PRELIMINARY REPORT ON FISCAL DESIGNS
FOR THE DEVELOPMENT OF ALASKA NATURAL GAS

BY
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For

State of Alaska
Legislative Budget & Audit Committee

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Section 2.1

A review of worldwide natural gas markets and their supplies

2.1 A Review of worldwide natural gas markets and their supplies

Prior to considering fiscal regimes in specific countries it is important to recognise the worldwide context in which natural gas is supplied and consumed and how Alaska and North America as a whole fits into that scheme. Figure 2.1.1 illustrates the global scheme of major international gas supply and demand.

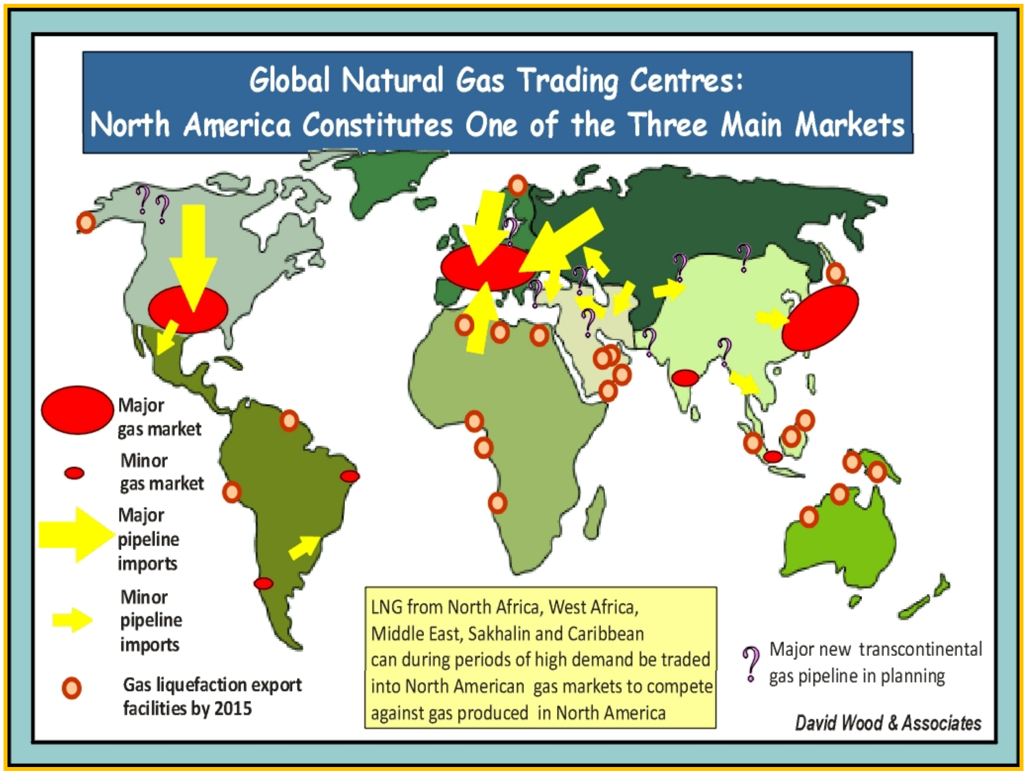


Figure 2.1.1 Global natural gas markets and locations of international supply.

What is clear is that there are three main import markets for natural gas: Europe, East Asia and North America. All three are in the Northern Hemisphere, with the main consumers being OECD nations. Seasonal demand for natural gas in global terms is skewed therefore towards the Northern Hemisphere winter. In addition to the three main markets there are emerging natural gas import markets in developing nations, most notably China, India and Brazil, all with substantial potential and expectation to increase gas imports in the coming decades. Several small-volume niche markets for natural gas imports (e.g. island nations, Chile and Thailand) are also developing, but will not be addressed further here.

Figures 2.1.2 and 2.1.3, based upon U.S. government and International Energy Agency's (IEA) data (IEA, 2007a and b), illustrate how natural gas imports by OECD nations in total have grown rapidly in the past 30 years, but growth in North America natural gas imports during that period has been quite limited. These figures also illustrate how gas imports are expected to grow to 2015 (investments already advanced to achieve this) and to 2030 (more speculative forecasts based on expected growth in energy demand and assumptions regarding costs and prices of competing fuels).

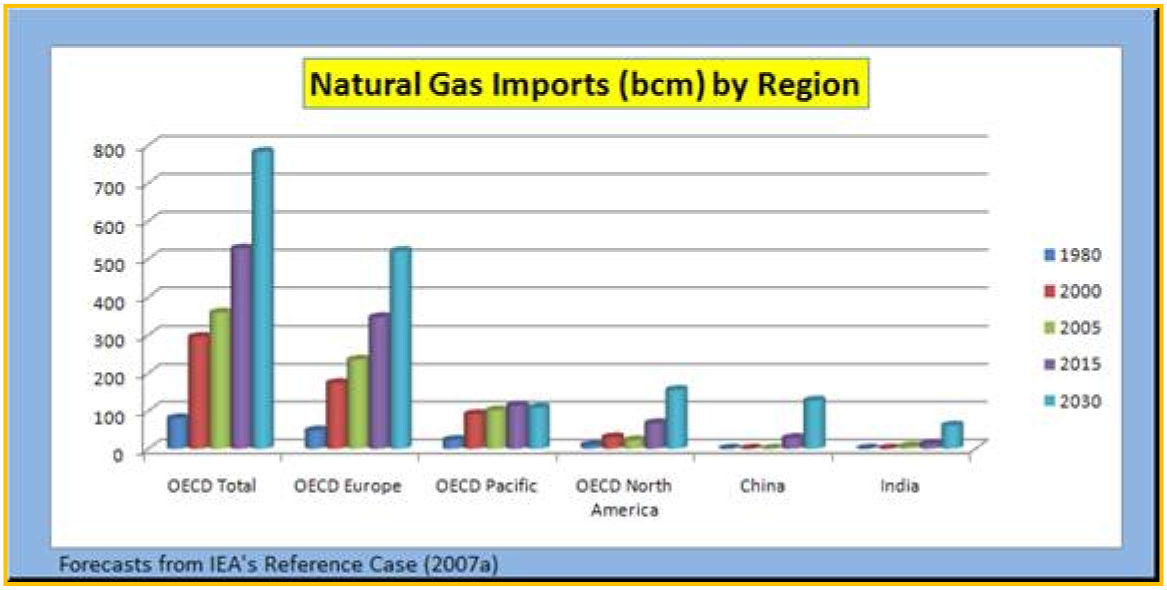


Figure 2.1.2 How key gas import markets compare and are forecast to grow in absolute (billions cubic metres-bcm. Note 35.3 bcf = 1 bcm) terms (IEA, 2007a).

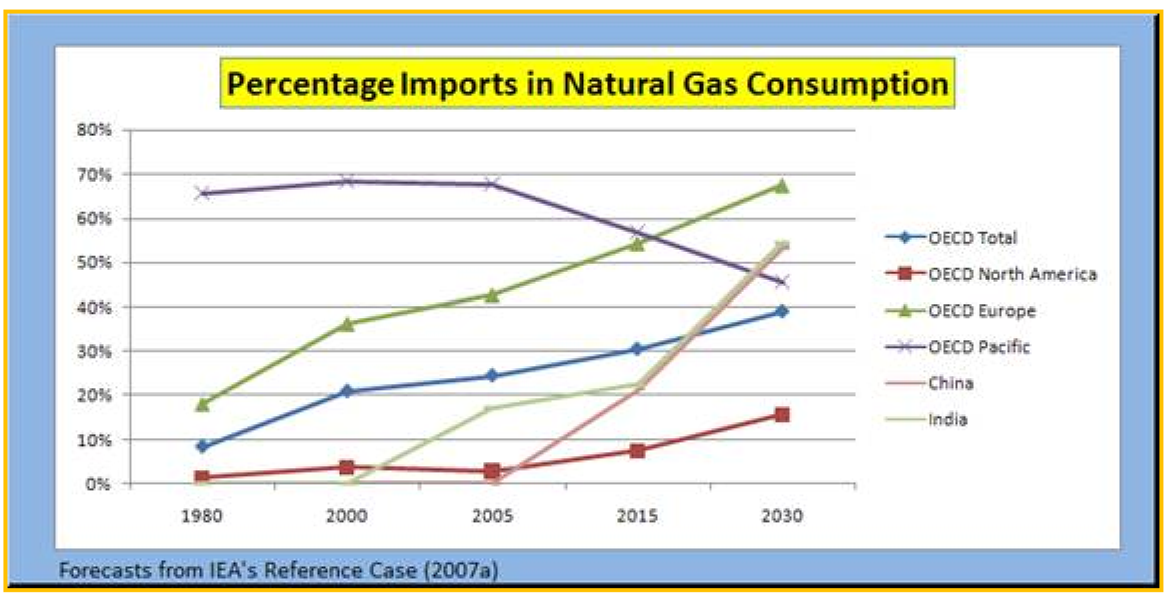


Figure 2.1.3. How key gas import markets are forecast to grow in percentage terms (IEA, 2007a).

The forecasts show natural gas imports continuing to grow rapidly and dominating supply in OECD Europe, but also to grow more rapidly in North America, exceeding 10% of gas consumed by 2020. This forecast indicates that Alaska gas will therefore be competing in price and volume terms with both domestic U.S. Lower 48 and Canada's conventional and non-conventional gas (coal-bed methane and shale gas) and imported gas in the form of LNG.

All the major gas import markets are set to increase their dependence on imports, with Europe approaching 70% and total OECD approaching 40% of import dependency by 2030. What is particularly striking is how rapidly imports are set to grow, both in absolute and percentage terms, in Europe, China and India. The IEA's definition of OECD Pacific (Figure 1.1.3) rather clouds the OECD Asian demand picture. OECD Pacific includes Australia, a major and growing gas exporter, which offsets the strong forecast growths for natural gas imports by OECD Asia's main consumers, Japan and South Korea, countries with almost no conventional natural gas resources or production that are almost totally dependent on imports for their gas supply. Japan, South Korea and China's appetite for more gas has been responsible for substantial increases in international gas prices since mid-2007.

Tens of billions of dollars are being sunk into capital infrastructure projects focused on expanding and developing new gas supply chains to the three main regional gas import markets. Both pipeline and LNG projects are attracting substantial investments, with LNG capacity growing more rapidly. LNG represents a little less than 30% of the internationally traded gas market and is expected to increase to some 35% over the course of the next decade. It is, however, the geographic diversity of the LNG projects, the number of new country entrants, both in liquefaction (suppliers) and as LNG importers (consumers), and the expanding role of short-term LNG trading which constitutes between 10% and 15% of the LNG trade that is revolutionizing the international gas business. LNG worldwide production capacity is expected to grow from 240 bcm in 2005 to 360 bcm in 2010 and to 470 bcm (possibly 600 bcm) in 2015 (IEA, 2007b).

Returning to Figure 2.1.1, it is Europe that has the most competition in terms of gas supply, with the traditional large gas pipeline suppliers Russia, Algeria and Norway (which by much of western Europe is considered as an importer to Europe as it is not part of the European Union) and an increasingly diverse range of LNG suppliers dominated by Algeria, Nigeria, Egypt and Trinidad. Supply from traditional indigenous producers, particularly the UK and Netherlands, is in decline, whereas demand for gas is increasing. There is considerable head-to-head competition between LNG and pipeline suppliers, but still most gas is traded on long-term contracts with prices indexed to crude oil (and/or fuel oil and distillate (gas oil) products). Projects moving gas from the Caspian region and ultimately the Middle East are being discussed (e.g. Nabucco and South Stream gas pipeline projects), but they are mired in geopolitics and manoeuvring by Russia to control (restrict?) the flow of competing supplies into the European market that it currently dominates. New LNG supply projects, diversifying suppliers and increasing confidence in long-term security of supply with less dependence on Russian gas is the strategic focus of the key EU gas markets.

