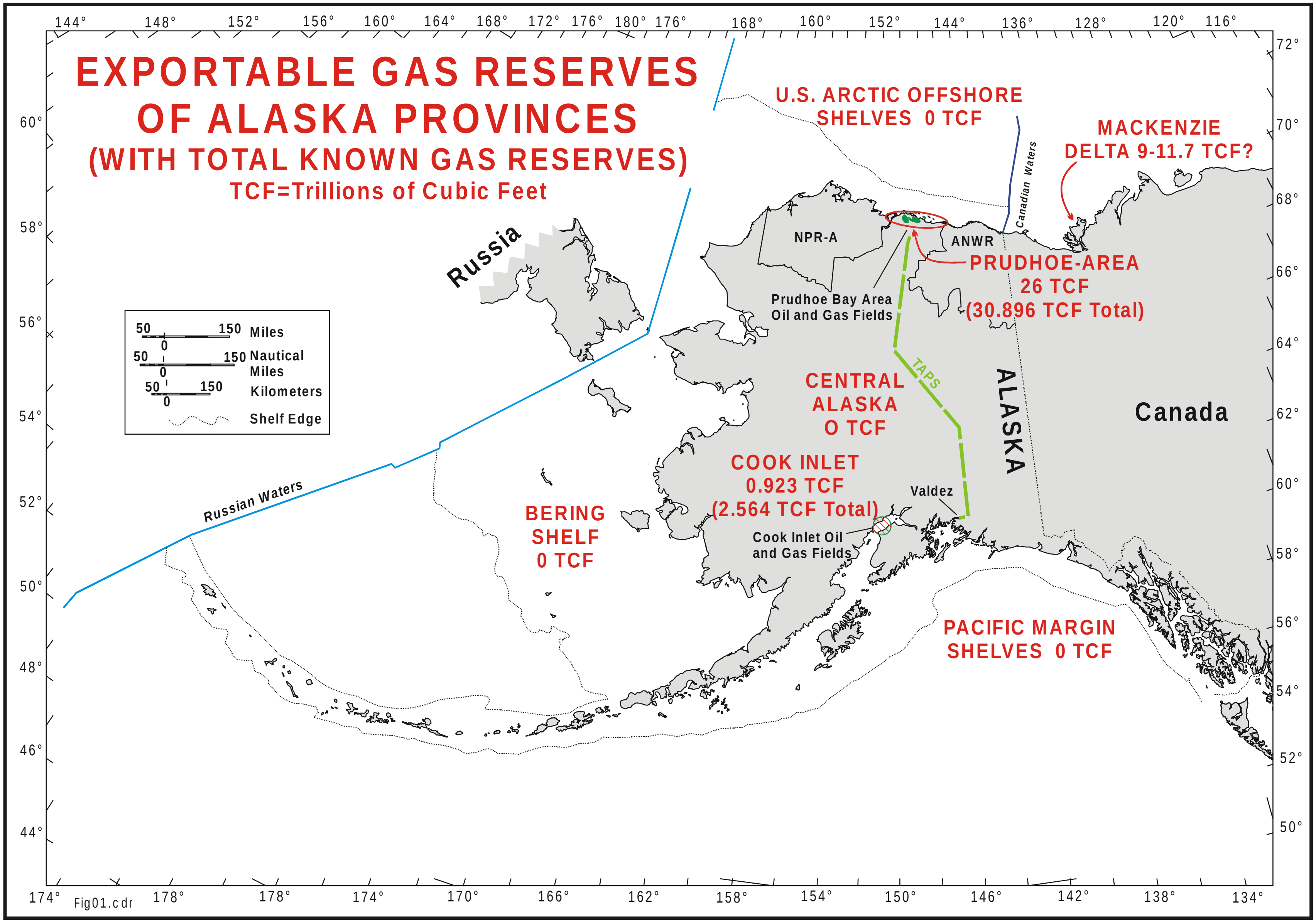

Figure 1: Potentially exportable known gas reserves of Alaska and Alaska Federal offshore, as of 2000. Total known gas reserves, some destined for local use, are shown in parens. Prudhoe-area exportable gas reserves (26 tcf) are presently stranded. Cook Inlet exportable gas reserves (0.923 tcf) are being 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).

