commission's decision to allow this fee was adjudicated as a TA filing, rather than being suspended for investigation and a hearing.[32] Therefore, it would be inappropriate to consider this prior Commission action as compelling precedent under these circumstances.

Notwithstanding these defects, Enstar makes a hardship argument in favor of using the fixed fee. It claims that "use of actual tariffs is [] unworkable" because gas will be delivered under APL-4 and this GSA at the same time and the APL-4 GSA has

---

[31] "Discrimination which is unreasonable is unlawful, discrimination based on justified differences in the cost of service or which is otherwise within the zone of reasonableness is permissible. When, however, the rate structure is such that one class of customers subsidizes another, discrimination may pass beyond its permitted scope and become undue or unreasonable."

[32] Exhibit J, attached, is a copy of selected portions of the transcript of the NorthStar GSA hearing held in Docket U-03-84. At page 107 of the transcript (attached), Enstar's witness Daniel Dieckgraeff admits the Moquawkie GSA was adjudicated as a TA filing.

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no transportation fee component. TA Letter page 6. This claim appears to have inadequate support on this record. Tariffs have been established for virtually all Cook Inlet gas pipelines, and to the extent new tariff rates need to be set, then the method to do so is hardly experimental. *See* 3 AAC 48.275. This is not complicated by APL-4 because Enstar and Marathon both know how much gas is supplied to Enstar under APL-4, as well as where it comes from. If volumes transported over pipelines are known, tariff rates can presumably be set.

Finally, the Marathon GSA requires Enstar to pay $0.25/Mcf on all gas regardless of whether it is transported on existing or not-yet-constructed pipelines. This differs substantially from both the Unocal and NorthStar GSAs which only impose a transportation fee on gas transported over new pipelines. *See* Exhibit A (Unocal GSA), at § 4.5 and Exhibit K (NorthStar GSA), at § 4.5. Enstar's TA Letter provides no explanation justifying this deviation from precedent.

B. The GSA's Term Should Be Investigated.

Enstar characterizes this GSA as a short term contract. TA Letter page 4. This appears to be an accurate characterization for Alaska-based GSAs assuming Enstar's representations that gas deliveries under it will not begin until 2009 are accurate. However, short term gas supply contracts are an unusual arrangement for Enstar. Virtually all of its existing and prior supply contracts are (or were) long term, and it is unclear what impact the relatively short term of this contract has had on other contract provisions, particularly price. Enstar provides no explanation on this issue in its TA Letter. It should be required to do so.

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Moreover, this GSA provides Enstar with no "economic-out" or "market-out" clause, which Enstar apparently credits to the GSA's "short" term. TA Letter, page 4. Although there may be some justification to have a contract term consistent with allowing Marathon to recover its incremental costs plus a reasonable return on its investment[33], the Commission should evaluate whether Enstar's captive ratepayers should be locked into rates for any period beyond this initial term without some escape clause.

The use of "economic-out" or "market-out" clauses is not unusual in the natural gas industry.[34] They also offer a valuable tool to avoid the necessity of constant regulatory intervention:

> "The virtue of this approach is that it would not require the regulator to devise and impose specific new contract provisions. In response to exercise of an economic-out, the

---

[33] As economist Scott Goldsmith testified in Docket U-01-007, on behalf of Unocal: "Existing reserves need a price at least as high as the incremental cost (primarily the cost of production) of bringing those reserves to market. A higher price that also covers the costs previously incurred to find and develop the reserves would, of course, be preferable, but if the market cannot support that price, or is unlikely to support it in the future, it is financially preferable to sell at a price that is at least a little bit above incremental costs (so that at least a portion of the investment in exploration and development can be recovered) rather than not sell at all." *See*, Exhibit L. attached. This Exhibit is a copy of selected portions of the Prefiled Reply Testimony of Oliver Scott Goldsmith submitted on behalf of Unocal in Docket U-01-07. The referenced quote is found on page 7.

[34] *See* J. McArthur, *The Take or Pay Crisis: Diagnosis, Treatment, and Cure for Immorality in the Marketplace*, 22 N.M. L. Rev. 353, 375 (1992) ("Other contracts have periodic, usually annual, price redetermination, sometimes coupled with an 'economic-out' clause which lets the pipeline terminate the contract if it doesn't like the price, or a 'market-out' clause which lets the pipeline reduce the price it pays as the market changes. Some have 'FERC-out' clauses, requiring refunds of costs that cannot be included in the pipeline's rate base.")

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> parties would be free either to conform their contract to new market conditions or terminate the relationship."[35]

The Commission should suspend this TA filing to investigate this significant public policy issue.

C. Arbitrage.

The GSA does not prohibit Marathon from purchasing gas from other sources at a lower price and reselling it to Enstar at the higher GSA price. In fact, Enstar actually says that this is a positive feature of this GSA because it means Marathon will be able to meet Enstar's needs "when gas is scarce."

Respectfully, the propriety of allowing Marathon to supply any or even all of its gas commitments through third party supply should be investigated. Under this GSA, Marathon is attempting to compel premium "exploration" pricing without doing any exploration, and could, if approved, enhance its windfall opportunities by simply acting as a middle-man to provide some or all of its commitments.

This same issue was raised in Docket U-01-007. There, the Commission imposed a limit on sale of third party gas under the Unocal GSA:

> While we agree with Unocal that gas in declining fields should not be stranded, we also understand the arbitrageconcerns. We find limiting Unocal's ability to sell third party gas to fifteen percent of the total annual gas volume sold is a reasonable limitation to the GSA and adequately protects the ratepayer.[36]

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[35] D. Watkiss, *Deregulation Myopia: Sacrificing The Filed Rate Doctrine and Rule Against Retroactive Ratemaking to Promote Competition in Gas Markets,* 42 S.W. L. J. 711, 754 (1988).

[36] Order U-01-07(8) at p. 13.

The Commission concluded a limit on arbitrage was appropriate for the NorthStar GSA as well. *See* Order U-03-84(7) at page 11.[37] But what is noteworthy in Docket U-03-84 was that Enstar claimed there was a need for arbitrage because NorthStar did not have "other proven gas sources." Here, Enstar admits Marathon is in exactly the opposite situation – with proven reserves – but still claims a right to arbitrage should be allowed. Respectfully, the Commission should not endorse a right to unlimited – or even limited - arbitrage on this limited record presented by a utility which faces no financial risk whatsoever in the contract it negotiated. The Attorney General respectfully believes that this issue should be investigated before Enstar's captive ratepayers should be compelled to purchase third party gas at the GSA's price.

IV. CONCLUSION

For all of the above reasons, the Attorney General respectfully requests the Commission suspend TA 139-4 for investigation, open an adjudicatory docket, and hold a hearing to consider the GSA. This will allow the Commission to develop a complete record in order to evaluate whether approval of the Marathon GSA would be in the public interest. The existing record is inadequate for this purpose.

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[37] "We conclude that at the present time there is little opportunity for NorthStar to engage in arbitrage because there are no alternate proven gas sources for NorthStar other than the North Fork field. However, NorthStar has indicated an interest in interconnecting with another pipeline in the future if there are gas reserves sufficient to meet ENSTAR requirements to serve the Homer market as well as other customers. Under these circumstances, we must be concerned with the possibility of arbitrage. NorthStar did not oppose a limitation on arbitrage, so we condition our approval of the Agreement to an arbitrage limitation equivalent to the one approved in the Unocal contract; not more than 15 percent of the total gas volume sold under the Agreement may come from third party sources."

DATED this 22ND day of December, 2005 at Anchorage, Alaska.

DAVID W. MÁRQUEZ
ATTORNEY GENERAL

By:

Steve Devries
Assistant Attorney General
Alaska Bar No. 8611105

VERIFICATION

I, Steve DeVries, verify that I believe the statements contained in this pleading are true and accurate.

Steve DeVries

SUBSCRIBED AND SWORN to before me this 22nd day of December, 2005.

Karyl Richards
Notary Public in and for Alaska
My commission expires: 4.20.09

KARYL RICHARDS
NOTARY
PUBLIC
STATE OF ALASKA

CERTIFICATE OF SERVICE
I hereby certify that true and correct copies of the foregoing *Comments of the Attorney General* were served, via hand delivery ~~fax and mail~~ on the following:

Julian Mason, Esq.
Bill Saupe, Esq.
Ashburn & Mason
1130 W. 6th Ave., Ste. 100
Anchorage, AK 99501
277-8235 (fax)

Karyl Richards 12.22.05
Karyl Richards Date

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GAS SALES AGREEMENT

BETWEEN

UNION OIL COMPANY OF CALIFORNIA

AND

ALASKA PIPELINE COMPANY

Effective Date November 17, 2000

"Storage Gas" means Gas acquired from a third party to put into storage (including Gas purchased or stored as LNG) or Gas taken from storage.

"Swing Rate" means the ratio of the Deliverability (MMcf per Day) to the annual purchases expressed as a daily average (MMcf/Day). For example, if annual purchases were 2.92 Bcf and Deliverability were 20 MMcf per Day, the Swing Rate would be $[20 \div (2920 \div 365)] = 2.5$.

"Termination Event" is defined in Section 13.11.

"Total Daily Deliverability" means the total amount of Gas (from all suppliers) that Buyer needs on any Day (expressed as MMcf per Day).

"Transportation Fee" is defined in Section 4.5.

"Unmet Requirements" means the difference between Requirements for any Year and the sum of Buyer's Existing Commitments for that Year, Additional Third-Party Commitments for that Year, and Unocal's Initial and Additional Commitments for that Year.

"Year" means a period of twelve (12) consecutive Months beginning on January 1 and ending on the next January 1.

ARTICLE II
SELLER'S EXPLORATION AND DEVELOPMENT COMMITMENT

2.1 Exploration Commitment: Buyer and Seller believe that there have been only modest discoveries of natural gas in the Cook Inlet area in the past thirty years. DNR records show that during that time gas supply available to the area has decreased from a 60-year supply to approximately a ten-year supply. Because sharp seasonal fluctuations in demand caused by cold winter weather, the parties believe there could be a shortage of gas within a few years, unless new sources of gas are discovered. Because of commitments made in this Agreement by Buyer, Seller commits to a prudent and aggressive exploration program in the Cook Inlet area as outlined in this Article II in order to increase gas reserves available to ENSTAR and its customers.

2.1.1 In anticipation of entering into this Agreement, Seller has spent approximately $3 million in identifying, acquiring, and preparing a comprehensive exploration program. Additionally, Seller has incurred over $1 million in overhead expenses associated with this program.

2.1.2 Seller commits to spend in excess of $1 million in lease rentals, seismic data and additional land acquisition costs within three years of the Effective Date.

2.1.3 Seller commits to spend in excess of $500,000 on technical staff salaries allocated to gas exploration within two years of the Effective Date.

2.1.4 Seller commits to spend in excess of $10 million for costs associated with drilling, completing and testing exploration wells that target new Gas reserves between October 1, 2000 and October 31, 2002.

2.2 Exploration Area: Seller agrees to make the additional expenditures and pursue the exploration program committed to in Section 2.1 in new areas outside of gas fields presently identified with a Field or Pool code by the Alaska Oil and Gas Conservation Commission. It is the intent of Seller to identify, develop, and produce new reserves from new fields, and to acquire and deliver new gas into the Cook Inlet area, including Anchor Point, Ninilchik and Homer.

2.3 Material Consideration: This exploration commitment is material consideration for Buyer to make this Agreement. If Seller fails to meet its exploration commitment, Buyer has all remedies available at law or in equity except as limited by Section 13.10.

ARTICLE III
SALE AND PURCHASE OF GAS

3.1 Quantity: Buyer is not required to purchase in any Year more Gas than the Annual Purchase Obligation. Subject to that limitation, Buyer will purchase and Seller will sell Gas in the quantities determined by this Article.

3.2 Initial Commitment: The Initial Commitment is the quantity of Gas necessary to make Buyer's Unmet Requirements equal zero in 2003, 2004, and 2005. Forecasts indicate that purchases of the Initial Commitment will start on January 1, 2004, but Buyer will actually begin taking the Initial Commitment when it first has Unmet Requirements (but not before January 1, 2003).

3.3 Additional Unocal Commitments: Each Year beginning October 1, 2002, Seller may commit additional Gas to Buyer as follows:

3.3.1 Exhibit C is Buyer's Forecast for ten Years beginning January 1, 2001. Buyer's Forecast is an estimate of (1) Requirements and (2) Gas that Buyer is obligated to purchase from: Buyer's Existing Commitments, the Initial Commitment, Additional Third-Party Commitments, and Additional Unocal

3.9 Operational Communications: Buyer will notify Seller (or anyone designated by Seller) by telephone periodically as to the volumes required by Buyer. Seller recognizes that Buyer may change its volumes more than once each Day and that a volume may not be changed for a number of Days. The purpose of this Section is to provide communication between Buyer and Seller about field operations and Buyer's needs. Communications under this Section do not change the obligations of the Parties.

ARTICLE IV
PRICE AND TRANSPORTATION FEE

4.1 Gas Price: Buyer shall pay Seller a Gas price (the "Price") for each Mcf of Gas purchased from Seller. The Price will be adjusted annually and the adjusted Price will be in effect for the following Year.

4.1.1 Price: The Price shall be the Daily Average Price of Henry Hub Natural Gas Futures (HHNGF).

4.1.1.1 The Daily Average Price of HHNGF shall be determined from the prices for "Henry Hub Natural Gas" futures contracts traded on the New York Mercantile Exchange or its successor. The Daily Average Price of HHNGF shall be the sum of the "Settle" prices reported for a contract traded during the immediately previous thirty-six month period ended each September 30th of the year prior to the year for which the Price is calculated for each day that the contacts are reported as the contracts for the Current Trading Month divided by the total number of days that such "Settle" prices are reported. "Current

Trading Month" means the final month in which a contact can be traded. The Daily Average Price of HHNGF shall then be converted in to a price per Mcf using the conversion factor of one (1) MMBTU equals one (1) Mcf.

4.1.1.2 The Price shall not be less than the Floor Price. The Floor Price shall be determined by the following formula:

$$FP = IP \times [(1 + \text{Adjuster}) \div 2]$$

FP = Floor Price for any given Year (in $ per Mcf)

IP = $2.75 per Mcf

$$\text{Adjuster} = \frac{\text{GDPIPD for the Quarter ended June 30 of the Year before the Year for which the Price is calculated}}{\text{GDPIPD for the Quarter ended June 30, 2001}}$$

"GDPIPD" means the Gross Domestic Product Implicit Price Deflator prepared by the Bureau of Economic Analysis, Economics and Statistics Administration, United States Department of Commerce.

4.2 References: If the source of data or information used to calculate the Price is not available or any Party, based on reasonable evidence, believes in good faith that (i) the sources have been computed or published in error, or (ii) the sources have so changed in the basis of calculation or reporting as to materially alter the validity of the Price adjustments as originally contemplated, then the Parties shall negotiate whether there is a reference failure and an appropriate amendment to or replacement of the Price formula.

4.3 Calculation: Buyer shall calculate the adjusted Price in October of each Year and provide the calculation and supporting data to Seller by ber 1st of that Year. Within thirty (30) Days of receipt of the ulation, Seller shall notify Buyer of the reasons for any objections to the calculation.

4.4 No Determination: If an adjusted Price cannot be determined by January 1 of any Year, the current Price will be used until the adjusted Price is determined. The current Price will then be changed retroactively to January 1st and Buyer will promptly pay or receive a credit (with interest at the rate set in Section 11.3) for the difference.

4.5 Transportation Fee: It is Seller's responsibility to build all pipelines and other facilities necessary to deliver the Gas to the Receipt Points. The Price includes all RCA-approved tariffs for pipelines operating on the Effective Date of this Agreement. If pipelines are constructed after this Agreement becomes effective, the Buyer shall reimburse Seller (in addition to the Price) the RCA-approved tariff for the new pipelines used to deliver Gas to Buyer, unless the RCA-approved tariff is more than $1.00 per Mcf. If the RCA-approved tariff is more than $1.00 per Mcf, the Parties must agree to any reimbursement in excess of $1.00 per Mcf. A pipeline is "used to deliver Gas to Buyer" (i) if the pipeline transports Gas directly from the production field to Buyer, (ii) if the pipeline is used to transport Gas to storage from which it is later delivered to Buyer, or (iii) if the pipeline is used to deliver Gas to a third party in exchange for Gas which will later be delivered to Buyer. The tariff will be invoiced in the Month following the Month in which the Gas is delivered to Buyer.

4.6 Peaking Gas Fee: Any Day that Seller supplies in excess of its Pro Rata Share of Maximum Deliverability Seller will be paid a fee for the excess of $1.00 per Mcf (in addition to the Price) increased or decreased each Year using the Adjuster in paragraph 4.1.1.2.

4.7 Price Example: Exhibit F is a comprehensive example of the calculation of Price.

ARTICLE V
<u>TERM</u>

The Effective Date of this Agreement is the date on which it has been executed by all Parties. Unless the Parties agree to extend this Agreement, this Agreement shall terminate on the earlier of (a) delivery of all Gas committed to be delivered, or (b) termination under another provision of this Agreement.

ARTICLE VI
<u>TAXES</u>

6.1 General Allocation: Seller shall pay all taxes, fees, penalties, and assessments attributable to the Gas or any other activity or facility prior to the Receipt Point. Buyer shall pay all taxes, fees, penalties, and assessments attributable to the Gas or any other activity or facility at or after the Receipt Point.

6.2 Specific Allocation: Buyer shall reimburse Seller for all Production Taxes on Gas produced for sale to Buyer. Gas is "produced for sale to Buyer" (i) if the Gas is delivered directly from the production field to Buyer, (ii) if the Gas is produced and put into storage from which it is later delivered to Buyer, or (iii) if

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STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

In the Matter of the Gas Sales Agreement Between Alaska Pipeline Company, a wholly owned subsidiary of SEMCO Energy, of which Enstar Natural Gas Company is a division, and Union Oil Company of California filed as TA117-4

Docket U-01-007

REGULATORY COMMISSION OF ALASKA
HEARING ROOM

August 14, 2001
8:38 o'clock a.m.

VOLUME III

PUBLIC HEARING

BEFORE: PAUL OLSON, HEARING EXAMINER

AND: G. NANETTE THOMPSON, RCA, CHAIR
WILL ABBOTT, RCA, COMMISSIONER
JAMES S. STRANDBERG, RCA, COMMISSIONER

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EXHIBIT B

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letters coming from Mr. Risser, and the meeting points he was putting down, the phone calls that he was making to Enstar. What you see is Marathon trying to compete on price by accelerating the delivery of gas to Enstar RD (ph) owners, already under contract to Enstar. Let's just sell it to you faster, it will be cheaper.

You see Unocal, on the other hand, beginning to put together an exploration program, the first real exploration program for a utility ever put together in Cook Inlet.

And you follow this forward and eventually what you see is that Marathon loses in that competition. It loses because where it chose to compete on price Enstar's management, I think quite correctly, wanted to get exploration now because of concern about long-term regional gas supply. So it was not interested in going for what may or may not be, given the direction of Henry Hub prices, may or may not be a short-term price advantage. But management made the choice, management for now chose to go with Unocal.

Now, I've been doing this gas supply contract thing for about 25 years. I can tell you that by gas contracting standards that was exciting. With the APL -- with the contract at Beluga, there was essentially no competition there. With APL-4, there was only token competition. To the best of my knowledge, there was no competition going on of any significant degree when Chugach bought gas from Marathon. This is the supply is to have real exploration for new gas. You don't improve the gas supply by burning the gas that you have.

The most disappointing aspect of -- or aspects of Staff's testimony to us, the PAS testimony, are two things. One is its focus on short-term price, intensely focused on short-term, and maybe ephemeral short-term price advantage.

And other -- the other is its apparent preoccupation with the Unocal XA, which is going to be the subject of Commission deliberations later. This deal is good for the community only if Unocal finds gas and develops it and delivers it, and then does it again and again and again. This is a long-term deal. There are all sorts of things we can do in the short term to have a little gas. But the point of the deal is to create a strong financial incentive for Unocal to continue to explore for and develop and deliver the gas to Enstar.

The -- all that XA does is invite the Commission to speculate about what other price Enstar might have gotten, to speculate about how much gas Unocal might find, to speculate about what other investment alternatives are available to Unocal in other places in the world, but going down that path, just makes it harder and harder and harder for us to deal with the industry buying gas. It's not a path that we want you to go down. We hope that Unocal will earn a good and generous profit out of this. We hope that Unocal, and we believe that Unocal is -- it has gas available. That it's going to find natural gas to serve the interests of Southcentral Alaska where over half of the state's population resides.