Contrast Europe's position with the Asian gas markets where there is very little gas imported by pipelines and almost all gas is sold under medium and long-term LNG contracts with prices indexed to crude oil (The Japanese Crude Cocktail (JCC) dominates the oil benchmarks used for indexing, not those used for spot and futures trading by much of the world such as West Texas Intermediate (WTI) and Brent crude oil benchmarks). These contracts have traditionally been robust from the gas supplier's perspective with take-or-pay provisions for some 90% of the contract volumes and floor gas prices that have exceeded the breakeven cost of supply. Major new gas pipeline export projects under construction are focused on China from Russia, Kazakhstan (and other Central Asian Republics) and Burma. These may in time be extended to Japan and South Korea, but China is seen as the market with greatest capacity and demand for large volumes of pipeline gas. The main suppliers of LNG to Asia are Indonesia, Malaysia, Australia, Qatar, Brunei, Oman and UAE. Alaska is one of several smaller LNG exporters to Japan (i.e., 61 bcf in 2006 and 47 bcf in 2007). Nigeria has exported more short-term cargoes to Asia in the last two years. Yemen, with an LNG plant in the final stages of construction, will soon be added to this list and one day Iran can also be expected to become a major exporter of gas to Asia (most probably to India and China).

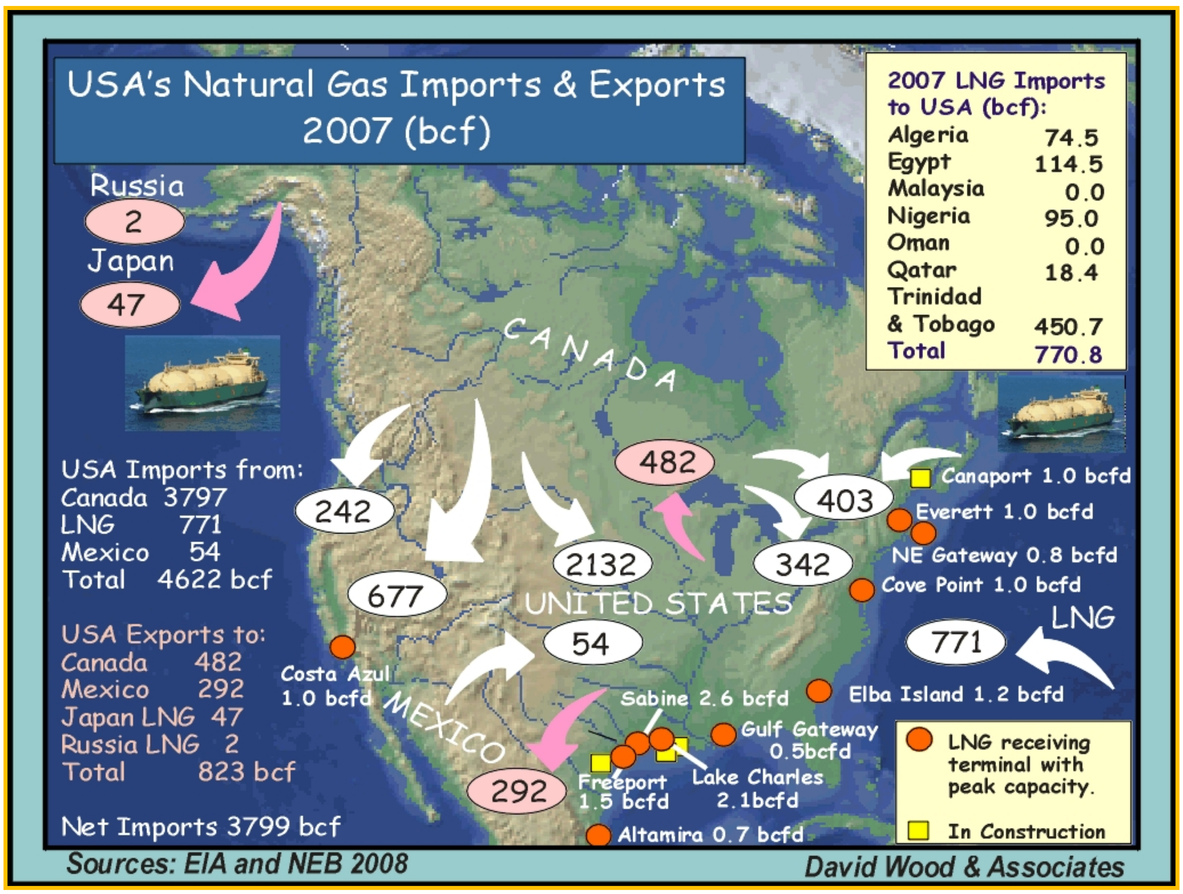


Figure 2.1.4 USA's natural gas import and exports for 2007 (Wood, Jan 2007 Petroleum Review, updated 2008). Note the 2 bcf sale from Alaska to Russia was a one-off spot sale to the Sakhalin facility for commissioning purposes in October 2007.

Contrast the European and Asian markets with the North American natural gas market on the basis of recent gas movements illustrated in Figure 2.1.4. In 2006 North America imported some 585 bcf of LNG compared to Japan's 2,890 bcf of LNG imports for that period. Some 65% of the U.S. LNG imports in 2006 came from Trinidad and Tobago (383 bcf) with Egypt, Nigeria and Algeria contributing the remaining volumes. LNG imports to the U.S. remained close to that level during 2007. However, during 2008 LNG imports to U.S. have slumped (Figure 2.1.5), partly due to high international prices caused by strong Asian demand and partly by domestic supply managing with the aid of new Gulf of Mexico and shale gas projects to meet more U.S. demand. Indeed many cargoes destined for U.S. regasification terminals have, because of contract flexibility, been redirected to the higher priced Asian and European markets

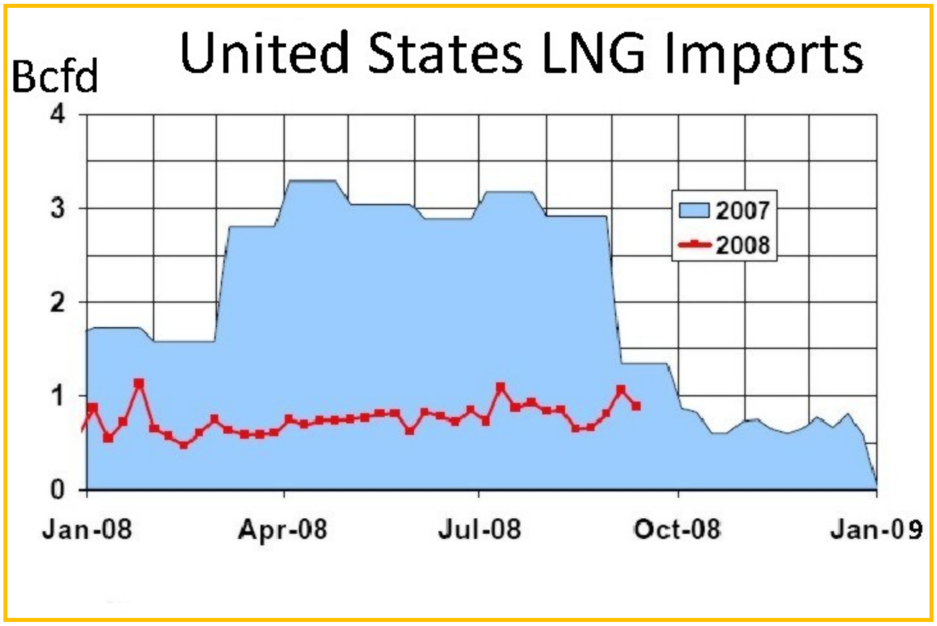


Figure 2.1.5 LNG imports to U.S. 2007 and 2008 compared. How much LNG comes to U.S. depends on price and alternative domestic U.S. gas supply costs, international LNG demand and price. If U.S. needs more LNG to meet future demand this could force U.S. gas prices higher depending on prevailing European and Asian LNG prices. Data source: EIA.

Some significant factors distinguish the U.S. Lower 48 gas market from other major international gas import markets:

1) Though isolated from overseas gas suppliers by two oceans, the U.S. has extensive cross-border pipelines connecting the Lower 48 states with Canada and Mexico. It could be reached by pipeline from Alaska (via Canada) but at substantial cost and, because of the time required to plan and build the required upstream and midstream facilities, that will not happen until after 2018.
2) Substantial volumes of natural gas have in the past three decades been imported to U.S. Lower 48 from Canada by pipelines, but Canadian gas import volumes are expected to decline in the short to medium term, partly because of dwindling reserves, but also because of greater domestic Canadian demand for gas yet to be developed (e.g. Mackenzie Delta) to serve energy and upgrading requirements in the tar sand and bitumen industries.

3) Natural gas is traded predominantly on a short-term basis indexed to spot benchmark gas prices (Henry Hub). Apart from the U.K. where much gas is also traded on a short-term basis indexed to spot gas, the vast majority of the gas traded internationally is sold on a long-term basis indexed to oil and oil products. Long-term contracts will certainly be crucial in financing the Alaska gas line, but once it is financed through long-term contracts, third-party access (TPA) to the line's incremental or spare capacity is likely to involve short-term, medium-term and long-term gas sales agreements. It is important that Alaska's fiscal design is flexible enough to enable all such contracts to function and provide appropriate fiscal revenues.
4) LNG / gas import facilities are not ideally located with respect to the main consuming markets of the Northeast Seaboard, Midwest and California markets. Much existing and additional LNG import capacity being built is located in the south and Gulf of Mexico requiring significant onward transport to the consuming markets.
5) The main consuming markets, notably California, are reluctant on environmental grounds to sanction new LNG import facilities within their markets. To overcome this LNG import facilities have and are being built in Mexico and Canada with a view to exporting some the gas received into the US.
6) Many in the U.S. (gas suppliers and consumers) are convinced that through investment in non-conventional gas supplies (coal-bed methane, shale gas) plus expensive deepwater field developments in the Gulf of Mexico and the Alaska gas pipeline, the capacity requirements for imported liquefied gas can be minimized over the coming decades. They believe that much of the new LNG import capacity under construction and filed for vastly exceeds gas import demand and much will not be built as it will be unable to secure supply.
7) Trinidad currently dominates LNG imports to the U.S. because of its closer proximity and lower shipping costs than rival LNG suppliers. New LNG supply chains recently commissioned (Egypt, Norway, Equatorial Guinea) and others in development, notably from Qatar, Russia (Sakhalin via Mexico), Indonesia (via Mexico), Angola, Libya, Peru and expansions in Nigeria and Algeria will compete to supply the substantial new LNG import capacity coming onstream in USA (Figure 2.1.6) prior to the 2018(*) to 2030 period when an Alaskan gas pipeline may be entering the gas market.

   (*) Note: the weight of testimony before the Alaska Legislature in mid-2008 suggested that a 2018 start-up date for any Alaska gas pipeline project had become unlikely as TransCanada was unable to conduct a full summer of field work in 2008.

