PROSPECTS FOR DEVELOPMENT OF ALASKA NATURAL GAS: A REVIEW

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by

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Alaska Gas: Key Drivers and Issues

- The first gas production from northern Alaska will focus on the proven, low-cost reserves at Prudhoe Bay (26 tcf).
- The most likely scenario for exports of northern Alaska gas is a gas pipeline down existing highways from Prudhoe Bay to Alberta, Canada. No decision has yet been announced. The State of Alaska, Yukon Territory, and most stakeholders advocate a highway route. Existing regulatory permits and international treaties, subject to review, authorize the highway route.
- Phillips Alaska estimates that prices above $3.50/mcf at Chicago city gate are needed for economic success. Chicago city gate prices were approximately $8/mcf in January 2001.
- Gas delivery to U.S. via gas pipeline from Prudhoe Bay is not expected before years 2007-2010. Regulatory delays or litigation could delay it.
- The gas pipeline will be sized for efficient transportation of the known gas reserves at Prudhoe Bay. For a 4.0 billion cubic feet per day pipeline, excess capacity would become available in year 2023 (assuming a 2007 start up).
- Cook Inlet remaining natural gas reserves (2.56 tcf) will be depleted by year 2012. New gas sources must be located soon to supply the majority of the State's population which lives in the area around Cook Inlet.
- The most attractive gas province in the Bering Sea is North Aleutian basin, which is closed by moratorium until year 2012.
- LNG export models are required for future Bering Sea gas production. Potential gas resources cannot be taken to the U.S. West Coast because there are no LNG receiving facilities. The most likely LNG export models deliver gas to Japan or other Asian Pacific Rim countries.
- Alaska has a huge resource base of discovered and undiscovered gas (217.91 tcf), but 88 percent of this gas is undiscovered. Expensive and time-consuming exploration programs will be required to identify new commercial gas fields.

Summary

Alaska contains 39.88 trillion cubic feet (tcf) of gas remaining in developed and known undeveloped fields. Some of this gas is in fields too small or remote to justify economic development. Of the known gas reserves, 26.92 tcf may be considered available for export at appropriate market prices and pending construction of new gas transportation systems. Most of this gas is in onshore fields and mostly beneath State of Alaska surface or submerged lands. No Federal offshore gas reserves are considered to be readily available for export at present.

Three percent (0.92 tcf) of Alaska's exportable gas reserves occur within fields in the Cook Inlet basin of southern Alaska and are at present dedicated to future LNG exports to Japan. Cook Inlet has 2.56 tcf in total remaining gas reserves, most of which is used locally or converted to fertilizer feedstock. At present rates of consumption, all Cook Inlet gas reserves will be depleted by year 2012.

Ninety-seven percent (26 tcf) of Alaska's exportable gas reserves occur within fields in or near the Prudhoe Bay field in northern Alaska. The Prudhoe Bay area gas reserve base totals 30.90 tcf (developed fields and Point Thomson field, not including carbon dioxide), but some of this gas will be consumed (current rate 0.2 tcf/yr) by future (oil and gas) production activities at Prudhoe Bay. The stranded gas reserves at Prudhoe Bay are presently attracting proposals for construction of a gas transportation system that can take the natural gas to markets outside of Alaska.

In the Mackenzie delta area of Canada (300 miles east of Prudhoe Bay), exploration drilling from 1970 and 1989 discovered 53 oil and gas pools about equally divided between the onshore and offshore areas. The Mackenzie delta area contains approximately 9-12 tcf of discovered gas, some of which may be in pools sufficiently large to justify construction of a new gas pipeline to take the gas south to Alberta. The largest gas field is Taglu (2.07 tcf) located onshore. All of the Mackenzie delta discoveries are stranded at the present time, although several development proposals are under consideration.

A total of 83 exploration wells have tested prospects in the Federal waters offshore Alaska since 1976. Exploration results have been disappointing, and the few significant oil and gas discoveries made in the Arctic remain undeveloped due to high capital costs and uncertain prices. Two offshore oil fields, Liberty and Northstar, will begin production in 2001-2003, but the associated gas will be used for lease operations. The Burger well, located on the Chukchi shelf 360 miles west of Prudhoe Bay, penetrated the largest gas pool found to date in the Alaska Federal offshore. However, Burger is located in a formidable setting far from existing infrastructure and is uneconomic to develop with current technology and price conditions.

Most (82%) of the 190.99 tcf of undiscovered natural gas resources forecast for Alaska and the Alaska Federal offshore occur in the Arctic. If the undiscovered gas resources in the Mackenzie delta (53 tcf) are added to those onshore in northern Alaska (63.5 tcf), and Federal submerged lands on the Beaufort (32.07 tcf) and Chukchi shelves (60.11 tcf), **the Arctic regional undiscovered gas potential totals 208.68 tcf.** This volume is equal to 40% of the total U.S. undiscovered conventional gas resource base (526 tcf). Arctic Alaska and the Mackenzie delta seem destined to someday become major producing areas for natural gas. However, a significant fraction of the undiscovered gas resources could occur in small, remote accumulations that may never be profitable to develop.

Across Alaska and the Alaska offshore, unconventional sources like gas hydrates and coal bed methane are estimated to contain up to 170,000 tcf of natural gas in place. Most of this hypothetical natural gas resource is contained in gas hydrates that are located far offshore in water depths exceeding 300 m and will remain inaccessible for the foreseeable future. However, 37 to 44 tcf of gas are estimated to occur in sub-permafrost gas hydrates in and around the Prudhoe Bay-area developed oil fields and might be exploited on an experimental basis once a gas transportation infrastructure is installed.

Resource assessments in 1995 and 2000 estimated the total undiscovered conventionally recoverable gas resource base and the fractions of that gas resource base that could be profitable to develop. Several Alaska provinces, onshore and offshore, were found to potentially hold economic gas resources at landed market prices of \$2.11 and \$3.52/mcf (constant

$2000, equivalent to oil at $18/bbl and $30/bbl). At $2.11/mcf paid at a variety of markets, 6.172 tcf gas might be economic to develop across Alaska (5.14 tcf for offshore alone). At $3.52/mcf, 12.23 tcf gas might be economic to develop (8.67 tcf for offshore alone). The undiscovered economically recoverable gas resources (12.230 tcf) represent only 6% of the 190.99 tcf total undiscovered conventionally recoverable gas resource base for all of Alaska.

At high gas prices like those witnessed in the U.S. in recent months, economic recoverability improves for most offshore Alaska provinces. At a gas price of $6/mcf (constant $2000) delivered to a variety of markets, the Alaska Federal offshore could contain a total of 35.78 tcf of undiscovered economically recoverable gas. At $6.00/mcf, 20.0 tcf could be economic to co-produce with oil resources on the Chukchi shelf and deliver as LNG to Pacific Rim markets. Associated gas resources produced through new offshore oil fields on the Beaufort shelf and delivered to a plantgate at Prudhoe Bay become economic at prices of $1.00/mcf or higher, with 4.66 tcf economically recoverable at $6/mcf. If produced gas is delivered to a hypothetical plantgate at Kivalina—the port for the Red Dog mining operation—Hope basin could have economically recoverable gas resources of 2.27 tcf at $6/mcf. Not all basins invite economic development. Even at a $6.00/mcf price, most of the Bering Sea provinces remain uneconomic. Gas prices of $10/mcf to $15/mcf would be required to support significant economic gas development in Norton basin, St. George basin, or Navarin basin. At $6/mcf, North Aleutian basin in southern Bering Sea offers 5.90 tcf of undiscovered, economically recoverable gas. However, North Aleutian basin is under a moratorium forbidding oil and gas leasing, exploration, or development until year 2012. At $6/mcf delivered to the local gas transmission pipeline network in Cook Inlet region, the Lower Cook Inlet (Federal waters) could have 1.24 tcf of undiscovered economically recoverable gas. At $6/mcf delivered as LNG to Japan, the Shumagin-Kodiak shelf and Gulf of Alaska shelf could have 1.40 tcf and 0.31 tcf, respectively, of undiscovered economically recoverable gas.

The Prudhoe Bay-area gas reserves (26 tcf) are the key assets that will drive near-term strategic decisions about how to transport and market stranded natural gas from northern Alaska. Since 1977, natural gas recovered during oil production has been re-injected to increase oil recovery or used as fuel for production facilities. Over 35 tcf of gas has already been produced and re-injected or consumed at the Prudhoe Bay area fields. In 1999, gross gas production from the North Slope oil fields was 3.15 tcf (8.63 bcfpd) of which 93 percent was re-injected.

The 5.8 billion barrels oil reserves remaining (as of late 1999) in the Prudhoe Bay area fields (originally17 billion barrels) are now only a little larger than the remaining gas reserves—an energy asset equivalent to 4.6 billion barrels of oil. Northern Alaska oil production is declining precipitously and there is some concern about when production will fall below the minimum required to profitably operate the Trans Alaska oil pipeline (TAPS). As the Prudhoe Bay area oil fields begin to approach depletion, daily gas production is increasing and gas-handling capacities may someday further constrain oil production. Expansion of gas-handling facilities may be required to allow oil production to continue at optimum rates, or, at least at rates sufficient for TAPS operations. Alternatively, gas sales out of Prudhoe Bay could help avoid capital outlays for new gas-handling equipment. Limited gas sales could begin at any time from the Prudhoe

Bay-area fields without affecting recovery of the remaining 5.8 billion barrels of oil reserves. Major gas sales could begin after year 2015 with no harm to ultimate oil recoveries, and the impacts of earlier gas sales could possibly be mitigated through measures like increased waterflood and carbon dioxide re-injection (Meyers, 2000).

At present, three concepts are in the forefront for commercializing the stranded gas resources in northern Alaska and Mackenzie delta:

- ***A New Pipeline Connecting to the Canadian gas pipeline network.*** Build conventional or high-pressure gas pipelines to carry the gas from Prudhoe Bay and Mackenzie delta to northern Alberta or British Columbia, where the new pipeline would join the Canadian pipeline network and supplement ongoing transmission gas exports to the U.S. Pipeline capacities of 2.5 bcfpd (0.9 tcf/yr) or 4.0 bcfpd (1.46 tcf/yr) delivered to the western Canada pipeline network typify most proposals.

- ***Liquefied natural gas (LNG) to Asian Pacific Rim.*** Build a conventional or high-pressure gas pipeline that carries the gas from Prudhoe Bay-area fields to a port in southern Alaska, where the gas is chilled to liquefied natural gas (LNG) and loaded on special LNG tankers for transport to the Asian Pacific Rim or perhaps the U.S. West Coast via return pipeline from hypothetical a port in western Mexico. System throughput for current proposals ranges from 1.5 bcfpd (0.5 tcf/yr) to 2.5 bcfpd (0.9 tcf/yr).

- ***Gas to liquids (GTL) and tankers to U.S. West Coast.*** Build a new facility in the Prudhoe Bay area and use GTL technology to convert natural gas to middle-distillate (diesel-like) liquids. The GTL product could be pumped in segregated batches through the Trans Alaska oil pipeline and then transported by tankers to the U.S. West Coast. A 50,000 bpd (0.5 bcfpd or 0.2 tcf/yr) plant has been promoted by one group, but BP-Amoco, a major owner of the gas at Prudhoe Bay, is presently building a small experimental GTL plant at Nikiski in Cook Inlet, Alaska (operational in 2002).

The original proposal for a gas pipeline through Canada—the Alaska Natural Gas Transportation System (ANGTS) and now sometimes called the "Highway Route"—followed the Dalton Highway from Prudhoe Bay to Fairbanks and then followed the Alaska Highway to central Alberta. A 1995 study published by the ANGTS group (abstr. by Thomas and others, 1996, p. 3-4) estimated that delivery costs for their $16.7 billion project would range from US$2.82/mcf to US$4.17/mcf in $1995 (or $3.29/mcf to $4.86/mcf in $2000). A similar "highway" gas pipeline project now being studied by the Prudhoe Bay gas owners would cost US$10 billion (2.5 bcfpd line) to US$12 billion (4.0 bcfpd line) and could profitably deliver gas to Chicago for $3.50/mcf (Meyers, 2000). Chicago city gate prices were approximately $8/mcf in January 2001. U.S. domestic natural gas demand, now at 22 tcf/year, is predicted to rise to 35.57 tcf/year by year 2020 (AEO, 2000, tbl. A1), thus ensuring a future of strong demand for any gas that can be profitably brought to the U.S. market from northern Alaska or Canada.

Alaska has the only LNG export operation in the U.S. Small amounts of LNG (0.06 tcf/year) from gas fields in Cook Inlet have been sent to Yokohama, Japan since 1971. A much grander LNG export model, shipping perhaps 0.9 tcf/year, has been proposed by Yukon Pacific Corporation for moving gas from northern Alaska into the Asian Pacific Rim and U.S. West Coast markets. The LNG project at the largest scale would require construction of a new gas conditioning plant at Prudhoe Bay, an 800-mile gas pipeline, a new LNG plant and marine terminal at Valdez in southern Alaska, and a new LNG tanker fleet, all for approximately $12.76 billion ($2000). No economic studies of the most recent LNG proposals are publicly available. A 1995 study by Thomas and others (1996) using a 0.85 tcf/yr LNG project costing $16.03 billion ($1995) found that a flat world oil price of $19.36/bbl ($1995) was required for the LNG project to economically "breakeven" (NPV_{10}=0). The AEO (2000) *Reference Case* forecasts that world oil will reach this price in year 2015. A $19.93 world oil price is approximately equivalent to an LNG price of $3.77/mcf (in September 2000, Cook Inlet LNG shipments to Japan were receiving $4.33/mcf). A 1999 DOE update study by Robertson (1999) found the LNG project to be unprofitable (NPV_{10}= — $2,402 billion), in fact providing the poorest return of all marketing concepts modeled by that study. An LNG export volume of 0.9 tcf/year would be equal to a very large fraction (28%) of the entire 1998 Asian Pacific rim LNG market (3.225 tcf/year). The chief risk element of the LNG proposals is that such large exports might flood the principal market and cause a price collapse. Because of market risk and capital cost considerations, plans for smaller initial LNG-based projects (output as low as 0.46 tcf/year, costing $8.2 billion to construct) have also been proposed, but the economics of the smaller scale projects are not publicly available.

Gas-to-liquids (GTL) technology forms an attractive option because it can supplement the throughput of the Trans Alaska oil pipeline (TAPS) and perhaps extend the operating life of this critically important oil transportation system decades into the future. The addition of GTL liquids to the oil transportation system would also moderate per-barrel oil pipeline tariffs, which are expected to rise in the future as the volume of pipeline throughput falls. The continued existence of the oil pipeline and a lowering of future oil pipeline tariffs are critical to the economics of future development of smaller, undiscovered oil fields in northern Alaska and the Arctic Federal offshore. A 1995 study by Thomas and others (1996) of a hypothetical 300,000 bpd (3 bcfpd or 1.1 tcf/yr) northern Alaska GTL project costing $13 billion found that a "breakeven" (NPV_{10}=0) flat world oil price of $19.94/bbl ($1995) was required for economic viability. The AEO (2000) *Reference Case* forecasts that world oil prices will not reach this price until after year 2020. However, in September 2000, the actual world oil price averaged $31.10/bbl (or $26.69/bbl in $1995). GTL, or at least its modern component processes, involve relatively new technologies that are only now entering commercial applications. A recent study of northern Alaska GTL economics by Robertson (1999) revealed that incremental construction of several small GTL facilities allowed for "learning"—resulting in cost reductions to facilities built later in the life of the project. This "incremental" GTL model provided the most favorable economic outcome. Future market demand for GTL product is expected to be robust. The chemical conversion of natural gas to liquid hydrocarbons creates an essentially refined product that is free of polluting agents and that as a transportation fuel can command premium market prices, particularly on the U.S. West Coast, where ultra-clean motor fuels will be mandated.

The gas transportation system that is eventually constructed to take Prudhoe Bay gas reserves to market will be scaled to the known reserve volumes. For this reason, the gas transportation system will be completely filled for years after start up with production from Prudhoe-area gas fields. Newly-discovered gas will have to await declines in the area production levels such that excess capacity (unfilled space) develops in the gas transportation system. If we assume that a gas pipeline to Prudhoe Bay is operational by year 2007 and that excess capacity becomes available after 90 percent depletion of known reserves, the earliest shipments of newly-discovered gas would be in year 2015 for an 8 bcfpd line, or year 2023 for a 4 bcfpd line, or year 2033 for a 2.5 bcfpd line. An 8 bcfpd gas pipeline has not been proposed but this is the present rate of gas recycling in the Prudhoe-area fields. There are currently proposals for the two smaller pipelines, of which the 4 bcfpd pipeline seems to be favored. Of course, if *substantial* new gas discoveries justified the additional expense, increasing pipeline pressure (adding compression equipment) could increase pipeline capacity at any time.

Northern Alaska and its contiguous continental shelves are richly endowed with natural gas. However, finding and developing any significant fraction of this undiscovered resource will prove very costly. At the current slow pace of leasing, exploration, and development, a significant fraction of the undiscovered natural gas endowment of northern Alaska could remain unavailable to meet market demands for many decades.

Because of the long lead-time required for major construction projects, the time may now be at hand for decisions about how to export the stranded natural gas reserves of northern Alaska and northwestern Canada. These decisions will lead to construction of a huge natural gas marketing infrastructure costing billions of dollars. Gas production strategies and new infrastructure will determine the character of oil and gas development in northern Alaska and northwestern Canada for many decades to come.

2. NATURAL GAS RESERVES AND PRODUCTION IN ALASKA

Gas Reserves of Northern Alaska and the Arctic Federal Offshore

Without an existing gas transportation system, natural gas is not presently being exported from northern Alaska. Large known reserves virtually ensures that some gas transportation system will soon be constructed.

The known gas volumes remaining in developed fields (25.930 tcf) and known undeveloped fields (5.687 tcf) of onshore northern Alaska total 31.617 tcf (fig. 1;tbls. 1, 2, 3). This is a minimum estimate because several fields are penetrated by single wells and the extents of the gas pools cannot be reliably estimated. Many undeveloped fields are located great distances (100 to 300 miles) distant from the main reserves at Prudhoe Bay and are unlikely to be developed in the near future, even once a gas transportation system is in place. Of the many undeveloped northern Alaska gas fields listed in table 3, only Point Thomson is reasonably close to the Prudhoe Bay infrastructure 60 miles to the west (fig. 2). Of the 30.896 tcf natural gas reserves in the Prudhoe-area fields and at Point Thomson, some fraction will be consumed to fuel future production operations.[1] Thomas and others (1996, tbl. 2.3) estimate that approximately 26 tcf will ultimately be available as marketable reserves to support future commercial exports (fig. 1; tbl. 1).

Gas production, supported by government subsidies, has occurred in shallow fields near the community of Barrow since 1949, with new fields added in 1974 and 1980 (fig. 2; tbl. 2). Through 1999, a cumulative total of 0.037 tcf of gas had been produced for the space heating, cooking, and electrical generation needs of the community of Barrow, Alaska (tbl. 2).

At the producing oil fields near Prudhoe Bay, gas produced with the oil is being used to fuel the production infrastructure and for enhanced oil recovery. As of year 2000, over 3.7 tcf had been consumed by oil production operations on leases in the Prudhoe Bay area. Re-injection of produced gas into Prudhoe-area fields is critical to enhanced oil recovery. In fact, almost 35 tcf of natural gas has actually been produced and re-injected into oil reservoirs to help maintain reservoir pressure and to drive oil to production wells (AKDO&G, 2000, p. 37). Gas exports, if started too early, could diminish ultimate oil recoveries, negatively impact cash flow, and perhaps shorten the ultimate operating life of the Trans-Alaska oil pipeline (TAPS). Regarding the importance of gas recycling to oil recoveries, ARCO (now Phillips) estimated that: 1) oil reserves lost as a consequence of premature gas exports would be 0.9 billion barrels of oil if gas exports began in year 2000; 2) lost oil reserves might reach 0.4 billion barrels if gas exports

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[1] *Higher estimates for "gas reserves" are given by different sources and may represent "gross" gas volumes. Some gas reserves will be consumed to support 20+ years of future oil production operations and support infrastructure (3.7 tcf already consumed at Prudhoe-area oil fields). Of the producing fields, only Prudhoe Bay, Pt. McIntyre, Endicott, and Lisburne fields have gas reserves in excess of lease operation requirements (Thomas and others, 1996, p. 2-8). Shrinkage with loss of natural gas liquids and removal of carbon dioxide (3-9% of gas volume; Thomas and others, 1996, p. 2-9) further diminish gas volumes.*

began in year 2005; and 3) no loss of oil reserves would be incurred if gas exports were delayed until year 2015 (cited in Thomas and others, 1996, p. A-7). Kevin Meyers, President and CEO of Phillips Alaska, Inc., recently commented (Meyers, 2000) that diversion of produced gas from re-injection to gas sales of 2.5 to 4.0 bcfpd[2] beginning in 2007 might cause an ultimate loss of 200 to 400 million barrels of oil production, if unmitigated. Mitigation measures including carbon dioxide re-injection and increased waterflood rates are being investigated within the owner companies.

The 26-tcf marketable gas reserve base near Prudhoe Bay represents a substantial energy resource, approximately equivalent to 4.6 billion barrels of oil in energy terms, a substantial quantity even when compared to the 17 billion barrels of original oil reserves. As of year 2000, 6.4 billion barrels of oil reserves remain in the Prudhoe Bay-area fields (AKDO&G, 2000, p. 12).

In the Mackenzie delta area of Canada, 300 miles east of Prudhoe Bay (fig. 1), it is estimated that 9 to 11.7 tcf of gas occur within 53 offshore and onshore fields that were discovered between 1970 and 1989 (NEB, 1998; Dixon and others, 1994, tbl. 1). The largest gas reserves in offshore fields are associated with oil and will probably be tied to oil production that lies perhaps decades into the future. The largest gas fields onshore, Taglu and Parsons, contain 2.071 and 1.253 tcf, respectively, with no other fields exceeding 1 tcf (NEB, 1998). Some fraction (no estimate available) of the onshore Mackenzie delta gas reserves involving some of the largest fields, which are not associated with oil, may be economic to develop now. However, the onshore natural gas reserves are also stranded at present awaiting construction of a gas transportation system.

Thirty-four exploratory wells have been drilled in the Federal offshore of the Beaufort and Chukchi Seas, an area of about 79,000 square miles. Varying quantities of oil and gas were discovered at about 12 sites.

In the Beaufort shelf, reserves[3] have been estimated for 5 fields: Northstar field, Liberty field, Kuvlum field, Hammerhead field, and Sandpiper field (fig. 3; tbl. 3). These oil fields offer collective gas reserves of 0.7 tcf (tbl. 3) that, if eventually co-produced with oil, would be re-injected to enhance oil recoveries and ultimately consumed on-site. Liberty and Northstar fields are not scheduled to begin oil production before year 2001 (2003 for Liberty), and construction has begun at Northstar.

On the Chukchi shelf, pooled gas was discovered at three sites (Crackerjack, Popcorn, and Burger wells), but the only pool of significant size was found at Burger structure (fig. 2). Preliminary (1993) estimates for the Burger gas pool range from 2 to 10 tcf, with a mean "reserve" estimate of 5 tcf (tbl. 3). However, even a very large gas pool at Burger could remain uneconomic for many years because it lies in perennially ice-bound waters 160 feet deep, 70 miles from shore, and 360 miles west of the northern Alaska infrastructure center at Prudhoe Bay.

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[2] *bcfpd, billions of cubic feet per day*

[3] *For purposes of this discussion, discovered oil or gas accumulations are referred to as "fields" and the associated estimates for quantities of oil or gas are described as "reserves", but include both proved and unproved reserves. The term "resources" is generally tied to undiscovered quantities of oil or gas in prospects, plays, basins, provinces, and regions.*

In conclusion, while northern Alaska offers potentially exportable gas reserves of 26 tcf but these reserves await a gas transportation system. Known gas reserves offshore on the Beaufort and Chukchi shelves are associated with small oil fields or are extremely remote and in either case are unlikely to be developed in the near future.

Gas Reserves of Tertiary-Age Basins of Central Alaska and the Bering Shelf

Only 9 wells have tested prospects in or near the Tertiary-age basins that spot Central[4] Alaska, a vast area of about 300,000 square miles (USGS, 1995). Rocks older than Tertiary in age are generally moderately to highly deformed, have experienced deep burial and severe heating, and now offer only negligible potential for oil or gas. Strata filling Tertiary basins offer better potential for gas resources, but none of the 9 wells in Central Alaska encountered any pooled gas (or oil) accumulations. Central Alaska therefore does not offer any known, potentially exportable gas reserves (fig. 1; tbl. 1).

A total of 24 exploratory wells have tested the most promising prospects in the Tertiary-age basins beneath Bering shelf, an immense area of approximately 350,000 square miles (fig. 4). The exploratory wells were drilled in isolated Tertiary-age basins that underlie the Bering shelf, including St. George basin (10 wells), Norton basin (6 wells), and Navarin basin (8 wells). In addition, deep stratigraphic test wells were drilled in Navarin (1 well), Norton (2 wells), St. George (2 wells), and North Aleutian (1 well) basins. Hope basin and St. Matthew-Hall basin were not penetrated by any wells, although two exploratory wells were drilled into Kotzebue basin, a feature beneath State of Alaska lands just east of and related to Hope basin (fig. 4). Although the Bering shelf Tertiary-age basins are generally considered gas-prone and some gas shows were encountered in wells, none of the 30 wells encountered pooled gas. The Bering shelf therefore does not offer any known gas reserves (fig. 1; tbl. 1).

Gas Reserves of Southern Alaska (Onshore Outside of Cook Inlet) and the Pacific Margin (Federal) Offshore Continental Shelves of Alaska

In Cook Inlet, in State waters near the town of Ninilchik and less than a mile east of Federal waters, the Starichkof State Unit No. 1 well encountered pooled gas (quantities not reported). The only Federal leases (2) presently active in Cook Inlet are near this well (located in fig. 5).

Near the City of Yakutat in eastern Gulf of Alaska (fig. 6), the Yakutat No. 3 well was drilled in 1959 and encountered shows that might indicate a gas pool. The City of Yakutat is reviewing the well data and is entertaining possible development of the gas pool for electrical power generation to supplement or replace imported diesel as the primary fuel for the community.

Eleven wells were drilled into the Copper River basin, a northeast extension of the Cook Inlet basin. Despite many geological characteristics in common with Cook Inlet, this basin apparently lacks some elements critical to formation of oil deposits (USGS, 1996, CD file: *prov03.rtf*, p. 9). Although minor gas shows were noted in

[4] *generally, that area between the Alaska Range and the north margin of the Brooks Range*

wells along the southern and eastern margins of the basin, none of the 11 Copper River basin wells encountered any pooled gas (or oil) accumulations. The Copper River basin of southern Alaska therefore does not offer any known, potentially exportable gas reserves.

On the Alaska Peninsula, west of Cook Inlet, oil and gas seeps are widely observed and these seeps attracted oil drillers to the area as early as 1903. Twenty-six (26) wells were drilled to test seeps (8) and anticlinal structures (18) in Tertiary and older rocks. Many wells encountered high geothermal gradients, consistent with the volcanic arc setting (USGS, 1995, CD file: *prov03.rtf*, p. 4-5, tbl. 1). Gas shows were noted in some wells, but no wells encountered pooled gas (or oil).

The land areas surrounding the Gulf of Alaska contain numerous oil and gas seeps (Flett, 1992, tbls. 7, 8, and 9). Katalla oil field, discovered in 1902 by drilling on a surface oil seep, produced and marketed 154,000 barrels of oil in the years 1902-1933 (fig. 6). The occurrence of the small oil field at Katalla has encouraged successive exploration programs through the years, offshore and onshore in the Gulf of Alaska, but all have failed to find any additional oil fields. Twenty-five wells and coreholes were drilled onshore in the eastern Gulf of Alaska and a 26th well was drilled on the continental shelf on State of Alaska lands near Middleton Island (USGS, 1995, CD file: *prov03.rtf*, p. 11). None of these wells discovered pooled accumulations of oil or gas, with the possible exception of the Yakutat No. 3 well near the City of Yakutat (fig. 6; noted above).

The offshore Pacific margin of Alaska includes the continental shelf areas near the Shumagin Islands, Kodiak Island, the southern parts of Cook Inlet, and the Gulf of Alaska (figs. 1, 4), altogether an area of approximately 126,000 square miles. A total of twenty-five wells have tested the Gulf of Alaska shelf (12 wells; fig. 6) and southern (Federal) areas of Cook Inlet (13 wells; fig.5). Eight (8) deep stratigraphic test wells were drilled on the Pacific margin, including Kodiak shelf (6 wells; fig.6), Gulf of Alaska shelf (1 well; fig. 6), and in southern Cook Inlet (1 well; fig. 5). The continental shelf near the Shumagin Islands has not been drilled. None of the 33 wells drilled on the Pacific margin encountered pooled gas accumulations.

In conclusion, neither southern Alaska onshore areas outside of Cook Inlet nor the Pacific margin continental shelves offer any known, potentially exportable conventional gas reserves (fig. 1; tbl. 1).

Gas Reserves of Cook Inlet

Oil and gas production has occurred in Cook Inlet basin from fields both onshore or beneath the waters of Cook Inlet itself for over 40 years, beginning with the discovery of 238 million barrels of oil at the Swanson River field in 1957 (tbl. 4; fig. 7). Most of these fields lie beneath State of Alaska lands. However, some onshore fields, like Swanson River, lie beneath Federal lands. There is no gas (or oil) production from the Federal offshore areas of Cook Inlet basin.

Very small quantities of gas, less than 0.010 tcf per year, were produced during the first seven years following the discovery at Swanson River. However, aggressive basin-wide exploration efforts prompted by the Swanson River discovery led to the identifications of many additional oil and gas fields by 1965 (tbl.4; fig. 7). From 1965 to 1970, Cook Inlet gas production quickly rose to modern levels of 0.15 to 0.22 tcf per year. In 1999, the last year for which complete information is available, Cook Inlet produced 0.211 tcf of natural gas (AKDO&G, 2000, p. 40). At this production rate, the 2.564 tcf of reserves remaining in 2000 (tbl. 4) can be projected to last 12.2 years (from 1999) or through year 2012.

Approximately 40% of the Cook Inlet gas production is currently used for field operations or is consumed locally (tbl. 5). Thirty-six percent of Cook Inlet gas production is exported to Japan as liquefied natural gas or “LNG”. Twenty-five percent of Cook Inlet gas production is used in the manufacture of fertilizer feed stocks (ammonia and urea) that are sold to world markets.

The ammonia-urea and LNG facilities at the Port of Nikiski were constructed in 1969 and helped spur the rapid expansion of Cook Inlet gas production in the early 1970’s (AKDO&G, 1998, fig. 4-2). The LNG plant has processed and shipped approximately 0.050 to 0.068 tcf per year since 1971; in 1998, 0.078 tcf were consumed to support 0.066 tcf[5] of LNG exports to Japan (AKDO&G, 1998, tbl. 6; Hakes, 1997). Presently, the Nikiski plant is the only significant LNG export facility in the U.S., although very small quantities have been trucked to western Mexico since August 1998 (DOE, 2000).

Since start-up in 1969, all Cook Inlet LNG exports have been received by two Japanese utilities, Tokyo Gas Ltd. and Tokyo Electric Power Co. Inc. In recent years, the shipping price of LNG leaving Port Nikiski has averaged $3.38/mcf (tbl. 6). Reflecting more recent volatility in world oil prices and Asian economic difficulties, Nikiski LNG prices slipped as low as $2.69/mcf by September 1998, but then rebounded to $4.33/mcf by September 2000 (tbl. 6).

The Japanese market pays a considerable premium for LNG. For example, U.S. LNG imports from Algeria, which must compete with U.S. domestic gas and pipeline imports from Canada, received an average price of $1.95/mcf for the 1995-1999 period. By comparison, the average 1995-1999 Nikiski (Japan-bound) LNG shipping price was $3.38/mcf (tbl. 6). In 1997, the U.S. became for the first time a net importer of LNG (Swain, 1999). Considering both exports and imports, the U.S. only accounted for about 3% of a total 1998 annual world LNG trade of 4.3 tcf (IPE, 2000, p. 238).

Japan imports 2.5 tcf per year or 59% of the total world annual LNG trade of 4.3 tcf (1998). Japan is the dominant (78%) importer of LNG in what is termed the “Asian Pacific Rim market”, which also includes South Korea (17%) and Taiwan (5%). The Asian Pacific Rim market imported a total of 3.2 tcf in 1998 (IPR, 2000, p. 238). The Nikiski plant in Cook Inlet supplies only 2.6% of annual Japanese gas demand, with most supplied by Indonesia and Malaysia, and lesser quantities by Australia, Brunei, and the United Arab Emirates (Hakes, 1997).

Unocal supplies gas to the ammonia-urea plant in Nikiski, which Unocal sold to Agrium Corp. in October, 2000 (PNAB, 2000d, p. A9). Phillips Petroleum Co. operates the LNG plant at

[5] *Some produced gas is consumed by LNG manufacture and some is lost as “boil-off” from ships while en route to Japan. The thermal efficiency for 1997 was 83%. The net efficiency of the process in Cook Inlet averages 82.5% (Feldman, 1996, p. 3-18).*

Nikiski. Marathon Oil Co. operates the LNG carriers. The LNG export operation takes gas mostly from Phillips and Marathon leases in the Cook Inlet basin, primarily the Kenai, Cannery Loop, Sterling, and North Cook Inlet fields (fig. 7). In 1996, Phillips and Marathon applied to the U.S. Department of Energy for a five-year extension of its export license, to cover LNG sales to Japanese utilities during years 2004 to 2009. The Phillips-Marathon application was protested by gas and electrical utilities in the Cook Inlet area, who feared, with some justification, that the proposed continued LNG sales would later cause a regional shortage of natural gas. A Department of Energy review concluded in April 1999 that adequate natural gas supplies exist in Cook Inlet to support LNG sales at current levels through 2009 (PNAB, 1999). However, the concerns raised by the Cook Inlet utilities highlight the unavoidable fact that unless additional reserves are found the entire natural gas reserve base in Cook Inlet will be exhausted by approximately year 2012 at present consumption rates.

In conclusion, as of 2000, the remaining gas reserves of Cook Inlet were 2.564 tcf. Given present consumption patterns (tbl. 5), 64% of this gas reserve will be used locally or converted to fertilizer feedstock. Thirty-six percent, or a total of 0.923 tcf, can be considered to be available for future export as LNG. At LNG contract consumption rates (0.078 tcf per year) for gas directed to LNG export, the 0.923 tcf LNG-dedicated gas reserves will be exhausted by year 2012.

3. UNDISCOVERED NATURAL GAS RESOURCE BASE IN ALASKA

Undiscovered Gas Resources of the Arctic Federal Offshore and Northern Alaska

Conventional Gas

The 2000 Minerals Management Service assessment (Wall, 2000, attch. 15) estimated that the mean undiscovered gas potential of the continental shelves offshore northern Alaska is 92.18 tcf. This estimate includes 32.07 tcf for Beaufort shelf and 60.11 tcf for the Chukchi shelf (tbl. 7; fig. 8). This gas occurs as both "associated" (as gas-caps and dissolved gas) and "non-associated" (no oil pool present) gas.[6] In the Beaufort shelf, the predicted mean gas volumes for individual undiscovered gas pools[7] range up to 7.0 tcf for non-associated pools and up to 1.6 tcf for gas associated with oil pools (Sherwood, 2000). The maximum (F05)[8] potential size of the largest hypothetical gas pool in Beaufort shelf exceeds 22 tcf. In Chukchi shelf, the predicted mean gas volumes for individual undiscovered gas pools range up to 10.2 tcf for non-associated gas and up to 2.4 tcf for gas associated with oil pools. The maximum (F05) potential size of the largest gas pool in Chukchi shelf exceeds 34 tcf (Sherwood, 2000).

The most recent (1995) U.S. Geological Survey assessment of the conventional gas resources of northern Alaska estimated that between 23 and 124 tcf of gas remain undiscovered, with a mean estimate or "expectation" of 63.5 tcf (tbl. 7, fig. 8). The undiscovered gas resources of northern Alaska are estimated to occur in accumulations ranging from 0.006 tcf to 37.5 tcf in size (USGS, 1995, CD DDS-36, *\region1\sizes1.tab*, play 111). The U.S. Geological Survey has estimated that 17.7 tcf or 28% of the northern Alaska undiscovered gas exists in conventional reservoirs greater than 15,000 feet deep (tbl.9; Dyman and others, 1998, tbl. 1).

Dixon and others (1994, tbl. 1) have estimated that undiscovered gas resources in the Mackenzie delta may range up to 60.5 tcf (25% probability) with a mean quantity or expectation of 53.3 tcf (fig. 8).

Gas Hydrates

An area of 7,500 square kilometers (2,900 square miles) of the continental slope of the Beaufort Sea, in water depths between 300 and 700 m (1,000 and 2,300 feet), is underlain by seismic features thought to mark gas hydrate deposits (Kvenvolden and Grantz, 1990, fig. 9). Collett (1995, pl. 21) has identified a much larger area for a gas hydrate play in the deep Beaufort Sea. An in-place[9] gas resource of 32,304 tcf (tbl. 8; fig. 9) has been estimated to be trapped within the Beaufort Sea gas hydrates (Collett and Kuuskraa, 1998, tbl. 1). An additional 71 tcf has been estimated for the shelf areas of the Beaufort and Chukchi Seas adjoining northern Alaska (tbl. 8).

Collett and Kuuskraa (1998, tbl. 1) have estimated that 519 tcf of natural gas (in-

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[6] *"associated" and "non-associated" gas quantities were not reported separately in the 2000 MMS assessment of offshore Alaska (Wall, 2000)*

[7] *mean, conditional, undiscovered, conventionally recoverable gas resources; pools may be considerably larger at low fractiles (or low probabilities for occurrence); "conventionally recoverable" means hydrocarbons that may be recovered to a conventional well bore using present-day or reasonably foreseeable future technologies*

[8] *F05 is the 5% fractile and equates to a 1-in-20 or 5% chance of occurrence for the predicted resource quantity; large gas fields occur much more rarely than small gas fields*

[9] *"in-place" means volume of gas resources stored in hydrates in subsurface, if brought entirely to the surface; no recoverability is implied*

place) may lie trapped within gas hydrates near the base of the 850 to 1,350 foot-thick permafrost layer beneath northern Alaska (Lachenbruch and others, 1988, tbl. 28.1, "z*"). The total area of this province is approximately 140,000 square kilometers or 54,000 square miles. In the area between the Prudhoe Bay field and the newly discovered Tarn field 45 miles to the west (fig. 3), Collett (1998) estimated that 37 to 44 tcf of natural gas (in-place) may reside within gas hydrates. Gas hydrates have been cored and detected by geophysical devices in several wells in this area (Collett, 1998).

Coal Bed Methane

Although some coals are present in the geologic column beneath the Beaufort and Chukchi Seas, no estimates have been made for coal bed gas resources in the offshore (tbl. 9). The vast coalfields of western parts of northern Alaska probably extend west and offshore beneath Chukchi shelf (fig. 10).

The State of Alaska is presently investigating coal bed gas resources as an energy source for rural communities that now must purchase liquid fuels at great expense. Smith (1995) estimated Alaska-wide in-place coal bed methane resources at 1,000 tcf. In a separate study, the Potential Gas Committee (PGC, 1999, tbl. 53) estimated the recoverable coal bed methane potential for all of Alaska to range from 15.0 to 76.0 tcf, with an average or expected resource of 57.0 tcf. As shown in figure 10, western parts of northern Alaska are underlain by vast coal deposits estimated to contain up to 4 trillion short tons of coal or approximately 72% of the total tonnage for the State. Some of the northern Alaska coals may be prospective for coal bed methane production. The State of Alaska has identified the northern Alaska coal fields as the top priority area for further coal bed methane investigations (drilling and degasification experiments) in the near future (Ogbe and others, 1999).

Undiscovered Gas Resources of Bering Shelf and Central Alaska

Conventional Gas

The Tertiary-age basins of the Bering shelf and Hope basin are generally considered gas-prone. In fact, only 20% of the hydrocarbon energy endowment of Hope basin and the Bering shelf basins occurs as oil (compared to 58% for the Chukchi and Beaufort shelves; Wall, 2000, attch. 15). Norton and St. Matthew-Hall basins are considered to offer potential only for gas.

The aggregate mean, undiscovered, conventionally recoverable natural gas resource base for Hope basin and the 5 Bering shelf basins is 22.19 tcf, a small fraction of the 155.68 tcf assessed for the much richer onshore and offshore areas north of the Brooks Range (tbl. 7, fig. 8). The undiscovered gas resources of the Tertiary-age basins of the Bering shelf are relatively low because of the general lack of reservoir formations or source rocks known to be capable of generating gas (or oil). The results of exploration drilling support this pessimistic view. The mean sizes of the largest undiscovered gas pools in these Tertiary-age basins are predicted to range from 0.4 tcf in St. Matthew-Hall basin to approximately 3.7 tcf in North Aleutian basin (Sherwood, 2000). The mean sizes of the largest gas pools in other basins are noted as follows: Navarin basin, 1.3 tcf; St. George basin, 2.3 tcf; Norton basin, 1.7 tcf; and Hope basin, 1.7 tcf (Sherwood, 2000).

The most recent U.S. Geological Survey assessment (USGS, 1995) of central Alaska predicts the occurrence, on average, of 2.8 tcf of undiscovered natural gas, possibly ranging up to 7.3 tcf (tbl. 7). Most (about 95%) of these gas resources occur in the Tertiary-age basins of central Alaska (USGS, 1995, DDS-36, *frac1.tab*). The maximum sizes of the undiscovered gas pools postulated for the Tertiary-age basins of central Alaska were estimated at 2.6 tcf, with median[10] expected sizes of 0.02 tcf (USGS, 1995, CD DDS-36, *region1\sizes1.tab,* plays 201, 205).

Gas Hydrates

In deep-water areas of the western Bering Sea[11], seismic features identified by Cooper (1978, fig. 5) and other investigators suggest the presence of gas hydrates across a vast area of over 400,000 square kilometers (150,000 square miles) (Collett, 1995, p. 35 and pl. 21). Collett and Kuuskraa (1998, tbl. 1) have estimated that the Bering Sea gas hydrates may hold 73,289 tcf of gas in-place (tbls. 8, 9), or an average areal richness of 763 mmcf per acre[12].

Although most of central Alaska is underlain by permafrost (Ferrians, 1965), no estimates have been made for gas resources potentially captured within subsurface gas hydrates.

Coal Bed Methane

Coals occur in some Tertiary-age basins in central Alaska, but no estimates have been made for coal bed methane resources. The State of Alaska has identified the Yukon basin (fig. 10) as offering particularly high potential (Tyler and others, 1998, p. 1). Gassy lignite was penetrated in a USGS climate history test well in the Yukon basin in 1994 (Tyler and others, 1998, p. 6). The State of Alaska is planning further investigations (seismic surveys, drilling, and degasification experiments) of the Yukon basin in the near future (Ogbe and others, 1999).

LAPP Resources, Inc. has initiated a project at Delta Junction Alaska (in the eastern Nenana basin; fig. 10), just south of Fairbanks which could supply all the gas needs of Fairbanks for many years. Fairbanks is not presently served by a natural gas supply, although very small quantities as LNG are currently trucked there from Cook Inlet basin. LAPP estimates Fairbanks demand at 17 bcf per year (D. Lappi, pers. comm., January 2001). LAPP has applied for 400,000 acres of *Shallow Gas Leases*[13] and estimates a resource potential of 5 TCF from coal seams alone (D. Lappi, pers. comm., January 2001). The Nenana basin project is located near the Alaska Highway or "ANGTS" gas pipeline route (fig. 27) currently proposed to commercialize northern Alaska gas reserves.

Undiscovered Gas Resources of the Pacific Margin (Federal) Continental Shelves of Alaska and Southern Alaska (Onshore)

Conventional Gas

The 2000 assessment of the Pacific margin offshore of Alaska predicted undiscovered, conventionally recoverable gas resources ranging between 2.42 and 18.92 tcf, with an average or mean gas resource of 8.22 tcf (tbl. 7; Wall, 2000). These undiscovered gas resources occur in pools for which the mean sizes of pools range up to 0.33 tcf (Cook Inlet), 1.21 tcf (Gulf of Alaska), and 2.0 tcf (Shumagin-Kodiak shelf) (Sherwood, 2000). At a 5% chance (F05), the largest undiscovered gas

[10] *median (F50), conditional, undiscovered conventionally recoverable gas resources as reported by Sherwood and others (1998, App. B); pools may be considerably larger at low fractiles (low probabilities for occurrence)*

[11] *in water depths between 1,000 to 2,400 m (3,300 to 7,900 feet) on the Bering Sea continental slope and rise, and, in very deep waters (3,700 to 4,000 m or 12,100 to 13,100 feet) of the deep Bering Sea oceanic basin*

[12] *This is a remarkably high concentration of gas. For comparison, the typical conventional gas reservoir might contain in place 2 to 4 mmcf gas per acre-foot, of which 50% to 80% (1 to 3.2 mmcf per acre-foot) might generally be recovered.*

[13] *a special program enacted in March, 2000 by the State of Alaska to encourage development of coalbed methane and other shallow gas resources, particularly in rural areas now dependent upon costly diesel fuel for power generation*

pool in Lower Cook Inlet may contain gas resources exceeding 0.9 tcf. The largest gas pools in Lower Cook Inlet are not associated with oil. At a 5% chance (F05), the largest undiscovered gas pool in Shumagin-Kodiak shelf may contain gas resources exceeding 6.5 tcf. None of the gas pools in Shumagin-Kodiak shelf are considered to be associated with oil. In the Gulf of Alaska, the largest gas pools were modeled as gas caps coexisting with underlying oil pools, although the geological model predicts some non-associated gas pools ranging up to 0.9 tcf in mean size.

The 1995 U.S. Geological Survey assessment (USGS, 1995) of southern Alaska predicts the existence of 0.7 to 4.3 tcf of undiscovered, conventionally recoverable gas, with an average expectation of 2.1 tcf (tbls. 7, 9). These gas resources occur mostly (80%+) in Cook Inlet[14], but some gas resources are also assigned to the Alaska Peninsula (USGS, 1995, CD DDS-36, *region1\prov03\frac1.tab*). The median (F50) size of undiscovered gas pools in Cook Inlet is predicted to be 0.017 tcf, with the maximum size predicted for undiscovered pools slightly exceeding 2.1 tcf. The maximum predicted size for undiscovered gas pools on the Alaska Peninsula is only 0.36 tcf (USGS, 1995, CD DDS-36, *\region1\sizes.tab*, plays 302, 303). Dyman and others (1998, tbl. 1) have postulated that 0.2 tcf or 10% of the undiscovered natural gas resources of southern Alaska occur in the Cook Inlet area in conventional reservoirs at depths greater than 15,000 feet (tbl.9).

Gas Hydrates

In deep waters of the Aleutian trench and slope and abyssal areas south of the Gulf of Alaska continental shelf, seismic features indicate the possible presence of gas hydrates. Collett and Kuuskraa (1998, tbl. 1) have estimated that 62,856 tcf of gas (in-place) may be trapped within these gas hydrates. The gas hydrate-bearing area of the Aleutian trench covers 530,000 square kilometers or 204,600 square miles (Collett, 1995, p. 41). With a mean in-place resource of 21,496 tcf gas, the average areal richness is 164 mmcf gas per acre.

No estimates are available for gas resources associated with gas hydrates in southern Alaska. Most of the Cook Inlet area and large parts of the lowland areas of southern Alaska are free of permafrost (Ferrians, 1965) and gas hydrates would generally not be anticipated in any significant quantity in the subsurface.

Coal Bed Methane

No estimates for coal bed methane resources for southern Alaska are available. Figure 10 shows that substantial coal deposits, totaling 1.535 trillion short tons, or over 27% of the Alaska total endowment, occur in southern Alaska coal fields, mostly in the Cook Inlet sedimentary basin. The coalfields at Chignik (located in fig. 10) may be particularly appropriate for coal bed methane production and are scheduled for further appraisal studies in the near future (Ogbe and others, 1999). The first coal bed methane test well in Alaska was drilled by the State of Alaska in northern Cook Inlet basin in 1994 and encountered coals yielding between 63 and 245 cubic feet of methane per ton of coal from 521 and 1,236 feet respectively (Smith, 1995).

Two commercial coalbed methane projects have been initiated in recent years in Cook Inlet sedimentary basin. First, Lapp Resources, Inc. initiated an exploration project at Houston, Alaska in the northern Cook Inlet basin. In 1997, Growth Resources, Inc. (GRI), a subsidiary of an Australian company, farmed in and drilled three commercial coal bed gas test wells in early 1998. One of these wells was

[14] *onshore lands and State of Alaska waters overlying the Cook Inlet sedimentary basin*

"dewatering"[15] five coal seams at the rate of 500 barrels per day in 1998 (Lappi, 1998), but that project now appears to have been temporarily abandoned. During February 2000, the State of Alaska initiated a new Shallow Gas Leasing program, which attracted applications for leases covering the old GRI acreage as well as about 300,000 more acres in the northern Cook Inlet Basin. Evergreen Resources, Inc., a specialist coalbed gas developer based in Denver, CO was one of the applicants. Second, UNOCAL and Ocean Energy, Inc. have an ongoing joint coalbed methane project, the "Pioneer" unit, near Wasilla, Alaska in northern Cook Inlet sedimentary basin. Clough (1999) presented the UNOCAL-Ocean Energy study of the 60,000 acre Pioneer coal bed methane prospect in northern Cook Inlet basin that indicated an in-place potential of 3.6 tcf or an average areal richness of 60 mmcf gas per acre. Two new test wells, a new water disposal well, and a re-completed existing well in the Pioneer unit were scheduled for production testing during the past (2000) summer, but that work has reportedly been deferred while Ocean Energy restructures its coalbed methane team and seeks new partners for part of its working interest.

Total Conventional Gas Resource Base (Discovered and Undiscovered) for Alaska

The undiscovered, conventionally recoverable gas resources[16] of Alaska and its continental shelves total 190.99 tcf (tbl.7). When added to the discovered, potentially exportable gas endowment of 26.923 tcf, we obtain a combined conventional gas reserve and undiscovered gas resource base of 217.913 tcf. Eighty-three percent of this "conventional" gas occurs in Arctic settings north of the Brooks Range.

Some of the undiscovered, conventionally recoverable gas resources may be discovered in the course of future oil exploration. Future development of Alaska gas discoveries will probably be initially confined to areas near existing infrastructure in northern Alaska (Prudhoe Bay area) or southern Alaska (i.e., Cook Inlet). At present consumption rates, Cook Inlet gas reserves will be exhausted by year 2012 and the coming shortage may prompt renewed exploration specifically for gas.

