Section 2 of Supplemental Filing of 11/14/12

was withdrawn, the judgment of the Court of Appeals was set aside, and the motion for rehearing and this cause was dismissed as moot.[2.6]

Shelton v. Exxon Corp.,[2.7] in an action by a nonexecutive owner against a lessee for underpayment of royalty and failure to prudently market gas, found a breach of the implied duty to prudently market the gas. The court concluded that the "lessee's duty was to do that which would be done by a reasonable, prudent operator holding *only* the lease in question,"[2.8] and this standard should not be reduced as to the plaintiff because the lessee had corporate warranty contracts legally unrelated to the lease in question.

[2.6] 760 S.W.2d 960 (Tex. 1988). Prior to the withdrawal of the judgment and opinion of the Texas Supreme Court in *Hagen*, that opinion was discussed in other appellate cases:

Transcontinental Gas Pipe Line Corp. v. American National Petroleum Co., 763 S.W.2d 809, 109 *O.&G.R.* 102 (Tex. App.—Texarkana 1988) (denying recovery of punitive damages absent proof of actual damages on tort claim), *rev'd and remanded sub nom.* American National Petroleum Co. v. Transcontinental Gas Pipe Line Corp., 798 S.W.2d 274, 109 *O.&G.R.* 137 (Tex. 1990) (holding that court of appeals should have upheld the judgment for tort recovery, subject to review for factual sufficiency of the evidence);

Pickens v. Hope, 764 S.W.2d 256, 108 *O.&G.R.* 583 (Tex. App., San Antonio, 1988, *error denied*) (concluding that there was no confidential or fiduciary relationship in the instant case between a mineral owner and a nonparticipating royalty owner).

Texas Oil & Gas Corp. v. Hagen is discussed in Lowe, "Developments in Nonregulatory Oil and Gas Law," 39 *Sw. Legal Fdn. Oil & Gas Inst.* 1-1, 1-15 (1988).

There is language in Texaco Inc. v. Duhé, 274 F.3d 911, 921–22 (5th Cir. 2001) that would apply a good faith test to determine if the marketing covenant obligations are met, although the court did not have to deal with that issue since it held that the royalty owner had either waived the issue or was estopped from making the argument.

Rutherford v. Exxon Co., U.S.A., 855 F.2d 1141 at 1145–1146, 110 *O.&G.R.* 542 (5th Cir. 1988), concluded that "Texas law, however, does not impose the obligations of a fiduciary in either event [on a lessee or on a unit operator] based on status alone. . . . The Texas courts require 'fairness' and 'good faith' from a lessee and unit operator, duties which fail to rise to the level expected of a fiduciary."

Cook v. Tompkins, 713 S.W.2d 417, 92 *O.&G.R.* 621 (Tex. App.—Texarkana 1986), held that:

> ". . . the lease operator complied with the implied covenant to market the oil when he sold the production to Basin, Inc. at the current market price. We also hold that this implied covenant does not impose a duty upon the lessee, his assignee, and all other parties owning an interest in the lease to make sure that the oil purchaser has the lessor's address. When the royalty oil was delivered to the purchaser for the lessor's account, the implied covenant to market was satisfied. The lessee, his assignee, and the other parties who own interests in the lease are not obligated to warrant or guarantee payment to the lessor for the oil which was delivered and credited to the account of the lessor."

[2.7] Shelton v. Exxon Corp., 719 F. Supp. 537, 112 *O.&G.R.* 153 (S.D. Tex. 1989), *rev'd on this point*, 921 F.2d 595, 112 *O.&G.R.* 180 (5th Cir. 1991) (concluding that the imprudent marketing claim had been released by a 1980 settlement).

[2.8] 719 F. Supp. at 549 (emphasis supplied).

" . . . Since the marketing scheme was Exxon's own, Exxon is at risk when the prudence of the scheme is judged. That is what the Court must now do.

. . . .

"The NGPA places ceilings on the prices at which different classifications of gas may be sold. The plaintiff demonstrated by credible evidence that the effects of the NGPA were known throughout the oil and gas industry months before the NGPA went into effect. However, in 1978 it was not settled Texas law that 'market value,' for purposes of market value leases, was limited by the regulated price at which that gas could be sold.

. . . .

"The eventual outcome was quite different. In 1981 it was determined that in Texas the market value of gas *is* limited by price regulations . . . . Therefore, as Shelton's expert witness, Mr. Bolton, credibly testified, the hypothetical contracts that Exxon could have entered into before the effective date of the NGPA would have benefitted Shelton by increasing the regulated price and the market value of the gas. Although in 1978 the possible benefits of the hypothetical contracts were uncertain, Exxon could have gained these significant benefits for the mineral interest owners without itself incurring costs related to the King Ranch lease operations and without by the same actions subjecting the mineral interest owners to any risks. Prudent marketing required Exxon to do so. Exxon's failure to do so can only be attributed to its interest in fulfilling its corporate warranties without having to purchase gas on the open market. Exxon's method of marketing the King Ranch gas completely subordinated the rights of the mineral interest owners to Exxon's financial gain. Exxon's acts and omissions in so doing were not those of a reasonable, prudent operator having its own and the plaintiff's interests in mind. Thus, Exxon breached its duty to prudently market the King Ranch gas."[2.9]

Absent inconsistent express lease provisions,[3] this marketing duty arises under any lease in which royalty is payable in kind or is based on the value of a fraction of the mineral produced.[4] Since return to the lessor is dependent on the sale

[2.9] 719 F. Supp. at 549.

[3] *See* §§ 858–858.3 *infra.*

[4] *See* Molter v. Lewis, *supra* at n.2; Darr v. Eldridge, *supra* at n.2.

Davis v. Cramer, 808 P.2d 358, 113 *O.&G.R.* 201 (Colo. 1991), reversing a court of appeals holding that the implied duty to market does not arise until the secondary term [793 P.2d 605, 111 *O.&G.R.* 20 (Colo. App. 1990)], commented as follows:

"The parties to this action agree that an implied covenant to market exists at some point, but both have failed to find support for either the position that the covenant operates, or the position that it does not operate in the primary term of the lease.

. . .

"Although most cases dealing with breach of implied covenants to market arise factually during the secondary term, Sandlin has failed to adduce a sound policy reason why those covenants should not apply during the primary term as well. Under Sandlin's interpretation, of the product once it is discovered, the implied covenant to market can be viewed as another application of the duty of cooperation that governs the relation of the parties to the lease contract.[5]

[Duty to market gas under leases providing for fixed sum royalty]

The duty to market the product also obtains under leases providing for the payment of a fixed sum of money per well per year if gas therefrom is sold or used off the premises.[6] One case held that less diligence is required of the lessee in performing the covenant under leases of this type than under leases reserving

a given property could sit idle and bring no profit for the entire period of the primary term, in this case ten years, so long as the lessee sold any amount of oil or gas at some time before the primary term expired. Presumably, that sale could take place one hour before the end of the term, and the conditions of the contract would be satisfied unless there was a specific provision requiring the lessee to market the gas within a different period of time. That interpretation would defeat the very purpose of the lease, which is to benefit both the lessee and lessor.

. . .

"We reverse the court of appeals and hold that the implied covenant to market oil and gas arises in the primary term of the lease. Upon remand, the court of appeals must review the trial court's determination that this implied covenant was breached. The covenant to market requires that the lessees exercise reasonable diligence to market the products. . . . The existence of reasonable diligence is primarily a question of fact."

Feriancek, "Implied Marketing Covenant During Primary Term," 6 *Nat. Res. & Environ.* No. 3, p. 60 (1992), observes that the decision in *Davis v. Cramer* leaves open the possibility that breach of the marketing covenant during the primary term may cause forfeiture of the lease, "an unduly harsh remedy for breach" of this covenant. "Developing, producing, and operating the property for the mutual benefit of both lessor and lessee could better be achieved by an award of damages."

On remand of *Davis v. Cramer,* the court concluded that there had been a breach of the implied covenant to market the product and that cancellation of the lease was the appropriate remedy in this case. Davis v. Cramer, 837 P.2d 218 at 225, 122 *O.&G.R.* 43 (Colo. App. 1992, *cert. denied*):

"If a lessee fails to market the product for an extended period without explanation, the lessor has made a *prima facie* case for cancellation. . . .

"Here, lessees failed to market the product for six years after the completion of the well and an ascertainment of production in paying quantities, and for three years after completion of a nearby pipeline. Further, the primary consideration for the lease was the expectation that royalties would result from the mining and operation and production and marketing of gas or oil.

"In this situation, cancellation of this lease in an action to quiet title is an appropriate remedy for lessees' breach of the implied covenant to market the product."

[5] On the duty of cooperation as the basic principle from which implied covenants are derived, *see* § 802.1, *supra.*

[6] *See, e.g.,* Howerton v. Kansas Natural Gas Co., 81 Kan. 553, 106 P. 47, *on reh'g,* 82 Kan. 367, 108 P. 813 (1910).

as royalty a percentage of the product produced,[7] but most cases apply the prudent-operator standard as the test of performance of the covenant to market regardless of the form of the royalty clause.[8] In the case of leases reserving a fixed, annual sum as royalty on producing gas wells, damages for breach of the marketing covenant will be limited to the amount of money specified by the royalty clause. If the specified sum is tendered by the lessee and accepted by the lessor, an action for breach of the marketing covenant cannot be maintained, even though the lessee has made no effort to market the gas, since the failure to market has caused the lessor no damage.[9]

[Duty to market oil under various forms of royalty clauses]

The form of the lease clause respecting royalty on oil may also affect the rights of the lessor under the implied marketing covenant. Some lease forms provide for the delivery of the royalty oil to the lessor in kind;[10] others couple this provision with an option in the lessee to purchase the royalty oil from time to time.[11] Under such leases, should the lessee be bound to market the oil belonging to the lessor?

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[7] Smith v. McGill, 12 F.2d 32 (8th Cir. 1926).

[8] *See* Howerton v. Kansas Natural Gas Co., *supra* note 6.

[9] *See* Hurst v. Petroleum Exploration, 221 Ky. 786, 299 S.W. 954 (1927); McGraw Oil and Gas Co. v. Kennedy, 65 W. Va. 595, 64 S.E. 1027, 28 L.R.A. (N.S.) 959 (1909). In each case the royalty clause provided for a payment of $200 per year per well producing gas when gas was used or sold off the premises. No gas was sold or used off the premises but lessee paid the royalty anyway. *Hurst* holds that damages cannot be recovered for breach of the covenant to market on these facts since lessor received all he was entitled to irrespective of marketing. *McGraw* adopts this position as one ground for denying cancellation of the lease.

[10] *E.g.*, "The royalties to be paid by lessee are: (a) on oil, one-eighth of that produced and saved from said land, same to bedelivered free of cost at the wells or to the credit of lessor in the pipeline to which the wells may be connected. . . ."

[11] *E.g.*, "To deliver to the credit of lessor, free of cost, in the pipeline to which lessee may connect wells on said land, the equal one-eighth part of all oil produced and saved from the premises, or, at the option of the lessee, from time to time the market price at the wells of such one-eighth on the day it is run to the pipeline or storage tanks";

"On oil, and other hydrocarbons which are produced at the well in liquid form by ordinary production methods, one-eighth of that produced and saved from said land, same to be delivered at the well in tanks provided by lessor, or to the credit of lessor into the pipeline to which wells may be connected; lessee may from time to time purchase any royalty oil or other liquid hydrocarbons in its possession, paying the market price thereof prevailing for the field where produced, on the date of purchase" (Louisiana form);

"Lessee shall deliver to the credit of the lessor, free of cost into the pipelines or tanks to which such well may be connected, one-eighth of all oil, condensate and their constituents produced and saved from wells on premises, or, in lieu thereof, lessee may, at its option, pay lessor as a royalty for all such oil, condensate and their constituents so produced and saved an amount equal to one-eighth of the gross sales proceeds realized by lessee from the sale of such products less one-eighth of the cost if any incurred by lessee in transporting such products to market from the premises."

The question needs to be divided into two parts. First there is the question whether the lessee is bound to use due diligence to produce (*i.e.*, to bring to the surface) the oil. The answer here must be yes, because the lessee has the exclusive operating rights, making the lessor dependent upon the operator's production to obtain his oil in kind. But does it follow that after producing the oil, lessee is bound to use reasonable effort to market the lessor's oil? Authority on the question is scarce; a dictum in one case would answer the question in the affirmative,[12] but there is contrary authority.[13]

[Product deliverable in kind to lessor]

If the lessor's share of the oil, under the royalty provisions of the lease, is deliverable in kind to the lessor, the oil is theoretically under the control of the lessor and arguably he should be the one to market it, not the lessee. As a practical matter, however, the typical lessor lacks both the experience and facilities to dispose of the oil produced, and for this reason we suggest that the lessee is under an implied duty to market oil, even though the lease provides for royalty in kind. Of course, under a royalty provision or division order that gives the lessor a share of the sale price of oil produced and marketed,[14] the duty to market

[12] Molter v. Lewis, 156 Kan. 544, 134 P.2d 404 (1943). The issue was whether the lessor was required to pay transportation costs arising from the trucking of his oil to the pipeline connection. The lease provided for royalty on oil as follows: "[t]o deliver to the credit of lessor, free of cost, in the pipeline to which he may connect his wells, the equal one-eighth part of all oil produced and saved from the premises." The court held the lessor liable for the transportation costs, and in the course of its discussion made the following observation: "Under an oil and gas lease such as we have here the proper development of the leased premises by the lessee places upon him the duty, among other things, of marketing the oil produced. . . . This is a covenant that the lessee should perform with the diligence of a prudent operator." Nevertheless a few sentences later the court said: "His contract is to deliver the oil to the lessor at the well." 134 P.2d at 406.

In Wolfe v. Texas Co., 83 F.2d 425 (10th Cir. 1936), the royalty clause provided for the lessee "[t]o deliver to the lessor, free of costs, in the pipeline to which he may connect his wells . . ." one-eighth of the oil. The court held that under this provision, the lessee had a duty to market lessor's oil, which duty gave lessee implied authority to enter into a contract for the sale of the oil (a division order) upon the customary terms. The division order provided for withholding royalty payments during the pendency of a title suit and this provision was held binding on the lessor, since the provision was customary and the lessee had authority to make the contract.