This contract was designed to directly address Cook inlet's diminishing natural gas reserves, and Unocal has stepped up to the plate and has committed to look for new sources of natural gas, and it's committed to do so without an assurance of any success, and without any assurance of recovering its costs.

Now, as Mr. Mason said, this contract is in most respects similar to contracts that you've approved in the past, but there's one major difference. The contracts you've approved in the past are traditional supply contracts. This is an exploration contract. Traditional supply contracts involve the sale of gas that already exists. It's there. An exploration contract is a contract where you have to go out and you have to find it. Traditional contracts won't solve Cook Inlet's problem, because if you simply use up existing reserves, you're simply accelerating the date when there's no more gas to sell, and that sort of an approach has not produced large reserves since the 1960s. So here, rather than sell existing reserves, we're going to go out and we're going to find new sources of gas.

Now, I believe this is the first time the Commission has had an exploration contract before it, and so I'm going to spend approximately half of my opening talking about what it

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners: G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

In the Matter of the Gas Sales Agreement between Alaska Pipeline Company, a wholly owned subsidiary of SEMCO Energy, which the Enstar Natural Gas Company is a division, and the Union Oil Company of California, filed as TA117-4	U-01-007

CORRECTED PREFILED REPLY TESTIMONY OF PATRICK J. COUGHLIN

I. Introduction

1\. Q. Please state your name and address.

A. My name is Patrick J. Coughlin and my address is 2426 Lord Baranof Drive, Anchorage, Alaska 99517.

2\. Q. What is the purpose of your testimony?

A. I have been asked to respond to the prefiled testimony of Mr. McConnell of the Public Advocacy Section ("PAS") and Mr. Risser of Marathon Oil Company ("Marathon") and to reply to their conclusions that the Gas Sales Agreement ("Contract') between Union Oil Company of California

("Unocal") and Alaska Pipeline Company ("Enstar") is not in the best interest of the State and Southcentral Alaska. I disagree with Mr. McConnell and Mr. Risser and have concluded that the Contract is in the best interest of the State and Southcentral Alaska because: 1) it advances an important policy goal of developing a long-term energy plan for Southcentral; 2) it encourages exploration for undiscovered resources under reasonable terms, including a reasonable price; and 3) it has positive socio-economic benefits for the State and Southcentral, and environmental benefits.

3. Q. What background and experience do you have that qualifies you to render such an opinion?

A. Since October of 1991, I have been directly involved in making public policy decisions regarding oil and gas development in the State of Alaska. Beginning in October of 1991, I served as Assistant Attorney General representing the Alaska Division of Oil and Gas. I served in this capacity through February of 1996, when I became the Deputy Director of the Division and served in that capacity until February of 2001. As Deputy Director, I supervised all the Division's employees except for the Director, and reported directly to the Director and the Commissioner of the Department of Natural Resources (DNR). In February of 2001, I contracted with the Senate Resources Committee to be its consultant on oil

1. proved developed reserves (quantity expected to be produced through existing wells or with minor expense);
2. proved undeveloped reserves (quantity expected to be produced with new or extended wells or with significant expense);
3. unproved discovered reserves (quantity of discovered resources that are too uncertain to be called reserves and divided into "probable" meaning a 50% chance of being produced and "possible" meaning a 10% chance of being produced); and
4. undiscovered resources (an undiscovered quantity that it is hypothesized to exist).

See DOE Export Matter decision Table 1 and Appendix A, attached to *Prefiled Testimony of Timothy F. McConnell* as **Exhibit TFM-9**. The program contemplated by the Contract is to find undiscovered resources, or to use the colloquial term used by the PAS, "wildcatting." The PAS notes that the drilling of wildcat wells has "industry source odds of finding gas perhaps no better than 50/50." *PAS's Response to Enstar Interrogatory No. 5* **(Exhibit PJC-4).** I believe the historical chances of finding oil and gas in commercial quantities is even less. According to Mr. Strickland, overall it is about 1 in 8. It is about 1 in 10 in Cook Inlet. **(Exhibit PJC-6).** It is precisely this risk that justifies a higher return on the investment in drilling a wildcat well than in the drilling a development well. The three biggest determinants of return are well and production costs, price and volume. If we assume that gas can be produced from a development well and exploration well at the same cost (highly unlikely) and the market will pay the same price for gas whether it comes from an exploration or development well, then the wildcatter will only drill an exploration well if

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STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

In the Matter of the Gas Sales Agreement Between Alaska Pipeline Company, a wholly owned subsidiary of SEMCO Energy, of which Enstar Natural Gas Company is a division, and Union Oil Company of California filed as TA117-4)	Docket U-01-007

REGULATORY COMMISSION OF ALASKA
HEARING ROOM

August 14, 2001
8:38 o'clock a.m.

VOLUME III

PUBLIC HEARING

BEFORE: PAUL OLSON, HEARING EXAMINER

AND: G. NANETTE THOMPSON, RCA, CHAIR
WILL ABBOTT, RCA, COMMISSIONER
JAMES S. STRANDBERG, RCA, COMMISSIONER

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Q (By Mr. DeVries) Refer to your direct testimony if you would at page 15 lines 18 through page 16 line 1.
A Page 15 which lines, please?
Q Sorry. It's page 15 lines -- excuse me, I think I have a wrong page reference here. My apologies.
MR. DeVRIES: Can we go off a record for just one second?
HEARING EXAMINER OLSON: Sure. Off record.
MR. DeVRIES: I apologize for.....
HEARING EXAMINER OLSON: Okay. Go off record.
(Off record - 10:43 a.m.)
(On record - 10:43 a.m.)
HEARING EXAMINER OLSON: Okay.
Q I'm sorry, Mr. Barnes. In your direct testimony on page 15 beginning on line 18 you talk about the use of the Henry Hub price marker for Alaska gas. Is that correct?
A Yes, it is.
Q And you say, I believe, Unocal proposed to drill prospects that had little known about them unlike Moquawkie which had a discovery well in place. Unocal was willing to step out into new areas for exploration. Is that a fair.....
A That's fair.
Q So correct me if I'm wrong, Enstar -- and I think you will, Enstar believes that the gas contract's price is fair because Unocal is going to look for new gas in new areas and you need a premium price to extract -- to get

these or to track these exploration dollars, is that correct?

MR. MASON: I object to characterizing the price as a premium price. That appears nowhere in the contract or anywhere else except in the mind counsel or to the (ph) contract price, whatever you want, but it's not.....

HEARING EXAMINER OLSON: I'm going to overrule the objection. The testimony is that for Alaska projects to go forward the price incentive had to be in place, and so the witness can disagree if he thinks it's a premium price or not. I'm going to allow him to ask the question.

Q Can you -- do you want to repeat the question?

A Please.

Q So am I correctly characterizing it by saying that you believe that this gas contract's price is fair because what Unocal is proposing to do is to go into a new -- is to find new gas in new areas and that you need this gas contract price in order to be able to attract those exploration dollars?

A Well, if you'll bear with me for a second. I know you'd like a yes or no answer, but here -- here is -- here's how I feel about it. If -- if you were going to drill just adjacent to an existing field you would -- a producer would have a good handle on what the likelihood of success is, not risky at all, and he'd know when he was going to do it. He could pick that time. We have a temporal issue here. Let's say we're talking about the wells will be drilled five years from now. And the question is how do you set a price today that will attract a producer to drill five years from now. And the only way to do that is to have a price that is compensatory to the producer five years from now.

It was our belief that a market price -- I hear lots of premium price discussed, but -- but today the Henry Hub price is not different by a significant amount that is being in Cook Inlet today by the utilities, by Chugach Electric and by Ma- -- and by -- by Enstar for the gas it's purchasing. We're talking about in the high two sixties versus call it $3. It's not a -- not a huge difference. But go out in the future, how do you pick a price that will cause the producer to drill at a future date and have some certainty. Well, the way you do that is you pick a price that they will be able to get in their largest market to do the same thing, to -- to drill for gas. And -- and so -- so that sort of price in our belief and -- and certainly in Unocal's belief was what was necessary to -- to find new supplies of gas to be available for these consumers. Yes.

Q Let me try asking you the question in a little bit different way.

A Okay.
Q Is Enstar contracting for new gas here?
A It's contracting for gas with -- with -- with the anticipation and with the obligation that Unocal drill some new gas.
Q So your expectation is you're paying the contract price in order to get new gas, isn't that correct?
A No, to get exploration for new gas.
Q And that's why you're paying the price that's commanded by this contract?
A That's the primary reason.
Q And to find this new gas your expectation -- Enstar's expectation is that Unocal's going to go to new areas, isn't that correct?
A That is correct, and Unocal shared with us what their general plans would be.
Q When you wrote your testimony did you have any expectation that Unocal would be targeting any areas where it may or may not have been before?
A Yes.
Q And what were those expectation?
A It was generally on the southern part of the Kenai Peninsula.
Q What were you told as far as historical information that Unocal had about prior history in those areas?

members of the public and Marathon employees or inside counsel have exited the hearing room and we're now in a confidential session. Madame Chair was indicating to me that we don't really have a designation between confidential and highly confidential because that was disallowed by the Commission in a request of differentiations between that type of confidential information. So we'll just call this a restrictive confidential hearing if that will work for the parties to designate that Marathon people are gone. Okay. Mr. DeVries.

CROSS EXAMINATION CONTINUED

BY MR. DeVRIES:

Q Do you recall the question?
A Why don't you repeat it?
Q Let's see if I recall it. I believe I was asking you what it was, what did Unocal tell you about their exploration plans as far as what information did they give you? What specifics did they give you?
A They reviewed the structures and the targets that they intended to explore as part of this program.
Q Generally or specifically? Did they show you maps, location?
A They showed in some cases specific locations that they intended to drill. In other -- in other cases structures.
Q Did they tell you how many wells they planned to drill?
A I believe they did.

Q Do you recall what that number was?
A No.
Q Did they tell you whether or not they had ever drilled in those areas in the past?
A I don't think the subject came up, but in general there -- there had been no exploratory wells in most of the areas is the way I recall it.
Q So basically it's your understanding that Unocal wasn't going to be going back to some place where they had drilled before and found gas before, rather they were going to a new area?
A That was my understanding.
Q On -- in your reply testimony on page 10.....
MR. DeVRIES: .....and this still does, I think, kind of potentially implicate confidential information. I'll let you know when I'm done with that.
Q But in your reply testimony on page 10 lines 1 to 15, you're talking about differentiating here what Marathon was proposing to do or at least you're drawing -- your testimony is about what Marathon was proposing to do when you were negotiating with them, is that.....
A No, what -- what they had been doing, I thought was what I was talking about here.
Q And Marathon had been concentrating on the edges of existing fields or re-drilling an old well which had been

C E R T I F I C A T E

UNITED STATES OF AMERICA)
)ss.
STATE OF ALASKA)

I, Rebecca Nelms, Notary Public in and for the State of Alaska, residing at Anchorage, Alaska, and Reporter for R&R Court Reporters, Inc., do hereby certify:

THAT the annexed and foregoing PUBLIC HEARING in Docket No. U-01-007 was taken by Suzan Olson the 14th day of August, 2001, commencing at the hour of 8:38 o'clock a.m, at the Regulatory Commission of Alaska Hearing Room, Anchorage, Alaska;

THAT this Transcript, as heretofore annexed, is a true and correct transcription of the proceedings transcribed by Meredith Downing, Lynn Hall, Wanda Ventres and myself;

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal this 15th day of August, 2001.

Rebecca Nelms
Notary Public in and for Alaska
My Commission Expires:10/10/02

STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners:

G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

In the Matter of the Gas Sales Agreement between Alaska Pipeline Company, a wholly owned subsidiary of SEMCO Energy, which the ENSTAR Natural Gas Company is a division, and the Union Oil Company of California, filed as TA117-4.	)	Docket No. U-01-007

REPLY TESTIMONY OF RICHARD F. BARNES

Q. Have you reviewed the direct testimony of Timothy F. McConnell?

A. Yes, I have.

Q. What general impression do you have from reading his testimony?

A. In reaching his conclusions, I believe that Mr. McConnell did not address the major issues that are the underpinnings of the gas supply situation in Cook Inlet. He did not respond to the issue of short gas supply in the region, except for his speculation (page 28, line 4) about the LNG plant shutting down in 2009 and possible access to North Slope gas from an extension to the proposed export pipeline. He did not discuss the need for major exploration projects to develop new Cook Inlet gas fields or how his proposals would affect the likelihood

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EXHIBIT E
PAGE 1 OF 2

A. Yes, there is. Unocal's gas is likely to be only one of the users of a new pipeline. It is reasonable to assume that a new pipeline will open up access to leases held by other producers or that other producers will have joint interests in fields explored by Unocal. Gas from these other producers may be shipped through the same pipeline. Pipeline sizing and operation will need to take into account the needs of these other producers. It is not inappropriate for Unocal or someone else to build and operate such a pipeline.

Q. Mr. McConnell says (page 11, line 1) that Henry Hub Futures pricing exposes ENSTAR's customers to upside price risk while precluding lower prices with a price floor. Do you think this is an appropriate price term?

A. If you believe that there is a supply problem, you need to gauge contract terms by how they will affect development of new supplies. Henry Hub Futures prices track what Cook Inlet producers can expect to sell gas for in the Lower 48, if they choose to spend their drilling budget in that area. The producers do have the choice, and until now, that is exactly what they have been doing with their exploration dollars. The budgets have not gone into Cook Inlet gas exploration, because of low prices and because of not knowing whether there will be a market. It is difficult to get corporate capital budgets committed to speculative drilling where the price is low or unpredictable and where there is no market. The price term is designed to endure over a long period at market prices that are obtainable elsewhere by major producers. There may be available some distressed gas, with little or no deliverability, at low prices. ENSTAR's customers need large amounts of gas in the wintertime. That fact will not change. Henry Hub prices are for flat gas deliveries, which makes drilling in that region even more appealing. The floor price gives more incentive for Unocal to drill than if it were not in place. When Unocal does its economic

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ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

Hurricane Damage to Natural Gas Infrastructure and Its Effect on the U.S. Natural Gas Market

Final

Submitted to:
The Energy Foundation

November 2005

Submitted By:

Energy and Environmental Analysis, Inc.
1655 N. Fort Myer Drive, Suite 600
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GLOSSARY OF TERMS

Energy and Power Units

British thermal unit (Btu): basic unit of energy; amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit

Million Btu (MMBtu): 1,000,000 Btu, roughly equivalent to 293 kilowatt-hours of electricity or 8 gallons of gasoline

Natural Gas Units

Cubic foot (cf): basic unit of natural gas delivery = ~1,030 Btu

Thousand cubic feet (Mcf) = ~ one million Btu

Million cubic feet (MMcf) = ~ one billion Btu

Billion cubic feet (Bcf) = ~ one trillion Btu

Trillion cubic foot (Tcf) = ~ one quadrillion Btu

Billion cubic feet per day (Bcf/d) = 0.365 Tcf per year = ~375 trillion Btu per year

Market Terms

Deliverability: The maximum rate at which natural gas can be withdrawn from a reservoir.

Basis: The difference in price for a commodity at two geographic locations.

Gas processing facility: A plant whose function is to condition natural gas by removing impurities and/or natural gas liquids.

Gas storage facility: A facility where natural gas is stored for later use. A storage field is typically a depleted oil or gas field but may also be a salt cavern or aquifer. Storage sites are located in both producing and demand regions.

Gas transportation facility: Natural gas pipelines, including gathering lines and intrastate and interstate pipelines.

Henry Hub: A physical location in southern Louisiana where a number of pipelines from the Gulf of Mexico and South Louisiana interconnect. The price of natural gas at Henry

Hub is an important index used for pricing gas throughput in the U.S. and for trades in the futures market.

Liquefied natural gas (LNG): Natural gas that is chilled to the point that it is a liquid at atmospheric pressure. Local distribution companies use LNG when storing natural gas above ground for extended periods. Also, natural gas is shipped long distances between countries in the form of LNG.

Shut-in (curtailed) production: The volume of oil or gas production that is temporarily closed off at the wellhead and prevented from reaching market for safety and operational reasons before and after hurricanes.

Working gas in storage: The volume of natural gas in storage that can be withdrawn to meet demand.

EXECUTIVE SUMMARY

The concentration of U.S. oil and gas production, processing, and transportation facilities in the Gulf of Mexico and onshore Gulf Coast means that a significant percentage of domestic oil and gas production and processing is prone to disruption by hurricanes. In addition, the very tight natural gas supply/demand balance that currently exists has magnified the impacts of large-scale hurricane disruptions on energy supply and prices.

Over the past decade, hurricanes entering the Gulf of Mexico have disrupted regional onshore and offshore oil and gas production. The 2004 and 2005 hurricane seasons have had a major impact on Gulf Coast production operations. Hurricane Ivan made landfall in September, 2004 causing significant production curtailments over a period of months. This year, Hurricane Katrina came ashore on August 29 and Hurricane Rita made landfall on September 24.

The combined effects of Hurricanes Katrina and Rita have had a profound effect on all sectors of the Gulf Coast natural gas industry as well as important segments of the gas consuming sector, making this hurricane season the most damaging in history. While the effects of Katrina and Rita are still unfolding, it is possible to evaluate the market impacts that have already occurred and to estimate what the ultimate effect on gas production and markets will be.

Hurricanes Katrina and Rita affected every component of the Gulf Coast natural gas infrastructure. The impacts on natural gas supply volumes and prices were particularly significant because:

- The natural gas market was already tight before the hurricanes.
- The Gulf Coast accounts for 40 percent of U.S. natural gas production.
- The combination of the two hurricanes in 2005 created a greater volume of production shut-in and damage to producing infrastructure than any recent storm. The two storms hitting in succession have lengthened the effect on the gas industry.
- The hurricanes also damaged natural gas processing and pipeline facilities needed to process and deliver gas to customers.
- The volume of curtailed production in the third week of October from both onshore and offshore areas of the Gulf Coast is approximately 5 billion cubic feet (Bcf) per day. This represents about one-half of pre-hurricane offshore production.

- Cumulative gas shut-ins through August, 2006 for Katrina and Rita are forecast to range from approximately 900 billion cubic feet to 1,100 billion cubic feet. This volume is over five times the shut-in volume from last year's Hurricane Ivan. The forecast indicates that the shut-in rate will decline from the current 5 Bcf per day to approximately 3.5 Bcf per day by December. Shut-ins are expected to continue through next spring, with a March, 2006 rate of approximately 2 Bcf per day.
- The hurricane damage to oil refineries resulted in a upward pressure on oil prices, which indirectly drives natural gas prices higher.

After last year's Hurricane Ivan, Henry Hub prices increased from a July level of $6/MMBtu to a peak of $8/MMBtu. By February of this year, natural gas prices had returned to slightly more than $6 but rose during the summer to about $10 as world oil prices increased. Hurricane Katrina made landfall in late August, and prices increased by about $2/MMBtu to $12/MMBtu. When Hurricane Rita struck in late September, Henry Hub prices increased to $15/MMBtu. Since that time, prices have declined slightly to the $13 to $14/MMBtu range.

Gas supplies this winter are expected to be much tighter than usual, even under normal weather conditions. Natural gas storage inventories at the start of the winter will be comparable to the recent five-year average but will be lower by about 200 Bcf than expected without the hurricane-induced supply disruptions. In addition, winter wellhead supplies will be unusually low, as production and gas processing facilities are expected to remain out of service for several more months pending repairs. Current price levels are expected to extend through the winter and, at best, gradually return to pre-hurricane levels as the infrastructure recovers. This will make U.S. consumers more vulnerable to additional price spikes and service interruptions, particularly if the winter is colder than normal or if other factors disrupt the supply infrastructure. Due to the very tight supply/demand situation, even small changes in supply or demand can have much larger effects on gas prices – either up or down. Gas prices in the longer-term will depend on other factors such as world oil prices and development of additional gas supply, either from North America or through LNG imports.

The effect of these price increases will be felt primarily in the eastern half of the U.S., which is most dependent on natural gas from the Gulf Coast region. The western U.S., which receives gas from the Rockies, the west Texas on-shore producers and Canada, will be less affected. The limited capacity to move gas from west to east will help create this differentiation between gas prices in the east and west.