Gas resources in coal beds may be developed within the coming decades, but the status of this resource remains highly speculative pending further drilling and testing of known coal deposits. Coal deposits possibly appropriate for coal bed methane production appear to be present in a number of Alaska basins, but their actual gas production potential remains largely unevaluated. Coal bed methane resources, when developed, will probably be used primarily by local (Alaskan) industries and communities. Smith (1995) speculated that the coal bed methane potential for Alaska may equal 1,000 tcf. The conventional gas reserve/resource base ***and*** coal bed methane resources therefore total 1,217.913 tcf for Alaska.

Gas resources associated with gas hydrates in Alaska offer an immense (169,039 tcf Alaska-wide) but largely speculative potential energy source. When added to the conventional and coal bed methane gas resources, we obtain a total Alaska gas resource base of 170,256.913 tcf. The 37 to 44 tcf in-place gas hydrate deposits associated with permafrost in the developed areas near Prudhoe Bay in northern Alaska would probably be extracted before any of the other, generally deep-sea Alaskan gas hydrate deposits.

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[15] *Generally, coal bed methane wells must undergo an initial period of water production to allow gas to move to well bores. With time, water production declines or ceases while gas production rises.*

[16] *expected (mean), undiscovered, conventionally recoverable gas, as reported by Wall (2000) and USGS (1995)*

However, no development of the Prudhoe-area gas hydrate resources is presently entertained and they will probably remain untapped until a gas transportation infrastructure for export of northern Alaska gas is constructed. Over ninety-nine percent (99%) of Alaska gas hydrate resources occur offshore in waters several thousands of feet deep and must be viewed as economically inaccessible for the long-term future (beyond the year 2020).

4. UNDISCOVERED, ECONOMICALLY RECOVERABLE GAS RESOURCES OF ALASKA

Rationales for Market and Transportation Scenarios Used in Economic Models

A wide variety of transportation and marketing scenarios have been used in the economic assessments of the Alaska Federal offshore provinces. Because no gas transportation system now exists in Alaska outside of Cook Inlet basin, all of the varied scenarios used in our economic assessments form valid hypotheses for future gas developments. Perceptions about the future of Alaska gas constantly change and new gas development schemes seem to arise with each passing month.

In each offshore province, we tried to identify the most likely or most practical market to which produced gas might be directed at the time of the assessment. In the 2000 assessment, gas is sent to local markets in 3 economic models and gas is sent to Japan as liquefied natural gas (LNG) in 7 economic models, the latter sharing a common destination but using 7 distinct transportation models.

Although sending offshore gas production from all provinces to a single hypothetical market might facilitate economic comparisons between provinces, no single market has emerged as the most likely candidate among the various export or development schemes under consideration by industry. Furthermore, a single-market approach would ignore certain economic realities and paint a distorted picture of the economic gas potential of the Alaska offshore. For example, gas produced in the Lower Cook Inlet might be justifiably modeled as being entirely exported as LNG to Japan. Indeed, 0.060 tcf per year is already exported in this manner from northern Cook Inlet gas fields (State lands) to Japan. However, the existing gas reserves in northern Cook Inlet are being rapidly depleted and could be exhausted by year 2012. The undiscovered gas volumes that we forecast for Lower Cook Inlet are modest (0.6 to 1.0 tcf economic gas) and any new gas production would be readily absorbed by the existing 0.2-0.3 tcf per year Cook Inlet basin gas market. An economic model directing the Lower Cook Inlet gas to the local market seems most practical in the context of the locations and quantities of the gas resources and the looming gas shortages forecast for Cook Inlet basin.

In contrast, the gas resources of Chukchi shelf, the Bering Sea (Norton, Navarin, St. George, and North Aleutian) basins, Shumagin-Kodiak shelf, and Gulf of Alaska shelf were all modeled as developed for export to Japan as LNG rather than delivered to Alaska markets. These areas are all highly remote, high-cost environments and none have ready access to any existing gas transportation systems. These areas must all bear the burden of constructing and amortizing costly new gas processing facilities and transportation systems. This burden is reflected in the low economic potential of these areas at gas prices in the $2.00/mcf to $3.50/mcf range. Traditionally, the Asian Pacific Rim LNG market has offered the highest prices for gas and the best chance for supporting future gas development in high-cost Alaska offshore provinces.

In both the 1995 and 2000 MMS economic assessments, each province was modeled as a stand-alone; that is, production from each province was required to financially support an independent oil and gas infrastructure. These assessments are therefore conservative because they do not allow for infrastructure sharing between different basins. The rationale for the stand-alone approach is partly based on the fact that these basins are leased on an individual basis. Leasing in one area does not necessarily entrain leasing in adjacent areas. In the Bering shelf—the area that would benefit most from infrastructure sharing—no basins are presently scheduled for leasing and the most promising (North Aleutian) basin is under a moratorium on leasing until year 2012. Although unlikely, it is imaginable that two or more Bering shelf basins might simultaneously provide gas to a shared shore-based LNG facility. In a scenario for infrastructure sharing by multiple basins, total project costs would be allocated to a much larger resource base. The quantity of economically recoverable gas resources for any group of gas-producing basins that share infrastructure would be higher than the stand-alone resources reported by the 1995 and 2000 assessments.

Results of Economic Assessment

The results of the economic assessment are reported in table 10. Economic gas resources are reported for two price scenarios, \$2.00-\$2.11/mcf and \$3.34-\$3.52/mcf. The U.S. Geological Survey used the \$2.00/mcf and \$3.34 scenarios in their 1995 assessment (Attanasi, 1998). The MMS uses \$2.11/mcf because it is linked to \$18/bbl oil on an energy basis with a 0.66 value discount for gas. A gas price of \$3.52/mcf similarly corresponds to an oil price of \$30/bbl. \$18 and \$30 oil prices are standard price scenarios used for economic modeling by the MMS. The \$2.00-\$2.11/mcf price range corresponds conveniently to the 1993-1997 five-year average U.S. wellhead gas price of \$1.99/mcf reported by DOE (1999a). The \$3.34-\$3.52/mcf gas price range corresponds approximately to the 1995-1999 average price paid for gas (\$3.38/mcf) as LNG bound for Japan from Nikiski, Alaska.

Table 10 shows that a total of 5.140 tcf of gas could be economically recoverable from the Alaska Federal offshore at a price of \$2.11/mcf. When added to an onshore total of 1.033 tcf, the total for all of Alaska rises to 6.173 tcf at \$2.11/mcf. The offshore total at \$3.52/mcf is 8.674 tcf, rising to 12.230 tcf when onshore totals are included.

The 2000 economic assessment of the Alaska offshore by Craig (2000) is the basis for the results shown in table 10, which shows a total of 5.140 tcf at \$2.11/mcf. The national summary report (MMS, 2001) shows a different total for the Alaska offshore, 1.6 tcf. The gas potentials for Beaufort shelf (2.934 tcf) and Hope basin (0.614 tcf) were left out of the Alaska total reported in MMS (2001) because the economic models for these areas did not transport the gas to existing markets outside of Alaska. In both cases, the economic gas resources were modeled as deliverable to new processing plants that do not exist at present. The gas could then be transported to markets outside Alaska in several forms (pipeline gas, LNG, or synthetic petroleum liquids) at added costs. The market destination and commodity type will dictate the final cost to consumers. The economic models used for these areas are only sensitivity studies showing what could be available to a local processing plant at a given price.

Undiscovered Economic Gas in Arctic Alaska Offshore and Northern Alaska (Onshore)

The 1995 Minerals Management Service (MMS) and U.S. Geological Survey (USGS) assessments of Alaskan gas resources both concluded that no economic gas resources (outside of known reserves) existed under then-current economic conditions in Arctic Alaska (tbl. 10). The MMS study (Sherwood and others, 1996, p. 9) noted that although very large gas resources probably remain undiscovered in the Chukchi and Beaufort shelves:

> "……because of the lack of a gas transportation system from Arctic Alaska and the presence of huge, but marginally profitable, proven gas reserves onshore it is very unlikely that development of new offshore gas fields will occur in the foreseeable future. Therefore, no economic gas resources are reported for the Beaufort and Chukchi shelf provinces."

Similarly, the USGS study (Attanasi, 1998, p. 8) concluded that:

> "Because of the absence of a market for the gas resources of Northern Alaska, non-associated gas fields were not evaluated and a zero price was attached to the extracted associated gas from oil fields"

The 2000 economic assessment of Beaufort shelf (Craig, 2000) assumed a different scenario than the 1995 study. The 2000 assessment assumed the existence of some unspecified future gas transportation system originating at Prudhoe Bay and with sufficient excess capacity to carry the gas (or perhaps synthetic petroleum liquids made from gas) to an unspecified export market. The model was designed to assess the economic viability of co-development of associated gas pools on Beaufort shelf for delivery via pipeline to a "plantgate" at Prudhoe Bay. All potential processing costs, transportation tariffs, and marketing costs downstream of the Prudhoe Bay plantgate were ignored. We took this approach because several proposals are competing for development of northern Alaska gas reserves and no single proposal has yet emerged as the most likely candidate. The Beaufort shelf model assumed that the gas is co-produced with oil, that gas development is largely supported by the oil development infrastructure, and that gas production costs are partially offset by revenues from co-produced oil. The results of this model were reported by Craig (2000) and are shown in table 10 and figure 13. The two price scenarios ($2.11/mcf and $3.52/mcf) in table 10 for Beaufort shelf represent the prices paid for gas sold at the Prudhoe Bay plantgate. At $2.11/mcf for the mean resource case, 2.934 tcf of gas may be economic to develop on Beaufort shelf and pipe to Prudhoe Bay. At $3.52/mcf for the mean resource case, 4.200 tcf of gas may be economic to develop. Significantly, figure 13 shows that $1.00/mcf at Prudhoe plantgate forms the threshold price for development of Beaufort shelf gas. The $1.00/mcf price for Beaufort gas must be added to any downstream costs to compute at a profitable threshold sales price at some distant export market. For comparison, existing gas sales at Prudhoe Bay now typically have handling costs of $0.20/mcf (State of Alaska, Tax and Royalty Regulations; Roger Marks, pers. comm., January 2001).

Although considerable undiscovered gas resources are forecast for Chukchi shelf (60.1 tcf, tbl. 7), the 2000 economic assessment by Craig (2000) found gas to be uneconomic at both of the price scenarios in table 10. We estimate that the minimum costs for delivering Chukchi shelf gas to Japan via a hypothetical gas pipeline to Valdez and then via LNG tanker fleet across the Pacific Ocean would be $3.63/mcf, which exceeds the higher price scenario

($3.52/mcf) of table 10. At prices above $3.63/mcf, Chukchi shelf offers some economic gas potential, as discussed in section 5 below.

Undiscovered Economic Gas in Bering Shelf (Offshore) and Central Alaska (Onshore)

In the 1995 MMS economic assessment conducted by Craig (1998a, 1998b), development of offshore gas resources in Hope basin and the Bering shelf basins assumed variations on an LNG export model with final delivery to the Asian Pacific Rim. The 2000 economic assessments by Craig (2000) revised the economic model for Hope basin, taking the gas to a local point of sale and ignoring the potential additional cost burdens of extended downstream gas export infrastructures. The economic models for Hope basin (and Lower Cook Inlet, discussed below) were designed for sales to local markets because local demand for natural gas actually exists in these two areas.

The LNG export models used in 1995 were retained in 2000 for the Bering shelf basins. The LNG export models included new offshore development platforms and wells along with costs for major transportation infrastructure components, such as pipelines, shore-based LNG plants, and marine terminals for the LNG carrier fleet.

The 1995 results (Craig, 1998b) for the Bering shelf (Norton, Navarin, St. George, and North Aleutian) basins are reported here in table 10 (and in relevant price-supply graphs) recast as valid for year 2000 (that is, in $2000) because of the small overall changes in oil and gas prices or development and production costs in the 1995-2000 period.

Table 13 lists pipeline lengths used in the economic assessments of the offshore provinces. Pipeline lengths vary greatly and can impose large cost burdens to potential gas development. Table 14 shows that marine LNG shipping tariffs for delivery to Yokohama, Japan range from $0.60/mcf to $1.20/mcf. Table 15 shows that gas pipeline tariffs and LNG processing alone can range from $1.02/mcf to $2.83/mcf, and when added to marine shipment tariffs, can exceed $3.00/mcf in some provinces without considering development and production costs at the offshore lease.

Some offshore basins lie near land sites suitable for ports and onshore LNG plants, and short subsea pipelines clearly offer a clear economic advantage for these basins. Constructing LNG facilities offshore might avoid the costs of lengthy subsea pipelines. However, offshore LNG plants were not entertained for these economic models because their feasibility has not been demonstrated. Offshore conditions of periodic heavy seas and perennial ice cover could impede offshore LNG loading and scheduled LNG tanker access to offshore facilities in most Alaska offshore basins.

For Hope basin, the 2000 economic model assumed the existence of a port (one exists now) and industrial complex (one doesn’t exist now) at Kivalina on the north shore of Kotzebue Sound. Produced gas from offshore fields was piped to a plantgate at Kivalina and sold. The gas sold to Kivalina could be piped to the existing Red Dog zinc mine 50 miles inland and replace costly imported diesel fuel for power generation and heating needs. Conceivably, the gas taken to Kivalina could also be converted to synthetic liquid petroleum fuels (at a future facility) and sold to the mining operation or the Bering Sea fishing fleet. The price-supply results shown in figure 15 and reported in table 10 are for gas delivered to Kivalina and do not account for any marketing or processing costs downstream from Kivalina. Figure 15 shows that the price threshold for economic gas resources in Hope basin is approximately $1.40/mcf.

Assuming Asian Pacific Rim LNG prices ($3.34 to $3.52/mcf[17] price scenario, tbl. 10), the economic assessments found a total of 3.028 tcf of undiscovered, economically recoverable gas in the Hope basin and Tertiary-aged basins of Bering shelf. Most of this economic gas is in Hope and North Aleutian basins. Although Hope basin gas pools are relatively small (maximum mean size, 1.7 tcf), the gas is only piped 100 miles to Kivalina and sold. In the North Aleutian basin, gas pools are predicted to be relatively large (up to mean size of 3.7 tcf; Sherwood, 2000) and the basin center lies only 70 pipeline miles from a hypothetical onshore LNG plant site at Balboa Bay on the south side of the Alaska Peninsula (fig. 11; tbl. 13). However, North Aleutian basin had to bear the costs of constructing the port and LNG plant at Balboa Bay in addition to costs of shipping the LNG to Japan, which offset its geographic advantages. Figure 19 shows that the price threshold for significant economic gas in North Aleutian basin ranges from about $1.50/mcf to $4.00/mcf, depending upon resource case.

For the Tertiary-age basins of central Alaska and southern Alaska excluding the Cook Inlet sedimentary basin, the U.S. Geological Survey economic assessment (Attanasi, 1998, p.8) concluded that:

> "The oil and gas resources of the Central Alaska province and of the Southern Alaska province outside the Cook Inlet were not evaluated by the economic analysis because these areas have very limited potential and expected discovery sizes are insufficient to offset cost barriers imposed by the hostile climate, primitive infrastructure, and remoteness from markets."

Therefore, central Alaska is not considered to offer any undiscovered economically recoverable gas resources at the present time (tbl. 10).

Undiscovered Economic Gas in the Pacific Margin (Offshore) and Southern Alaska (Onshore)

In the 2000 economic model for Lower Cook Inlet, the gas was piped to landfall at the existing gas pipeline network in Cook Inlet basin (presumably Kenai). At landfall, the gas was sold to an unspecified buyer for ultimate resale to residences, utilities, and industrial users in the areas surrounding Cook Inlet. The gas development scenario for Lower Cook Inlet is summarized in table 12 and figure 11. The price-supply results graphed in figure 21 and reported in table 10 are for gas sold within Cook Inlet basin. Gas production was modeled as largely supported by the oil development infrastructure and revenues from co-produced oil partially offset gas production costs. The 2000 assessment of Lower Cook Inlet forecasts 0.599 tcf of gas at $2.11/mcf and 0.997 tcf of gas at $3.52/mcf delivered to the Kenai area pipeline landfall. Figure 21 shows that the price threshold for economic gas resources in Lower Cook Inlet is approximately $1.00/mcf.

Shumagin-Kodiak shelf was assumed to utilize the existing marine terminal and LNG plant (expanded with some new construction) at Nikiski in Cook Inlet. LNG carriers were assumed to be contracted through a third party shipping company and a shipping tariff was paid to transport the

[17] *$3.52/mcf LNG in the Asian Pacific Rim market is approximately equivalent to an oil price of $16.50 per barrel using energy parity to oil and the oil price to Asian Pacific Rim LNG price conversion formula of Thomas and others (1996, p. 5-10). $3.52/mcf for domestic U.S. gas is approximately equivalent to an oil price of $30.00 per barrel, using the conventional 0.66 gas value discount relative to oil.*

gas to Yokohama, Japan (tbl.12). The substantial costs of construction and operation of a regasification plant at the receiving port were not deducted in the netback to the producer. The gas transportation scenario used in the 2000 MMS assessment is summarized in table 12 and figure11.

The Shumagin-Kodiak shelf offers 0.449 tcf of undiscovered, economically recoverable conventional gas at $3.52/mcf delivered as LNG to Japan. Eastern parts of Kodiak shelf are within 215 pipeline miles (tbl. 13) of the existing port and LNG plant at Nikiski in Cook Inlet (fig.11). Expanding the Nikiski plant to handle Shumagin-Kodiak gas production avoids the large capital outlays for new LNG plants and marine terminals that burden development of other Alaska offshore basins using the LNG model. Nevertheless, figure 22 shows that the price threshold for economic gas resources in Shumagin-Kodiak shelf is approximately $3.00/mcf.

Although the Gulf of Alaska shelf is assessed with 4.2 tcf in conventional gas resources (tbl.7), none of this gas was deemed economic to recover in either the 1995 or 2000 MMS assessments (Craig, 1998b; 2000). Larson and Martin (1998) predicted that the gas in the Gulf of Alaska shelf occurs mostly in association with oil. The gas would not be available for gas sales because it would be re-injected over the 20+ year productive lives of the oil fields to help maintain reservoir pressure and as fuel for production operations at the leases. Aside from lengthy subsea pipelines, the main cost burden to development of gas on Gulf of Alaska shelf is the marine terminal and LNG plant that would have to be constructed at Yakutat (model described in tbl. 12 and fig. 11). Model simulation runs conducted by Craig (1998b, p. 362-3) in the 1995 MMS assessment showed that the profitability of oil developments in the Gulf of Alaska shelf was decreased by gas co-production and sales. Therefore, the 1995 and 2000 economic assessments of the Gulf of Alaska shelf did not report any economically recoverable gas (Craig, 1998b, p. 362-365; 2000). Figure 20 shows that the price threshold for significant quantities of economic gas resources on Gulf of Alaska shelf ranges between $5.00/mcf and $8.00/mcf.

The uplands and State of Alaska waters of Cook Inlet were evaluated by the USGS (Attanasi, 1998, tbl. 1) as offering 3.556 tcf of economically recoverable gas in a premium Pacific Rim LNG price scenario ($3.34/mcf; tbl. 10). In the USGS domestic gas price scenario ($2.00/mcf), Attanasi (1998, tbl. 1) estimated that 1.033 tcf of undiscovered natural gas may be economically recoverable in the uplands and State waters of Cook Inlet basin. As noted above, the same study dismissed any economic oil or gas potential in southern Alaska outside of the northern Cook Inlet sedimentary basin.

Total Undiscovered Economic Gas in Alaska

In conclusion, the endowment of economically recoverable gas in the Alaska Federal offshore ranges from 5.140 tcf at $2.11/mcf to 8.674 tcf at $3.52/mcf with gas delivered to an assortment of markets. The economic gas volume at $3.52/mcf represents about 7 percent of the 122.8 tcf conventional gas resource base for the Alaska offshore (tbl. 7). The total economic gas for all of Alaska, offshore and onshore, ranges from 6.173 tcf (at $2.00-$2.11/mcf) to 12.230 tcf (at $3.34-$3.52/mcf) or at most about 6 percent of the aggregate offshore and onshore 191.2 tcf conventional gas resource base (tbl. 7).

Most of the gas resource base of Alaska

fails economic viability tests because it either occurs in remote locations with formidable logistical hurdles and high development costs for new infrastructure, or, because it occurs in relatively small pools. Where gas is associated with oil, gas production is economic in some cases because costs are offset by oil production revenues. Non-associated gas pools are not treated separately as a group in the assessment models and could benefit from co-production of condensate, but surely face more severe economic hurdles than the associated gas pools.

Very little of the vast gas resources forecast for the offshore have been located by drilling, including the “economic” gas volumes predicted by our models. An expensive exploration drilling program, preceded by a vigorous leasing program, will be required to confirm or refute the existence of these undiscovered economic gas resources.

5. UNDISCOVERED ECONOMICALLY RECOVERABLE GAS RESOURCES POTENTIALLY AVAILABLE AT $6.00/MCF IN THE ALASKA FEDERAL OFFSHORE

In early January 2001, Henry Hub (Louisiana) gas prices were approximately $7/mcf and Los Angeles city gate prices were approximately $12/mcf. These runaway prices will surely stimulate the search for new gas reserves, perhaps even in the frontier offshore basins of Alaska. The purpose of this section is to examine the potential for economic gas in the Alaska offshore at prices that are quite high by historical standards, like those witnessed in recent months in the U.S. domestic gas market. These high prices may or may not be sustainable into the future, but it is instructive to ask what the offshore gas potential might be under high price conditions.

The economic models for the Alaska offshore province assume a variety of market destinations that make it difficult to draw direct economic comparisons at some single gas price. However, the main point of the exercise is not to compare offshore provinces but to simply ascertain if significant gas resources in the Alaska offshore do become economic at high natural gas prices. To that end, we will examine the gas resources that might become economic to recover at $6/mcf ($2000), which inflates (at 3.1%) to a nominal gas price of $11.05/mcf by year 2020. This starting reference price is about three times higher than recent historical domestic U.S. wellhead gas prices (1995-1999 average, $2.01/mcf), about 1.5 times the recent historical prices for LNG (1995-1999 average, $3.38/mcf) delivered to Japan (tbl. 6), and nearly twice recent historical U.S. domestic city gate gas prices (1995-1999 average, $3.20/mcf; DOE, 2000).[18]

The sum of Alaska offshore gas resources that are economic to develop at $6/mcf ($2000) is 35.78 tcf for the mean resource case (tbl. 16). The estimates for economically recoverable gas at $6/mcf are read from the price-supply graphs that are presented in figures 13 to 22. The quantities of gas economic at $6/mcf are listed by province in table16 and are also posted on a regional map in figure 23.

The 2000 economic model for Beaufort shelf assumed that the point of sale would be a plantgate at the Prudhoe Bay industrial complex. Here, the gas would be sold to separate commercial enterprises that presumably would export the gas in some unspecified form to markets outside of Alaska. At $6/mcf paid at Prudhoe Bay, from 1.13 to 14.30 tcf of gas might be economic to develop on Beaufort shelf, with 4.66 tcf of economic gas for the mean resource case (fig. 13).

Figure 14 shows a gas price-supply curve for the mean resource case for Chukchi shelf. The lower part of the price-supply graph for Chukchi shelf is shaded to set apart gas that might be used locally within the Arctic Alaska[19] or Prudhoe Bay infrastructures[20] from gas that might be commercial to export. Although some gas could be consumed by local field operations, the assumption here is that a significant Alaska market for the gas, besides that needed to run North Slope production facilities, does not exist. Our estimate for a

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[18] *Future demand for natural gas is tied to economic growth. Energy prices are a key component of inflation. It follows that if energy prices were to double, there would be a lower demand with slower economic growth. Energy prices cannot rise sharply without affecting other elements of the economy.*

[19] *Arctic Alaska: hypothetical newly-constructed infrastructure, offshore or onshore*

[20] *Prudhoe Bay operations since 1977 have consumed approximately 3.7 tcf of gas (tbl. 2)*

minimum (breakeven) delivery cost for Chukchi shelf gas as LNG to Japan is $3.63/mcf. The region of the price-supply graph above $3.63/mcf in figure 14 represents the gas resources that are potentially available for export. Although the Chukchi shelf model calculated positive economic values at prices below $3.63/mcf, this is because of some of the assumptions in the economic model. The Chukchi shelf gas is assumed to be co-produced with oil. The produced gas is not re-injected but immediately piped to a regional trunk pipeline head at Prudhoe Bay, then piped to Valdez, converted to LNG, and shipped to Japan. Because gas development is largely supported by the oil development infrastructure (wells, production platforms, etc.), gas production and pipeline transmission costs are partially offset by revenue from co-produced oil. Even when gas is produced and sold at a loss, the losses may be fully compensated by oil revenues. Therefore, net positive outcomes are sometimes computed in trials at gas prices below $3.63/mcf. At the hypothetical high price of $6/mcf ($2000) paid at the point of sale in Japan, the Chukchi shelf offers 20.0 tcf, or 56% of the 35.78 tcf total for the entire Alaska offshore (tbl. 16).

Hope basin is located near the existing Red Dog mine terminal and barge port at Kivalina, which is the assumed point of sale for Hope basin produced gas in the 2000 economic model. Economic gas at $6/mcf sold at Kivalina ranges from 1.9 tcf for the mean resource case to 8.2 tcf for the high resource case in Hope basin (fig.15; tbl.16).

In Navarin basin, Norton basin, and St. George basin, the costs for development and export of gas as LNG to Japan are greater than potential revenues from gas sales, even at $6/mcf. All of these basins are uneconomic for commercial gas development at prices under $10/mcf delivered to Japan (figs. 16, 17, and 18; tbl. 16).

North Aleutian basin is located in relatively shallow water and is close to a suitable site for an LNG plant and all-season harbor (not existing at present) at Balboa Bay (see fig.11). North Aleutian basin also offers the potential for large gas pools at relatively shallow subsurface depths (6000 ft). Economic gas at $6/mcf delivered as LNG to Japan ranges from 5.9 tcf for the mean resource case to 15.3 tcf for the high resource case for North Aleutian basin (fig.19; tbl.16).

The relationship between price and undiscovered economically recoverable gas resources in the Gulf of Alaska shelf is presented in figure 20. The lower part of the price-supply graph (below $3.04/mcf price) for the Gulf of Alaska shelf is shaded to set apart gas that might be marketed locally in Alaska (field operations and public consumers) from gas that might be commercial to export to distant markets outside of Alaska. For the Gulf of Alaska shelf, our estimate for a breakeven delivery cost as LNG to Japan is $3.04/mcf. The regions of figure 20 above $3.04/mcf therefore can be taken to represent the gas resources that might be viable as exports. At the hypothetical gas price of $6/mcf at a point of sale in Japan, the Gulf of Alaska offers only 0.31 tcf of exportable gas resources. Prices approaching $10/mcf would be required to develop a significant fraction of the gas resources of the Gulf of Alaska shelf in this economic model.

The economic model for Lower Cook Inlet assumes that produced gas is sold to the existing gas pipeline network in northern Cook Inlet for resale by a separate business entity to utilities and residential customers. Most of this gas will be consumed locally, but some could be exported by separate commercial enterprises downstream of the point of sale. At $6/mcf sold in northern

Cook Inlet, from 0.67 to 1.92 tcf of gas might be economic to develop, with 1.24 tcf of economic gas in the mean resource case.

Shumagin-Kodiak shelf benefits from proximity to an existing LNG export facility and port at Nikiski in northern Cook Inlet. Economic gas at $6/mcf delivered as LNG to Japan ranges from 1.4 tcf for the mean resource case to 6.4 tcf for the high resource case for Shumagin-Kodiak shelf (fig.22; tbl. 16).

6. LONG TERM (YEARS 2010 TO 2050) EXPORT OPTIONS FOR ALASKA NATURAL GAS

Current Alaska Gas Export Issues and Background

At present, liquefied natural gas (LNG) exports from Cook Inlet, Alaska, to Yokohama, Japan, represent the only Alaskan gas sold to markets outside of Alaska. Cook Inlet gas is also converted to fertilizer feedstock and exported from Alaska. No natural gas is being marketed from northern Alaska, although approximately 3.7 tcf has already been consumed by local oil production operations at Prudhoe Bay (tbl.2). Almost 35 tcf of natural gas have been produced and re-injected into oil reservoirs in Prudhoe Bay area fields to help increase oil recoverability (AKDO&G, 2000, p. 37). The gas reserves of northern Alaska are "stranded" because no transportation system to export the gas has been constructed.

Clearly, any discussion of future gas exports from Alaska must focus on northern Alaska because 97 percent of remaining known Alaska gas ***reserves*** (tbl. 1) and 81 percent of undiscovered Alaska gas ***resources*** (tbl. 7) occur north of the Brooks Range in northern Alaska. Of course, any of the new infrastructure or technologies used to develop northern Alaska gas might also eventually support development of gas resources in central Alaska, southern Alaska, the Bering shelf basins, or the Pacific margin continental shelves.

Since the discovery of the gas reserves in the Prudhoe Bay field over 30 years ago, various schemes for exporting northern Alaska gas have been entertained. Of all of the schemes, one involving a gas pipeline to southern Alaska, conversion to liquefied-natural-gas, or "LNG", and marine transportation of LNG to Pacific Rim markets has been the most enduring. However, the LNG market is small and could be overwhelmed by any large LNG project.[21] Now, other competing proposals with different markets may offer more profitable options for developing the huge northern Alaska gas reserves.

The producing oil fields on the North Slope are now declining rapidly toward ultimate depletion (fig. 24). The recent addition of new production from Tarn and Alpine fields, although certainly significant in the context of U.S. oil fields, cannot offset the huge declines at the Prudhoe Bay and Kuparuk fields.[22]

Re-injection of large quantities of produced gas has helped maintain reservoir pressure and has enhanced the recovery of oil[23], but gas exports could probably begin sometime between years 2005 and 2015 with no loss in ultimate oil recovery. A gas marketing system beginning construction today would probably be operative no sooner than year 2010 (Thomas and others, 1996, p.vii), although both BP-Amoco and Phillips Alaska have announced that gas sales could

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[21] *Northern Alaska production currently handles (and could produce to market) a very large volume of gas, larger than the entire Asian Pacific Rim market. For example, 2.6 tcf gas was produced and re-injected into Prudhoe-area oil fields in 1998, as compared to 3.2 tcf LNG gas consumption in all of Asia in 1998 (AKDO&G, 2000, p. 34; IPE. 2000, p. 238)*

[22] *Prudhoe Bay and Kuparuk fields are the largest and second-largest producing fields in the U.S. At peak production in approximately year 2003, the combined rates from Alpine and Tarn fields are expected to be approximately 80,000 bopd. At that time, the rest of the northern Alaska fields are projected to be producing at a combined rate of 800,000 bopd.*

[23] *It was noted above that diversion of produced gas away from re-injection and to major gas sales beginning as early as year 2000 might cause a loss of 1 billion barrels in ultimate oil recovery (Thomas and others, 1996, p. A-7).*

begin as early as 2007. With time, the quantity of annual gas production at Prudhoe-area fields has increased,[24] and if gas sales are not initiated, the gas handling and re-injection facilities, now operating near capacity, will have to be expanded at some cost (Thomas and others, 1996, p. 1-2). Lastly, as the producing oil fields decline, the future operating life of the Trans-Alaska oil pipeline system (TAPS) has become an important issue. Therefore, there is a growing urgency for some decision on how to best market northern Alaska gas.

At present decline rates, the oil transported through TAPS will drop to 400,000 barrels per day by years 2009-2010 and to 200,000 barrels per day by year 2016 (fig. 24). This range in throughput rates probably brackets the economic daily minimum throughput for continued profitable operation of the pipeline (Thomas and others, 1993). Although it has been reported that the economic threshold for TAPS may be as low as 100,000 barrels per day, this is not supported by any publicly-available studies by the pipeline or field operators (Thomas and others, 1996, p. 1-9). Pipeline shutdown in year 2009 at 400,000 barrels per day would result in a loss of 1.2 billion barrels of ultimate oil recovery; shutdown in year 2016 at 200,000 barrels per day results in a loss of 0.5 billion barrels of ultimate oil recovery (Thomas and others, 1996, p. 2-11). Shutdown of the TAPS line, whenever it occurs, will certainly strand all undeveloped oil fields and curtail exploration in northern Alaska and the Arctic offshore for the foreseeable future.

Figure 25 shows the effect of gas exports via gas pipeline (beginning in 2005) on the operating life of TAPS. The operating life of TAPS is only shortened by one year for the 200,000 minimum throughput case. If the Prudhoe Bay gas reserves are exported by gas pipeline, TAPS will reach an economic limit at 200,000 bpd between the years 2015 to 2016.

Figure 26 shows the effect of converting natural gas to synthetic petroleum liquid products at Prudhoe Bay and then transporting the liquids through TAPS to the marine terminal at Valdez, Alaska. Under this scenario, the operating life of TAPS is lengthened by at least 20 years. Using the minimum throughput case of 200,000 barrels per day, TAPS could remain operational until year 2036. This incidental benefit of the gas-to-liquids (or "GTL") option, the extension of the economic life of TAPS, may be one of the most important considerations in the decision of to how to market northern Alaska gas.

A prolonged economic life for TAPS provides an important window of opportunity for future discovery and development of additional oil and gas fields in northern Alaska. However, even the day-to-day TAPS operating costs and tariffs can also form a barrier to commercialization of small fields. As throughput falls, per-barrel tariffs should rise to pay for the relatively fixed TAPS operating costs. TAPS tariffs are projected to rise from $2.34 per barrel in 1998 to $6.83 per barrel ($1995; $12.97 per barrel nominal) in year 2016 (Thomas and others, 1996, tbl. B.3). Some 1995 DOE models for future TAPS tariffs are shown in figure 33. It is noteworthy that with the addition of liquids from gas conversion, the TAPS tariffs might be held to $4.00 per barrel ($1995) or lower (Thomas and others, 1996, fig. B.3), which could encourage profitable development of some smaller fields.

It should be noted that the existing TAPS line cannot be used to transport gas, even

[24] *At Prudhoe Bay field, the original producing gas-oil ratio was 730 cubic feet per barrel of oil, but by 1997 had risen to 12,000 cubic feet per barrel (AOGCC, 1997, p. 114). Annual gas production from the Prudhoe Bay field was 0.1 tcf in 1977 but had risen to 2.8 tcf (7.8 bcfpd) in 1999 (AKDO&G, 2000, p. 34).*

mixed with the oil. Pumping the oil through TAPS requires specific gas contents and vapor pressures for reasons of pipeline engineering and pump mechanics. In general, natural gas cannot be efficiently transported in empty oil pipelines (Thomas and others, 1992, p. 3-2) although conversions (gas pipeline to oil pipeline and *vice versa*) of small lines are sometimes done. Gas pipelines generally operate at higher pressures[25], require compressor stations rather than pump stations, and for efficient operation have different dimensional requirements (Wetzel and Benson, 1996, p. 3). Neither the gas owners nor the pipeline operators have proposed using the TAPS oil pipeline to transport natural gas.

Historically, two options for exporting northern Alaska gas that involve building new gas pipelines have been in the forefront: 1) a gas pipeline that exports gas through Canada to the U.S.; and 2) a gas pipeline that lies next to TAPS and delivers gas to Valdez (or other ports), where it is cryogenically (chilled) liquefied and placed as LNG on special tankers for transport to Pacific Rim markets. These two options are summarized as the "Pipeline to Canada" and "TAGS-LNG" options in table 17.

The conversion to LNG liquid is only temporary for purposes of efficient ship transport. At delivery ports, the LNG is converted back to gas in "regasification" plants and then used in conventional gas applications.

More recently, an old technology has made great strides in costs and efficiencies and now is a prominent third option for export of northern Alaska natural gas. Gas to liquids, or "GTL", is a blanket term for several processes that convert gas to petroleum liquids or petrochemical feedstock that is then used in the traditional applications for such materials. As noted above, converting natural gas to liquids in the Prudhoe Bay area offers the important economic advantage of using the existing TAPS oil pipeline and oil tanker fleet to transport the product to market.

The three transportation systems that now form the most likely candidates for exporting Alaska natural gas are summarized in table 17. These options are reviewed in detail in the following sections.

Other options, best described as conceptual, are also noted as potential methods of marketing Alaska natural gas. These include new pressurized gas containment vessels like the "COSELLE" system, bulk shipment of "pelletized" natural gas hydrates (NGH), and submarine LNG tankers. Basic descriptions of these systems are given in table 18. Although interesting, none of these experimental technologies have been proposed for marketing of Alaska natural gas. As such, they are not reviewed in further detail in this report.

Gas Pipelines Through Canada to U.S.

The Original (1977) ANGTS Proposal

The "Alaska Natural Gas Transportation System" (or ANGTS) was a 1970's proposal to build a gas pipeline from Prudhoe Bay along the existing TAPS oil pipeline to Fairbanks, then turning east to follow the Alaska Highway into Canada. The proposed pipeline was designed to join the existing Alberta pipeline network at Caroline in central Alberta and was to be altogether about 2,100 miles in length (fig.27). The

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[25] *800 to 1,200 pounds per square inch or "psi" (O&GJ, 1999a); operating pressures in the proposed high pressure TAGS gas pipeline might range from 1,700 psi to 2,700 psi (Metz and Whitmore, 1999, fig. 4); the maximum design pressure of the TAPS oil pipeline is 1,180 psi (Alyeska, 1999, "pipeline engineering"), with some sections constructed to support only 832 psi operating pressure (R. Wall, pers. comm., Sept., 1999).*

existing Canadian pipeline system then would carry the gas to Canadian markets or to the U.S. West Coast or Midwest. This proposal was originally approved by both the U.S. (Carter administration) and Canadian governments in 1977, but was deferred because of falling gas prices, rising costs, landowner opposition, and the need to retain gas at Prudhoe Bay for use in enhanced oil recoveries (PNAB, 2000a, p. A22).

The costs of delivering gas to the U.S. via the ANGTS system were estimated in 1995 to lie between $2.82/mcf and $4.17/mcf, based on project construction costs of approximately US$16.7 billion (ANGTS, 1995). Inflating these delivery costs to year 2000 dollars would require a minimum price range of approximately $3.29/mcf and $4.86/mcf. For comparison, Canadian gas exports to the U.S. averaged $1.89/mcf during the 1993-1997 five-year period, with prices tumbling to $1.66/mcf in September 1998 but rising to $3.89/mcf by June 2000 (DOE, 2000).

Not considered in the original ANGTS proposal was the Mackenzie delta, which is now known to offer discovered gas reserves of 9-11.7 tcf (fig. 1) and undiscovered gas resources of 53.3 tcf (fig. 8). The Canadian pipeline network in Alberta and British Columbia is expanding northward toward Mackenzie delta. Recent gas strikes have located 1.5 to 4.0 tcf in new gas reserves in the Fort Liard area, which has extended the Canadian pipeline network northward into southernmost Northwest Territories (fig. 27).

In recent months, a number of new or revised proposals for transcontinental gas transmission pipelines connecting the stranded Prudhoe Bay-area gas reserves to the North American gas marketing infrastructure have been announced. These new proposals are buoyed by strong support from the Dene and Inuvialuit native communities of northwestern Canada—a reversal of a 25-year stance in opposition to pipeline construction and development (PNAB, 2000a, p. A22). This turnabout is partly because land claim disputes of 25 years ago have since been settled (Speiss, 2000a).

The New (2000) ANGTS—Highway Route Proposals

Foothills Pipe Line Highway Route Proposal

Canada-based Foothills Pipe Lines (which is jointly owned by TransCanada PipeLines and Westcoast Energy) proposes to join with an unspecified Alaska-based gas pipeline group to share costs of constructing a gas pipeline south from Prudhoe Bay to Delta Junction, near Fairbanks (fig. 27). From Delta Junction, the Alaska group would independently extend a pipeline to an LNG plant at an undetermined site in southern Alaska, ultimately supporting LNG exports to the Asian Pacific Rim. From Delta Junction, the Foothills group would independently extend a pipeline to Caroline, Alberta, joining Foothills-owned pipelines that now export 0.4 tcf/year to the U.S. West Coast and 0.8 tcf/year to the U.S. Midwest (PNAB, 2000a, p. A22). The new Foothills pipeline from Fairbanks to Caroline would carry 0.7 tcf/year. The Foothills system would access the Mackenzie delta with a 460-mile spur pipeline along the Dempster Highway (fig. 27). The chief advantages of the new ANGTS proposal are the cost sharing of the Prudhoe-Delta Junction leg and the fact that the Foothills project possesses regulatory approvals and right-of-ways that were granted in the 1970's. In fact, Foothills claims that the 1970's legislation grants them the exclusive right to deliver northern Alaska gas to the Canadian pipeline network (Speiss, 2000a, p. F6).

Prudhoe Bay Gas Owner Group Highway Route Proposal

The three principal corporate owners (Phillips Alaska, BP-Amoco, and Exxon-Mobil) of the natural gas reserves at Prudhoe Bay have initiated a $75 million team project to conduct economic studies of pipeline route options, to choose a route, and to begin the permit application process, all by the end of 2001 (Speiss, 2000b). Although a route has not been chosen, public statements by Tim Holt, President of BP Canada (Holt, 2000) and Kevin Meyers, President and CEO of Phillips Alaska (Meyers, 2000) suggest a preference for the ANGTS or "highway" route. Alaska Governor Tony Knowles, the Alaska Congressional Delegation, and Yukon Territory Premier Pat Duncan have all indicated a preference for the highway route (Speiss, 2000b). Preliminary estimates from Phillips Alaska for the highway pipeline route are US$10 billion for a 2.5 bcfpd (0.9 tcf/yr) system and US$12 billion for a 4.0 bcfpd (1.5 tcf/yr) system (Meyers, 2000). Kevin Meyers indicated that gas sales could begin as early as 2007 and that Chicago city gate prices over $3.50/mcf would support a profitable project (as of late January, Chicago city gate gas prices were approximately $8.00/mcf). On January 08, 2001, Alaska Governor Tony Knowles signed an executive order establishing a State National Gas Policy cabinet and introduced a legislative bill to allow the administration to negotiate tax incentives for the highway gas pipeline project (ADN, 2001)..

<u>The Mackenzie Valley Pipeline Proposals</u>

The Arctic Resources "Northern Gas Pipeline" Proposal

Arctic Resources is a venture consortium organized by Houston-based Municipal Energy Resources Group (or "MERC") to promote an alternative pipeline system to tap Arctic stranded gas reserves. Former Canadian Cabinet Minister Harvie Andre heads the Canadian office and partnership inquiries have been initiated with TransCanada PipeLines (part owner of Foothills!) and Enbridge—the major pipeline operators in western Canada. Arctic Resources proposes the construction of a 1,400 mile pipeline from Prudhoe Bay to western Alberta, passing through the Mackenzie delta and southward along the Mackenzie River valley. The 300-mile subsea pipeline leg from Prudhoe Bay to the Mackenzie delta would be located offshore on the Beaufort Sea shelf to avoid the U.S. Arctic National Wildlife Refuge (Alaska) and the adjoining Canadian Ivvavik National Park (Yukon Territory). The Arctic Resources pipeline, with a capacity of about 1.5 tcf/year (0.9 tcf/yr from Prudhoe Bay, 0.6 tcf/yr from Mackenzie delta), would reportedly cost about US$5-6 billion to construct (Speiss, 2000a). The northern gas pipeline project could deliver Prudhoe Bay gas to the U.S. domestic gas market for tariffs in the $1.25/mcf to $1.50/mcf range and would reportedly remain profitable at gas prices as low as $2.00/mcf (Hoglund, 2000).

The TransCanada Pipeline Proposal

An alternative proposal by TransCanada pipeline would build a 0.5 tcf/year-capacity high-pressure gas pipeline from Gordondale, Alberta to the Mackenzie delta, following the Mackenzie River valley. The construction costs for this pipeline project are estimated to range from US$2-3 billion (Speiss, 2000a). This pipeline does not attempt to reach Prudhoe Bay-area gas reserves and would be a stand-alone project to Mackenzie delta. However, Greg Stringham of the Canadian Association of

Petroleum Producers has commented that a stand-alone Mackenzie delta project using the Mackenzie River valley route may be economically marginal (Speiss, 2000a, p. F6).

The Mackenzie Delta Gas Owners Pipeline Proposal

The owners of the gas reserves in Mackenzie delta are optimistic about the prospects for development and have proposed a separate Mackenzie Valley pipeline project. Gulf Canada Resources announced that it is working on a feasibility study jointly with other Mackenzie delta reserve owners (including Imperial Oil, Shell Canada, and Mobil Oil Canada). These companies jointly own about 6 tcf in Mackenzie delta gas reserves (Harts E&P, 2000, p. 11). The feasibility study will be completed in 2001 (O&G J, 2000). The owner's group has estimated that a stand-alone Mackenzie Valley 0.8 bcfpd-capacity (0.3 tcf/yr) gas pipeline system could be ready to take gas to Alberta as early as 2006 (PNAB, 2000e). Brian MacNeill, President of Enbridge, noted that any Mackenzie Valley pipeline will cost in the ranges of C$4 billion and would likely be a joint project between several gas owners and perhaps three Canadian pipeline companies (PNAB, 2000e, p. A23).

GTL: Gas to Liquids Technology

Review of Process

Gas-to-liquids, or "GTL", is a blanket term for a group of processes that convert methane into liquid fuel or liquid petrochemical feedstock. The conversion to liquid is permanent and the liquid products are used in conventional applications. The GTL processes are quite distinct from liquefaction of natural gas, or "LNG", where gas is chilled to the point where it becomes a liquid for purposes of shipboard transportation. Once delivered, LNG is restored to its original gaseous state and is then used in conventional natural gas applications.

A process for converting methane to liquid hydrocarbon was originally invented in 1923 by German chemists Hans Fischer and Franz Tropsch (Singleton, 1997, p. 69). The process is often referred to as the "Fischer-Tropsch" process, or "F-T" in the shorthand of the trade. "F-T process" is now often used as a synonym for gas-to-liquids or "GTL". The Fischer-Tropsch process, or allied processes using coal, were used to produce liquid fuels for Germany in World War II, eventually supplying 95% of the aviation fuel used by the German Air Force, the *Luftwaffe* (Nation, 1997, p. 15).

The GTL process begins by attacking the methane molecule, which consists of one carbon atom and four hydrogen atoms, and splitting the molecule into its atomic constituents. In fact, any organic material, including bitumen (tar) and coal, can be split into its constituent carbon and hydrogen atoms. The carbon and hydrogen atoms liberated by the breakup of methane molecules, with the addition of oxygen and formation of carbon monoxide, become "***syngas***", which is taken and re-combined into "synthetic" hydrocarbon liquids. The GTL process is summarized in figure 28.

Naturally occurring crude oil is made up of molecules composed of carbon and hydrogen that are either ring-shaped (aromatics) or that are long chains that are called alkanes or paraffins. The GTL process creates alkanes. Chain length controls physical state (boiling/freezing points), viscosity, and density. For example, a methane molecule contains 1 carbon atom and is the shortest possible "chain", whereas the chain-like molecules that compose diesel fuel contain 14 to 18 carbon atoms (Hunt, 1979, tbl. 3-4). The molecules that compose lubricating oil contain 26 to 40 carbon atoms. At the far extreme from methane, the molecules that compose asphalt or bitumen are very long chains that may contain 2,000 carbon atoms (O&GJ, 1999c). Figure 29 illustrates the molecular sizes of various liquid products, as described by numbers of carbon atoms, and their refinery distillation sequence when extracted from naturally-occurring crude oil.

In the second step in the GTL process, the carbon and hydrogen atoms that are liberated by breakup of methane are combined into long-chain molecules, thus creating "synthetic" hydrocarbon liquids. A chain molecule is illustrated as the "synthesis" product in figure 28. The length of the synthesized chain can be specified by process design to produce a particular liquid or wax. The process consumes large quantities of energy. The thermal efficiency[26] of the GTL processes range from 50% to 69%, with a theoretical limit of 78% (Thomas and others, 1996, pp. xiv, 3-11).

Major cost reductions in GTL have recently been achieved with technologic breakthroughs in both of the two main steps in the process. The first step, as noted, involves the creation of "syngas", a mixture of hydrogen and carbon monoxide (fig. 28). In breaking up the methane molecule, the carbon is united with oxygen to create carbon monoxide[27]. The pure oxygen that is preferred for some processes for syngas creation is very expensive to obtain. Most recent advances in the syngas step have centered upon: 1) finding a cheap source for pure oxygen; 2) finding a way to use less oxygen; or 3) finding a way to use air directly. The oxygen problem is reviewed in a following section. The first step, the partial oxidation of methane and creation of syngas, has traditionally accounted for about 60% of liquid synthesis costs and offers great opportunities for cost reductions through discoveries of new technologies (Thomas and others, 1996, fig. 3.2).

The second step, "synthesis" of petroleum liquids, involves a group of chemical reactions, in the presence of catalysts, in which hydrogen and carbon monoxide are combined to form diesel-type liquids, alcohol, ammonia/urea, waxes, or other chemical feedstock. Often, the direct products of synthesis are waxes that must be cracked to form petroleum liquids. Most recent cost reductions in the second step have involved discovering inexpensive, stable catalysts that can withstand high temperatures and exposure to contaminants. The synthesis step in GTL traditionally accounts for about 30% of liquid synthesis costs (Thomas and others, 1996, fig. 3.2).

<u>The Oxygen Source for Methane Breakup and Syngas Creation: Recent Developments</u>

The requirement for oxygen represents a large fraction of the costs of creating syngas. Traditionally, the oxygen was obtained from air by an expensive cryogenic (chilling the air to -350°F) "air-separation" process. Researchers at Argonne National Laboratory and industry collaborators recently discovered a type of filter that purifies oxygen from air at a fraction of the cost of

[26] *energy content of GTL liquids/energy content of feedstock natural gas*

[27] *This is only a partial oxidation of the methane. Full oxidation, or combustion, produces carbon dioxide and water, neither of which can be used as fuel or feedstock. An alternative technology for splitting methane into a mixture of carbon monoxide and hydrogen involves passing a methane-oxygen mix through an electric arc. This alternative process is termed "cold plasma" by Automated Transfer Systems Corp. of Calgary (Hydrocarbon Online, 1998). A separate "plasma quench" process injects methane into a superheated hydrogen plasma where it is converted to acetylene and quench-cooled to stabilize the acetylene, which is then converted to the desired hydrocarbon liquids (Avellanet, 1999).*

the traditional separation process (Thomas and others, 1996, p. 3-9). The Department of Energy is now funding an $84 million multi-firm research program focusing on filter, or “ceramic membrane” technologies (DOE, 1997). The University of Alaska-Fairbanks joined the effort in May 1999 with a $2.5 million grant to research ways of manufacturing a structurally more durable ceramic membrane (DOE, 1999b). The ceramic membrane process for extracting oxygen from air promises to provide great cost savings to the syngas creation step. However, the commercial application of ceramic membrane technology may be at least 10 years away (Corke, 1998a, p. 78).