ARCTIC ALASKA OIL AND GAS FIELDS AND OFFSHORE WELLS

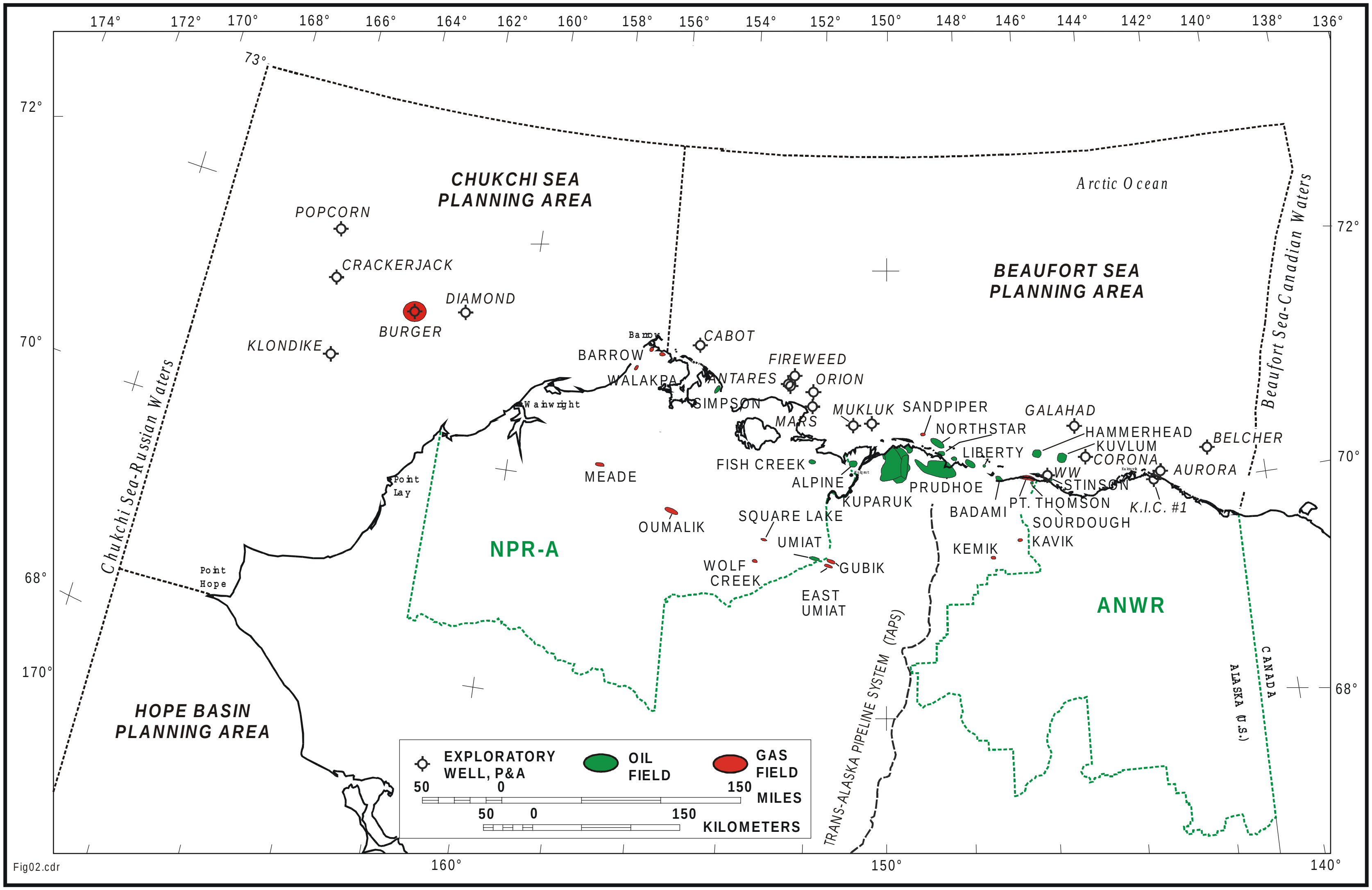

Figure 2: Oil and gas fields, offshore exploration wells, and oil pipeline system (TAPS) for Arctic Alaska.