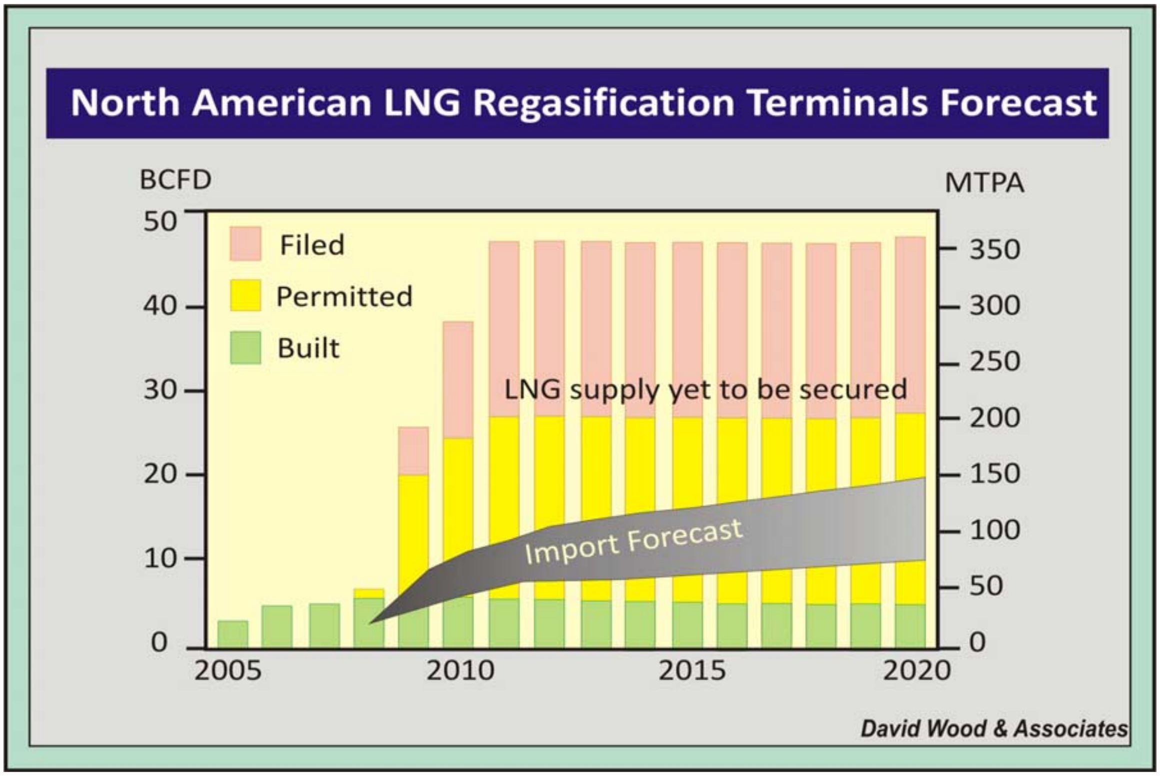


Figure 2.1.6. Forecast of U.S. LNG receiving terminal capacity.

These factors taken together make trading gas long-term into the North American market quite different to trading gas into the other major international gas markets. Access to substantial supplies of LNG at peak U.S. gas demand periods are at times adversely affected by price indexation to Henry Hub prices. In recent years high oil prices have meant that it is more favourable for LNG suppliers to land short-term cargoes in Asia and Europe where higher gas prices have existed. LNG cargoes have tended to move to the U.S. only during the Northern Hemisphere's summer when European and Asian demand and gas prices are low. In summer 2007 short-term LNG was drawn to demand in Japan rather than the US. This indicates that long-term volume contracts are important to secure supply, but many LNG suppliers are concerned about committing to long-term Henry Hub gas prices which have in the past two years been low in global terms.

Although there is clearly competition to Alaska pipeline gas from LNG import suppliers to U.S., those LNG importers also face substantial commercial challenges posed by gas pricing, not ideally located import facilities and high costs of long-distance supply chains. It is the flexibility of LNG suppliers to potentially switch their supplies between markets to capture periodic demand premiums that provide them with some commercial advantage over a gas pipeline supply chain from Alaska to the Lower 48 states that is locked into U.S. gas market and gas price risks. Many of the more-recent LNG contracts have destination flexibility clauses included. These were originally negotiated by buyers wishing to redirect cargoes, but more recently sellers also have recognised there is significant value in having the ability to re-direct some cargoes to higher-priced markets at any given point in time.

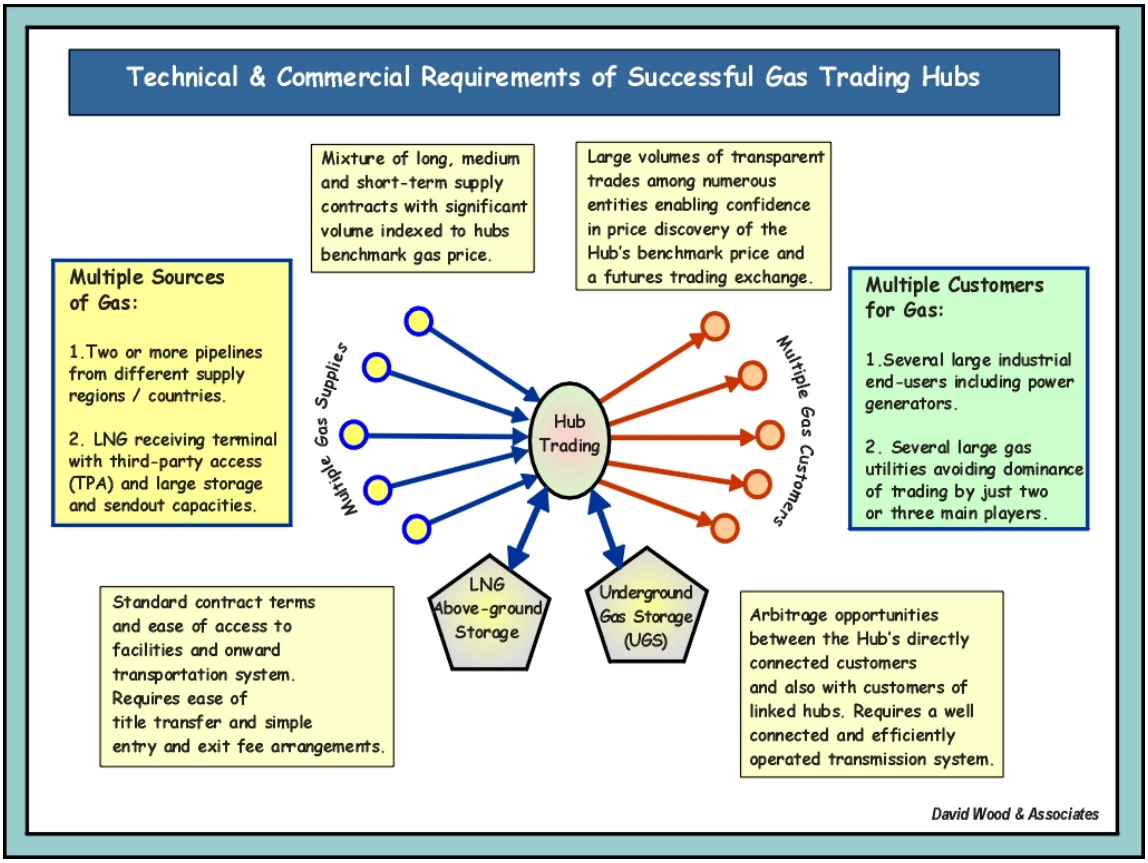


Figure 2.1.7 Key roles for gas hubs in extracting value for equity participant in modern gas import supply chains.

The trading hubs for North Slope gas will not be in Alaska, at least not initially with just one gas pipeline. Probably Alaska gas will feed into hubs in Canada, the northern Midwest states and/or California, which are also connected to competing gas supplies. This will mean that Alaskan gas will have to compete with those other sources of gas. Depending on the delivered costs of Alaskan gas to such hubs some fiscal accommodation may be required from Alaska at some point along that supply chain. For Alaska to become a gas trading hub itself the state or private companies would need to invest in multiple gas field developments, alternative export routes and infrastructure, i.e. LNG, LPG, GTL, petrochemical plants, and or more than one pipeline out of Alaska and probably gas storage along those supply chains. If markets support such large investments the additional infrastructure would introduce increased flexibility and competition, which in turn should open new markets.

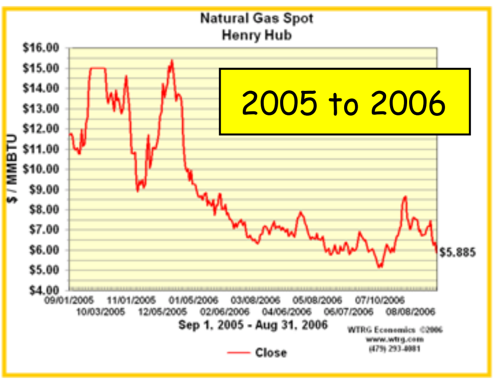
Figure 2.1.7 identifies what is required for a gas import location to become a successful hub. Whereas this study is focused on upstream fiscal design, it should be recognised that how and where an Alaskan gas pipeline interfaces with a Lower 48 gas hub will have a significant impact on the value that can be extracted from upstream suppliers (and the taxation revenues accruing to the State of Alaska) into that market. Alaska needs to consider if it should pursue midstream/downstream equity involvements in some, or any of, (1) the pipeline, (2) infrastructure associated with the AECO gas hub in Canada, and (3) infrastructure at the market end of the gas pipeline in the Lower 48, to which the Alaska gas pipeline should ultimately connect. State equity investment was a controversial point in the 2004-2006 Stranded Gas Development Act discussions and the potential advantages of such involvement require further explanation.

An argument can be made that if the state holds equity interests along the full gas supply chain it will more easily be able to extract value from sales revenues that materialize from commodity transactions along that supply chain. For example, revenues from NGLs extracted and sold at a Canadian hub from Alaska gas sold into that hub as wet (high calorific value) gas may not fully flow back to Alaska. To be clear the higher value of wet gas should be reflected in the royalty valuation and production value, thus benefitting the state, because the higher calorific value of wet gas makes it worth more than dry gas. However, Alaska would, by exporting wet gas, lose out on the profit of the value-added process of extracting and selling ethane and LPG, even though it would capture some additional value from the higher calorific value of moving wet gas rather than dry gas out of state. The value added of extracting the ethane and LPG will stay with the gas treatment plant in Canada (or the Lower-48 states). Similarly gas sold under long-term contract into Canada could result in some gas being placed temporarily by some gas buyers in seasonal storage for subsequent short-term sales into lower-48 states to meet peak (high price) demand. If Alaska's gas producers sell their gas (or the state sells its royalty portions of gas produced) upstream of that sector of the supply chain it will not necessarily be in a position to receive all of those incremental benefits. Such positions along the full supply chain to the Lower 48 states are likely to be taken by the major IOCs producing Alaska gas. The revenue streams that flow back to Alaska may not include the full value for the ethane and LPG contained in that gas.

By being involved in the whole supply chain (even with a very small equity interest) would provide the state with a share of those incremental benefits and a clearer insight to their full potential value. However, such an equity stake would come with the risk of a loss during periods of low demand and prices for ethane and LPG. It may be possible for the State of Alaska fiscally to assess a destination value for ethane and LPG, whether extracted or entrained, of the wet gas sold based upon published benchmark prices (less the cost of extraction) at a gas treatment plant outside Alaska and apply that to wet gas sold along the supply chain from one IOC affiliate to another. However, it will remain difficult to assess full value for the gas and all of its products if a number of third-party transactions are involved in movements to several destination markets.