The current popular method for reducing oxygen demand is through the addition of steam to the oxygen feed, or “steam reforming”. The steam reforming reaction occurs at high temperature (800-900°C) in the presence of a nickel catalyst. The reaction produces a mixture of hydrogen, carbon monoxide, and carbon dioxide (Corke, 1998a, p. 72). The carbon dioxide must be separated from the mixture and the hydrogen-carbon monoxide mix is not ideal for syngas, so extra costs are incurred that offset oxygen savings.

Syntroleum Corp of Tulsa has developed a process that uses air directly and avoids the high costs of extracting oxygen from air (Corke, 1998, p. 74). However, the air process introduces large quantities of nitrogen into the syngas, which must be separated at some cost. Gray and Tomlinson (1999) compared the economics of pure-oxygen versus air-based processes and found that for pure oxygen the syngas preparation costs form 46% of costs but the synthesis step forms only 21% of process costs. In the air-based process, the syngas preparation forms only 38% of costs, but more costs are shifted to liquid synthesis, which then forms 30% of overall costs. At a scale of 50,000 barrels per day plant output, the air-based process was slightly more costly. At a different scale, the air-based process could be less costly. The air-based process offers a distinct advantage of requiring far less physical plant space (no air separation unit) and can be made small and compact, perhaps even mountable on barges for offshore locations.

Synthesis of Liquids from Syngas: Recent Developments

The creation of liquid hydrocarbons from syngas, or “F-T synthesis”, generates a mixture of liquid or waxy compounds that must be separated or refined to obtain the pure components. The average molecular weight of the synthesis product is determined by catalyst type, H_2/CO ratio of the syngas, process pressure, and process temperature (Thomas and others, 1996, p.3-9). So, the selection of catalyst partly depends upon the type of product desired. Catalyst costs, efficiencies, and durabilities are also important considerations. Some common gas contaminants such as sulfur or mercury are very destructive to some GTL catalysts (Corke, 1998, p. 71). Cobalt-based catalysts have generally replaced the early iron-based catalysts. The efficiency, or activity of the cobalt-based catalysts varies widely with how the cobalt is supported. Titania-supported cobalt catalysts provide only 20% of the productivity of newer alumina-supported cobalt or “GasCat” catalysts (Singleton, 1997, p. 68). The alumina-supported cobalt catalyst also lasts about 5 times longer than the titania-supported cobalt catalysts (Singleton, 1997, p. 70). The efficiency differential among catalysts is important to overall GTL process costs. Liquid production costs for the titania-supported cobalt catalyst process are roughly $20 per barrel but for the alumina-supported cobalt catalyst process are only $15 per barrel (Singleton, 1997, tbl. 1).

A new player in the GTL arena, Catalytica Corporation, has received $2 million in DOE funding to develop its direct methane oxidation (DMO) process, which uses complex catalysts to convert gas directly to methanol or synfuels and thereby avoids the expense of creating syngas (Knott, 1997, p. 19).

Overall Trends in Technology-Driven GTL Economics

Generally, production of remote gas accumulations using either LNG, long pipelines, or GTL technology were only feasible for very large, long-lived fields. In the recent past, hypothetical GTL projects were only justifiable on paper when they exceeded 50,000 barrels per day output, a level of gas usage (0.5 bcfpd or 0.2 tcf per year) possible in only about 4% of the world's gas fields outside of the U.S. (Von Flatern, 1997, p. 56). The recent technological advances briefly reviewed above are resulting in GTL processes possibly profitable at rates as low as 2,500 barrels of output per day (gas requirement 25 mmcfpd or 0.009 tcf per year). GTL plants at this scale are even small enough to be usd in small modules on offshore platforms or on barges moved to remote sites.

A plant cost equating to $30,000 per barrel of daily output (a 100,000 bpd plant would thus cost $3 billion to construct) has been viewed as the approximate breakeven cost for projects that are located near existing infrastructure (existing pipelines or oil shipment ports) and a cheap source of gas (Von Flatern, 1997, p. 56). Recent technological advances could drop plant costs to between $12,000 to $27,000 per barrel of daily output (in which case a 100,000 bpd plant would cost $1.2 to $2.7 billion to construct). At these low costs, GTL plants at smaller scales may be affordable for remote, expensive-to-develop gas.

Commercial GTL Projects and Planned Projects

As of September 1998, only two commercial GTL plants were operating in the world. The first plant, commissioned in 1991, obtains syngas from coal and is operated by Mossgas at Mossel Bay in South Africa. The second plant in existence at that time was natural gas-based and was operated by Shell at Bintulu, Malaysia. The Shell plant was built for $850 million (Knott, 1997a, p.17) and was commissioned in 1993. The Bintulu plant used oxygen at the rate of 2.5 metric tons per day from a companion air separation plant, at the time the largest single oxygen unit in the world (Knott, 1997a, p. 17). The Bintulu plant was destroyed by fire originating with an explosion in the air separation plant in late 1998 (Corke, 1998a). Repairs have been completed at Bintulu and the plant resumed operations in June 2000, producing 12,000 bpd of ultra-clean fuels and specialty products (O&GJ, 2000a, p.2).

Several large GTL projects are in planning or under construction at this time (Knott, 1997a). Perhaps the largest commercial GTL project recently entertained is a $1.5 billion 100,000 bpd plant to be operated by Exxon in Qatar, which has immense stranded gas reserves in the 380 tcf North field (Aalund, 1998, p. 36). However, the Qatar project has apparently been temporarily shelved. Elsewhere, Chevron has joined Sasol Ltd., the South African energy firm with decades (since 1955) of GTL experience[28] in a joint venture in worldwide exploitation of stranded gas reserves. Chevron and Sasol are building a $1 billion GTL plant in Nigeria, scheduled

[28] *The Sasol process used since 1955 to produce liquid fuels from coal has recently produced at rates exceeding 150,000 barrels per day.*

for completion in year 2002, that is one of the largest current GTL projects in the world (ADN, 1999a).

Texaco and Arco recently licensed rights to the process developed by Tulsa-based Syntroleum Corp (ADN, 1997). Exxon has operated a 200 bpd pilot GTL plant in Baton Rouge for three years. Exxon has spent over $200 million on GTL research and has acquired 280 patents related to the process (Baker, 1996, p. 9). In addition to Qatar, Exxon is reportedly considering GTL projects in Alaska, Yemen, Australia, and Papua New Guinea. Marathon has licensed Syntroleum Corp technology and is considering a GTL project for some of their Sakhalin Island gas reserves (Von Flatern, 1997, p. 60). Syntroleum Corp is reportedly planning a $55 million barge-mounted GTL plant (Nation, 1997, p. 15). Syntroleum Corp and Enron are planning to build the first commercial GTL plant ever in the U.S. with operations beginning in year 2001. This 8,000-bpd plant will be built in Sweetwater County, Wyoming and will convert natural gas into specialty products like lubricants, drilling fluids, and liquid-normal paraffins (Alaska Report, 1998a, p. 6). On an even smaller scale, Rentech, Inc., of Denver built a 250 bpd GTL plant at a landfill near Pueblo, Colorado in 1993, but had to abruptly abandon the operation because of insufficient gas supply. The plant was then upgraded to 360 bpd capacity and shipped to Kumchai field in India to reduce gas flaring as an air quality measure (Knott, 1997b).

Elements of Costs Critical to GTL Plant Commerciality

The critical factors affecting GTL profitability are feedstock costs, scale (the larger the better), process (efficiency) costs, and product market value. A breakdown of the cost components of a plant of the scale of the 100,000 bpd Exxon plant once proposed for Qatar was prepared by Arthur D. Little, Inc., and published by O&GJ (1998). The cost breakdown for the Qatar plant is reproduced here in figure 30. In the Qatar model, syngas production accounts for 30% of costs, liquid conversion (synthesis) and upgrading (refining, cracking waxes) for market accounts for 23% of costs, plant operations account for 25% of costs, and feedstock (natural gas) accounts for 22% of costs. This hypothetical 100,000-bpd plant is projected to be commercial at a Brent oil price of $20/bbl (O&GJ, 1998, p. 34). As of May 2000, Brent oil was quoted at about $29/bbl (ADN, 2000).

Using a typical conversion rate of one million cubic feet of gas yielding 100 barrels per day of GTL product[29], the feedstock gas cost for the 100,000-bpd model in figure 30 is only $0.38/mcf. Singleton (1997, tbl. 1) used a $0.35/mcf feedstock gas price in comparing different GTL technologies. However, most models for commercial GTL projects assume feedstock gas prices of $0.50 or more (Corke, 1998b, p. 99; Baker, 1997, p. 18). In some remote areas, feedstock gas prices will be considerably higher.

In Qatar, the feedstock gas cost is reportedly $0.50/mcf and the GTL project has financial support from marketing of coproduced condensate, which can lower GTL project costs by 25% (Corke, 1998b, figs. 4, 5). (In some gas development projects, condensate production from gas is claimed through prior contractual agreement by other parties such as royalty owners.) Feedstock gas prices have a tremendous impact upon GTL project economics because so much gas is used to make a small volume

[29] *Shell's Bintulu plant produced 12,500 bpd of middle distillates (diesel) from 100 million cubic feet per day, or 1mmcfd = 125 bpd. The Exxon GTL project in Qatar will convert 500 to 1,000 mmcfgpd to 50,000 to 100,000 bpd, or 1 mmcfgpd to 100 bpd, or, 10,000 cubic feet to 1 barrel (Hakes, 1997, p. xix).*

of liquid. A $0.50/mcf gas price, though outwardly cheap, translates to a $5.00 cost component for each barrel of GTL liquid product. A 1995 DOE study of a GTL project for the Prudhoe Bay area used gas prices of $0.40/mcf to $0.53/mcf that incorporated a 10% net-back (Thomas and others, 1996, tbl. B.6). Gas from outlying areas won't be this cheap. Our economic model for the Beaufort shelf cannot deliver gas to the Prudhoe Bay area—where a GTL plant would theoretically be built—for less than $1.00/mcf (fig. 13). This translates to a feedstock cost of $10 per barrel of GTL product. Gas in accumulations at distance from a hypothetical GTL plant near Prudhoe Bay might cost more than $2.00/mcf to deliver profitably to the plant. This would translate to a $20.00 feedstock gas cost in each barrel of GTL product.

Figure 31 combines feedstock and plant capital costs to show their joint impact upon GTL project profitability. As an example using figure 31, a plant that cost $30,000 per daily barrel (of GTL yield) to build and that buys feedstock gas for $1.00/mcf will require a Brent oil price[30] of $21/bbl to be profitable at a 15% return on investment. Plant costs are determined primarily by scale. The graphic in figure 32 shows the relationship of plant scale or output capacity to ultimate liquid production costs for one type of GTL plant, showing that important savings are realized at the largest scales of projects.

Larger projects offer an economy of scale that is critical to project economics. Economy of scale can be described by the function:

$$Cost \;=\; Constant \;\; X \;\; Capacity^{Y}$$

where the Y exponent is a decimal fraction. For refining and petrochemical operations, the value of Y is typically 0.5 to 0.8; for GTL plants, it is about 0.66 (Corke, 1998a, p. 77). A economy of scale function for one kind of GTL plant is graphed in figure32.

Capital outlays for plant construction and process costs exert primary controls on overall GTL project economics. However, full details and assumptions inherent in reported economic analyses are seldom revealed. Lack of details (for example, cost-of capital, project timeframe, plant depreciation, rate of return, among others) precludes any direct comparisons between various studies or verifications of conclusions. A study by Marshall Frank of Chem Systems (as reported by Baker, 1997, p.18) illustrates some of these sensitivities. Assuming a small-scale 12,000 bpd GTL plant with a $0.50/mcf feedstock cost, Frank estimated total production costs of $15.50 to $18.00 per barrel of output at a break-even level. While this seems competitive with crude oil, factoring in economic parameters such as depreciation and rate of return could raise the actual cost of the GTL product from this example plant to over $50 per barrel of output. This is clearly not competitive with expected crude oil prices. Without full disclosure it is impossible to objectively evaluate published economic analyses showing that GTL production costs approach parity with crude oil prices.

Market Receptivity for GTL Products

One advantage of GTL is that the world market for motor fuels (common GTL products) is very large and can easily absorb new sources.[31] Furthermore, the world

[30] *Brent oil is an arbitrary index to which GTL product market value may be scaled. The nominal value of GTL product, depending on type of liquid, may exceed Brent oil by several dollars per barrel.*

[31] *World production of transportation fuels is approximately 55 million barrels per day or 20 billion barrels per year (Singleton, 1997, p. 69). This is the majority part of world crude oil production of about 70 million barrels per day or 26 billion barrels per year (Corke, 1998b, p. 98). Many GTL plants would*

market is changing in ways that are favorable to future demand for GTL product, particularly an increasing world reliance upon diesel as a transportation fuel (Hackworth, 1999, p. 25). GTL product can be upgraded directly to fuel, or, can serve as a blending feedstock to environmentally improve "dirtier" crude oil-based fuels. In addition, fuel and vehicle emission standards are becoming more restrictive, increasing the preference for GTL-based fuels which are generally free of sulfur compounds, toxic metals, and emit lower quantities of nitrous oxides and particulate matter (Hackworth, 1999, p. 15). GTL liquids contain no aromatic compounds and are biologically benign. GTL liquids are classified by the Environmental Protection Agency as "Non-Toxic/Biodegradable" (Peterson, 2000). As such, GTL liquids are sometimes used in the Gulf of Mexico in drilling fluid and can be discharged directly into seawater.

GTL products could command premium market prices. Because GTL plant yields are essentially refined products, they attract prices comparable to conventional refined products. Diesel fuel and kerosene typically sell for $5 to $6 per barrel more than the crude oil from which they were made (Baker, 1997, p. 18). A 1995 DOE study of a GTL project in northern Alaska allowed a premium of $5/bbl (compared to ANS crude oil) in its economic analysis (Thomas an others, 1996, p. B-10). An economic study of GTL projects by Corke (1998b, p. 100) valued GTL plant yields as mainstream refined (crude oil-based) products.[32] However, even greater price premiums might be expected considering the superior environmental qualities of GTL-based fuels. Marshall Frank, President of Chem Systems, believes that the low-sulfur GTL diesel fuel may carry a $3 to $4 per barrel "environmental" premium beyond crude oil-based diesel. However, cognizant of the requirements for cleaner fuels in California, many of the U.S. West Coast refineries are installing new processing equipment. Under competitive market forces the premium for GTL diesel may be much less than predicted by Mr. Frank and DOE analysts.

GTL Prospects for Northern Alaska Natural Gas

A 1995 DOE study estimated that GTL conversion of the 26 tcf of northern Alaska gas reserves would create 3 billion barrels of liquids (Thomas and others, 1996, p. B-24). At an average market value of $25/bbl, these GTL liquids, which could be exported to the U.S. West Coast through existing production infrastructure, represent a $75 billion asset that is increasingly the focus of research and schemes for development.

The 1995 DOE study by Thomas and others (1996) analyzed a GTL project for development and marketing of northern Alaska gas. The hypothetical project that was modeled was a single large plant with a peak output capacity of 300,000 barrels per day. The 300,000-bpd capacity was chosen for the model plant because it would consume gas at about the same rate as a hypothetical LNG project that was also a subject of the DOE study. A 300,000-bpd GTL plant is three times larger than any GTL project entertained or under construction anywhere in the world today.

The DOE study assumed the new construction of a $13 billion ($1995; equivalent to $15.1 billion in $2000) infrastructure to develop gas reserves in Prudhoe Bay-area fields and the Point Thomson field (5 tcf) 50 miles to the east (fig. 3). Gas reserves are converted to GTL products over a 30-year project life. Model

have to be built to significantly displace the world market for transportation fuels.

[32] *The Corke study did not specify values. In June, 1999, fuel oil was priced at $0.45/gal ($18.90/bbl) and gasoline at $0.56/gal ($23.52/bbl), delivered to New York harbor (ADN, 1999b).*

plant costs were $40,000 per barrel of daily output (Thomas and others, 1996, p. xi), in retrospect perhaps a rather high figure for a plant of this capacity (fig. 31). However, GTL construction costs in the Alaska environment are probably higher. For example, Robertson (1999, p. vii) notes that construction projects in northern Alaska are typically 1.3 to 2.0 times more expensive than comparable projects in the U.S. Gulf Coast. The DOE model piped GTL liquid output through TAPS to Valdez for tanker shipment to the U.S. West Coast. The DOE model assumed a process thermal efficiency of 60%. The model assumed real growth in oil prices at a rate of 2.4% per year. Project economics are quite sensitive to oil price assumptions, as will be illustrated below. TAPS oil throughput tariffs are expected to rise sharply as crude oil production declines (curve for “no gas sales”, fig. 33), but the GTL project was modeled as having a moderating effect on pipeline tariff increases (“GTL project”, fig. 33). In the DOE study, marine oil shipment tariffs were held fairly constant (between $1.25 to $1.44 per barrel; Thomas and others, 1996, tbl. B.2). However, marine tariffs are expected to increase over time because of new double-hull requirements for tankers established by the Federal Oil Pollution Act of 1990 (OPA 90). An extra cost of $0.60/bbl is expected as a result of OPA 90 in year 2005 (AKDOR, 1997, p. 20).

The 1996 DOE study found that the hypothetical northern Alaska GTL project was profitable as modeled. At a 10% return on investment, the project yielded a net present value (NPV_{10}) of $10.7 billion (Thomas and others, 1996, tbl. 1). However, using an $18/bbl flat[33] oil price forecast, the GTL project was not economic; that is, it failed to provide a 10% rate of return. The study calculated that the “breakeven” $1995 flat oil price needed to provide a 10% rate of return ($NPV_{10} = 0$) was $19.94/bbl (Thomas and others, 1996, pp. xiii-xiv).

All of the major cost components of GTL projects are loosely constrained at present because of the rapidly developing nature of the technology. Plant construction costs are partly controlled by locale and labor force and can only become known through on-site experience. Any GTL project in northern Alaska will be a pioneering enterprise in this regard. We have already noted that new projects in Alaska can cost two times more than comparable projects in other parts of the world. Although large-scale output will ultimately be required for northern Alaska GTL, several technologies seem well established for plants at scales ranging from 2,000 bpd to 50,000 bpd. Thus, with the GTL process, it may be possible to start small and incrementally grow the enterprise, building upon knowledge and experience while minimizing exposure to the financial risks related to the many unknown cost factors. Rather than a single large plant, a future commercial GTL project in northern Alaska might consist of a system of several parallel plants of various sizes and process-types built in succession over a number of years. In a recent study, Robertson (1999) found that the highest present value (NPV) of the options studied was provided by an incremental approach to GTL at Prudhoe Bay. However, an important assumption leading to this conclusion was that plant construction could take advantage of a learning curve, which leads to lower unit costs over time. This learning curve is by no means guaranteed and presents a risk element in the economic modeling results.

BP-Amoco entered the GTL arena in Alaska by first announcing plans for a $70

[33] *“Flat” price—increases at same rate as inflation, historically about 3% per year but modeled at 2.2% per year in the DOE study (Thomas and others, 1996, p. B-14), with no “real” (in excess of inflation) growth.*

million pilot GTL plant[34] at Prudhoe Bay (Nelson, 1999a). It was later announced that the BP-Amoco plant would instead be constructed near the Port of Nikiski in Cook Inlet. Construction has begun at Nikiski and the plant will be operational and producing 300 bpd from 300 mmcfgpd by 2002 (PNAB, 2000f, p. A19).

A small Alaska-based company, Alaska Natural Gas to Liquids Co. or "ANGTL", was formed in 1998 to promote a Sasol[35] proposal to build a $2.5 billion 50,000 bpd GTL plant[36] near Prudhoe Bay (ADN, 1999c). The ANGTL proposed plant would produce diesel at about 40,000 bpd for U.S. markets and 10,000 bpd of naphtha[37] for Asian Pacific Rim markets (Nelson, 1999b).

Assuming for the moment a future northern Alaska commercial GTL project and use of TAPS, there remain some additional technical issues to be resolved before large amounts of GTL can enter the TAPS pipeline. For example, if GTL product is mixed with the normal TAPS crude oil, the GTL product must be conditioned to be physically compatible with the crude. However, it seems unlikely that GTL product will be actually mixed with the crude oils carried by TAPS. GTL liquids are essentially refined products, and, if mixed with natural crude oil laden with sulfur and toxic metals, would lose some of the $5+/bbl premium value they might otherwise command. It therefore seems more likely that GTL product will be put through TAPS in discrete batches and will go to dedicated or partitioned tankers in Valdez. This will require the construction of storage tanks or other means to handle alternating batches of pipeline throughput.[38] In any event, some capital outlays will probably be required to use the existing infrastructure to transport GTL liquid products. The Department of Energy has funded a 3-year study by the University of Alaska-Fairbanks focusing on the problems that GTL throughput may present to the TAPS pipeline (Kamath and others, 1999).

<u>Summary of GTL Potential for Northern Alaska</u>

In summary, gas-to-liquids conversion is a rapidly emerging technology with the potential to unlock northern Alaska's vast gas reserves. Present experience with the technology suggests that it is marginally economic at the present time and unproven at the production levels proposed for northern Alaska (up to 300,000 bpd). Despite the commercial promise of these new GTL technologies, they must be viewed as experimental at the present time. However, energetic and well-funded GTL research programs at a host of laboratories and pilot plants appear to be discovering many new ways to slash GTL production costs. The major attractions of using GTL technologies to develop northern Alaska natural gas include the following:

- The existing, mostly amortized oil transportation infrastructure might be utilized with minor modifications.
- GTL can extend the operating life of the existing oil transportation pipeline (TAPS), and, by moderating future tariff increases, may provide an economic

[34] *at $50,000/bbl/day, the BP-Amoco pilot plant would produce approximately 1,400 barrels per day*
[35] *Sasol is the South African firm that has operated GTL plants since 1955 and has produced 700 million barrels of GTL-based diesel and gasoline products (Nelson, 1999b)*
[36] *plant cost of $50,000 per barrel of daily output*
[37] *naphtha (C_8-C_{12}) is intermediate between gasoline (C_5-C_{10}) and kerosene and jet fuels (C_{11}-C_{13}); Bruce and Schmidt, 1994, fig. 2.*

[38] *The volumetric capacity ("linefill") of the TAPS oil pipeline is about 9 million barrels. Existing storage capacity at the marine terminal in Valdez is 9.18 million barrels. The capacities of individual tankers serving TAPS range from 0.2 to 1.8 million barrels (Alyeska, 1999).*

future for marginal oil or gas accumulations in northern Alaska

- GTL facilities can be designed for a wide range of output levels and capacity might be added at incrementally lower costs with ongoing experience.
- World and U.S. legislation regarding transportation fuels are changing in ways that will increase future demand for clean-burning diesel fuels, including those obtained from GTL processes. GTL product will be directed to a very large and growing market that can easily absorb the new (GTL-derived) production of clean-burning fuel.

TAGS-LNG: Trans-Alaska Gas Pipeline System (TAGS) and Conversion to Liquefied Natural Gas (LNG) for Marine Shipment

Background

Transportation of natural gas as LNG is a proven technology that is now used to serve a 1998 world trade of 4.3 tcf per year and that is growing 6 percent annually (IPE, 2000, p. 238-240). The technology consists of cryogenically refrigerating natural gas (to approximately –260°F) until it assumes a much more compact liquid form more economic to transport to distant markets.[39] The LNG is then placed upon special tankers for delivery to regasification plants at tidewater ports. At receiving points, the LNG is restored to a gaseous state and is sold for conventional natural gas applications. The refrigeration process uses some gas and some additional gas (1 to 3%) is consumed by the LNG tankers as fuel. Typically, the overall thermal efficiency of the process is 80% to 91% (Feldman, 1996; Thomas and others, 1996, p. xi).

Most world LNG is marketed from Australia, Indonesia, and Malaysia to Japan. Some additional LNG is marketed from North Africa to Europe (Hakes, 1997). The U.S. is both an importer and exporter (in nearly equal amounts) of LNG. In 1997, the U.S. exported 0.0622 tcf of LNG at an average price of $3.83/mcf (net value, $238 million) from the port of Nikiski, Cook Inlet, Alaska, to Yokohama, Japan. During the same period, the U.S. imported 0.0778 tcf of LNG at an average price of $2.73/mcf (net value, $212 million) into regasification facilities in Massachusetts and Louisiana (Swain, 1999, tbl. 5). Aggregate U.S. trade of 0.14 tcf per year only accounts for 3% of world LNG trade.

The principal advantage of the LNG-based system for marketing northern Alaska gas is that it is a proven technology for large-scale operations and costs are relatively well known. Because of the established nature of the technology, it is unlikely that many new process technologies will emerge in the future to dramatically reduce costs.

The disadvantages of the LNG-based system for northern Alaska stem primarily from high initial costs related to the remote location of the gas reserves and project scale.

- Although processing capacity can be added incrementally (in modules called “trains”), the gas delivery system (TAGS pipeline) must be sized for full capacity operation.
- Because of high project costs (estimated as high as $15 billion in 1995), the project has required a very large export capacity (about 0.7 tcf per year), so that revenues are sufficient to meet capital and operating costs. (However, we note that more recent LNG models incorporating certain tax exemptions

[39] *gas at the appliance burner contains approximately 130 btu/gallon; pipeline gas contains 10,000 btu/gallon; LNG contains 86,000 btu/gallon, about 60% of the energy content of 35° API crude oil (140,000 btu/gallon); from Wetzel and Benson (1996)*

have proposed export rates as low as 0.2 tcf per year and construction costs as low as $8.2 billion [PNAB, 2000b, p. 1].)

- Even at throughput of 0.7 tcf per year, the payback period is long and economics are very sensitive to the time interval for "ramp-up" to maximum production.
- LNG sales of 0.7 tcf per year would represent 22 percent of the 1998 3.2 tcf/year Asian Pacific Rim market, and overly ambitious ramp-up could depress LNG market prices. However, a less aggressive ramp-up will adversely affect payback period and overall project economics.
- There are many other potential large-scale LNG projects worldwide (both "greenfield" [new] and expansions of existing projects) that have competitive advantages over the TAGS-LNG project in terms of proximity of gas to ports, shipping distances to markets, and incentives provided by host governments. These competing projects can deliver LNG to existing markets at lower costs.
- Creating new niche markets to receive Alaska LNG will be difficult because of the high capital costs of new receiving infrastructure (marine terminals and regasification plants) that could cost several billions of dollars per site.

The Yukon Pacific Corporation, L.P. Proposals for TAGS-LNG

Yukon Pacific Corporation, L.P. (hereafter, YPC) years ago secured the rights-of-ways along the proposed corridor for the overland gas pipeline. YPC has authored several proposals for LNG-based gas transportation systems for taking northern Alaska gas to markets in the Pacific Rim. More recent proposals are generally scaled-down versions of the original proposal.

The basic elements of the original TAGS-LNG proposal are described in table 17 and annotated in figure 35. The original 1995 estimate for the TAGS-LNG system totaled $15 billion (equivalent to $16 billion in $1999) for a system with a capacity of 14 million metric tons or 0.7 tcf per year. The $15 billion price tag has been viewed by the gas owners as too high. Since 1995, efforts have been focused on finding ways to reduce this construction cost estimate to around $12 billion ($1995). A second major problem with the original YPC proposal is that no market large enough to readily absorb the proposed 0.7 tcf/year output could be identified. In response to these concerns, in April 2000 YPC presented a sketch of a new proposal that dramatically scales down project output and capital outlays. The scaling down of the project became possible because of the new creation of a port authority (involving municipalities along the pipeline route) that would construct the pipeline and liquefaction plant. Saving would stem from the special tax status of the port authority. The smaller scale project was described as costing $10.4 billion overall to construct, with an early phase costing $8.2 billion and providing throughput of 9 to13 mmt/year (0.45 to 0.65 tcf/year), followed by an expansion providing ultimate throughput ranging from 13.5 to 18 mmt/year (0.68 to 0.90 tcf/year) (PNAB, 2000b, p. A1).

In October 2000, YPC revised the April proposal. The October proposal begins with a "phase 1" 2-train[40] system capable of exporting 9.2 million metric tons (MMT) (or 1.5 bcfpd or 0.5 tcf/yr) for US$8.16 billion.[41]

[40] *LNG processing plants are built in "trains" of related processing equipment with a fixed output capacity. Processing plant capacities are increased by installing additional "trains"*

[41] *$8.16 billion includes a Prudhoe Bay gas conditioning plabt, a pipeline, a 2-train LNG plant at Valdez, and an LNG tanker fleet*

(This excludes US$5 billion in construction interest and financing costs; PNAB, 2000g, p. A22.) Phase 2 might expand the project to 3 or 4 trains with system throughput capacities of 0.7 tcf/yr or 0.9 tcf/yr and costing $10.42 billion or $12.76 billion, respectively. A novel feature for the latest YPC proposal is the concept of taking the LNG to Baja Mexico and landing it near Tijuana just south of the U.S. border, then piping the gas north[42] to southern California.

Few details, particularly for economic return, have been made available for the newer YPC proposed projects. Therefore, the remainder of this review addresses the original TAGS-LNG project, which has been the subject of several economic studies.

The original YPC proposal called for construction of a $1.4 billion ($1.6 billion in $1999) gas conditioning plant in the Prudhoe Bay area, a $6.38 billion ($7.2 billion in $1999) gas pipeline 42 inches in diameter[43] and 800 miles in length from Prudhoe Bay to Valdez, a $2.6 billion ($2.9 billion in $1999) LNG plant and marine terminal in Valdez, and a $3.8 billion ($4.3 billion in $1999) fleet of 15 new LNG tankers.

YPC has asserted that its proposal is economic with start-up as early as year 2005. Gas owner advocacy of an LNG-based concept has been lukewarm at best. The Prudhoe Bay gas owners have indicated on a number of occasions that the $15 billion YPC TAGS-LNG project is just too expensive to be profitable, and, that ways must be found to lower costs. Hence, the newer YPC proposals for scaled-down projects.

[42] *There is an existing line that now carries gas south from San Diego to Baja and it is possible that this line could be modified to carry gas north (PNAB, 2000g, p. A22)*

[43] *This is a very large gas pipeline. Most gas pipelines of transcontinental scale in the mainland U.S. are 30 to 36 inches in diameter (PennWell, 1999, p. 20-25).*

A proprietary study by Pedro Van Meurs of Calgary commissioned by the State of Alaska (abstracted by Bradner, 1997) concluded that the original YPC proposal would probably require a 12% return on investment to offset several perceived areas of risk and attract investors. At $15 billion ($1995) initial costs and LNG prices of $3.50/mcf [44], Van Meurs concluded that the project would yield an 8.9% rate of return. Lowering the costs to $12 billion only produced a rate of return of 10.8%, still below the 12% minimum. At LNG prices of $3.90/mcf, the project achieved a 12.9% return on investment. However, at these high prices, competition from other LNG projects increases, placing downward pressure on market prices. Van Meurs believed that this “competition risk” could raise investor’s minimum requirements for return-on-investment to 14%, which would then require even lower capital outlays. This aptly illustrates the conundrum of TAGS-LNG project economics and the price volatility risk associated with the small LNG market.

The huge up-front investments required for the original YPC proposal make it sensitive to the time interval required for production to “ramp-up” to maximum rates. A short ramp-up improves economics because positive cash flows are generated more quickly. Oil projects (and conventional gas projects) usually have a very short ramp-up to peak production and this is one reason that they can be so profitable. This is illustrated in figure 36, which shows a relatively short payback period (time interval to achieve positive net cash flow) for the crude oil project. The longer ramp-up and flat production profile associated with LNG projects significantly extend the payback period and can render the

[44] *in 1998, prices for Asia-bound LNG fell below $2.70/mcf (DOE, 1999a), but as of September 2000 had rebounded to $4.33/mcf*

project uneconomic overall, even if a positive net cash is eventually realized. For example, the Van Meurs study assumed that the Asian Pacific Rim market would be unable to absorb the maximum output of the YPC proposal until year 2010, so it used a 6-year ramp-up. The 6-year ramp-up was viewed as reasonable by gas specialists at both BP-Amoco and ARCO and an economist with the State of Alaska (Jones, 1997). Using the 6-year ramp-up, the model predicted a rate of return insufficient (<12%) to attract investors. However, using a modestly shorter (3- to 4-year) ramp-up, which YPC felt was achievable, a YPC analysis of the same TAGS-LNG project found "sufficient rates of return" to attract investors (Jones, 1997).

Viability of the TAGS-LNG Project for Northern Alaska Natural Gas

A major risk faced by the TAGS-LNG project at any scale is price volatility. The prices of LNG delivered to Japan are contractually determined by formulae that link LNG prices to world oil prices. Therefore, within a contract, LNG prices can rise and fall with daily changes in world oil price. One model for a contractual relationship between LNG and world oil price is shown in figure 37. (This model was used in a 1995 DOE study of the TAGS-LNG project by Thomas and others [1996].)

In September 1998, oil prices fell to $11.38/bbl from $16.41/bbl the previous year. In the corresponding period, prices for LNG shipped from Cook Inlet to Japan dropped from $3.58/mcf to $2.69/mcf (DOE, 1999a). Clearly, this scale of price volatility could quickly transform a profitable project into a losing enterprise and represents a very real risk for any long-term LNG project, particularly during the long payback period.

An Asian Pacific Rim LNG market price of $3.50/mcf has traditionally formed the anecdotal minimum price for an economic TAGS-LNG project. Wetzel and Benson (1996, p. 14) of BP-Amoco, for example, cited a minimum LNG price of $3.50/mcf. A 1995 DOE study of a somewhat larger (17 million metric tons or 0.85 tcf per year) TAGS-LNG project found a 10% return on investment could be realized at a "breakeven" 1995 flat oil price of $19.36/bbl, which, adjusting for inflation, corresponds approximately to a 1999 LNG price of $4.26/mcf ($3.77/mcf in $1995; formula of Thomas and others, 1996, pp. xiv, B-11, dropping the 10% Asian price premium over oil price parity). More pessimistic results were obtained in a 1994 study by Attanasi (1995), who concluded that an LNG-based transportation system for northern Alaska gas would incur delivery costs of $5.89/mcf to $6.97/mcf (or $6.86/mcf to $8.12/mcf in $1999).

Clearly, given publicly-available cost estimates and recent historical LNG prices (1995-1999 average of $3.38/mcf for Nikiski LNG bound for Japan) , the original TAGS-LNG project seems economically marginal at best. Prices are now (January 2001) much higher, but it is not known if these high prices will be sustained. Government incentives or support may be required to allow an LNG project to move forward. Many LNG projects worldwide benefit from some government participation in the form of financial involvement (through national energy companies), providing infrastructure, or providing "holidays" from taxes or royalties (Wetzel and Benson, 1996). These subsidized LNG projects directly compete with the proposed northern Alaska LNG project.

Wetzel and Benson (1996, p. 15) have pointed out that holidays from property taxes, severance taxes, and royalties in the early years of a project can be particularly helpful to overall project economics because such holidays boost revenues in the part of the project where cash flows are still negative and act to shorten the payback period. The main impediment to LNG project profitability is the long payback period (illustrated schematically in fig.36). A long payback increases exposure to various economic risks, including those related to price volatility, prior to amortizing the large capital costs.

Jeff Lowenfels, President of YPC, has proposed to the "pipeline mayors" (mayors of municipalities along the proposed TAGS pipeline corridor) and other State officials that they consider delaying collection of property taxes. Over $400 million in property taxes are expected to be incurred during the 4- to 5-year project construction period that will precede any revenue generation (ADN, 1997b). In 1998, the State of Alaska passed the *Alaska Stranded Gas Development Act*, which would allow the Alaska Department of Revenue to negotiate a special tax structure with the gas owners that might provide some financial relief to the TAGS-LNG project (Bradner, 1998). Another tactic proposed is the formation of a "port authority" involving municipal participation in the construction and operation of the TAGS pipeline and a liquefaction plant at a southern Alaska port. A port authority rating allows funding at lower rates (equivalent to municipal bonds) as well as creating an income tax exempt business structure, estimated to provide savings of $3 billion in Federal tax exemptions alone (Hove and others, 1999). A port authority agreement has been approved by the North Slope Borough and the municipalities of Fairbanks and Valdez, but is awaiting approval from the Federal Internal Revenue Service.

Conclusions on Economics of Development Proposals for Northern Alaska Natural Gas

In 1995, the ANGTS (1995) group estimated that a new pipeline from Prudhoe Bay to Alberta, Canada could deliver gas to the U.S. for between $2.82/mcf and $4.17/mcf ($3.29/mcf to $4.86/mcf in $2000). As of January 2001, Chicago city gate prices were approximately $8/mcf. If these prices can be sustained, a pipeline project can certainly succeed.

The results of a 1995 DOE study by Thomas and others (1996) that compared the economics of GTL and TAGS-LNG projects for northern Alaska gas are presented in table 20. The DOE study reported that the GTL and TAGS-LNG projects return similar net present values (NPV_{10}) given the model assumptions. In the case of the GTL project, an NPV_{10} of $10.7 billion was obtained; for TAGS-LNG, an NPV_{10} of $11.5 billion was obtained. From an economic standpoint, these projects are essentially identical.

Critical to the economic success of both projects was the assumption of 2.4% real annual growth in world oil prices, based on the 1995 *Reference Case* forecast by the Energy Information Administration (Thomas and others, 1996, p. xi). When the projects were modeled with a flat oil price of $18/bbl ($1995), both failed to return a positive NPV_{10} (Thomas and others, 1996, p. xiii).

The 1995 DOE study calculated the flat ($1995) world oil prices that would be required to "breakeven" at a 10% return on investment (or $NPV_{10} = 0$). For the GTL case, a breakeven flat $1995 oil price of $19.94/bbl was obtained. For the TAGS-LNG project, a breakeven flat $1995 oil price of $19.36/bbl ($1995) was obtained (tbl. 20; Thomas and others, 1996, p. xiii-xiv). As shown in table 20, these world oil prices correspond approximately (using

Asian Pacific Rim LNG price[45] conversions) of $3.88/mcf (GTL) and $3.77/mcf (TAGS-LNG).

A follow-up DOE study by (Robertson, 1999) concluded that a phased GTL project was the most economically attractive alternative ($914 million NPV_{10} at $18 flat oil price). In comparison, the full-scale TAG-LNG project was the least economically attractive investment alternative (-$2,991 million NPV_{10}).

Figure 38 compares the breakeven world oil prices obtained by the 1995 DOE study to the most recent (for 2001) world oil price forecasts by the Energy Information Administration (AEO, 2000). The AEO (2000) price model is shown in table 19. All prices have been placed on a common footing in 1995 dollars in table 19 and figure 38. The AEO *Reference Case* for future world oil prices intersects the $19.36/bbl TAGS-LNG breakeven oil price in year 2015 but it fails to intersect the $19.94/bbl GTL breakeven oil price by year 2020, where the forecast price is $19.83/bbl ($1995).

As of this writing, no decision has been reached on how to transport northern Alaska gas to market but an announcement is expected at any time. A pipeline through northern Canada will be expensive and subject to volatility of U.S. domestic gas prices but represents a familiar technology and would access the world's largest (22 tcf/yr) single natural gas market. The LNG-based strategy utilizes a well-founded technology but is subject to a world market that is small and subject to price volatility. The GTL-based strategy is a developing technology unproven at commercial scale but would direct its products to a huge and very receptive world market for transportation fuels. All three concepts have economic risks, but from different sources.

[45] *On energy parity, calculated as [$oil price/5.13(btu conversion)], as modified from Thomas and others (1996, p. B-11).*

Current oil and gas prices are sufficient to support any of the proposed northern Alaska gas export projects, but the sustainability of the recent record-breaking high prices is questionable.

The abundance of both proven stranded reserves and undiscovered gas resources in northern Alaska could support a variety of export options that target different markets. BP-Amoco's business unit leader Tim Holt indicated in late 1999 that there were sufficient gas reserves in northern Alaska to support all three of the competing schemes for gas marketing (PNAB, 2000, p. A22). However, prudent business decisions will be based on booked ***gas reserves*** and not future, undiscovered, theoretical ***gas resources***. In the end, gas exports from northern Alaska may simultaneously follow all three proposed paths to market, including transmission gas by pipeline to the U.S., diesel (GTL) to the U.S. West Coast, and LNG to the Asian Pacific Rim or U.S. via Mexico.

Offshore Gas Development Must Await Excess Capacity

An important question for offshore gas development in northern Alaska is the time of the earliest opportunity to add any hypothetical new offshore production to whatever gas transportation system is eventually constructed to Prudhoe Bay. For a period of time after startup, this gas transportation system will be completely filled with throughput from the Prudhoe Bay area reserves. Eventually, as gas production from the Prudhoe Bay area fields declines, extra room (excess capacity) would become available in the gas transportation system.

Since a gas transportation system has not been selected, we can only offer some general comments about when excess capacity might become available to take Beaufort (or Chukchi) shelf gas to an export market. We will assume for this exercise that a gas pipeline is constructed, is operational by 2007, and is never modified for greater capacity. We will also assume that gas production and pipeline throughput begins to decline after 90 percent depletion of area reserves (23.4 tcf out of 26 tcf). Based on these assumptions, excess capacity would become available between ***8 and 26 years*** after first gas exports begin from Prudhoe Bay, depending upon pipeline capacities. Specifically:

- A 2.5 bcfpd (0.9 tcf/yr) export pipeline out of Prudhoe Bay would develop excess capacity after 26 years of operation (Year 2033).
- A 4.0 bcfpd (1.46 tcf/yr) export pipeline out of Prudhoe Bay would develop excess capacity after 16 years of operation (Year 2023).
- An 8.0 bcfpd (2.92 tcf/yr) export pipeline out of Prudhoe Bay would develop excess capacity after 8 years of operation (Year 2015). (8 bcfpd is the current rate of gas recycling at Prudhoe Bay and probably represents the maximum possible production rate.)

The largest pipeline currently proposed has a 4.0 bcfpd capacity and represents the most likely scenario. However, assuming an 8.0 bcfpd gas export pipeline to Prudhoe Bay is operational by year 2007 (the most optimistic scenario), offshore gas could not be added to the pipeline before year 2015. However, if new reserves were found that justified further investments, pipeline throughput could be increased by increasing pipeline pressure (adding compression equipment), thereby providing any needed additional throughput capacity.

7. TRENDS IN LEASING AND EXPLORATION OF THE ALASKA FEDERAL OFFSHORE AND STATE OF ALASKA

Alaska Federal Offshore

Annualized statistics for leasing and exploration activities in the Alaska Federal offshore are reported in table 21. Selected statistics from table 21 are compared to historical oil price trends in the bar graphs of figures 39, 40, 41, 42, 43, 44, 45, 46, and 47.

In 20 lease sales held over a 23-year period (1976 to 1999), a total of over 8.6 million acres within 1,598 tracts were leased in the Alaska Federal offshore (figs. 39, 40). The lands that were leased in all of these sales represent about 6 percent of all of the areas that were opened to leasing.

In lease sales in the late 1970's, during a time of rising oil prices, lease sale offerings involved small areas. Over 60 percent of these lease offerings were, in certain instances, taken by bonus[46] bids (fig. 41). In the 1980's and early 1990's, lease offerings followed the "area-wide" concept, and over 35 million acres were put on the auction block in 1984, 1988, and 1991, but only 1 to 6 percent of the offered tracts were leased (fig. 41; tbl. 21). In more recent years, the sizes of lease offerings have declined (figs. 39, 40), but the fractions taken have remained small, not exceeding 5% in recent sales (fig. 41). Total (accepted) bonus bid revenues for all 20 lease sales sum to over $6 billion (tbl. 21) nominally ($10 billion in $1999). Annual revenues from lease sales in the Alaska OCS have declined from a 1982 high of $2.1 billion ($3.5 billion, $1999) in total accepted high bids to less than $6 million in recent years. The Mukluk prospect, a legendary dry hole northwest of Prudhoe Bay (fig.2), alone accounted for over $1.0 billion ($1.7 billion in $1999) in bonus bids in Sale 71 (1982). Sale revenues declined sharply following the 1986 oil-price crash, which also coincided with the end of the 1982-1985 cycle of leasing, exploration, and abandonment of the Bering shelf basins (fig. 42). Bid values on a per acre basis have also declined since a 1979 peak of $5,800 per acre (nominal) in the first Federal/State offshore lease sale in the Beaufort Sea to less than $100 per acre for most sales held in Alaska since 1991 (tbl. 21; fig. 43).

Although a total of 1,598 leases have been issued in the Alaska Federal offshore, only 83 exploratory tests were drilled to evaluate offshore prospects and basins. The average time interval between acquisition of leases and drilling of exploratory wells, or "lag", has ranged up to 10 years, but the historical average is 2.4 years (statistical standard deviation = 1.8 years). If lag is indexed to the dates of well completions, as in figure 44, we observe that average time lags have generally risen into the 1990's. Lease sales in the 1980's, particularly in the Bering Sea, brought drilling platforms into remote areas where the high mobilization costs mandated maximum utilization of a few platforms by cooperative drilling programs. For this reason, many wells

[46] *A "bonus" bid is a monetary value offered to acquire a lease in a competitive sealed-bid lease sale. Other lease terms, such as rentals (annual payments), royalties (fractions of future production belonging to landowner), and lease periods are fixed and known to the prospective bidders at the time of the lease sale.*

were drilled in a short time to test the Bering Sea basins (e.g., the 1984-1985 drilling peaks in fig. 46).

In the late 1980's and early 1990's, as it became apparent that small fields (termed "satellites") near existing oil fields in the Prudhoe Bay area could be commercial to develop. Appraisal work, including 3-D seismic surveys and exploratory drilling, continued in the Beaufort Sea on leases held for nearly a decade. Figure 45 shows "lag" indexed to year of issue of lease. This bar chart shows that the highest average lags correspond to the 1979 and 1982 lease sales in the Beaufort Sea.

Few data exist to address the lag between leasing and development in the Alaska Federal offshore because there have been so few commercial discoveries. Table 21 lists two entries for fields that have not yet been put on production. The leases over Northstar field were issued in late 1979 and production from that field is not expected to begin before year 2001, for a minimum lag of 21 years. The leases over Liberty field were first issued in 1982 and production is not expected to begin before year 2003, for a minimum lag of 20 years.

The peak years for exploration drilling in the Alaska Federal offshore were 1984 and 1985, just prior to the 1986 oil-price crash (fig.46). Of the 34 wells drilled in this two-year period, 24 wells (71%) were drilled in the Norton, Navarin, and St. George basins of the Bering Sea, with the remainder in the Beaufort Sea (7) and Cook Inlet (3). Year 1985 saw the conclusion of the cycle of exploration and abandonment of the Bering Sea basins. The 83 exploration wells in the Alaska Federal offshore penetrated a total footage of 875,915 (166 miles) of offshore stratigraphic column, with peak footages obtained in years 1984-1985 (fig. 47).

As of January 2001, only 3 percent of the offshore acreage ever leased, or 84 leases involving 301,400 acres, remained active. These active leases are in the Beaufort Sea (82 leases) and Cook Inlet (2 leases). The trend in recent years has been toward "focused sales" or smaller lease offerings near existing oil infrastructure in the Beaufort Sea and Cook Inlet. Proximity to existing infrastructure could shorten the lead-time between discovery and development as well as minimize the cost of new processing facilities and pipelines. Even with these smaller lease offerings, less than 5% of the offered tracts typically receive bonus bids, and the average bid values are generally less than $100 per acre. The most recent offshore wells were drilled in 1997 in the Beaufort Sea (Warthog, Liberty), and those particular wells followed a 4-year period of no exploration drilling in the Federal OCS off Alaska.

The current situation in the Alaska Federal offshore is that lease sales are infrequent, a small fraction of offered tracts receive bids, and very few exploratory wells are drilled. Decades typically pass between discoveries and development. At this pace of leasing and exploration, it would take many decades to discover and develop a significant fraction of the immense gas resources estimated for the Alaska Federal offshore.

State of Alaska

Since 1959, the State of Alaska has held 83 lease sales that leased over 13 million acres in 5,210 tracts for total bonus bids of $2 billion nominal

(AKDO&G, 1999). The largest State lease sale was in 1969, where lands near the newly discovered (1968) Prudhoe Bay field were leased for over $900 million. Most of Prudhoe Bay field had been leased in 1965 (Sale 14) for a mere $6 million nominal (AKDO&G, 1999; Specht and others, 1987, fig. 18)!

The 1969 sale also saw the greatest average bonus dollar value per acre—over $2,100 nominal per acre. The second highest dollar value per acre was in the 1979 joint Federal-State Beaufort Sea sale, where bonus bids averaged over $1,900 nominal per acre (AKDO&G, 1999).

Kornbrath (1994, p. 14) noted that on average, in all State oil and gas lease sales through 1994, 43.5% of the offered acreage had been leased. This leased fraction is much higher than the 6% of offered lands historically taken as leases in Federal offshore sales. Statewide, about 11% of leases have been drilled. By comparison, only about 5% of the aggregate 1,598 Federal offshore leases have been tested by exploratory wells. The drilling success rate (discovery of oil or gas fields, both commercial and subcommercial) onshore has averaged about 9% (Kornbrath, 1994, p. 15). The success rate for commercial discoveries onshore has been about 4% (Kornbrath, 1994, p. 16). About 6% of State leases have yielded commercial production of oil or gas (Kornbrath, 1994, p. 16). Aggregate petroleum revenues to the State of Alaska from 1965 to 1997 total $44.4 billion nominal (AKDOR, 1997, tbl. 21, sum of *"Total Petroleum Revenue"*). Current petroleum revenues are approximately $2 billion annually, representing 80% of annual State of Alaska revenues.

8. MORATORIA AND SEQUESTERED RESOURCES IN THE ALASKA FEDERAL OFFSHORE

The North Aleutian basin, also known as the Bristol Bay basin, has been under a moratorium forbidding oil and gas activities since October 1989. This moratorium was extended by Federal legislation several times in the 1990's. On 12 June 1998, President Clinton issued an Executive Order extending the moratorium on North Aleutian basin (and the Atlantic, Pacific, and eastern Gulf of Mexico continental shelves) until 30 June 2012 (Alaska Report, 1998b). As a result of this moratorium, the oil and gas resources of North Aleutian basin are regarded as sequestered for the foreseeable future.

North Aleutian basin offers the largest resource endowment of the Bering shelf basins because it contains high-quality reservoir formations and large, simple structures that may form petroleum traps. Figure 48 shows the location of North Aleutian basin with an inset table summarizing the undiscovered oil and gas resources. Both industry and government share a high opinion regarding the potential of the North Aleutian basin. Industry interest was high in the one OCS lease sale held in this area (Sale 92, 1988) despite the fact that it was preceded by the 1986 crash in oil prices. Total high bonus bids amounted to $95.4 million on 23 tracts (averaging $784 per acre). These leases were subsequently returned to the government under a "buy-back" settlement. No prospects were tested.