[13] Cedar Creek Oil & Gas Co. v. Archer, 112 Mont. 477, 117 P.2d 265 (1941): In an assignment of a lease, assignor reserved one-fourth of total gas production to himself, giving the assignee an option to purchase the gas at the market price. *Held*, no duty to market the assignor's gas arose under the assignment. To imply such duty is to render meaningless the option of the assignee to purchase the gas.

[14] *E.g.*, "The lessee shall pay to the lessor as royalty, hereinafter specified, on the said substances or any of them, produced, mined, saved and marketed from the said lands, namely:

"(a) 12½% of the current market value at the well of all oil and other liquid hydrocarbons, or any of them, saved at the well, produced and marketed." (A Canadian form for privately held lands.)

would obtain, since the lessor lacks the power of disposition and is therefore at the mercy of the operator. The duty to market may also be satisfied through the execution of a division order that acts as a sale of the lessor's in kind royalty oil.

[Royalty on natural gas payable on market value or amount realized]

We have discussed earlier the fact that several states differentiate between market value and amount realized or proceeds royalty clauses when it comes to natural gas production (*see* § 650). In a situation in which the parties have an express royalty clause providing for a market value calculation, can the implied covenant to market, including the duty to obtain the highest price obtainable, effectively convert the market value royalty clause into an amount realized clause? In *Yzaguirre v. KCS Resources, Inc.*,[15] the Texas Supreme Court rejected the application of the implied covenant to market as urged by royalty owners in a situation in which the lessee was receiving a contract price for natural gas that was much higher than the market value. The court concluded that to apply the implied marketing covenant would change the express terms of the royalty clause calling for a market value based royalty. The court observed:

> "Essentially, the Royalty Owners wish to use an implied marketing covenant to negate the express royalty provisions in the leases and transform the 'market value' royalty into a 'higher of market value or proceeds' royalty. . . . We disagree. The implied covenant to reasonably market oil and gas serves to protect a lessor from the lessee's self-dealing. . . . It does not override the express terms of the oil and gas lease whenever a lessee negotiates a sales contract that turns out to be especially lucrative. We will not now rewrite this lease's plain terms to give the Royalty Owners the benefit of a bargain they never made."[16]

[Implied covenant to place production in marketable condition]

A recent development in royalty law has been for courts to find that a lessee has an obligation to prepare natural gas production for market. The rationale for this has partly been a notion that gas has not been produced until a marketable product has been achieved and partly a conclusion that the implied covenant to market as a prudent operator includes an implied duty to prepare the natural gas for a market and even to transport the gas to a commercial market. These cases from Arkansas, Colorado, North Dakota, Oklahoma and West Virginia are collected and analyzed at § 645.2, *above*.

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[15] Yzaguirre v. KCS Resources, Inc., 53 S.W.3d 368 (Tex. 2001).

See also De Los Santos v. Coastal Oil & Gas Corp., No. 05-97-00029-CV, 1999 Tex. App. LEXIS 6100 (Tex. App.—Dallas Aug. 17, 1999) (unpublished opinion).

[16] 53 S.W.3d at 374. For a discussion of the general principle that implied covenants do not preempt or supersede the express agreement of the parties, see § 858 *infra*.

bp

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July 21, 2008

The Honorable Bettye Davis
State Capitol, MS 3100
Juneau, AK 99801

Dear Senator Davis:

Thank you for the opportunity to discuss with you the advancement of the Alaska gas pipeline project (Project). As you requested, I am providing this letter to summarize BP's concerns with the State attempting to advance the Project under AGIA, including an attachment that provides further detail about our concerns with TransCanada's withdrawn partner liability.

As you know, BP wants to work together with the State and interested 3rd parties to advance the construction of the Project and we look forward to the day when we can ship our Alaska North Slope gas to Alaska and other North America markets. A successful project underpins our hope for a long future for our company in Alaska and plays a major role in securing a financial future for all Alaskans.

Since the discovery of oil and gas at Prudhoe Bay, we have diligently explored, developed, and produced our leases, and we have complied with all terms in our leases and in the Prudhoe Bay Unit Agreement. Our exploration and development has resulted in over 11 billion barrels of oil production to date from the Prudhoe Bay Unit (PBU), 2 billion barrels in excess of the original estimate of 9 billion barrels of ultimate recovery. We now believe with continued diligent efforts we can exceed 13 billion barrels of production from the PBU. Recycling gas has played an important role in this achievement.

To obtain this level of production, we and our co-lessees have spent over $40 billion in capital investment alone on PBU exploration, development, and production activities and construction of TAPS to move oil to market. North Slope oil production has generated over $77 billion in State tax and royalty payments. The PBU operating expense supports about 5,000 families annually. Royalty payments from the PBU lessees have made possible the Alaska Permanent Fund, whose value today exceeds $37 billion.

Since 2000, when North American natural gas prices finally began to rise after decades of excess supply, our efforts to develop a gasline project have consisted of:

- 2001-2002: Formed a study group with ConocoPhillips and ExxonMobil, which spent over $125 million dollars examining various options for a gas export project and concluding that a southern route through Canada was the best option.
- 2003: Worked with the Alaska legislature which unanimously reauthorized the Stranded Gas Development Act (SGDA).
- 2002-2004: Worked with the federal government to develop legislation, the Alaska Natural Gas Pipeline Act, to expedite construction of a pipeline.
- 2005-2006: Negotiated in good faith with the Alaska government under the SGDA to advance a project; the resulting contract was not acted upon by the legislature.
- 2007: Participated in the AGIA legislative process, the State's most recent effort to advance a gas pipeline project.

And today we are advancing the Project under Denali – The Alaska Gas Pipeline (Denali). No entity or group of entities has spent more money or worked harder to advance the Project since 2001 than the PBU lessees.

Our interests and the State's interests are aligned in building a pipeline together because we would both be shippers on a line. We both want to build the pipeline for the lowest cost, resulting in highest netback value for the State and us. Nevertheless, we recognize that other entities may have better ideas. If an entity were to bear the expense and take the risk of building a pipeline, we would be delighted to ship gas on their pipeline provided we had a reasonable expectation of making a profit. Indeed, if a credit worthy entity were willing to buy our gas on commercially reasonable terms, we would sell it to them today.

However, before Denali, no entity (including the State) has been willing to buy our gas or to bear the expense and take the risk of building a pipeline. Certainly, TransCanada has not. Yes, TransCanada has testified that they are willing to build the pipeline, but only if shippers including the State and BP provide the financial guarantees that cover the expense and the risk. The State could substantially reduce the risks associated with the Project if the State were to provide a process that would allow for more balanced terms than are being provided by TransCanada's current proposal.

Advantages of the Denali Project

Denali is Consistent with Federal Law: Denali is advancing under existing US and Canadian federal law, and the owners of Denali will fully comply with the terms of ANGPA and FERC law. The terms of an AGIA license could require either TransCanada or the State of Alaska to advance a Project in conflict with both ANGPA and FERC law. We see such an approach as highly problematic, because of significant litigation risks and attendant delay.

No Exposure to Treble Damages Claim: The terms of AGIA would require the State to pay treble damages to TransCanada if the State were to offer tax or royalty incentives to a competing project. The Administration testified this could cost the State over $1 billion. Denali creates no such exposure.

No Exposure to Withdrawn Partner Liabilities: TransCanada, and possibly any of its partners on the Alaska gas pipeline project including the State, may face a claim of $37 billion from partners who have previously withdrawn from a TransCanada subsidiary company (see Attachment under "Background", items 2-5). The legislature should be aware that no withdrawn partner has stepped forward to release TransCanada from liability. In its testimony, TransCanada made clear that it would not indemnify the State, potential partners, or other Shippers from this liability.

BP agrees with the analysis of Goldman Sachs who noted that "a) there could be legal merit in the notion that TransCanada has a 'duty of loyalty' to the withdrawn partners; and b) that this would create a degree of contingent liability and legal risk for potential shippers and/or investors." Goldman also says that this risk could be managed or clarified by TransCanada seeking resolution of the issue, by further legal action, or that other approaches could be taken by TransCanada. But TransCanada has not resolved this issue of significant exposure. Denali faces no such exposure. Additional information about this issue is included in Attachment 1.

No Requirement for the State to Commit to Ambiguous "License" Terms: The "License" offered by the State to TransCanada purportedly consists of the Alaska Gasline Inducement Act, the Request For Application issued under AGIA, and TransCanada's application with responses to information requests. If anything is in conflict, AGIA controls. These documents say nothing about important, basic contractual obligations like Force Majeure, for instance. Also, the Administration has testified that the terms contained in TransCanada's application may be modified, subject to the Administration's judgment of increasing value to the State. In other words, what exactly constitutes the duties and rights of both the State and TransCanada is not clear.

Incentive to Control Costs: BP's incentive is to control construction costs and reduce cost overruns. This maximizes the netback value for all shippers including the State. TransCanada, on the other hand, increases its profit and cash flow with higher costs. This fundamental difference would impact netback values through the life of the Project.

No Requirement for Alberta Tying Arrangement: TransCanada's requirement that any shipper on the Project must ship gas out of Alberta is inconsistent with an open, competitive market approach to shippers. By forcing shippers of Alaska gas to exclusively use the TransCanada system in Alberta TransCanada would use its monopoly power as owner of the Alaska gas pipeline to preclude shippers from seeking more commercially competitive options. Denali has stated its intent to offer transportation service out of Alberta if shippers desire that service.

No Requirement of State Funds: Finally, TransCanada is asking for $500 million in State funding to get to FERC certification while only exposing $124 million of TransCanada's resources. TransCanada has been free to start work on the Project at any time, but has not. TransCanada has conducted no field work on its own, but would start only once it secures a State funding match. Denali is asking for nothing to support advancing its project.

Why Not Combine TransCanada with Denali?

Some have suggested that the "winning way" would be to somehow combine the efforts of Denali and TransCanada. On the surface, this might seem to be a reasonable solution. We've said in the past, and continue to say today that we welcome the participation of ANY third party who can add value and help manage the risks associated with this project. And after all, my company, BP, is TransCanada's biggest customer. We believe that TransCanada is a fine company; however, there are serious issues and concerns with such an "arranged marriage" on this project. Further, a license granted to TransCanada under AGIA will create an impediment to a potential joinder between the parties as the terms of AGIA are fixed and the State is limited as a participant in such discussions because of the treble damages provision of an AGIA license.

There are significant issues to resolve that require unfettered conversations. As we've mentioned, TransCanada faces a multi-billion dollar withdrawn partner liability. This liability is a real risk to anyone who partners with TransCanada on the Alaska gas pipeline project. We have obtained a legal opinion from one of the largest, most prestigious firms in the United States and their opinion is the risk is real and obviously very significant. The risk can be solved by TransCanada. But it remains a risk today and a barrier to partnership because TransCanada has not solved the problem.

Also, should TransCanada be granted an AGIA license, they would be required under its restrictive terms to offer tariff terms that are not commercially reasonable, and that conflict with FERC law. As we have testified before, BP is motivated to offer commercially reasonable terms consistent with FERC regulation, and that was one key reason we could not submit a bid under AGIA in the first place. A license makes resolving these issues much more difficult.

Point Thomson Resource is Essential to a Successful Gas Pipeline Project

BP has serious concerns with the DNR's recent denial of the Point Thomson plan of development (POD). The POD submitted to the DNR Commissioner satisfies all the DNR's stated requirements. Indeed, as AOGCC Commissioner Cathy Foerster stated at the recent legislative hearings, from a technical perspective "the plan does exactly what the State wants Exxon to do." The POD provides for full delineation of the Point Thomson area resource. It provides for early liquids development. It makes Point Thomson gas available for a future gas sale. And the Point Thomson owners are aligned on this way forward with no one party able to block development.

Point Thomson gas is essential for any gas pipeline project. If Point Thomson gas were available under this POD for the gas pipeline open season, the Point Thomson lessees with that resource could use the Point Thomson gas to underpin their substantial financial commitments.

BP remains committed to developing the Point Thomson resource and hopes to find a solution as soon as possible. Our objective is to work with the DNR and other Point Thomson lessees to find a mutually agreeable solution in time to make these vital resources available so as to help ensure the success of an open season. We believe it is in all the parties' best interests to resolve this soon and move forward with the development plans without further delay.

Fiscal Stability

Many participants have recognized that shippers like BP will need fiscal stability before making the enormous financial commitments required at open season. MidAmerican said as much during their AGIA testimony. In fact, so did TransCanada. TransCanada even noted this in their application:

> *"TransCanada would rely on the State of Alaska to take all feasible actions exclusively within its authority as a sovereign power to ensure a favorable economic environment for potential Shippers on the Project. Those actions include engaging with the ANS Producers to reach agreement on a commercially reasonable and predictable upstream fiscal regime that balances the needs of the State and the ANS Producers." - Section 2.2-52*

The Administration has testified that TransCanada would likely be at the table if and when fiscal terms were being negotiated with potential shippers. The Administration said that offering fiscal terms to all shippers, even if that was determined to be good State policy, would give rise to a treble damages claim by

TransCanada. The terms of AGIA restrict the State from providing an essential ingredient for a successful Project. Denali offers the commercial flexibility required to ensure the flexibility is available to shippers and the State to ensure project success.

BP wants to have a successful open season. We expect that having fiscal terms agreed with the shippers beforehand would increase the likelihood of a successful open season. The specter of treble damages owed by the State if fiscal terms are negotiated jeopardizes the prospects of that successful open season. That's not good for any Project that seeks to hold a successful open season.

BP is Committed to Continue Moving Ahead with Denali

From our previous testimony on AGIA and from our public comments you've heard our concerns with AGIA and a TransCanada license. They include:

- The requirement of commercially unreasonable terms for customers
- The conflicts with FERC and Federal Law
- The exposure to a multi-billion dollar withdrawn partner liability claim
- The State's exposure to claims of treble damages
- The impediments to a potential TransCanada/Denali solution
- The delays to the Denali project in favor of permits being awarded to the AGIA licensee.

BP is committed to moving forward with the Denali project and is spending millions of dollars already this summer to do just that. Doing so is in the best interest of our company and serves the best interest of the State of Alaska as well. We will continue to move as fast as we can with the State's cooperation.