Some in Alaska believe that LPG should be extracted from North Slope gas in Alaska, and not in Canada, so that it can be shipped around the state to meet local needs rather than establish a larger commercial project shipping those products out of state. Both are technically possible, but commercially it may be easier to find a short-term market for LPG in Canada. A case can be made for fiscal incentives to be granted to LPG extraction facilities to encourage upstream developers of wet gas fields to consider Alaska-based NGL extraction and gas treatment plants. At the current time the economic case for LPG facilities development in Alaska is stronger in the case of building a gas liquefaction (LNG) plant, rather than associated with the initial phase of a gas pipeline. This is because a gas liquefaction plant would be located at a port facility, some adjustment to LPG content of the LNG would be required and that at least some of the LPG could be moved by ship outside Alaska.

The foregoing sets the scene for subsequent discussions on international upstream gas fiscal design. It emphasizes the need for upstream fiscal design to address issues that go far beyond the upstream petroleum province where the gas is reservoired and integrate midstream and market issues specific to the supply chains being developed. Each gas supply region and each international market has its own particular set of issues and challenges to consider. What is clear is that supply chains for gas imports are becoming longer and more expensive and at the same time more diversified in terms of supply. On the other hand, a shortage of international gas in production has become more pressing since 2004 and there is strong competition, which is forecast to intensify in the coming decades, among the three major markets to secure long-term access to gas supplies. The gas price trends in each of the three major international gas markets are dislocated from the other two major markets. Figure 2.1.8 shows spot gas price trends in U.S. for the past three years.



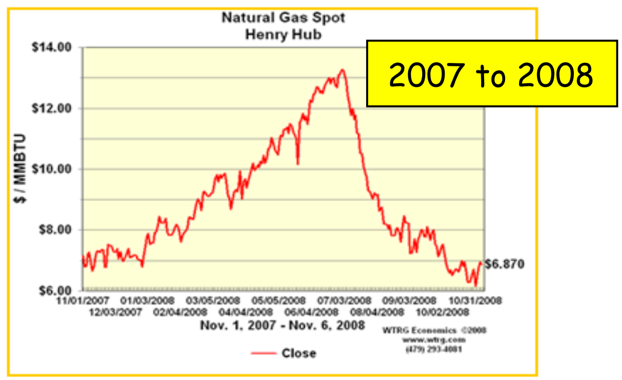


Figure 2.1.8 Recent volatility of U.S. natural gas prices. Note the slightly different vertical on the two graphs, which each show how gas prices might vary over a 12-month period. Data source: www.wtrg.com (NYMEX).

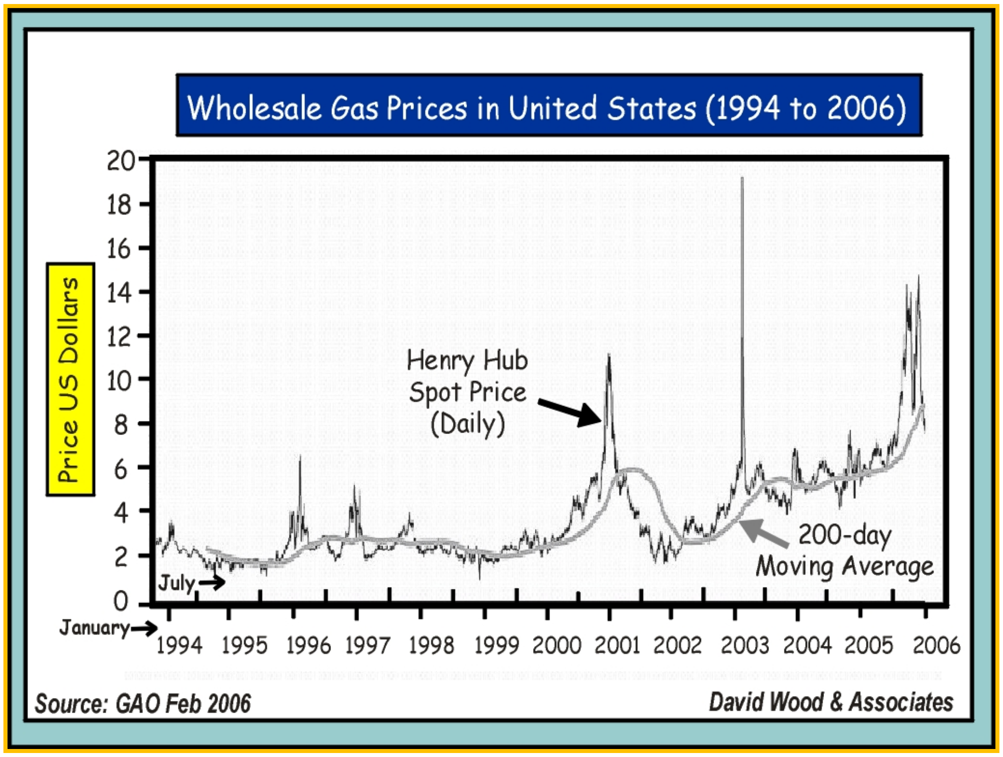


Figure 2.1.9 Volatility of U.S. natural gas prices also has occurred periodically in the past. Indeed the U.S. wellhead gas price spent most of the 1990's at below $2/mmbtu (GAO, 2006).

There is an important role for short-term and medium-term contracts, but long-term contracts remain essential to underpin the large investments required for long-distance supply chains. Take-or-pay provisions in gas sales contracts, minimum or floor prices and price indexation to competing fuels are as important as upstream fiscal terms in establishing commercially viable gas supply chains in most international markets. This has not been the case in the U.S. gas market where prices are linked to shorter-term Henry Hub prices.

The Henry Hub gas price trend from 1994 to 2006 shows sustained low prices during the 1990s with a few minor spikes. Since 2000 there is a trend to increasing price and three major price spikes. The Federal Energy Regulatory Commission (FERC) and the Commodities Futures Trading Commission (CFTC) play key roles in ensuring that natural gas prices are determined in a competitive and informed marketplace. Since the exposure of market manipulation by some companies in the 2000 /2001 gas price crisis in California, both of these agencies monitor natural gas markets and investigate instances of possible market manipulation. The U.S. Government Accountability Office (GAO, Feb 2006) has reported on the price spikes shown in Figure 2.1.9. and indicated ongoing investigations into the price spikes of late 2005:

"Most recently, prices rose sharply following the landfall of two hurricanes in the Gulf region. It appears that the price spike was caused by the unexpected decrease in the supply of natural gas in late 2005 following Hurricanes Katrina and Rita, exacerbated by factors that raised demand.

Because of the damage caused to production, processing, importing, and transporting infrastructure in the Gulf region, wholesale prices climbed to a high of $15 per million BTUs by December 2005. Other factors—such as market manipulation—may also have affected wholesale prices. Our ongoing work examining futures trading in natural gas markets will address this issue later this year."

No subsequent report has yet emerged to support market manipulation.

In short-term deregulated commodity markets during times of short supply market manipulation becomes a temptation to some suppliers long in gas.

Since 2004 it has been a seller's market in the international LNG sector with short-term demand outstripping supply. For those gas exporters and exporting nations able to participate in short-term LNG trading such a situation offers substantial commercial advantages adding short-term opportunities for higher profits to complement their long-term export contracts. High and volatile gas and oil prices have dominated the markets in recent years (Figure 2.1.8). In early June 2008 Henry Hub spot natural gas prices broke through $12/mmbtu. In winter 2007/8 some spot LNG cargoes sold to Japan reached $20/mmbtu. There is no global natural gas price.

The natural gas prices in North America, Europe and Asia are dislocated and driven by a range of distinct but overlapping factors. Figure 2.1.10 displays an influence diagram for natural gas prices in Europe to illustrate this point. Some factors are specifically relevant to European energy markets; others do also impact or are impacted by North American and Asian gas markets.

Although gas prices are currently high worldwide, there is no guarantee that they will remain so over the lifespan of a major gas pipeline export project. Fiscal design for long-term, high-cost upstream investment projects have to consider how best to sustain commerciality during periods of sustained low prices as well as ensuring appropriate distribution of economic rent in periods of very high prices. They have to do by appropriate choice of upstream fiscal instruments, integrated with fiscal returns from midstream infrastructure and the terms and conditions of long-term gas sales agreements. Fiscal designs should not simply rely on an assumed high or low price but essentially focusing on making sure the fiscal system is robust under both extremes, and that a different goal is being catered to at each extreme. Truly progressive fiscal systems work at both ends of the spectrum.

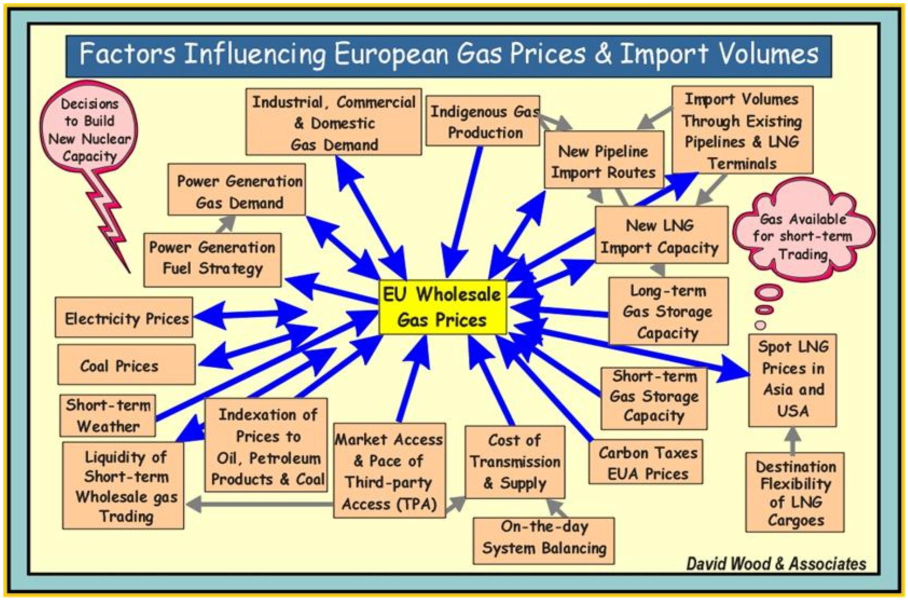


Figure 2.1.10 Factors impacting European gas supply, demand & prices. Only some of these are relevant to North America and require specific fiscal approaches.

Figure 2.1.11 tabulates average gas price trends in several regional markets on an annual basis from 2007 going back to the 1980s in some cases. Also shown for comparison is the average delivered OECD crude oil price in U.S.$/mmbtu.

This information is illustrated graphically in Figure 2.1.12, which shows LNG, crude oil and European gas prices historically pre-2005 tended to track each other, with LNG representing the high point and European Gas the low point of the range in any one year. Such relationships have ceased to be predictable since 2005.

Gas prices have risen steeply in past 6 years but in 2007 significant regional differences emerged. Gas prices have followed oil more closely in 2008 in many areas of the world but not in North America. Historically only during short-term crude oil price spikes has oil price previously exceeded LNG price for sustained periods.