Based on a single COST well (Turner and others, 1988) and older exploration wells drilled on the Alaska Peninsula, the North Aleutian basin is considered to offer potential mostly for gas (Parker and Newman, 1998). The mean endowment of undiscovered, conventionally recoverable gas is 6.79 tcf (mean case), ranging up to 17.33 tcf in the high (5% probability) resource case (tbl. 22).

Economic modeling in the 1995 and 2000 MMS assessments both assumed stand-alone LNG gas-export scenarios. Table 22 lists oil and gas resources for North Aleutian basin under a range of price scenarios. At a gas price of $3.52/mcf (approximately the price expected for sales to the Asian Pacific Rim LNG markets) the economically recoverable gas ranges from 1.272 tcf in the mean resource case to 12.3 tcf in the high resource case (5% chance). At a very high price of $6/mcf, 5.9 tcf of natural gas may be economically recoverable in the mean case, with up to 15.3 tcf possible for the high resource case (fig. 19). For perspective, the Cook Inlet producing, depleted, and non-producing fields are estimated to have held 8.6 tcf in original gas reserves, of which 6.05 tcf have been produced, marketed, and consumed (tbl 4).

A relatively large gas resource base in a favorable geographic location in North Aleutian basin would support commercial development through a small grassroots LNG project exporting gas to Asia (Craig, 1998b). If constructed, this onshore infrastructure could be utilized by future gas finds in other basins of the Bering shelf that are unable to support the high stand-alone cost of an LNG project. However, under the prevailing moratorium, the gas potential of the North Aleutian basin remains sequestered for the near-term future.

9. CONCLUSIONS AND PROSPECTS FOR FUTURE COMMERCIAL GAS PRODUCTION FROM THE ALASKA FEDERAL OFFSHORE

In onshore Alaska, 97 percent of the known, potentially marketable gas reserves occur in the northern part of the State at or near the Prudhoe Bay field. The 26 tcf natural gas reserves of northern Alaska form the key untapped asset that will drive an important decision in the near future on how to market Alaska's natural gas.

As of this writing (January 2001), the method for transporting this 26 tcf gas reserve to market has not been selected. Three methods are presently competing for the forefront: 1) ***Canadian gas pipeline***, an overland pipeline system (ANGST or Mackenzie Valley) connected into the Canadian transmission gas pipeline network; 2) ***GTL***, a system involving conversion of gas to liquids for conveyance through the existing crude oil transportation infrastructure to the U.S; and 3) ***TAGS-LNG***, a system involving a gas pipeline to Valdez or other southern Alaska ports with LNG shipments to the Asian Pacific Rim. The project that is eventually chosen to carry this gas to market will require huge new infrastructure(s) at great cost. The nature and financial requirements of these infrastructures could determine the future economic viability of the TAPS oil pipeline and determine the fate of undeveloped oil and gas pools in northern Alaska and the Arctic Federal offshore.

In the Alaska Federal offshore, 83 exploration wells have located only one significant gas accumulation. Burger structure, with an estimated 2-10 tcf of gas, lies in perennially ice-bound Chukchi shelf water 160 feet deep, 70 miles from shore, and 360 miles west of the northern Alaska infrastructure at Prudhoe Bay. At historical gas prices, the Burger gas pool is not economic to develop. On the Beaufort shelf, small quantities of gas associated with oil were found at 5 sites.

Historically, exploration of the Arctic Federal offshore has searched primarily for oil because it was the only commercial commodity. However, the search for oil offshore neither purposefully nor inadvertently avoided gas. Most lease bidding and exploration drilling simply targeted the largest and most obvious potential traps in each offshore basin, the kinds of targets traditionally most successful in the hunt for oil or gas. Many exploration wells were drilled in basins now viewed as highly gas-prone. Notably, all 24 Bering Sea exploration wells—targeting the most promising structures—failed to find any significant gas pools in the supposed "gas-prone" Navarin, St. George, or Norton basins.

Alaska and its offshore areas are estimated to contain 190.99 tcf of undiscovered gas resources.[47] Eighty-two percent of this undiscovered gas, or 155.68 tcf, occurs in northern Alaska and the Arctic offshore. It is the Arctic areas of Alaska that are most richly endowed with gas reserves and undiscovered gas resources. A major gas transportation system will probably soon be constructed to the gas reserves at Prudhoe Bay.

Clearly, any near-term future development of the undiscovered natural gas resources of Alaska will first focus upon the Arctic. ***However, the 156 tcf of undiscovered Arctic gas is just that—not yet discovered.*** Finding and developing any significant fraction of this undiscovered gas will be extremely costly. And, at the current pace of exploration, particularly in offshore areas, development of a significant fraction of the

[47] *mean, undiscovered, conventionally recoverable*

Arctic gas resource base could require many decades.

The future gas transportation system that will be constructed to export Prudhoe Bay gas will be sized to a capacity appropriate for the 26 tcf of known, marketable gas reserves. For some period of time after start-up, the gas transportation system will be completely filled with gas produced from the onshore fields at and near Prudhoe Bay. Without modifications to expand the capacity of the gas transportation system, any newly discovered gas reserves onshore or offshore might have to wait 8 to 26 years (depending on initial system capacity) before they could be accepted by the gas transportation system.

The pace of exploration of the Alaska Federal offshore, typically rather slow, is now at an historic low. Twenty-three years of Alaska offshore exploration produced 14 stratigraphic test wells and 83 rank exploration wells. During this same period, 1,598 leases were issued; only 5% of these leases were directly tested by exploration wells. Only 84 leases remain active at time in the Alaska Federal offshore. The average exploration-drilling rate over the 23-year period has been 3.6 wells per year. However, only 2 wells were drilled in the past 6 years.

Any leases issued today can expect a very long waiting period prior to any production of the resources that may lie beneath them. The lag between lease issuance and exploration drilling has ranged from 1 to 10 years, with an historic average of 2.4 years. Northstar field was discovered in 1984, 5 years after the lease was issued in 1979. Northstar field is one of two commercial offshore fields (Northstar and Liberty) that may begin production in years 2001-2003, in both cases over 20 years after lease issuance and 15 years after discovery.

Exploratory wells typically cost from $15 million (southern Alaska offshore) to $50 million (Arctic offshore), although some wells have cost much more (Mukluk well in Beaufort shelf cost $120 million). Because of the high costs of these wells and the low rate of drilling success in the Alaska offshore, few exploratory wells are drilled. As we have observed in the Bering Sea, disappointing results from the first round of exploratory drilling can cause industry to condemn entire basins. The Bering Sea basins, last explored in 1985, remain abandoned by the petroleum industry.

In summary, relatively few tracts are now being offered for lease in the Alaska Federal offshore. On average, only a small fraction (about 6%) of offered tracts have been taken as leases. Historically, only a very small fraction (about 5%) of leases are actually tested by wells. Less than 2% of the offshore exploratory wells have discovered significant gas pools. We conclude that at the present pace of leasing, exploration, and discovery, most of Alaska's offshore gas resources will not be developed for many decades to come.

When a gas transportation infrastructure is constructed to export the proven gas reserves in northern Alaska, a wider search for additional gas resources may result in the discovery of commercially viable gas fields—probably fields that are reasonably close to the existing infrastructure. These future offshore gas fields could represent significant additions to the northern Alaska gas reserve base, but are probably only a small fraction of the larger resource base. Most of the undiscovered offshore gas resources are truly remote and very costly to develop. Only the largest and most favorably located gas pools in the Alaska Federal offshore may ultimately export gas to commercial markets outside of Alaska.

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Table 1

Potentially Exportable, Known Gas Reserves for Alaska as of 2000

	Gas Reserves Available for Future Export
Onshore Areas and State of Alaska Lands	
Northern Alaska and Arctic Offshore	26.0 tcf[1] (presently stranded)
Central Alaska	0 tcf
Southern Alaska (Cook Inlet)	0.923 tcf[2] (now consuming 0.078 tcf/yr)
Federal Offshore Areas	
Arctic Offshore (Chukchi and Beaufort Seas)	0 tcf[3]
Bering Shelf and Hope Basin	0 tcf
Pacific Margin continental shelves	0 tcf
Total Gas Reserves Available as of 2000	***26.923 tcf***

[1] Thomas and others, 1996, tbl. 2.3; total known onshore gas reserves remaining in 2000 = 31.617 tcf (see tbls. 2, 3)

[2] 36% of Cook Inlet production in 1998 was directed to LNG exports (AKDO&G, 2000, p. 63). Assuming that the same fraction of 2000 remaining Cook Inlet gas reserves (2.564 tcf including undeveloped fields; see tbl. 4) will be consumed by future LNG exports, we estimate that 0.923 tcf will be exported in the future with depletion of Cook Inlet exportable gas reserves by year 2012. The non-exported 1.641 tcf of year 2000 Cook Inlet gas reserves will be used by local power or gas utilities (1.002 tcf) or ammonia-urea manufacture (0.0.639 tcf). Contract deliveries of 0.0644 tcf per year of LNG from Cook Inlet to Yokohama, Japan consumes about 0.078 tcf per year, or an 83% thermal efficiency (AKDO&G, 1998, p. 41).

[3] 0.7 tcf in known undeveloped oil fields in Beaufort shelf; if developed, would probably be consumed by oil production operations on the leases. 5.0 tcf in Burger structure in Chukchi shelf, considered uneconomic for near term future

tcf: trillion cubic feet

Table 2

Gas Reserves of Developed Fields, Arctic Alaska, as of Year 2000

FIELD[1]	FIELD TYPE	DISCOVERY DATE	REMAINING GAS RESERVES , tcf (2000)	GAS CONSUMED, tcf (1999)[5]	ORIGINAL GAS RESERVES, tcf
Developed Fields or Fields Under Development-Prudhoe Bay Area					
Badami Unit	Oil	1990	0.039[2]	0.001[4]	0.040
CRU-Alpine	Oil	1994	0.060[2]	0	0.060
CRU-Satellite	Oil	Various	na	na	na
DIU-Endicott	Oil	1978	0.843[2]	0.143[4]	0.986
DIU-Eider	Oil	1998	na	0.003[4]	na
KRU-Kuparuk	Oil	1969	0.590[2]	0.397[2]	0.987
KRU-West Sak	Oil	1969	na	0.001[4]	na
KRU-Tabasco	Oil	1992	na	0.0004[4]	na
KRU-Tarn	Oil	1997	0.021[2]	0.018	0.039
KRU-Kup. Sat.	Oil	Various	na	na	na
MPU-Kuparuk	Oil	1969	0.014[2]	0.020[4]	0.034
MPU-Sch.Bluf.	Oil	1969	na	0.006[4]	na
MPU-Sag Riv.	Oil	1969	na	0.001[4]	na
North Star	Oil	1984	0.450[2]	0	0.450
PBU-Prud. Bay	Oil	1969	23.000[2]	3.048[4]	26.048
PBU-Midnight Sun	Oil	1997	na	0.004[4]	na
PBU-Satellites	Oil	Various	na	na	na
PBU-Lisburne	Oil	1968	0.276[2]	-0.093[4]	0.183
PBU-Niakuk	Oil	1981	0.026[2]	0.046[4]	0.072
PBU-N. Prudhoe	Oil	1970	na	0.006[4]	na
PBU-Pt. McIntyre	Oil	1988	0.577[2]	0.133[4]	0.710
PBU-West Beach	Oil	1976	na	0.013[4]	na
Subtotals			*25.896*	*3.7474*	*29.609*
Developed Fields-Outside Prudhoe Bay Area (Barrow Area)					
East Barrow	Gas	1974	0.005[2]	0.008[4]	0.013
South Barrow	Gas	1949	0.004[2]	0.022[4]	0.026
Walakpa	Gas	1980	0.025[2]	0.007[4]	0.032
Subtotals			*0.034*	*0.037*	*0.071*
Total Developed for Arctic Alaska			***25.930***	***3.7844***	***29.680***

[1] CRU=Colville River Unit; DIU=Duck Island Unit; KRU=Kuparuk River Unit; MPU=Milne Point Unit; PBU=Prudhoe Bay Unit
[2] AKDO&G, 2000, p. 12; here generally rounded to nearest 0.001 tcf
[3] Thomas and others, 1991, tbl. 2-5
[4] AKDO&G, 2000, p. 34-37; here generally rounded to nearest 0.001 tcf
[5] gas consumed by oil production operations on lease or by local community; no gas is exported at present
na = quantity not available; tcf: trillion cubic feet

Table 3

Gas Reserves of Undeveloped Fields, Arctic Alaska, as of Year 2000

FIELD	FIELD TYPE	DISCOVERY DATE	REMAINING GAS RESERVES, tcf (2000)	GAS CONSUMED, tcf (1999)	ORIGINAL GAS RESERVES, tcf
Undeveloped Known Fields-Outside Prudhoe Bay Area					
East Umiat	Gas	1963	0.004[1]	0	0.004
Gubik	Gas	1951	0.600[1]	0	0.600
Kavik	Gas	1969	na[1]	0	na
Kemik	Gas	1972	na[1]	0	na
Meade	Gas	1950	0.020[1]	0	0.020
Point Thomson	Gas/Oil	1977	5.000[2]	0	5.000
Square Lake	Gas	1952	0.058[1]	0	0.058
Umiat	Oil	1946	0.005[1]	0	0.005
Wolf Creek	Gas	1951	na	0	na
Subtotals			*5.687*	*0*	*5.687*
Offshore Undeveloped Known Fields					
Beaufort Sea					
Hammerhead	Oil	1985	Σ = 0.700 tcf (Federal Portion Only for North Star) Individual Field Gas Reserves Not Available		
Kuvlum	Oil	1993			
Liberty	Oil	1982			
Northstar	Oil	1984			
Sandpiper	Gas/Oil	1986			
Chukchi Sea					
Burger	Gas	1990	5.0[3]	0	5.0
Subtotals			*5.700*	*0*	*5.700*
Total Undeveloped for Arctic Alaska			***11.387***	***0***	***11.387***
Total Developed for Arctic Alaska (tbl. 2)			***25.930***	***3.7844***	***29.680***
Totals for Arctic Alaska			***37.317***	***3.7844***	***41.067***

[1] Thomas and others, 1991, tbl. 2-5
[2] AKDO&G, 1998, tbls. 1, 4; here generally rounded to nearest 0.001 tcf
[3] mean value, in range of possible values from 2 tcf (F95) to 10 tcf (F05); preliminary estimate by J. Craig, 1993
na = quantity not available; tcf: trillion cubic feet

Table 4
Cook Inlet—State of Alaska Lands
Gas Reserves of Developed and Known Undeveloped Fields as of Year 2000
(No Federal OCS Reserves)

FIELD	FIELD TYPE[1]	DISCOVERY DATE[1]	REMAINING GAS RESERVES , tcf (2000)	GAS CONSUMED, tcf (1999)	ORIGINAL GAS RESERVES, tcf
Developed Fields or Fields Under Development					
Beaver Creek	Oil/Gas	1972/1967	0.097[2]	0.145[2]	0.242
Beluga River	Gas	1962	0.600[2]	0.666[2]	1.266
Cannery Loop	Gas	1959	0.020[2]	0.089[2]	0.109
Granite Point	Oil/Gas	1965/1993	0.019[2]	0.119[2]	0.138
Ivan River Group[4]	Gas	1966-1979	0.020[2]	0.082[2]	0.102
Kenai	Gas	1959	0.225[2]	2.162[2]	2.387
McArthur River	Oil/Gas	1965/1968	0.383[2]	1.001[2]	1.384
Middle Ground Shoal	Oil/Gas	1962/1982	0.008[2]	0.104[2]	0.112
North Cook Inlet	Gas	1962	0.917[2]	1.411[2]	2.328
North Trading Bay	Oil/Gas	1965/1979	0.019[2]	0.012[2]	0.031
Sterling	Gas	1961	0.030[2]	0.003[2]	0.033
Swanson River[6]	Oil/Gas	1957/1960	0.108[2]	0.189[2]	0.297
Trading Bay	Oil	1965	0.027[2]	0.063[2]	0.090
West McArthur River	Oil	1991	na[2]	0.001[2]	~0.001
Subtotals			*2.473*	*6.047*	*8.520*
Known Undeveloped or Shut-In Fields					
Albert Koloa	Gas	1968	0[3]	0.0001 (test)[2]	0.0001
Birch Hill	Gas	1965	0.011[2]	0.0001 (test)[2]	0.0111
Falls Creek	Gas	1961	0.013[2]	0.00002 (test)[2]	0.01302
Mowquawkie	Gas	1965	0[3]	0.001[2]	0.001
Nicolai Creek	Gas	1966	0.002[2]	0.001[2]	0.003
North Fork	Gas	1965	0.012[2]	0.0001 (test)[2]	0.0121
North Middle Ground Shoal[6]	Gas	1964	na[3]	na	na
Redoubt Shoal	Oil	1968	0[3]	0[2]	na
Tyonek Deep[5]	Oil	1991	0.030[2]	0	0.030
West Foreland	Gas	1962	0.020[2]	0	0.020
West Fork	Gas	1960	0.003[3]	0.004[2]	0.007
Subtotals			*0.091*	*0.00632*	*0.09732*
Totals for Cook Inlet			***2.564***	***6.05332***	***8.61732***

[1]AOGCC (1997)
[2]AKDO&G, 2000, p. 13 & 38-40; generally rounded to nearest 0.001 trillion cubic feet (tcf)
[3]AKDO&G, 1998, tbl. 1; generally rounded to nearest 0.001 trillion cubic feet (tcf)
[4]Ivan River Group includes Ivan River (1966), Lewis River (1975), Pretty Creek (1979), and Stump Lake (1978) Units
[5]beneath North Cook Inlet field
[6]see Middle Ground Shoal field
[7]Federal onshore lands and producing properties. As of 1999, 2.811 tcf of gas had been produced from Swanson River oil field, but 2.888 tcf of gas (produced from other fields) had been injected for reservoir pressure maintenance (AKDO&G, 2000, p. 40)
na = not available

Table 5

Uses of Cook Inlet Produced Gas in 1998[1]

Manner of Gas Use	Quantity, tcf, (% of annual production)
Field Operations (Used on Lease, Vented, Flared)	0.017 (8%)
Electrical Power Generation	0.033 (15%)
Gas Utility Sales	0.027 (13%)
Ammonia-Urea Manufacture for Export	0.054 (25%)
LNG Export to Yokohama, Japan	0.078 (36%)
Miscellaneous	0.006 (3%)
Total 1998 Gas Production	*0.215 (100%)*

[1] AKDO&G, 2000, p. 63
tcf: trillion cubic feet

Table 6

1995-1999 Average LNG Shipping Prices[1] and Recent Price Volatility
LNG Leaving Port Nikiski, Cook Inlet, Alaska and Delivered to Yokohama, Japan

Year	Average Shipping Price $U.S. (Nominal) /mcf[2]
1995	$3.41
1996	$3.65
1997	$3.83
1998	$2.91
1999	$3.08
September, 1998 (U.S. oil at $11.28/bbl)	$2.69
December, 1999 (U.S. oil at $22.55/bbl)	$3.81
September, 2000 (U.S. Oil at $30.03/bbl)	$4.33[3]
Average 5-Year 1995-1999 LNG Price	*$3.38*

[1] LNG prices from DOE, 1999a and 2000, web site postings, *ftp://ftp.eia.doe.gov/pub/oil_gas/natural_gas* and *http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/prices.html*; oil prices from *http://www.eia.doe.gov/oil_gas/petroleum/info_glance/prices.html* and *ftp://ftp.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/txt/tables01.txt*
[2] 1 mcf (thousand cubic feet) of Cook Inlet gas ≈ 1.01 mmbtu (million British thermal units); Swain, 1999, tbl. 5
[3]DOE Fossil Energy web site, *www.fe.doe.gov*, January 2001

Table 7

Conventional Natural Gas Resource Base for Alaska as of 2000

(Risked, Undiscovered, Conventionally Recoverable; Excludes Coalbed Gas and Gas Hydrates)

Area	F95[15] (tcf)	Mean (tcf)	F05[15] (tcf)	Area Chance[16]
Arctic Alaska				
Northern Alaska[1]	23.3	63.5[3]	124.3	1.0[1]
Beaufort shelf[2]	12.86	32.07[4]	63.27	1.0[2]
Chukchi shelf[2]	13.56	60.11[5]	154.31	1.0[2]
Subtotal[15]		155.68[6]		
Bering Shelf, Hope Basin, and Central Alaska				
Hope basin (offshore)[2]	0.0	3.38[7]	11.06	0.61[2]
Bering shelf[2]				
Navarin basin	0.0	6.15	18.18	0.88
North Aleutian basin	0.0	6.79[8]	17.33	0.72
St. George basin	0.0	3.00	9.72	0.94
Norton basin	0.0	2.71	8.74	0.72
St. Matthew-Hall basin	0.0	0.16	0.69	0.44
Central Alaska[1]	0.5	2.8[9]	7.3	1.0[1]
Subtotal[15]		24.99		
Pacific Margin and Southern Alaska				
Southern Alaska (mostly Cook Inlet-State of Alaska Lands)[1]	0.7	2.1[10]	4.3	1.0[1]
Cook Inlet (Federal Offshore)[2]	0.66	1.39[11]	2.49	1.0[2]
Gulf of Alaska (Federal Offshore)[2]	0.94	4.18[12]	10.59	0.99[2]
Shumagin-Kodiak shelf[2]	0.0	2.65[13]	11.35	0.4[2]
Subtotal[15]		10.32		
Subtotal for Alaska Federal Offshore		122.59		
Subtotal for Alaska Onshore		68.4		
Total Undiscovered Gas Potential for Alaska[15]		***190.99***[14]		

[1] USGS, 1995, tbl. 2, and CD DDS-36, *region1\convtab.tab*
[2] Craig (2000)
[3] estimated at 68.2 tcf by PGC (1997, tbl. 55 and 1999, tbl. 52)
[4] estimated at 33.5 tcf by PGC (1999, tbl. 53)
[5] estimated at 19.5 tcf by PGC
[6] estimated at 121.2 tcf by PGC
[7] estimated at 0.6 tcf by PGC
[8] estimated at 6.5 tcf by PGC
[9] PGC (1999, tbl. 52) estimate for “Interior Basins” province = 0.5 tcf
[10] PGC estimate for “Cook Inlet-Susitna” province = 4.5 tcf
[11] estimated at 2.1 tcf by PGC (1999, tbl. 53)
[12] PGC (1999, tbl. 53) estimates for “N. Gulf of Alaska Shelf” and “Southeastern Alaska Shelf” provinces sum to 1.7 tcf
[13] estimated at 1.7 tcf by PGC (1999, tbl. 53)
[14] PGC (1999, tbl. 53) total for Alaska = 143.1 tcf
[15] Fractile values (F95, F05 gas quantities) are not additive. F05 represents a 1 in 20 (or 5%) chance that the indicated gas quantity will be exceeded. Mean values may be added.
[16] chance that the area contains at least one pool of oil or gas capable of flowing to a conventional wellbore

na: not available
tcf: trillion cubic feet

Table 8

Gas Hydrate Gas Resource Base for Alaska
(Unconventional, Continuous-Type Gas Resources)

	Gas In Place (tcf)[1]		
Area	**F95 (tcf)**	**Mean (tcf)**	**F05 (tcf)**
Alaska Offshore Province			
Beaufort Sea	0	32,304	116,555
Bering Sea	0	73,289	264,899
Aleutian Trench	0	21,496	183,663
Gulf of Alaska	0	41,360	257,835
Alaska Onshore Province (Northern Alaska)			
Topset Play (Onshore)	0	105	388
Topset Play (Offshore[2])	0	43	161
Foldbelt Play (Onshore)	0	414	1,914
Foldbelt Play (Offshore[3])	0	28	128
Total Gas Hydrate Resource Base for Alaska[4]		***169,039***	

[1] Collett and Kuuskraa, 1998, tbl. 1; USGS, 1995. "In place" means volume of gas resource stored in hydrates in subsurface, if brought in entirety to surface conditions. Not all of the subsurface resource would be recovered by any method for extraction and recovery efficiencies for gas hydrate production are not known.

[2] Includes some shelf areas of Beaufort and Chukchi Seas north of Brooks Range foldbelt

[3] Includes offshore extension of Brooks Range foldbelt into Chukchi Sea

[4] Fractile values (F95, F05 gas quantities) are not additive. F05 represents a 1 in 20 (or 5%) chance that the indicated gas quantity will be exceeded. Mean values may be added.

tcf: trillion cubic feet

Table 9

Total Gas Resource Base for Alaska as of Year 2000

Trillions of Cubic Feet (tcf)

Area	Exportable Reserves (tcf)[1]	Conventional Undiscovered (tcf)[2]	Deep Tech. Conv. Recoverable (tcf)[3]	Gas Hydrates (tcf)[4]	Coal Bed Methane (tcf)[5]	Total (Sums by Rows, tcf)
Northern Alaska (Onshore)	26.000	63.5	17.7	519	ne	608.5
Beaufort Sea	0	32.07	ne	32,325[7]	ne	32,357.07
Chukchi Sea	0	60.11	ne	50[7]	ne	110.11
Bering Sea[6]	0	22.19	ne	73,289	ne	73,311.19
Central Alaska (Onshore)	0	2.8	ne	ne	ne	2.8
Southern Alaska (Onshore)	0.923	2.1	0.2	ne	ne	3.023
Pacific Margin (Offshore)	0	8.22	ne	62,856	ne	62,864.22
Alaska Total by Category	***26.923***	***190.99***	***17.9***[3]	***169,039***	***1,000***	***170,256.913***

[1] Potentially exportable, known gas reserves as of 2000 (tbl. 1). Northern Alaska reserves are presently stranded because of the absence of a transportation infrastructure.

[2] Risked, mean, undiscovered, conventionally recoverable gas resources (tbl. 7); only a small fraction of this gas may be economically recoverable.

[3] subcategory of "Conventional Undiscovered" gas resources[2] and already included in those estimates (col. 3); mean, undiscovered, technically recoverable, deep (>15,000 feet) conventional gas resources (Dyman and others, 1998, tbl. 1); southern Alaska estimate is for Cook Inlet

[4] gas volumes (surface conditions***) in place*** as unconventional, continuous-type gas hydrate deposits (tbl. 8; Collett and Kuuskraa, 1998, tbl. 1). Recoverability of methane from gas hydrates is not known and is not implied by these estimates. It is unlikely that all of the in place gas would be recoverable.

[5] Smith (1995) estimated that in-place coal bed methane resources for all of Alaska might reach 1,000 trillion cubic feet. The most likely volume of coal bed methane for all of Alaska was estimated at 57 tcf by PGC (1997, tbl. 55 and 1999, tbl. 53). The PGC estimate includes but does not separate northern Alaska, Gulf of Alaska (noted in PGC report as Bering River), and the Alaska Peninsula of southern Alaska (noted in PGC report as Chignik and Herendeen Bay)

[6] includes Hope basin

[7] Topset play (offshore) of Collett and Kuuskraa (1998, tbl. 1), with 43 tcf, arbitrarily split between Chukchi (21 tcf) and Beaufort (22 tcf) Seas. The Foldbelt play (offshore) of Collett and Kuuskraa, with 28 tcf, was assigned to the Chukchi Sea.

ne: no estimates available

Table 10

Economic, Undiscovered Natural Gas Resources for Alaska

(Risked, Undiscovered, Conventional, Economically Recoverable; Excludes Coal Bed Gas and Gas Hydrates)

Area	Domestic U.S. Gas Price (Mean (tcf) at Gas Prices $2.00-$2.11/mcf[1])	Asian LNG Market Price (Mean (tcf) at Gas Prices $3.34 to $3.52/mcf[2])
Arctic Alaska		
Northern Alaska[3]	No economic gas resources	
Beaufort shelf[4]	2.934	4.200
Chukchi shelf[5]	No economic gas resources	No economic gas resources
Subtotals	***2.934***	***4.200***
Bering Shelf, Hope Basin, and Central Alaska		
Hope basin (offshore)[8]	0.614	1.506
Bering shelf[7]		
Navarin basin	0.036 (~negl.)	0.075 (~negl.)
North Aleutian basin	0.880	1.272
St. George basin	0.049 (~negl.)	0.103 (~negl.)
Norton basin	0.024 (~negl)	0.072 (~negl.)
St. Matthew-Hall basin	Gas not evaluated; no economic gas	
Central Alaska[3]	Gas not evaluated; no economic gas	
Subtotals	***1.603***	***3.028***
Pacific Margin and Southern Alaska		
Southern Alaska (Cook Inlet—State Lands)[6]	1.033	3.556
Cook Inlet (Federal Offshore)[9]	0.599	0.997
Gulf of Alaska (Federal Offshore)[10]	No economic gas resources	
Shumagin-Kodiak shelf[7]	0.004 (~negl.)	0.449
Subtotals	***1.636***	***5.002***
Subtotals for Alaska Federal Offshore	5.140[11]	8.674[11]
Subtotals for Alaska Onshore	1.033	3.556
Total Undiscovered Gas Potential for Alaska	***6.173***	***12.230***

[1] These gas prices approximate the 1993-1997 five-year average well head prices for domestic U.S. gas ($1.99/mcf) as reported by DOE (1999a) and form a useful convention

[2] These gas prices bracket the 1995-1999 five-year average shipping price ($3.38/mcf) for LNG leaving Port Nikiski, Cook Inlet and bound for Yokohama, Japan (see tbl. 6) and form a useful benchmark; prices in late 2000 for Nikiski LNG have exceeded $4.00/mcf

[3] Attanasi, 1998, p. 8

[4] Craig (2000); prices for gas delivered to Prudhoe Bay plantgate, rather than outside export markets.

[5] Chukchi shelf gas was not assessed in Year 2000 study. We estimate that $3.63/mcf represents the minimum processing and delivery cost to Yokohama, Japan using a modified version of the Yukon-Pacific TAGS-LNG model (the latter described in tbl. 17).

[6] Attanasi, 1998, tbl. 1; calculated by present authors as sums of separately tabulated entries for associated gas (with oil) fields and conventional non-associated gas fields, at gas prices of $2.00/mcf and $3.34/mcf in Year $1994 (here assumed equivalent to Year $2000 because of little overall inflation in prices or costs in the 1994-2000 period)

[7] Craig (1998b, tbl. 27.12), at gas prices of $2.11/mcf and $3.52/mcf; not amended from 1995

[8] Craig (2000); prices are for gas delivered to hypothetical Kivalina plantgate

[9] Craig (2000); prices are for gas delivered to gas pipeline network in Cook Inlet basin

[10] Craig (2000)

[11] MMS (2001) reports totals of 1.6 tcf and 3.0 tcf for the $2.11/mcf and $3.52/mcf cases, respectively. Because local markets were used in the economic models, the Beaufort shelf and Hope Basin results shown here were not included in that report.

tcf: trillion cubic feet

~negl.: essentially negligible, reported values are artifacts of analytical method

Table 11
Summary of Gas Transportation Scenarios Used in 1995 and 2000 Assessments for Economically Recoverable Gas in Alaska Arctic and Bering Shelf Federal Offshore
(modified after Craig [2000], Sherwood and Craig [2000], and Craig [1998a, tbl. 26.3])

Province	Gas Transportation Scenario
Arctic Alaska Offshore	
Beaufort shelf	The Year 2000 assessment of Beaufort shelf (Craig, 2000) assumes the existence of an unspecified gas transportation system (possible either gas-to-liquids or gas pipeline) originating at the Prudhoe Bay complex. Gas produced with oil on Beaufort shelf would be gathered via subsea pipelines to either of 2 central offshore gas storage and processing facilities (located approximately at “BEAU” in fig. 11), then transported via 120-mile subsea and land gas pipelines to the Prudhoe Bay “plantgate”, where the gas is sold. Gas sales prices at the Prudhoe Bay plantgate determine the economically recoverable gas resources of Beaufort shelf.
Chukchi shelf	We assume the existence of an 800-mile TAGS gas pipeline from the Prudhoe Bay area to Valdez, Alaska. Gas was assumed to be transported via subsea pipelines that gather to either of two central offshore gas storage and processing facilities (located at “CHUK” in fig. 11), then transported via 150-mile subsea trunk gas pipelines to the northwest coast of Alaska, then via a 400-mile overland gas pipeline to the Prudhoe Bay area. Gas was then taken down the TAGS line to Valdez, converted to LNG, then shipped via tanker 4,000 miles to Yokohama, Japan, and delivered to existing regasification plants. Gas sales prices in Japan therefore determine the economically recoverable gas resources of Chukchi shelf. The results of this study are shown in figure 14. Gas was not assessed in the Craig (2000) study because Chukchi gas development is viewed as probably occurring far beyond the 2007-2012 5-year planning cycle for which that study was conducted.
Hope Basin and Bering Shelf	
Hope basin	The Craig (2000) assessment assumed that gas and condensate would be marketed to a hypothetical onshore industrial complex at Kivalina, where the gas, condensate, and possible synthetic fuels (from gas-to-liquids) would be marketed to the zinc mining operations at Red Dog, the Bering Sea fishing fleet, and local communities. Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at “HB” in fig. 11), then is transported via a 100-mile subsea trunk pipeline to a “plantgate” at Kivalina port. Prices at the Kivalina plantgate determine the economically recoverable gas resources of Hope basin.
Norton basin	Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at “NOR” in fig. 11), then transported via 65-mile subsea trunk pipeline to Nome, converted to LNG at a newly-built gas plant, then shipped as LNG to Japan, where gas sales prices determine the economically recoverable gas resources of Norton basin.
Navarin basin	Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at “NAV” in fig. 11), then is transported via a 700-mile subsea trunk pipeline to Balboa Bay on the Alaska Peninsula, converted to LNG at newly-built gas plant, then shipped as LNG to Japan, where prices determine the economically recoverable gas resources of Navarin basin.
St. George basin	Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at “SGB” in fig. 11), then is transported via a 340-mile subsea trunk pipeline to Balboa Bay on the Alaska Peninsula, converted to LNG at newly-built gas plant, then shipped as LNG to Japan, where prices determine the economically recoverable gas resources of St. George basin.
North Aleutian basin	Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at “NAS” in fig. 11), then is transported via 70-mile subsea trunk pipeline to Balboa Bay on the Alaska Peninsula, converted to LNG at newly-built gas plant, then shipped as LNG to Japan, where prices determine the economically recoverable gas resources of North Aleutian basin.

LNG: Liquefied natural gas

Table 12

Summary of Gas Transportation Scenarios Used in 1995 and 2000 Assessments for Economically Recoverable Gas in Alaska Pacific Margin Federal Offshore

(modified after Craig [2000], Sherwood and Craig [2000], and Craig [1998a, tbl. 26.3])

Province	Gas Transportation Scenario
Pacific Margin Offshore	
Shumagin-Kodiak shelf	Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at "KS" in fig. 11), then is transported via a 215-mile subsea trunk pipeline to the port of Nikiski in Cook Inlet, where it is converted to LNG at the existing plant, then shipped as LNG to Japan, where gas sales prices determine the economically recoverable gas resources of Shumagin-Kodiak shelf.
Cook Inlet	In the Craig (2000) study, gas is assumed to be marketed locally to industries and communities along the shores of Cook Inlet. Gas from producing oil fields and non-associated gas fields is gathered to a central offshore storage and processing facility (located approximately at "COOK" in fig. 11) and then conveyed by a 125-mile subsea trunk line to the existing gas transmission pipeline network, with landfall probably near Kenai. Cook Inlet basin gas prices determine the economically recoverable gas resources of the Cook Inlet Federal Offshore.
Gulf of Alaska shelf	In a 1995 internal study, we assumed that Gulf of Alaska gas would be co-produced with oil and then gathered via subsea pipelines to offshore gas storage and processing centers (located approximately between the "GOA" sites in fig. 11) and then conveyed via a 30-250 mile subsea gas pipeline to Yakutat, where newly constructed LNG and port facilities would process and load the gas on tankers bound for existing regasification plants in Japan, 4,000 miles to the west. Gas sales prices in the Asian Pacific rim markets and the high cost of constructing new LNG and port facilities at Yakutat therefore determine the economically recoverable gas resources of the Gulf of Alaska shelf. The results of this study are shown in figure 20. However, a 1995 study published by Craig (199a, tbl. 26.3) noted that gas is predicted to be associated with oil and would probably be used for decades at the lease to enhance oil recovery and to fuel lease operations. Sensitivity studies found that any attempt to market gas during oil production placed a negative economic burden on oil production. The Craig (2000) resource assessment reaches similar conclusions and notes that gas development on the Gulf of Alaska shelf is very unlikely in the 2007-2012 time frame of that assessment.

LNG: Liquefied natural gas

Table 13
Gas Trunk Pipeline Lengths Used in 1995 and 2000 MMS Economic Assessments
(modified after Craig, 1998a, tbl. 26.2 and Craig, 2000)

Federal Offshore Province	Basin Pipeline Lengths[1] (miles)
Beaufort shelf[2]	120
Chukchi shelf[2]	550
Hope basin	100
Norton basin	65
Navarin basin	700
St. George basin	340
North Aleutian basin	70
Shumagin-Kodiak shelf	215
Cook Inlet basin (Federal OCS)	125
Gulf of Alaska shelf[3]	30-250[4]

[1] Basin pipelines are large-diameter trunk lines and may include both overland and offshore segments. New pipelines are modeled as capital costs.
[2] Arctic gas is presently stranded by lack of a gas transportation infrastructure from the Prudhoe Bay area. Basin pipeline lengths are distances required to reach the Prudhoe Bay infrastructure from offshore gathering facilities.
[3] gas mostly coexists with oil and would be retained on-site for decades to enhance oil recovery and lease operations
[4] entered as "play pipelines" in original table 26.2 of Craig (1998a)

Table 14
Gas Shipping Routes and Marine LNG Tariffs
(modified after MMS [2001], Sherwood and Craig [2000], and Craig [1998a, tbl. 26.1])

Offshore Provinces	Transit[1] and Destination Ports	Distance (miles)[2]	Marine LNG Tariff ($/mcf)[3]
Beaufort shelf	No Shipping; Piped to Prudhoe	na	na
Chukchi shelf	Valdez to Yokohama	4000	$0.80
Hope basin	No Shipping; Piped to Kivalina	na	na
Norton basin	Nome to Yokohama	3100	$0.93
St. George basin	Balboa Bay to Yokohama	3000	$0.60
Navarin basin	Balboa Bay to Yokohama	3000	$0.60
North Aleutian basin	Balboa Bay to Yokohama	3000	$0.60
Cook Inlet	No Shipping; Piped to Nikiski	na	na
Gulf of Alaska shelf	Yakutat to Yokohama	4000	$1.20
Shumagin-Kodiak shelf	Nikiski to Yokohama[4]	3800	$1.14

[1] Transit ports are hypothetical sites (except for pipeline delivery and sales points at Prudhoe Bay, Kivalina, and Nikiski) for new shore-based gas LNG facilities. Transit ports are located in figure 11.
[2] Distances are obtained from Defense Mapping Agency (1985) and are converted from nautical miles to statute miles (1.0 nautical mile = 1.151 statute mile). Tanker routes are great circle tracks.
[3] Gas tariffs for liquified natural gas (LNG) are assumed to average $0.20/mcf per 1,000 miles for large LNG carriers (125,000 cubic meters ship capacity or 2.8 bcf delivered). Tariffs for smaller LNG carriers (20,000 cubic meters ship capacity or 0.4 bcf delivered) that can access shallow water ports are assumed to average $0.30/mcf per 1,000 miles.
[4] Route presently in use for Cook Inlet gas exports (fields beneath State of Alaska lands). See tables 1, 4, 5.

Table 15

Total Gas Processing and Transportation Tariffs[1]

Federal Offshore Province	Gas Processing and Handling Tariffs ($/mcf)	Marine LNG Tariff ($/mcf)	Total Tariffs (Gas Processing and Transportation) ($/mcf)[2]
Beaufort shelf[4]	Not Estimated	Not Estimated	Not Estimated
Chukchi shelf	$2.83	$0.80	$3.63
Hope basin[5]	Not Estimated	Not Estimated	Not Estimated
Norton basin	$1.02	$0.93	$1.95
Navarin basin	$1.32	$0.60	$1.92
St. George basin	$1.40	$0.60	$2.00
North Aleutian basin	$0.75	$0.60	$1.35
Shumagin-Kodiak shelf[6]	$2.33[5]	$1.14	$3.47
Cook Inlet basin (Federal OCS)[7]	Not Estimated	Not Estimated	Not Estimated
Gulf of Alaska shelf	$1.84	$1.20	$3.04

[1] Processing and transportation tariffs do not include costs of field discovery and appraisal drilling, development well drilling, installing production platforms, building new pipelines, or building new gas plants, all which are treated as capital costs

[2] from Craig, 1998a, tbl. 26.2

[3] Five-year 1993-1997 average delivered prices for gas loaded at Port of Nikiski in Cook Inlet and bound for Yokohama, Japan (DOE, 1999a)

[4] Gas development modeled as gas delivered via pipeline to Prudhoe Bay plantgate.

[5] Gas development modeled as gas delivered via pipeline to Kivalina industrial complex plantgate.

[6] The higher tariff for Shumagin-Kodiak shelf relative to other southern Alaska basins reflects the use of an expanded, existing Nikiski facility, with a tariff for capital cost recovery, operating costs, and marine terminal loading fees. Other basins have lower tariffs because major new infrastructure costs (LNG plant and marine terminal) are handled separately as pre-production capital costs.

[7] Gas development modeled as gas delivered via pipeline to existing gas transmission pipeline network near Nikiski.

Table 16

Economic, Undiscovered Natural Gas Resources for Alaska Offshore At $6/mcf ($2000)

(Risked, Undiscovered, Conventional, Economically Recoverable Gas as Read from $6/mcf Price on Price Supply Graphs; Excludes Coal Bed Gas and Gas Hydrates)

Area	**Mean Resource Case** Economic Gas (tcf) at $6/mcf	**High (F05) Resource Case[1]** Economic Gas (tcf) at $6/mcf
Arctic Alaska Offshore		
Beaufort shelf[2]	4.66	14.30
Chukchi shelf[2]	20.00	Not Calculated
Subtotals	*24.66*	- -
Bering Shelf and Hope Basin		
Hope basin	2.27	7.22
Norton basin	negligible	negligible
Navarin basin	negligible	negligible
St. George basin	negligible	negligible
North Aleutian basin	5.90	15.30
Subtotals	*8.17*	*22.50*
Pacific Margin Offshore		
Gulf of Alaska[3]	0.31	Not Calculated
Cook Inlet (Federal Offshore)	1.24	1.92
Shumagin-Kodiak shelf	1.40	6.40
Subtotals	*2.95*	- -
Total Undiscovered Gas Potential for Alaska Federal Offshore at $6/mcf	***35.78***	- -

[1] The high resource case is the low-probability case; F05 corresponds to a 5% probability that the indicated resource quantities will be met or exceeded.

[2] Arctic gas presently stranded by lack of transportation system

[3] Gulf of Alaska gas is modeled as mostly associated with oil and would be largely used to enhance recovery in oil fields and for lease operations

tcf: trillion cubic feet; mcf: 1,000 cubic feet

Table 17

Current Options for Transportation and Marketing of Alaska Natural Gas

GAS MARKETING OPTION	BASIC ELEMENTS AND TECHNOLOGY
PIPELINE TO CANADA	***Gas pipeline to Canadian pipeline network.*** Original proposal was *Alaska Natural Gas Transportation System (ANGTS)*, but other proposals have been announced. Gas pipeline (1,400 or 2,100 miles) along Mackenzie Valley or Alaska Highway to Canadian gas pipeline system. A 1995 study of ANGTS estimated gas delivery costs from $2.82 to $4.17 per mcf.[1] **Main positives**: proven technology. **Main negative**: high cost.
TAGS-LNG	***Trans-Alaska Gas Pipeline System and Conversion to Liquefied Natural Gas***. Large-diameter (36-42 inch) gas pipeline to Valdez with shipment as cryogenically liquefied natural gas or "LNG" to Asian markets. LNG is converted back to gas in a regasification plant at delivery site and is then used in conventional natural gas applications. LNG purchaser will provide receiving port facilities and regasification plant. Current proposal design capacities range from 0.46 to 0.9 tcf per year. Breakeven flat oil price = $19.36 per barrel oil price equivalent[1] or $3.77/mcf LNG for a 0.85 tcf per year project modeled in 1996 DOE study. Other estimates for LNG delivery costs (to Japan) for the TAGS-LNG project are as high as $6.97/mcf.[6] **Main positives**: proven technology; premium price received in Asian markets. **Main negatives**: large initial investment; no presently-identified long-term market; size of project (up to 0.7 tcf per year) very large compared to world LNG market (4.3 tcf per year) and Asian LNG market (3.2 tcf per year); many projects with competitive advantages; no significant future cost reductions.
GTL	***Gas to Liquids Conversion***. Project requires a northern Alaska plant that converts gas permanently to diesel-like liquid fuel or other chemical feed stocks which are then pumped through the Trans-Alaska oil pipeline and then shipped in conventional tankers to Pacific rim ports. No large-scale project is currently proposed but a DOE study modeled a hypothetical project at 2.5 tcfg per year converted to 300,000 barrels of liquid product per day at peak output[4], with a total investment of $13 billion.[5] The converted product is refined and may attract a $5 to $10 premium (over oil price) per barrel. Breakeven flat oil price = $19.94 per barrel[1] oil price equivalent in 1996 DOE study. Estimates for conversion costs are falling rapidly with aggressive new research programs and more recent estimates for conversion costs falling near $15 per barrel[3] with new technologies. **Main positives**: small-scale start-ups possible, with future expansion; known market for refined product attracting premium prices; use existing oil transportation infrastructure and extend operating life of TAPS line; large cost reductions foreseen with new technology. **Main negatives**: unproven technology at needed scale of project; present high costs (but declining with new technologies).

[1] Thomas and others, 1996, pp. xiv, 3-4; "breakeven" includes 10% rate of return for Prudhoe Bay gas only
[2] Jones, 1999, p. 19
[3] Singleton, 1997, tbl. 1
[4] Thomas and others, 1996, p. B-24, tbl. B.12
[5] Thomas and others, 1996, tbl. 2
[6] Attanasi, 1995, tbl. 4

Table 18

Experimental Options for Transportation and Marketing of Stranded Natural Gas

GAS SHIPMENT OPTION	BASIC ELEMENTS AND TECHNOLOGY
COSELLE CNG	***Cran and Stenning "COSELLE" Compressed Natural Gas Containment Vessels.*** New type of pressurized gas containment vessel (small-diameter pipe coiled into a carousel rather than individual bottles) for transporting compressed natural gas in ships at costs as low as $0.60/mmbtu or 20% of LNG shipping costs ($3.25/mmbtu for comparable volume of LNG)[1]
NGH	***Pelletized Hydrates of Natural Gas***. Gas is mixed with water and chilled to produce hydrate pellets which can be bulk loaded (like grain) into refrigerated storage in otherwise conventional freighter ships. System can be scaled to any need. Hydrates are melted at receiving location and gas is used in conventional applications. Costs of NGH transportation system estimated to be only 75% of LNG systems[2]
Submarine LNG Tankers	***LNG Containment Vessels Placed Aboard Submarines***. Proposed for shipment of ice-bound Kara Sea gas from Russia to Asian markets. Twenty-two Russian-built submarine tankers, each with capacity of 170,000 cubic meters (6 mmcf). Subsea gas production piped to LNG plant on Novaya Zemlya Island, then transferred to submarine LNG tankers for an 11-day voyage beneath ice of Arctic Ocean to Alaska's St. Matthew Island, then transferred to conventional surface LNG tankers for shipment to Asian ports. Fleet capacity will be 21 million tons or 1.05 tcf per year. No cost estimates published.[3]

[1] Stenning, 1999, fig. 1
[2] JPT, 1999, fig. 1; LeBlanc, 1995
[3] George,1996; 1997

Table 19

AEO 2001 World Oil Price Forecasts
(Shown in $1995)

Case	Year 1999	2005	2010	2015	2020
Reference[1]	$15.36	$18.44	$18.91	$19.37	$19.83
Low Economic Growth[2]	$15.36	NR	$18.32	$18.52	$18.73
High Economic Growth[2]	$15.36	NR	$19.36	$20.09	$20.81
Low World Oil Price[3]	$15.36	NR	$13.36	$13.36	$13.36
High World Oil Price[3]	$15.36	NR	$23.59	$24.98	$25.15

[1] AEO (2000, tbl. A1); discounted (3.1% per year) from $1999 to $1995, price per barrel
[2] AEO (2000, tbl. B1); discounted from $1999 to $1995, price per barrel
[3] AEO (2000, tbl. C1); discounted from $1999 to $1995, price per barrel
Reference, Low World Oil Price, and High World Oil Price cases graphed in figure 38
NR: not reported

Table 20

Comparative Economics of GTL vs. TAGS-LNG Projects for Northern Alaska Gas
(from 1995 DOE Study[3])

Economic Element	GTL[1]	TAGS-LNG[2]
NPV_{10} with 2.4% Real Oil Price Growth[3]	$10.7 billion	$11.5 billion
Total Capital Investment[4]	$12.9 billion	$16.9 billion
Breakeven (NPV_{10} = 0) Flat Oil Price[5]	$19.94/bbl	$19.36/bbl
LNG Price Equivalent to Breakeven Flat Oil Price[6]	$3.88/mcf	$3.77/mcf
Earliest Economic Viability (Using AEO 2001 *Reference Case*)[7]	2020+	2015

[1] GTL: Gas to Liquids, or F-T synthesis

[2] TAGS-LNG: Trans-Alaska Gas Pipeline System and Conversion to Liquefied Natural Gas for Marine Shipment to Asian Pacific rim (primarily Japan)

[3] Thomas and others, 1996, tbl. 1; NPV_{10}: net present value carrying a 10% return on investment; calculated here with an assumed 2.4% annual real (above inflation) growth in oil prices; in $1995

[4] Thomas and others, 1996; for a 17 million metric ton (0.85 tcf) per year TAGS-LNG project (the Yukon Pacific proposal is for a 14 mmt or 0.7 tcf per year project), and, a 300,000 barrel per day GTL project; in $1995

[5] Thomas and others, 1996, p. xiv; B1-B2; in $1995; world oil price, assumed to be $1 greater than Alaska North Slope crude price.

[6] On energy parity, in $1995, calculated as [$oil price/5.13 (btu conversion)]; modified from conversion formula of Thomas and others (1996, p. B-11) which uses 10% LNG Asian price bonus over energy parity with oil.