Thank you again for the opportunity to discuss this important matter.

Sincerely,

David Van Tuyl

David Van Tuyl
Gas Commercialization Manager
BP Exploration (Alaska) Inc.

cc: Senate President Lyda Green
Speaker of the House John Harris

Attachment

Attachment: TransCanada's ANNGTC Withdrawn Partner Liability

Although TransCanada did not disclose this fact in its AGIA application, TransCanada potentially faces a multi-billion dollar liability associated with an earlier attempt to advance an Alaska gas pipeline project. This liability represents a real risk to potential TransCanada partners and the State, and if realized, could prevent a TransCanada project from advancing.

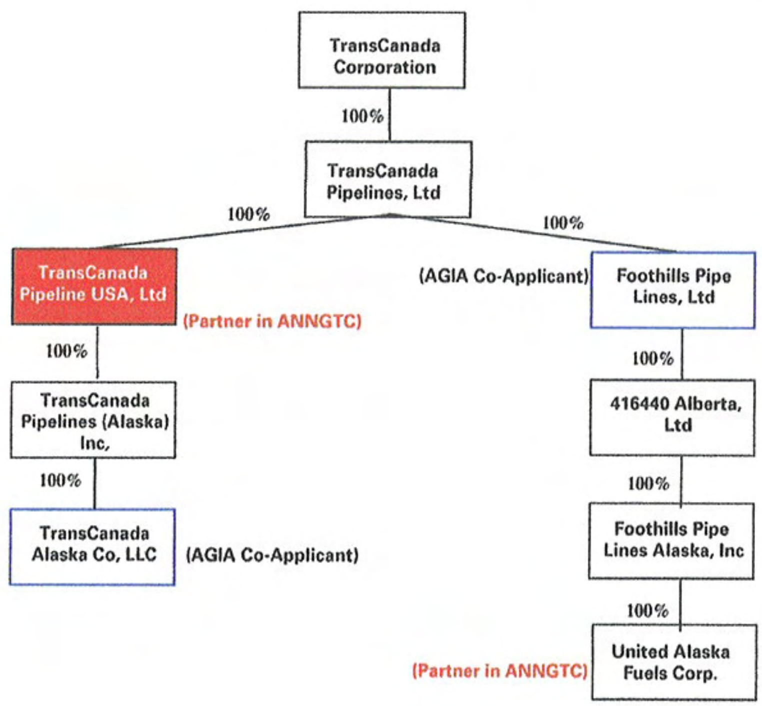
- TransCanada failed to disclose the risk of potential withdrawn partner liability in its AGIA application.
- TransCanada has not shown that the risk of potential withdrawn partner liability will be avoided through its proposed corporate structuring and the use of affiliates and subsidiaries.
- TransCanada has not proffered any waivers from withdrawn partners relieving TransCanada of any potential liability.
- TransCanada has not addressed the fact that even if it were to obtain a parent guarantee, the market capitalization supporting the guarantee is approximately half of the potential liability at project start-up ($20 billion v. $37 billion) and thus insufficient to backstop the risk to TransCanada and any partners.
- TransCanada has not addressed the fact that if the potential withdrawn partner liability was passed on to shippers through the tariff if would significantly reduce the netback to the State.
- TransCanada has not addressed the fact that the potential withdrawn partner liability could encumber not only TransCanada but any partner to the Alaska gas pipeline project, including the State.

Background:

1. AGIA requires an applicant to provide "information relevant to the commissioners' evaluation of the readiness and ability of the applicant to complete the project" [AS 43.90.130(19)].
2. ANNGTC was formed in the 1970's in an attempt to build an Alaska natural gas pipeline project and spent several hundred million dollars to obtain a conditional FERC certificate in Alaska. (April 12, 2007 Alaska Northwest Natural Gas Transportation Company (ANNGTC) submission to FERC, page 1) ("Submission").
3. ANNGTC has recently been active in pursuing its project in Alaska, having submitted an application to the State for a right-of-way as recently as June, 2004.
4. Many partners have since withdrawn from ANNGTC. As these partners withdrew, they retained rights of repayment, except in the case of "undue hardship," from the partnership upon project startup. At the end of 2006, the liability reported by ANNGTC to FERC for these withdrawn partners was $8.9 billion (Submission pages 2 and 11).
5. The withdrawn partner liability will continue to increase at 14% per year (Submission page 9), and is expected to reach $37bn by TransCanada's assumed project startup date of 2018.
6. The withdrawn partners include entities owned by Sempra Energy, NiSource, Williams, MidAmerican, Loews, and PG&E. According to TransCanada, one partner has transferred its rights to a trust for the benefit of the California Public Utilities Commission.
7. TransCanada's market capitalization is approximately $20bn as of July 18, 2008 (source: Yahoo finance), which is just over half the potential liability at startup.

Observations and Implications:

1. TransCanada claims that payment of the withdrawn partner liability would cause undue hardship on the pipeline company and would therefore not be payable under the partnership agreement. Given the projections of potential project revenues that TransCanada provided in its application, however, it is not clear that the hardship clause would apply.
2. ANNGTC's acknowledgement, cited in TransCanada's January 24, 2008 letter to the State, of the "uncertainties" created by its "contingent liabilities" conflicts with TransCanada's denial of any risk associated with the withdrawn partner liability.
3. TransCanada identifies its AGIA applicant, TransCanada Alaska Co, LLC, as a subsidiary of TransCanada Pipeline USA, which is an ANNGTC partner (see diagram below, replicated from TransCanada's January 24, 2008 letter to the State). This corporate structure demonstrates the relationship between ANNGTC and the AGIA co-applicant, confirming the relevance of this withdrawn partner liability.
4. Even a small uncertainty attached to such a large potential liability creates a very significant and potentially insurmountable concern to potential partners, shippers and the State.



Alaskan LNG Exports Competitiveness Study

Alaska Gasline Port Authority (AGPA)

Final Report

July 27, 2011

consulting
strategy

monetisation • strategy • transactions • business environment • government • consulting

Wood Mackenzie

Strategy with substance

Background

As part of its interest in promoting a large volume pipeline from the North Slope to a 2.7 bcfd liquefaction facility in Valdez (and a lateral to serve south central Alaskan demand), AGPA has contracted Wood Mackenzie to evaluate the economic competitiveness of Alaskan LNG exports relative to other proposed liquefactions projects at various stages of development.

With oil prices hovering today around $100 per barrel, and expected to remain at or around that level for an extended period of time, the Alaskan LNG export opportunity appears today to make economic sense. Typical Asian oil-indexed LNG pricing delivers product to regasification terminals at over $15 per mmBtu. On the other hand, Lower-48 and Canadian natural gas, if exported as LNG, could potentially be delivered to Asia at or around a cost of $10 per mmBtu, subject to various assumptions and costs.

The purpose of this report is to help AGPA to develop an informed perspective as to the overall economic attractiveness of the proposed Valdez LNG export facility.

Please note all future values throughout this study are given in nominal terms.

Agenda

Agenda

From an economic perspective, Alaskan LNG exports are competitive, viable across scenarios, and could generate between $220 and $419 billion for Alaska*

- The numbers generally "work" for Alaskan LNG exports when the global oil price is north of $75/bbl oil and Asian firm contract pricing reflects a 13%(+) oil indexation** (indexation for firm contracts today is approximately 14.85%)
  - Alaskan LNG exports have a delivered cost structure below $10/MMBtu. Given a range of infrastructure cost scenarios, oil prices projected utilizing Woodmac's April 2011 NAGS price outlook or the NYMEX forward strip, and LNG - oil indexation pricing to Asia of 13 – 16%, Alaskan LNG could be priced DES between $18.00 - $46.00/MMBtu through 2050.
- Proposed Alaskan LNG exports have a substantial cost advantage relative to possible competing LNG supply projects
  - Alaskan LNG would use assets that are producing gas for re-injection (essentially limited to gathering, transport and processing costs)
  - Most competing Australian projects and proposed NA LNG exports yet to secure Final Investment Decision (FID) are expected to deliver LNG to Asia at costs of $10 - $12/MMBtu under current gas price assumptions
- Assuming start-up in 2021 and a project life of 30 years, royalties (12.5%) and state taxes (starting at 25% post-royalties) could yield a total of between $220 and $419 billion*
  - Royalties (12.5%) and state taxes (starting at 25% post-royalties) could yield $2.4 to $24 billion per year.
- While we do not address them, there are a number of commercial challenges associated with all liquefaction projects
  - Economics are important, but commercial issues such as the scale of value chain requirements (pipes, storage, etc.), buyer risk tolerance, financing arrangements, etc. are critical

Taking all into account – basis, shipping, capital requirements – Alaska LNG export facilities can deliver LNG to Asia less expensively than US Lower 48 or Canada and competitively vis-à-vis traditional Australian LNG sources

Wood Mackenzie

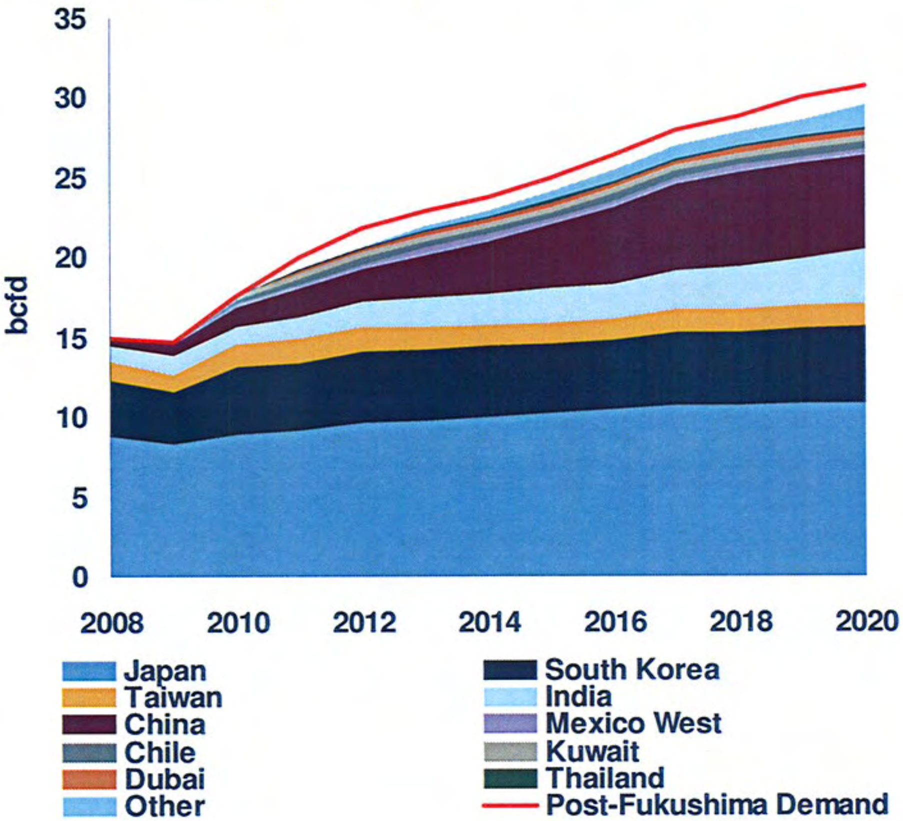
*Total undiscounted taxes and royalties values utilize nominal figures (2.4% inflation), 14.85% indexation, and avg. recourse rate of $4.18. Assuming a nominal discount rate of 5%, the NPV of taxes and royalties is between $65 and 124 billion.

**Oil indexation price example: With an oil price of $100/bbl, "oil indexation" of 14.85% yields a gas price of $14.85/MMBtu

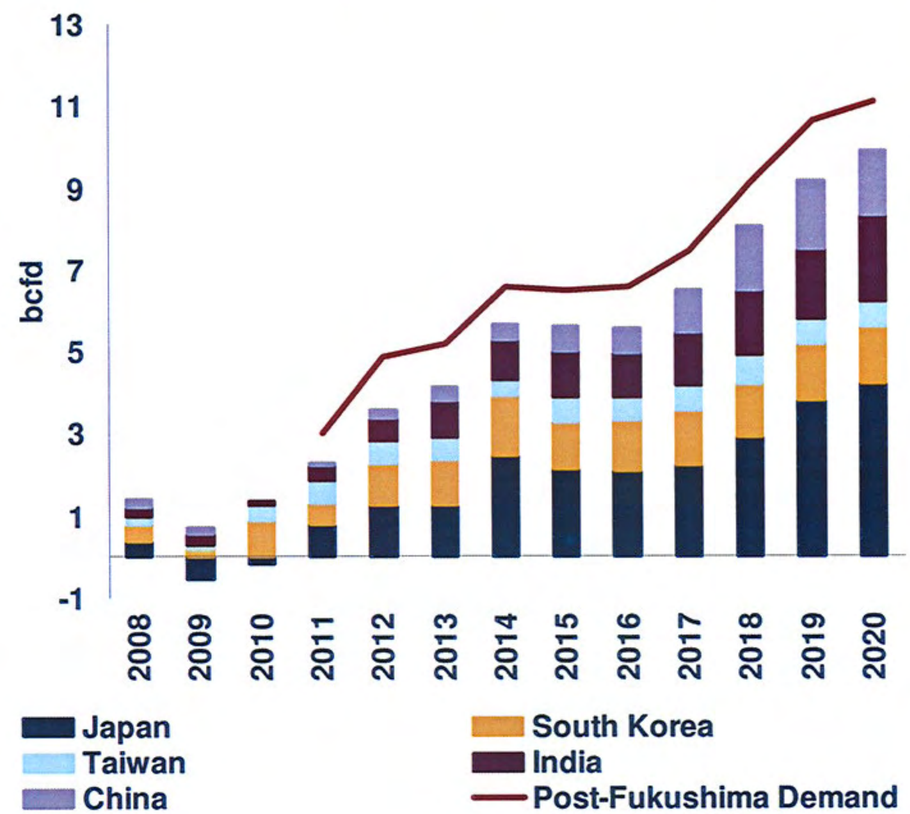
Agenda

China is a key driver of Pacific LNG demand growth, but traditional JKT (Japan, Korea, Taiwan) markets still account for most uncontracted demand