Indicative Gas Prices (US $ / million btu)						
	LNG	Natural gas				Crude oil
Year	Japan cif	European Union cif	UK (Heren Index)	USA (Henry Hub)	Canada (Alberta)	OECD Countries cif
1985	5.23	3.83				4.75
1986	4.10	3.65				2.57
1987	3.35	2.59				3.09
1988	3.34	2.36				2.56
1989	3.28	2.09		1.70		3.01
1990	3.64	2.82		1.64	1.05	3.82
1991	3.99	3.18		1.49	0.89	3.33
1992	3.62	2.76		1.77	0.98	3.19
1993	3.52	2.53		2.12	1.69	2.82
1994	3.18	2.24		1.92	1.45	2.70
1995	3.46	2.37		1.69	0.89	2.96
1996	3.66	2.43	1.87	2.76	1.12	3.54
1997	3.91	2.65	1.96	2.53	1.36	3.29
1998	3.05	2.26	1.86	2.08	1.42	2.16
1999	3.14	1.80	1.58	2.27	2.00	2.98
2000	4.72	3.25	2.71	4.23	3.75	4.83
2001	4.64	4.15	3.17	4.07	3.61	4.08
2002	4.27	3.47	2.37	3.33	2.57	4.17
2003	4.77	4.40	3.33	5.63	4.83	4.89
2004	5.18	4.56	4.46	5.85	5.03	6.27
2005	6.05	6.28	7.38	8.79	7.25	8.74
2006	7.14	8.77	7.87	6.76	5.83	10.66
2007	7.73	8.93	6.01	6.95	6.17	11.95

Note: cif = cost+insurance+freight (average prices).
1 million btu = 10 therms = 293 kWh

Source: BP Statistical Review June 2008 David Wood & Associates

Figure 2.1.11 Indicative historical average annual natural gas prices from around the world compared to crude oil on a US$/boe basis. Data from BP Statistical Review (June, 2008).

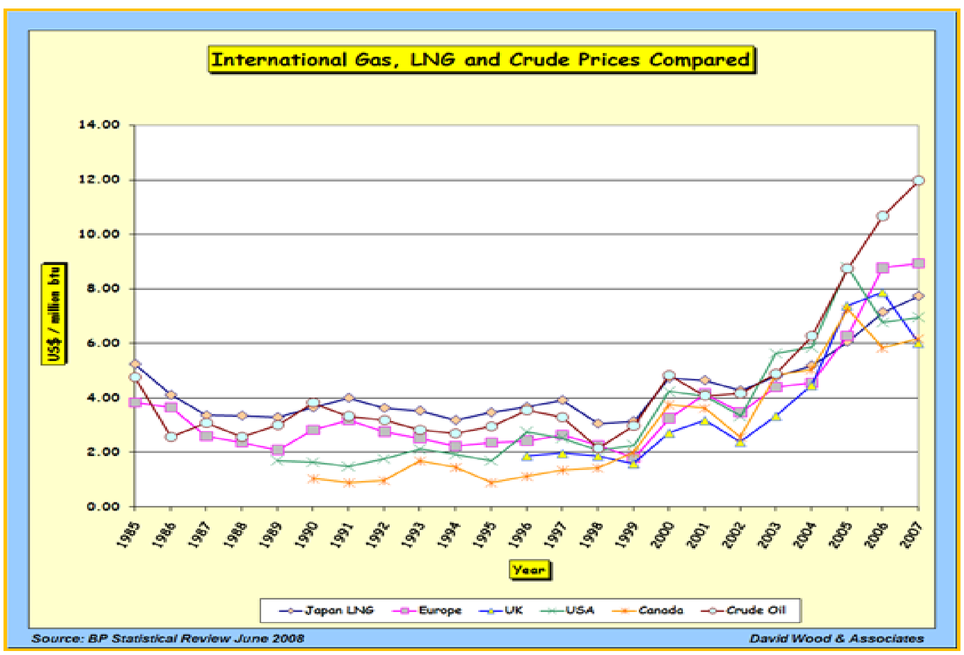


Figure 2.1.12 Indicative historical average annual natural gas prices quoted in Figure 2.1.10 displayed graphically. Data from BP Statistical Review (June, 2008).

Figure 2.1.13 compares regional LNG prices from selected countries in Asia, Europe and North America periodically between 2005 and 2008. These show significant variation, particularly between regions due to different long-term contractual arrangements and in particular different fuel indexation methods. In Asia LNG is indexed to crude oil, in Europe it varies between crude oil, fuel oil and gas oil and the price of pipeline gas supplies, in North America it is primarily indexed to the Henry Hub gas benchmark. Strong demand has kept prices high in most markets since 2006. Prices fell in U.S. and parts of continental Europe in mid-2007, but have risen sharply since, especially in Asia since mid-2007. Much LNG was diverted away from U.S. to Asian and European markets in mid-2008.

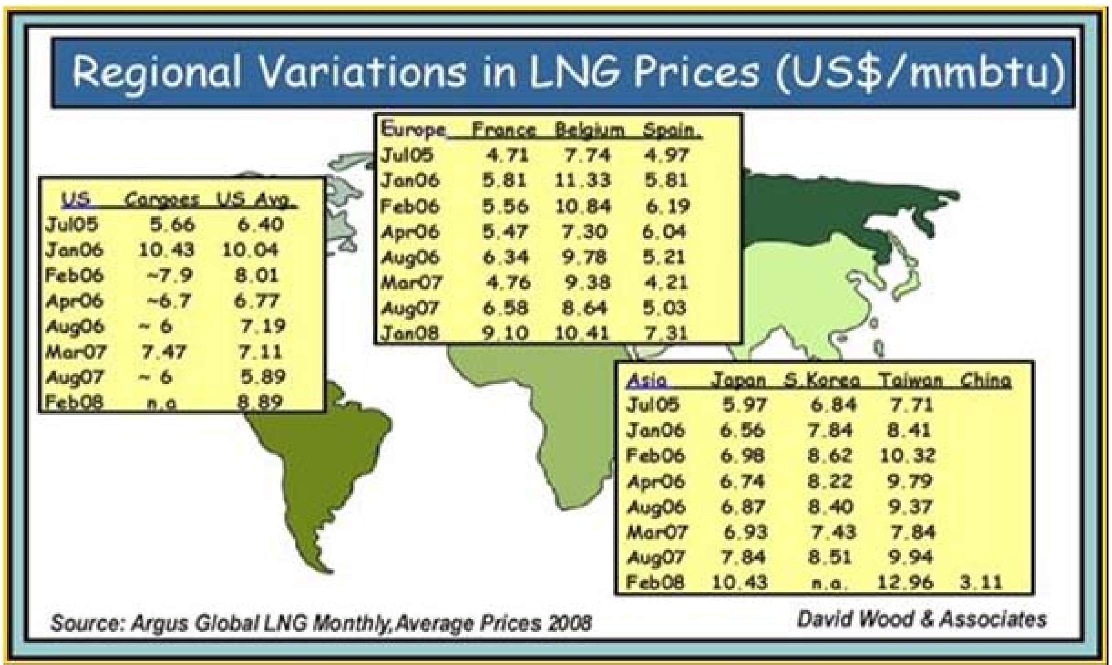


Figure 2.1.13. Regional variations in delivered LNG prices updated from figure included in (Wood, Energy Tribune, December, 2007) Data from Argus Global LNG (2005 to 2008).

The sudden increase in Japan's gas demand in mid-2007 due to nuclear power plant shutdowns coincided with a period of unprecedented high oil prices and a time when several of Japan's long and medium-term LNG supply contracts came up for renewal / price renegotiation. The S-curve price formula that prevailed in Japan's last major round of long-term (i.e., 10-year plus) LNG contract negotiations in 2001 had been successful in protecting it to a large extent from the rapid rise in oil prices over the past four years. Indeed LNG prices imported to Japan had remained significantly lower than crude oil (i.e. some 35% lower) on an energy equivalence basis (see Figure 2.1.13). However, LNG suppliers have been reluctant to renew supplies on such a formula unless the coefficients are adjusted to secure higher gas prices as and when oil prices increase.

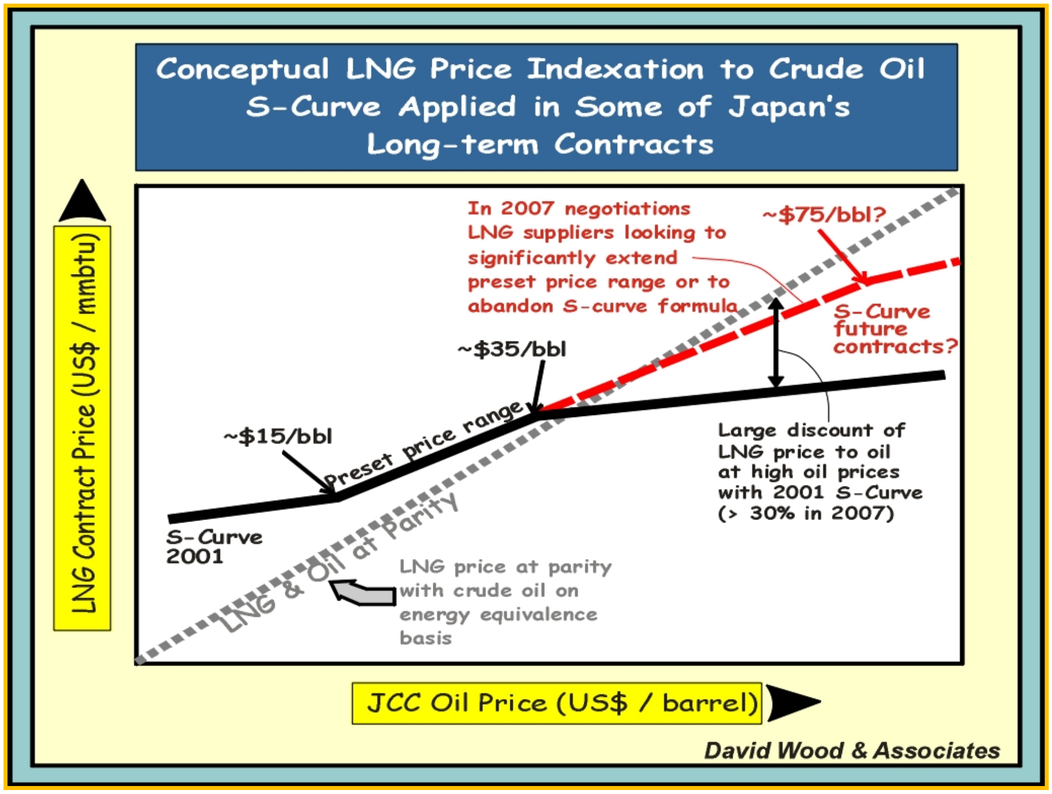


Figure 2.1.14. Changing market conditions have lead in 2007 and 2008 to a dilution of Japan's favoured S-curve LNG price formula that helped to stabilize LNG prices in Japan under some long-term contracts from 2001 to 2007. LNG in 2008 is trading into Asia at close to parity with crude oil prices. Figure from (Wood, Energy Tribune, December, 2007).

Japan's S-curve LNG pricing mechanism is worthy of some consideration as it demonstrates that LNG can be indexed to crude oil prices in a variety of ways and moderated to offset risks for both buyers and sellers. The primary objective of the S-curve mechanism is to limit the impact on LNG prices of extreme oil price fluctuations (Wood, 2007). It has certainly been tried and tested in this regard in the past seven years. The formula is generically defined as

P \$/mmbtu CIF Japan = AX + B + S

Where:
A, B are constant coefficients
X is the crude oil (Japanese Crude Cocktail – JCC – Japan's average oil import CIF price)
S coefficient is added to the price formula to further flatten or dampen the price curve only when the JCC price, which historically has averaged WTI price less about $1/barrel, lies above or below a preset price range, which in 2001 contracts spanned the range of $15 and $ 35 / barrel.

Applying the S-formula established in 2001, LNG prices change linearly in proportion with crude oil prices in preset price ranges – approximately $20/barrel to $40/barrel. That preset range seemed likely to cover all upside oil price eventualities at the time they were negotiated in

2001. If the price of crude oil rises or falls outside that preset range, then the rise or fall in LNG prices is further dampened by the additional “S” coefficient which then becomes effective providing transitional floor and ceiling LNG prices (Figure 2.1.13).