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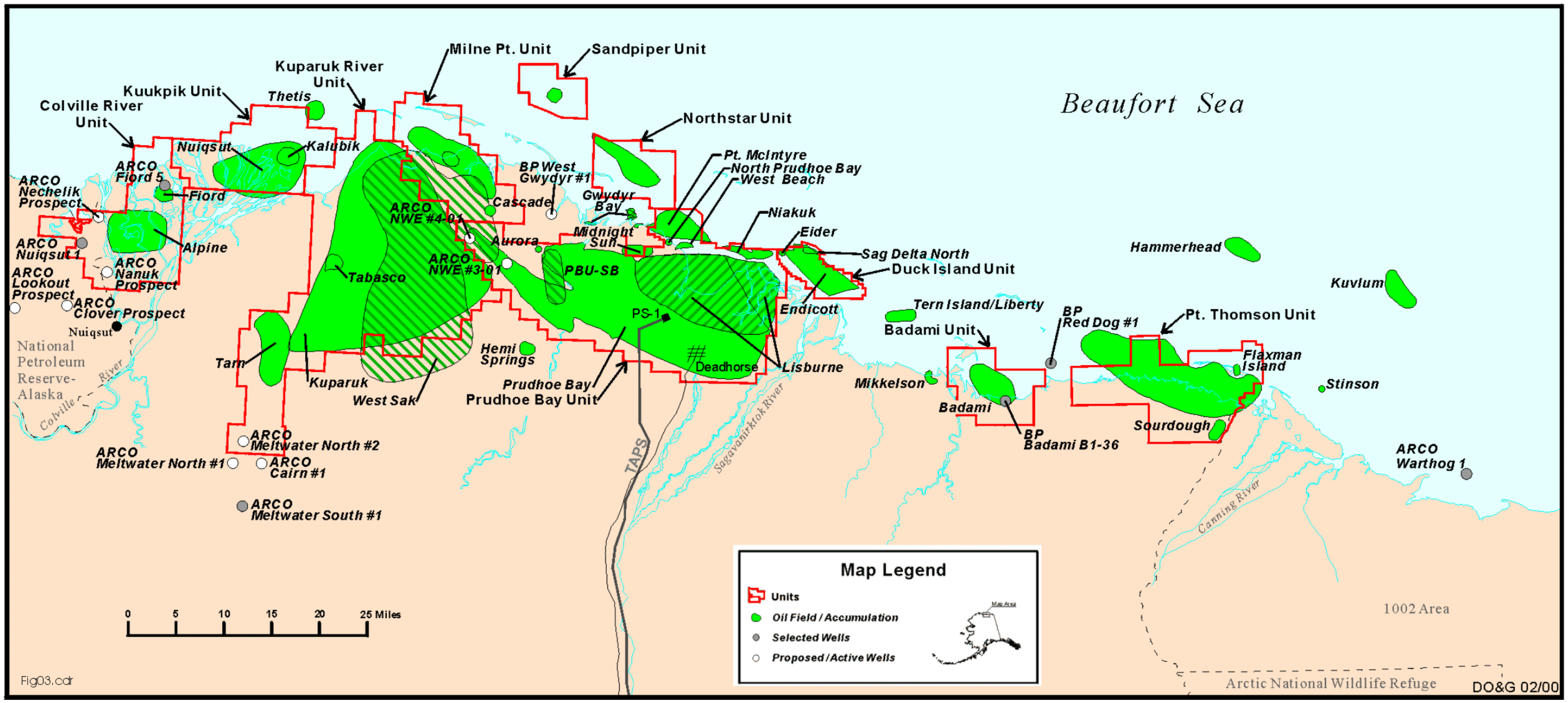


Figure 3: Major oil and gas fields, production infrastructure, and current activity in the Prudhoe Bay area as of December 2000. Map adapted from State of Alaska, Department of Natural Resources, Division of Oil and Gas, web site posting at *http://www.dnr.state.ak.us/oil.*