Pacific/ME LNG Demand



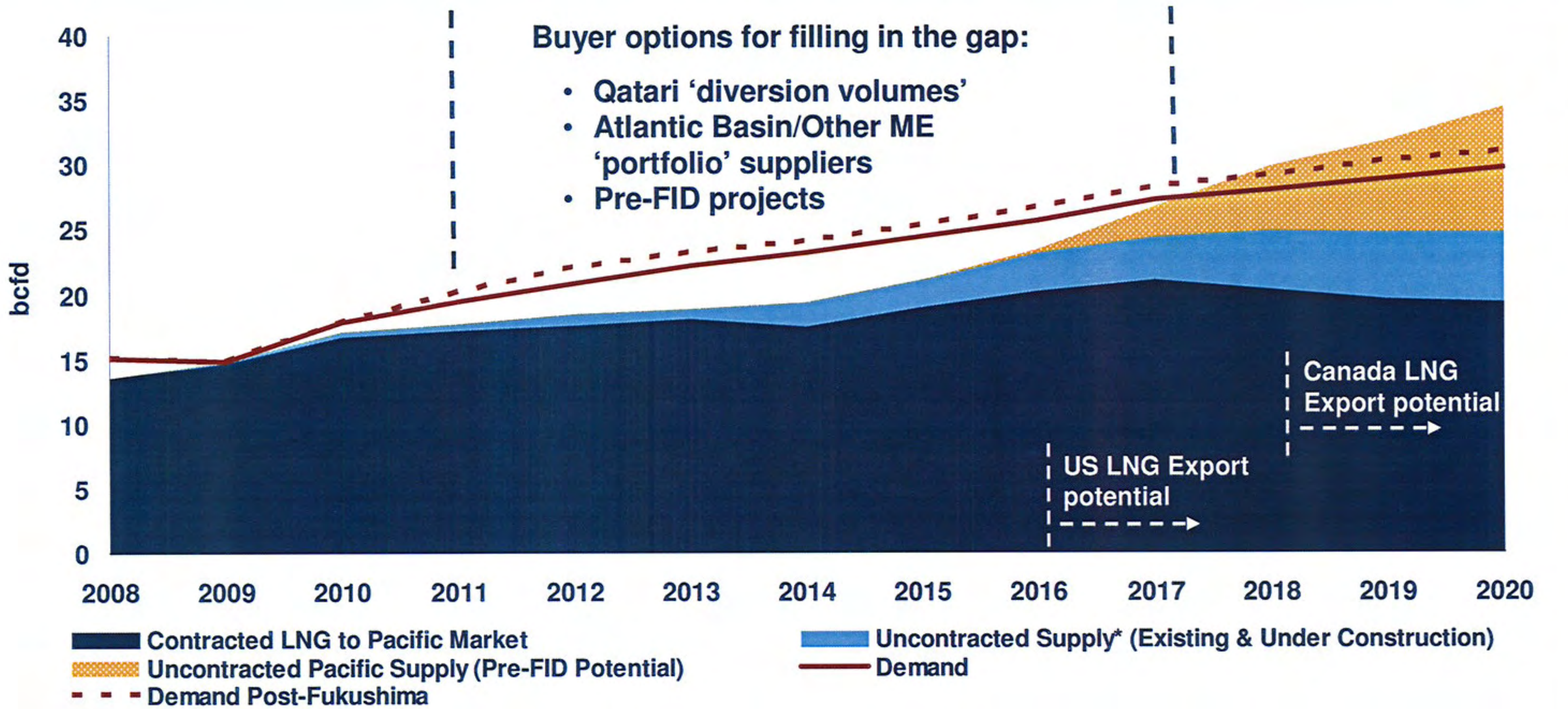
Uncontracted Demand, Selected Countries



Source: Wood Mackenzie LNG Tool, Feb'11, Global Gas Service H1 '11

The Pacific Basin market is short of proximate LNG and a number of projects will compete for long-term supply requirements (including Alaska LNG)

Pacific/ME Basin LNG supply vs demand

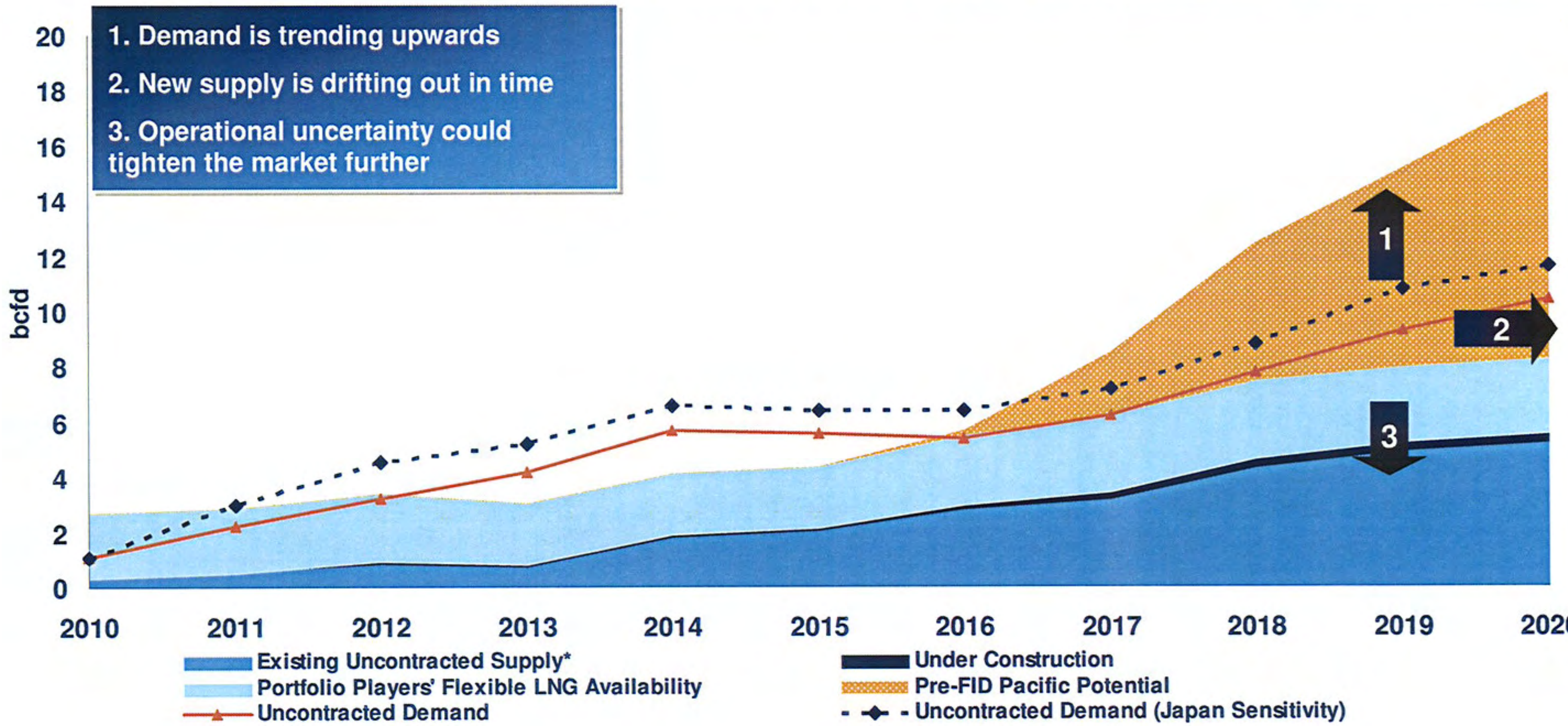


*Includes uncontracted supply from Pacific Basin and Middle East supply projects, but excluding 'flexible' Qatari volumes that are 'allocated' to the Atlantic Basin

Source: Wood Mackenzie LNG Tool, Feb'11, Global Gas Service H1 '11

There is insufficient Atlantic portfolio LNG to bridge the gap and the market is tighter than it appears (since Fukushima) supporting current LNG prices

Pacific Basin uncontracted LNG supply vs demand, including portfolio supplies

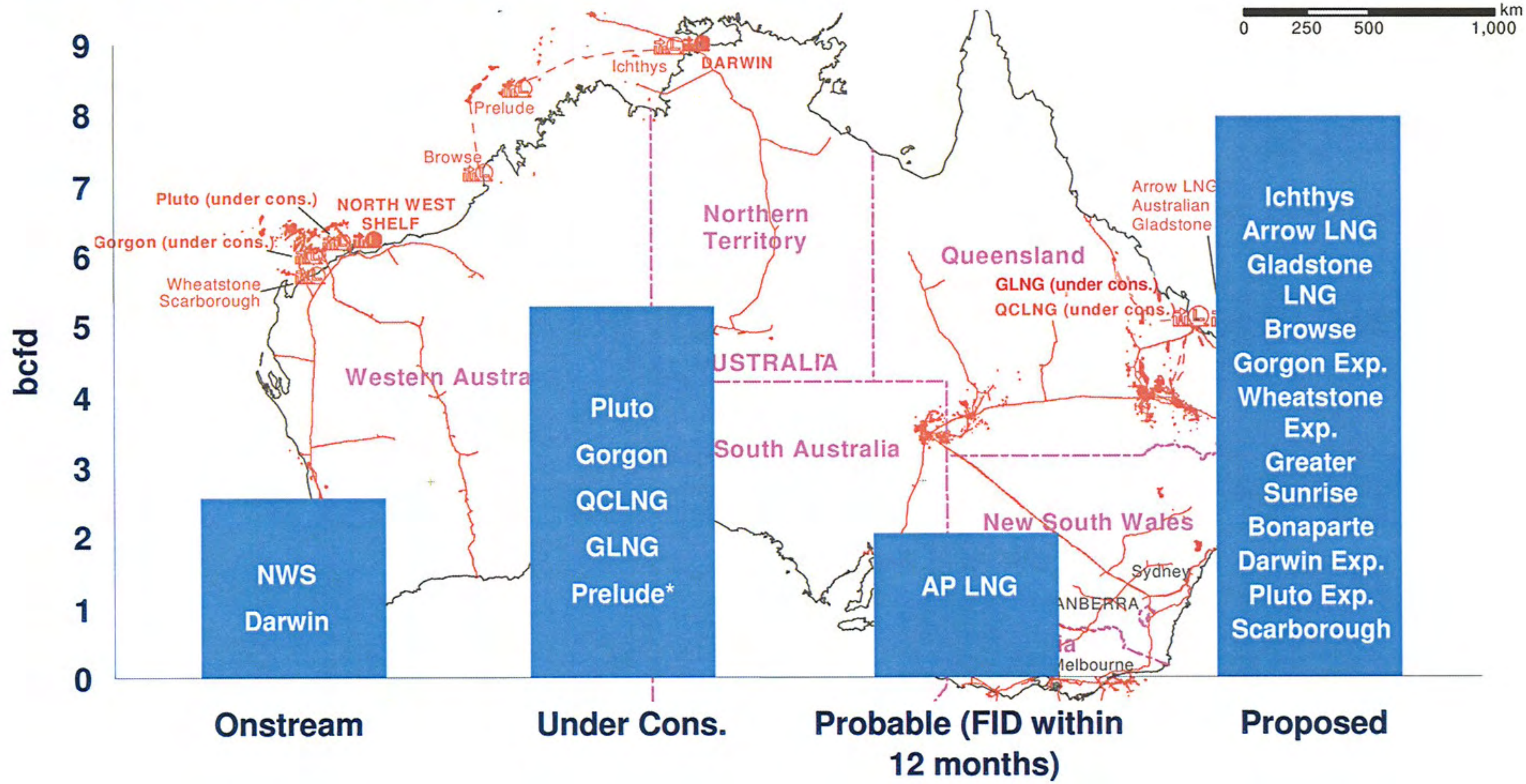


*Includes uncontracted supply from Pacific Basin and Middle East supply projects, but excluding 'flexible' Qatari volumes that are 'allocated' to the Atlantic Basin

Source: Wood Mackenzie LNG Tool, Feb'11, Global Gas Service H1 '11

Agenda

Australia will help fill the Pacific supply gap with over 7 bcfd of capacity on-stream or currently under construction…