Relating to Japan’s 2001 agreements the price of Qatar LNG sold to Japan was reported to involve a floor price of $3.60/mmbtu CIF-Japan (some $2.50/mmbtu FOB-Ras Laffan) and for the preset price range the “A” coefficient of the formula was 0.1485. The values of the “B” and “S” coefficients and the exact limits of the preset price range have, to the author’s knowledge, not been disclosed. In 2003 China and India managed to secure long-term (5-year plus) LNG contracts on similar formula arrangements with a much lower value of “A” but no “S” term. Such contracts lead to a lower, flatter and more stable price relationship than Japan’s S-curve formula. At the JCC price of $20 / barrel the Guangdong price formula was reported at $3.1/mmbtu CIF, which represents a 20% discount to Japan’s price formula.

In some of the recently renewed term contracts with Australian suppliers, in order to secure supply, Japanese buyers have had to accept LNG prices linked to crude oil prices on an energy-equivalent basis without the dampening effects of the S coefficient. The impact of such changes is likely to result in the average LNG price delivered to Japan (i.e. the average of many contracts signed in different years on different terms) being within 20% of crude oil price on an energy equivalent basis beyond 2010. Japan's import prices paid for LNG cargoes, both long-term and short-term, can therefore be expected to become more volatile in response to oil price movements beyond 2008 (Figure 2.1.14).

The pricing formula and indexation adopted in long-term natural gas sales contracts is clearly crucial in establishing and maintaining commercially viable supply chains in volatile markets.

The EIA Annual Energy Outlook 2008 with Projections to 2030 (June 2008) includes forecasts of U.S. gas production by source, base-case forecasts for LNG imports which are linked to a reference price forecast that shows modest increase in real terms, and alternative possible forecasts for LNG imports depending on natural gas prices (see Figures 2.1.15 to 2.1.18).

In the AEO2008 reference case (EIA, June 2008), Lower 48 wellhead prices for natural gas are projected to decline from current levels to an average of $5.32 per thousand cubic feet (2006 dollars) in 2016, then rise to $6.63 per thousand cubic feet in 2030. Henry Hub spot market prices are projected to decline to $5.82 per million Btu in 2016 and then rise to $7.22 per million Btu in 2030.

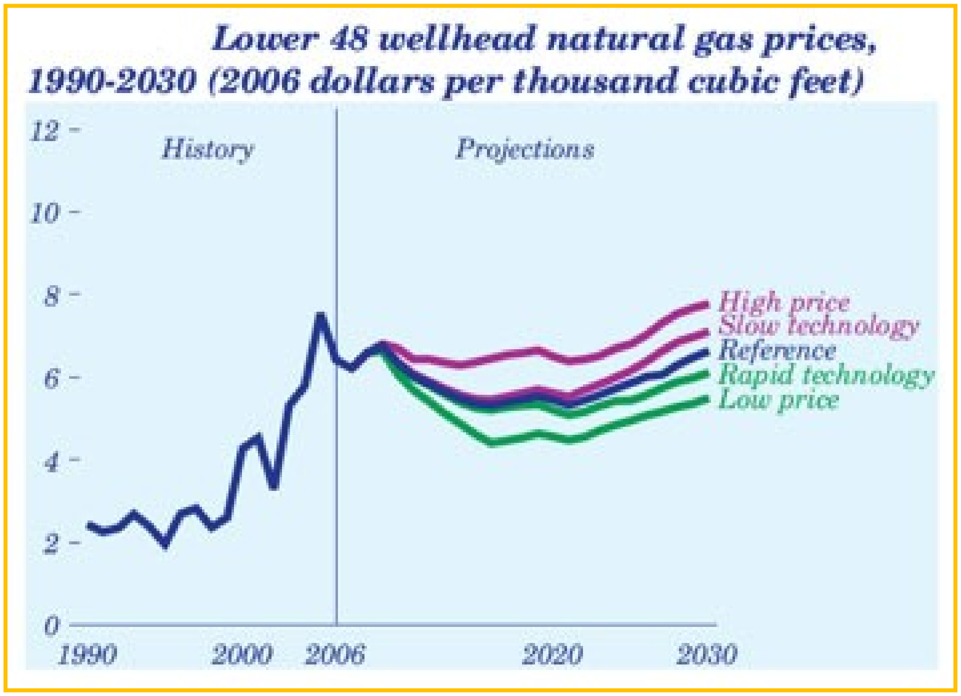


Figure 2.1.15. EIA (June, 2008) Lower 48 gas price forecasts to 2030

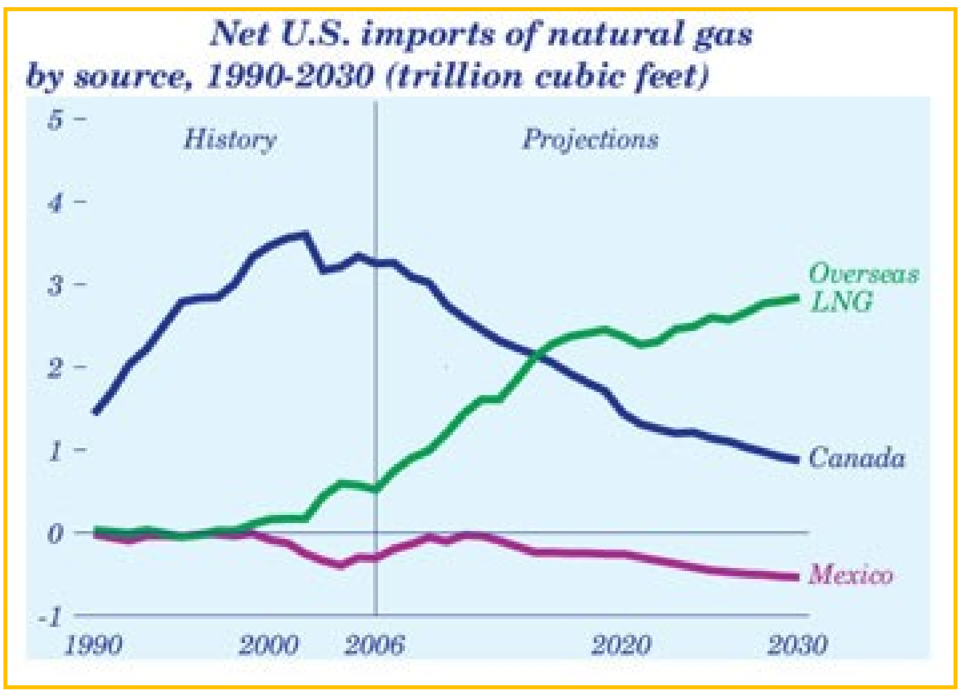


Figure 2.1.16. EIA (June, 2008) forecast of U.S. natural gas imports to 2030 highlighting a significant increase in LNG accompanied by a sharp decline from Canada.

EIA (June, 2008) make the point that LNG Imports are the source of natural gas supply most affected in the price cases. Net U.S. imports of LNG are expected to vary considerably from year to year, depending on both the level of U.S. natural gas prices and whether those prices are higher or lower than prices elsewhere in the world. Higher prices overseas are expected to reduce U.S. LNG imports, and lower prices overseas are expected to increase U.S. imports. U.S. LNG imports are much less sensitive to economic growth rates, which determine the level of domestic natural gas consumption. Given the uncertainty in future domestic and overseas natural gas prices, the level of future U.S. LNG imports is highly uncertain.

Figure 2.1.17. EIA (June, 2008) forecast of LNG imports by U.S. to 2030 highlighting the significant uncertainty due to international gas and oil price uncertainties. At low prices substantially more LNG would be imported and it would become a more significant threat in terms of competition for Alaska gas.

EIA forecast in June 2008 that an Alaska natural gas pipeline would begin transporting natural gas to the Lower 48 states in 2020. As a result, Alaska's natural gas production incurs a step increase at that time rising to 2.0 trillion cubic feet in the EIA reference case.

Alaska's current natural gas production involves two distinct streams: one from the North Slope and the other from the Cook Inlet. Some 3 trillion cubic feet of gas is brought to the surface on Alaska's North Slope, every year, with about 92% of the gas produced reinjected and the rest used for North Slope operations (with 10 million cubic feet per day set to go to Fairbanks under the new Fairbanks Natural Gas LLC contract in 2010.) If and when there is a 4 bcf a day gasline, approximately half of that 3 tcf would supply sales through that line. Meanwhile in Cook Inlet, annual gas production of 170 bcf (2007 DNR number) is shared between export and local use.

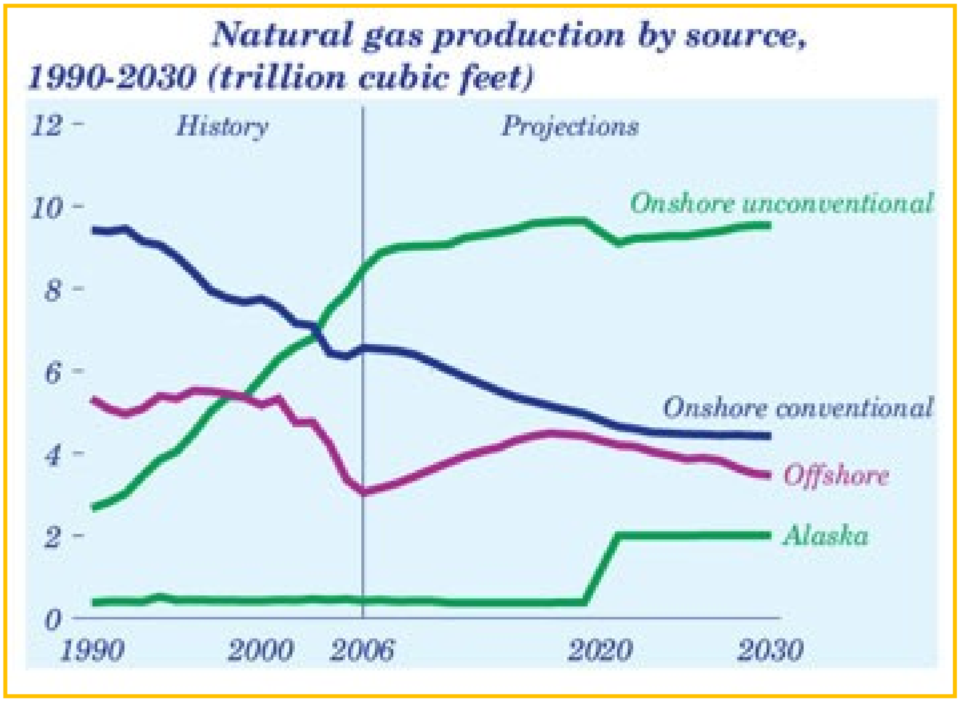


Figure 2.1.18. EIA (June, 2008) forecast of U.S. natural gas production to 2030. Alaska gas from 2020 is the only source with potential to expand substantially. EIA sees unconventional (e.g. shale gas and coal bed methane) with only limited growth from 2010 to 2030 suggesting limited competition for Alaska gas from that source. LNG imports are replacing the decline in conventional onshore and offshore production in the Lower 48.

Long-term uncertainties about how natural gas will fit within primary energy supply strategies and energy mixes (e.g. politically influenced decisions concerning future fiscal incentives to build more nuclear and renewable power plants instead of natural gas-fired power plants) also impact upstream fiscal design. Global concerns over long-term sustainability of supply and greenhouse gas (GHG) emissions for all fossil fuels mean that additional costs either in the form of carbon taxes (a cost on production) or carbon sequestration infrastructure (capital investment) may be imposed on the gas and oil industry.