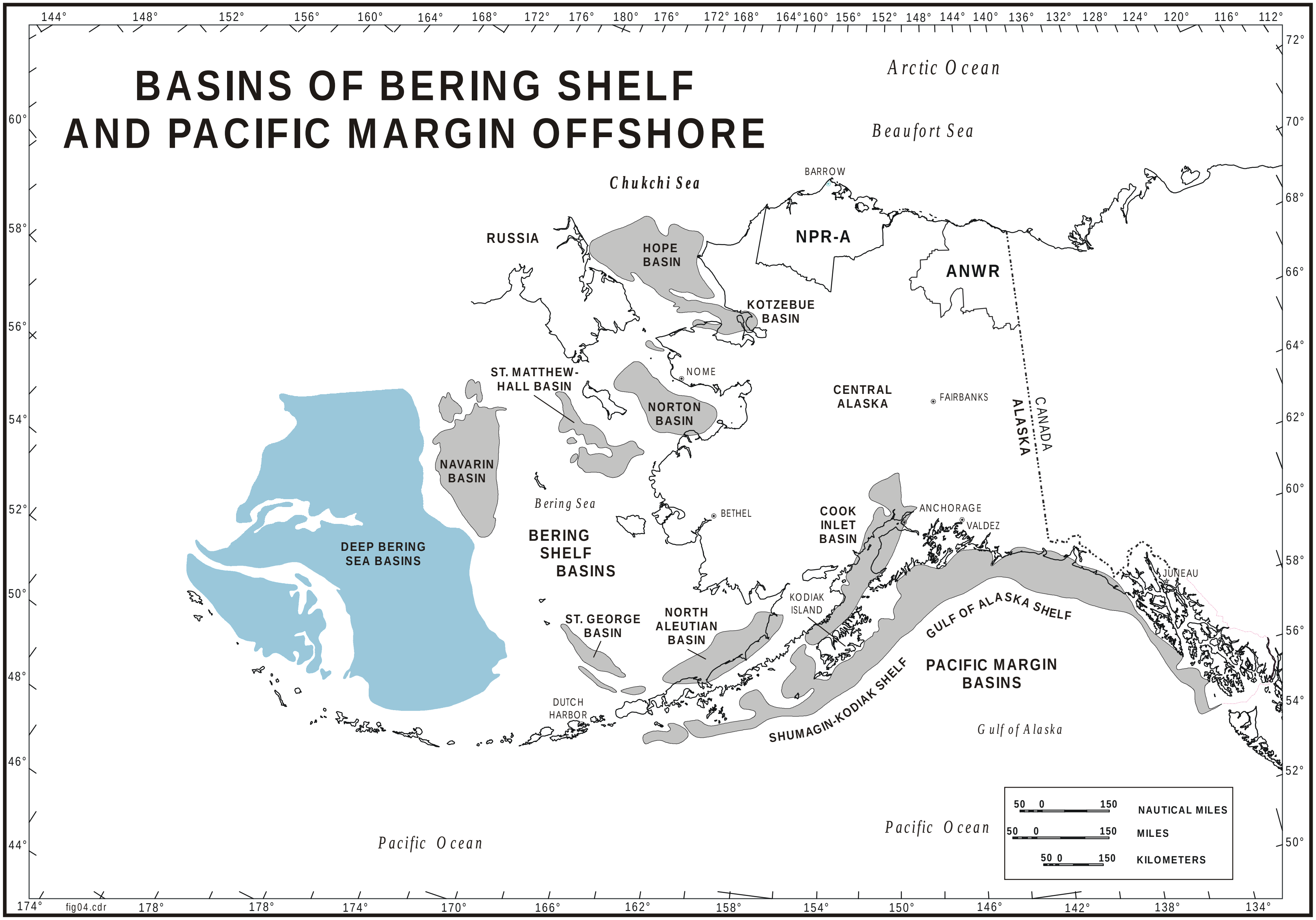


Figure 4: Hope basin, basins of the Bering shelf, Cook Inlet, and the Pacific margin offshore.