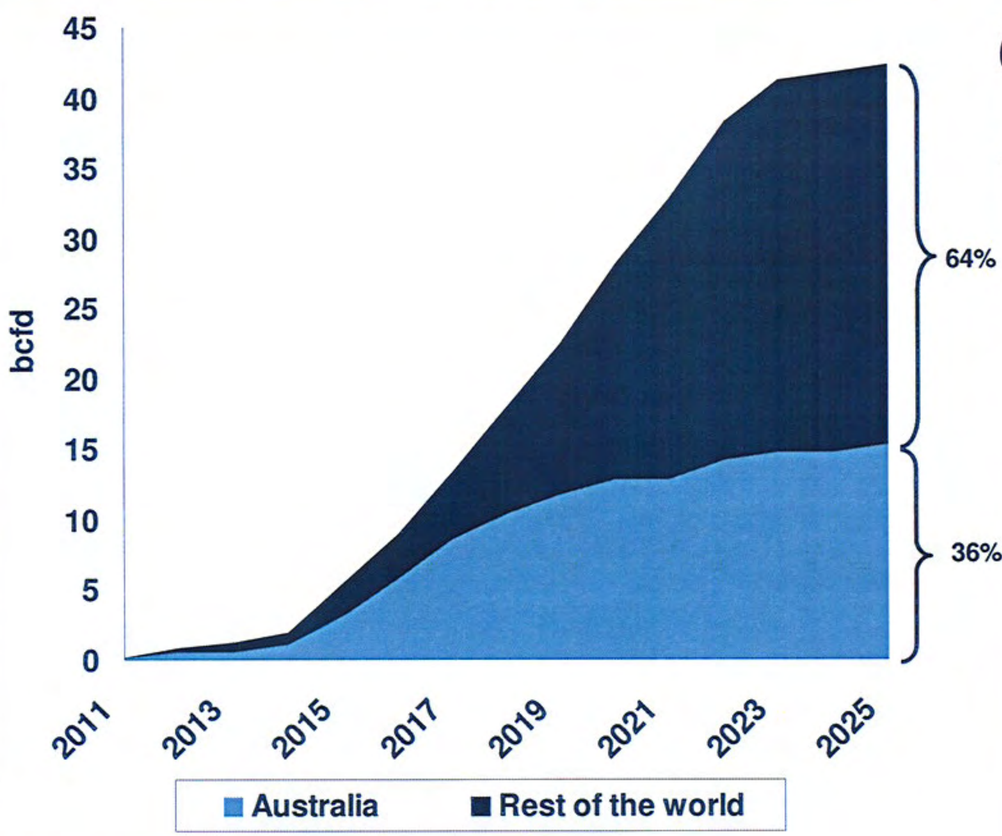
* Prelude took FID in mid May

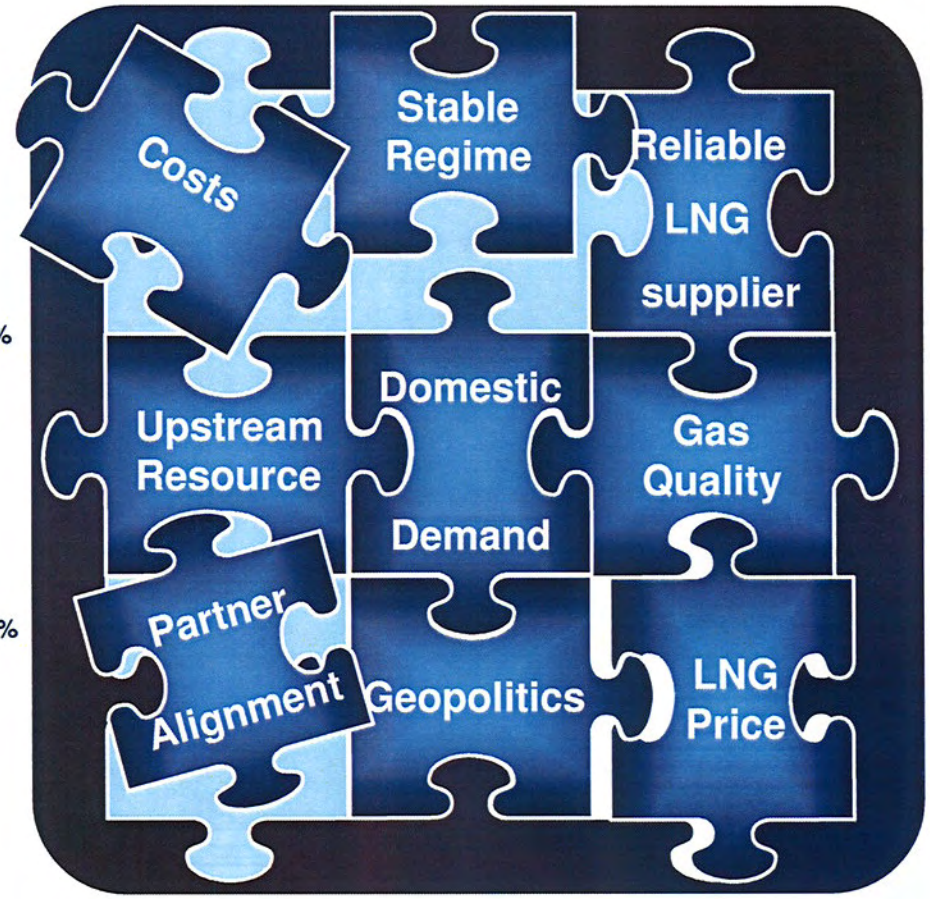
Source: Wood Mackenzie. As of May 2011.

Wood Mackenzie

...and continues to dominate the global outlook for new LNG supply due to its large gas resource base and attractive investment climate

'Potential' LNG supply*: Australia and the rest of the world



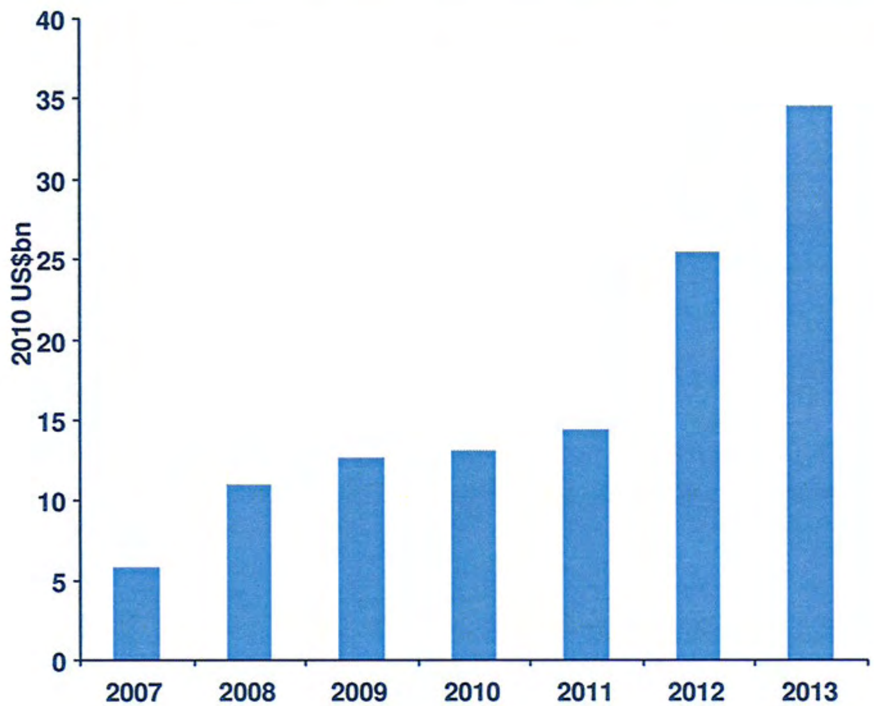


*Includes under construction, probable and proposed LNG capacity globally

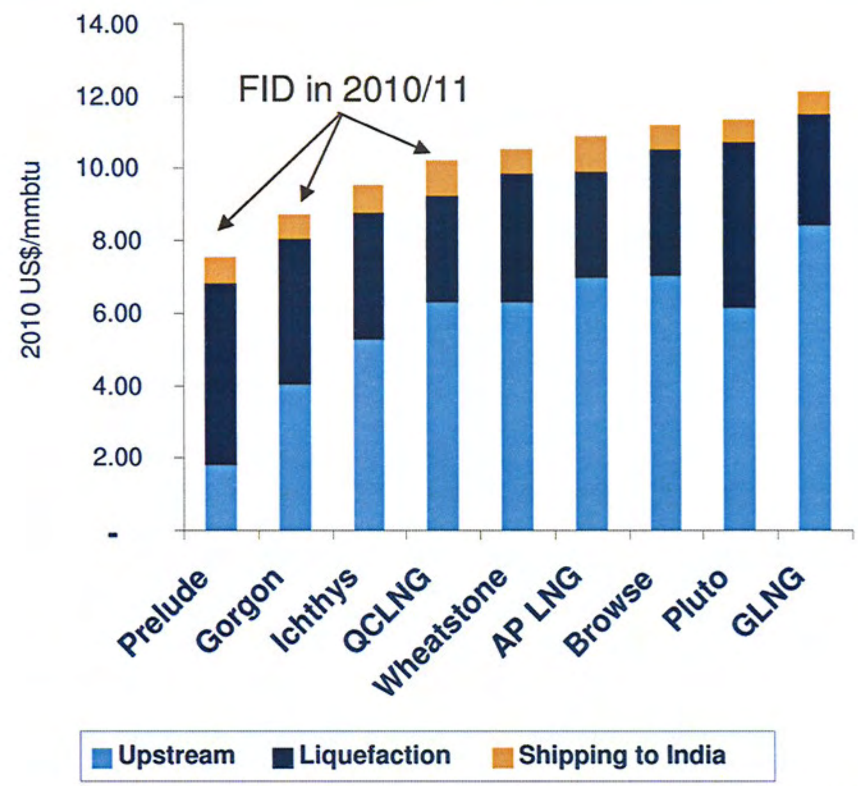
Source: Wood Mackenzie LNG Tool

But rising costs are putting pressure on Australian project economics… Which sponsors are best placed to mitigate against cost over-runs and delays?

Australian oil and gas upstream and liquefaction capital expenditure



DES cost stacks for Australian LNG projects (base Capex)*



* *The analysis is taken from the February 2011 LNG Service Insight: 'Might Rising Costs In Australia Propel North America LNG Exports'.*

Source: Wood Mackenzie CAT, LNG GEM, LNG Tool

There may be headroom for a few North American LNG export projects

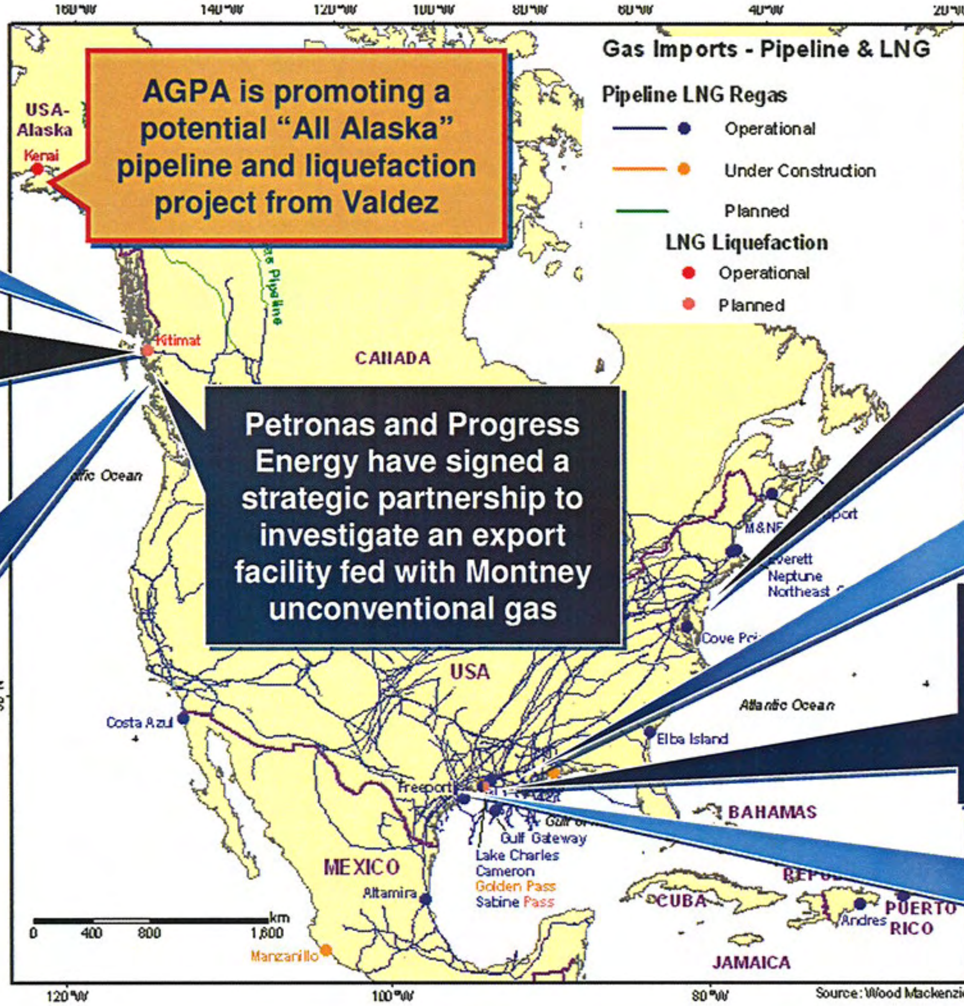
Douglas Channel Energy Partnership project is a proposed 0.9 mtpa barge facility near Kitimat

Kitimat LNG is a proposed 5 mtpa facility (Apache/EOG/EnCana) fed with shale gas from Horn River / Montney

Shell/Mitsubishi (with PetroChina, KOGAS and several Japanese utilities) and Nexen/LNG Japan are reportedly considering similar schemes in the BC area

AGPA is promoting a potential "All Alaska" pipeline and liquefaction project from Valdez

Petronas and Progress Energy have signed a strategic partnership to investigate an export facility fed with Montney unconventional gas



Dominion has announced plans to add export capacity at the Cove Point regas facility

BG and Southern Union have announced plans to add 2 bcfd of export capacity at the Lake Charles regas facility

Cheniere is proposing to add 1.0 bcfd of export capacity at the existing Sabine Pass LNG regas facility and has signed 6 non-binding MOUs for capacity

Macquarie/Freeport are proposing to add 1.4 bcfd of export capacity at the existing Freeport LNG regas facility