[7] based on AEO (2001, tbl. A1) price forecasts for world oil (*reference case*; see tbl. 19) and breakeven flat oil prices calculated by Thomas and others (1996, p. xiv)

Table 21
Historical Data for Oil and Gas Leasing in the Alaska Federal Offshore

YEAR	NO. TRACTS OFFERED	TOTAL ACRES OFFERED	NO. TRACTS LEASED	TOTAL ACRES LEASED	FRACTION LEASED	TOTAL HIGH BIDS ACCEPTED ($)	TOTAL HIGH BIDS ACCEPTED ($1999)	AVERAGE BID ($) VALUE PER ACRE	AVERAGE BID ($1999) VALUE PER ACRE	NUMBER OF EXPLORATION WELLS	LAG (YRS) FR. LEASE TO TEST, BY DRILL DATE	FOOTAGE (FT) DRILLED	LAG (YRS) FR. LEASE TO TEST, BY LEASE DATE	LAG (YRS) FR. LEASE TO PRODUCTION, BY LEASE DATE
1976	189	1,008,499	76	409,058	0.41	559,836,587	1,129,823,436	1,369	2,763	0	0	0	1.4	
1977	135	768,580	87	495,307	0.64	398,471,313	779,987,598	804	1,574	7	1	100,021	2.2	
1978	0	0	0	0		0	0	0	0	6	1.7	62,280	0	
1979	46	173,423	24	85,776	0.49	488,691,138	899,928,010	5,697	10,491	4	2	33,311	4.6	21+
1980	210	1,195,569	35	199,261	0.17	109,751,073	196,030,395	551	984	4	3	42,610	3	
1981	328	1,854,547	14	78,850	0.04	4,576,395	7,928,289	58	100	0	0	0	3.3	
1982	478	2,610,860	121	662,860	0.25	2,055,632,336	3,454,162,384	3,101	5,211	3	3	38,255	4	18+
1983	897	5,068,538	155	876,815	0.17	744,332,202	1,213,124,721	849	1,384	2	3.5	31,209	1.4	
1984	6,455	35,822,442	390	2,135,703	0.06	1,383,177,658	2,186,542,607	648	1,024	13	1.7	114,499	3.1	
1985	0	0	0	0		0	0	0	0	21	1.9	208,478	0	
1986	0	0	0	0		0	0	0	0	6	3.3	61,866	0	
1987	0	0	0	0		0	0	0	0	1	8	14,650	0	
1988	7,910	43,908,928	552	3,087,676	0.07	593,294,267	830,071,437	192	269	1	4	18,325	2.3	
1989	0	0	0	0		0	0	0	0	2	3	25,158	0	
1990	0	0	0	0		0	0	0	0	3	4	25,416	0	
1991	6,893	37,544,952	85	436,217	0.01	23,924,329	30,542,817	55	70	4	4	37,786	2	
1992	0	0	0	0		0	0	0	0	1	8	8,500	0	
1993	0	0	0	0		0	0	0	0	3	6.7	28,439	0	
1994	0	0	0	0		0	0	0	0	0	0	0	0	
1995	0	0	0	0		0	0	0	0	0	0	0	0	
1996	1,413	7,282,795	29	100,025	0.01	14,429,363	15,813,323	144	158	0	0	0	1	
1997	88	427,886	2	9,766	0.02	253,965	269,955	26	28	2	1	25,111	0	
1998	247	920,983	28	86,371	0.09	5,327,093	5,492,233	62	64	0	0	0	0	
1999	0	0	0	0		0	0	0	0	0	0	0	0	
2000	0	0	0	0		0	0	0	0	0	0	0	0	
TOTALS	***25,289***	***138,588,002***	***1,598***	***8,663,685***		***$6,381,697,719***	***$10,749,717,205***			***83***		***875,915***		

($): denotes nominal dollars ($1999) : denotes inflation-adjusted dollars, from nominal dollars (of the time) to 1999 dollars using average annual inflation (i)=3.1% [$1999=$NOMINAL $(1+i)^n$, where n=1999-Nominal Year

Table 22

Offshore Oil and Gas Resources Sequestered by Moratorium of North Aleutian Basin
(Moratorium on Offshore Oil and Gas Leasing and Exploration Until Year 2012)

Oil and Gas Resources	Low Resource Case (F95)	Mean	High Resource Case (F05)
Recoverable Oil Resources[1]	0.00 bbo	0.230 bbo	0.57 bbo
Economic Oil Resources at $18/bbl[2]	0.00 bbo	0.024 bbo	0.20 bbo
Economic Oil Resources at $30/bbl[2]	nr	0.036 bbo	nr
Recoverable Gas Resources[1]	0.00 tcfg	6.790 tcfg	17.33 tcfg
Economic Gas Resources at $2.11/mcf[2]	0.00 tcfg	0.880 tcfg	7.71 tcfg
Economic Gas Resources at $3.52/mcf[2]	nr	1.272 tcfg	12.30 tcfg[3]
Economic Gas Resources at $6/mcf[4]	nr	5.900 tcfg	15.30 tcfg

[1] Sherwood and others, 1996, tbl. 1. “Recoverable oil and gas resources” refer to undiscovered, conventionally recoverable resources. F95 represents a 95% chance that the indicated quantity will be met or exceeded, whereas F05 represents a 1-in-20 (or 5%) chance that the indicated quantity will be exceeded

[2] Craig, 1998b, tbls. 27.11, 27.12; oil and gas prices in $2000.

[3] estimated from price-supply graph of Craig (1998b, fig. 27.5c)

[4] table 16, this report; gas price in $2000.

bbo: billions of barrels of oil

tcfg: trillions of cubic feet of gas

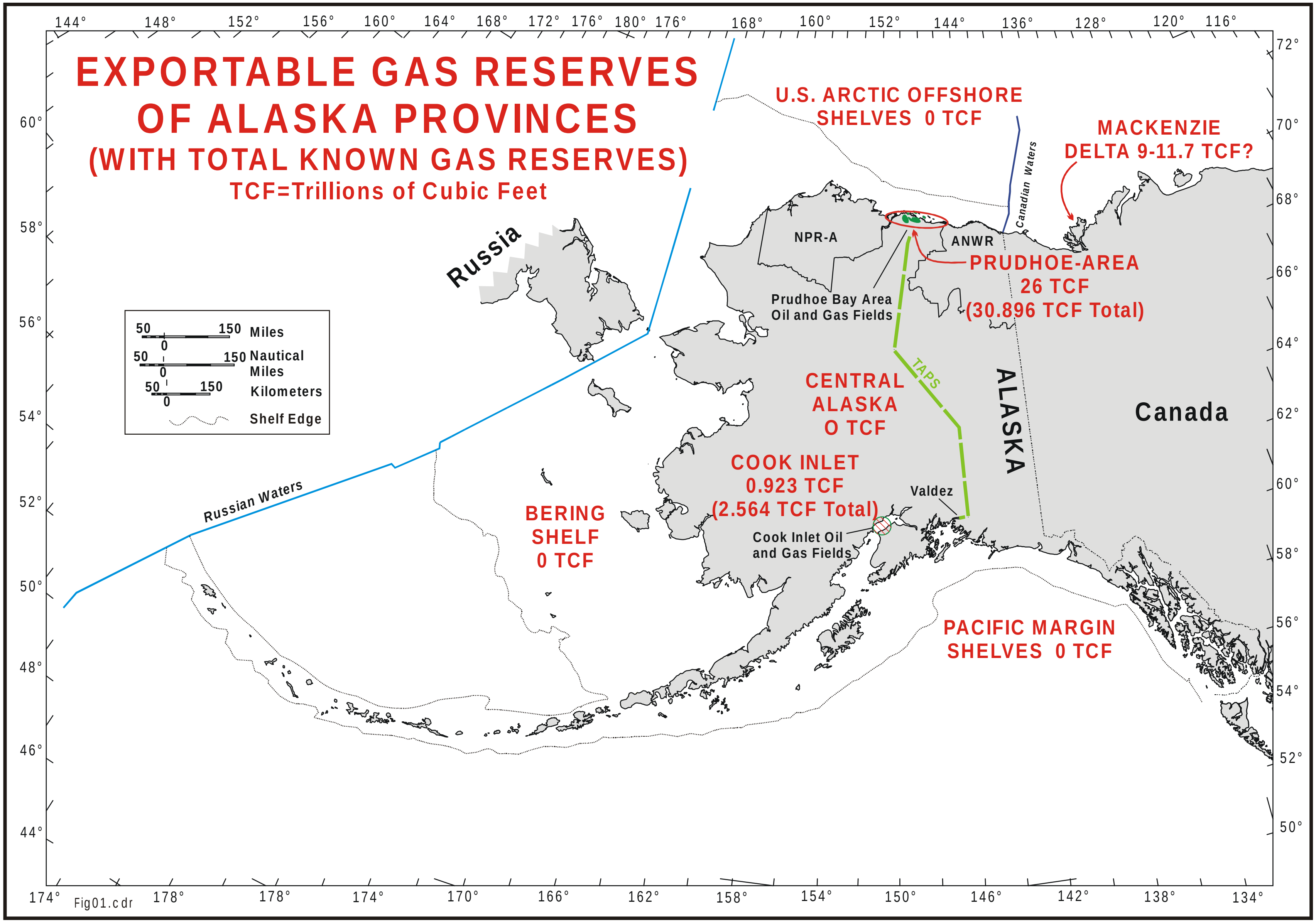


Figure 1: Potentially exportable known gas reserves of Alaska and Alaska Federal offshore, as of 2000. Total known gas reserves, some destined for local use, are shown in parens. Prudhoe-area exportable gas reserves (26 tcf) are presently stranded. Cook Inlet exportable gas reserves (0.923 tcf) are being consumed to support exports (as LNG) at the rate of 0.078 tcf per year and may be exhausted by year 2012. See table 1 for Alaska data. Mackenzie delta reserves from Dixon and others (1994, tbl. 1) and NEB (1998).

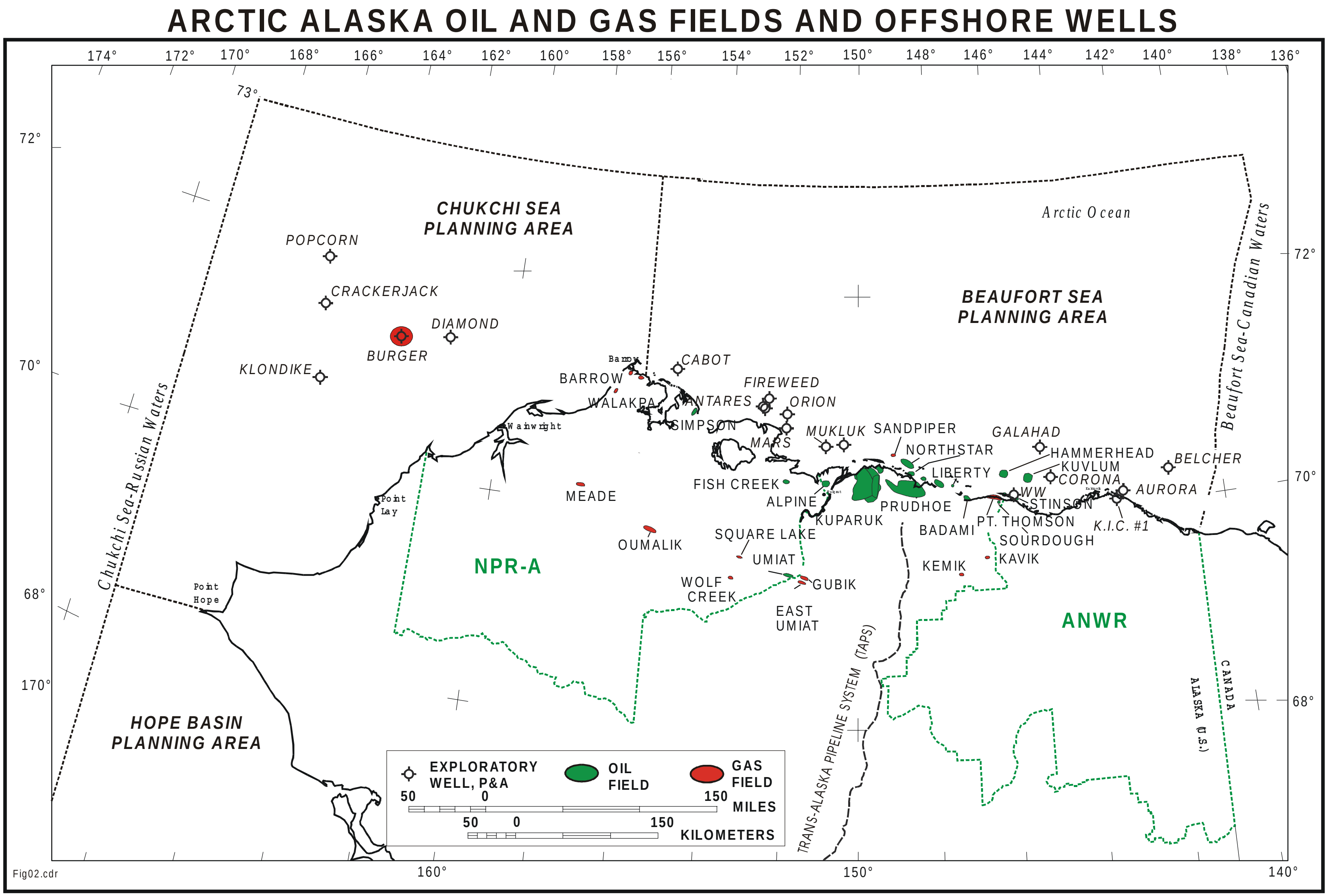


Figure 2: Oil and gas fields, offshore exploration wells, and oil pipeline system (TAPS) for Arctic Alaska.

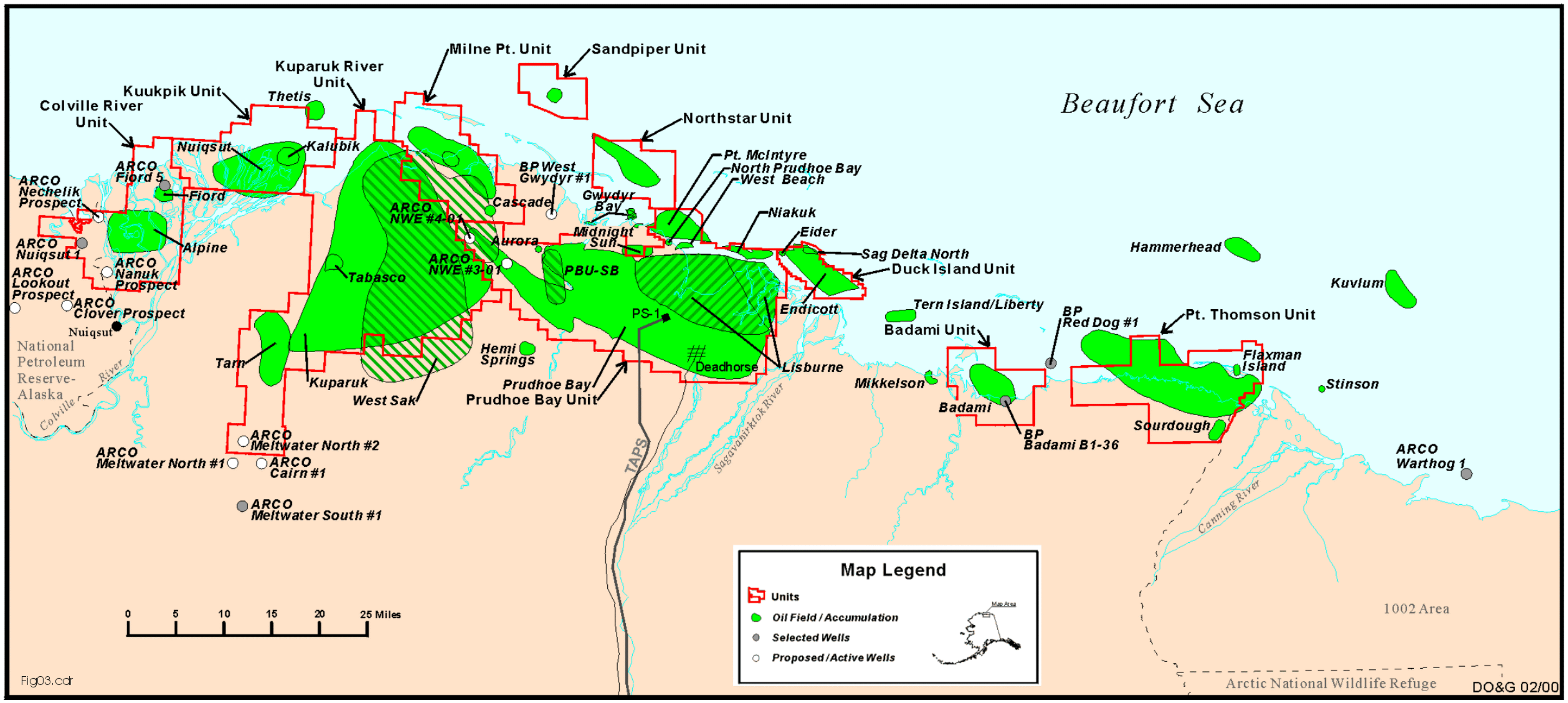


Figure 3: Major oil and gas fields, production infrastructure, and current activity in the Prudhoe Bay area as of December 2000. Map adapted from State of Alaska, Department of Natural Resources, Division of Oil and Gas, web site posting at *http://www.dnr.state.ak.us/oil.*

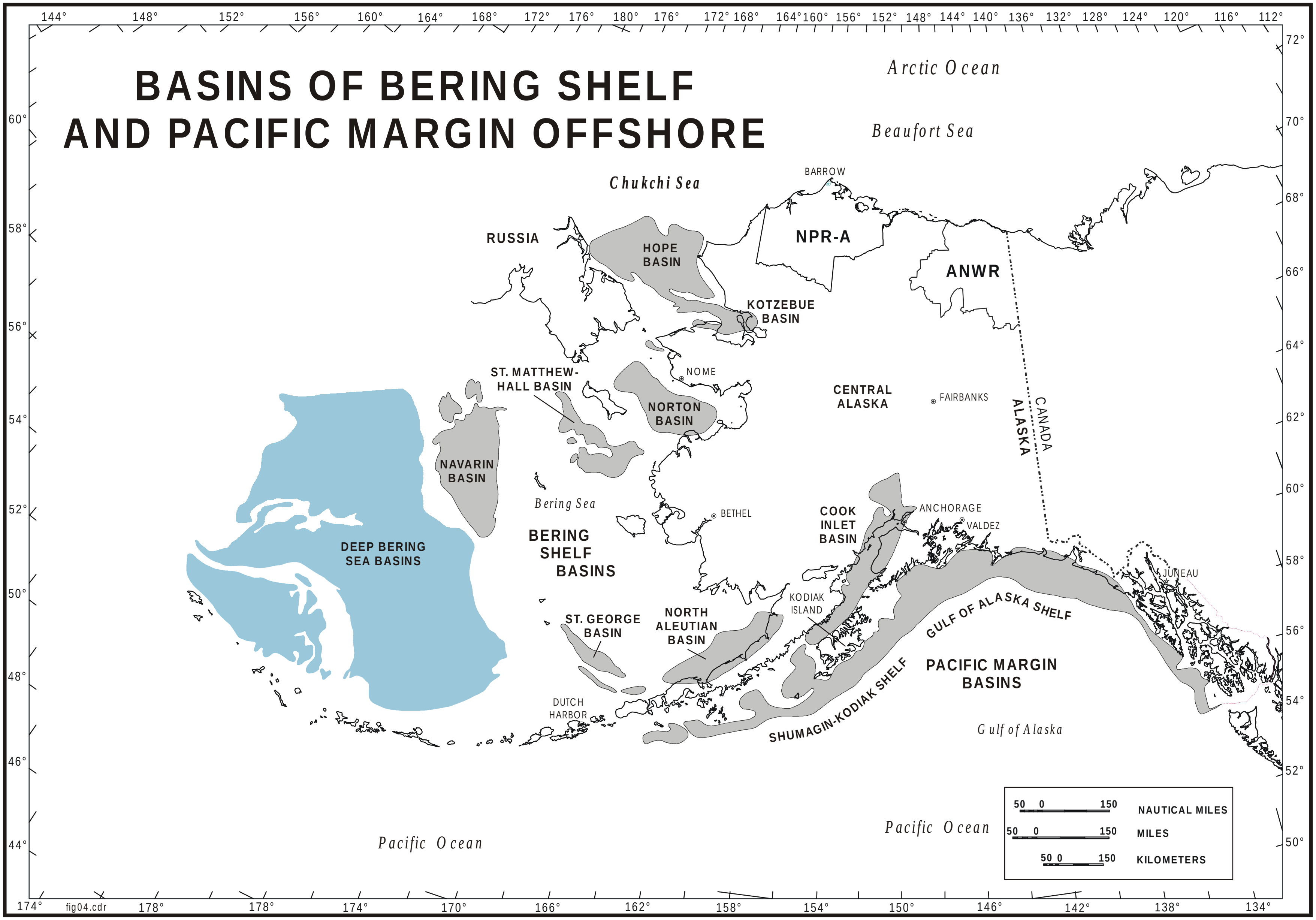


Figure 4: Hope basin, basins of the Bering shelf, Cook Inlet, and the Pacific margin offshore.

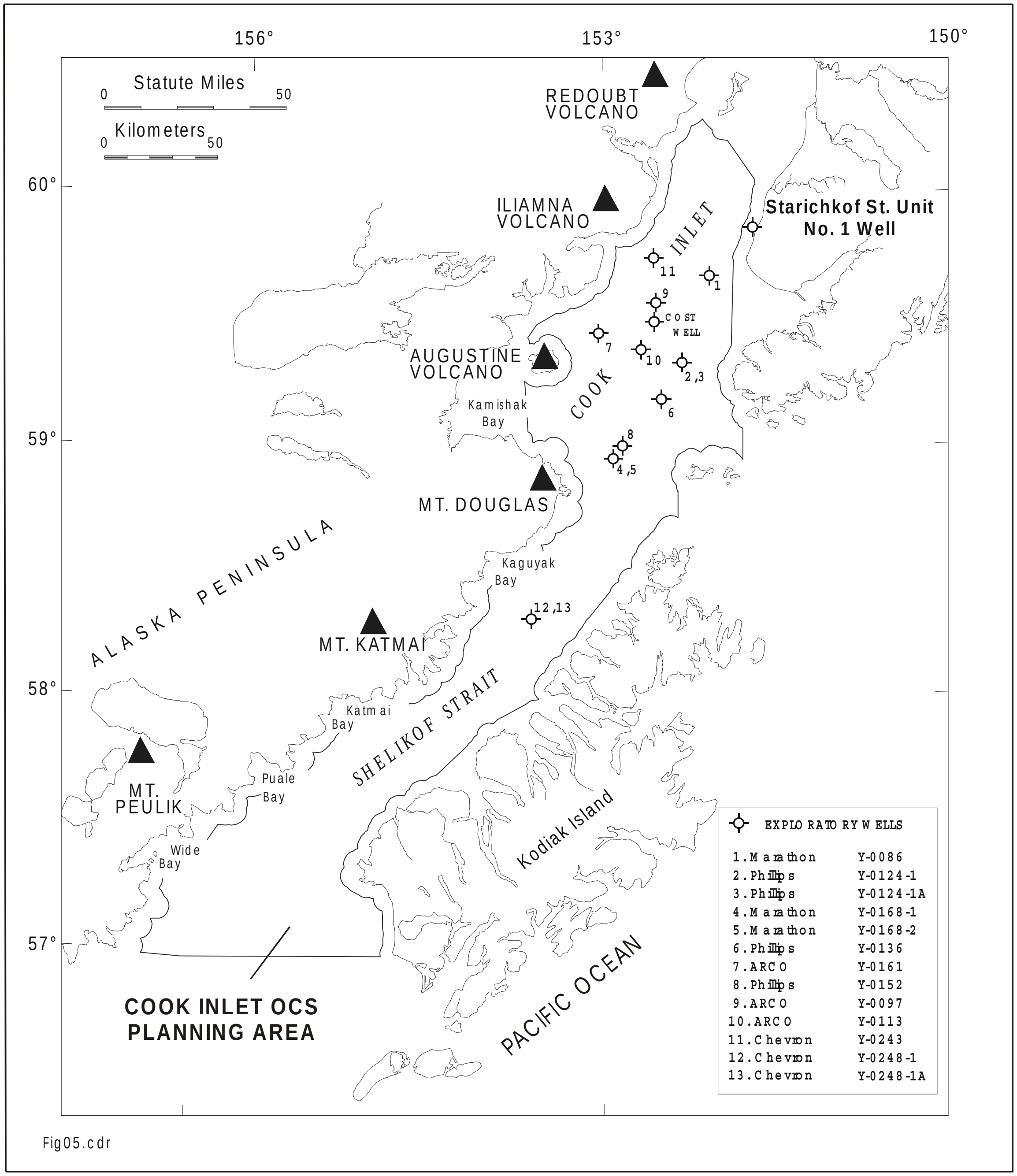


Figure 5: Exploratory and stratigraphic test ("COST") wells of the Cook Inlet Federal OCS Planning Area. The Starichkof St. Unit 1 well in State of Alaska waters near Ninilchik tested gas, suggesting gas potential for some nearby areas of Federal OCS waters.

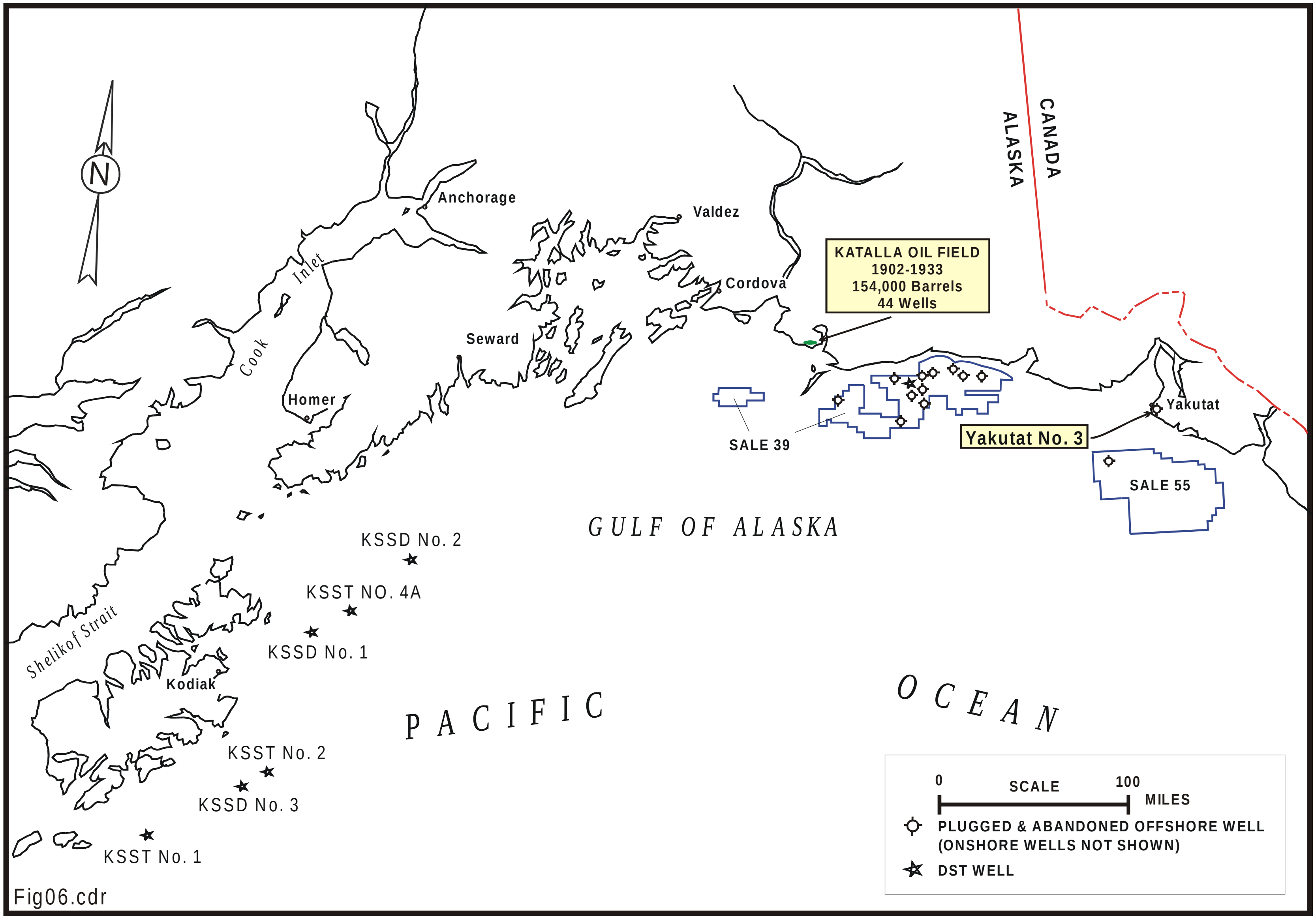


Figure 6: Exploratory wells and stratigraphic test (DST) wells of Kodiak and Gulf of Alaska shelves (Federal offshore only), areas of Federal offshore lease sales in Gulf of Alaska, and locations of Katalla oil field and Yakutat No. 3 well.

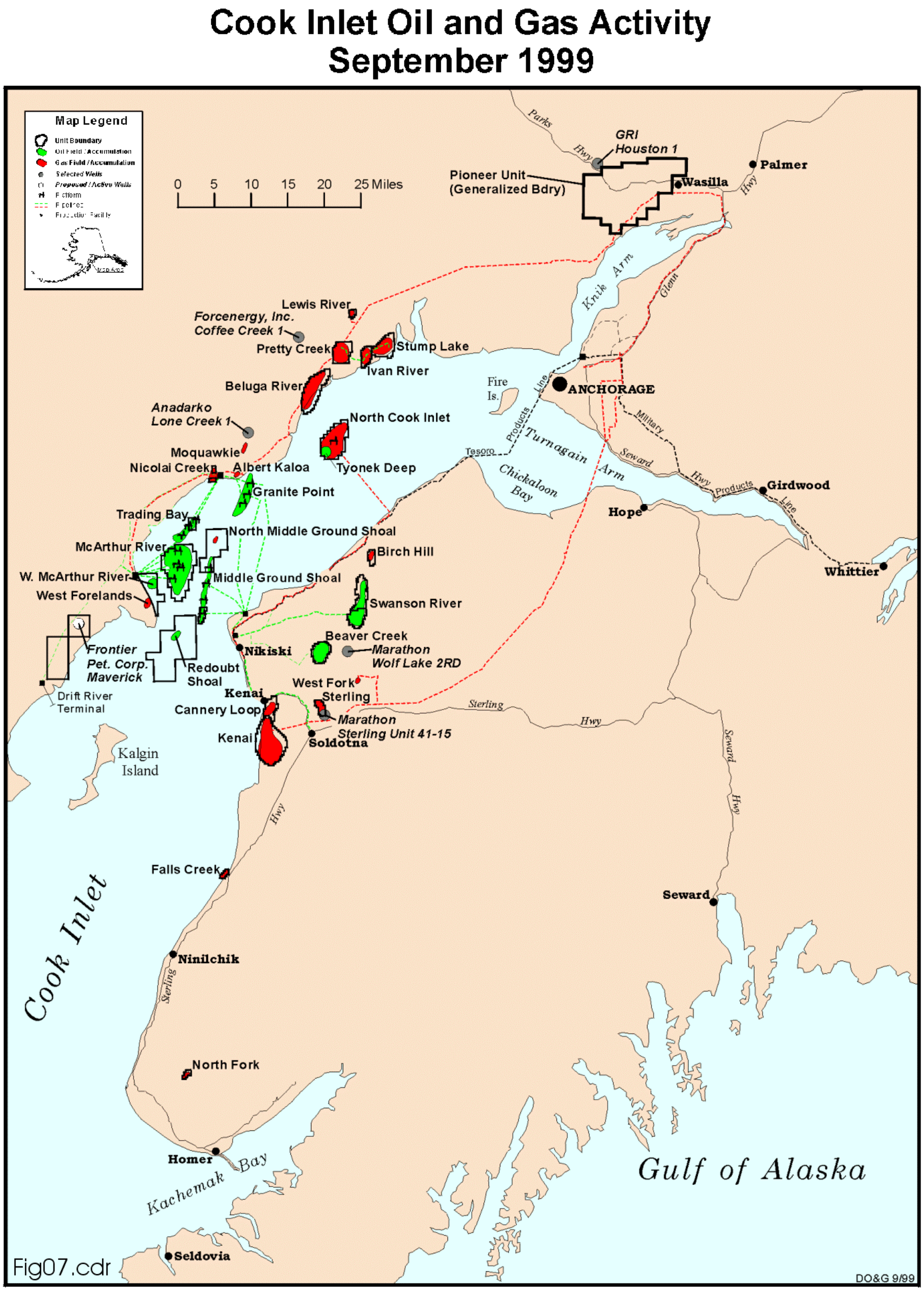


Figure 7: Oil and gas fields, production infrastructure, and current activity in Cook Inlet (State of Alaska) as of September 1999. Map adapted from State of Alaska, Dept. of Natural Resources, Division of Oil and Gas, web site posting at *http://www.dnr.state.ak.us/oil.*

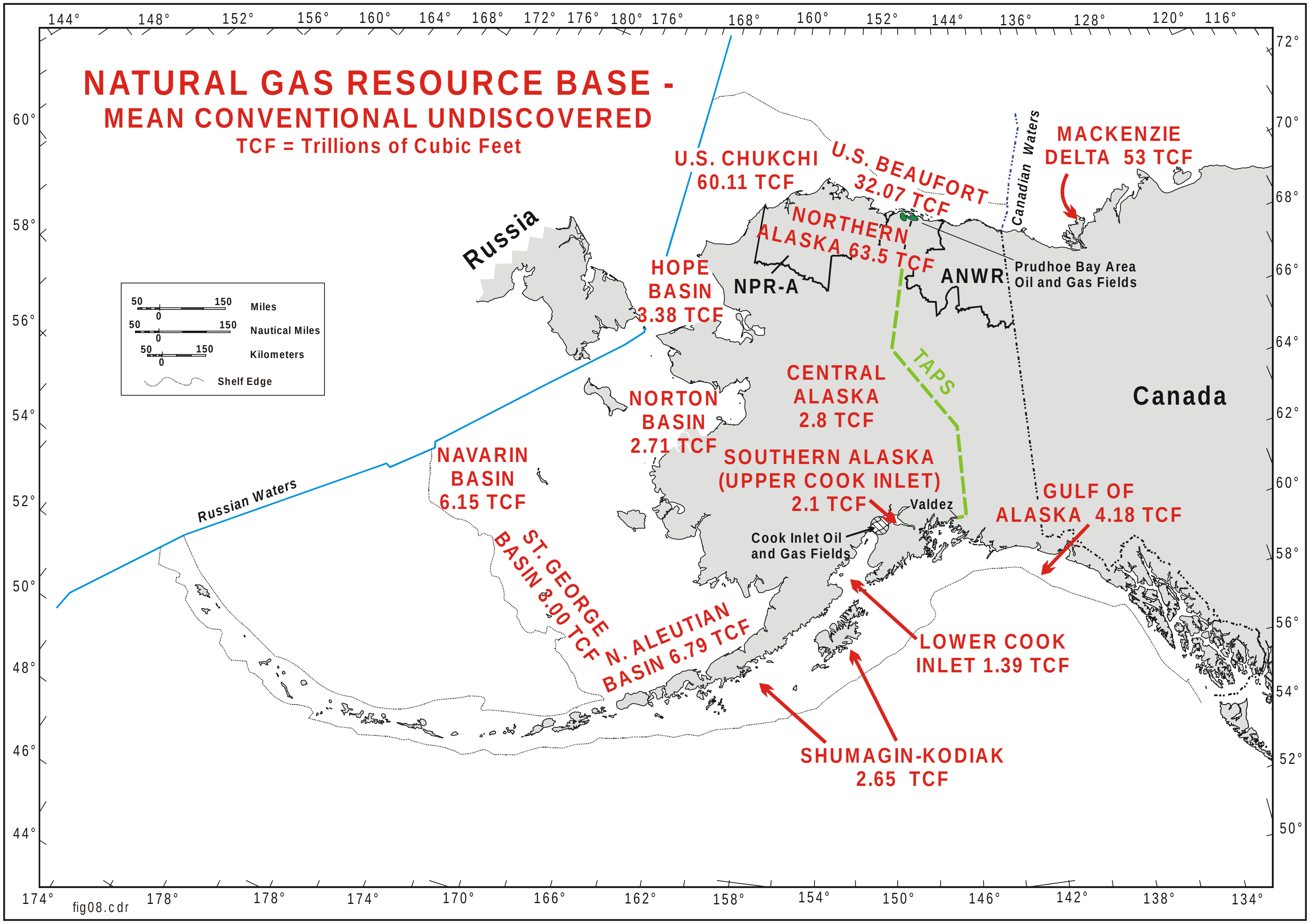


Figure 8: Conventional natural gas resource base (mean, risked, undiscovered, conventionally recoverable gas; excludes coal bed gas and gas hydrates) for Alaska provinces as of 2000 (USGS, 1995; Sherwood and others, 1996; Craig, 2000). Total Alaska (onshore and offshore) undiscovered conventional gas resource base = 190.99 tcf (tbl. 7). Mackenzie delta gas resources from Dixon and others (1994, tbl. 1).

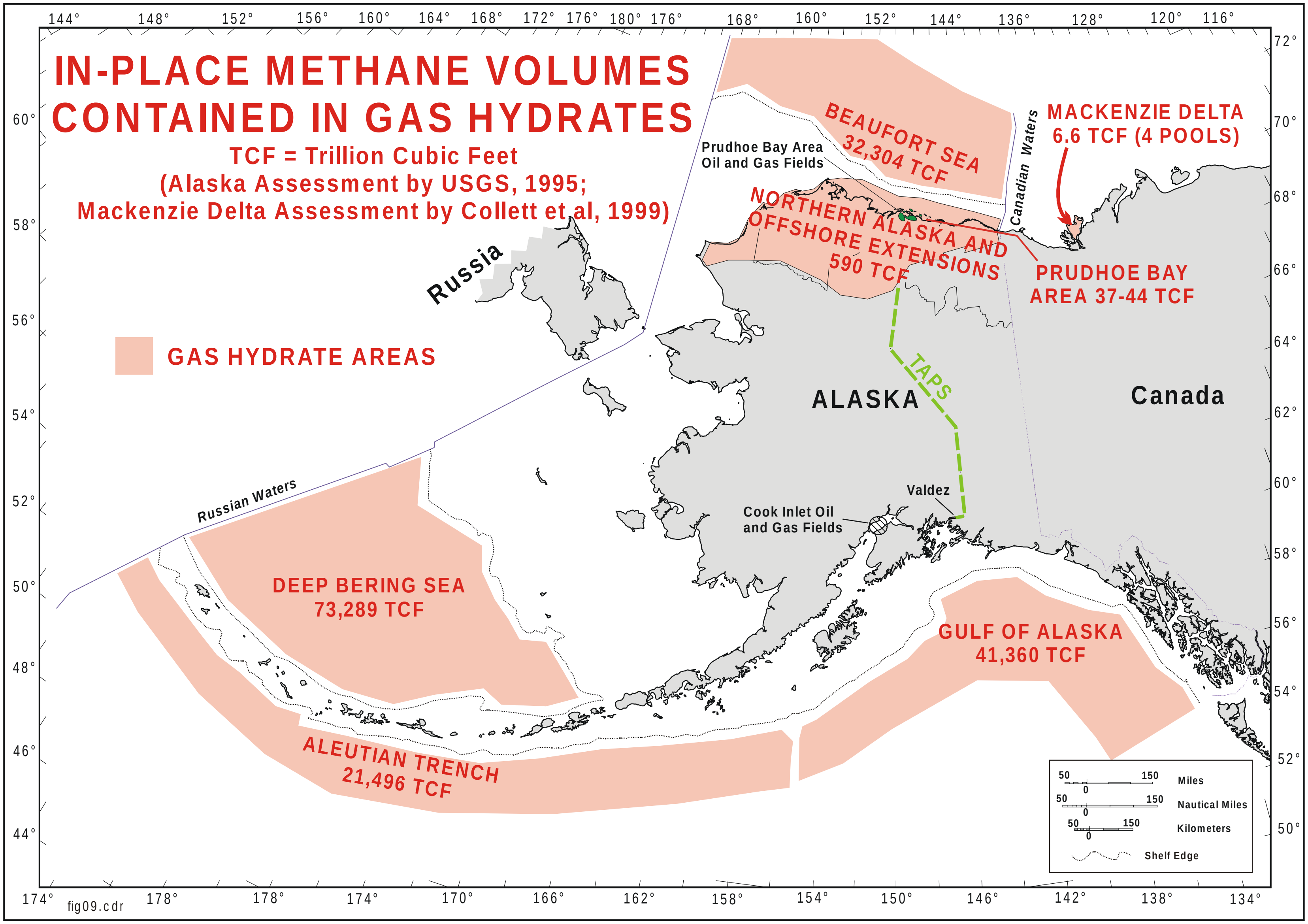


Figure 9: Gas hydrate methane resources (in place volumes) for Alaska and Alaska offshore. Resource estimates from USGS (1995, *Hydrates*, pl. 21), Collett and Kuuskraa (1998, tbl. 1), and Collett (1998, p. 4). Total for Alaska = 169,039 tcf. Mackenzie delta gas hydrate resources for 4 accumulations on Richards Island (Mallik, Ivik, North Ivik, and Taglu), as reported by Collett and others (1999, tbl. 4).

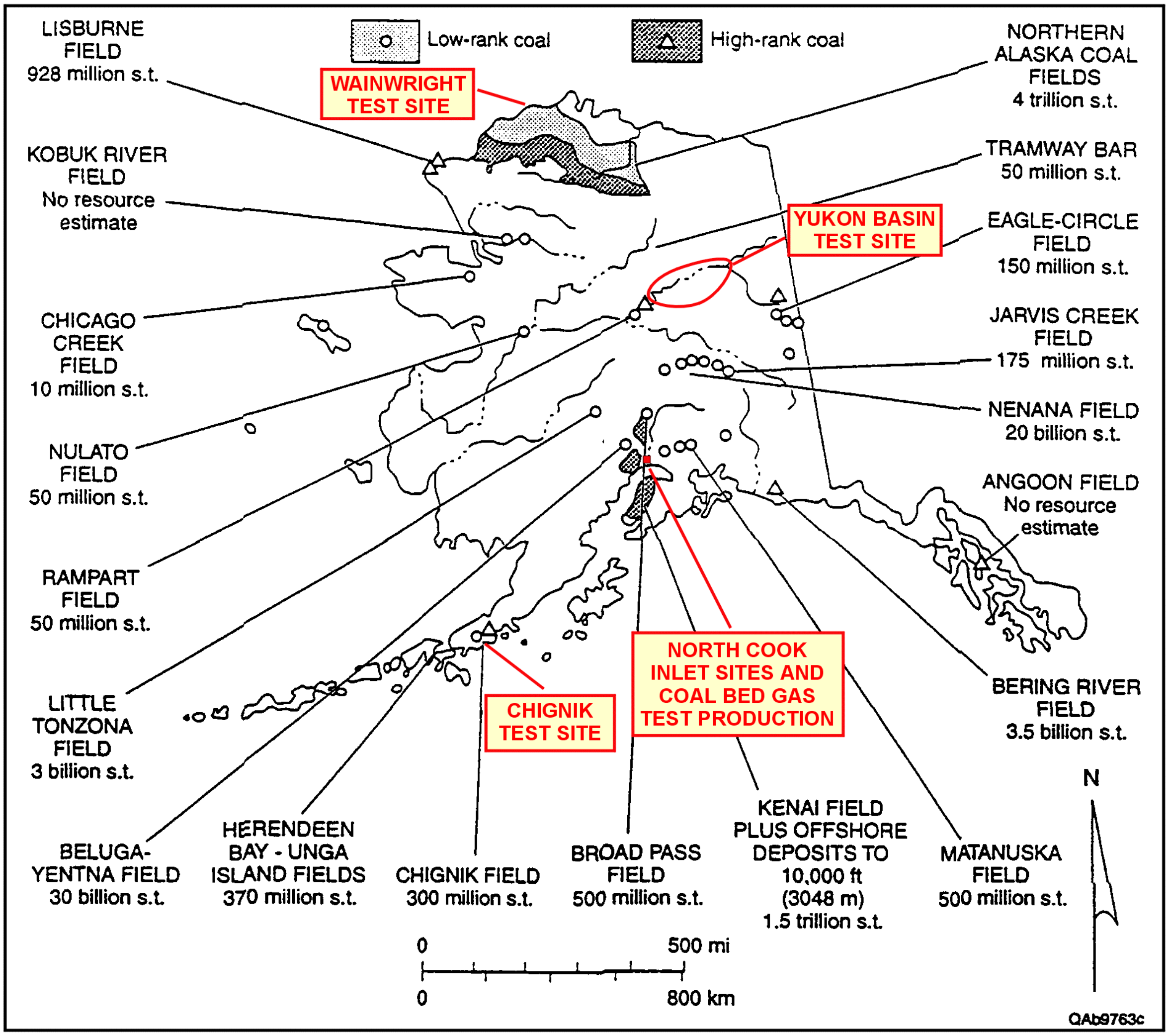


Figure 10: Major coal fields and field resources (s.t. = short tons; 1 s.t. = 0.9078 metric tons). Total tonnage for Alaska is 5.56 trillion tons. Smith (1995) estimated that total coal bed methane resources of Alaska might reach 1,000 tcf. The Potential Gas Committee (PGC, 1999, tbl. 53) estimated the coal bed methane potential for all of Alaska to range from 15.0 to 76.0 tcf, with an average or expected resource of 57.0 tcf. The map of coal fields shows where coal bed methane resources are likely to occur, with larger gas resources probably, but not necessarily, associated with larger coal fields. The largest coal field is that of northern Alaska, with 4 trillion short tons of coal or 72% of the State endowment. Map adapted from Tyler and others (1998, fig. 6).

A coal test well in northern Cook Inlet basin in 1994 encountered coals which yielded 63 to 245 cubic feet of gas per ton (Smith, 1995). The State of Alaska plans to conduct exploratory drilling at the Wainwright, Chignik, and Yukon basin sites in order to appraise coal bed methane potential (Ogbe and others, 1999).

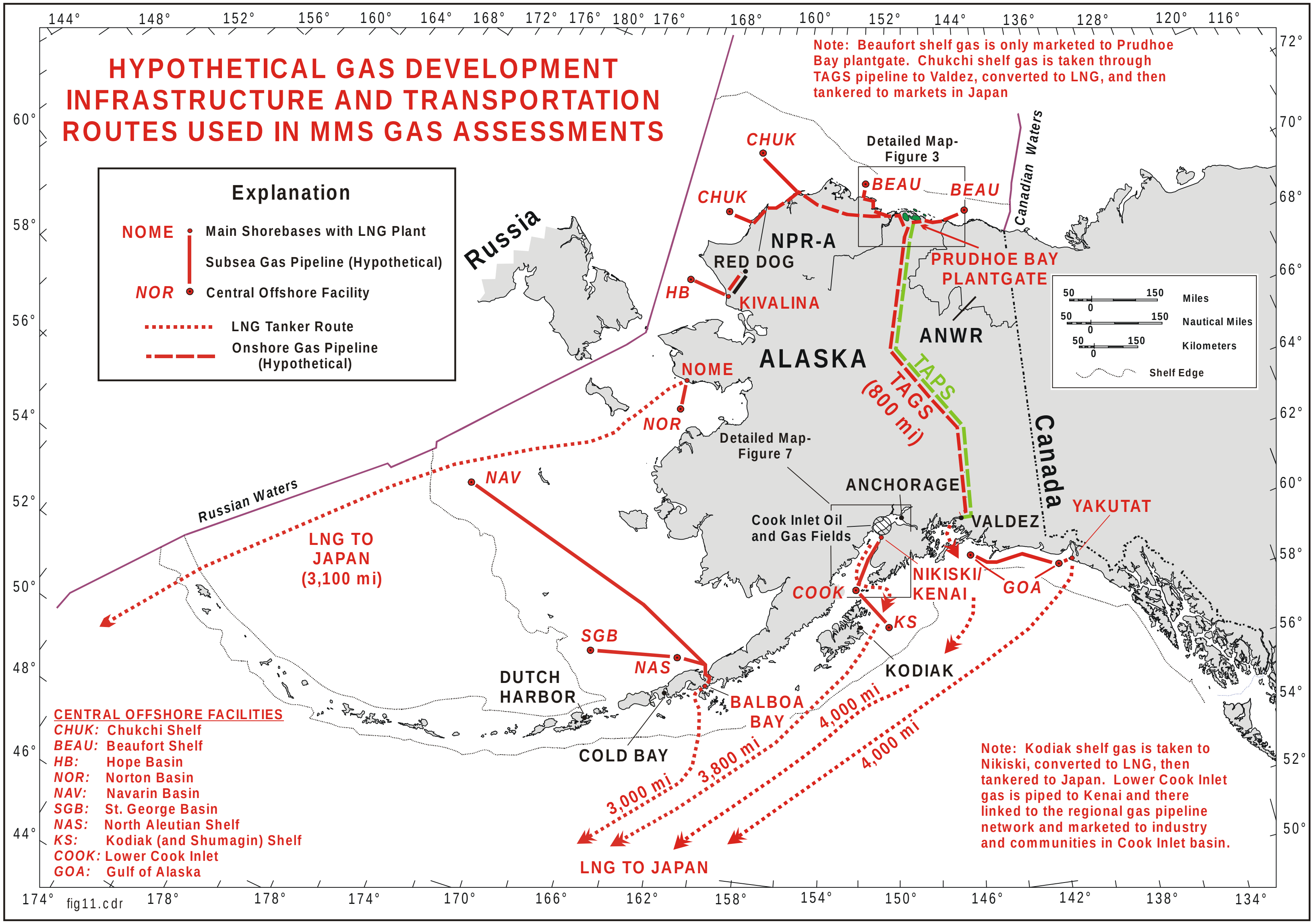


Figure 11: Hypothetical gas development infrastructures used for economic modeling of Alaska Federal offshore in 1995 and 2000 MMS assessments of the Alaska offshore. Central offshore facilities are located near areas of highest potential at hypothetical sites representative of average pipeline distances to shorebases, ports, and receiving facilities.