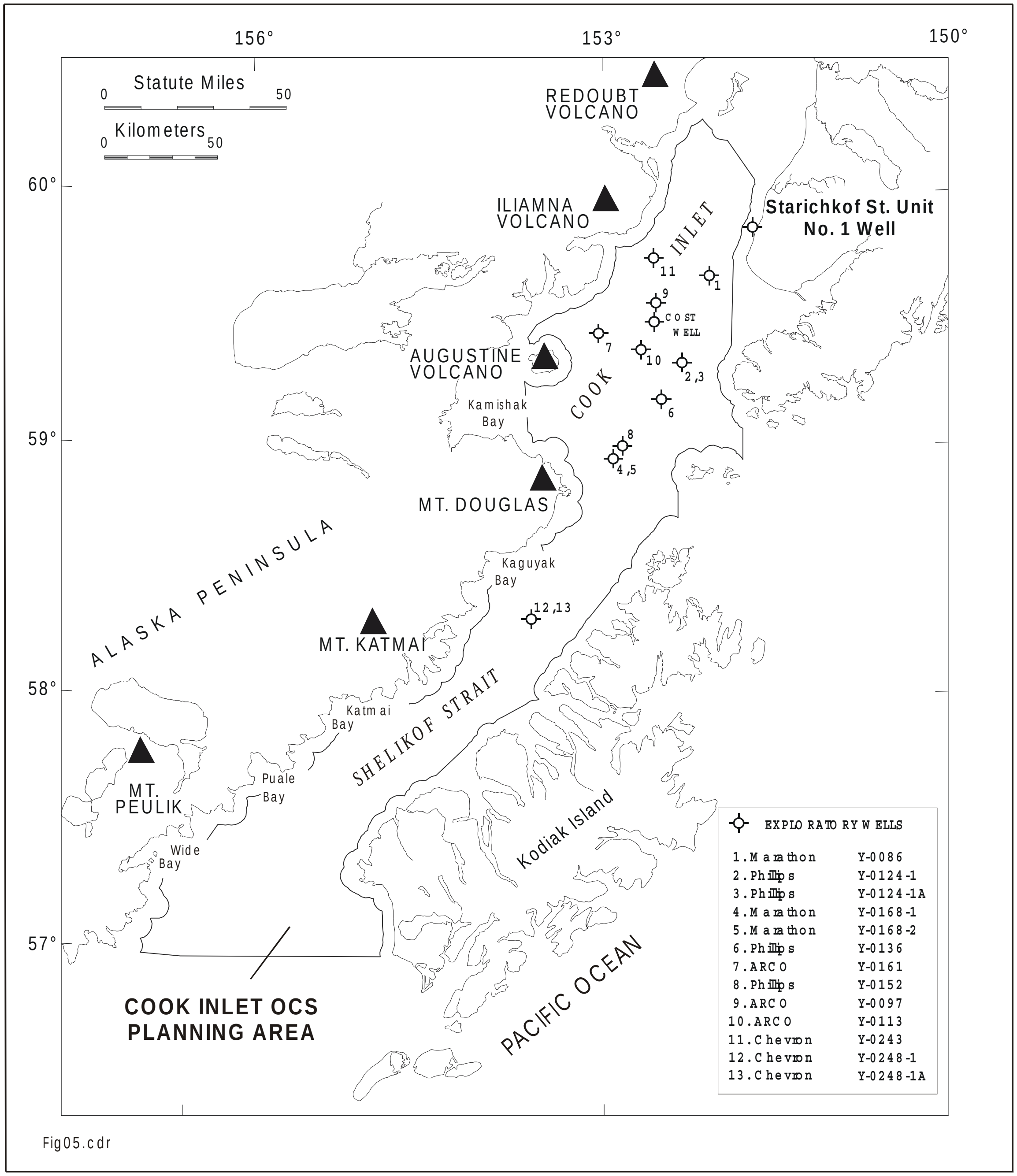


Figure 5: Exploratory and stratigraphic test ("COST") wells of the Cook Inlet Federal OCS Planning Area. The Starichkof St. Unit 1 well in State of Alaska waters near Ninilchik tested gas, suggesting gas potential for some nearby areas of Federal OCS waters.