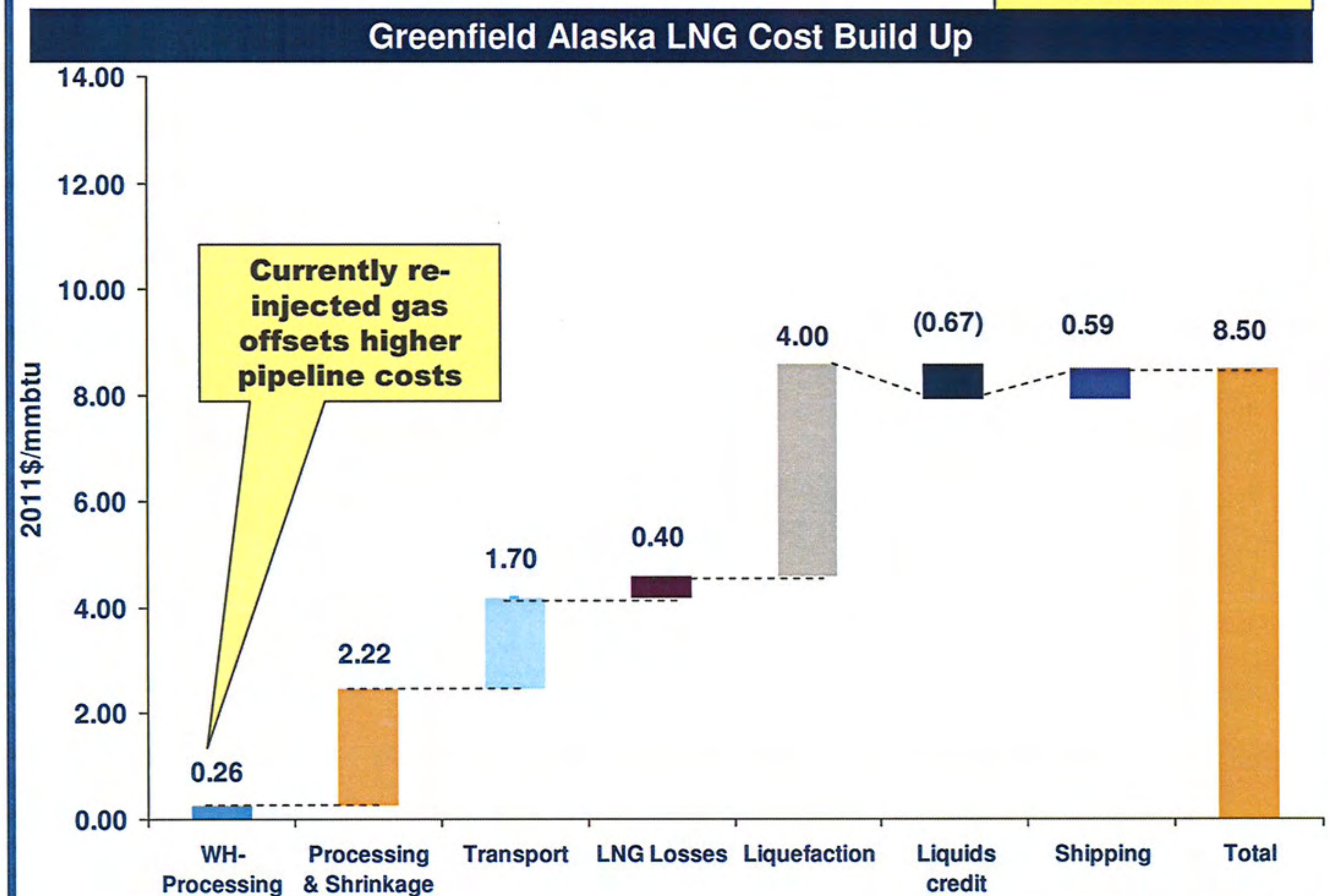
Source: Wood Mackenzie

Access to currently re-injected gas upstream puts the Alaska LNG liquefaction project in an economically competitive position relative to others...

ESTIMATE

Key Assumptions

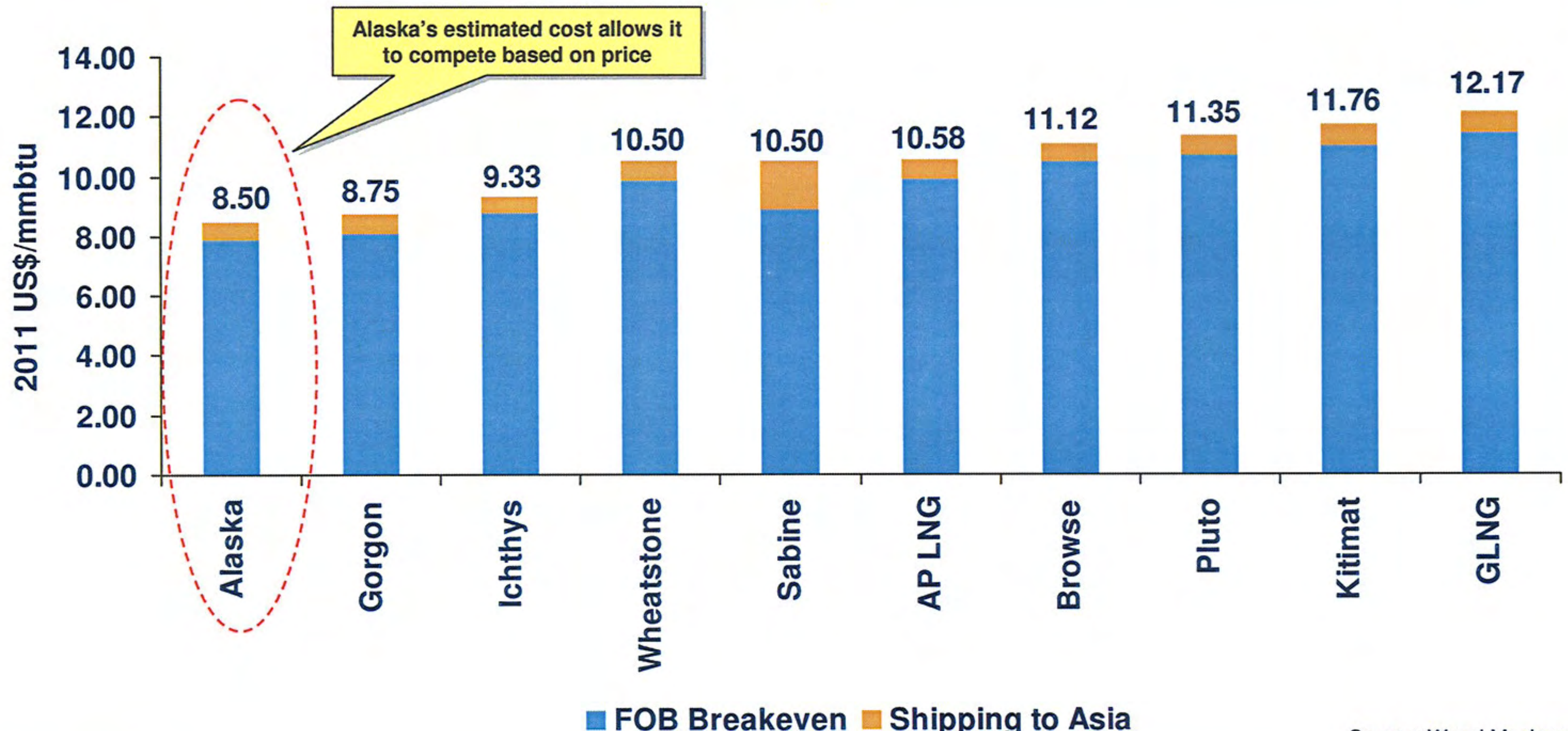
- All data from "Transcanada XOM Alaska Pipeline Project Open Season Notice, 2010, Valdez LNG Case" except below items:
- Liquefaction:
  - CapEx: $1,200/ton; est. rate covers CapEx, Opex, 12% nom. ROE.
  - Alaska LNG losses 9.65%
- Shipping Assumptions:
  - Ship: 155,000 m³
  - CapEx/ship: $200 million
  - OpEx: $15,000/day; 2.33% annual escalation
  - 8% ROE after tax
- LNG Processing Losses: estimated from AGIA NPV Report, Fig. 7.2
- Liquids credit determined using $80/bbl netback price for LPG and volumes provided by AGPA (88,000 MMBtu/d; ~20,000 bpd)



Source: Wood Mackenzie

...and it competes favorably with both proposed Australian and other North American export facilities which have yet to reach FID

DES Cost Stack Comparison



Source: Wood Mackenzie

Two pricing norms have emerged in recent long-term Pacific Basin deals

Conventional LNG

- Most recent deals are understood to have been priced at 14.85% JCC, with additional deals for pre-FID projects being negotiated at the same level
- Qatar is now also understood to be willing to accept 14.85% JCC as a price from 'established' Asian buyers
- Some evidence that buyers are seeking high s-curves in new deals in light of the current high oil price outlook

Coalbed Methane (CBM) LNG

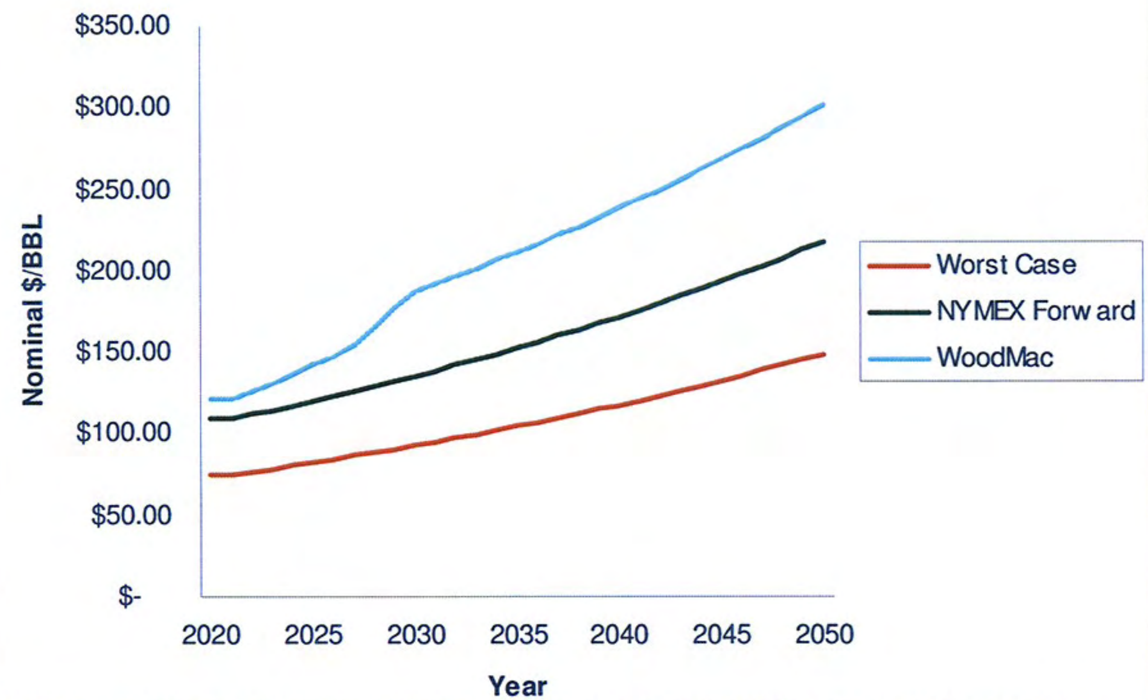
- Recent deals are understood to feature s-curves, reflecting the fact that CBM LNG is a harder sale than conventional LNG
  - Primary slope of ~14.5% JCC between the kink points
  - Slopes of ~12% above and below the kink-points
- Market rumours indicate that APLNG has gone beneath these levels
  - But exact pricing terms remain uncertain
- Lower (s-curve) prices, combined with non-price concessions (see next slide) are essential in order to sell CBM LNG into a market with limited appetite for the product

Oil indexation will technically remain the standard in long-term gas contracting but additional mechanisms will be required to ensure that pricing remains within the relevant pricing boundaries

We evaluated Alaskan LNG export economics based upon two primary long-term crude oil pricing scenarios

- The extended forward NYMEX strip from July 5, 2011 is treated as a base case
- Combining the NYMEX strip scenario with a second scenario utilizing Woodmac's April 2011 NAGS price outlook, we establish the range of likely NPVs
- In a final test, we evaluated a "worst case" scenario of an inflation adjusted oil price of $75 / bbl throughout the projection period
- Oil prices and oil price scenarios are viewed as fully disconnected from North American natural gas prices

WTI Oil Nominal Prices

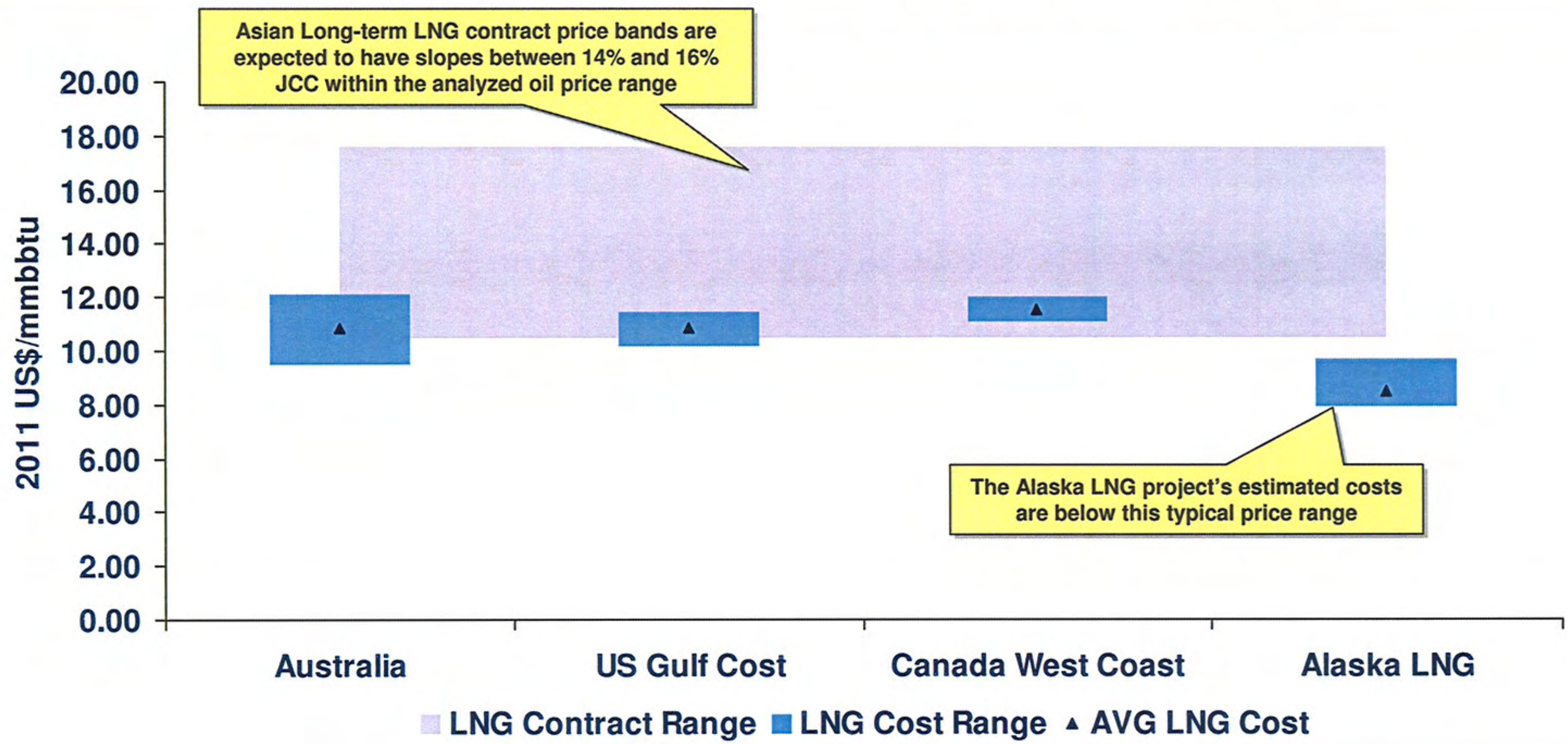


NYMEX forward strip data from July 5, 2011; Woodmac data from April 2011 NAGS outlook; all prices nominal