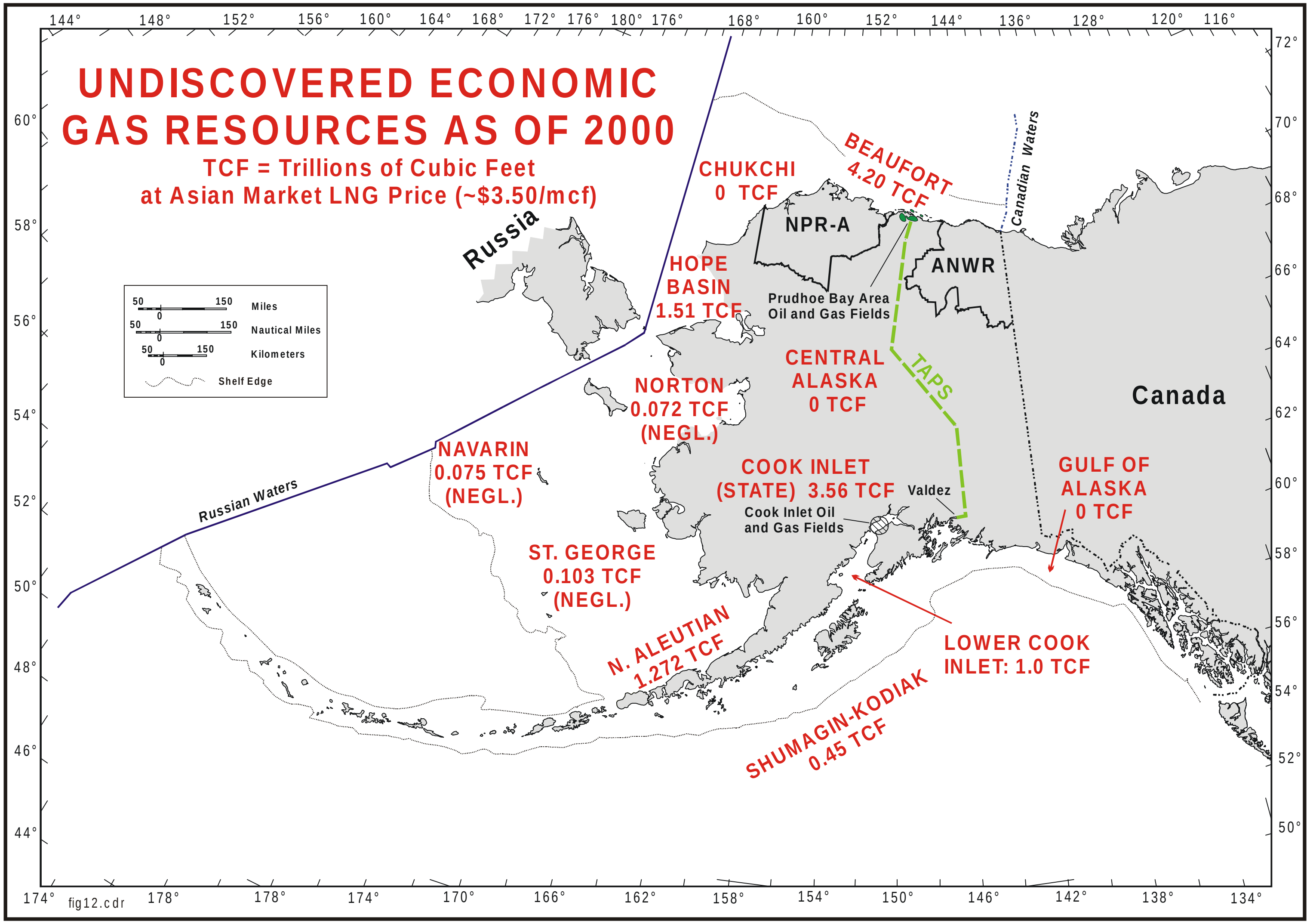


Figure 12: Undiscovered, economically-recoverable conventional natural gas resources of Alaska and Alaska Federal offshore, as of 2000, at gas prices comparable to LNG marketed to Japan ($3.34 to $3.52/mcf). Natural gas in Arctic Alaska (offshore and onshore) is presently stranded by the absence of a gas transportation infrastructure. Bering shelf economic gas resources occur mostly in North Aleutian basin. Onshore data from Attanasi (1998); offshore data from Craig (1998b, tbl. 27.12; 2000, tbl. 1B).

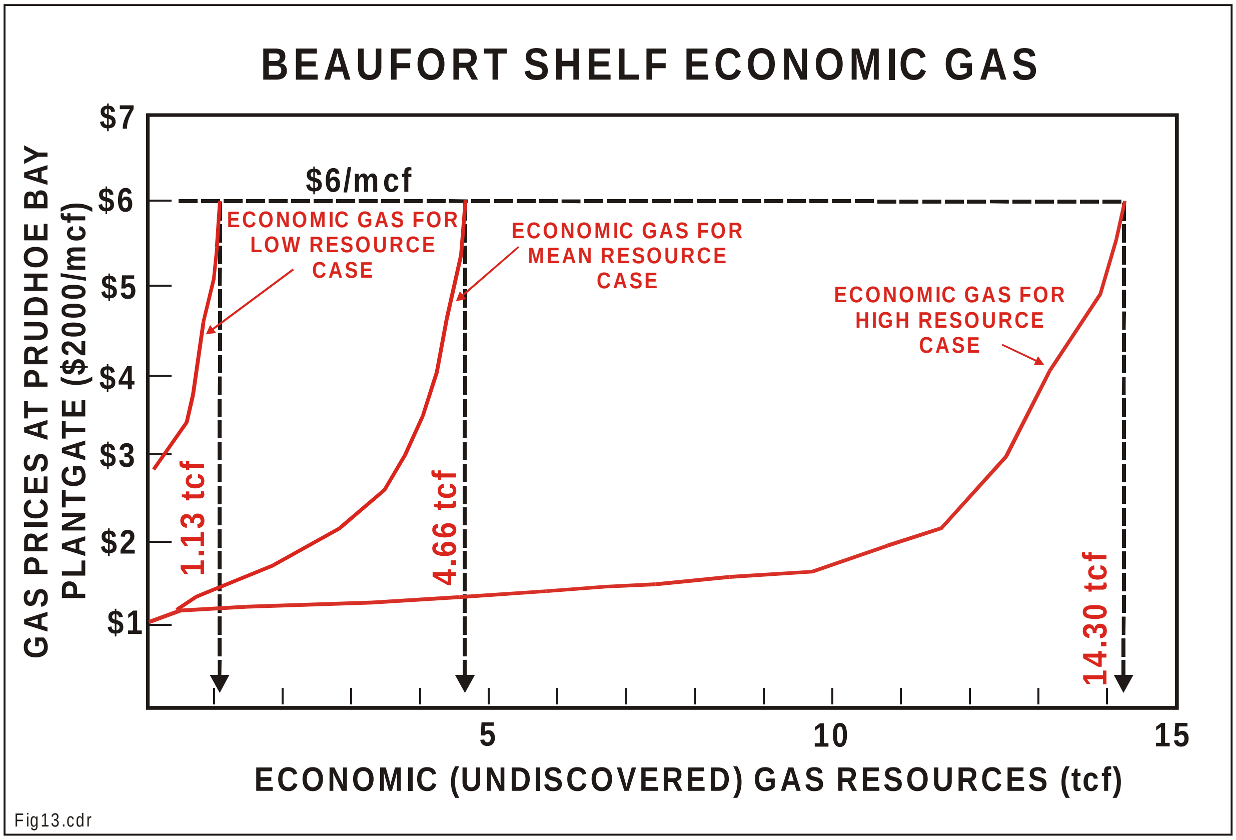


Figure 13: Price-supply curves for undiscovered economically-recoverable gas in Beaufort shelf, delivered to Prudhoe Bay plantgate. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 1.13, 4.66, and 14.30 tcf of gas could be economically recoverable in the low (F95, or 95% probability of occurrence), mean, and high (F05, or 5% probability of occurrence) resource cases, respectively. The total endowments of conventionally recoverable gas resources are 12.86 tcf for the low resource case, 32.07 tcf for the mean case, and 63.27 tcf for the high case. It is assumed that the gas is co-produced with oil and piped to Prudhoe Bay where it is sold. It is also assumed that gas development is supported by the oil development infrastructure and that gas production costs are largely offset by revenue from co-produced oil. Diagram modified after Craig (2000, fig. 2B).

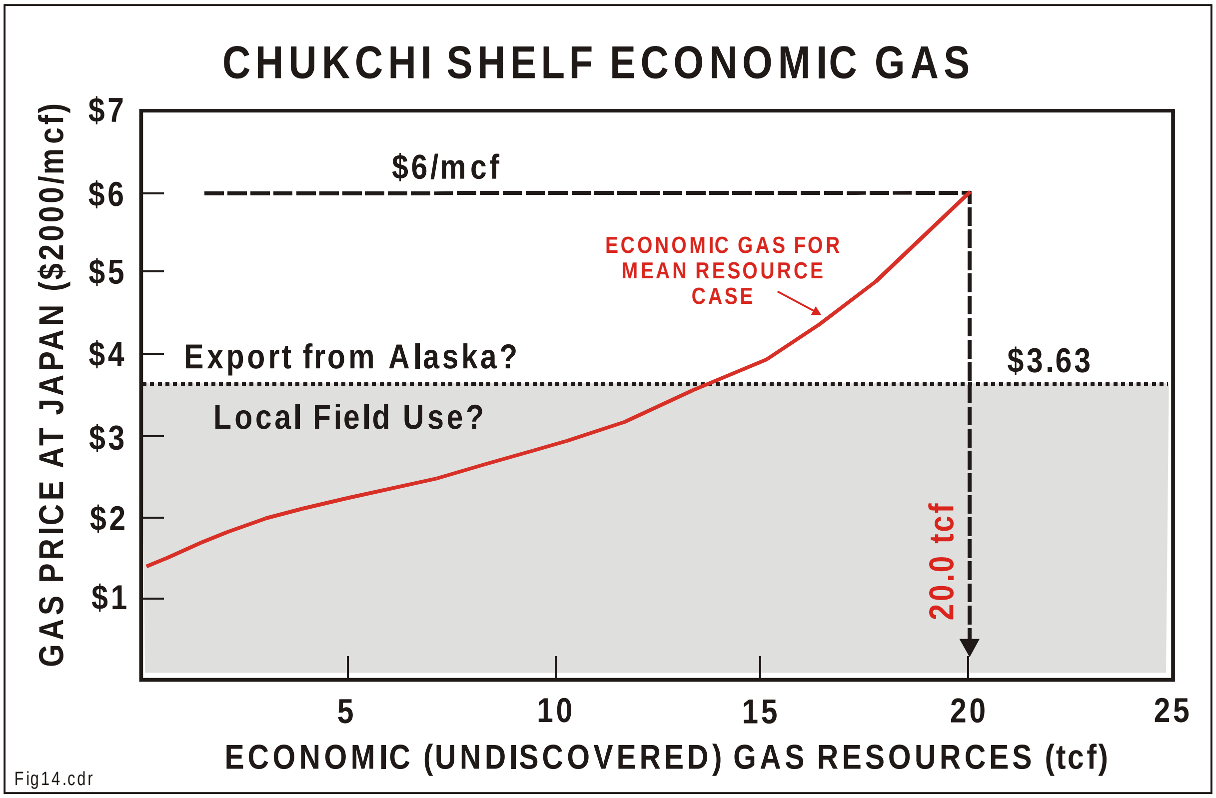


Figure 14: Price-supply curves for undiscovered economically recoverable gas in Chukchi shelf and marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 20.0 tcf of gas could be economically recoverable from Chukchi shelf in the mean resource case, out of a 60.11 tcf total endowment of conventionally recoverable gas. No high (F05, or 5% probability of occurrence) resource case is available. Key assumptions include: 1) gas is coproduced with oil in associated pools and is also produced from non-associated gas pools; 2) a new TAGS gas pipeline is operational and carries the gas to Valdez; 3) LNG is tankered from Valdez to Japan; 4) the delivery to Japan via the new pipeline/LNG system is $3.63/mcf; and 5) no regasification charges are added at the point of LNG delivery. Because gas development is largely supported by the oil development infrastructure and gas production costs are offset by revenue from co-produced oil, positive economic outcomes are calculated at prices below $3.63/mcf in some trials.

The diagram is based on internal sensitivity studies that postdate the 1995 assessment reported by Craig (1998b).

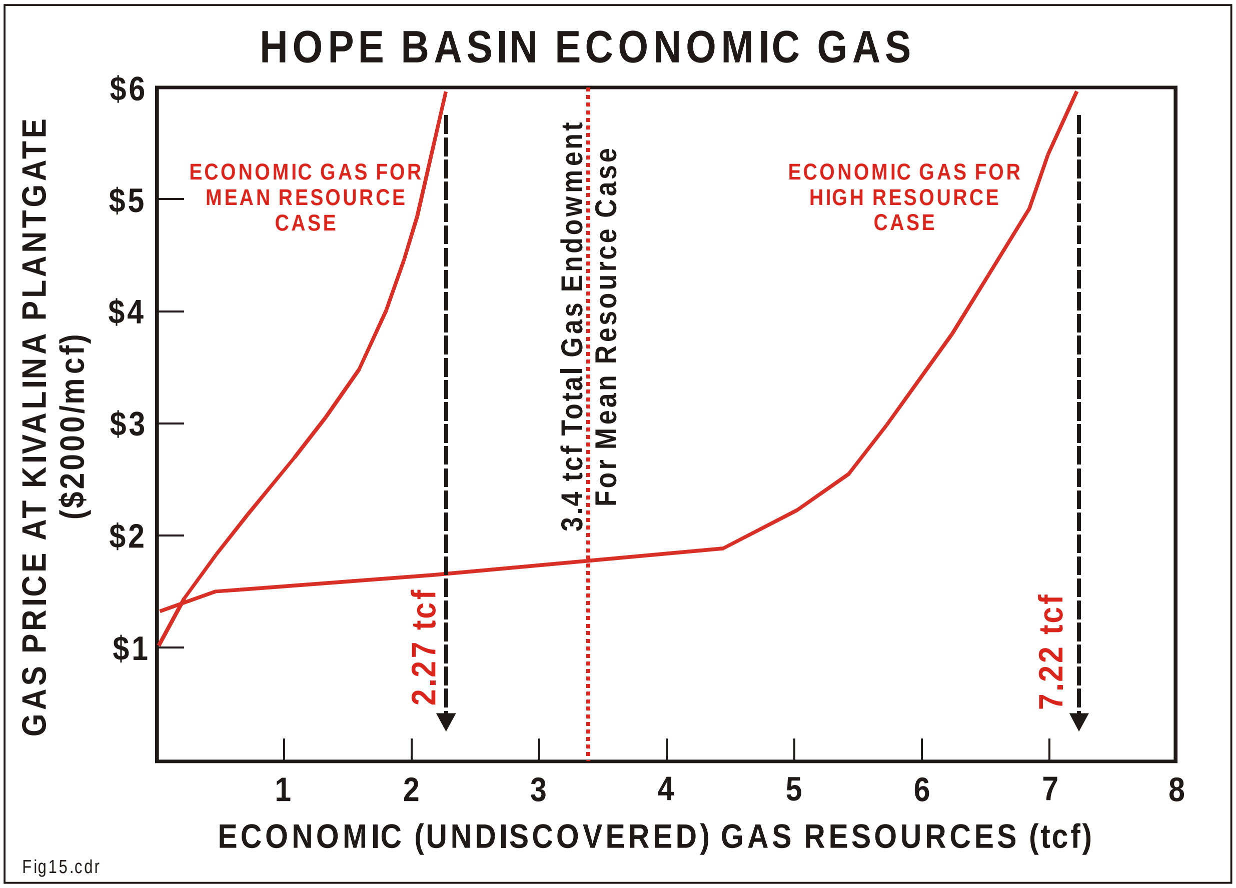


Figure 15: Price-supply curves for undiscovered economically recoverable gas in Hope basin if marketed to a hypothetical industrial complex at the port of Kivalina, Alaska, where Red Dog mine ore is presently stockpiled for shipping to smelters outside of Alaska. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 2.27 tcf of gas could be economically recoverable from Hope basin in the mean resource case, with up to 7.22 tcf possibly recoverable at the high (F05, or 5% probability of occurrence) resource case. The total endowments of conventionally recoverable gas resources are 3.38 tcf for the mean case and 11.06 tcf for the high case. Diagram modified after Craig (2000, fig. 4a).

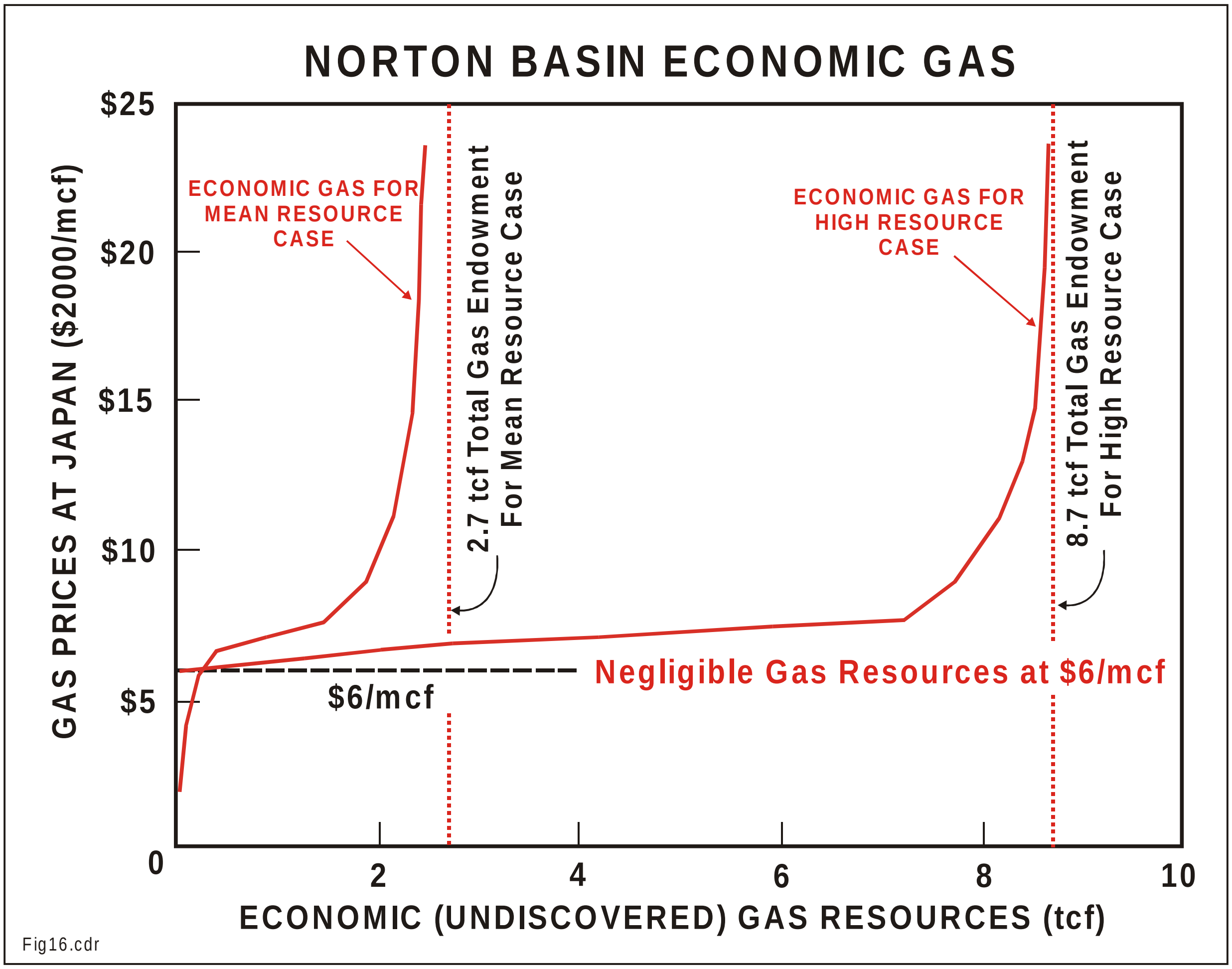


Figure 16: Price-supply curves for undiscovered economically-recoverable gas in Norton basin if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), only negligible quantities of gas could be economically recovered from Norton basin in either the mean resource case or the high (F05, or 5% probability of occurrence) resource cases. The total endowments of conventionally recoverable gas resources are 2.71 tcf for the mean case and 8.74 tcf for the high case. Diagram modified after Craig (1998b, fig. 27.7c) and recast here in $2000 because we assume little overall increase in oil and gas prices or petroleum industry costs in the 1995-2000 period.

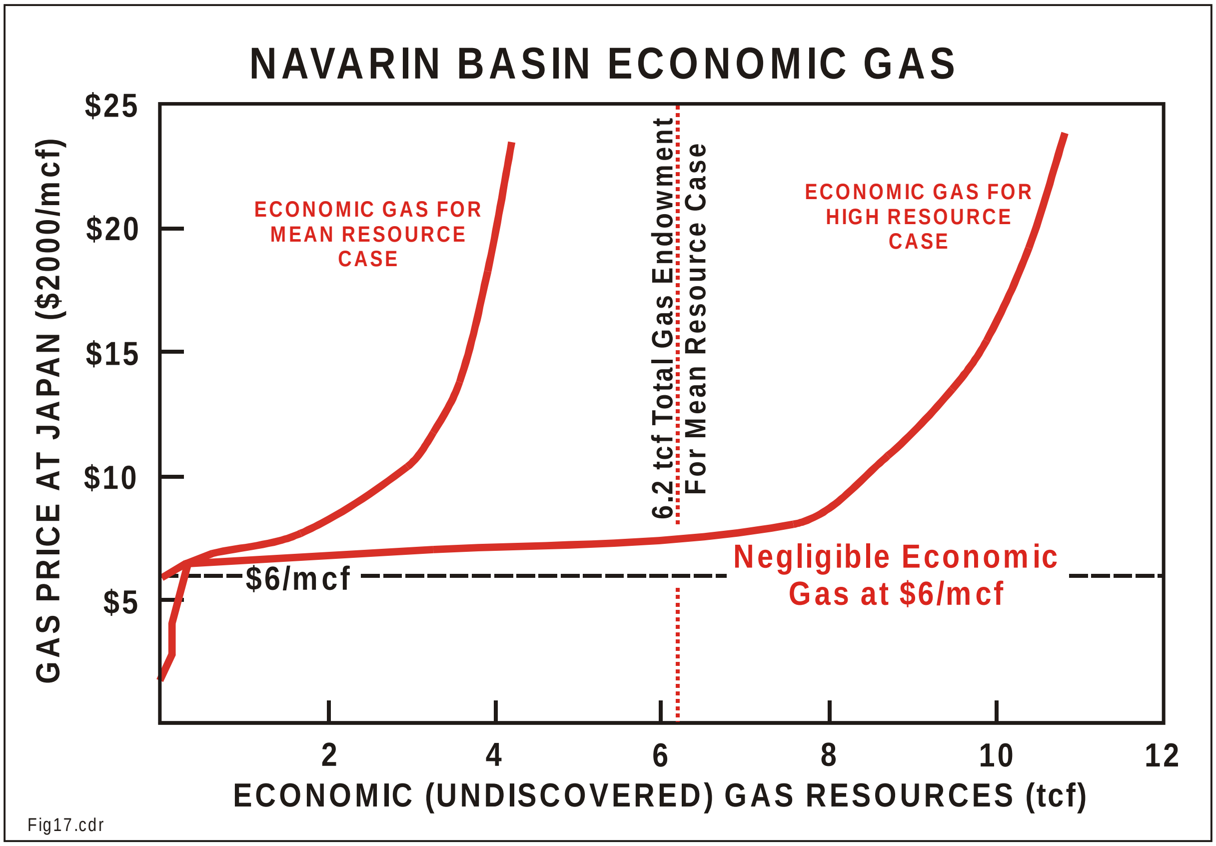


Figure 17: Price-supply curves for undiscovered economically recoverable gas in Navarin basin if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), no gas resources could be economically recoverable at either the mean or the high (F05, or 5% probability of occurrence) resource cases. The total endowments of conventionally recoverable gas are 6.15 tcf for the mean case and 18.18 tcf for the high case. Diagram modified after Craig (1998b, fig. 27.4c) and recast here in $2000 because we assume little overall increase in oil and gas prices or petroleum industry costs in the 1995-2000 period.

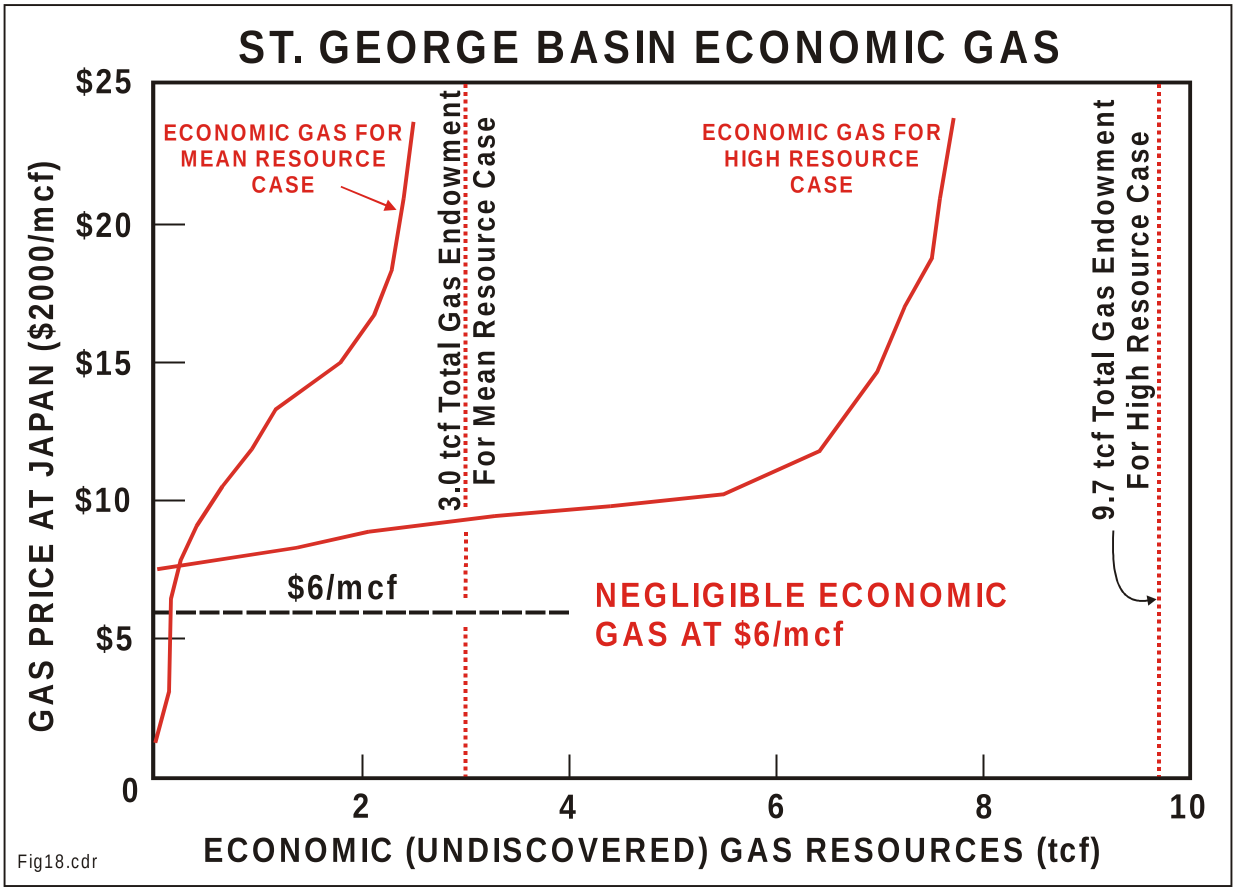


Figure 18: Price-supply curves for undiscovered economically recoverable gas in St. George basin if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), only negligible quantities of gas are economically recoverable from St. George basin in either the mean resource case or the high (F05, or 5% probability of occurrence) resource cases. The total endowments of conventionally recoverable gas resources are 3.00 tcf for the mean case and 9.72 tcf for the high case. Diagram modified after Craig (1998b, fig. 27.6c) and recast here in $2000 because of little overall inflation in oil and gas prices and petroleum industry costs in the 1995-2000 period.

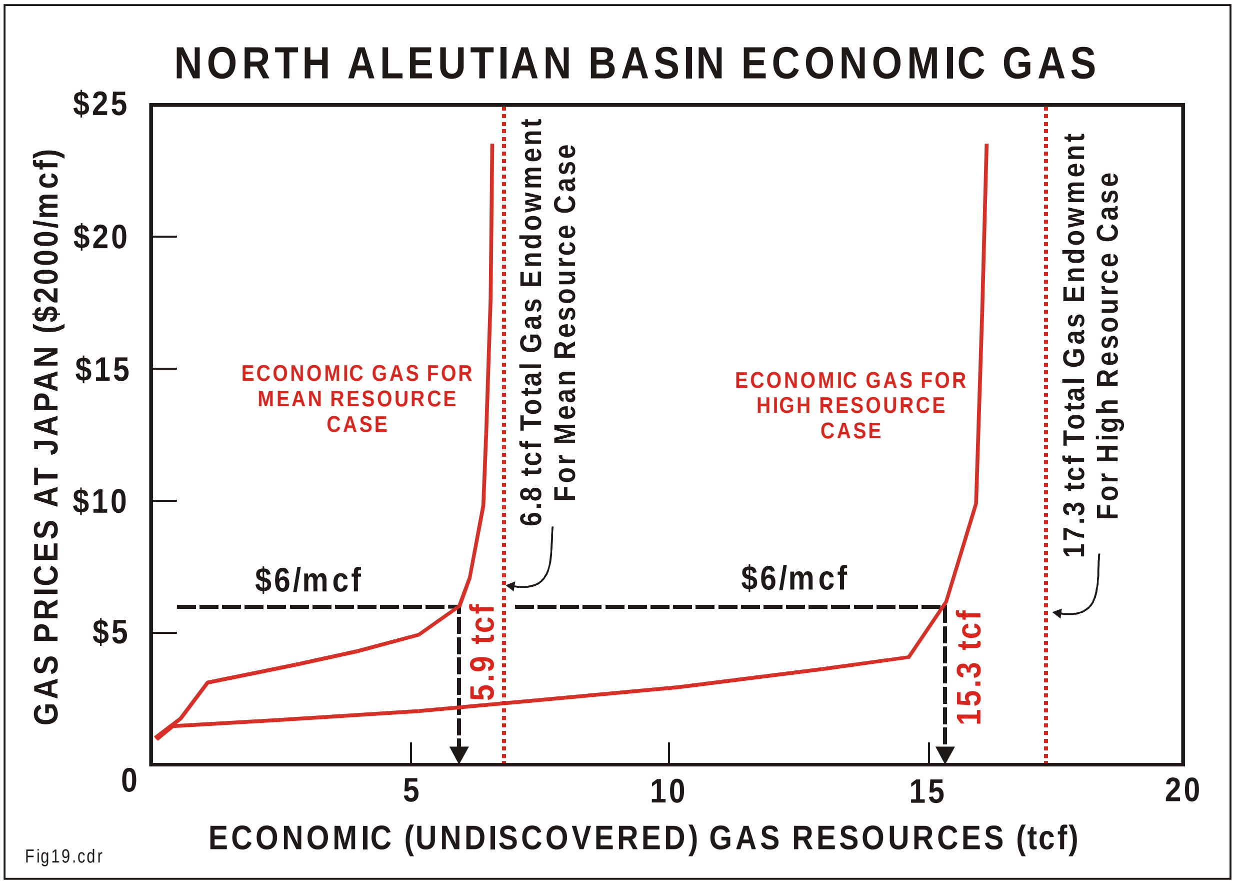


Figure 19: Price-supply curves for undiscovered economically recoverable gas in North Aleutian shelf if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 5.9 tcf of gas could be economically recoverable from North Aleutian shelf in the mean resource case, with up to 15.3 tcf possibly recoverable at the high (F05, or 5% probability of occurrence) resource case. The total endowments of conventionally recoverable gas resources are 6.79 tcf in the mean case and 17.33 tcf in the high case. Diagram modified after Craig (1998b, fig. 27.5c) and recast here in $2000 because we assume little overall increase in oil and gas prices or petroleum industry costs in the 1995-2000 period.

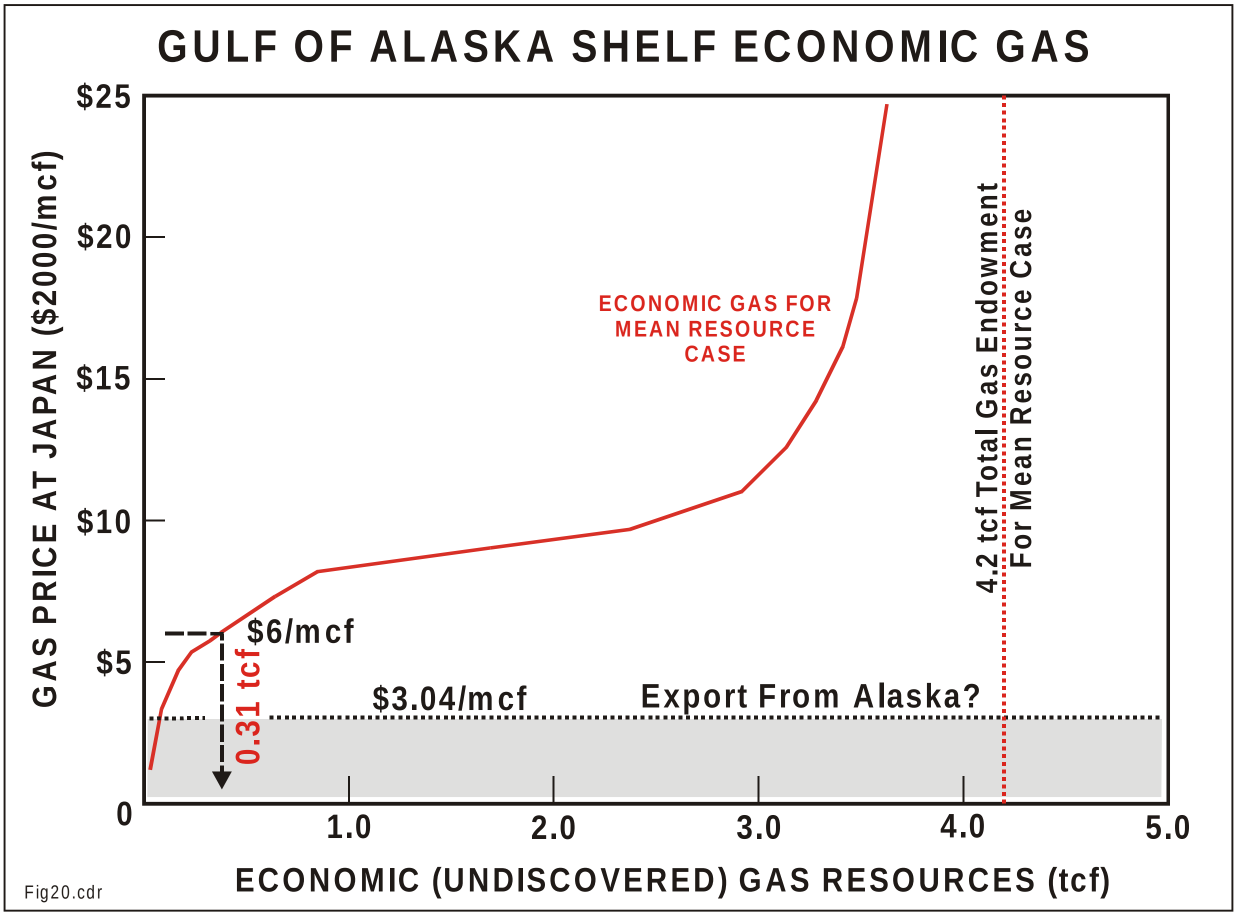


Figure 20: Price-supply curves for undiscovered economically recoverable gas in Gulf of Alaska shelf if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 0.31 tcf of gas could be economically recoverable from the Gulf of Alaska shelf in the mean resource case. The total endowment of conventionally recoverable gas resources is 4.18 tcf for the mean resource case. No economic results for the high (F05, or 5% probability of occurrence) resource case are available. Assumptions include: 1) gas is coproduced with oil and is piped to a hypothetical LNG plant at Yakutat; 2) LNG is transported via shallow-draft tankers to Japan; 3) minimum processing and delivery costs are $3.04/mcf; and 4) no regasification charges are added at the point of delivery in Japan. Because gas development is supported by the oil development infrastructure and gas production costs are largely offset by revenues from co-produced oil, positive economic trials are possible at prices below $3.04/mcf.

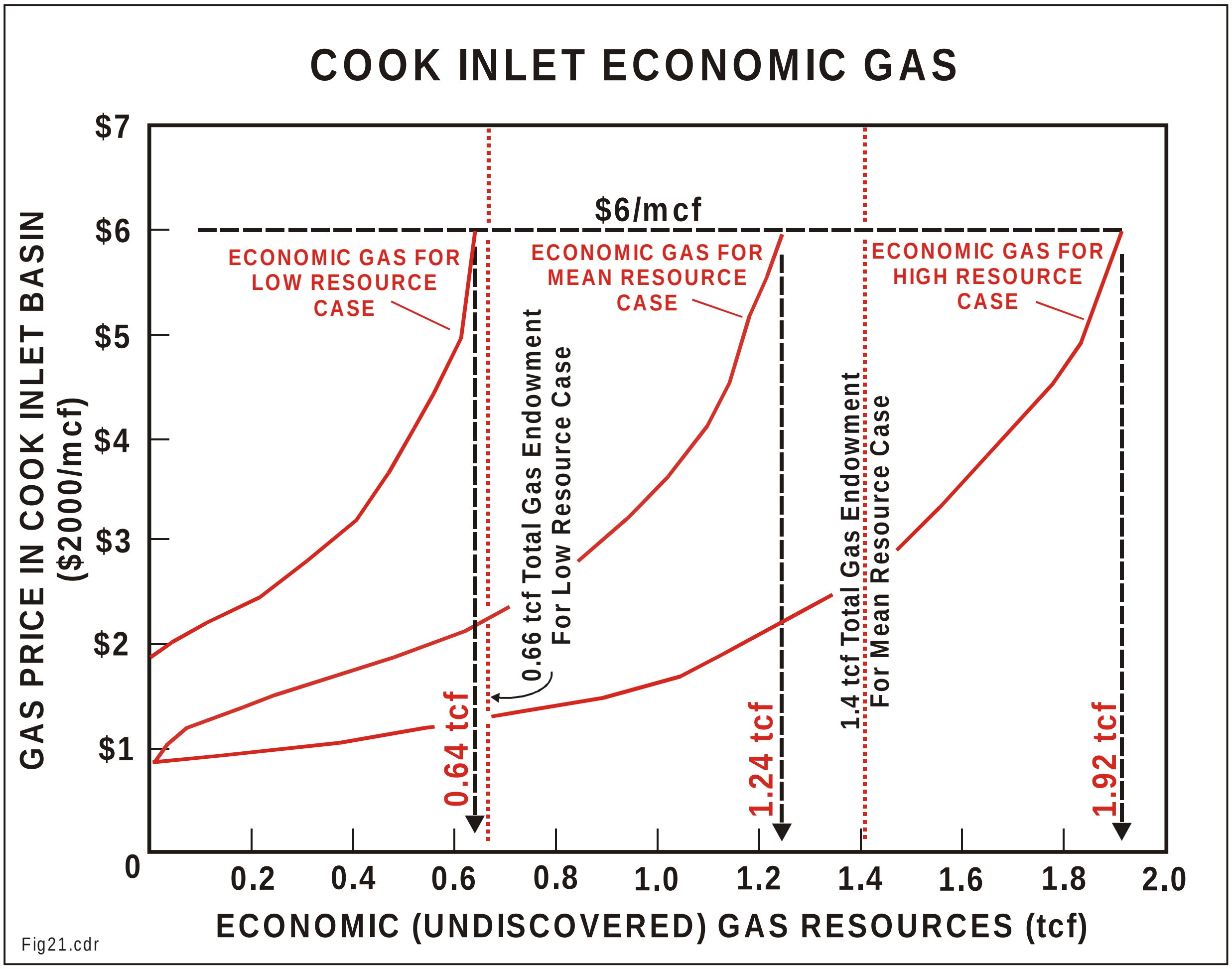


Figure 21: Price-supply curves for undiscovered economically recoverable gas in Cook Inlet (Federal waters) if delivered to local markets within Cook Inlet basin. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 0.64, 1.24, and 1.92 tcf of gas could be economically recoverable from Cook Inlet in the low (F95, or 95% probability of occurrence), mean, and high (F05, or 5% probability of occurrence) resource cases, respectively. Total endowments of conventionally recoverable gas resources are 0.66 tcf in the low case, 1.39 tcf in the mean case, and 2.49 tcf in the high case. Gas is assumed to be largely co-produced with oil. It is also assumed that gas development is supported by the oil development infrastructure and that gas production costs are largely offset by revenues from co-produced oil. Diagram modified after Craig (2000, fig. 5b).

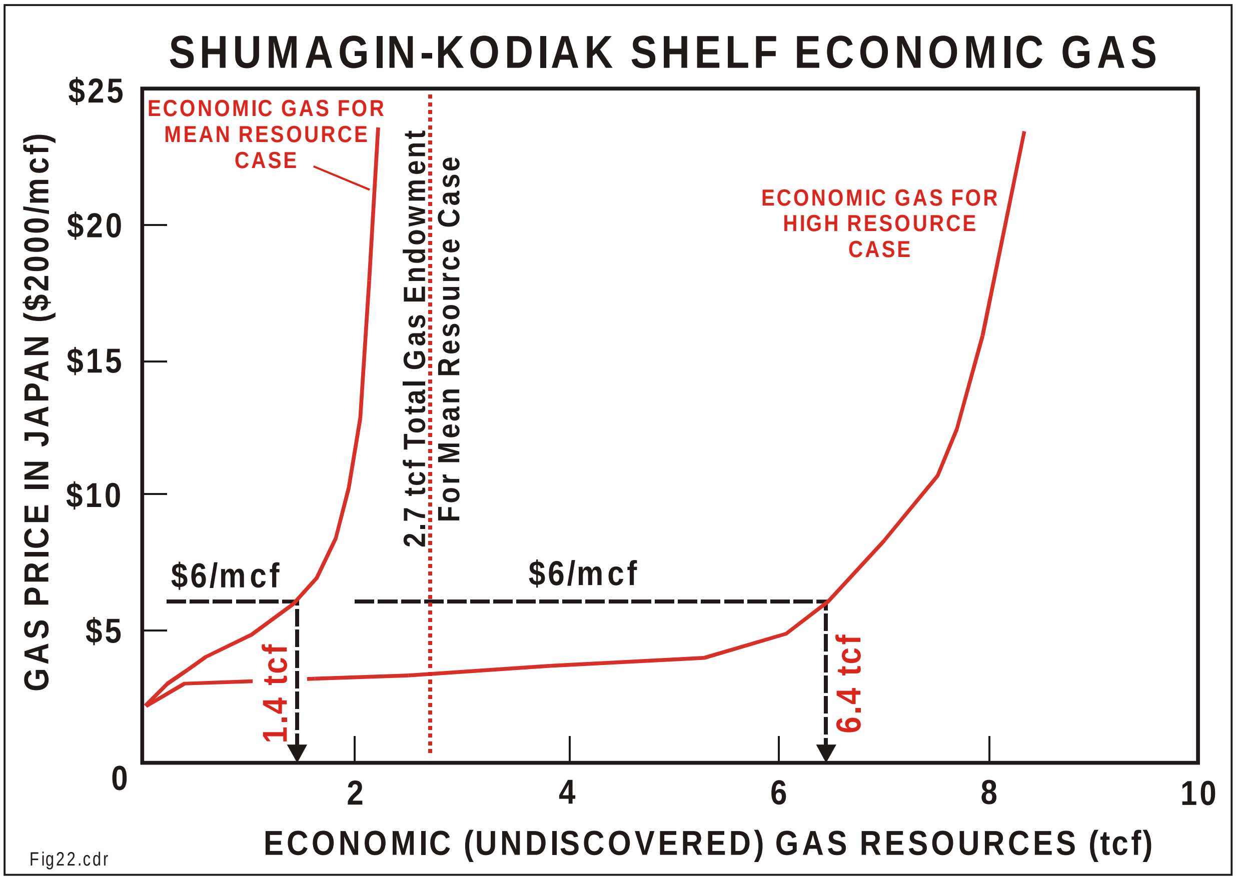


Figure 22: Price-supply curves for undiscovered economically recoverable gas in Shumagin-Kodiak shelf if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 1.4 tcf of gas could be economically recoverable from Shumagin-Kodiak shelf in the mean resource case, with up to 6.4 tcf possibly recoverable at the high (F05, or 5% probability of occurrence) resource case. Total endowments of conventionally recoverable gas resources are 2.65 tcf for the mean case and 11.35 tcf for the high case. Diagram modified after Craig (1998b, fig. 27.10c) and recast here in $2000 because we assume little overall increase in oil and gas prices or petroleum industry costs in the 1995-2000 period.

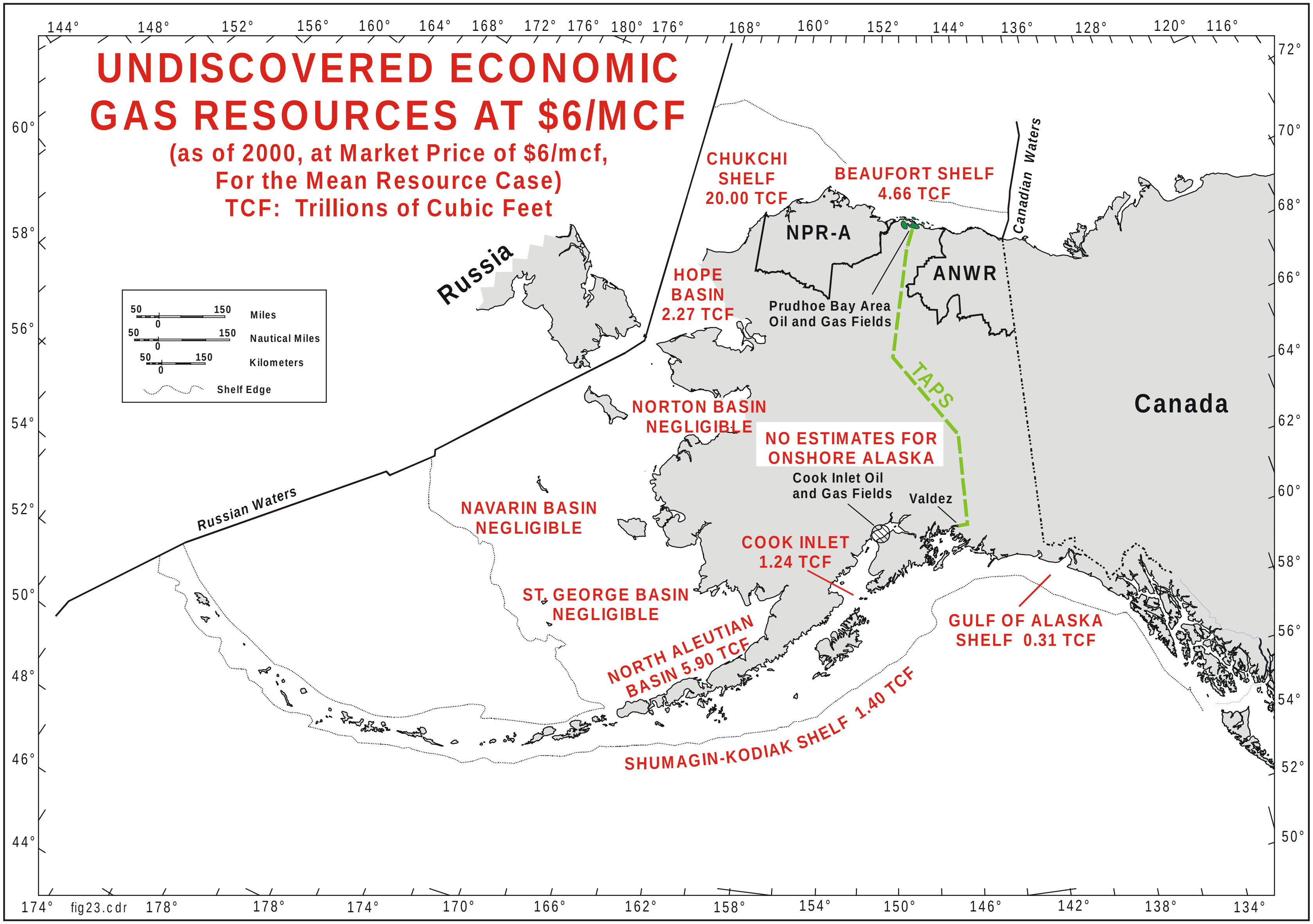


Figure 23: Economic, undiscovered gas resources for Alaska offshore at a price (delivered to various markets) of $6/mcf in $2000 (equivalent to $11.05/mcf in $2020) and at the mean resource case. Offshore economic gas resources at $6/mcf total 35.78 tcf.

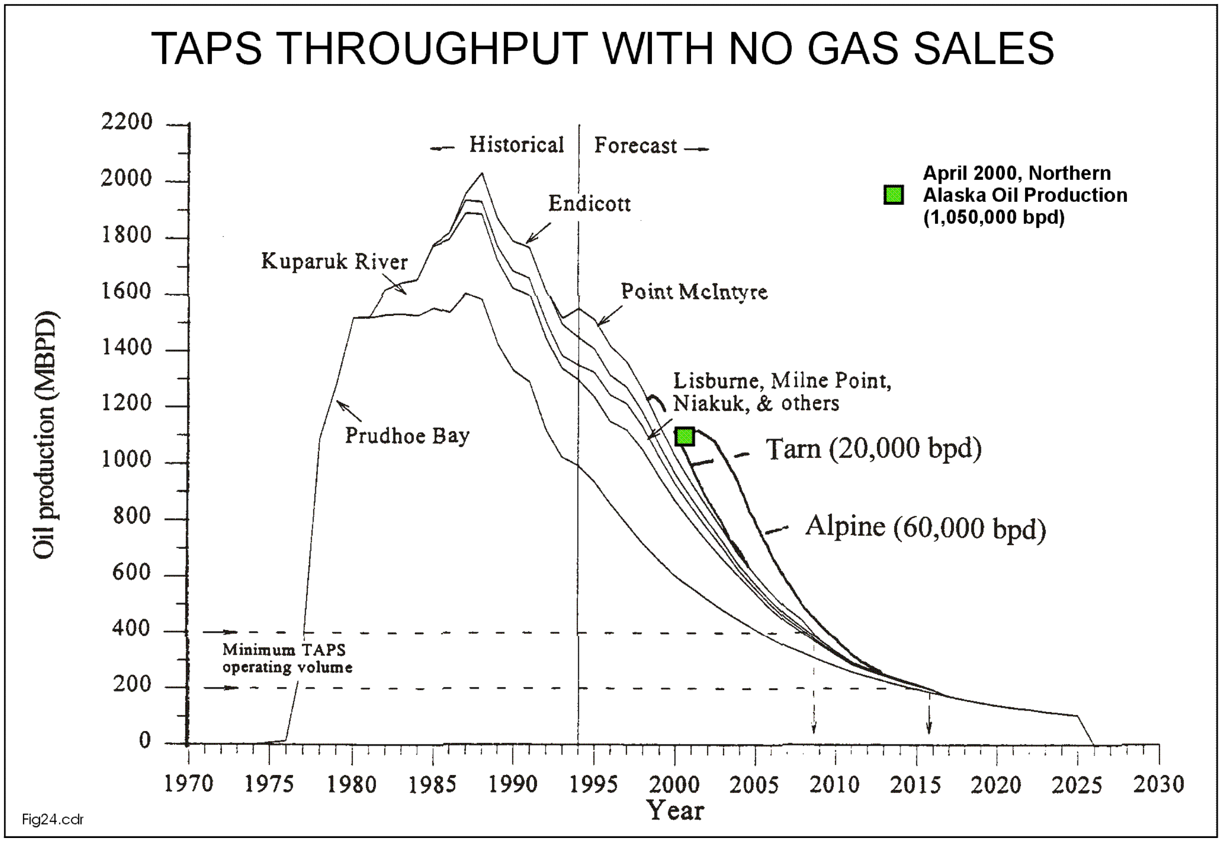


Figure 24: Production decline projections for northern Alaska producing fields in Prudhoe Bay area. Contributions from new fields at Tarn and Alpine have been added as sketches based on estimates for maximum production rates. These new fields, although significant, will not materially prolong the economic life of TAPS, projected to end when throughput falls to some level between 400,000 bpd (year 2009) and 200,000 bpd (year 2016). Diagram modified after Thomas and others (1996, fig. 2).