The effect will also be most significant for large industrial and power generation gas consumers, who tend to rely more on spot market gas purchases. The vast majority of residential and commercial customers purchase gas from a regulated local distribution company (LDC). The LDC charges its customers for the delivery of the natural gas plus the cost of the gas commodity delivered to the local citygate. The increases in the price of the gas commodity are passed directly to customers. The timing and method of this price transparency depend on the regulations in individual states. In some cases there can be an automatic, monthly purchased gas adjustment. In other cases, the adjustment is made through a periodic adjustment in the LDC rates.

LDCs are very sophisticated buyers of natural gas. They maintain a mixed portfolio of spot and long-term gas purchases, inject a large amount of gas into storage during the summer and sometimes use financial hedging tools to protect themselves against price volatility. To the extent that the hurricane effects on gas prices are relatively short lived through the 2005-2006 heating season, most LDCs and their customers will be somewhat insulated from the effects through forward purchases and gas put in storage prior to the price increases.

Nevertheless, the higher prices will have some effect on LDC customers and a potentially larger effect on large industrial and power generation customers, who purchase gas directly from producers and are more likely to purchase spot market gas. The exact effect on consumer cost is difficult to estimate due to the mix of purchasing options, the effect of LDC purchasing strategies as well us the uncertainty over prices.

The effect of gas prices on electricity prices in any region depends on:

- The gas share of generation
- The structure of the electricity market

Under traditional regulated utility rates, the cost of electricity is based on the average cost of generation. If gas is a large share of generation in a region, then higher gas prices will have a significant effect on electricity prices. Several electric utilities have already announced electric rate increases due to higher gas prices.

In states with restructured electricity markets, the price of electricity is based on the cost of generation of the marginal unit. If there is mostly gas generation on the margin, then the price of electricity will be set by the price of electricity even if the majority of the total generation is from non-gas generators. Thus, in restructured electricity markets such as California, Texas, PJM, New York and New England, electricity prices are closely correlated to natural gas prices. This has been reflected in higher wholesale electricity prices throughout the year and during the post-hurricane period.

1 NATURAL GAS INFRASTRUCTURE

1.1 Overview

The concentration of U.S. oil and gas production, processing, and transportation facilities in the Gulf of Mexico and onshore Gulf Coast makes a significant percentage of domestic oil and gas production and processing vulnerable to disruption by hurricanes. In addition, the very tight natural gas supply/demand balance that currently exists means that any large-scale hurricane disruptions will have a magnified impact on energy supply and prices.

The nature and extent of this situation has been demonstrated by hurricanes that struck the Gulf Coast in 2004 and 2005 – Hurricane Ivan in the fall of 2004, and Hurricanes Katrina and Rita this year. In both cases, oil and gas production in the Gulf of Mexico was significantly curtailed due to hurricane-related shut ins, and the result was an increase in natural gas prices just before the winter heating season. While the impact of Hurricane Ivan on gas markets was important historically, the combined effects of Katrina and Rita this year are having a far greater impact, with major implications for the North American gas market.

This paper focuses on natural gas production and markets, but also discusses some of the impact on oil production and processing. The objectives are to:

- Provide an overview of U.S. gas markets and an understanding of the long-term trends in production and energy supply.
- Describe the production and transportation infrastructure in the Gulf Coast/Gulf of Mexico region,
- Evaluate the aspects of U.S. gas markets that contribute to increased hurricane impacts.

1.2 Background on U.S. Natural Gas Supply and Infrastructure

The U.S. natural gas supply is provided by a complex infrastructure that comprises several different industry sectors. The major components include:

- Natural gas production
- Natural gas processing

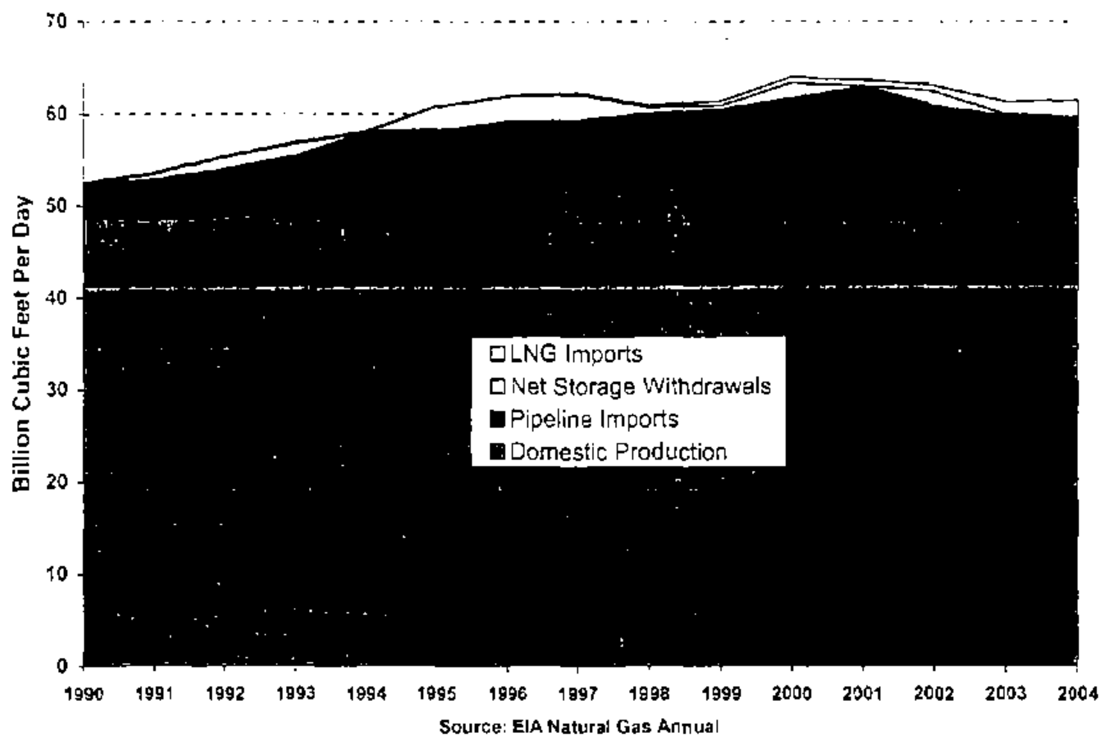
- Natural gas transmission pipelines
- Natural gas storage

Important components of each of these sectors are located in the U.S. Gulf Coast region and are susceptible to hurricane damage and disruption. Each is described below.

1.2.1 Natural Gas Production

U.S. annual gas demand is approximately 22 trillion cubic feet per year (Tcf) or 61 billion cubic feet per day (Bcfd). Of this amount, 52 Bcfd is produced domestically and 9 Bcfd is imported through pipelines or as liquified natural gas (LNG). LNG imports currently account for only about 2 Bcfd. Figure 1-1shows U.S. gas supply trends since 1990. Domestic gas production has been relatively flat over the past ten years, as the primary historical sources of supply have been depleted. New onshore production will need to come from different, more expensive geologic formations and much of the potential new resources are limited by environmental restrictions.

Figure 1-1
U.S. Gas Supply Since 1990



U.S. demand growth has been met with imports, primarily pipeline imports from Canada. Net gas pipeline imports from Canada increased from 3.7 Bcfd in 1990 to 9.2 Bcfd in 2001 but have since declined to 7.5 Bcfd in 2004. Production in Canada's Western Canadian Sedimentary Basin increased through the 1990's from 10 to 16 Bcfd, but has flattened in recent years. Over the longer term, non-conventional plays including coalbed methane are expected to result in substantial contributions to Canadian production.

The other growing source of gas supply is liquefied natural gas (LNG) imports. Although LNG imports increased from 0.2 Bcfd in 1990 to 1.8 Bcfd in 2004, they still comprise only about 3 percent of total supply. The U.S. has five operational LNG import facilities with a combined regasification capacity of approximately 4 Bcfd. Existing facilities are as follows:

- Everett, MA; 1.04 Bcfd
- Cove Point, MD; 1.00 Bcfd
- Elba Island, GA; 0.68 Bcfd
- Lake Charles, LA; 1.20 Bcfd
- Gulf Gateway, Gulf of Mexico 0.5 Bcfd

The full utilization these U.S. facilities is currently limited by lack of liquefaction capacity in gas exporting countries and competition for spot cargos from Asian and European importing countries.

A large number of additional LNG import facilities have been proposed. Projects have been proposed for the Gulf Coast/Gulf Offshore, Atlantic Coast, and Pacific Coast. Plans have been approved by FERC for new terminals and expansions to existing terminals along the Gulf Coast in Texas and Louisiana, and a project has been approved in the northeastern U.S. Facilities in the Bahamas are also planned. Opposition to the siting of terminals has been strong in California and the Northeast. Should such opposition be successful, most of the future LNG import capacity will be constructed both onshore and offshore in the Gulf Coast region.

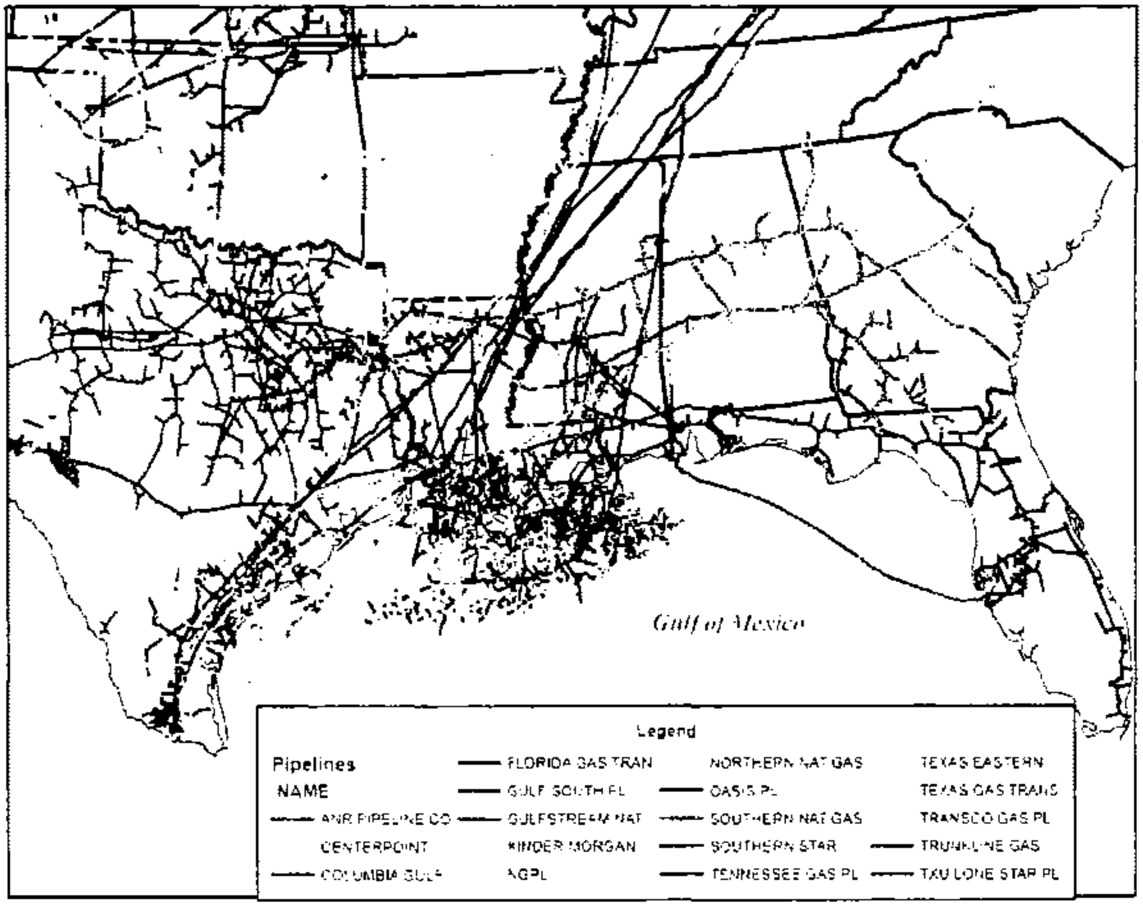
1.2.2 Natural Gas Processing Facilities

Natural gas has a variety of impurities and heavier hydrocarbons that must be removed before it can be injected into pipelines for delivery to consumers. Gas produced in the Gulf Coast region is generally "wet," having a significant component of heavier hydrocarbons such as ethane, propane, and butane. The gas must generally be processed to remove these components. Natural gas processing plants in the producing areas perform this task. The processing is energy-intensive and subject to disruption by loss of electric power.

1.2.3 Natural Gas Transmission Pipelines

As discussed above, most U.S. domestic natural gas production has historically been in the Gulf Coast region. An extensive network of gas transmission pipelines has been constructed to deliver this gas to end users throughout the U.S. (Figure 1-2). Many of these pipelines originate in the Gulf Coast region. Gas is moved through the pipelines by gas compressors positioned about every 75 miles along the pipeline. Most of the compressors are powered by natural gas from the pipeline so they do not require electricity as a primary power source. However, they may be subject to disruption due to loss of electric power for their control and communication systems.

Figure 1-2 Gulf Coast Gas Pipelines



1.2.4 Natural Gas Storage

Natural gas consumption is highly seasonal due to the high winter consumption for space heating in homes and business. The peak winter consumption is actually higher than the daily capacity to produce natural gas and move it via pipelines to end markets. In order to supply the peak demand, natural gas is stored in underground geological formations both in the gas producing regions and the downstream consuming regions. Gas is injected into storage primarily during spring, summer and fall and withdrawn during the peak winter demand period. As summertime gas demand for power generation has increased in recent years, there has been more competition for storage injection gas volumes on very hot summer days. The amount of gas in storage varies from year to year but storage of about 3.1 trillion cubic feet (Tcf) of gas is considered "full" storage for the winter heating season. Inadequate storage prior to the heating season can result in higher gas prices during the heating season.

1.3 Role of the Gulf Coast Region

The Gulf Coast and Gulf of Mexico is the location of a large fraction of the U.S. oil and gas production, processing, and transportation infrastructure. Table 1-1 summarizes the major components, including producing fields and wells, rig activity, pipelines, gas processing, refining and LNG import facilities.

Figure 1-3 shows the annual natural gas production trends for the onshore and offshore Gulf Coast. The Gulf Coast onshore is defined here as including the following areas:

- Texas Districts 1 through 4 (Texas coastal plain from South Texas to Southeast Texas)
- Louisiana
- Mississippi
- Alabama

Onshore Gulf Coast gas production has declined somewhat in recent years but the region still represents 20 percent of Lower-48 gas production. Between 2000 and 2004, onshore production declined by about 1.5 Bcfd. Traditional onshore Gulf Coast plays are relatively mature from an exploration standpoint, but operators have done a good job of maintaining production. As with other mature areas of the U.S., the application of advanced drilling and completion technology has met with a great deal of success.

As shown in Figure 1-3 the Gulf of Mexico produces about 11 Bcfd or 22 percent of Lower-48 gas production. The majority of offshore production originates in the federal waters of Louisiana, which contributes 8 Bcfd.

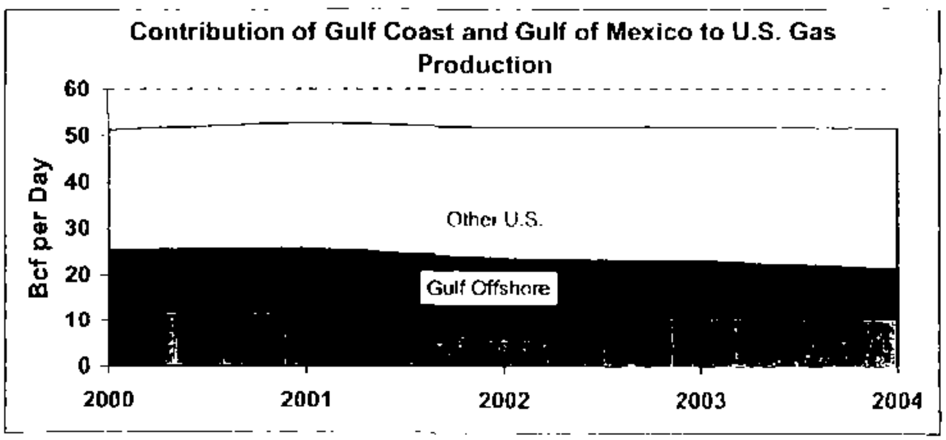
Table 1-1 U.S. Gulf Coast Oil and Gas Infrastructure

		Offshore		Onshore	Gulf Coast Region
Offshore Fields					
Producing fields					
	Shelf	800			
	Deepwater	150			
	Total	950			
Total offshore platforms		4,000			
Manned offshore platforms		819			
Producing Gas Wells			TX	68,600	
			LA	16,900	
			MS	400	
			AL	5,200	
		3,040	Total	91,100	94,140
Active drilling rigs					
			TX	630	
			LA	110	
	Floating	45	MS	10	
	Jackup	110	AL	4	
	Total	155	Total	754	909
Pipeline Miles		33,000		185,000+	217,000
Gas processing plants					
Number		0		40+	
Capacity (Bcf/d)		0		18	
Refinery Capacity (Th. b/d)					
Texas (Including Corpus Christi)		0		4,120	4,120
Louisiana		0		593	593
Total				4,713	4,713
LNG Import Facilities		1		1	2

Figure 1-3
Contribution of Gulf Coast and Gulf of Mexico to U.S. Natural Gas Production (Bcf per day)

		Gulf Coast Onshore				Gulf Offshore Total					Gulf Region
	Lower-48	Texas Gulf Coast Onshore	LA Onshore	MS and AL	Total	Texas State Waters	LA State Waters	LA Gulf of Mexico	TX Gulf of Mexico	Total	
2000	51 27	7.18	3.61	1 20	11.98	0.16	0 35	9 93	3.14	13.59	25 57
2001	52.93	7 02	3.62	1.20	11 84	0.18	0.43	10 23	3 23	14.07	25 91
2002	51.76	6.50	3 33	1.27	11.10	0 18	0.33	9.39	2.73	12.64	23.73
2003	51.91	6.41	3.16	1 22	10.79	0.18	0 35	8.09	2.91	12.33	23.11
2004	51.54	6.11	3.23	1 16	10.50	0 18	0.33	7.81	2.82	11.13	21 64

	Gulf Onshore Percentage Of Lower-48	Gulf of Mexico Percentage Of Lower-48	Gulf Coast Region Total Percentage Of Lower-48
2000	23.4%	26 5%	49 9%
2001	22.4%	26.6%	49.0%
2002	21.4%	24.4%	45 9%
2003	20.8%	23.7%	44.5%
2004	20 4%	21.6%	42.0%



Source: EIA Through 2003 with EEA Estimates for State Breakout in 2004

Gulf of Mexico production occurs in both shelf (less than 200 meters of water) and deepwater areas (200 or more meters of water). The Gulf of Mexico shelf has been active since the 1940s while the deepwater play became active in the 1980s. Production has declined on the shelf in recent years, but this decline has been largely offset by increasing deepwater production, so that total offshore production has declined only moderately. Between 2000 and 2004, total Gulf of Mexico gas production declined about 2 Bcfd.

Deepwater gas production now exceeds 4 Bcfd and continues to increase. Approximately 300 discoveries have been made, with about 150 fields in production. New plays continue to emerge, showing that the deepwater truly has excellent long term potential for oil and gas supply. A wide range of production facilities are being employed in the deepwater play. These include tension leg platforms, spars, and subsea completions with tie-backs to either deepwater or shelf platforms. The "hub and spoke" system is being used in many cases. This involves the use of a central platform with subsea tiebacks to surrounding satellite fields.

Deep drilling exploration on the shelf (15,000 feet below the mud line) is in its very early stages but this region holds great promise for long-term offshore production. A big advantage of the play is the extensive transportation and processing infrastructure on the shelf and onshore. As production from shallow-drill fields has declined, this has left unused pipeline and processing capacity that can be used for the deep-drill production. Current deep-drill production on the shelf is about 1 Bcf per day or one-tenth of total offshore production.

In summary, the onshore Gulf Coast and Gulf of Mexico represent a large fraction of total U.S. gas production. Figure 1-4 shows that the Gulf Coast onshore and offshore region represented 42 percent of U.S. gas production in 2004. This was down from approximately 50 percent in 2000.