Source: CME.COM and Wood Mackenzie

The Alaska LNG export project's estimated cost is below typical LNG contract prices…

Range of LNG Costs Delivered to Asia vs. Typical Contract Price Range



Players who win LNG contracts first win the race to FID

...The NYMEX strip scenario (base case) yields annual tax and royalty revenues of $2 to 16 billion to the state, for a total of $220 billion over the 30-year life of the project*

- Model at right depicts the NYMEX strip base case utilizing Woodmac's 2.4% inflation rate beyond NYMEX projected years.
- Producer net income of $178 billion

Model	2021	2022	2023	2024	2025
Nominal WTI oil price	$ 109.56	$ 112.19	$ 114.88	$ 117.64	$ 120.46
Asia DES Price	16.86	17.26	17.68	18.10	18.54
Less Infl adj. Shipping Rate / MMBtu	0.59	0.60	0.62	0.63	0.65
Less Pipe Transportation (will not vary significantly)	4.18	4.18	4.18	4.18	4.18
Less Liquefaction	4.00	4.00	4.00	4.00	4.00
= Wellhead Net Back Value / MMBtu	8.09	8.48	8.88	9.29	9.71
Daily production in millions of MMBtu	2.7	2.7	2.7	2.7	2.7
Annual production in millions of MMBtu	986	986	986	986	986
Taxes and Royalties					
Alaska 12.5% share of production in MMBtu	123	123	123	123	123
Alaska royalty = 12.5% share * Netback Value	997	1,045	1,094	1,145	1,196
Remaining gas Taxable under ACES in MMBtu	862	862	862	862	862
Tax Rate to $5 / MMBtu	0.25	0.25	0.25	0.25	0.25
Tax Rate between $5 and 15.42 / MMBtu	0.324	0.334	0.343	0.353	0.363
Tax Rate beyond 15.42 / MMBtu	0.324	0.334	0.343	0.353	0.363
Total ACES Taxes	2,263	2,440	2,629	2,829	3,041
Total Royalties and Taxes	**2,386**	**2,564**	**2,752**	**2,952**	**3,164**
Sum of Royalties and Taxes	**220,101**				
Period (years from 2011)	10	11	12	13	14
Discount Factor	0.61	0.58	0.56	0.53	0.51
PV of Taxes and Royalties ($MMs)	1,465	1,499	1,532	1,565	1,598
NPV Taxes and Royalties 2021 - 2050 ($MMs)	$ 65,021				
Producer					
Revenues = 87.5% share * netback value ($MMs)	6,979	7,315	7,660	8,013	8,375
Less ACES Taxes	2,263	2,440	2,629	2,829	3,041
Post-tax netback to producer	4,716	4,875	5,031	5,184	5,334
Sum Producer Netback	**178,278**				
Period	10	11	12	13	14
Discount Factor	0.39	0.35	0.32	0.29	0.26
PV	1,818	1,709	1,603	1,502	1,405
Producer NPV 2021 - 2050 ($MMs)	$ 22,576				

Players who win LNG contracts first win the race to FID

Wood Mackenzie

*NYMEX strip to 2018 then 2.4% inflation;14.85% indexation, avg. recourse rate $4.18 assumed to be flat (annual increases in operational costs would be incrementally small). Model uses nominal figures and nominal discount rate. Assuming 5% nominal discount rate, NPV of taxes and royalties amounts to $65 billion.

...The Woodmac scenario yields annual tax and royalty revenues of $3 to 24 billion to the state, for a total of $419 billion over the 30-year life of the project*

- Model at right depicts the Woodmac scenario, which uses the NAGS April 2011 oil price forecast through 2030, followed by the 2030 price projected to 2050 using Woodmac's long-term inflation rate of 2.4% (oil prices shown in nominal terms)
- Producer net income of $187 billion

Model	2021	2022	2023	2024	2025
Nominal WTI oil price	$ 121.97	$ 125.75	$ 130.99	$ 136.40	$ 141.96
Asia DES Price	18.70	19.28	20.07	20.89	21.73
Less Infl adj. Shipping Rate / MMBtu	0.59	0.60	0.62	0.63	0.65
Less Pipe Transportation (will not vary significantly)	4.18	4.18	4.18	4.18	4.18
Less Liquefaction	4.00	4.00	4.00	4.00	4.00
= Wellhead Net Back Value / MMBtu	9.93	10.49	11.27	12.08	12.90
Daily production in millions of MMBtu	2.7	2.7	2.7	2.7	2.7
Annual production in millions of MMBtu	986	986	986	986	986
Taxes and Royalties					
Alaska 12.5% share of production in MMBtu	123	123	123	123	123
Alaska royalty = 12.5% share * Netback Value	1,224	1,293	1,389	1,488	1,589
Remaining gas Taxable under ACES in MMBtu	862	862	862	862	862
Tax Rate if below $5 / MMBtu	0.25	0.25	0.25	0.25	0.25
Tax Rate if between $5 and 15.42 / MMBtu	0.368	0.382	0.401	0.420	0.440
Tax Rate if beyond 15.42 / MMBtu	0.368	0.382	0.401	0.420	0.440
Total ACES Taxes	3,155	3,455	3,893	4,371	4,891
Total Royalties and Taxes	**3,278**	**3,579**	**4,016**	**4,495**	**5,014**
Sum of Royalties and Taxes	**419,101**				
Period (years from 2011)	10	11	12	13	14
Discount Factor	0.61	0.58	0.56	0.53	0.51
PV of Taxes and Royalties ($MMs)	2,013	2,092	2,236	2,384	2,532
NPV Taxes and Royalties 2021 - 2050 ($MMs)	$ 124,030				
Producer					
Revenues = 87.5% share * netback value ($MMs)	8,565	9,049	9,720	10,413	11,125
Less ACES Taxes	3,155	3,455	3,893	4,371	4,891
Post-tax netback to producer	5,410	5,594	5,827	6,041	6,234
Sum Producer Netback	**187,551**				
Period	10	11	12	13	14
Discount Factor	0.39	0.35	0.32	0.29	0.26
PV	2,086	1,961	1,857	1,750	1,642
Producer NPV 2021 - 2050 ($MMs)	$ 24,126				

Players who win LNG contracts first win the race to FID

*WM NAGS price outlook to 2030 then 2.4% inflation; 14.85% indexation, avg. recourse rate $4.18 assumed to be flat (annual increases in operational costs would be incrementally small). Model uses nominal figures and nominal discount rate. Assuming 5% nominal discount rate, NPV of taxes and royalties amounts to $124 billion.

...The "worst case" scenario yields annual tax and royalty revenues of $0.4 to 6 billion to the state, for a total of $75 billion over the 30-year life of the project*

- Model at right depicts the "worst case scenario in which prices are held flat at an inflation adjusted price of $75/bbl
- Producer net income of $131 billion

Model	2021	2022	2023	2024	2025
Nominal WTI oil price	$ 75.00	$ 76.80	$ 78.64	$ 80.53	$ 82.46
Asia DES Price	10.34	12.01	12.30	12.59	12.89
Less Infl adj. Shipping Rate / MMBtu	0.59	0.60	0.62	0.63	0.65
Less Pipe Transportation (will not vary significantly)	4.18	4.18	4.18	4.18	4.18
Less Liquefaction	4.00	4.00	4.00	4.00	4.00
= Wellhead Net Back Value / MMBtu	1.57	3.23	3.50	3.78	4.07
Daily production in millions of MMBtu	2.7	2.7	2.7	2.7	2.7
Annual production in millions of MMBtu	986	986	986	986	986
Taxes and Royalties					
Alaska 12.5% share of production in MMBtu	123	123	123	123	123
Alaska royalty = 12.5% share * Netback Value	194	398	431	466	501
Remaining gas Taxable under ACES in MMBtu	862	862	862	862	862
Tax Rate to $5 / MMBtu	0.25	0.25	0.25	0.25	0.25
Tax Rate between $5 and 15.42 / MMBtu	0.168	0.207	0.214	0.221	0.228
Tax Rate beyond 15.42 / MMBtu	0.168	0.207	0.214	0.221	0.228
Total ACES Taxes	228	577	646	720	799
Total Royalties and Taxes	**351**	**701**	**769**	**843**	**922**
Sum of Royalties and Taxes	**74,939**				
Period (years from 2011)	10	11	12	13	14
Discount Factor	0.61	0.58	0.56	0.53	0.51
PV of Taxes and Royalties ($MMs)	215	410	428	447	466
NPV Taxes and Royalties 2021 - 2050 ($MMs)	$ 21,617				
Producer					
Revenues = 87.5% share * netback value ($MMs)	1,357	2,784	3,020	3,261	3,509
Less ACES Taxes	228	577	646	720	799
Post-tax netback to producer	1,129	2,206	2,373	2,541	2,710
Sum Producer Netback	**131,018**				
Period	10	11	12	13	14
Discount Factor	0.39	0.35	0.32	0.29	0.26
PV	435	773	756	736	714
Producer NPV 2021 - 2050 ($MMs)	$ 13,217				

Players who win LNG contracts first win the race to FID

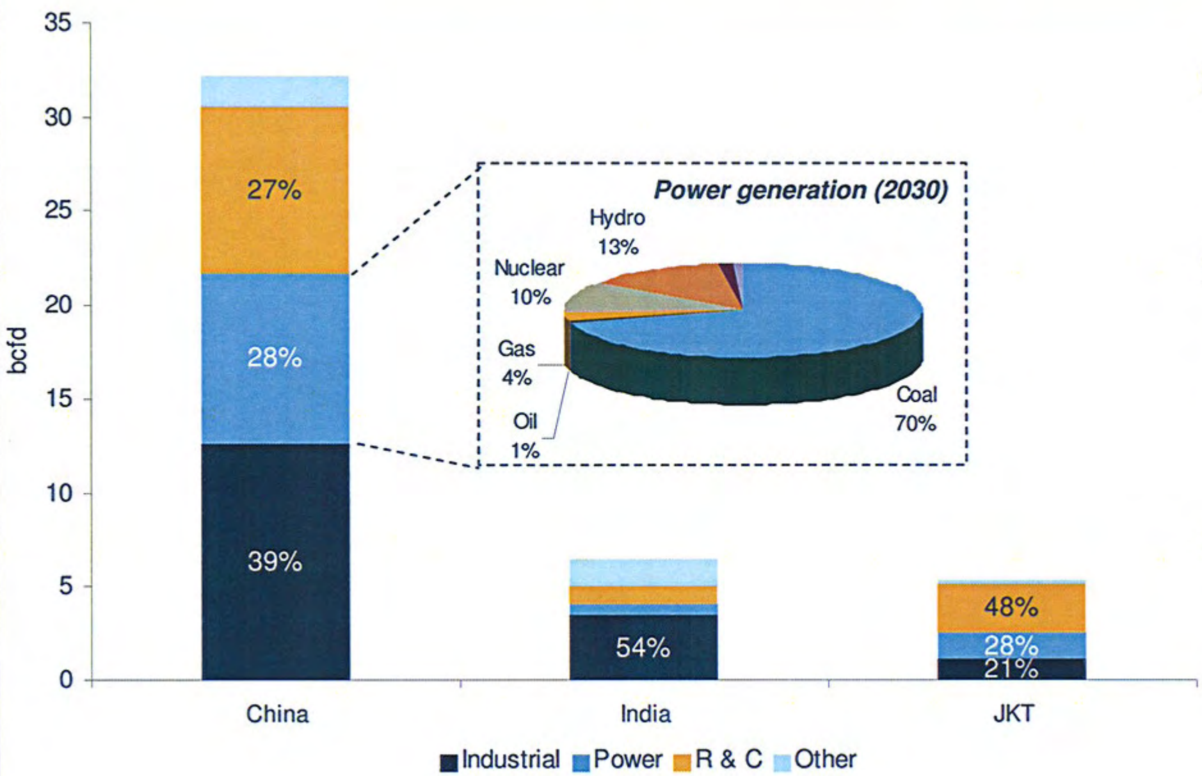
2.4% inflation, 14.85% indexation, avg. recourse rate $4.18 assumed to be flat (annual increases in operational costs would be incrementally small). Model uses nominal figures and nominal discount rate. Assuming 5% nominal discount rate, NPV of taxes and royalties amounts to $22 billion.