Fiscal design planning for projects to be sanctioned over the coming decade need to anticipate and address both the commercial impact and fiscal implication of pending energy legislation. These are issues confronting the upstream gas industry around the globe not just North America. Though Congress in 2008 failed to adopt any of the climate-change and CO2 emission-reduction bills introduced, it is expected that the new president and new Congress will take up the issue in 2009. Most observers expect Congress to pass some version of a CO_2 cap-and-trade bill during 2009 / 2010, but it remains unclear what form it will take and what costs it will impose on the oil and gas industry. It is assumed in this report that CO_2 emissions will be limited by federal law, possibly with a cap-and-trade system, and that will ultimately need to be factored into the fiscal design.

The analysis of the international gas markets and the issues confronting them described here provides several reasons why fiscal design in the upstream sector should not be considered in isolation of downstream and market issues. In comparing fiscal terms of different major supply countries, it is necessary to take into account some of the global issues outlined above and the markets they are supplying and the nature of their supply chains.

Natural Gas Import Points to Lower 48

Alaska natural gas once connected by a gas pipeline to the Canada-to-U.S. gas pipeline network may ultimately enter the U.S. at a number of points. Figures 2.1.19 and 2.1.20 identify the main Canada – U.S. import points and the volumes of gas flows through those points in 2007. Alaska gas will be competing with Canada gas production and LNG imports to North America in terms of customers and price.

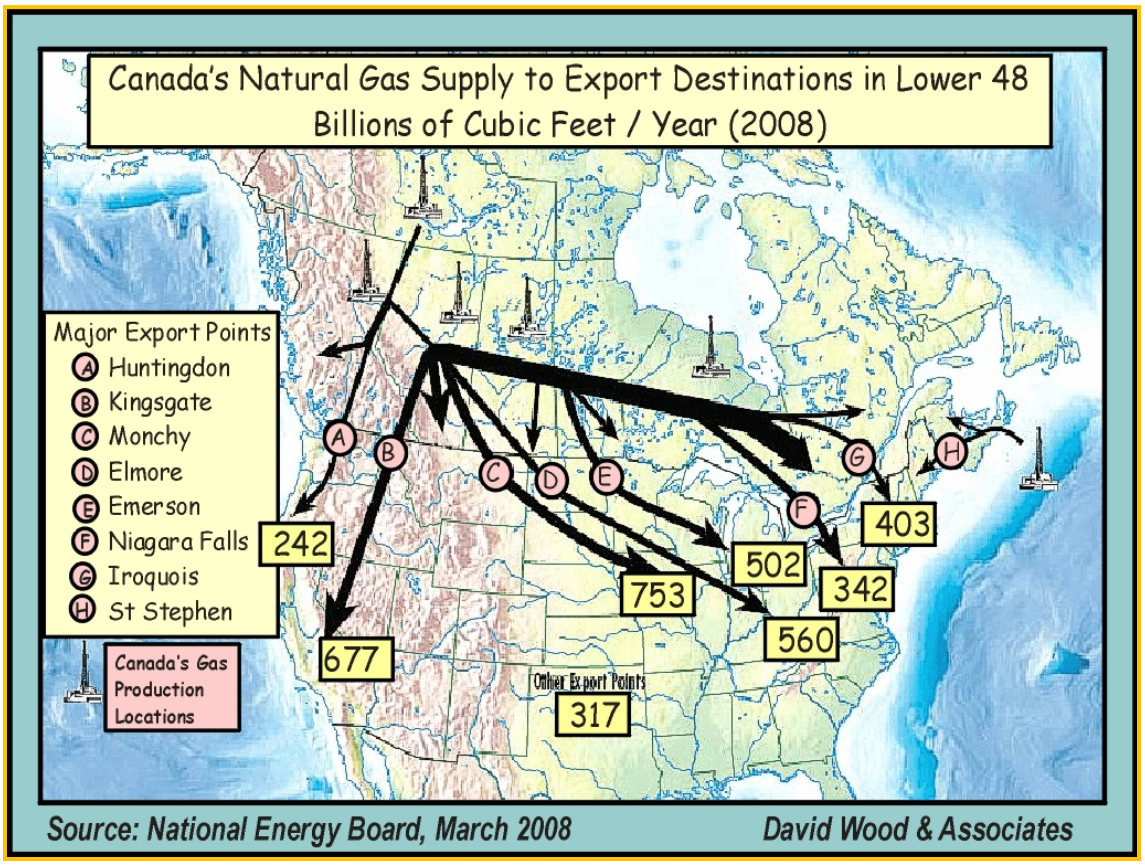


Figure 2.1.19. Volumes of natural gas imported to U.S. Lower 48 from Canada in 2007 at major export locations. Once in Canada's gas pipeline system Alaska gas could be transmitted to Lower 48 West Coast, Midwest and east coast destination markets.

Natural Gas Export Volumes Canada to United States					
	2003	2004	2005	2006	2007
Export points	bcf/year				
Huntingdon	303	259	272	210	242
Kingsgate	561	673	601	626	677
Monchy	763	758	713	695	753
Elmore	570	564	588	570	560
Emerson	399	417	458	424	502
Niagara	284	305	340	335	342
Iroquois	321	325	365	367	403
Others	314	297	354	296	317
Total	**3516**	**3599**	**3690**	**3523**	**3797**

Source: NEB 2008 *David Wood & Associates*

Figure 2.1.20. Volumes of natural gas imported to U.S. Lower 48 from Canada at major export locations from 2003 to 2007.

Forty natural gas pipelines, representing approximately 23 billion cubic feet (Bcf) per day of capacity, import and export natural gas between the United States and Canada or Mexico. Between 1990 and 2007, import pipeline capacity from Canada increased by 169 percent (to 17.3 Bcf per day) and from Mexico by 147 percent (to 0.9 Bcf per day). Although Mexico is a major oil producer, it does not produce enough natural gas to meet its domestic needs and imports gas along the U.S. border.

Canada's natural gas pipeline system is highly interconnected with the United States. As of September 2008 the United States had 63 locations where natural gas can be exported or imported: 24 locations are for imports only, 18 locations are for exports only, 13 locations are for both imports and exports and 8 locations are liquefied natural gas (LNG) import facilities. Imported natural gas represents some 16 % of the gas consumed in the United States annually in 2008, compared with some 11% in 1996.

In 2007, the top five import points accounted for about 70 percent of all natural gas brought into the United States via pipeline. They were:

Port of Morgan, Montana (Northern Border Pipeline)

Eastport, Idaho (Gas Transmission Northwest)
Sherwood, North Dakota (Alliance Pipeline Company)
Noyes, Minnesota (Great Lakes Gas Transmission Company)
Noyes, Minnesota (Viking Gas Transmission Company)

The major export gas pipelines from Canada to U.S. are:

The 1,300-mile, 1.9-Bcf/d ***Gas Transmission Northwest*** pipeline runs from the British Columbia-Idaho border to the Oregon-California border, connecting TransCanada's western Canadian network to the U.S. domestic market.

The 1,857-mile 1.35 Bcf/d Alliance pipeline runs from northeast British Columbia to just southwest of Chicago, Illinois.

The 2,000-mile, 2.4-Bcf/d ***Great Lakes Gas Transmission*** pipeline runs from Emerson, Manitoba to St. Clair, Ontario, servicing Minnesota, Wisconsin, and Michigan.

The 400-mile, 0.9-Bcf/d ***Iroquois Gas Transmission*** System pipeline running from the New York-Canada border to Long Island serves natural gas distribution networks in New York State.

The 280-mile, 0.2-Bcf/d ***Portland Natural Gas Transmission*** System distributes natural gas from Quebec to greater New England.

The 780-mile, 650-MMcf/d ***Maritimes and Northeast*** Pipeline transports natural gas from Canada's Atlantic natural gas fields to Dracut, Massachusetts, where it interfaces with the U.S. domestic network.

A major challenge for Canada is to sustain current levels of gas production and exports to U.S. Domestic gas consumption in Canada is rising and reserves are declining (Figure 2.1.21). Canada is addressing this by building and planning LNG import terminals (e.g. Canaport – 84% completed in October 2008) and a proposed pipeline to bring Mackenzie Delta gas to market. Gas from Alaska would undoubtedly help to maintain gas throughput in the existing Canada to U.S. pipeline network.

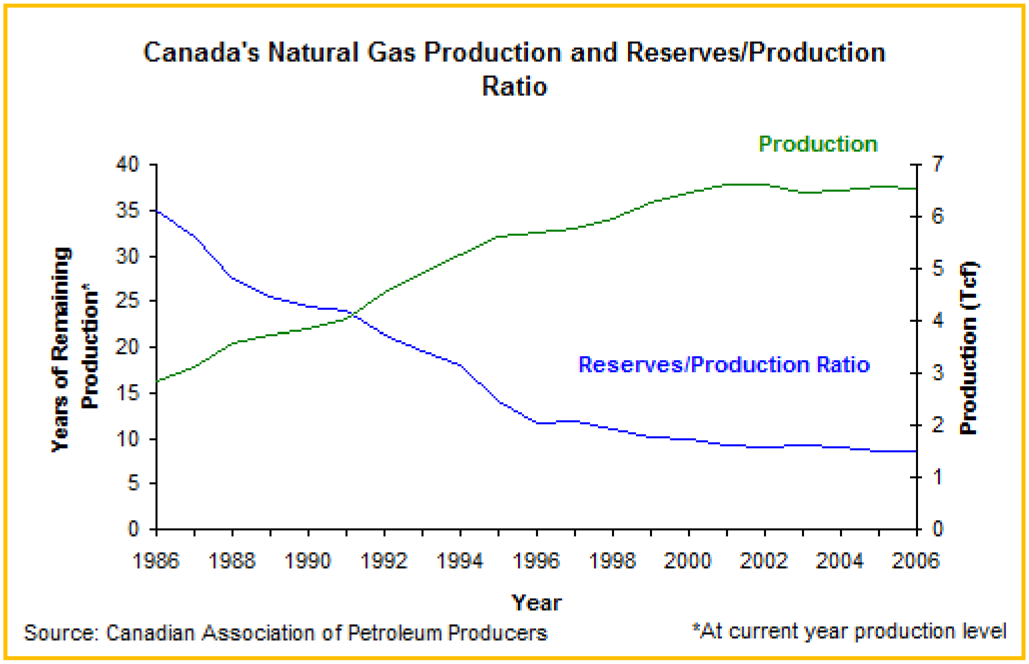


Figure 2.1.21. Canada gas production and R/P ratio history. Source: EIA Canada Country Brief May 2008.

Figures 2.1.22 illustrates existing pipeline and LNG import locations to Lower 48.