Pipelines

Figure 1-5 is a map of the western and central Gulf of Mexico showing the network of oil and gas pipelines, with oil lines in green and gas pipelines in red. The area shown in white is the continental shelf area with water depths of up to 200 meters. Beyond this point is the deepwater region, where oil and gas fields produce in water depths of up to 7,000 feet. The current southern extent of deepwater production is shown by the location of the oil pipelines. The map shows that the majority of development on the shelf has occurred offshore from Louisiana and offshore of the upper Texas Gulf Coast, with relatively little development to date of the areas to the west offshore of the lower Texas Gulf Coast.

Refineries

Oil refining centers in the Gulf Coast region are shown in Figure 1-6. There are four major refining centers. From west to east, these are Corpus Christi, Houston/Texas City, Beaumont-Port Arthur, and Lake Charles. By far the greatest amount of refining capacity is found in the Houston/Texas City area, with approximately 2.3 million barrels per day of capacity. This is followed in importance by the Beaumont-Port Arthur are at 1.1 million barrels per day. South Louisiana refining capacity is about 600,000 barrels per day. The map shows the pre-landfall forecast track of hurricane Riate. The final track was farther east, near Port Arthur.

Drilling Rigs

Figure 1-6 shows the locations of active onshore drilling rigs in September of 2005. The map shows that there area several concentrations of activity in the onshore region, including East Texas/North Louisiana, North Texas, and the Gulf Coast. A significant concentration along the coastline is apparent in South Louisiana. The activity along the coast represents the traditional onshore Gulf Coast sandstone plays, while the activity farther inland is primarily targeting non-conventional plays, which have become very active over the past decade.

LNG Terminals

The U.S. currently has five LNG import terminals and two of these are located in the Gulf Coast region. These are the Lake Charles facility in southwestern Louisiana and the Gulf Gateway offshore facility. Figure 1-7 is a map showing the location of proposed LNG projects in the region.

Figure 1-4
Gulf Coast Contribution to U.S. Natural Gas Production

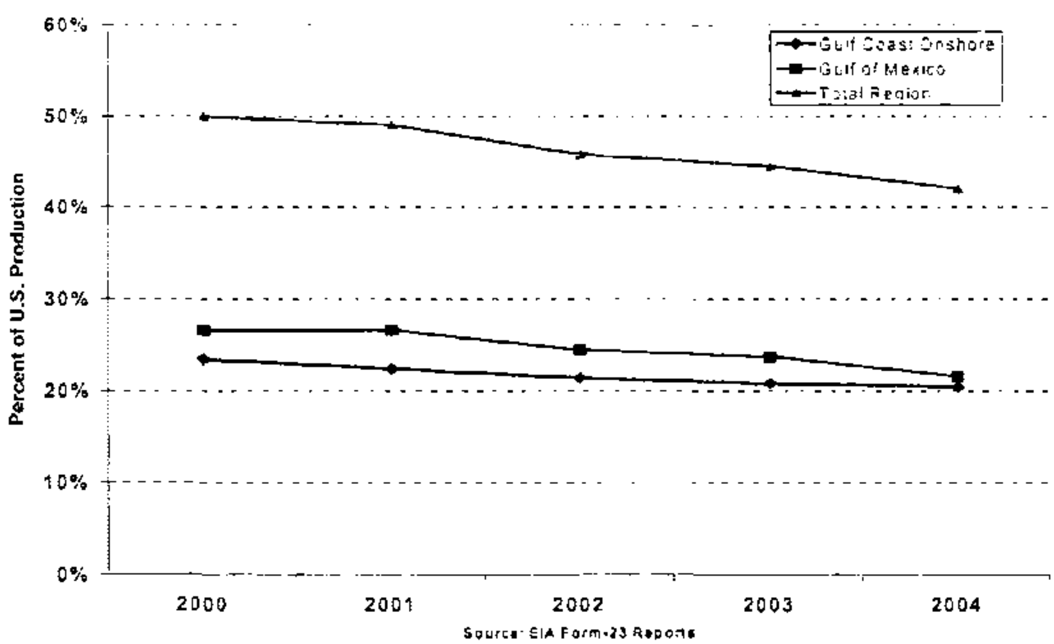
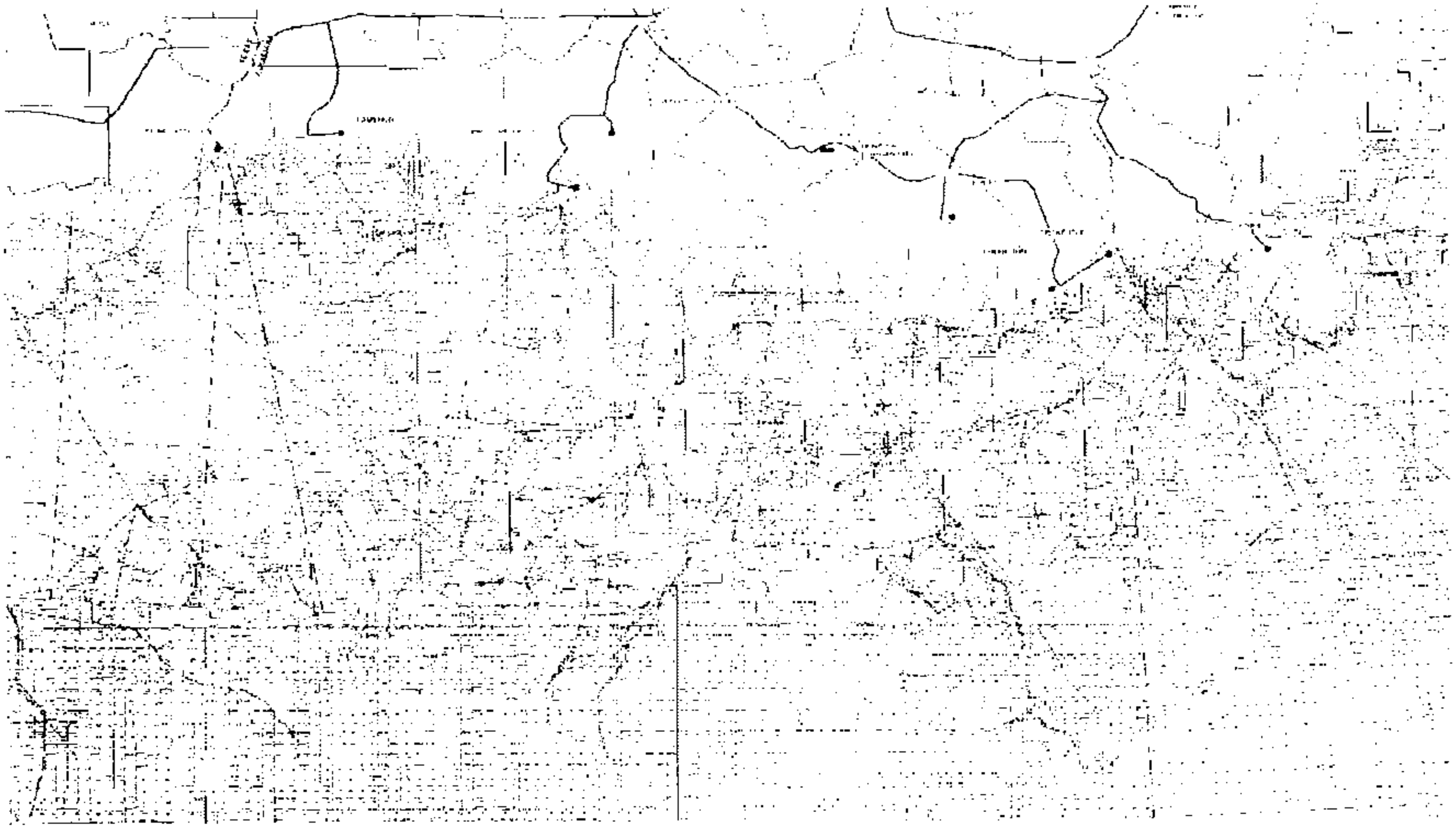


Figure 1-5
Central Gulf of Mexico Pipelines and Fields

(Oil pipelines in green and gas pipelines in red. Major deepwater fields at termini of pipelines.)



Source. Oil and Gas Journal Online

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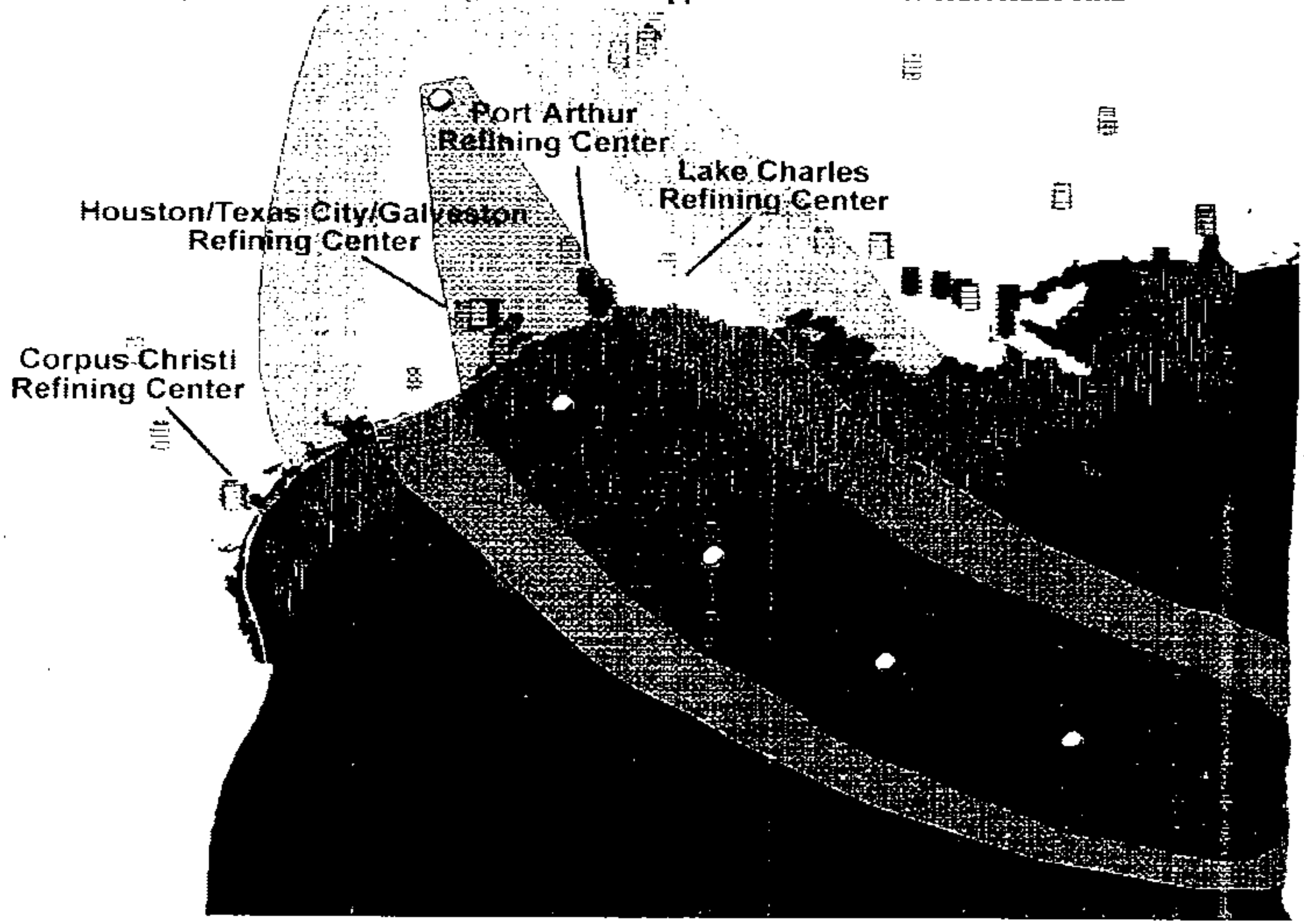
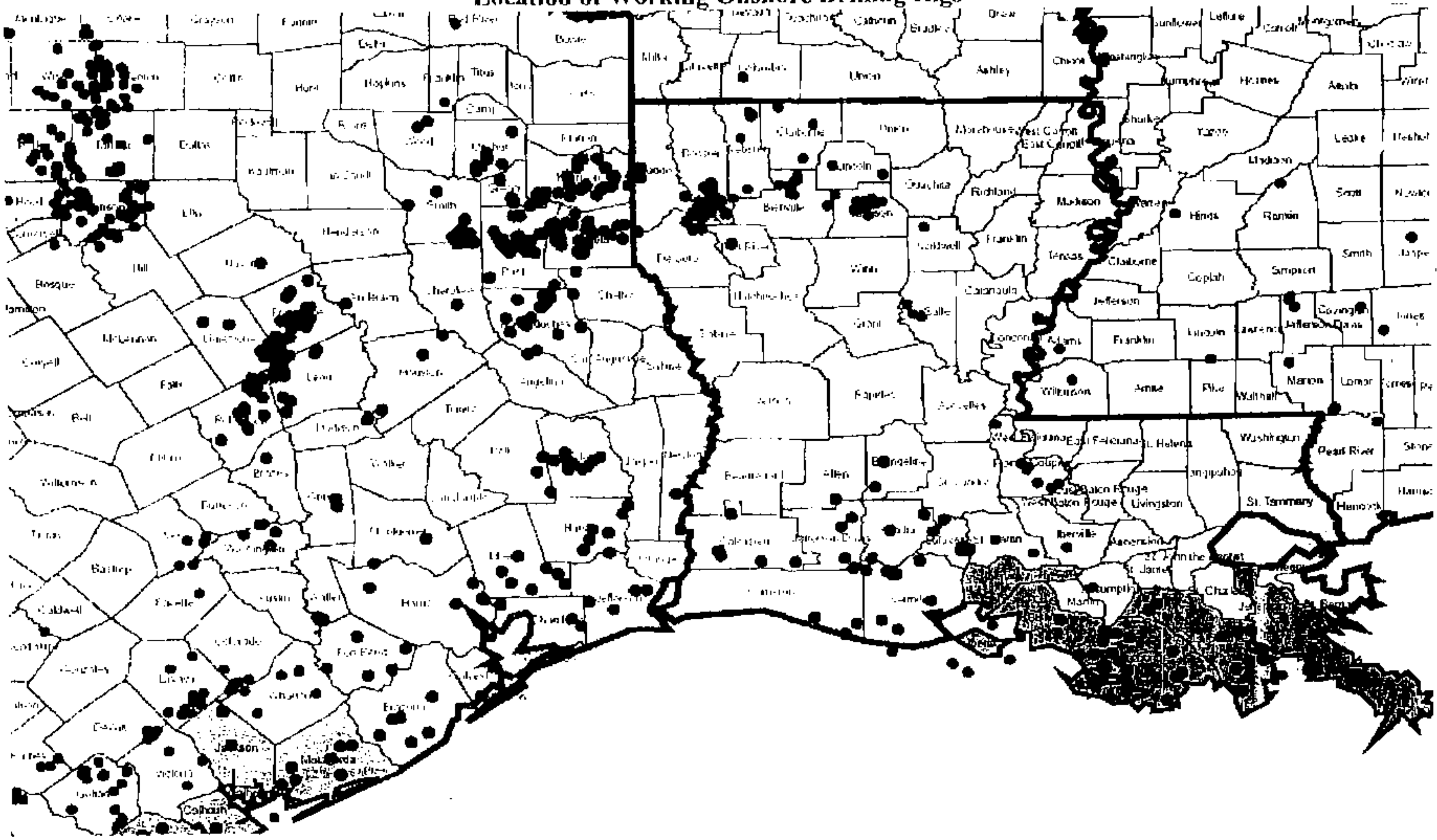
Figure 1-6
Major Gulf Coast Refining Centers and Approximate Track of Hurricane Rita



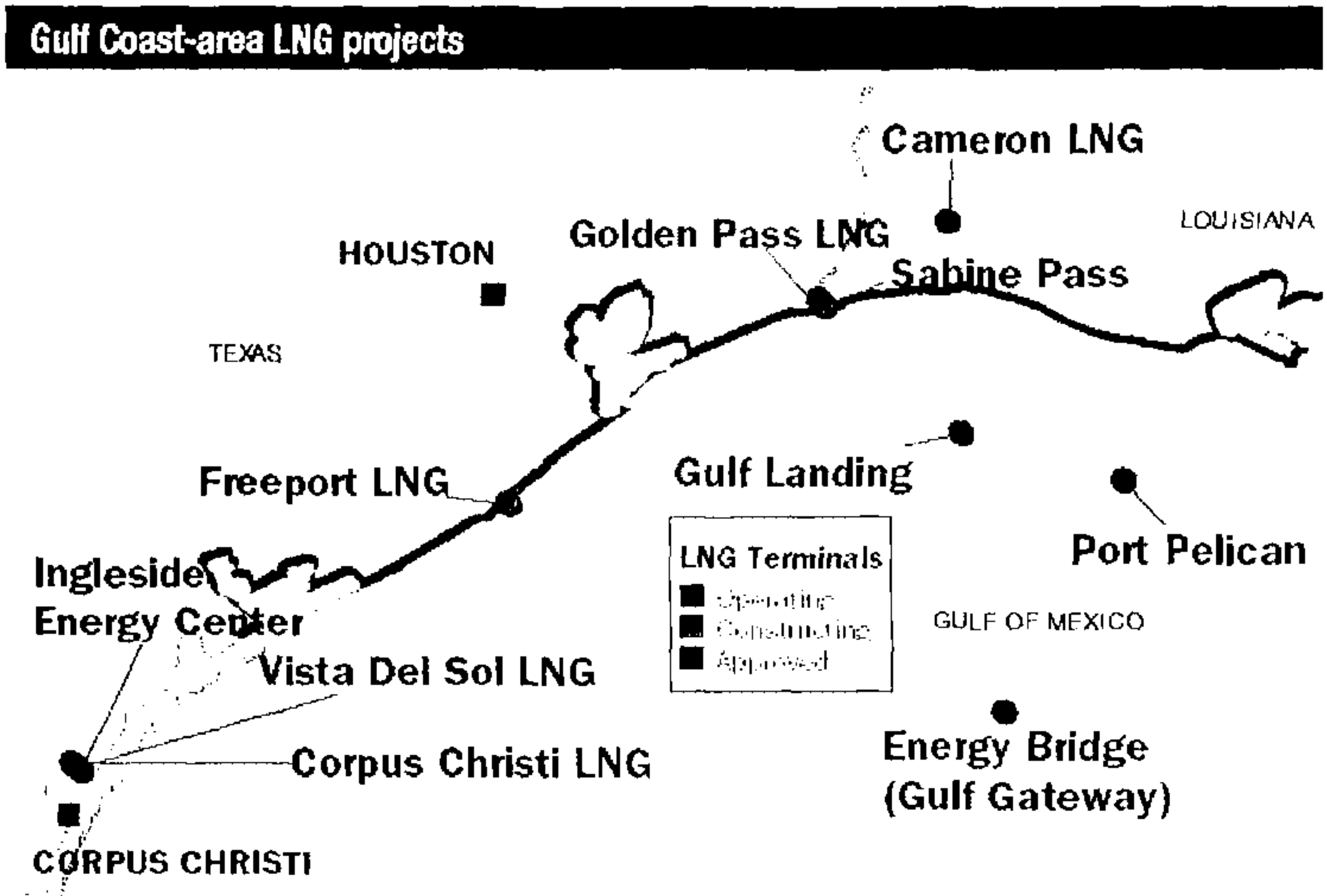
Source: EIA Katrina/Rita status report website

Figure 1-7
Location of Working Onshore Drilling Rigs



Source: Rig Data

Figure 1-8
Proposed Onshore and Offshore Gulf Coast LNG Projects



Source: Gas Daily

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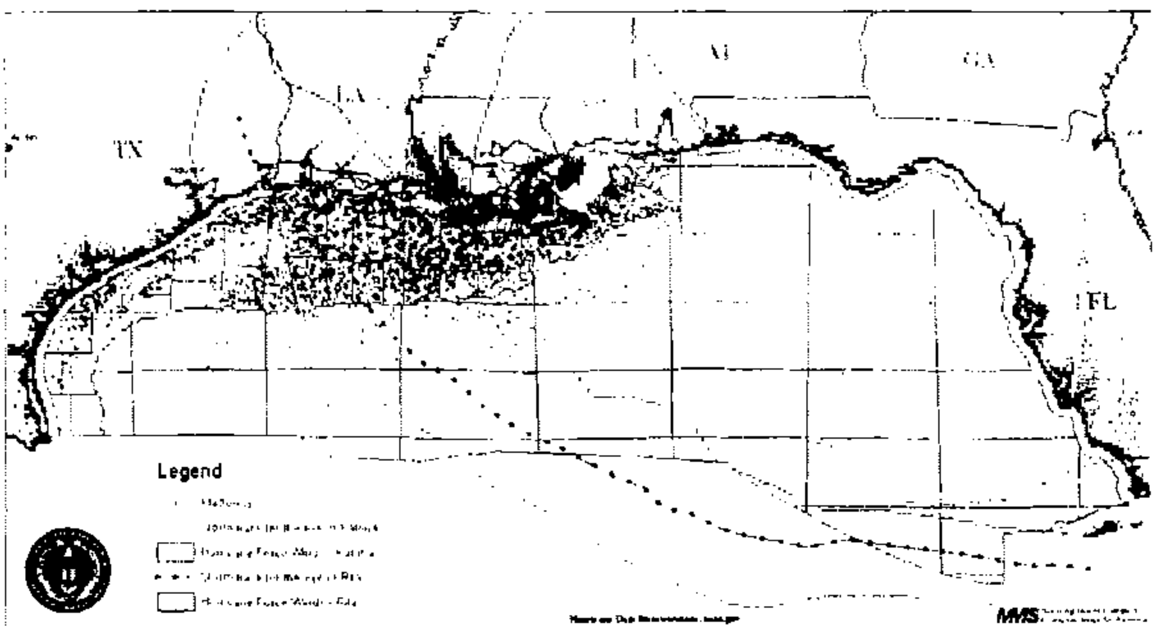
2 INFRASTRUCTURE IMPACTS OF THE 2005 HURRICANES

Over the past decade, hurricanes entering the Gulf of Mexico have disrupted regional onshore and offshore oil and gas production. The 2004 and 2005 hurricane seasons have had a major impact on Gulf Coast production operations. Hurricane Ivan made landfall in September 2004 causing significant production curtailments over a period of months. This year, Hurricane Katrina reached land on August 29 and Rita made landfall on September 24.