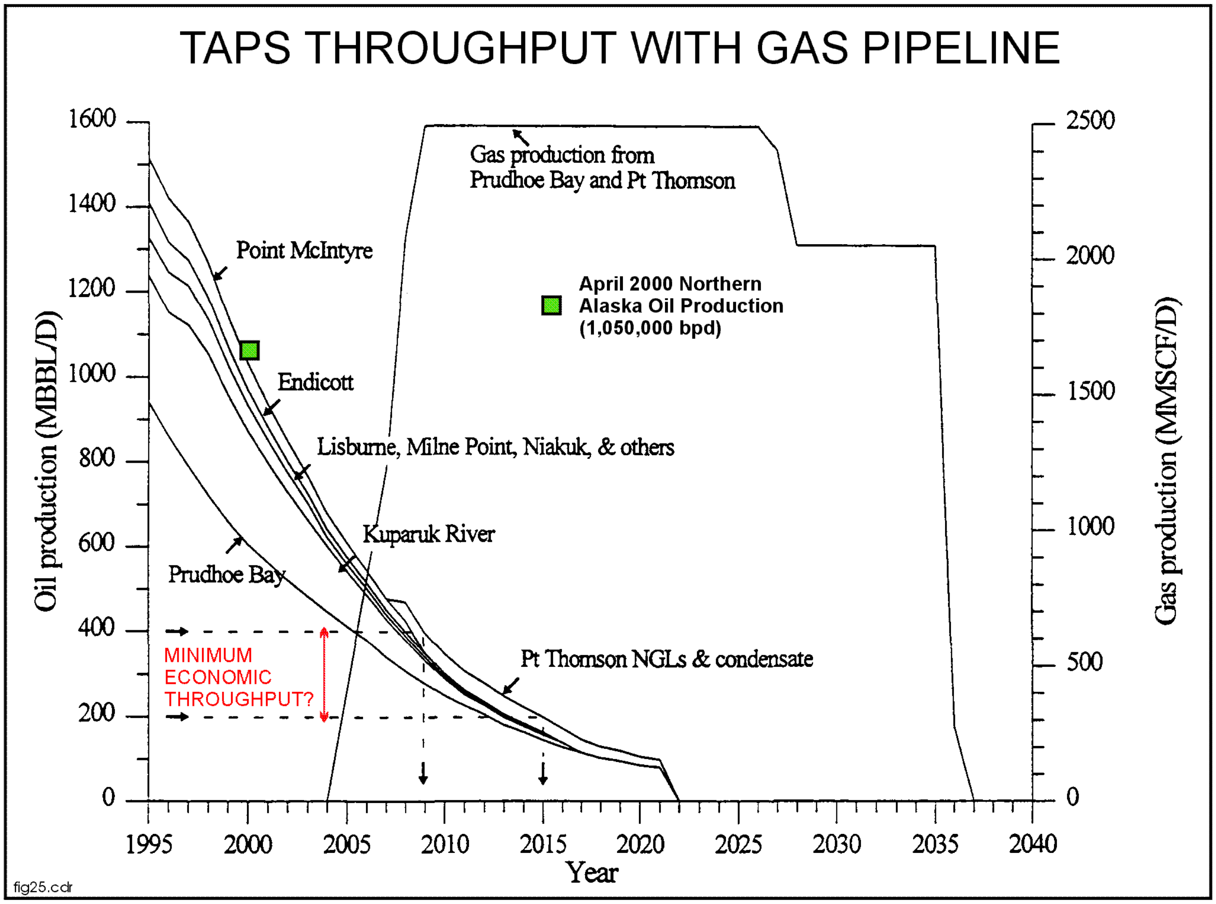


Figure 25: Model for TAPS (oil pipeline) throughput if gas is conveyed through a separate gas pipeline for export from southern Alaska. The economic life of TAPS is shortened about 1 year (to year 2015) at the 200,000 bpd threshold (compare to fig. 24). Diagram adapted from Thomas and others (1996, fig. 2.8).

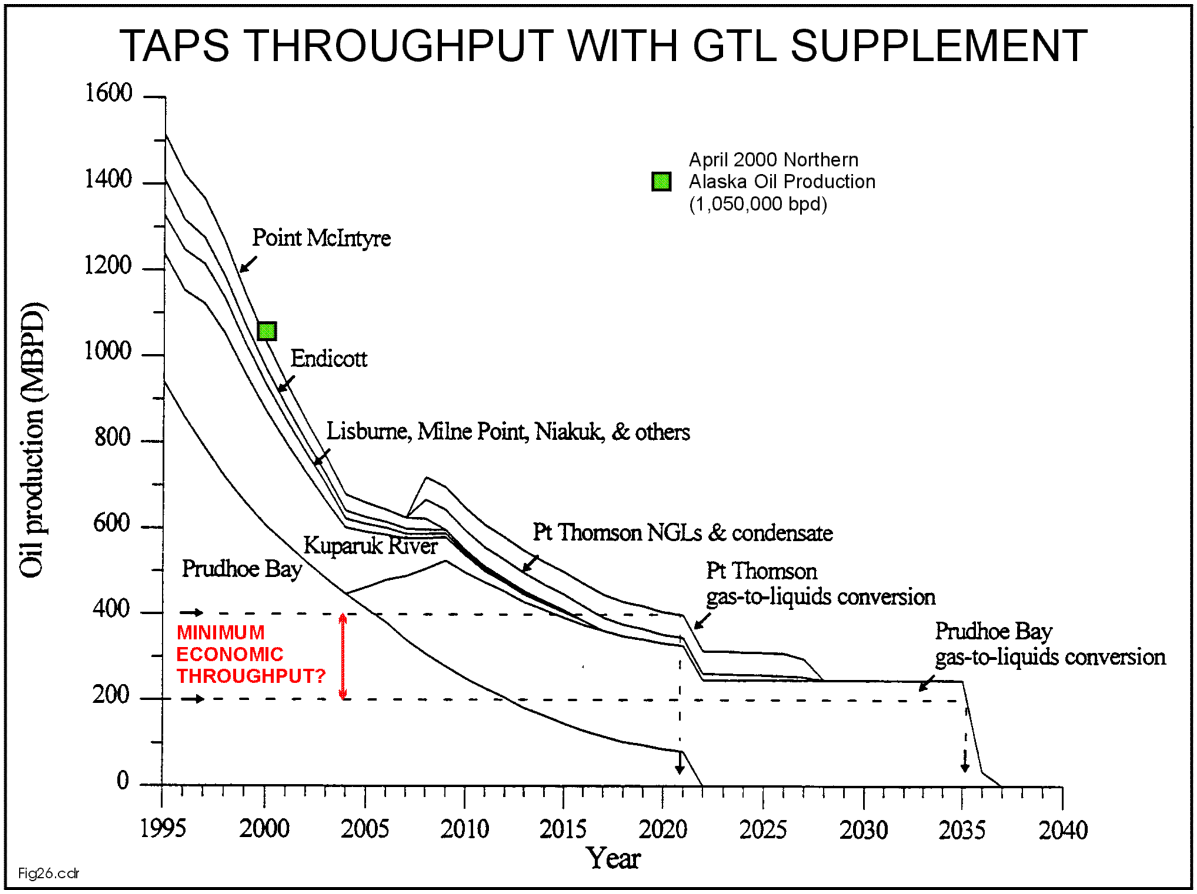


Figure 26: Model for TAPS (oil pipeline) throughput if gas is exported as GTL liquid conversion product through the TAPS line to the tanker facilities at Valdez. The economic life of TAPS is extended by about 20 years over other gas export options at the 200,000 bpd throughput threshold. Diagram from Thomas and others (1996, fig. 2.9).

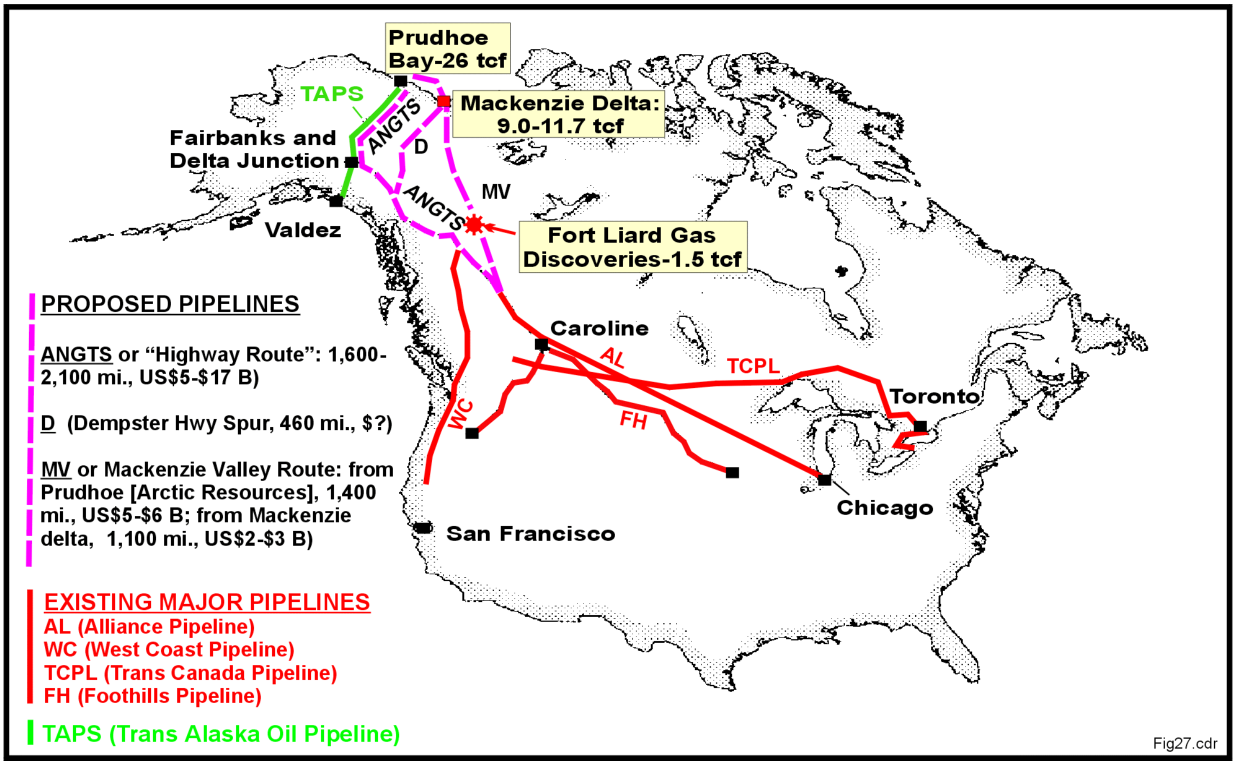


Figure 27: Routes of proposed "ANGTS" (Alaska Natural Gas Transportation System, now referred to as the "highway route"), "MV" (Mackenzie Valley), and "D" (Dempster highway spur) gas pipelines proposed for transportation of natural gas from Prudhoe Bay (26 tcf) and Mackenzie delta (9 to 11.7 tcf) fields to existing pipelines in northern Alberta and British Columbia, Canada. Recent gas discoveries in the Fort Liard area (1.5 tcf and growing) will extend the Canadian pipeline network northward toward the Mackenzie delta. The "over the top" route proposed by Arctic Resources Ltd. involves a subsea pipeline from Prudhoe Bay to Mackenzie delta and then a land pipeline southward down the Mackenzie River valley. A stand-alone spur line from Mackenzie delta to northern Alberta is also proposed. Map adapted from Attanasi (1995, fig. 1) and Speiss (1999a).

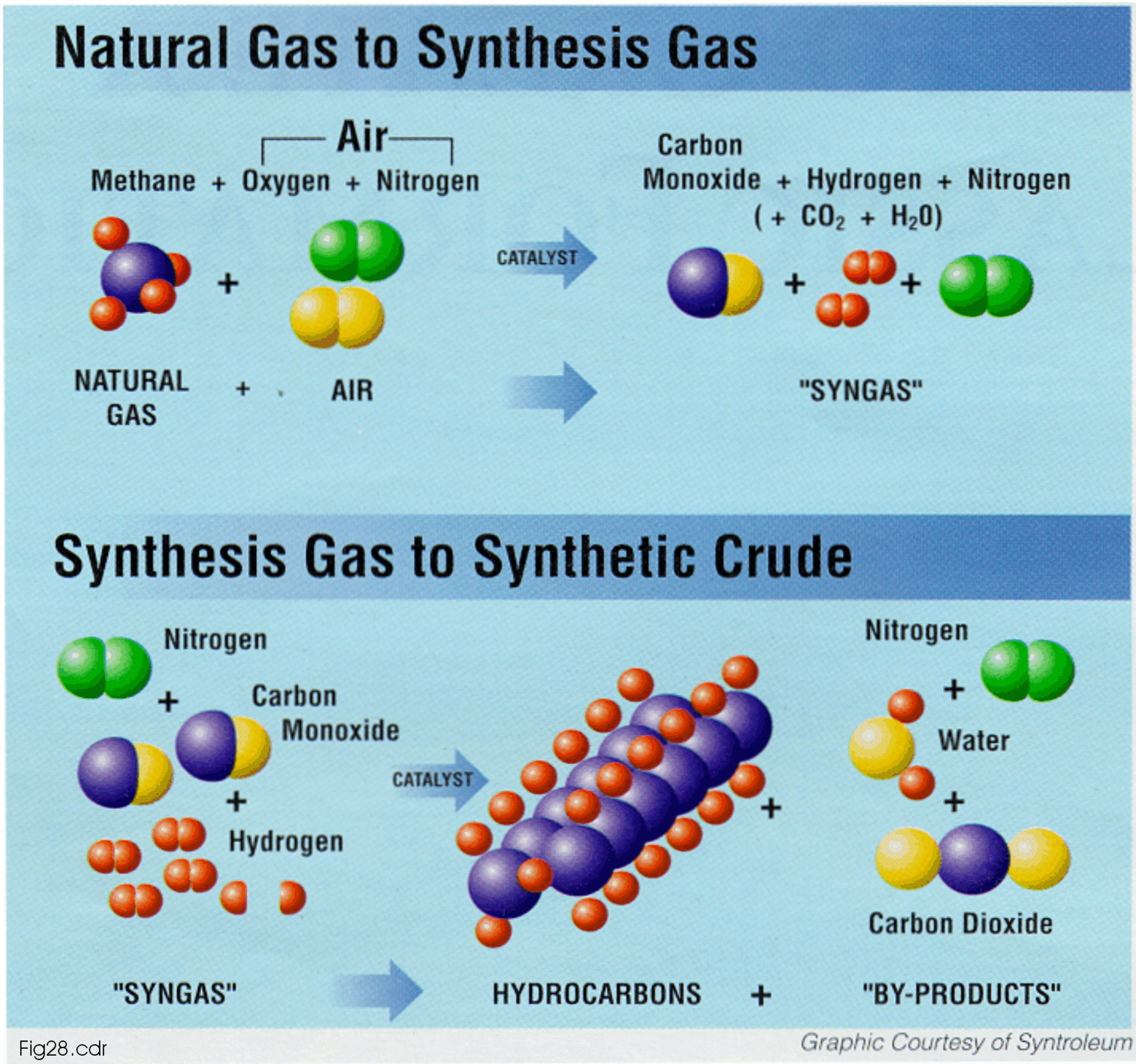


Figure 28: ***Gas-to-Liquids, Fischer-Tropsch Process, or "F-T Process".*** **This schematic shows the basic steps in converting methane or natural gas into synthetic liquids. First, methane is broken into hydrogen and carbon, the latter united with oxygen to create carbon monoxide. The mix of hydrogen and carbon monoxide is called synthetic gas or "syngas". Second, the carbon monoxide is reacted with hydrogen in the presence of a catalyst to build long hydrocarbon chains consisting of 14 to 20 carbon atoms. Hydrocarbon chains of this length are diesel-type liquids, or "synthetic crude." Other liquid products can be formed, depending upon process design. Diagram created by** ***Syntroleum Corp.*** **and adapted from publication by Nation (1997).**

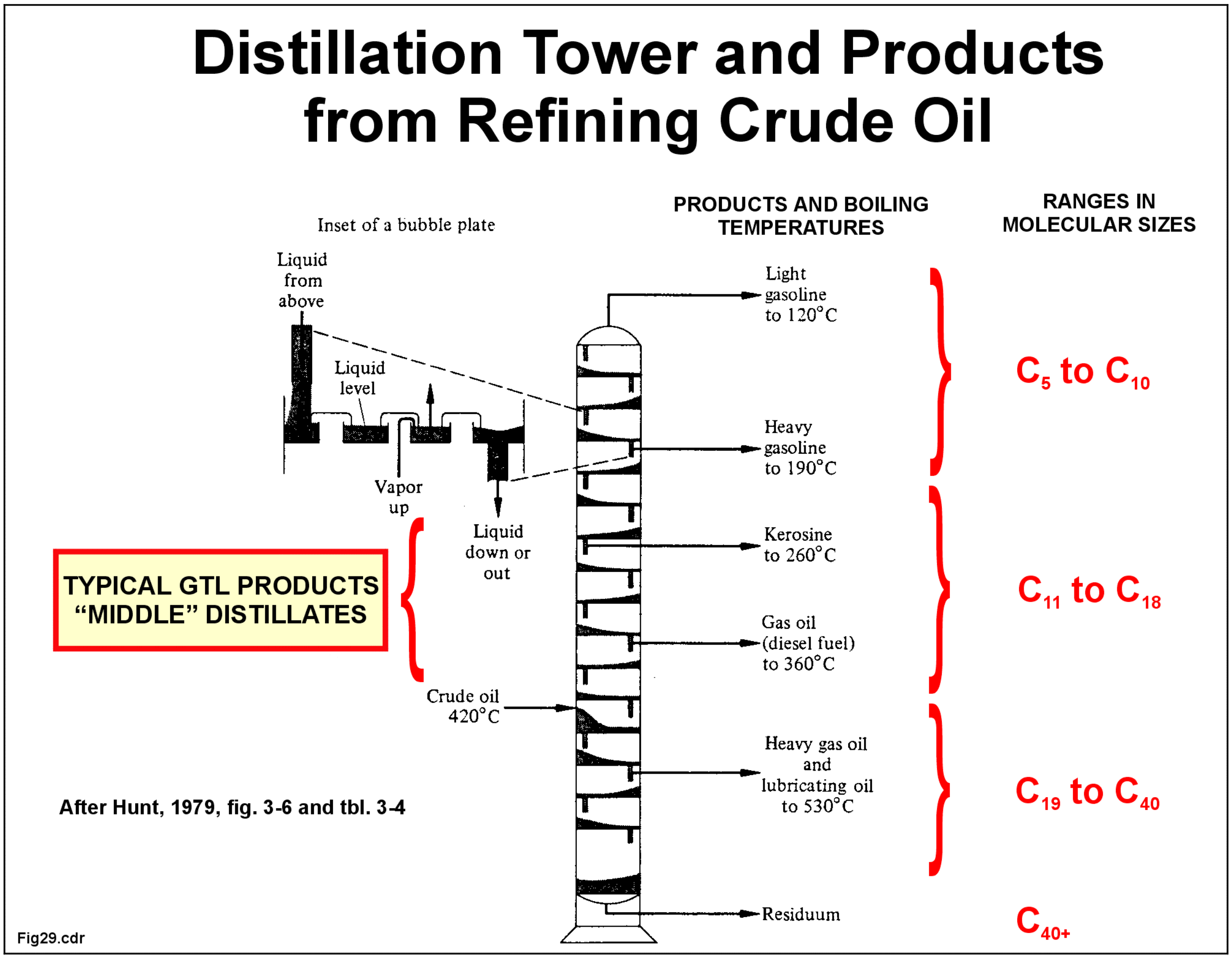


Figure 29: Sketch of distillation tower and products from refining of crude oil. Bubble plates separate liquids on basis of density and molecular size, which controls boiling (vaporization) points. Gas-to-liquids or GTL conversion typically produces fuels in the gasoline to diesel range, corresponding roughly to "middle" (of tower) distillates. Diagram adapted from Hunt (1979, fig. 3-6, with information from his tbl. 3-4).

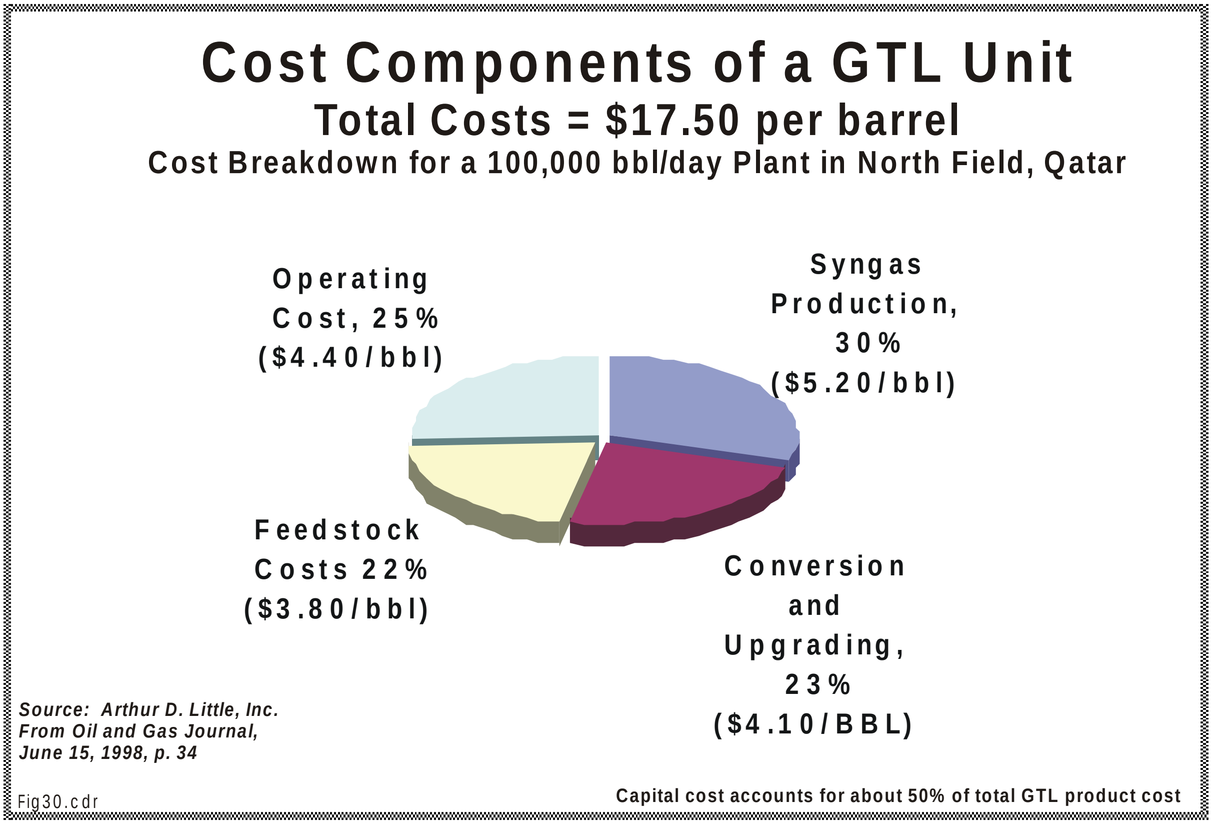


Figure 30: Cost components of a gas-to-liquids facility at output scale of 100,000 barrels of product per day, located in Qatar. Feedstock costs of $3.80 per barrel of conversion liquid are approximately equivalent to $0.38/mcf of feedstock gas. Diagram redrawn from O&GJ (1998, p. 34).

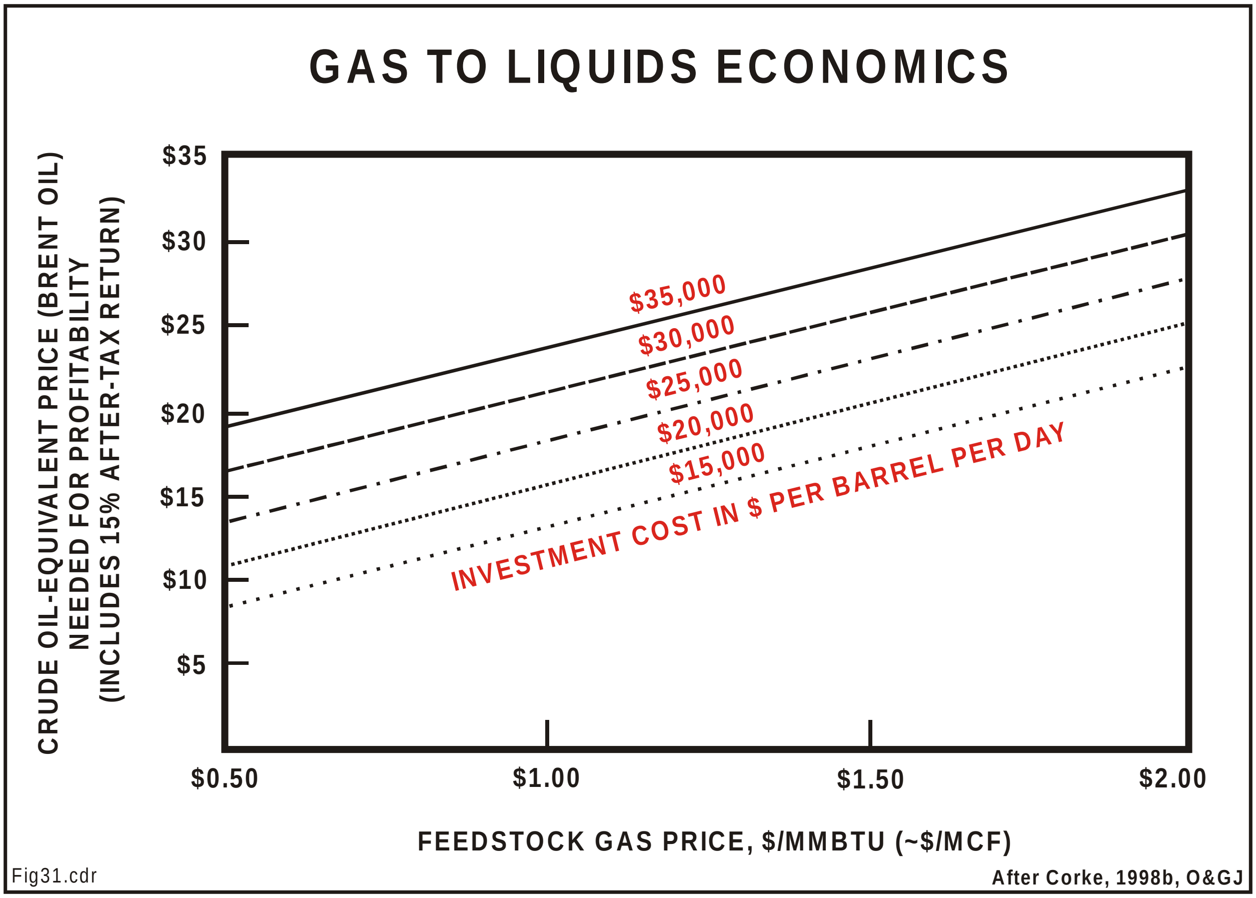


Figure 31: Economics of GTL projects and relationship to feedstock gas costs. $0.50/mcf roughly translates to $5.00 per barrel of liquid GTL product. Investment costs for plant construction are represented in dollars per barrel of daily plant output and are determined by plant scale. Larger plants benefit from economies of scale and correspond to the lowest investment costs in dollars per barrel per day. A plant that cost $30,000 per barrel per day to construct and using gas costing $1.00/mmbtu will require a Brent oil price (an arbitrarily chosen index) of $21 per barrel to yield a 15% after-tax R.O.I. Diagram re-drawn after Corke (1998b, fig. 4) for dry gas project with no revenues from condensate co-production.

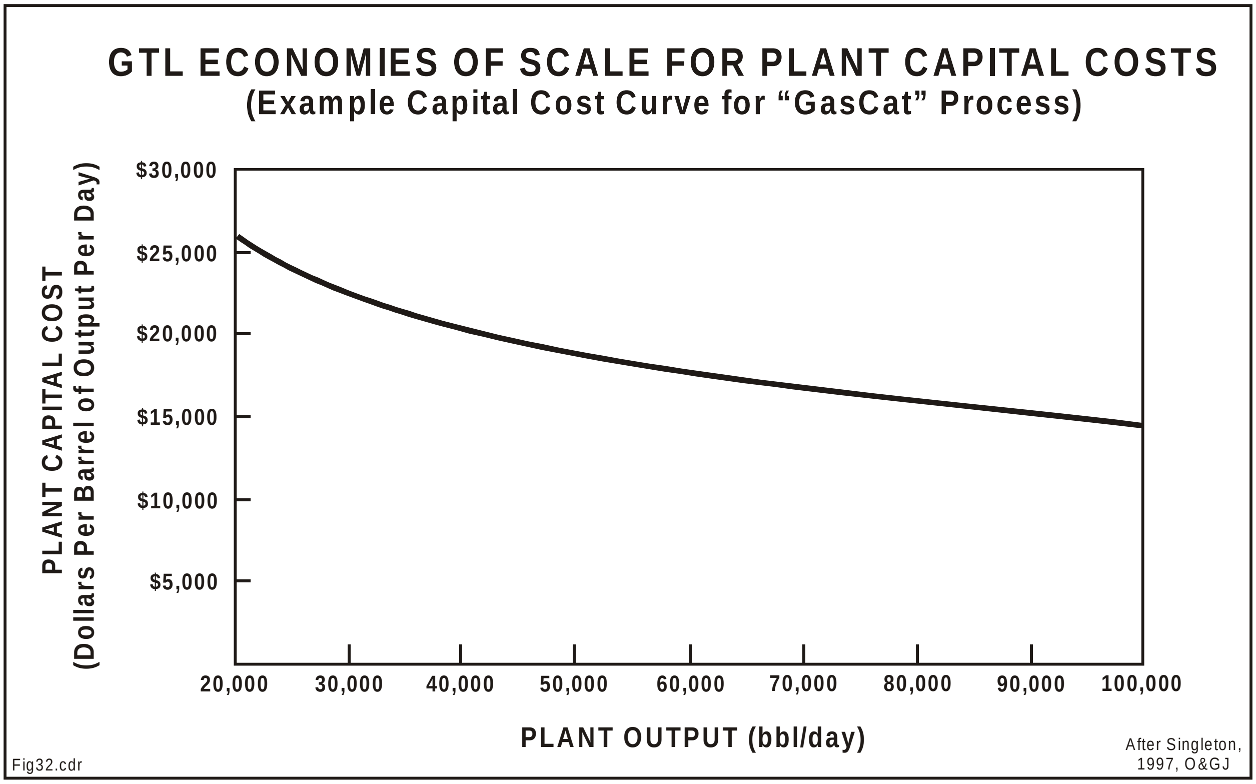


Figure 32: Example from "GasCat" process showing how larger GTL plants benefit from economy of scale and can produce liquids from gas more cheaply. For example, capital costs for this type of GTL plant, when designed for an output capacity of 100,000 barrels of liquid product per day, are only $15,000/barrel/day, nearly half the costs of plants with capacities smaller than 20,000 barrels per day. Diagram redrawn from Singleton (1997, fig. 3).

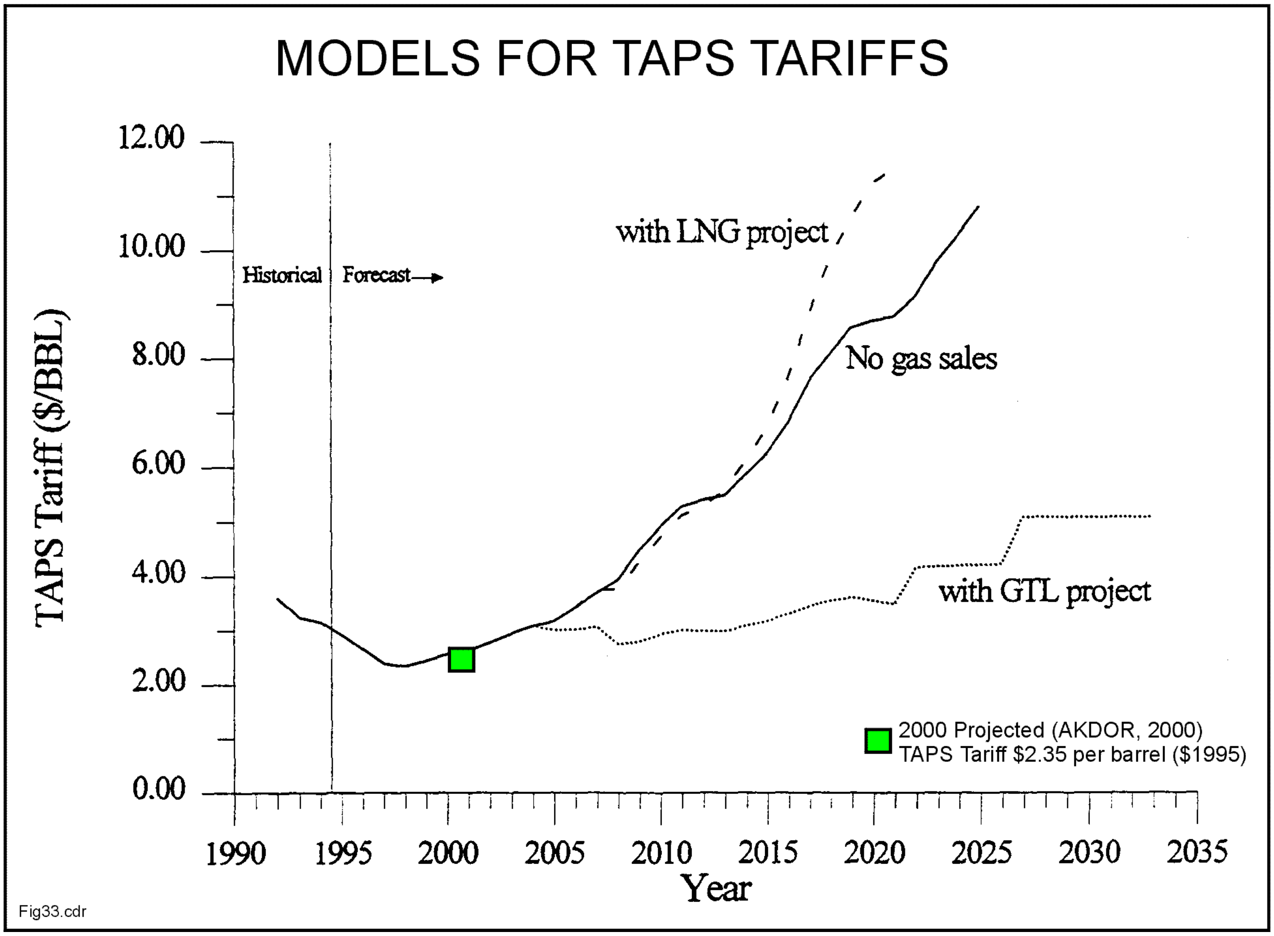


Figure 33: Trans-Alaska oil pipeline (TAPS) tariff projections to year 2035, shown in $1995. A gas-to-liquids (GTL) project will add to pipeline throughput and will moderate future tariff increases, potentially allowing small future oil (and gas?) discoveries to be economic to produce. A liquified-natural gas (LNG) project requiring a separate gas pipeline will shorten the economic life of TAPS and may result in high tariffs for TAPS which might make future small discoveries uneconomic to develop. Diagram from Thomas and others (1996, fig. B.3). Current tariff from projection for 2000 in AKDOR (2000, tbl. 15) indicating $2.74 per barrel (nominal; $2.35 in $1995).

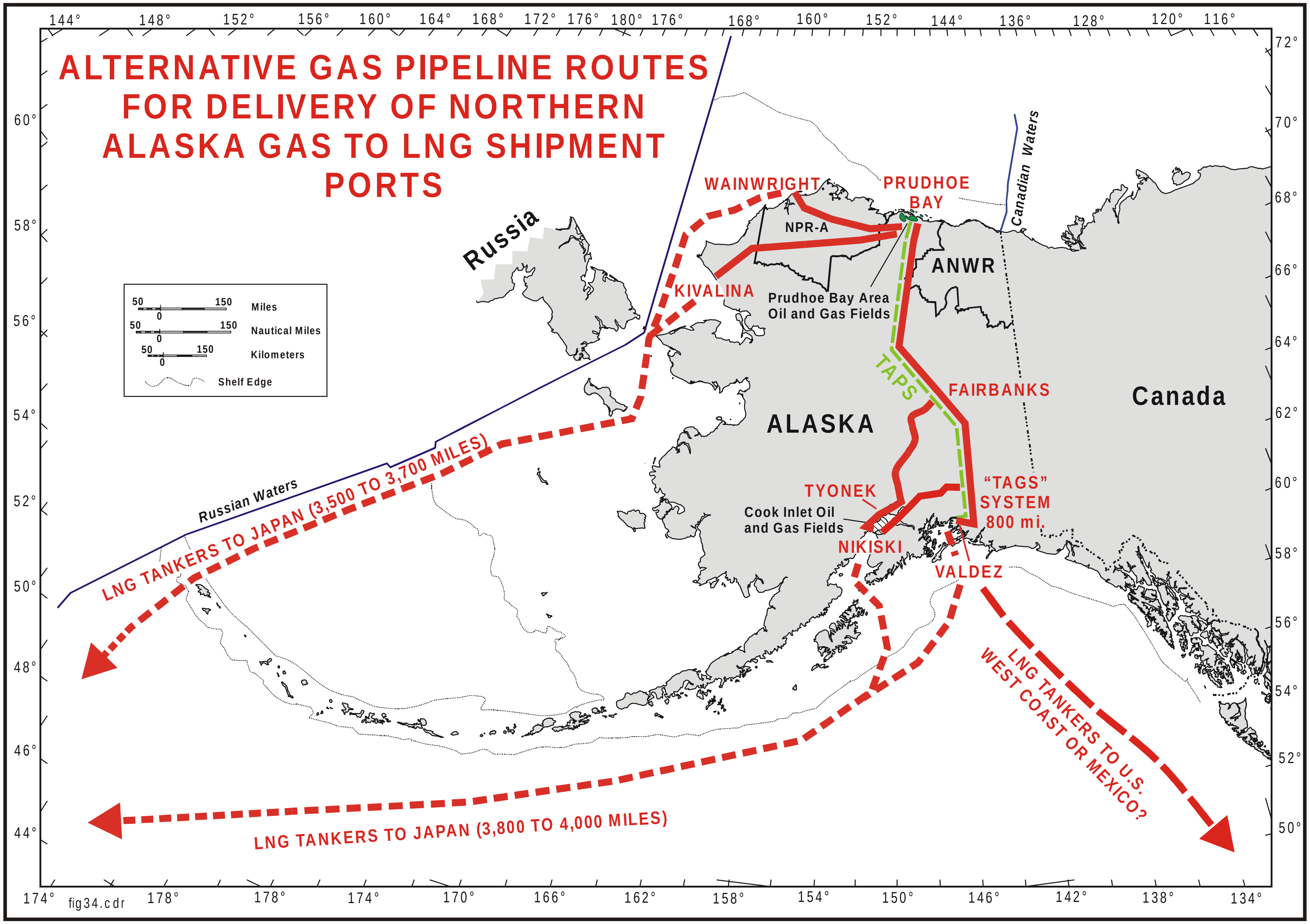


Figure 34: Proposed routes for gas pipelines carrying northern Alaska gas to LNG facilities at Alaskan shipping ports. The Yukon-Pacific Corporation "TAGS" system carrying gas 800 miles from Prudhoe Bay to Valdez forms the traditional route, although a lines to export terminals in Cook Inlet are also candidates. Speculative northwest Alaska pipeline routes carrying gas to Wainwright or Kivalina are replotted from Alyeska (1996).

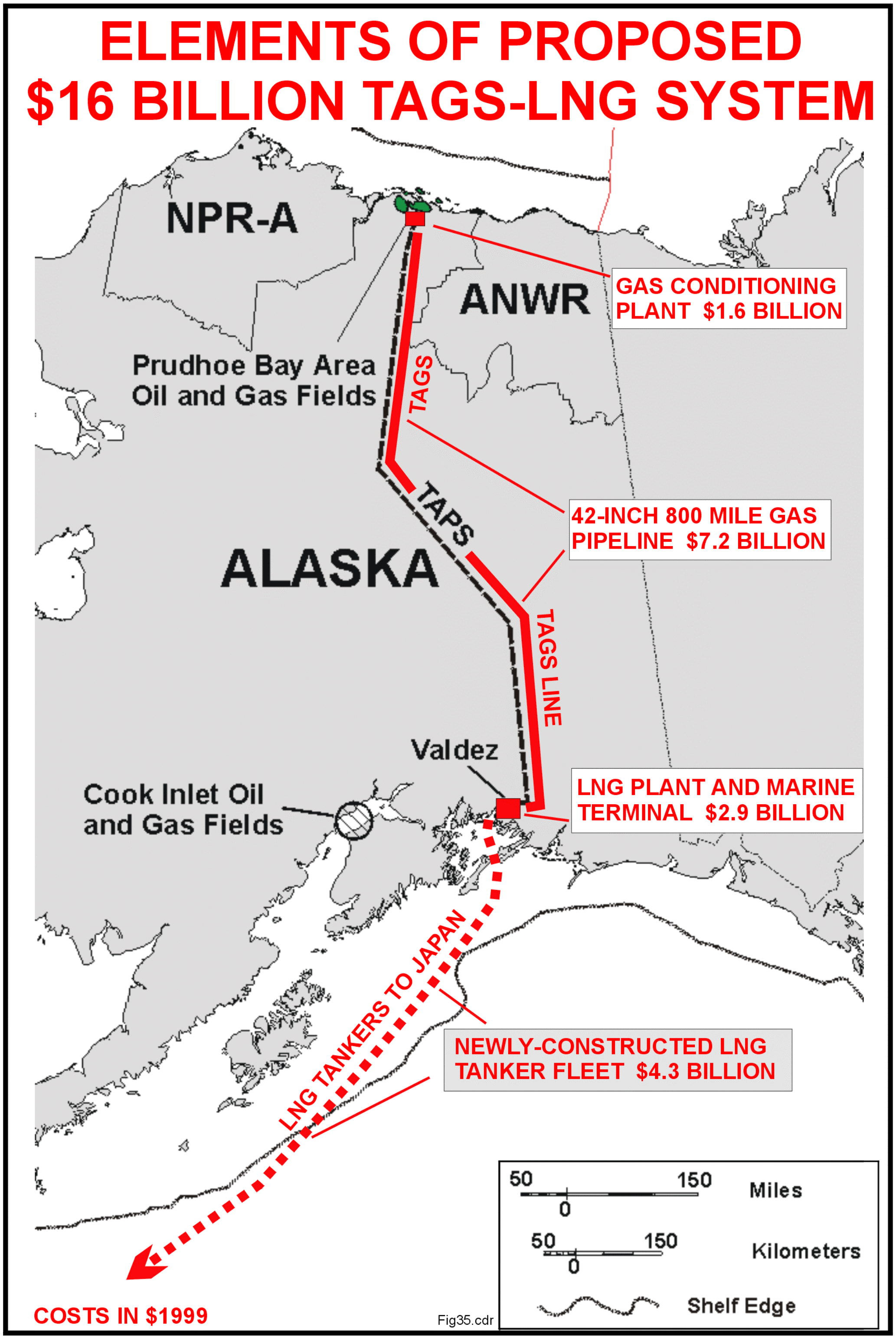
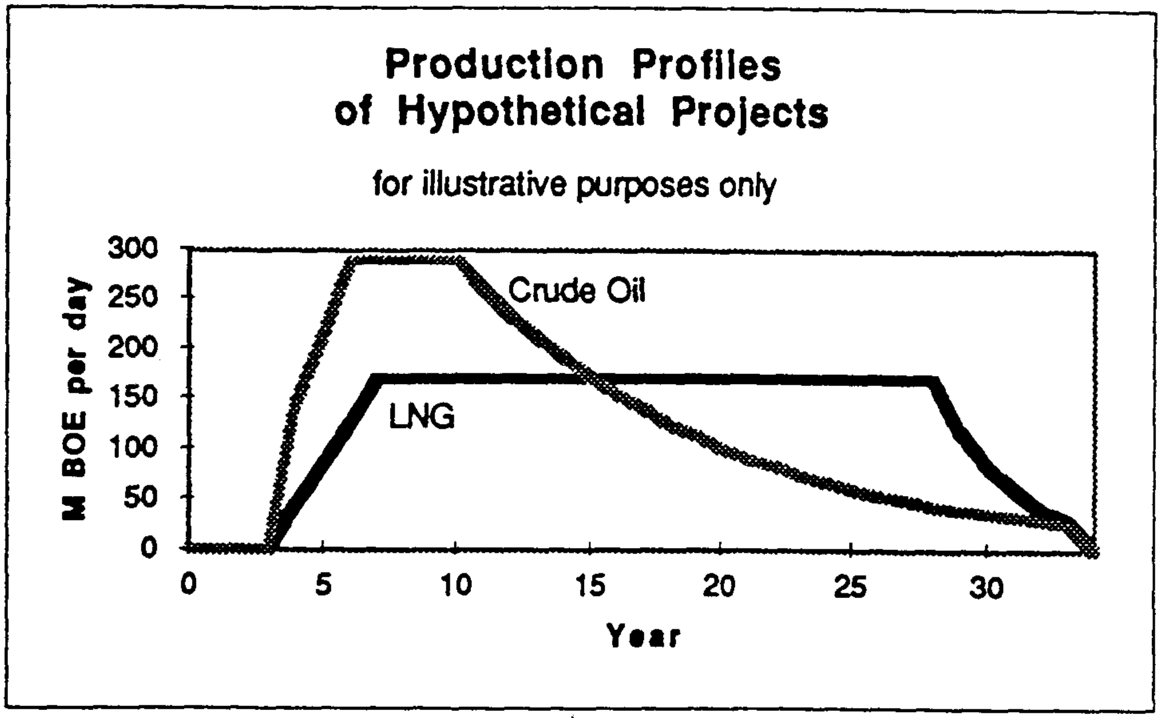


Figure 35: Elements of proposed TAGS-LNG gas transportation system requiring capital outlays for initiation of project. Cost estimates for 14 million metric ton (0.7 tcf) per year project from Thomas and others (1996, p. B-20 to B-21), with reported $1995 costs adjusted to $1999.



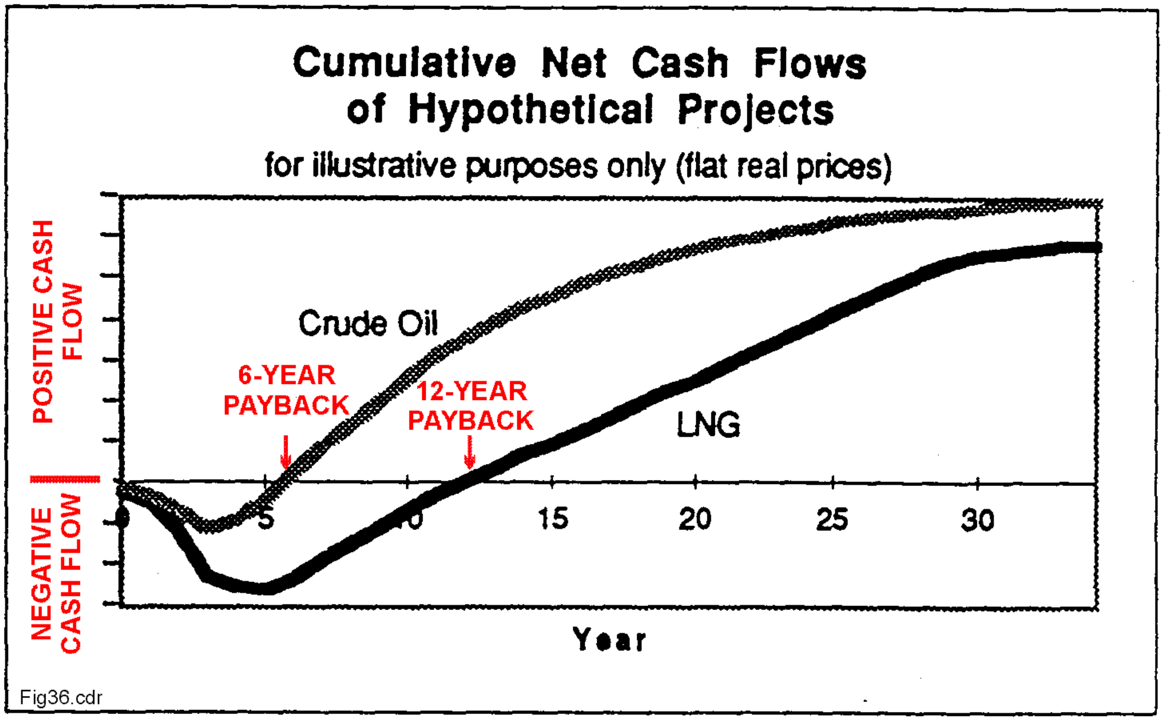


Figure 36: Comparison of production profiles for crude oil and LNG projects showing the effects of the time interval for "ramp-up" to maximum production on overall project economics. Because of the longer ramp-up and flat production profile, cash flows remain negative much longer for the LNG project, delaying payback and increasing the risk of exposure to unfavorable fluctuations in price (LNG is tied to world oil prices). Adapted from Wetzel and Benson (1996, p. 5).