Agenda

LNG Pricing Perspectives

Gas price ceilings differ by region – in Asia, the price ceiling is increasingly based on displacing oil products in the R/C/I sectors

Asia gas demand growth 2010 - 2030

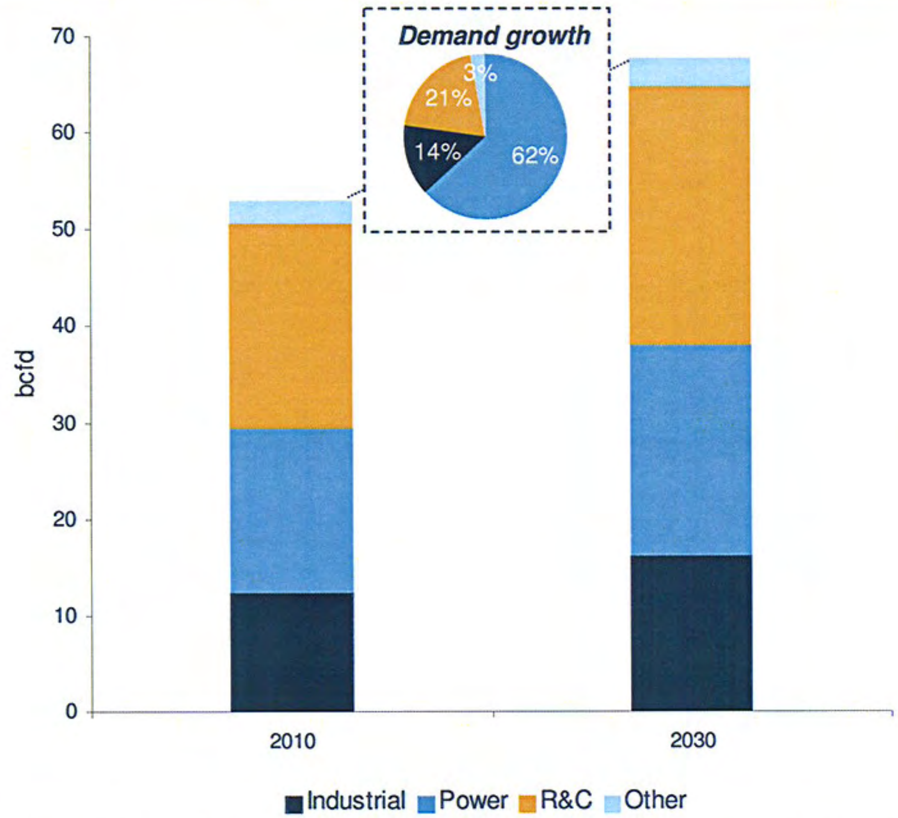


- Historically, the desire for fuel diversity and need for security of supply (primarily in Japan) drove relatively high regional gas prices
- Moving forward, Wood Mackenzie sees oil substitution in the R&C and Industrial sectors in China and India as the primary force behind maintaining premium pricing in the Asian market
- It is however expected that in JKT a premium will continue to be paid for security of supply

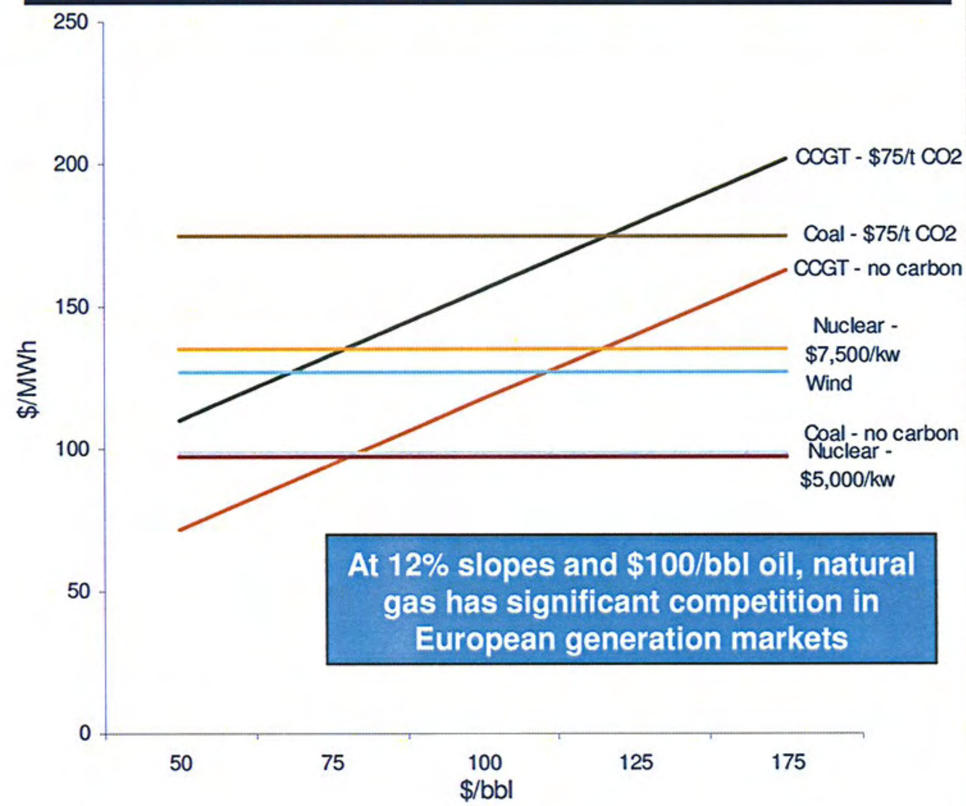
Source: Wood Mackenzie Global Gas Tool, H2 2010

While in Europe the gas price ceiling is "soft" and influenced by the economics of alternative forms of power generation

Europe gas demand



Europe power generation screening curve



At 12% slopes and $100/bbl oil, natural gas has significant competition in European generation markets

Note: 12% discount rate, no taxes, levelized capital cost, Gas fired CCGT: LNG costs at 12% slope plus $0.8/mmbtu combined shipping and regas. $1,200/kw, 25 years useful life. 6,900 Btu/KWh, LHV heat rate, 92.5% utilization, 1135 lbs/MWh of CO2 emissions; Coal: $3,750/kW, 30 years useful life. $4.25/mmbtu delivered, $9,275 btu/kWh heat rate, 92.5% utilization. 2250 lbs/MWh CO2 emissions; Nuclear: 30 years useful life, 92.5% utilization. No subsidies; Wind: $1,800/kw, 20 years useful life, 27.5% utilization, $25/MWh grid access. No subsidies

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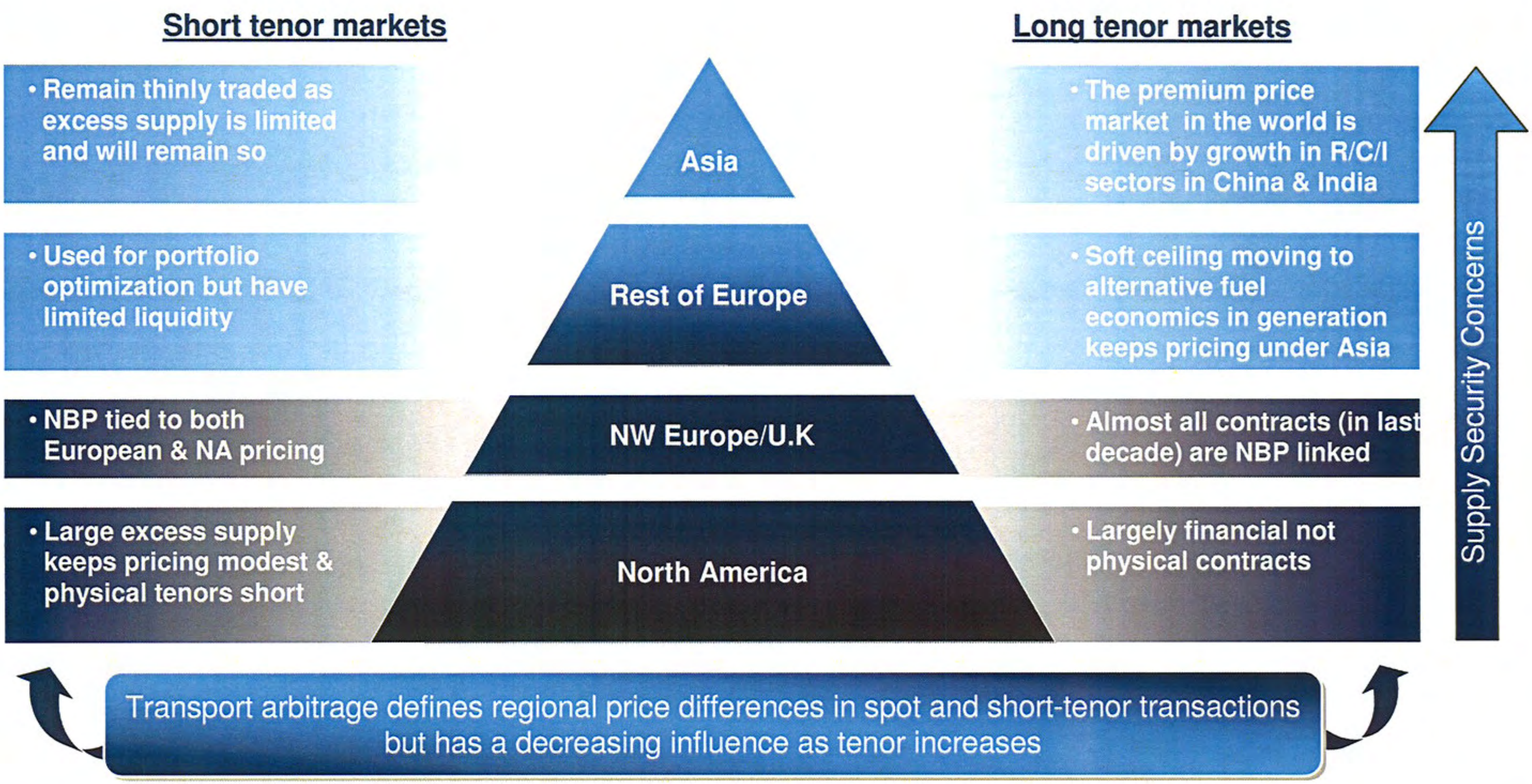
Ultimately the markets develop a relative hierarchy by geography and tenor



Long-tenor gas contracts will remain oil-indexed in geographies that lack liquid, reliable gas indices as an alternative

Requirements for Gas-Indexed Term Deals

- **A reputable index must exist that is deep and difficult, if not impossible, to manipulate; e.g.:**
  - North America (HH et al)
  - The UK (NBP) and NW Europe
  - *Not the Rest of Europe, not Asia*
- **The index must reflect floor and ceiling economics in the market in which it is used; that is, to gain widespread acceptance the index must serve a real economic purpose to buyers and sellers**
  - HH makes obvious sense in NA (just as NBP does in the UK) as the index is related to actual development costs and alternative fuel economics
  - But would there be significant demand for HH-indexed gas in Asia where the floor is oil or fixed price linked and the ceiling is oil linked?

Rationale Behind Oil-Indexed Deals

- **Historical comfort: sellers are largely long oil price risk and don't mind more; sellers have done similar deals for years**
- **Oil indices are deep and solid; manipulation risk is relatively low**
- **Agency risk: no one has ever lost their job for doing an oil-indexed deal. Buyers, particularly certain Asian buyers, do not generally seek innovation in LNG contract pricing terms**
- **For the most part, oil indexation does what it is supposed to do**
  - For buyers with oil product alternatives, oil indexation at slopes less than oil-equivalent prices locks in economics

But many of those "oil-indexed" deals will remain so in name only

"Oil indexation" is just the beginning . . .

- **In reality "oil parity" indexation would appear to meet both buyer and seller needs only within a limited range of oil prices**
    - Development costs for LNG in Asia of around \$9-\$10/mmBtu FOB suggest the need for floors around \$60/bbl at 14.85% slopes
    - In Europe, even at more modest slopes (e.g., 12%) as oil prices rise above roughly \$100/bbl other generation sources are increasingly advantaged

. . . but not the end

- **As a result, a variety of mechanisms have and will continue to emerge and evolve to shape the risk profile of the typical "oil indexed" contract; e.g.:**
    - Different slopes or constants
    - S-curves, even extreme examples, that better match the economic market reality of floor costs and ceiling alternative pricing
    - A variety of contract re-openers predicated on certain oil prices or other triggers

Oil indexation will technically remain the standard in long-term gas contracting but additional mechanisms will be required to ensure that pricing remains within the relevant pricing boundaries

Assumptions used in the tax and revenue discount model

Assumptions		
Production	2.7	Bcf/d
Conversion	0.000001	
Shipping	$ 0.59	
Asia DES Price calculated as % of WTI:	14.85%	
Base Case: 14.85% of real 2011 price		
WM Price Case: April 2011 NAGS Price Outlook		
NYMEX Forward Curve Case:		
Transportation Cost Scenarios:		
Low Negotiated	$ 2.25	
High Negotiated	$ 2.92	
Low Recourse	$ 3.64	
High Recourse	$ 4.72	
Average Recourse	$ 4.18	
Liquefaction	$ 4.00	
Base Royalty on Net Back Value	12.5%	
Taxable under ACES Law	87.5%	
Base ACES Royalty	25%	
Incremental tax for each $ beyond 5	2.4%	
Incremental tax for each $ beyond 50% tax	0.6%	
State of Alaska Nominal Discount Rate	5%	
WoodMac LT Inflation Rate Forecast	2.4%	
Producer Nominal Discount Rate	10%	

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Energy Security Initiative
at BROOKINGS

Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas

Charles Ebinger
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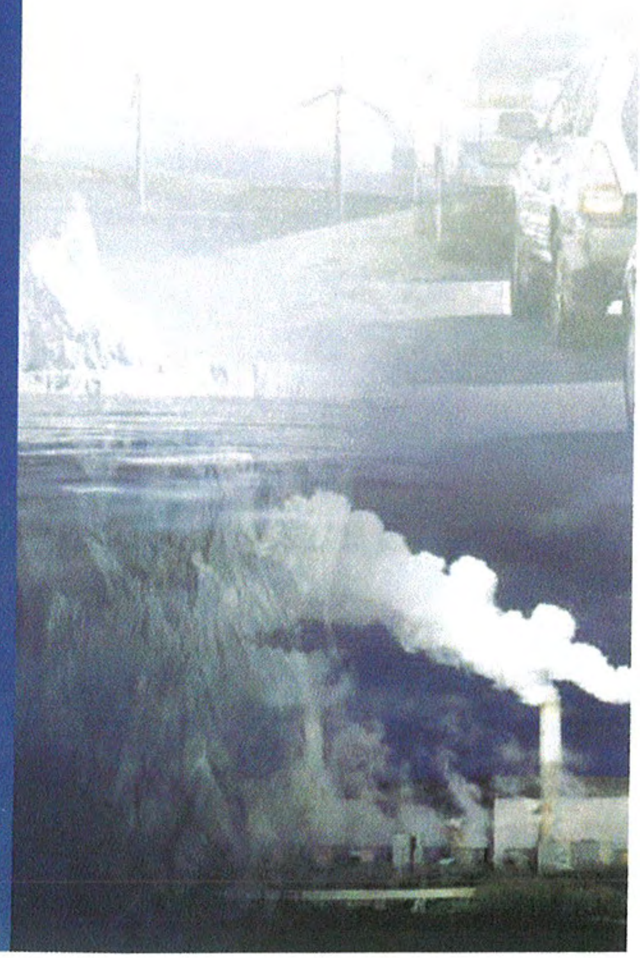

MAY 2012
Policy Brief 12-01