Figure 2-1 Hurricanes Rita and Katrina, August – September 2005



Source: Minerals Management Service

The combined effects of Hurricanes Katrina and Rita have had a profound effect on the all sectors of the Gulf Coast natural gas industry as well as important segments of the gas consuming sector. In fact, the 2005 hurricane season is the most damaging in history. While the effects of Katrina and Rita are still being determined, it is possible to evaluate the market impacts that have already occurred and to estimate what the ultimate effect on gas production and markets will be. This section summarizes the effect of the hurricanes on the Gulf Coast natural gas industry and consuming sectors.

2.1 Hurricane Impact on Production

For safety reasons, operators "shut-in" production from offshore platforms expected to be in the path of a hurricane. The platforms are then abandoned until the storm passes. If there is no damage or minimal damage, production can be restored quickly -- often within a week or two. On the other hand, more serious damage to infrastructure can result in months of partially curtailed production.

Figure 2-2 compares the offshore platform evacuations for Hurricane Ivan in 2004 and Katrina/Rita this year. The chart shows that both Ivan and Katrina caused the evacuation of a large percentage of the 819 manned platforms. The Katrina evacuations were of longer duration, however, with about 200 platforms remaining evacuated after 12 days from landfall. After the arrival of Hurricane Rita, essentially all of the manned platforms in the Gulf of Mexico were evacuated.

Figure 2-2
Platform Evacuations from Recent Hurricanes

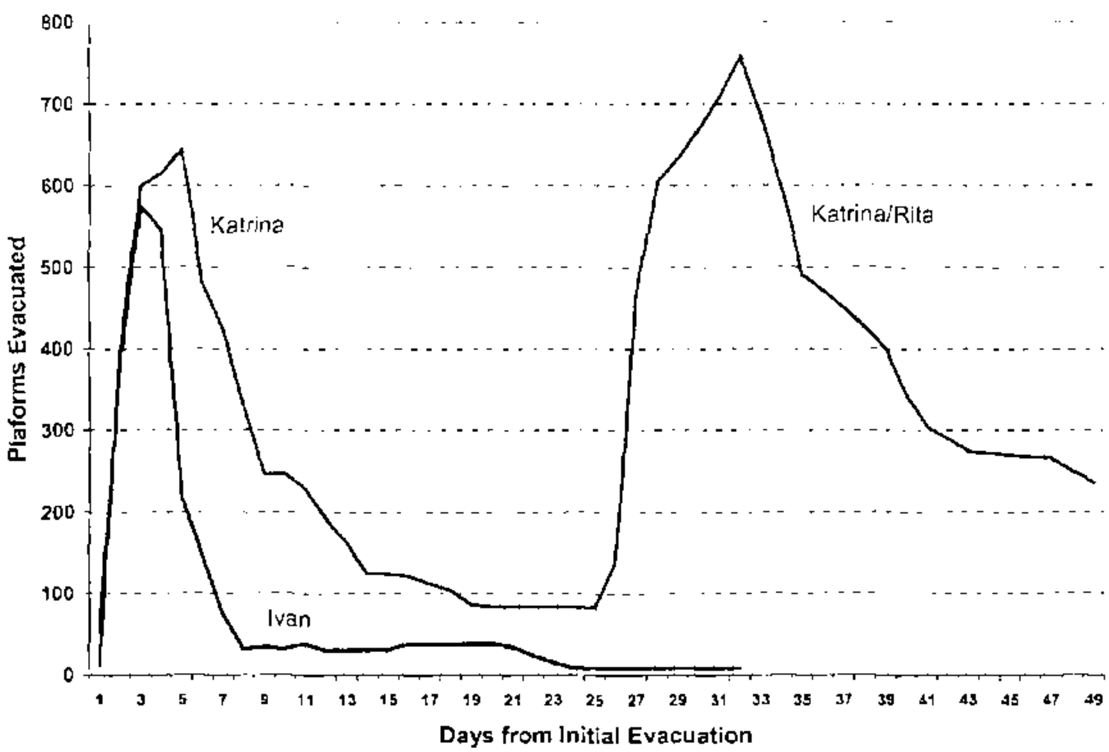


Table 2-1 summarizes the offshore impact of hurricanes Katrina and Rita compared to hurricane Ivan in 2004. Not shown here is the onshore damage to refining and gas processing. There are 4,000 platforms in the Gulf of Mexico, and 819 of these are manned platforms. Ivan destroyed 7 platforms, while Katrina and Rita destroyed 111 platforms. To date, the great majority of destroyed platforms have been older shelf facilities with small production volumes. However, the storms this year did result in the loss of one modern deepwater platform (Typhoon Field in 2,700 feet of water).

Table 2-1
Offshore Hurricane Damage and Impact Summary - Ivan, Katrina, and Rita
(Excludes Onshore Damage to Oil Refining and Gas Processing)

Energy and Environmental Analysis
Source: DOE Office of Electricity Delivery and Energy Reliability

	Total GOM	Ivan	Katrina	Rita	Katrina + Rita
Platforms					
Total in Gulf	4,000				
Total Manned	819				
Platforms in path		150	1,300	1,600	2,900
Destroyed		7	46	65	111
Extensive Damage		20	20	32	52
Drilling Rigs					
Total in Gulf	134				
Destroyed		1	4	4	8
Extensive Damage		4	9	10	19
Adrift		5	6	13	19
Unaccounted for		0	0	0	0
Pipelines Damaged		102	21	23	44
Peak Shut-in Production					
Gas (Bcf/d)	10.0	6.5	9.4	5.2 /1	9.4
Oil (MMB/d)	1.6	1.4	1.6	0.6 /1	1.6
Cumulative and Forecast Shut-in (Offshore)					
Gas (Bcf)		172		Mid-Case	981 /2
				Best	891
				Worst	1,120
Maximum Evacuations	819	575	660	754	1,414

/1 The 5.2 Bcf/d for Rita is an EEA estimate of the total shut-in volume attributed specifically to Rita. It is calculated as the total peak value of 8.6 Bcf/d less the estimated 3.4 Bcf/d from Katrina before Rita struck. The 0.6 MMB/d oil shut in is based on a total peak Rita value of 1.52 MMB/d less the 0.88 MMB/d estimated Katrina portion before Rita struck.

/2 EEA forecasts through August, 2006.

Typically about 130 drilling rigs have been active offshore. The majority are "jackup rigs" that operate on the shelf, and some are "floaters" that can operate in water depths of up to 10,000 feet. A reported 8 rigs were destroyed and 19 rigs were damaged in this year's storms.

Damage to the pipelines that bring gas onshore from the platforms can be a major aspect of hurricane damage, and can result in production shut-ins. Hurricane Ivan did extensive damage to offshore pipeline systems. Much of this damage was the result of subsea mudslides, which were caused by instability in shallow water areas of the Mississippi River delta.

EEA has evaluated the volumes of shut-in gas production from Hurricanes Ivan, Katrina, and Rita. We have also developed forecasts of production shut-ins for Katrina and Rita. Figure 2-3 shows the gas production shut-in history of Gulf of Mexico hurricanes since 1995. Katrina and Rita have had by far the most impact on production, followed by Ivan last year and by Hurricane Lili in 2002. All of the other storms had lower peak shut-in volumes and most or all of the production was restored within two weeks.

Figure 2-3
Shut-ins from Hurricanes Since 1995

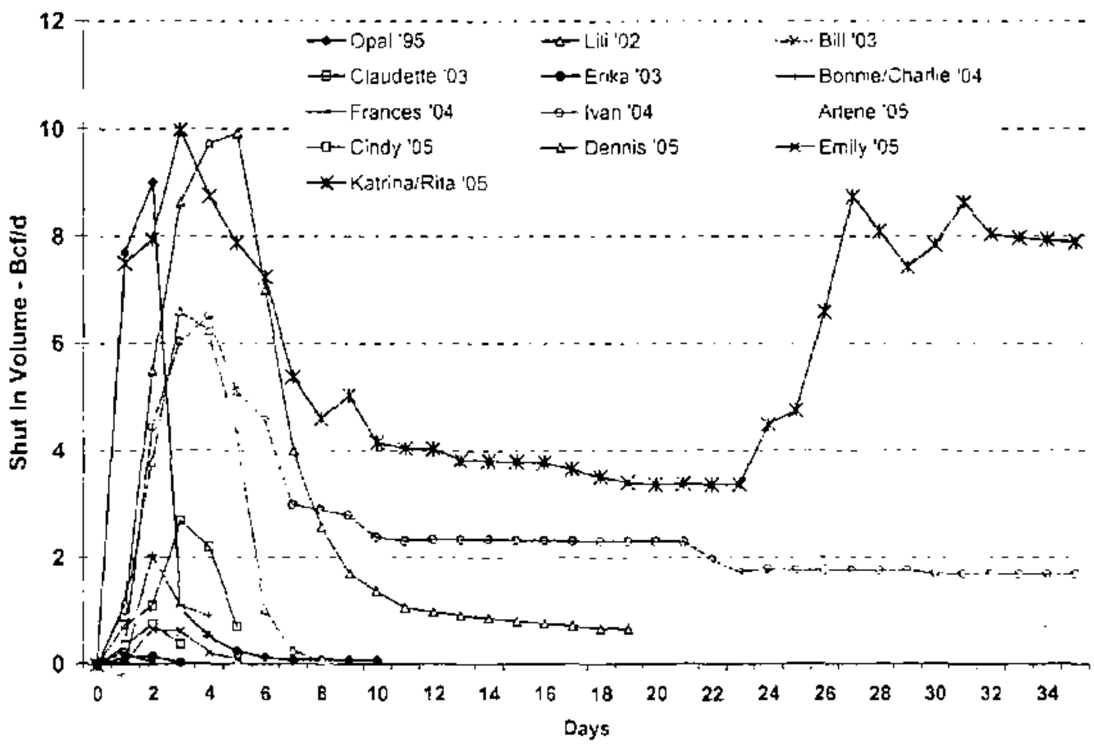


Figure 2-4 shows the total shut-in production by year and storm (in sequence) since 1995. Interestingly, the chart shows that storm-related shut-ins have been much more significant since 2002.

Table 2-2 summarizes the production shut-ins and gas market impact from the Hurricane Ivan last year and Katrina and Rita this year. Total shut-ins for Ivan were 174 Bcf. This compares to the current EEA estimate of 900 to 1,100 Bcf for the combined effects of Katrina and Rita this year and next year. Also shown on the table is the impact on Gulf Coast natural gas prices and the gas storage level achieved last year and forecast for this year.

Figure 2-5 shows the daily shut-in gas production in the Gulf of Mexico. Volumes are presented on the basis of days from landfall. Figure 2-6 presents the shut in data on a cumulative basis. The charts show the initial 100 days from landfall.

Figure 2-4
Total Shut-in Production By Year and Storm Sequence

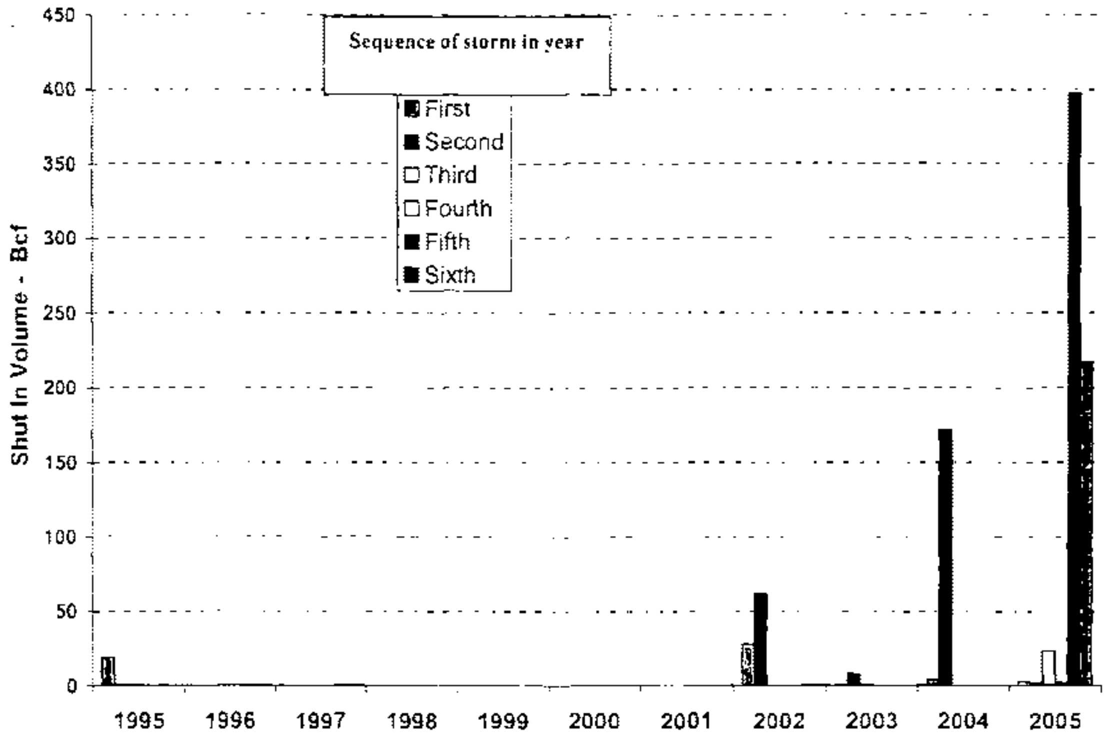
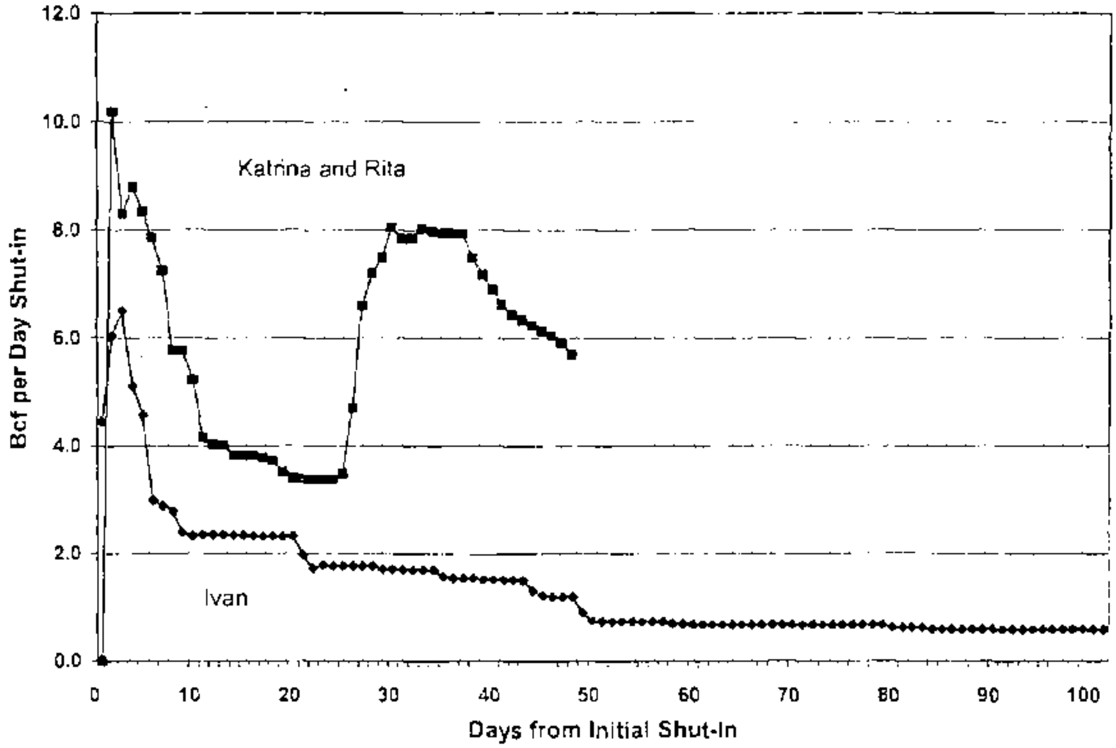


Table 2-2
Impact of 2004-05 Hurricanes on U.S. Gas Production and Markets

	Units	Ivan - 2004	Katrina - 2005	Rita - 2005
Peak rate of gas production shut in	Bcf per day	6.5	9.4	5.2 /1
Actual or forecast cumulative shut in gas production	Bcf	174	Total for both storms 900 - 1,100 Bcf	
Henry Hub gas price change				
Pre-storm	Dollars per MMBtu	$4.35	$9.60	
Post-storm	Dollars per MMBtu	$6.25	$12	$15
Gas storage level on Nov. 1	Tcf	3.3	3.1 (forecast - Katrina plus Rita)	

1/ The 5.2 Bcf/d for Rita is an EEA estimate. The total peak for Rita including Katrina was 8.6 Bcf/d. EEA has estimated that during the peak for the Rita shut-ins, the Katrina shut-ins were 3.4 Bcf/d. The difference is the Rita value.

Figure 2-5 Daily Shut-In Gas Production-Hurricanes Katrina/Rita and Ivan



Hurricane Ivan had a peak shut-in rate of 6.5 Bcf per day. This represents about 60 percent of the normal offshore rate (including state waters) of 11 Bcfd. This was followed by a relatively rapid recovery down to a level of 2.5 Bcfd after 8 days. Two months after landfall, the shut-in volume was down to about 0.7 Bcfd. The total cumulative shut-in volume for the storm was 174 Bcf.

Hurricane Katrina experienced an initial shut-in rate of almost 9 Bcfd, or about 80 percent of offshore production. The shut-in rate fell pretty rapidly to 4 Bcfd after 8 days. However, after 20 days, the rate was still about 3.5 Bcfd. This rate had stabilized prior to the onset of Hurricane Rita shut-ins.

Hurricane Rita made landfall on September 24 and Rita shut-ins started several days earlier. The Minerals Management Service does not report separate shut-in statistics for the two events. This is not possible because of the overlapping area affected by both hurricanes. Combined Katrina and Rita shut-ins peaked at 8 Bcfd about 5 days after initiation. Combined cumulative shut in production to date exceeds 250 Bcf.

Figure 2-7 and Table 2-3 present EEA's analysis and forecast of ultimate Katrina and Rita gas shut-ins. Figure 2-7 shows the shut-in forecasts through March, 2006. Prior to the onset of Rita shut-ins, the daily shut-ins from Katrina had declined to about 3.4 Bcfd. After the onset of Rita, shut-in volumes again spiked to over 8 Bcfd.