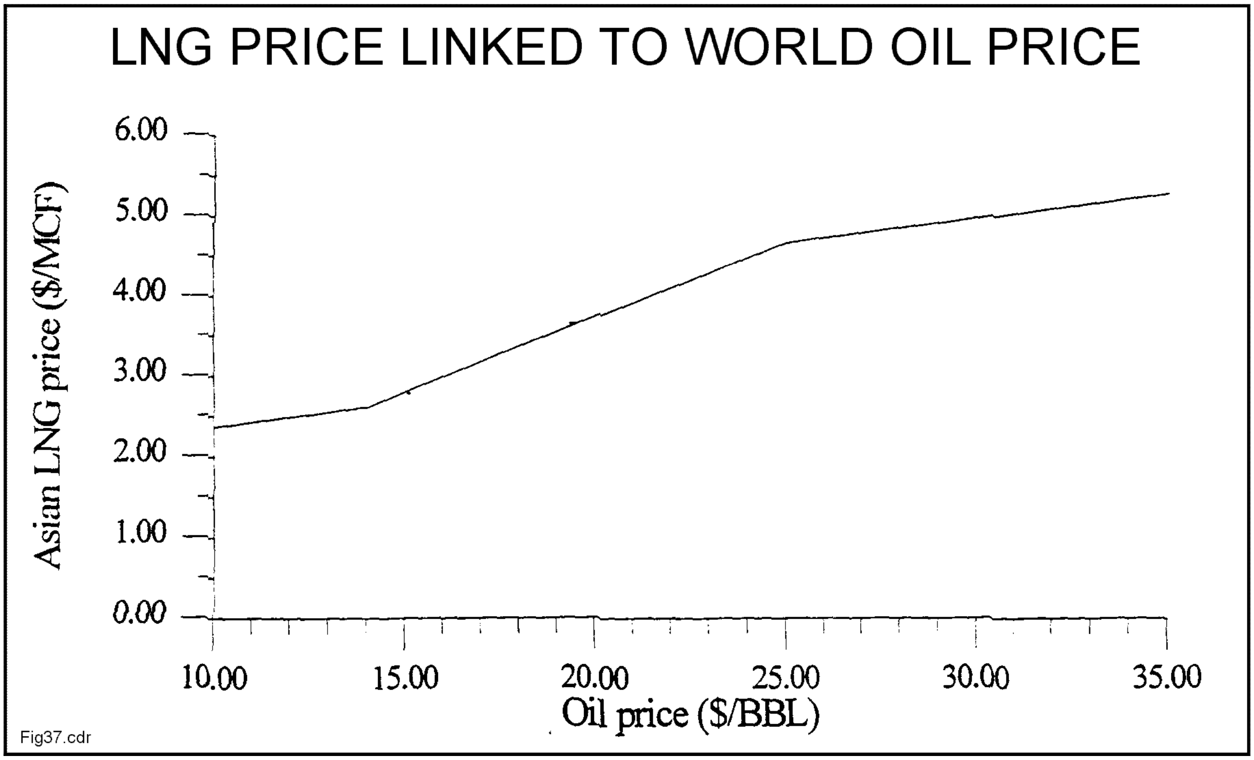


Figure 37: Example of relationship of LNG prices to world oil prices in long-term sales contract. The relationship is drawn so that the LNG provider is contractually protected from financial harm resulting from low (<$15/bbl) oil prices, while the LNG buyer is protected from financial harm resulting from very high (>$25/bbl) oil prices. Between $15/bbl and $25/bbl, LNG prices vary directly, more or less on energy parity, with world oil prices. Diagram adapted from Thomas and others (1996, fig. B.7).

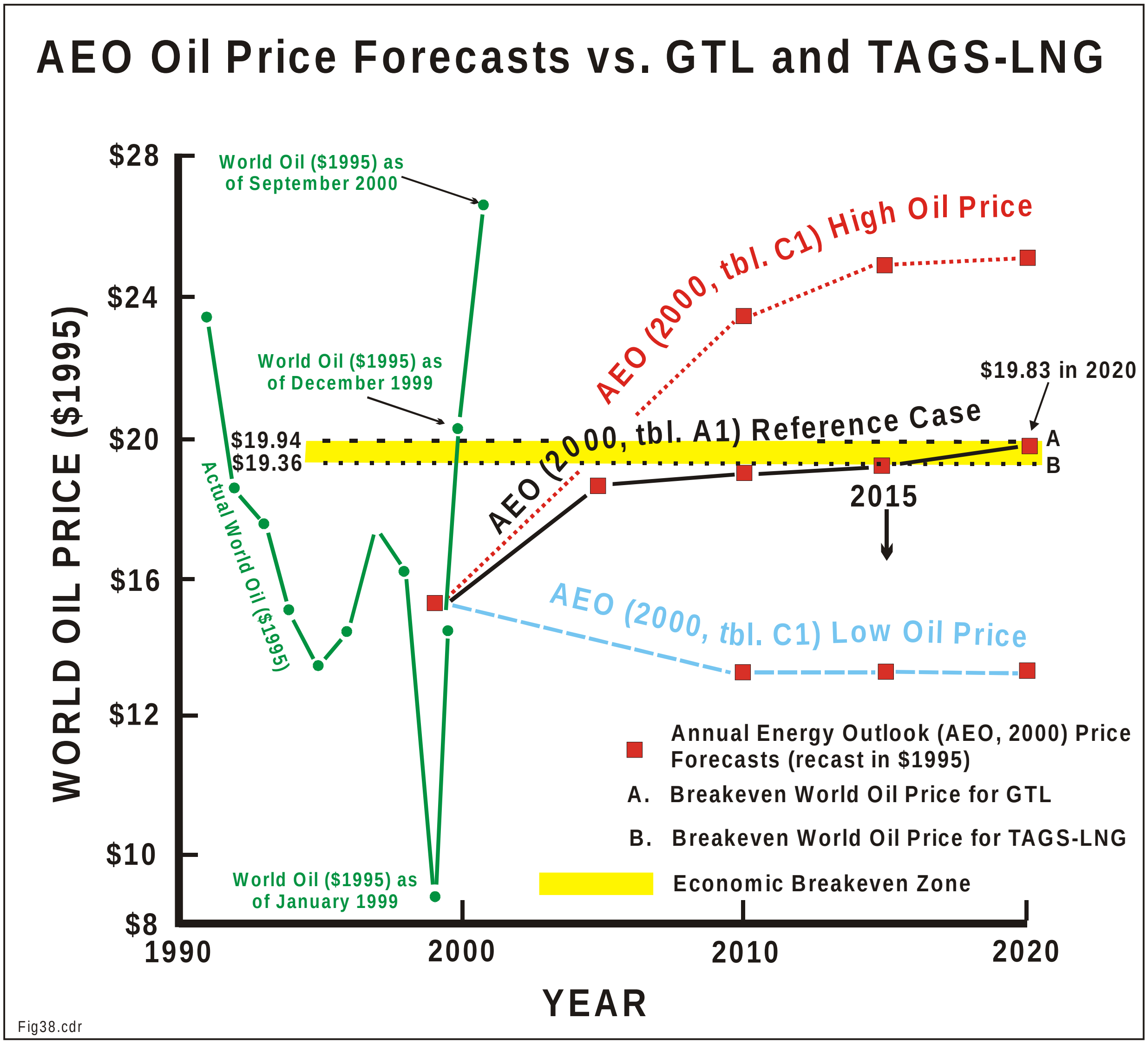


Figure 38: AEO *Energy Outlook 2001* (AEO, 2000) forecasts for world oil prices and 1995 DOE results for breakeven ($NPV_{10} = 0$) flat oil prices ($1995) for GTL ($19.94/bbl) and TAGS-LNG ($19.36/bbl) projects for northern Alaska natural gas, as reported in a 1995 DOE study by Thomas and others (1996, p. xiv). The AEO *Reference Case* forecast (tbl. 19) intersects the breakeven oil price for TAGS-LNG in year 2015 and the breakeven oil price for GTL after year 2020. The breakeven oil prices correspond approximately to Asian Pacific rim LNG prices of $3.88/mcf and $3.77/mcf, respectively, while Japan-bound LNG shipments from Nikiski, Alaska have remained above $4/mcf since January 2000. World oil prices were as low as $9.93/bbl ($8.79 in $1995) in January 1999 but rose to $31.10/bbl (or $26.69/bbl in $1995) by September 2000.

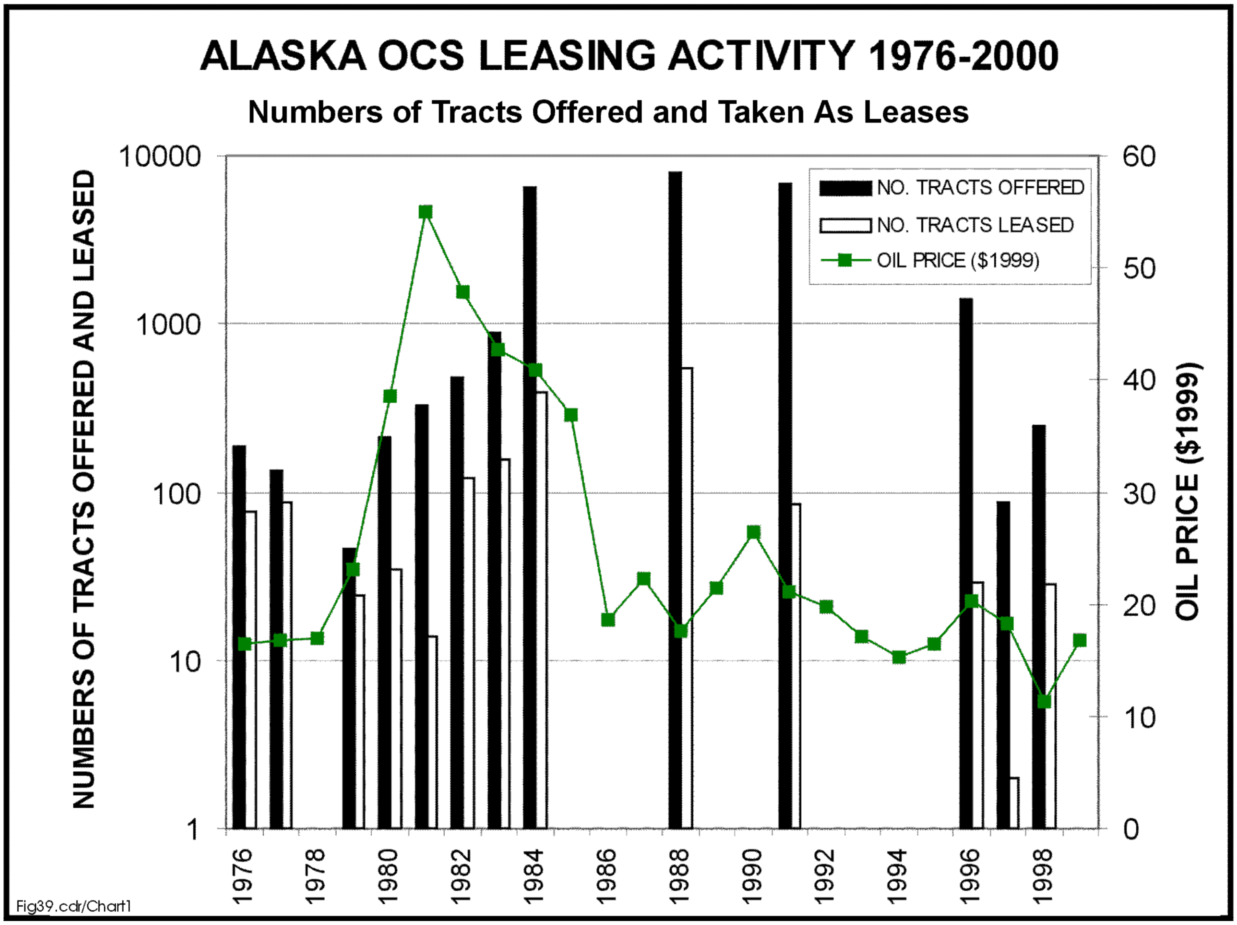


Figure 39: Bar chart for numbers of tracts offered and leased in the Alaska Federal offshore in the years from 1976 to 2000, with world oil prices adjusted to 1999 dollars. A total of 25,289 tracts were offered and a total of 1,598 (or 6.3%) were leased. Some of the largest lease sales in terms of numbers of tracts offered and leased occurred in the period 1985 to 1992 following the 1986 oil price crash. However, revenues from lease sales in this period were much lower than sales in the pre-crash 1981-1984 period (fig. 42).

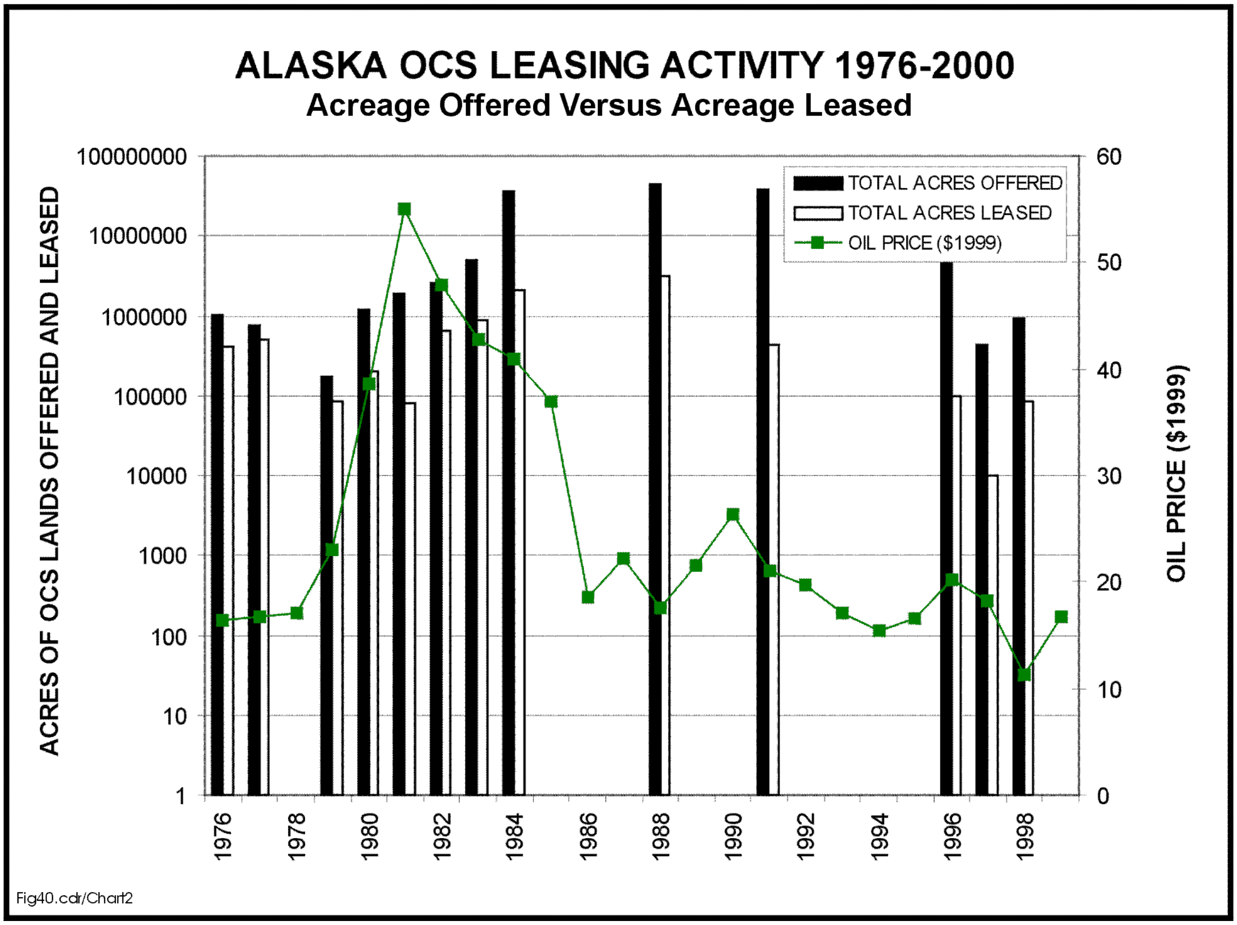


Figure 40: Bar chart for numbers of acres offered and leased in the Alaska Federal offshore in the years from 1976 to 2000, with world oil prices adjusted to 1999 dollars. A total of 138,588,002 acres were offered and a total of 8,663,685 acres (or 6.3%) were leased. Some of the largest lease sales in terms of numbers of tracts offered and leased occurred in the period 1985 to 1992 following the 1986 oil price crash. However, revenues from lease sales in this period were much lower than sales in the pre-crash 1981-1984 period (fig. 42).

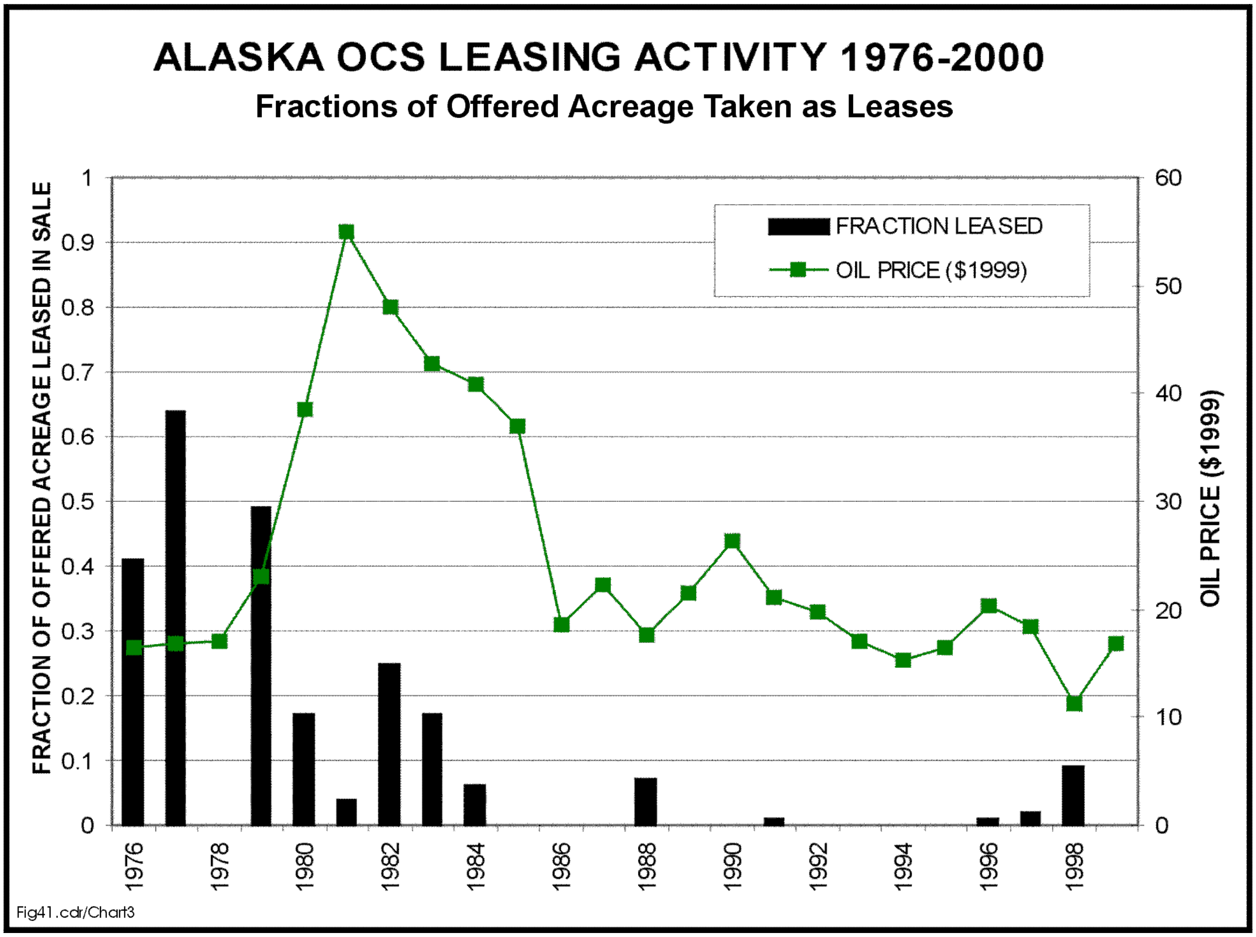


Figure 41: Bar chart for fractions of offered acreage actually leased in lease sales in the Alaska Federal offshore in the period 1976 to 2000, with world oil prices adjusted to 1999 dollars. In early lease sales, over 40% of the lands offered were leased. However, the lease strategy moved to area-wide offerings in 1983, with the consequence that much greater land areas were made available for lease. Following the oil-price crash of 1986, the oil industry became much more selective at lease sales and fractions taken in post-1983 sales have not exceeded 5 percent.

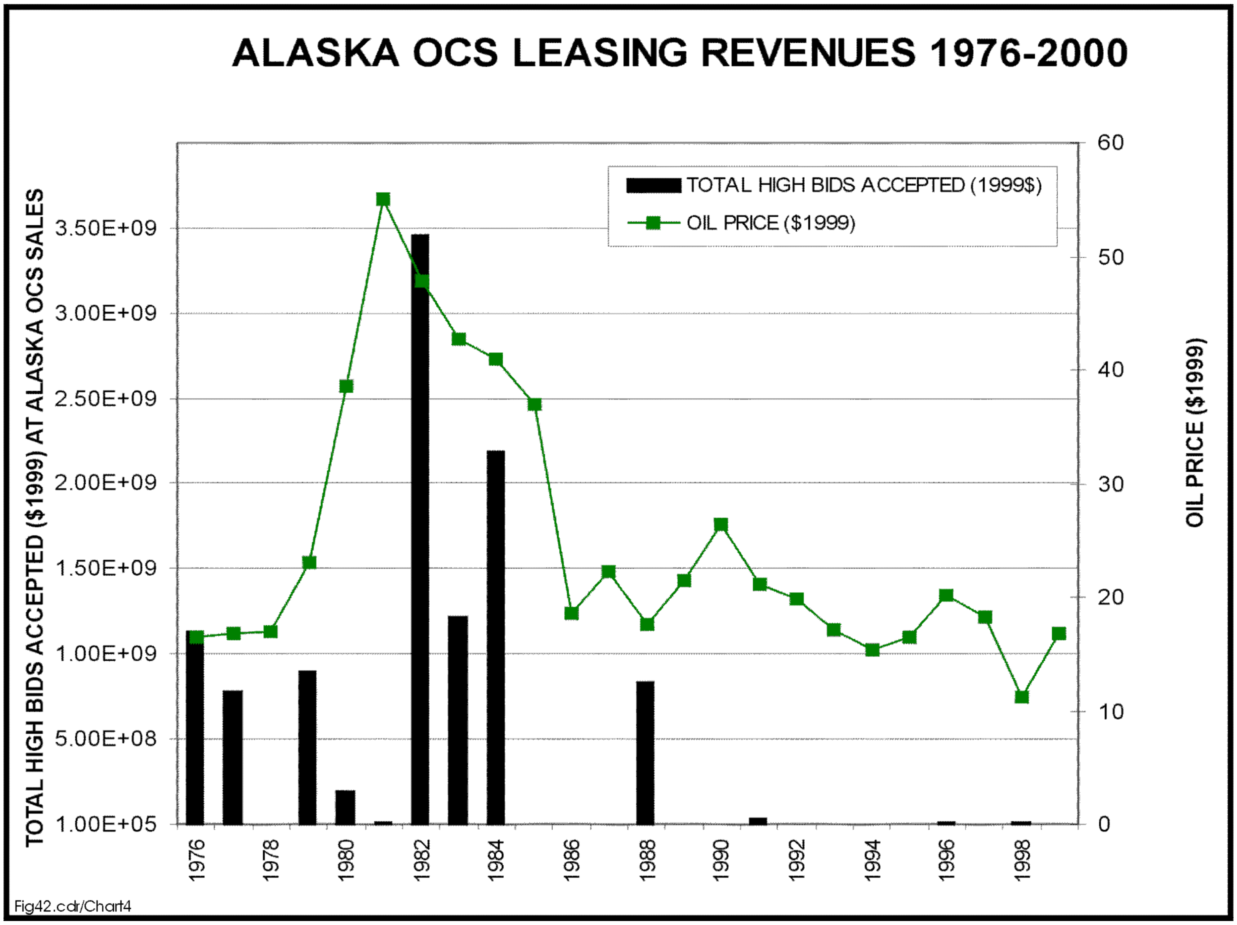


Figure 42: Bar chart for total high bids (adjusted to 1999 dollars) accepted in lease sales in the Alaska Federal offshore in the period 1976 to 2000, with world oil prices (also adjusted to 1999 dollars). Bonus (lease bid amount) revenues nearly reached $3 billion in 1982 but declined sharply following the oil-price crash of 1986. The decline in bonus revenues also reflected completions of exploration cycles for basins that were leased for the first time, explored with disappointing results from several wells (particularly in the Bering Sea), and then abandoned. The total nominal bonus bid revenues for all lease sales in the Alaska Federal offshore is $6,381,697,719 (over $10 billion in $1999).

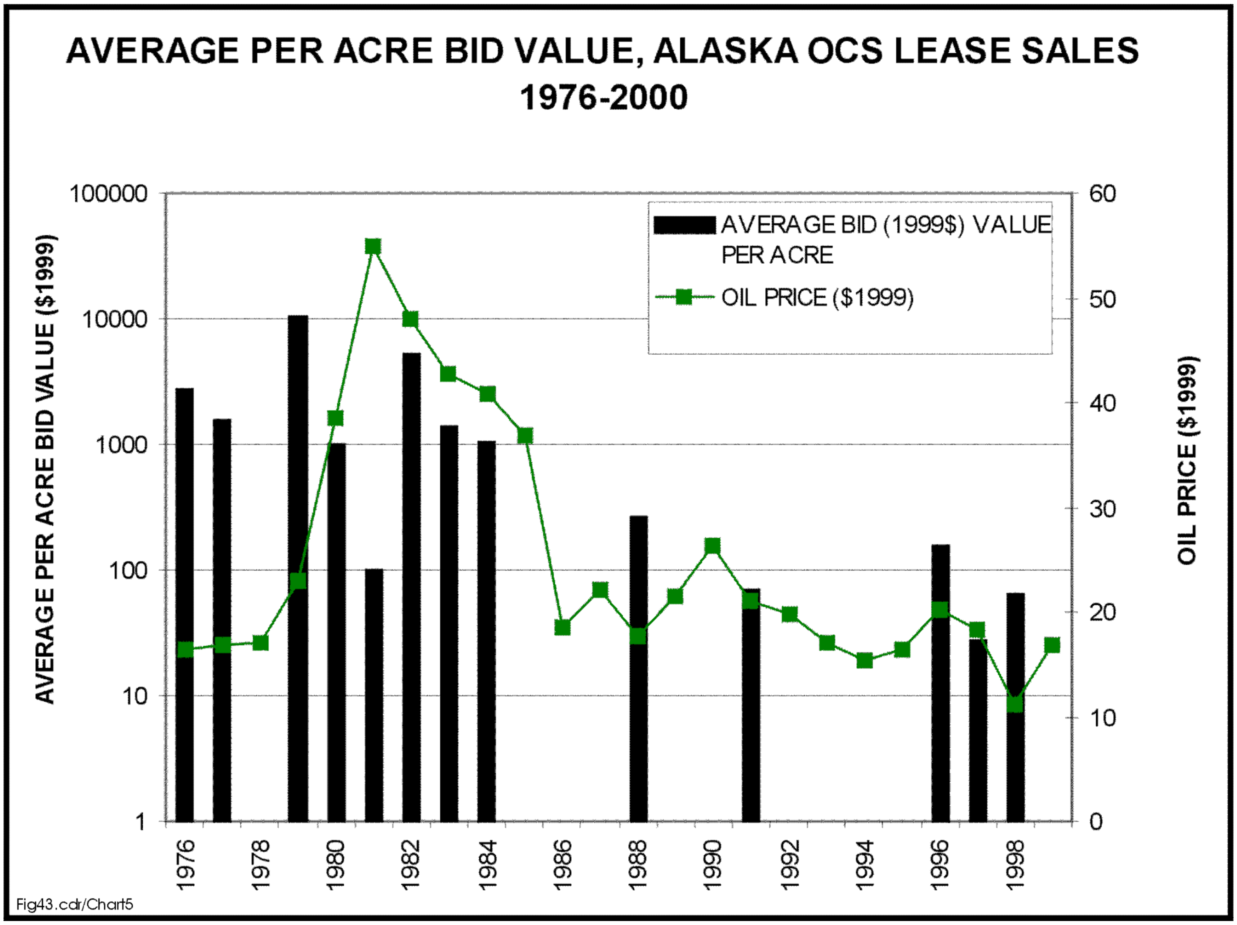


Figure 43: Bar chart for average bonus bid values (adjusted to 1999 dollars) per acre for leases sales in the Alaska Federal offshore from 1976 to 2000, with world oil prices (in $1999) also shown. The opening of unexplored basins to leasing during the early 1980's, coupled with high expectations for future oil prices, drove bonus bids over $10,000 per acre in the 1979 Beaufort "BF" State-Federal sale. Since the oil-price crash of 1986, bonus bids have typically averaged less than $100 per acre, reflecting a more subdued exploration environment.

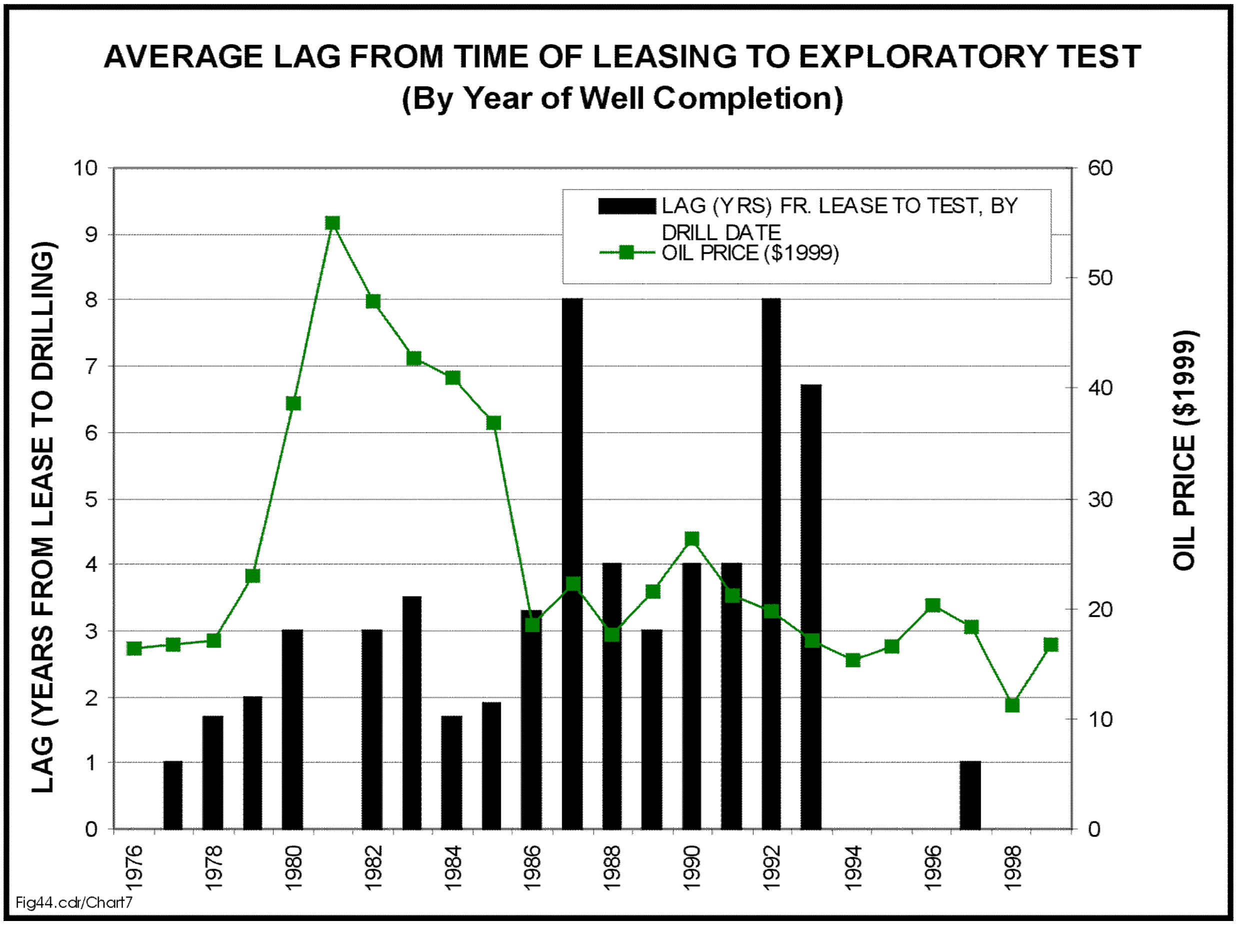


Figure 44: Bar chart for average time lag (in years) between the dates that leases were acquired and the dates when the first exploration wells were drilled, indexed to year that the well was completed. Most leases were never drilled. Only 83 exploration tests were drilled in the Alaska Federal offshore, while 1,598 tracts were leased over the 22-year period. Many basins, particularly in the Bering Sea, were promptly explored within 1 to 2 years following lease sales and then promptly abandoned. Drilling in the Beaufort Sea has involved some leases held as long as 10 years. In general, the pace of drilling has slowed and the lag between leasing and exploratory drilling has increased. The average time lag for all 83 exploratory wells in the Alaska Federal offshore is 2.4 years and the median time lag is 1.5 years.

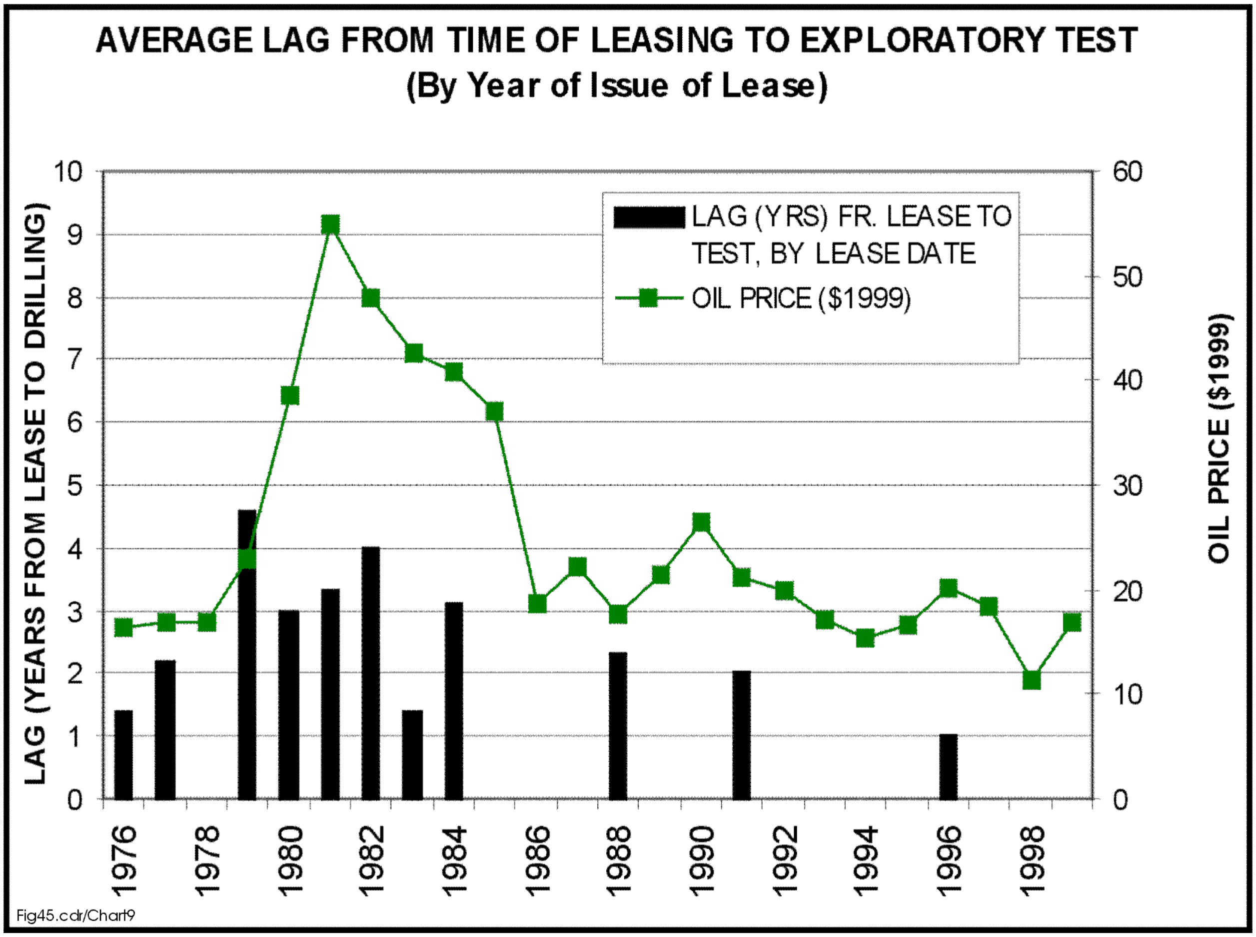


Figure 45: Bar chart for average time lag (in years) between the dates that leases were acquired and the dates when the first exploration wells were drilled, indexed to year that the lease was acquired. Most leases were never drilled. Only 83 exploration tests were drilled in the Alaska Federal offshore, while 1,598 tracts were leased over the 22-year period. Many basins, particularly in the Bering Sea, were promptly explored within 1 to 2 years following lease sales and then promptly abandoned. Drilling in the Beaufort Sea has involved some leases held as long as 10 years; these are the leases with the highest average lags in years 1979 ("BF" sale) and 1982 (Sale 71). The average time lag for all 83 exploratory wells in the Alaska Federal offshore is 2.4 years and the median time lag is 1.5 years.

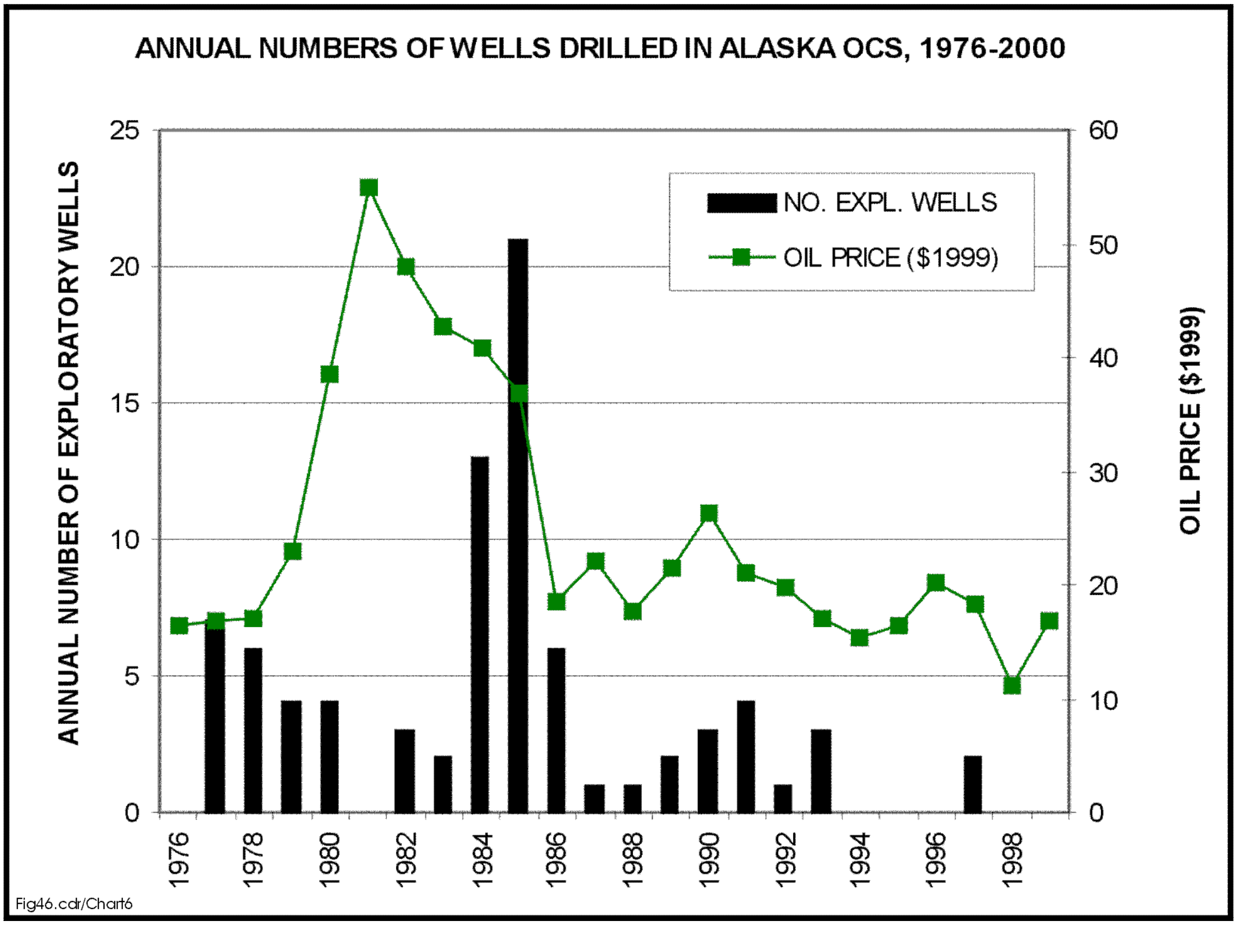


Figure 46: Bar chart for numbers of exploratory wells drilled annually in Alaska Federal offshore from 1976 to 2000, with world oil prices ($1999) also posted. A total of 83 exploratory wells have been drilled in the Alaska Federal offshore. The largest spikes in drilling activity, when 10 to 20 wells were drilled annually, occurred during aggressive drilling programs in newly-leased basins of the Bering Sea in the early 1980's, prior to the oil-price crash of 1986.

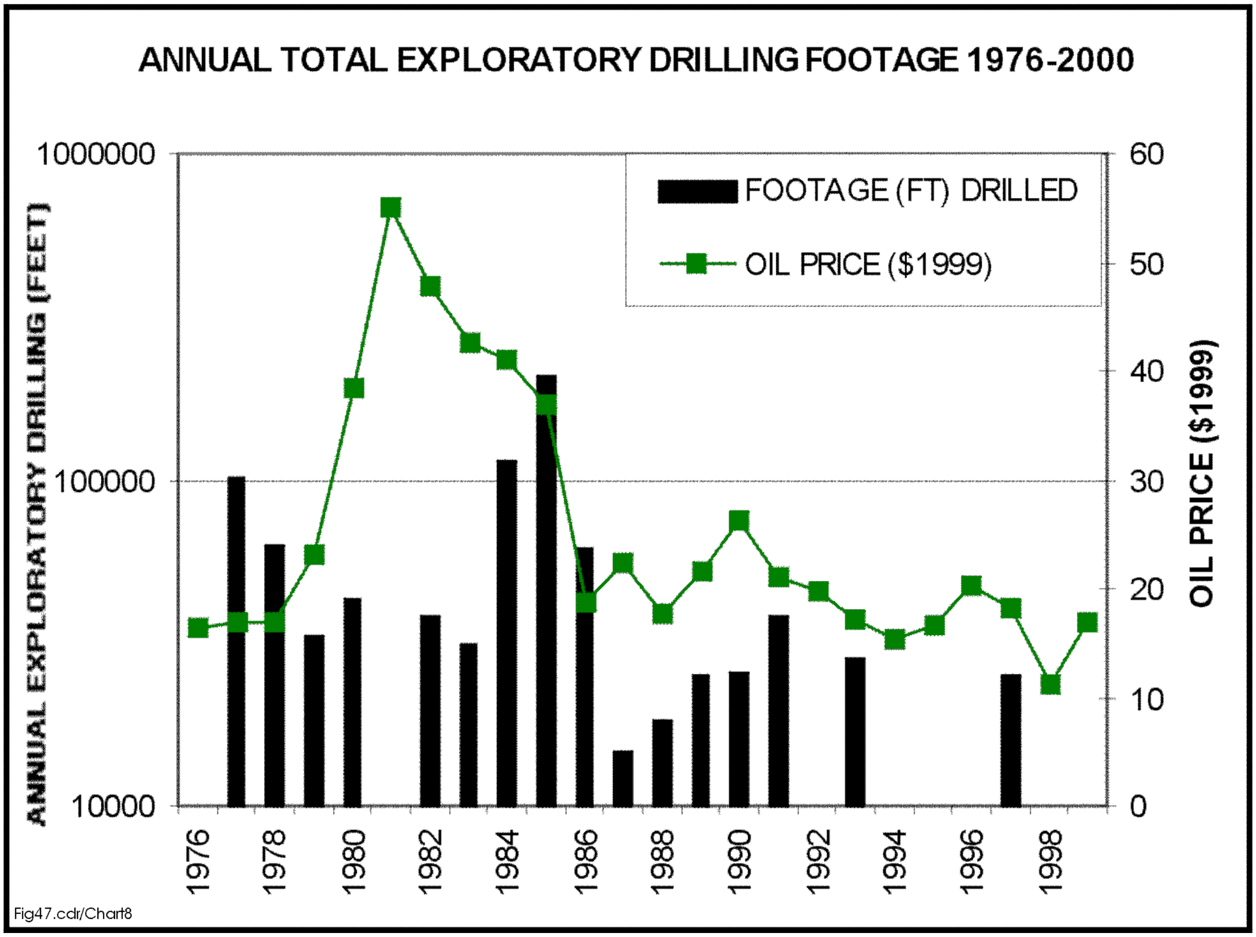


Figure 47: Bar chart for aggregate annual footages for exploratory wells drilled in Alaska Federal offshore from 1976 to 2000, with world oil prices ($1999) also posted. A total of 83 exploratory wells have been drilled in the Alaska Federal offshore with aggregate penetration footage of 875,915 feet. The largest spikes in annual footages represent aggressive drilling programs in newly-leased basins of the Bering Sea during the mid-1980's just before the oil-price crash of 1986.

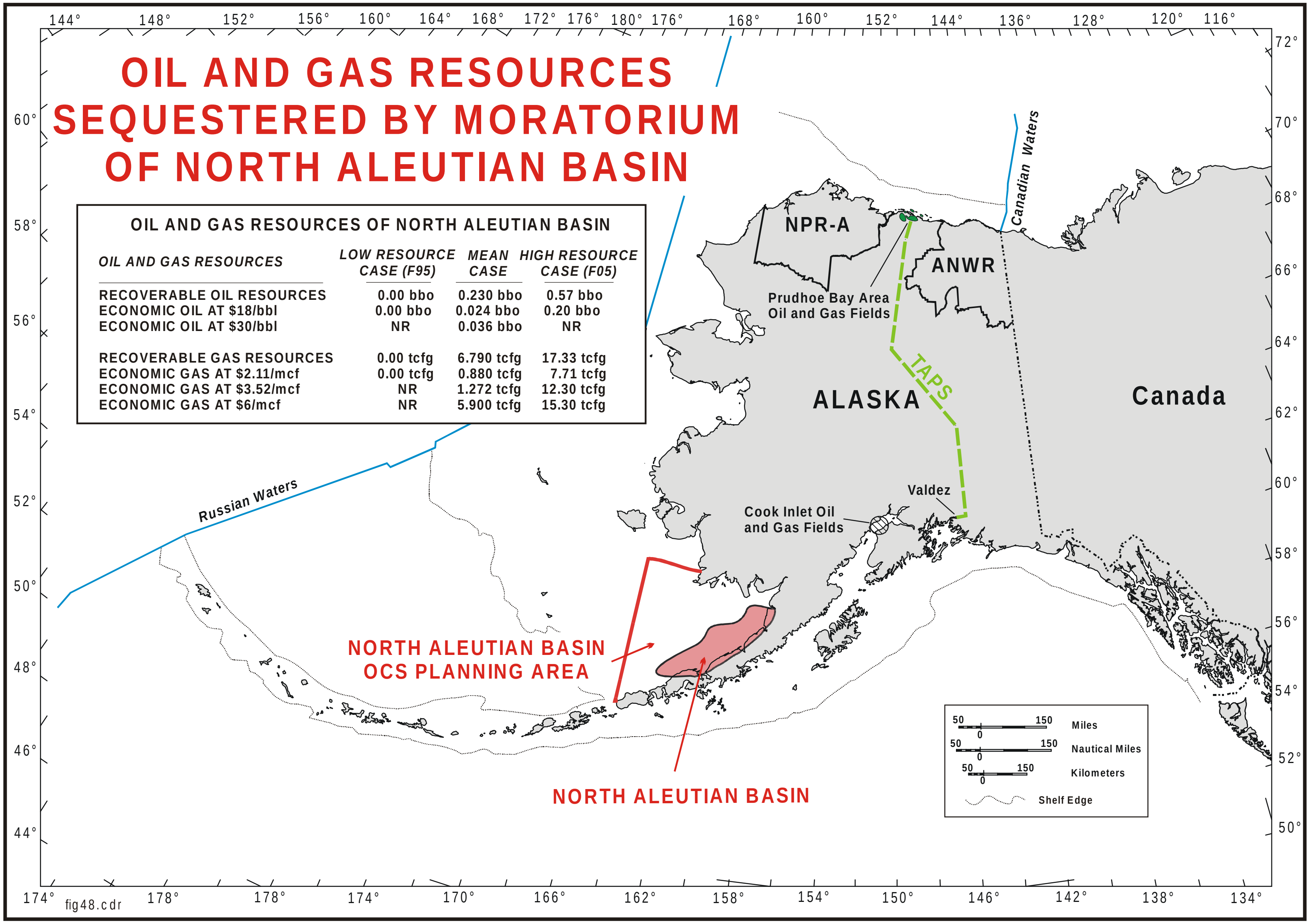


Figure 48: Locations of North Aleutian basin and North Aleutian basin OCS Planning Area, the latter under a moratorium since 1989 that forbids oil and gas leasing and exploration until year 2012. Oil and gas resources for Federal offshore part of North Aleutian basin (beyond 3 miles from shore) are shown in inset table and table 22.