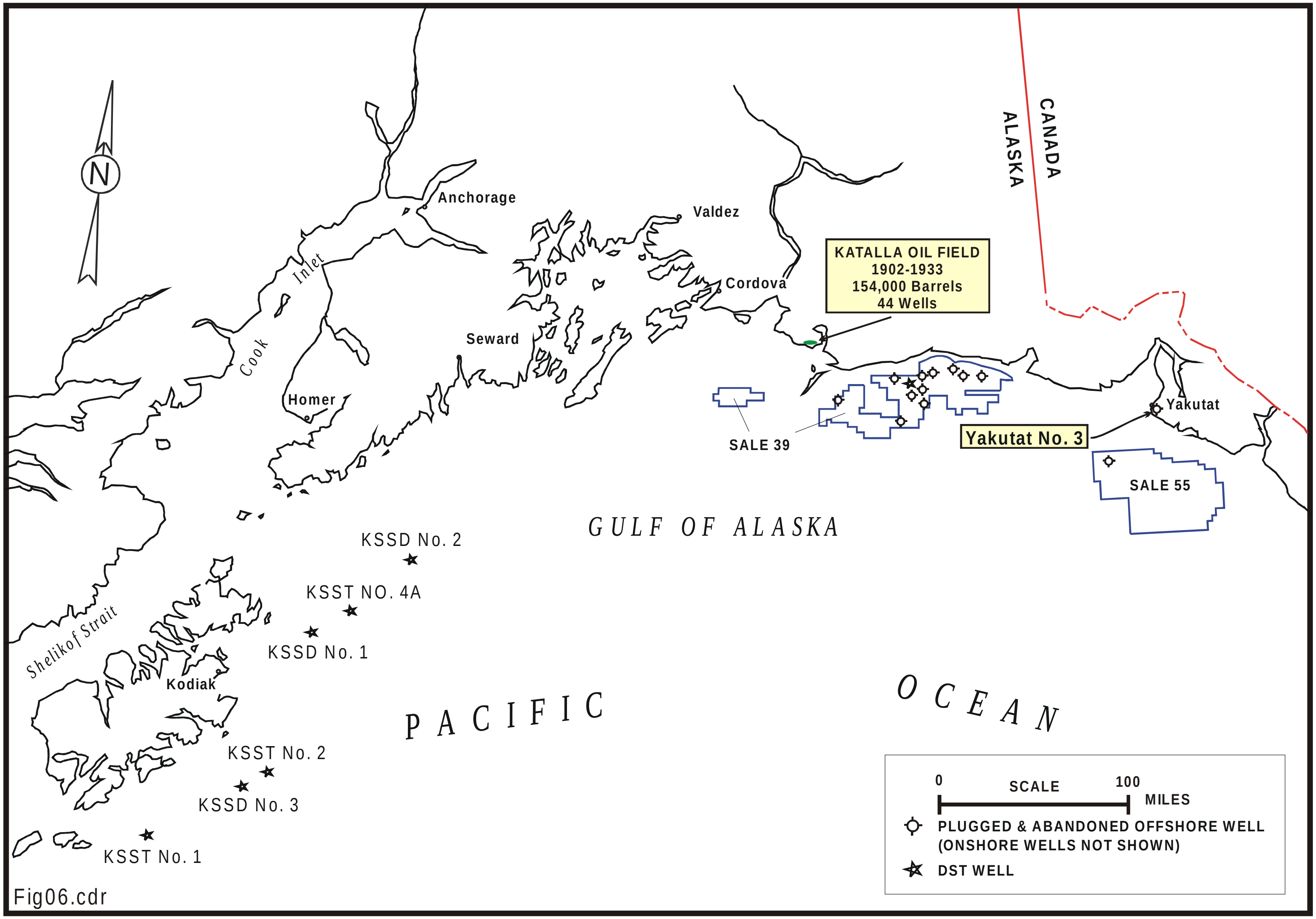


Figure 6: Exploratory wells and stratigraphic test (DST) wells of Kodiak and Gulf of Alaska shelves (Federal offshore only), areas of Federal offshore lease sales in Gulf of Alaska, and locations of Katalla oil field and Yakutat No. 3 well.