Figure 2-6
Cumulative Shut-In Gas Comparison – Hurricanes Katrina/Rita and Ivan

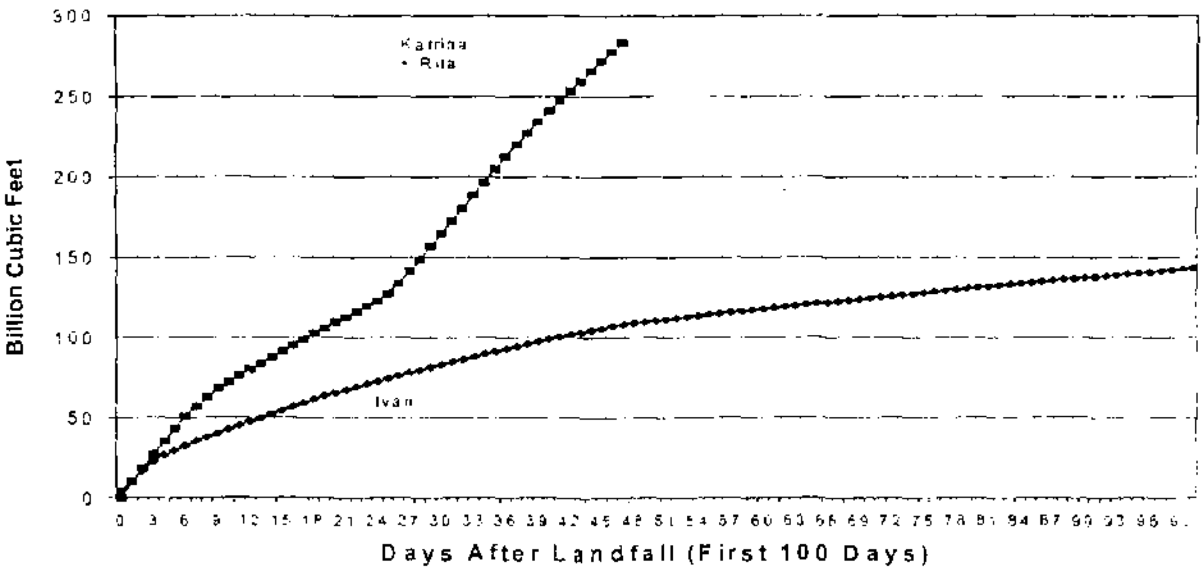


Figure 2-7
EEA Forecast of Total Production Shut-Ins from Katrina and Rita

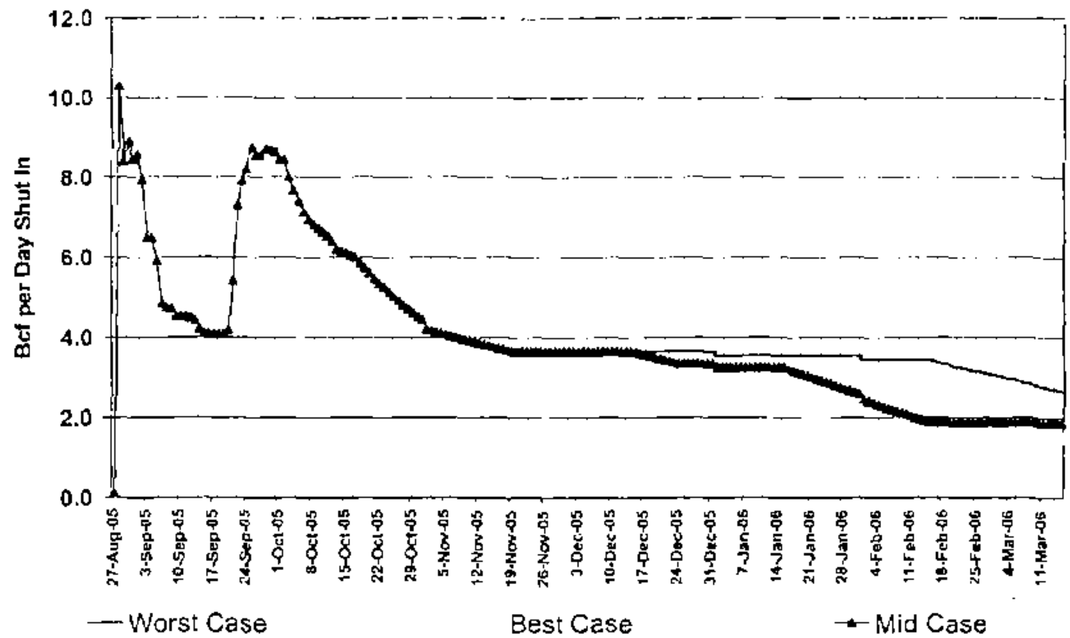
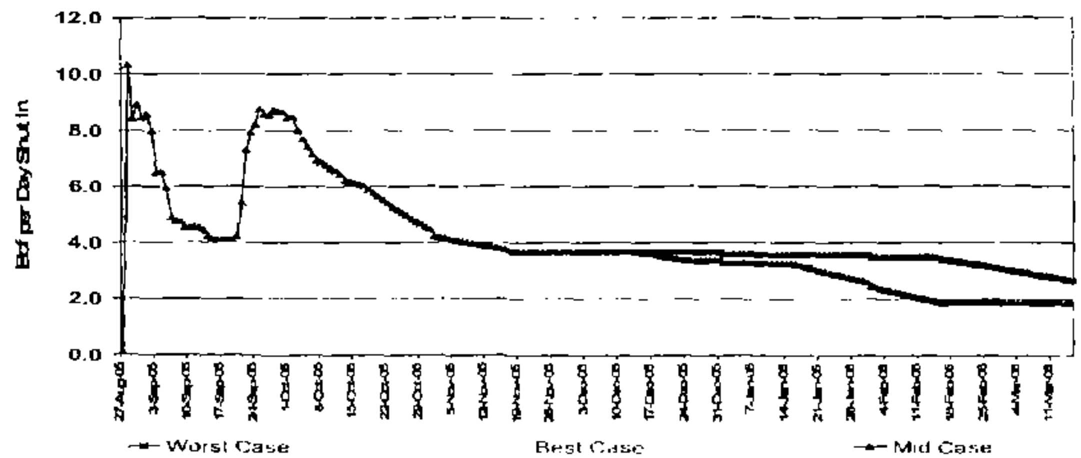


Table 2-3
Summary of Gas Production Shut-In Volumes for 2005 Hurricanes

		Ivan OCS- 2004			EEA Forecast for Katrina and Rita - 2005 and 2006								
					Mid-Case			Best-Case			Worst-Case		
Month	Days	Average Shut-in bcf/d	Bcf	Cumul. Bcf	Average Shut-in bcf/d	Bcf	Cumul Bcf	Average Shut-in bcf/d	Bcf	Cumul Bcf	Average Shut-in bcf/d	Bcf	Cumul. Bcf
Aug	31	0	0	0	1.15	36	36	1.15	36	36	1.15	36	36
Sept	30	2.00	60	60	6.05	182	217	6.05	182	217	6.05	182	217
Oct	31	1.50	47	107	6.10	189	406	6.10	189	406	6.10	189	406
Nov	30	0.75	23	129	3.82	115	521	3.82	115	521	3.82	115	521
Dec	31	0.40	12	141	3.50	109	629	3.14	97	618	3.65	113	634
Jan	31	0.70	22	163	3.05	95	724	2.25	70	688	3.55	110	744
Feb	28	0.40	11	174	2.05	57	781	1.50	42	730	3.32	93	837
Mar	31	0.00	0	174	1.85	57	839	1.50	47	776	2.75	85	922
April though August	153				0.93	142	981	0.75	114	891	1.30	198	1120
Total			174			981			891			1,120	

Comparison of Gulf Coast Recovery Scenarios
(EEA October 17, 2005)



Katrina Shut-ins Began August 27 and Rita Shut-ins began September 10
Highlighted values are estimates and projections.

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EEA is forecasting that the total volume of shut-in production for Katrina and Rita will range from 900 to 1,100 Bcf through next August, with a middle estimate of approximately 980 Bcf. The forecast shut-ins from this season's storms will total more than five times that of Hurricane Ivan last year. By a large margin, this will be the most damaging hurricane season on record for the industry. The EEA forecast indicates that the mid-October shut-in rate of 5 Bcfd will decline to approximately 3.5 Bcfd by December and 1.9 Bcfd by next March. Under the worst case scenario, shut-ins could be at a level of 2.8 Bcfd by next March.

Onshore and state-water offshore gas production in South Louisiana also has been heavily impacted. The Louisiana state regulatory agency conducted as survey of 396 operators in a 38-parish region, shown in Figure 2-8. The survey currently shows that a reported 1.1 Bcfd of gas production had been "restored" as of October 6th. The volume of shut-in production since the arrival of Katrina is still unknown, because there are hundreds of wells for which the state agency has not determined a status. EEA is estimating that a minimum of 0.5 to 0.75 Bcfd of onshore South Louisiana production was shut in at the peak.

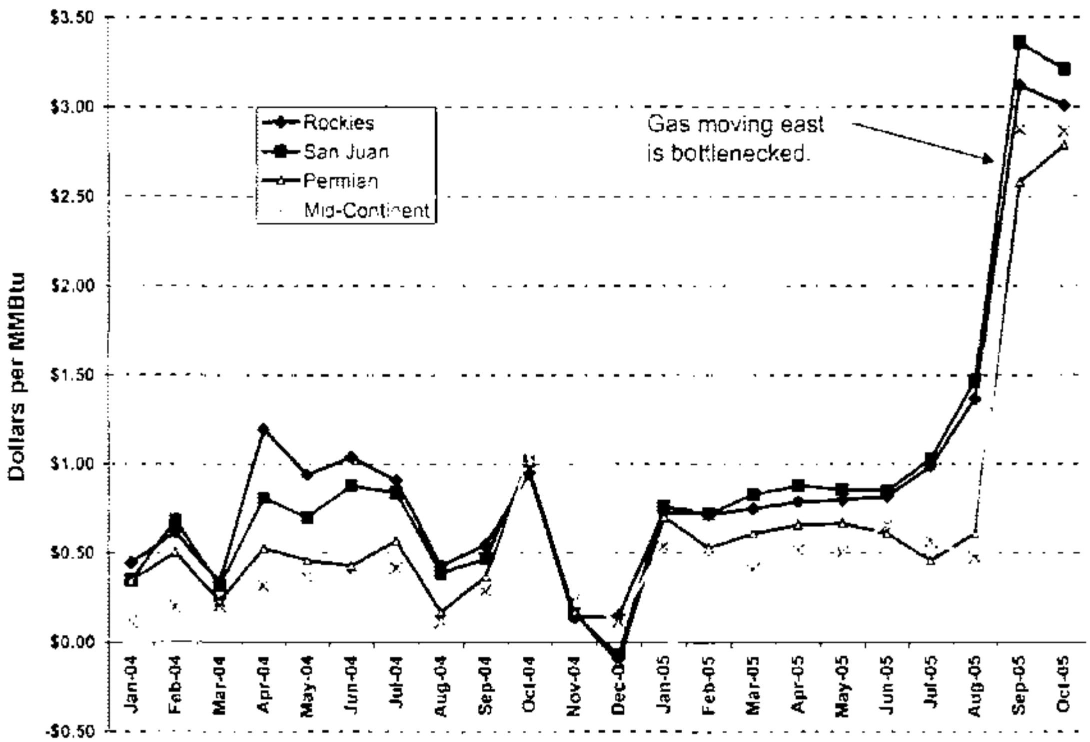
Figure 2-8
Status of Onshore Oil and Gas Production in Southern Louisiana

	29-Sep	30-Sep	3-Oct	4-Oct	5-Oct	8-Oct	10-Oct
Wells reported to be restored to production	162	291	609	710	784	1,108	1,206
Known shut-in wells	1,017	1,267	1,824	1,903	2,034	2,549	2,536
Wells with unknown status	4,770	4,391	3,516	3,336	3,131	2,292	2,207
Total wells in 38 parish region	5,949	5,949	5,949	5,949	5,949	5,949	5,949
"Restored" gas production rate (MMCFD)	92.6	125.7	182.7	216.3	410.2	535.7	607.5
Known shut-in gas production	?	?	?				
Potential production with unknown status	?	?	?				
Total normal gas production (MMCFD)	2,235	2,235	2,235	2,235	2,235	2,235	2,235
"Restored" oil production rate (Th B/d)	4.76	8.10	17.60	19.90	25.30	39.64	43.59
Total normal oil production (Th B/d)	203.10						
Normal production per well (mcf/d)	376						
Percent of total gas restored	4.1%	5.6%	8.2%	9.7%	18.4%	24.0%	27.2%
Estimated daily production per well (Mcf/d)	572	432	300	305	523	483	505

Source: Louisiana DNR; 2005

While natural gas infrastructure in the Gulf Coast was several affected by the hurric production in other areas, such as the Rockies and Canada, was not affected. In thec increased production or deliveries from these other producing areas could help offset the losses from the Gulf Coast. However, in this case, there is inadequate pipeline capacity to move the gas from west to east. Figure 2-9 shows the regional gas prices differences to Henry Hub since the beginning of 2004. Starting this summer, the price difference between each of these regional points and South Louisiana has increased greatly. This large basis differential is an indicator of transportation bottlenecks in moving gas from west to east, and is apparent when looking at all of the major gas producing regions west of Louisiana, including the Permian, San Juan, Mid-Continent, and Rockies. Thus production losses in the Gulf could not be mitigated by western producing areas.

Figure 2-9
Natural Gas Price Locational Basis to South Louisiana



2.2 Impact on Gas Processing

The combined effects of Hurricanes Katrina and Rita on the onshore Gulf Coast gas processing industry were very significant. DOE conducted a survey of regional gas plant operators of facilities with a capacity of at least 0.1 Bcfd.

The survey results as of early October are shown in Table 2-4. During the peak outage period a total of 21 gas plants with a total processing capacity of 13 Bcfd were off line. The survey indicated that 10 of the 21 plants were off line due to lack of gas supply or other problems not related to onsite plant damage, while eleven plants were damaged, including several large plants in South Louisiana. The table shows that the four plants for which operators initially reported damage have a combined capacity of over 5 Bcfd. Using data from the Oil and Gas Journal, EEA estimates that the 21 plants that were off line represented about 7.3 Bcfd of throughput. This volume of throughput is a large percentage of regional daily gas production.

Table 2-4
Impact of Katrina and Rita on Gulf Coast Gas Processing

	Number	Capacity Bcf/d	2004 Throughput Bcf/d
All plants >100 MMcfd Capacity			
LA	29	17 3	10.5
MS	1	1.0	0.8
TX	4	0.6	0.3
Total	34	18.9	11.5

Non-Operating from October 4, 2005 Survey (EIA)	Number	Capacity Bcf/d	2004 Throughput	2004 Utilization Rate (%)
Operational but no supply	10	5 4	2.7	50%
Damaged (see below)	11	7.7	4 6	60%
Total	21	13.1	7.3	56%

South Louisiana Gas Plants Reported Damaged as of Early October	Capacity Bcf/d	2004 Throughput	2004 Utilization Rate (%)
Dynegy Yscloskу	1.85	1.34	72%
Enterprise Venice	1.30	1.00	77%
Enterprise Toca	1.10	0.62	56%
Amerada Sea Robin	0 90	0.57	63%
Williams Cameron	0.43	0.11	26%
Subtotal	5.58	3.64	65%
Other damaged plants >100 mmcfd	2 10	1.00	48%
Total	7.68	4.64	60%

Sources: DOE Survey - Office of Electricity Delivery Reports; Oil and Gas Journal Gas Plant Data
EEA, October 10, 2005

Gas produced in the Gulf Coast region is generally "wet," having a significant component of heavier hydrocarbons such as ethane, propane, and butane. The gas must generally be processed to remove these components. It is possible in some cases to blend unprocessed gas with drier gas to meet pipeline requirements, and this has been done to help the current situation. However, continued delays in restoring gas processing capacity would affect the speed with which regional gas production is restored.

2.3 Impact on Gas Transmission Pipelines

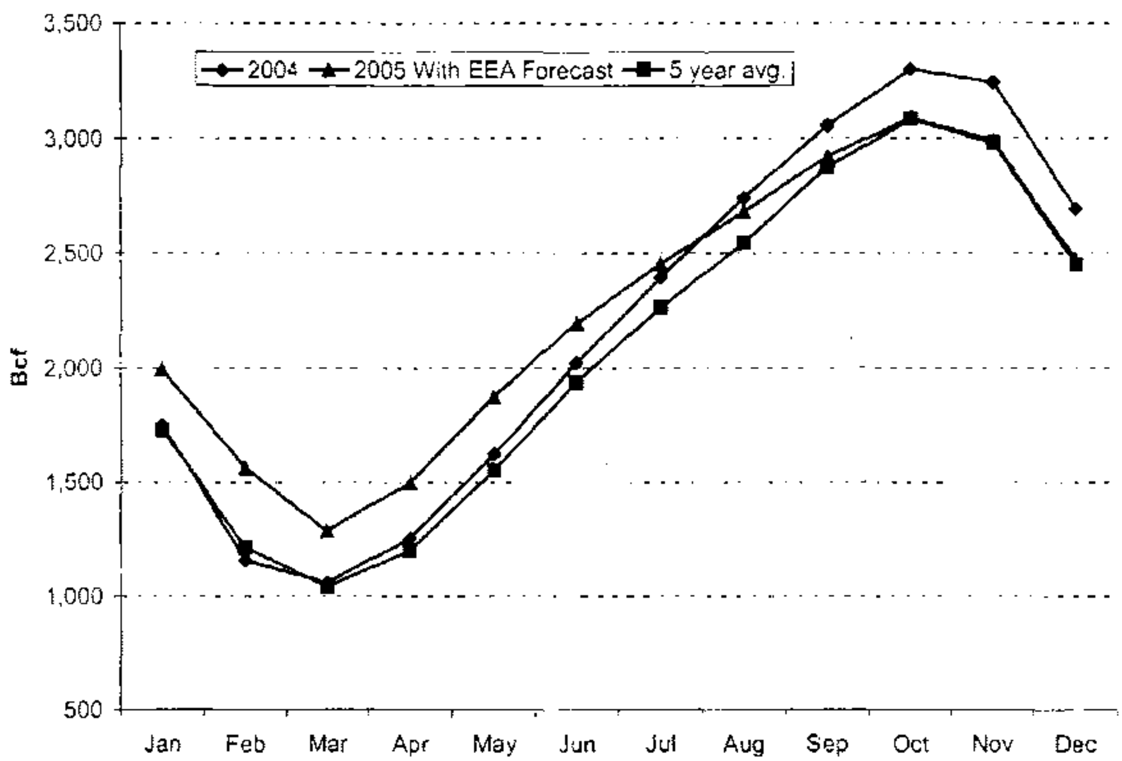
Many gas transmission pipelines also have been directly affected by recent hurricanes. Damage to offshore pipeline occurs because of undersea mudslides and destruction on compressor platforms. Onshore pipelines can be damaged by floods and erosion along the pipeline right-of-way and by water damage to compressor stations and measurement and control equipment. The operation of gas pipelines can also disrupted by electrical outages that render control equipment inoperable.

2.4 Impact on Gas Storage

The traditional storage injection season runs from early summer through the end of October. U.S. working gas storage capacity is more than 3.5 trillion cubic feet. In a typical year, storage levels fluctuate between a low of around 1 Tcf and a high of just over 3 Tcf, with peak storage occurring near the beginning of November.

Figure 2-10 shows the monthly working gas storage volumes from the beginning of 2004. The 2005 volumes include EEA's forecast through the end of the year. The line with the box symbol is the running five-year average for each month of the year.

Figure 2-10
U.S. Gas Storage Working Inventories – End of Month Volumes



The 2004 series shows that working gas last year attained a level of 3.3 Tcf, even with the Ivan shut-ins. The 3.3 Tcf was significantly higher than the five year average peak.

This year, EEA is forecasting a peak storage level of 3.1 Tcf. In terms of gas storage, EEA is forecasting a storage level of 3.1 Tcf on November 1, which is close to the five year running average.

The amount of gas going into storage is a function of supply and demand. This year, we did have a hotter than average summer, resulting in high summer gas demand. However, earlier this year storage was running substantially above average. An additional factor this fall is the volume of demand lost because of the hurricane, as discussed below. This demand loss partially offsets the supply that was shut in, allowing more gas to be injected than might otherwise be expected.