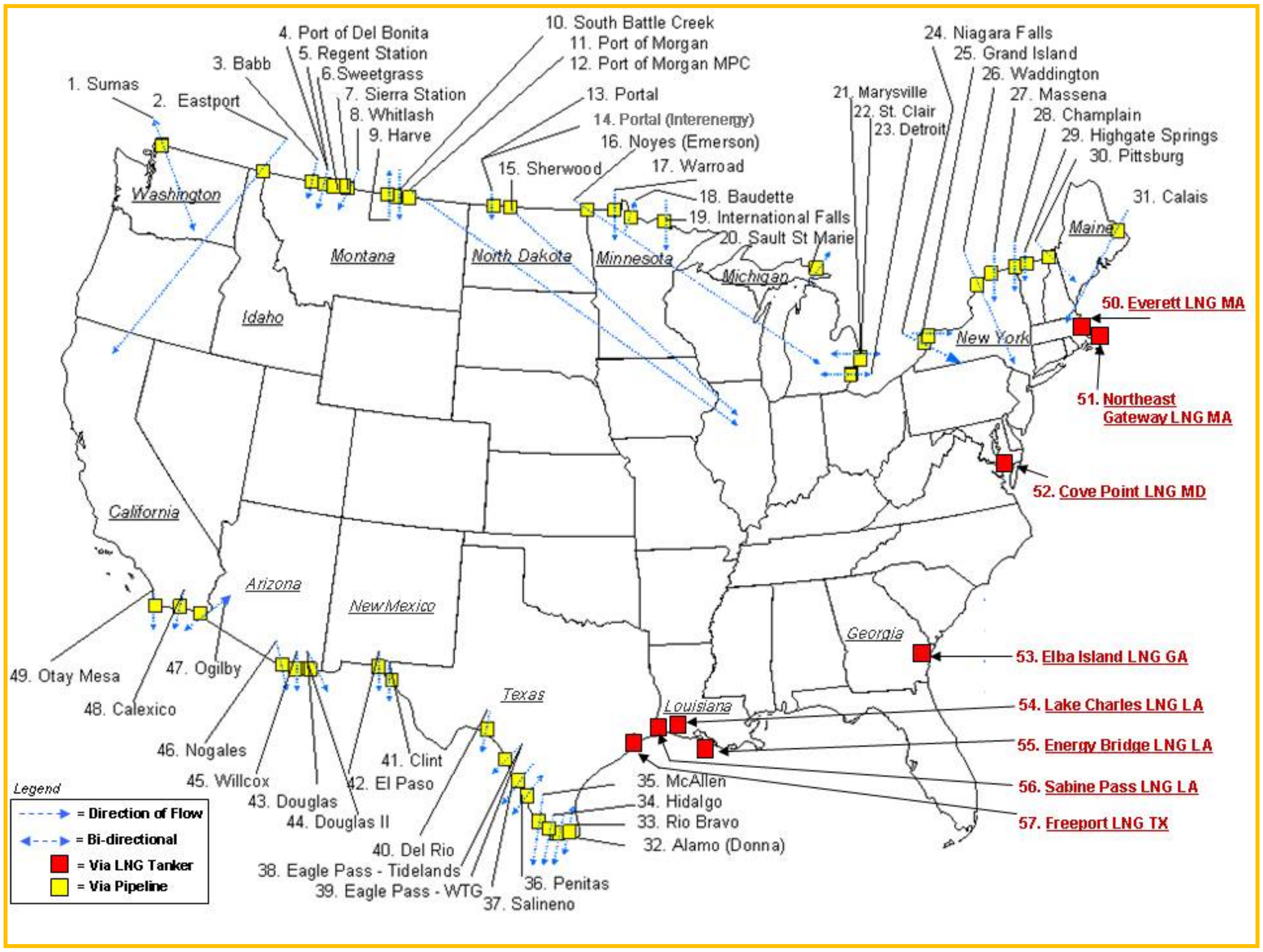


Figure 2.1.22. U.S. Natural Gas Import/Export Locations, as of September 2008 (source EIA).This map identifies all existing import points along Canada Lower 48 border plus import locations from Mexico to Lower 48 and operational LNG receiving terminals in Lower 48.

Figures 2.1.23 provides more details of the existing LNG import terminals in North America.

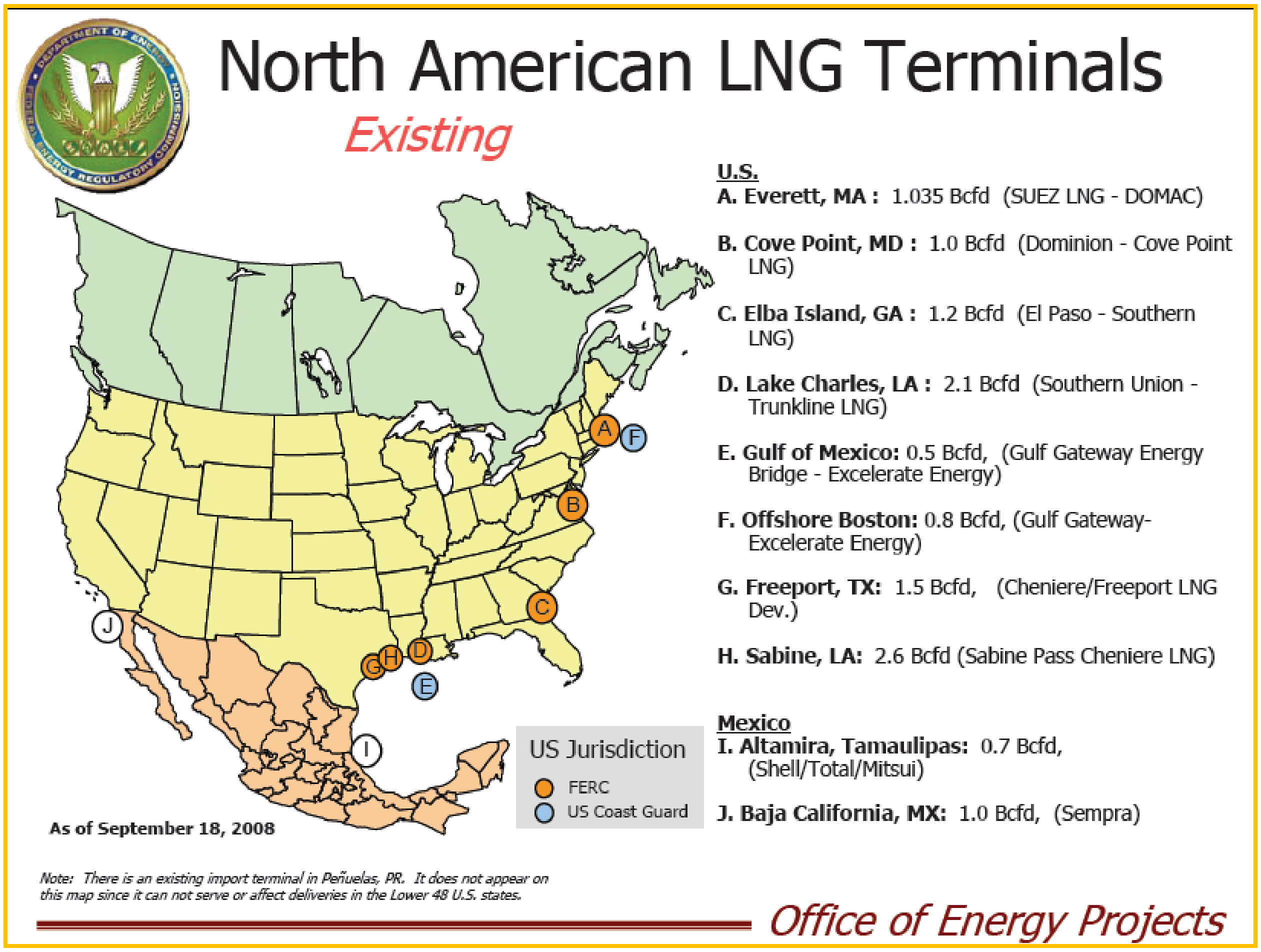


Figure 2.1.23. Existing North America LNG import terminals.

Figure 2.1.24 illustrates the large number of LNG import terminals in operation or under construction. These existing terminals, plus several others in different planning stages, will ultimately import increasing volumes of international gas that will compete with domestic North America gas production, including that from Alaska. By comparing Figures 2.1.23 and 2.1.24 it becomes clear how significantly the North America (i.e., Lower 48, Canada and Mexico) LNG import infrastructure is likely to expand prior to 2018, the earliest date at which Alaska gas will enter the Lower 48 gas market.

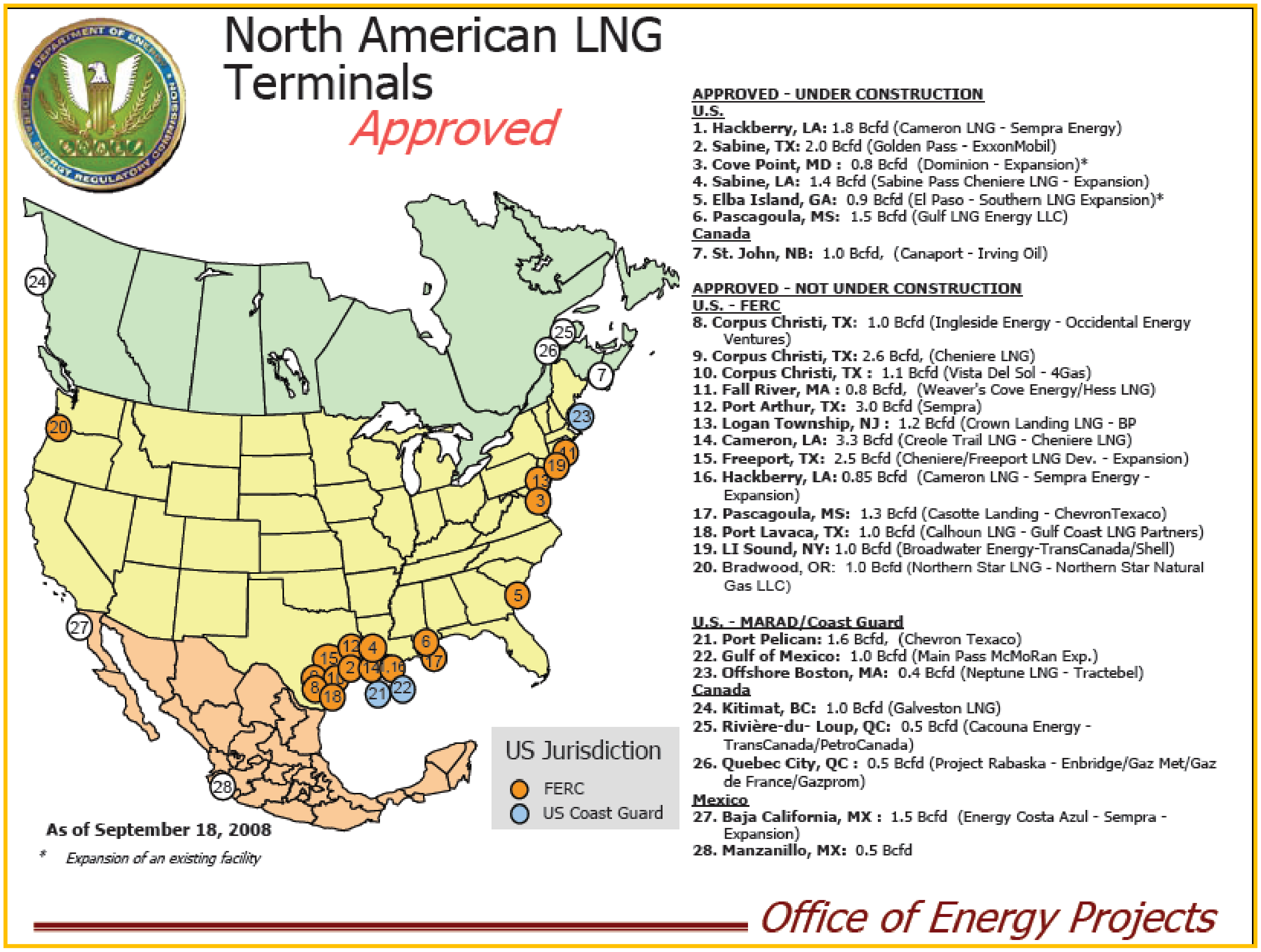


Figure 2.1.24. Approved (but not yet built) North America LNG import terminals. Note the Bradwood planned LNG terminal in Oregon is the first to have received FERC approval (September 2008) on the U.S. West Coast.