Cook Inlet Oil and Gas Activity
September 1999

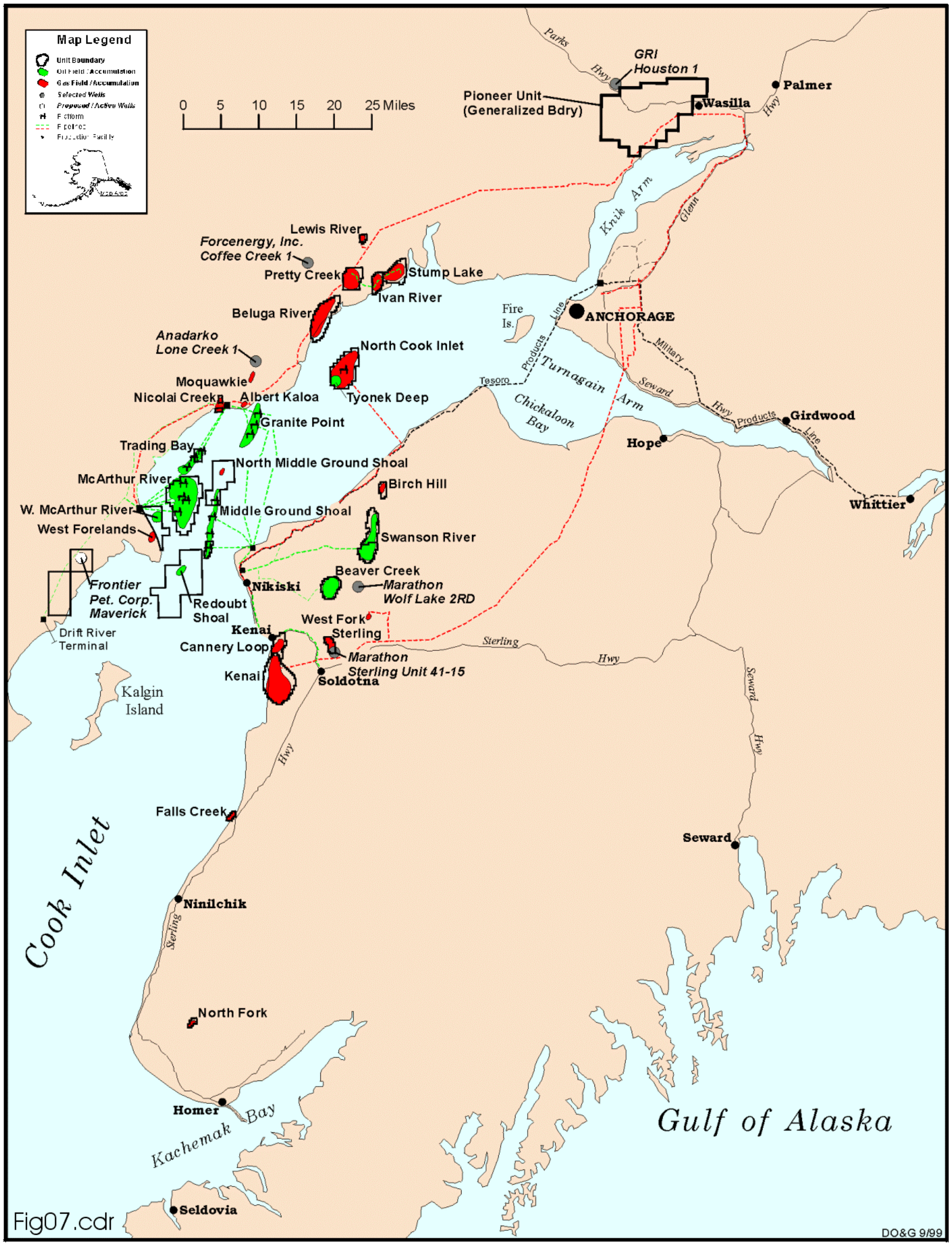


Figure 7: Oil and gas fields, production infrastructure, and current activity in Cook Inlet (State of Alaska) as of September 1999. Map adapted from State of Alaska, Dept. of Natural Resources, Division of Oil and Gas, web site posting at *http://www.dnr.state.ak.us/oil.*

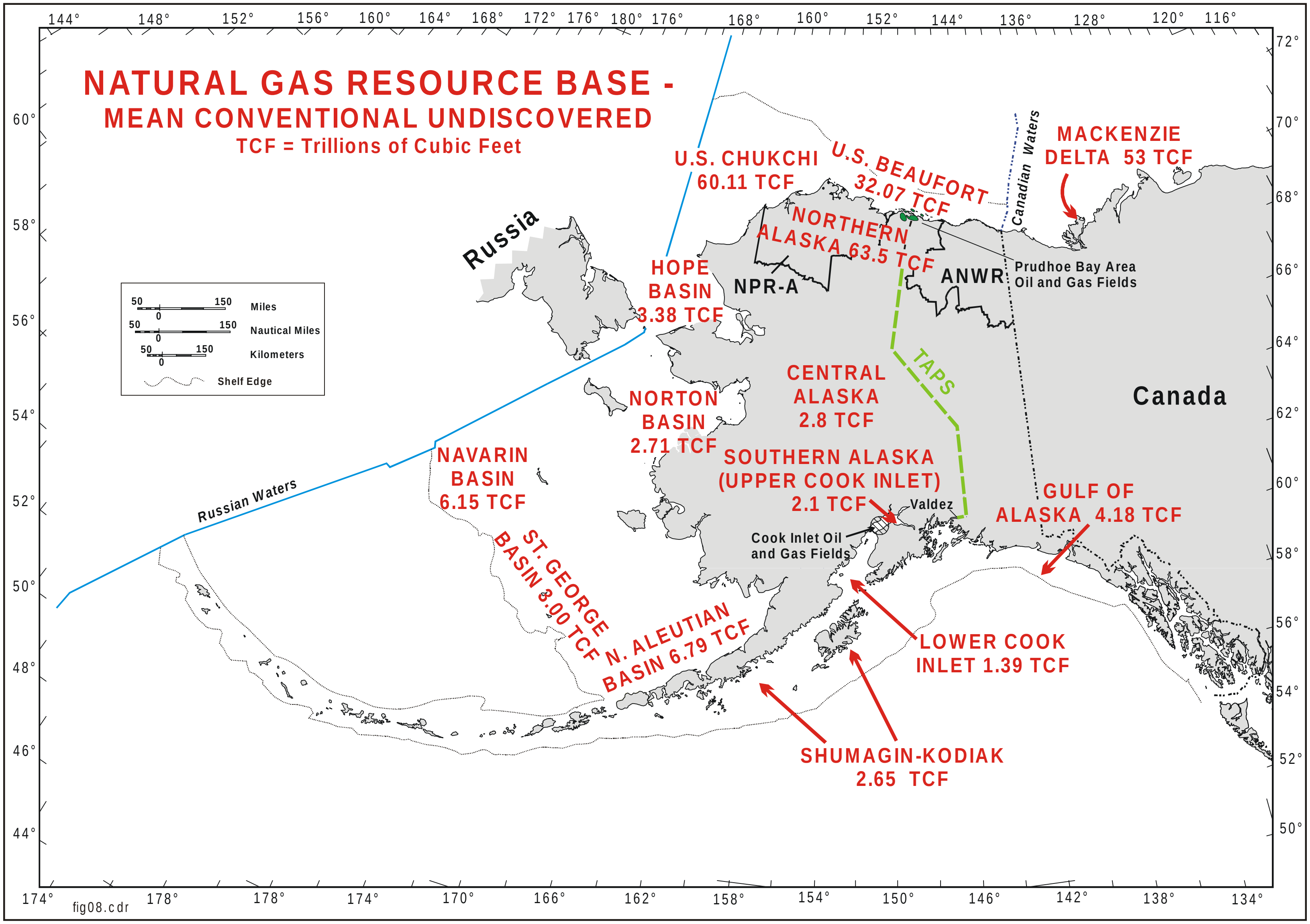


Figure 8: Conventional natural gas resource base (mean, risked, undiscovered, conventionally recoverable gas; excludes coal bed gas and gas hydrates) for Alaska provinces as of 2000 (USGS, 1995; Sherwood and others, 1996; Craig, 2000). Total Alaska (onshore and offshore) undiscovered conventional gas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