2.5 Refinery Shut-Ins

Hurricanes Katrina and Rita have had a major impact on Gulf Coast refining and gasoline markets. Gulf Coast region (including Louisiana) refining capacity is 8 million barrels per day, which represents 47 percent of the U.S. total of 17 million barrels.

Table 2-5 is a listing of the major refineries that were impacted by Katrina and Rita. The table shows the extent of refinery closures resulting from the storms. The Texas refineries were generally reported to be re-starting by Mid-October, while the New Orleans area refineries remained shut down.

Table 2-5 Refinery Capacity and Status – Texas and Louisiana Gulf Coast

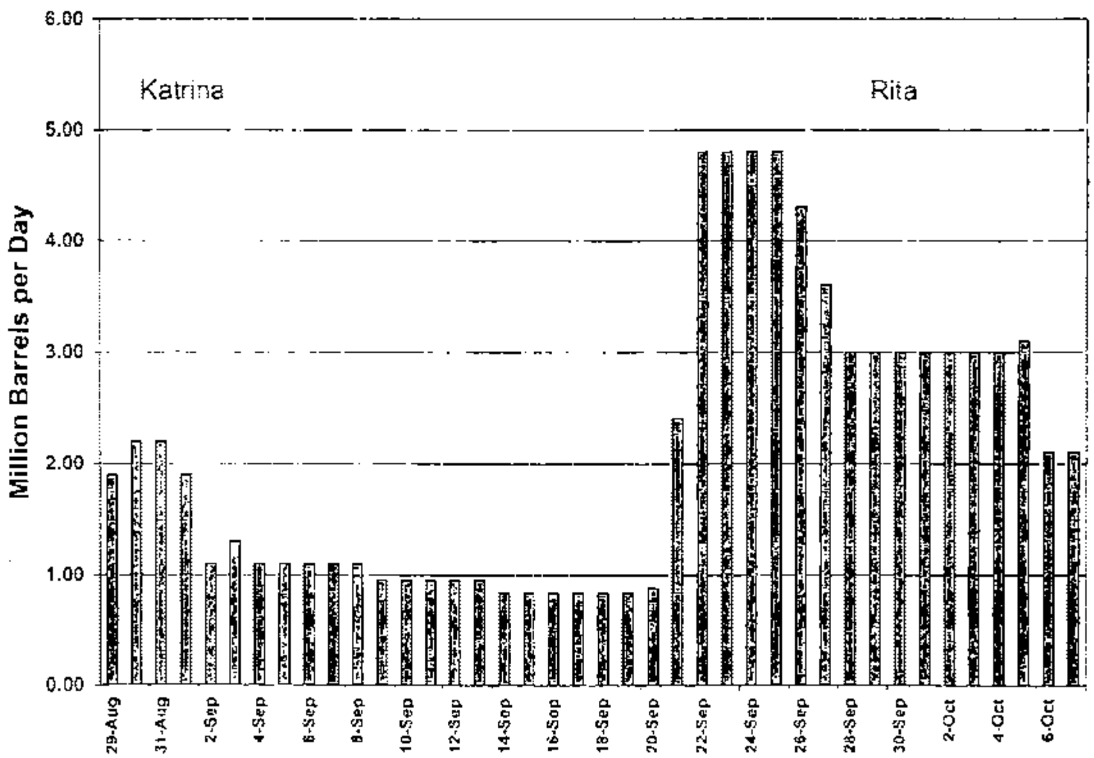
Company	Location	Capacity (Bbls/d)	Status (Oct. 5)	Status (Oct. 12)
New Orleans Area Katrina Shut-Downs (Three refineries)				
		554,000	Shut down	Shut down
Refineries Impacted by Hurricane Rita				
Lake Charles				
Citgo	Lake Charles	324,000	Shut down	Restarting
ConocoPhillips	West Lake, LA	239,000	Shut down	Restarting
Calcasieu	Lake Charles, LA	30,000	Shut down	Operating full rate
Total		593,000		
Beaumont-Port Arthur				
ExxonMobil	Beaumont, TX	348,000	Shut down	Shut down -pwr. restored
Shell (Motiva)	Port Arthur, TX	285,000	Shut down	Shut down -pwr. restored
Total	Port Arthur, TX	234,000	Shut down	Shut down -pwr. restored
Valero	Port Arthur, TX	255,000	Shut down	Restarting
Total		1,122,000		
Houston/Texas City				
Shell Deer Park	Deer Park, TX	334,000	Restarting	Oper. at reduced rate
Lydonell Citgo	Houston, TX	270,000	Restarting	Oper. at reduced rate
Crown Central	Pasadena, TX	100,000	Restarting	Operating full rate
Valero	Houston, TX	83,000	Operating full rate	Oper. at reduced rate
ExxonMobil	Baytown, TX	557,000	Restarting	Operating full rate
BP	Texas City, TX	437,000	Shut down	Shut down
Valero	Texas City, TX	210,000	Operating reduced rate	Operating full rate
Marathon	Texas City, TX	72,000	Operating full rate	Operating full rate
ConocoPhillips	Sweeny, TX	229,000	Operating full rate	Operating full rate
Total		2,292,000		
Corpus Christi (Total)		706,000		
Total Gulf Coast (TX and LA)		5,267,000		

Figure 2-11 shows the refinery shut-ins starting just before Katrina. About 2 million barrels per day of refinery outages were reported initially after Katrina. The refineries that were affected most by Katrina are located in Southern Louisiana and Mississippi. Following Katrina, the shut in volume declined to about 1 million barrels per day. This is the volume represented by four refineries in the New Orleans area. These refineries are expected to remain shut down for some time.

Hurricane Rita refinery shutdowns were greater than for Katrina because its path was projected into the upper Texas Gulf Coast, which is the location of a large percentage of

U.S. refining. Major refining centers include, from east to west: Lake Charles, Beaumont-Port Arthur, Houston/Texas City/Galveston, and Corpus Christi. Hurricane Rita resulted initially in the shutdown of over 4 million barrels per day of capacity. As of early October, about 2 million barrels per day of capacity remained shut down.

Figure 2-11
Shut-In Refinery Capacity – August- October 2005



2.6 Storm-Related Demand Losses

The regional destruction of Katrina and Rita has resulted in a significant loss of gas demand. Gas demand loss in the storm damaged region includes:

- Power outages to electricity users, including residential, commercial, and industrial
- Reduced petroleum refining use of gas
- Reduced demand for gas as a petrochemical feedstock and other industrial uses

Demand loss also occurs in the entire gas market, with higher prices causing conservation efforts and reduced industrial demand.

Because of the extent of the 2005 storms, a large number of electricity customers experienced power outages. As shown in Table 2-6, power customers were most affected in Louisiana. Through early October, the total number of customer outage days in that state was of 17 million. Texas and Mississippi each have experienced over 5 million customer-days of outage.

The chemical production industry in the U.S. is concentrated along the Gulf Coast. In an early October assessment, the American Chemistry Council stated that most chemical plants in the Gulf Coast were closed or operating at reduced rates. The plants were closed because of lack of power, lack of gas supplies, or because of gas prices exceeding $14/MMBtu.

While storm-induced demand loss is forecast to amount to only a fraction of the shut-in gas production, it will be a significant aspect of gas markets this winter.

Table 2-6
Power Outages Caused by Katrina and Rita-
August through Early October, 2005

State	Total Customer-Days of Outage Documented (Millions)	Peak Number of Customers Without Power (Thousands)
LA	17.3	1,038
TX	5.2	860
MS	6.6	909
AL	2.4	624
FL	3.4	1,101
Total	34.9	

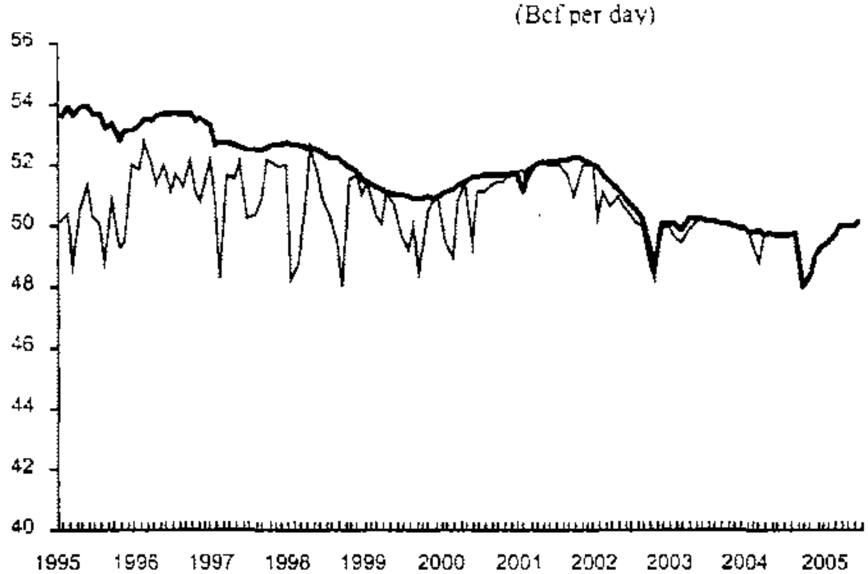
Power-outage days are the number of outages recorded each day, summed through early October.

3 IMPACT ON GAS PRICES

3.1 Gas Price Background

The price of natural gas is largely determined by the balance of North American (U.S. and Canadian) production and demand. Figure 3-1 shows U.S. lower 48 natural gas production (red/lower line) vs deliverability (blue/upper line). Deliverability is the capacity to produce and deliver natural gas to customers at any given time. In the late 1990s, deliverability was well above actual production. There was more than adequate capacity to deliver the gas being consumed by consumers. This resulted in "low" gas prices in the $2.50 to $3/MMBtu range.

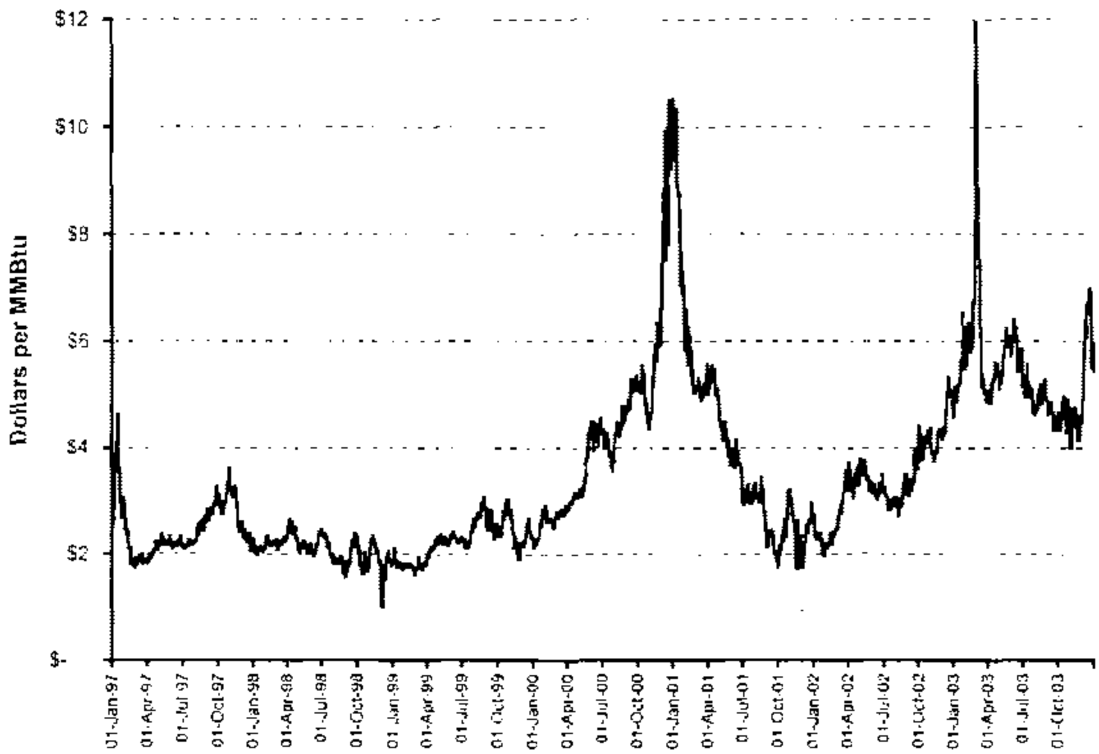
Figure 3-1
Lower 48 Gas Production vs Deliverability
(Bcf per day)



In recent years, deliverablity has declined so that all available capacity is required to meet demand. While additional gas is being supplied through imports, total North American gas production has remained relatively flat while demand has continued to grow. The U.S. gas market is now in a very tight supply/demand balance situation, leading to high prices and high volatility.

Figure 3-2 shows natural gas prices at the Henry Hub pricing point in Southern Louisiana. It shows gas prices starting to increase from the historically low levels as the supply/demand balance begins to tighten in 1999. Abnormally cold weather during the winter of 2000/01 exacerbated this situation, leading to a very high price spike to over $10/MMBtu. In this tight supply/demand environment, even small changes in supply or demand can lead to large changes in price. Large disruptions in supply, such as the damage from hurricanes Katrina and Rita can produce even larger changes. After a brief return to lower levels in 2001, gas prices continued to increase due to continued tight conditions.

Figure 3-2
Daily Henry Hub Gas Price (1997-2003)



In addition to the basic supply/demand situation, oil prices are another important determinant of natural gas prices. Fuel switching from gas to oil in large boilers is an important factor in establishing gas prices on the margin. Higher oil prices usually lead to higher natural gas prices.

Oil prices are determined by worldwide supply and demand, and demand in developing countries such as China has outstripped previous projections, putting a strain on world crude supply. In July of this year the crude oil price increased to $53 per barrel, reflecting this tight supply. During July and August, crude prices increased to over $60 per barrel. The rise in oil prices and tight supply/demand situation for natural gas led to increasing gas prices in the U.S. with prices reach $8 to $10/MMBtu by late summer of 2005.

3.2 Hurricane Impact on Wellhead Gas Prices

As described in Section 2, hurricanes Katrina and Rita affected essentially every component of the Gulf Coast natural gas infrastructure. Based on this preceding discussion, one would expect significant impacts on natural gas prices for the following reasons:

- Natural gas markets were already tight prior to the hurricanes.
- The Gulf Coast accounts for about 40 percent of U.S. natural gas production.
- The combination of the two hurricanes in 2005 created a greater volume of production shut-in and damage to producing infrastructure than has ever been experienced.
- The two storms hitting in succession have lengthened the effect on the gas industry.
- The hurricanes also damaged natural gas processing and pipeline facilities needed to process and deliver gas to customers.
- The hurricane damage to oil refineries resulted in upward pressure on oil prices, which indirectly drive natural gas prices upward.

Figure 3-3 shows the gas price history at the Henry Hub facility in South Louisiana starting in January 2004. After last year's Hurricane Ivan in September, Henry Hub prices increased from a July level of $6/MMBtu to a peak of $8/MMBtu. By February of this year, prices had returned to slightly more than $6. Over the summer, higher oil prices pushed natural gas prices to above $8/MMBtu. When hurricane Katrina made landfall in late August, prices increased to $12/MMBtu for the reasons described above. When hurricane Rita struck in late September, Henry Hub prices increased to $15/MMBtu. Since that time, prices have declined slightly to the $13 to $14/MMBtu range.

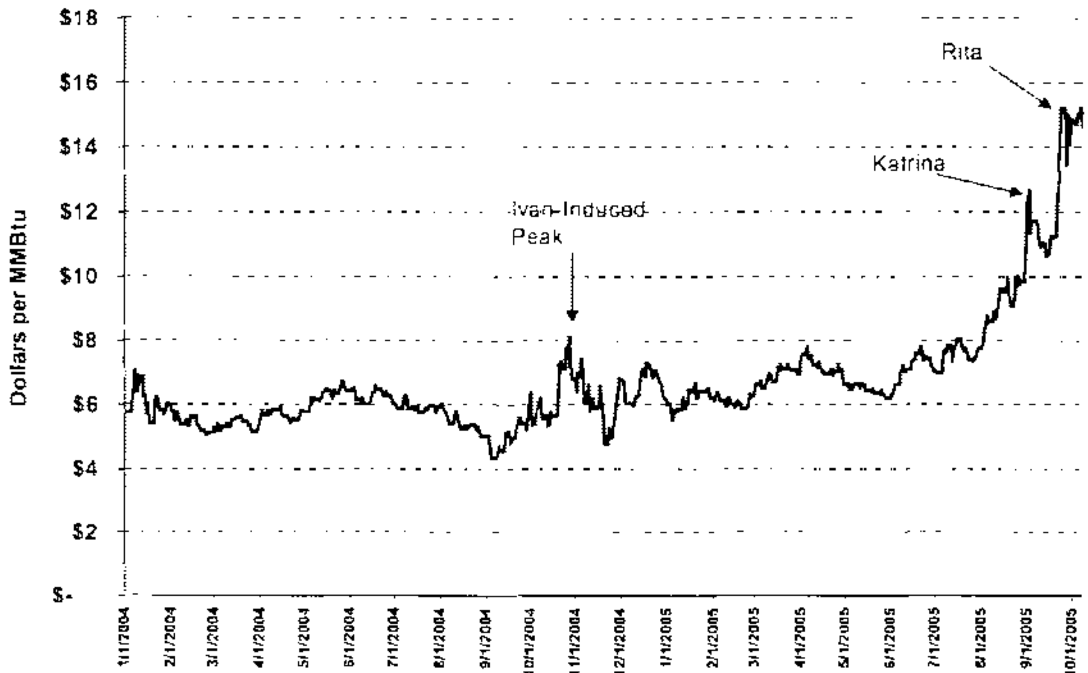
In looking at the impact of Katrina and Rita, it is important to note that gas prices had been increasing even before the hurricane season. As increasing volumes of offshore production are restored, gas prices are expected to decline to a level more consistent with this already elevated trend. Gas prices are expected to remain in the $13 to $14/MMBtu range through the winter and gradually drop back to the $8 to $10/MMBtu range later next year. Gas prices in the longer-term will depend on other factors such as world oil prices and development of additional gas supply, either from North America or through LNG imports.

Gas supplies this winter are expected to be much tighter than normal even under normal weather conditions. Natural gas storage inventories at the start of the winter will be comparable to the recent five-year average but will be lower by about 200 Bcf than expected without the hurricane-induced supply disruptions. In addition, winter wellhead supplies will be unusually low as production and gas processing facilities are expected to remain out of service for several more months pending repairs. This will make the U.S.

consumers more vulnerable to additional price spikes and service interruptions this winter.

As noted above, this effect will be primarily for the eastern half of the U.S., which is most dependent on natural gas from the Gulf Coast region. The western U.S., which receives gas from the Rockies, the west Texas on-shore producers and Canada, will be less affected. The limited capacity to move gas from west to east will help create this differentiation between gas prices in the east and west.

Figure 3-3 Daily Henry Hub Natural Gas Prices (2004-05)



3.3 Impact on Retail Gas Prices

The vast majority of residential and commercial customers purchase gas from a regulated local distribution company (LDC). The LDC charges its customers for the delivery of the natural gas plus the cost of the gas commodity delivered to the local citygate. The gas commodity cost is a direct passthrough, the LDC does not charge a fee on the commodity. However, the increases in the price of the gas commodity are passed directly to customers. The timing and method of this price transparency depend on the regulations in individual states. In some cases there can be an automatic, monthly purchased gas adjustment. In other cases, the adjustment is made through a periodic adjustment in the LDC rates.

LDCs are very sophisticated buyers of natural gas. They maintain a mixed portfolio of spot and long-term gas purchases, inject a large amount of gas into storage during the summer and sometimes use financial hedging tools to protect themselves against price volatility. They typically would not plan to purchase a large amount of gas on the spot market during the heating season. To the extent that the hurricane effects on gas prices are relatively short lived through the 2005-2006 heating season, most LDCs will be somewhat insulated from the effects through forward purchases and gas put in storage prior to the price increases.

The cost of the interstate gas transportation and the LDC delivery charges is a significant part of the retail price of gas to residential and commercial gas customers but is largely independent of the price of the gas commodity. This tends to dampen the effect of wellhead price volatility on retail gas prices. For example, the average cost of gas delivery has been roughly between $4 and $6/MMBtu over the last seven years. Thus, in the late 1990s when the wellhead price of gas was around $2/MMBtu, the average delivered price of gas to residential customers was $6 to $7/MMBtu. In 2004, the average wellhead price of gas was $5.49 and the average delivered price of gas to residential customers was $10.74/MMBtu[1]. So while the wellhead price more than doubled, the delivered residential price went up by about 64% due to the large fixed portion of the retail price.

Nevertheless, the higher prices will have some effect on LDC customers and a potentially larger effect on large industrial and power generation customers, who purchase gas directly from producers and are more likely to purchase spot market gas. The exact effect on consumer cost is difficult to estimate due to the mix of purchasing options, the effect of LDC purchasing strategies as well us the uncertainty over prices. However, as a rough estimate, if the average effect on gas price seen by ultimate consumers is $2/MMBtu over six months affecting two thirds of U.S. gas consumption then the additional cost to consumers is about $13 billion.

3.4 Impact on Electricity Prices

The effect of gas prices on electricity prices in any region depends on:

- The gas share of generation
- The structure of the electricity market

Under traditional regulated utility rates, the cost of electricity is based on the average cost of generation. If gas is a large share of generation in a region then higher gas prices will have a significant effect on electricity prices. The speed with which this effect will be felt depends on the rate-making structure in the region. In some cases, there is an automatic monthly adjustment for fuel prices. In other cases, the adjustment must wait for a rate case.

The electric generation sector is the second largest (after industry) and fastest growing consumer of natural gas. Natural gas fuels about 17 percent of total U.S. electric generation but that share is much higher in some regions. For states with traditional electricity rates structures, the effect of higher gas prices will be more significant in states

[1] *Natural Gas Monthly*, U.S. EIA.

with a high gas market share. Several electric utilities have already announced electric rate increases due to higher gas prices.

In states with restructured electricity markets, the price of electricity is based on the cost of generation of the marginal unit. If there is mostly gas generation on the margin then the price of electricity will be set by the price of electricity even if the majority of the total generation is from non-gas generators. Thus, in restructured electricity markets such as California, Texas, PJM, New York and New England, electricity prices are closely correlated to natural gas prices. This has been reflected in higher wholesale electricity prices throughout the year and during the post-hurricane period.

3.5 Summary and Conclusion

The combined impact of Hurricanes Katrina and Rita has had a profound effect on all sectors of the Gulf Coast natural gas industry as well as important segments of the gas consuming sector, making this hurricane season the most damaging in history.

The concentration of U.S. oil and gas production, processing, and transportation facilities in the Gulf of Mexico and Gulf Coast means that a significant percentage of domestic oil and gas production and processing is prone to disruption. In addition, the very tight supply and demand situation that existed in the U.S. even before this season's hurricanes has magnified potential hurricane impacts.

Gas supplies this winter are expected to be much tighter than normal because storage inventories at the start of the winter will be lower by about 200 bcf due to the hurricane-induced supply disruptions. Also, winter wellhead supplies will be unusually low as production and gas processing facilities are expected to remain out of service for several more months pending repairs. Cumulative shut-in production through August, 2006 is expected to be 890 to 1,120 bcf. This will make U.S. consumers more vulnerable to additional prices spikes and service disruptions.

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BEFORE THE
REGULATORY COMMISSION OF ALASKA 01 JAN 12 PM 2:2

Before Commissioners:

G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

In re: Application for Approval of New Gas Supply Contract with Union Oil Company of California	§ § §	TA 117-4

COMMENTS OF MARATHON OIL COMPANY

AND

MARATHON ALASKA NATURAL GAS COMPANY

Pursuant to the Notice of Utility Contract Filing issued by the Regulatory Commission of Alaska (the "Commission") in the above-captioned matter on December 19, 2000, Marathon Oil Company and Marathon Alaska Natural Gas Company, (collectively "Marathon") respectfully submit their comments respecting the application of ENSTAR Natural Gas Company ("Enstar") for Commission approval of a new gas supply contract between Alaska Pipeline Company ("APL") and Union Oil Company of California ("Unocal").

Marathon Oil Company ("MOC") is incorporated under the laws of the State of Ohio and has substantial natural gas production operations in the State of Alaska. MOC supplies natural gas to APL, Enstar's affiliate, for Enstar's public utility sales and operations. MOC also sells gas in the retail gas market, which has

In the tariff advice letter, Enstar asserts on page 2 that "there is no take or pay under this contract". However, this glib statement is belied by the fact that, pursuant to Section 3.4.2, APL may indeed be required to make "take-or-pay payments" to Unocal if APL fails to take all of the gas which Unocal elects to sell to it. Thus, Enstar's ratepayers may have the opportunity to pay $10 per Mcf or more for gas which they may never receive, and the Commission should closely examine this provision.

Section 3.6 allows the seller to decline to sell gas if its own production is deemed not to be economic. Of course, Unocal could purchase gas from a 3rd party producer, and if the producer failed to deliver the gas on the grounds that it was uneconomic, then, in that situation, APL might have had a claim against Unocal. However, APL has magnanimously waived <u>all</u> of its remedies in the event that Unocal does not deliver gas. See Section 3.3.4(vi). This is another example of a contract replete with benefits to Unocal and burdens to Enstar's ratepayers.

As discussed above, the Commission may want to pay particular attention to the pricing provisions set forth in Article IV, not only because of their direct impact on the ratepayers of Enstar (and they would be considerable) but also because of the impact that such prices would have in destroying the spot market for gas in the Cook Inlet and, with it, all of Enstar's competition in the retail gas sales market. During the past several weeks, Henry Hub prices that would be utilized to price gas sold in 2003 under this contract have ranged from $6 to $10 per Mcf, and as of January 12, 2001, the Henry Hub price is approximately $8.50 per Mcf. According to Mark Legueze, acting director of the Energy Information Agency of the U. S. Department of Energy, gas demand will continue to outstrip supply for another twelve to eighteen months. See December 13, 2000 Gas Daily, page 5. Thus the actual base price payable in 2003 is likely to be much, much higher than the Floor Price of $2.75 per Mcf.[11]

Finally, pursuant to Section 12.2, the agreement specifically provides that Unocal is not required to make any attempt at performance (including exploration activities) "until Seller has negotiated and entered into an agreement with DNR concerning terms and conditions acceptable to Seller (in its sole discretion) clarifying Seller's obligations to the DNR under existing royalty agreements and lease agreements as they relate to Gas sales to Buyer and the Alaska Nitrogen Products fertilizer plant". For the reasons discussed above, Unocal should not be allowed to tie up Enstar's purchase program on the premise that it might obtain a waiver of the MFN clause from DNR. In addition, as explained above, given the detrimental impact of such a waiver on other Cook Inlet producers, the matter is unlikely to be resolved for years. The real question, then, that the Commission must ask itself is how long it is willing to wait while other producers abandon drilling programs until it orders Enstar to consider alternative contracts which will actually benefit its ratepayers.

Conclusion

Marathon readily recognizes that its commercial concerns are of very little interest and play a negligible role in the considerations of the Commission. But the Commission has an obligation to determine whether it is in the best interests of Enstar's ratepayers to approve an illusory contract which (1) contains no firm requirement for the

[11] Not only does Unocal benefit from a high base price under the contract, but it would also be entitled to severance tax reimbursement (worth about 10% of the base price), transportation cost reimbursement up to $1.00 per Mcf, and "peaking fees".

seller to sell any gas, (2) could drive up costs exponentially to the ratepayers if the seller chooses to deliver gas, (3) threatens the spot market and all of Enstar's competition in the retail market, (4) would destroy exploration and production programs of other producers, and (5) would prevent APL from realistically pursuing alternative gas supplies indefinitely. Marathon submits that approval of the contract would seriously disserve the interests of Enstar's ratepayers and therefore requests that the Commission summarily reject the contract and provide definitive instructions to APL to resume negotiations with Cook Inlet producers leading to the execution of one or more contracts that will serve the best interests of the ratepayers. If the Commission elects not to reject the contract summarily, then it should set the matter for hearing to explore each of the issues discussed above.

Respectfully submitted,

MARATHON OIL COMPANY
MARATHON ALASKA NATURAL GAS COMPANY

DATED: 12 January 2001

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Attorney for
Marathon Oil Company
Marathon Alaska Natural Gas Company

STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners:

G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

In the Matter of the Gas Sales Agreement between Alaska Pipeline Company, a wholly owned subsidiary of SEMCO Energy, which the ENSTAR Natural Gas Company is a division, and the Union Oil Company of California, filed as TA117-4.	Docket No. U-01-007

PREFILED DIRECT TESTIMONY OF DANIEL M. DIECKGRAEFF

Q. **For the record, please state your full name, title, and business address.**

A. My name is Daniel M. Dieckgraeff, I am Vice President, Finance and Rates and also Treasurer of ENSTAR Natural Gas Company and Alaska Pipeline Company (which I will refer to collectively as "ENSTAR"), and my address is 3000 Spenard Road, Anchorage, Alaska 99503.

Q. **Please briefly describe your present job responsibilities at ENSTAR and your work experience.**

A. As Vice President for Finance and Rates, as well as Treasurer, I am responsible for all accounting and finance functions at ENSTAR. In addition, I have responsibility for the

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...AL CORPORATION
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...AGE, ALASKA
...-5914
...276-4331

A. Again, the objective was to have a price term that would produce the effect of Cook Inlet drilling projects competing on par with the Lower 48 alternative of oil companies. An oil-based index may not be tied to competing gas projects. Also, for reasons of diversification, it made sense to ENSTAR to have at least one contract tied to a different index.

Q. Why isn't Marathon correct when it argues that the Henry Hub price will lead to exorbitant prices for Alaska consumers?

A. Marathon apparently forgets that the Agreement uses a trailing 36-month average of the Henry Hub prices. The $8.00/Mcf to $10.00/Mcf prices cited by Marathon are anomalous. Attached as Exhibit DMD-7 is a graph showing ENSTAR's gas supply contract price since 1995 and what a contract price would have been using the 36-month NYMEX gas price provision that is in the Unocal Agreement. If in effect today, the 36-month contract price would be $2.637 per Mcf, just $0.005 per Mcf *less* than ENSTAR is now paying under its Beluga contract. (The Marathon APL-4 price would be the same also, except for a "collar" provision that reduces the amount of increase or decrease in a given year.) Again, we believe that the prevailing prices being paid in Cook Inlet have been insufficient to spur new development.

Even with the increases in natural gas prices in the Lower 48 since last fall, the 36-month average price as of March 23, 2001 would give only $3.24 per Mcf, still well below the prices cited by Marathon. Moreover, on March 2, 2001, the *Anchorage Daily News* reported that the world's leading energy price experts are predicting that the current spike in gas costs will ease and prices will most likely stabilize in the $3.50/Mcf range over the next several years.

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Finally, the Commission has to keep in mind that the gas cost charged to ENSTAR's customers is a weighted average of all of our gas purchases. For the next three years, Marathon will continue to provide over 70 percent of ENSTAR's gas, and it will be providing over 50 percent through 2005. The Unocal volumes will likely represent only 30 percent of our gas purchases in 2004 through 2006. In fact, even if Unocal were to commit additional gas to ENSTAR, it would be 2008 before Unocal provided more than 50 percent of ENSTAR's supply. Even if the Henry Hub price were to remain abnormally high, which the experts do not expect, the impact would be softened by this fact alone.

Q. What does Marathon mean when it says that the price will destroy the "spot market" in Alaska and wipe out all competition in the retail gas market in Southcentral Alaska?

A. I am not sure. To ENSTAR's knowledge there is no true spot market in Alaska. The gas that is sold under short-term arrangements does not have the swing our customers need. That is an industrial, not a utility, market. ENSTAR should not try to meet long-term customer needs with a short-term spot supply.

Q. Let's turn briefly to the issue of production taxes and fees, a point on which Marathon is critical of the Agreement. What does the Staff Report have to say on this topic?

A. The Staff Report approves of this provision:

> The [Agreement] states Unocal will pay all taxes and fees, and ENSTAR will reimburse Unocal for production taxes. Including reimbursement of production

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taxes is standard industry practice and consistent treatment as in previous contracts.

Q. Do you agree?

A. Yes. In fact, our APL-4 contract with Marathon has similar provisions. We normally pay for production taxes. As for severance taxes, the Commission should note that there is a six-month limitation built into the Agreement. This six-month "statute of limitations" ensures that ENSTAR's customers will not be exposed to tax adjustments long after the gas is used. If ENSTAR is overbilled, we are entitled to reimbursement with interest.

Q. The Staff Report next addresses the transportation provisions of the Agreement. Why does ENSTAR believe that the transportation arrangements it negotiated are reasonable?

A. As Staff correctly notes, the Agreement provides that ENSTAR will not be charged a transportation fee for gas shipped in existing pipelines. However, Section 4.5 of the Agreement provides that ENSTAR will pay a transportation fee not to exceed $1.00/Mcf under a tariff that must be approved by the RCA for any new pipeline that Unocal builds.

Staff is also correct that ENSTAR, Unocal, and Homer Electric Association are currently investigating the feasibility of constructing a new Southern Kenai Peninsula pipeline to serve Homer, Anchor Point, Ninilchik, and other communities in the region. ENSTAR agrees that there may be a transportation charge if this project becomes a reality. New pipeline infrastructure (like a pipeline from the Kenai field to Homer) may be necessary to develop the gas fields of tomorrow.

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STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners: G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

In the Matter of the Gas Sales Agreement between Alaska Pipeline Company, a wholly owned subsidiary of SEMCO Energy, which the Enstar Natural Gas Company is a division, and the Union Oil Company of California, filed as TA117-4	))))))))	U-01-007

PREFILED TESTIMONY OF DANIEL B. THOMAS

I. Introduction

1. Q. Please state your full name.

A. Daniel B. Thomas.

2. Q. What is your occupation?

A. I am a Senior Land Advisor for Union Oil Company of California ("Unocal") in Anchorage, Alaska.

3. Q. What is the purpose of your testimony?

35. Q. If the Contract were in effect on March 23, 2001, and Unocal was delivering gas to Enstar under the Contract, what would the price have been using Henry Hub pricing?

A. The price would have been $3.24 per Mcf, using the 36 month average.

36. Q. Is there a floor price in the Contract?

A. Yes. The floor price is determined by a formula set forth at Paragraph 4.1.1.2. The floor price is $2.75 per Mcf, adjusted for one-half of inflation after 2002.

37. Q. Didn't the Commission recently approve a Gas Sales Agreement in which Enstar agreed to purchase gas for $2.75 per Mcf, adjusted for inflation?

A. Yes. That agreement (the "Moquawkie Agreement") involves the sale of gas to Alaska Pipeline Company (Enstar) by Anadarko Petroleum Corporation and Phillips Alaska, Inc. from the Moquawkie field, which is on the west side of Cook Inlet. The Commission approved that agreement on July 27, 2001 (TA 114-04). That agreement does not have a floor price, as does our Contract with Enstar. Instead, all gas under Enstar's agreement with Anadarko Petroleum and Phillips is priced at $2.75 per Mcf for the year 2002 and, for 2003 and beyond, is priced at $2.75 per Mcf adjusted for inflation.

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Mark K. Johnson, Chair Kate Giard Dave Harbour James S. Strandberg G. Nanette Thompson

In the Matter of the Gas Sales Agreement between ENSTAR Natural Gas Company, a division of SEMCO ENERGY, INC. and NORTHSTAR ENERGY GROUP, INC., filed as TA125-4	U-03-084

REGULATORY COMMISSION OF ALASKA
HEARING ROOM

January 13, 2004
9:00 o'clock a.m.

VOLUME II
PUBLIC HEARING

BEFORE:	PATRICIA CLARK, HEARING EXAMINER
AND:	KATE GIARD, COMMISSIONER, RCA DAVE HARBOUR, COMMISSIONER, RCA JAMES S. STRANDBERG, COMMISSIONER, RCA

APPEARANCES:

FOR ENSTAR NATURAL GAS CO:	MR. A. WILLIAM SAUPE Ashburn & Mason Attorneys at Law 1130 West Sixth Avenue Suite 100 Anchorage, Alaska 99501
FOR NORTHSTAR ENERGY GROUP, INC.:	MS. HEATHER GRAHAME Dorsey & Whitney Attorneys at Law 1031 West Fourth Avenue Suite 600 Anchorage, Alaska 99501

APPEARANCES (CONTINUED):

FOR THE ATTORNEY GENERAL:

MR. STEVE DeVRIES
Assistant Attorney General
State of Alaska
Attorney General's Office
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Anchorage, Alaska 99501

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Q But as far as recent contracts, Moquawkie was pretty much the first time that this concept of having a transportation fee had been introduced into Enstar's gas supply agreements, is that a fair statement?
A I b- -- it's the first one where we agreed to pay the producer for transportation. Actually the Beluga the contract we had to build a 57 million dollar pipeline to bring it to Anchorage. We undertook that cost and had a rate case as a result of it. In this case we decided that we'd let them shoulder the costs and we'd pay them a fee for it.
Q When you say this case are you talking about.....
A I'm talking about the.....
Q .....Moquawkie?
A .....Moquawkie contract, yes.
Q And the Moquawkie gas contract, that was adjudicated, was it not, as a TA filing, it wasn't suspended and -- to an adjudicatory docket, is that correct?
A That's correct.
Q Now since Moquawkie the only other gas contract that you have that contains a transportation fee is Unocal?
A The only other contract that we've had that we brought to the Commission for approval that has been approved has -- is the Unocal contract.
Q And the rates for the transportation fee in Unocal they're

GAS SALES AGREEMENT

BETWEEN

NORTHSTAR ENERGY GROUP, INC.

AND

ENSTAR NATURAL GAS COMPANY,

A DIVISION OF SEMCO ENERGY, INC.

Effective Date: July 31, 2003

4.3 Calculation: Buyer shall calculate the adjusted Price in October of each Year and provide the calculation and supporting data to Seller by November 1st of that Year. Within thirty (30) Days of receipt of the calculation, Seller shall notify Buyer of the reasons for any objections to the calculation.

4.4 No Determination: If an adjusted Price cannot be determined by January 1 of any Year, the current Price will be used until the adjusted Price is determined. The current Price will then be changed retroactively to January 1st and Buyer will promptly pay or receive a credit (with interest at the rate set in Section 10.3) for the difference.

4.5 Transportation Fee: It is Seller's responsibility to build all pipelines and other facilities necessary to deliver the Gas to the Receipt Point at Anchor Point. The Buyer shall reimburse Seller (in addition to the Price) the RCA-approved tariff rate for Gas delivered through the new pipeline from Seller's Leases to Buyer's Receipt Point at Anchor Point. ("Transportation Fee.") Buyer shall have the right, without objection by Seller, to participate fully at Buyer's expense in all RCA proceedings affecting the tariff rate. Any charges under the tariff will be invoiced in the Month following the Month in which the Gas is delivered to Buyer.

4.6 Price Example: Exhibit 5 is a comprehensive example of the calculation of Price, including the rounding convention.

STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners:

G. Nanette Thompson, Chair
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REPLY TESTIMONY OF
OLIVER SCOTT GOLDSMITH

Q. Please state your name, occupation, and business address.

A. My name is Oliver Scott Goldsmith. I am a professor of economics at the Institute of Social and Economic Research (ISER) of the University of Alaska Anchorage. My business address is 3211 Providence Drive, Anchorage, 99508.

Q. Please state your qualifications.

A. I have been on the staff of ISER for 26 years during which time I have been actively involved in research on the Alaska economy, state fiscal issues, and energy and natural resource economics with special reference to Alaska.

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EXHIBIT L
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incentive, and the inducement of a dedicated market, there is no reason for Unocal to explore in Cook Inlet.

Q. Why is the price necessary to coax investment in new reserves higher than the price necessary to bring existing reserves to the market?

A. Existing reserves need a price at least as high as the incremental cost (primarily the cost of production) of bringing those reserves to market. A higher price that also covers the costs previously incurred to find and develop the reserves would, of course, be preferable, but if the market cannot support that price or is unlikely to support it in the future, it is financially preferable to sell at a price that is at least a little bit above incremental costs (so that at least a portion of the investment in exploration and development can be recovered) rather than not sell at all.

In contrast, a producer would not invest in exploration for new reserves if there was no market for any gas discovered and if he did not think the price he could receive for that gas would cover all of his costs including exploration (some wells do not find commercial quantities of gas), development, and production, as well as producing a return on his investment comparable to the return he could obtain by investing elsewhere.

Q. What is the significance to this contract of the $2.75 price at Moquawkie? (McConnell direct, p. 25, line 21)

A It tells us the price at which a producer will sell gas which has been discovered but not fully developed. My understanding of Moquawkie is that gas was discovered there before the

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