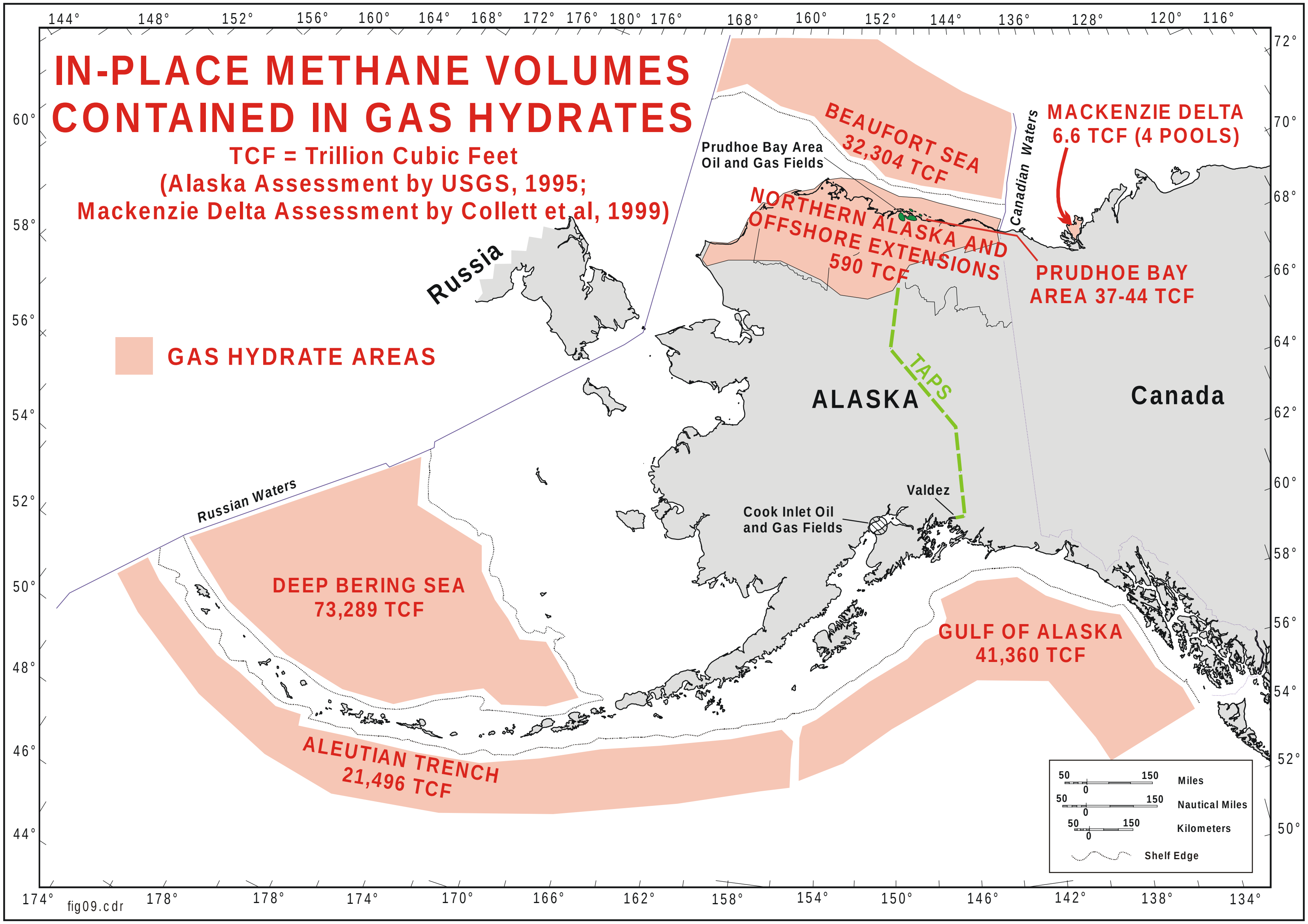


Figure 9: Gas hydrate methane resources (in place volumes) for Alaska and Alaska offshore. Resource estimates from USGS (1995, *Hydrates*, pl. 21), Collett and Kuuskraa (1998, tbl. 1), and Collett (1998, p. 4). Total for Alaska = 169,039 tcf. Mackenzie delta gas hydrate resources for 4 accumulations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

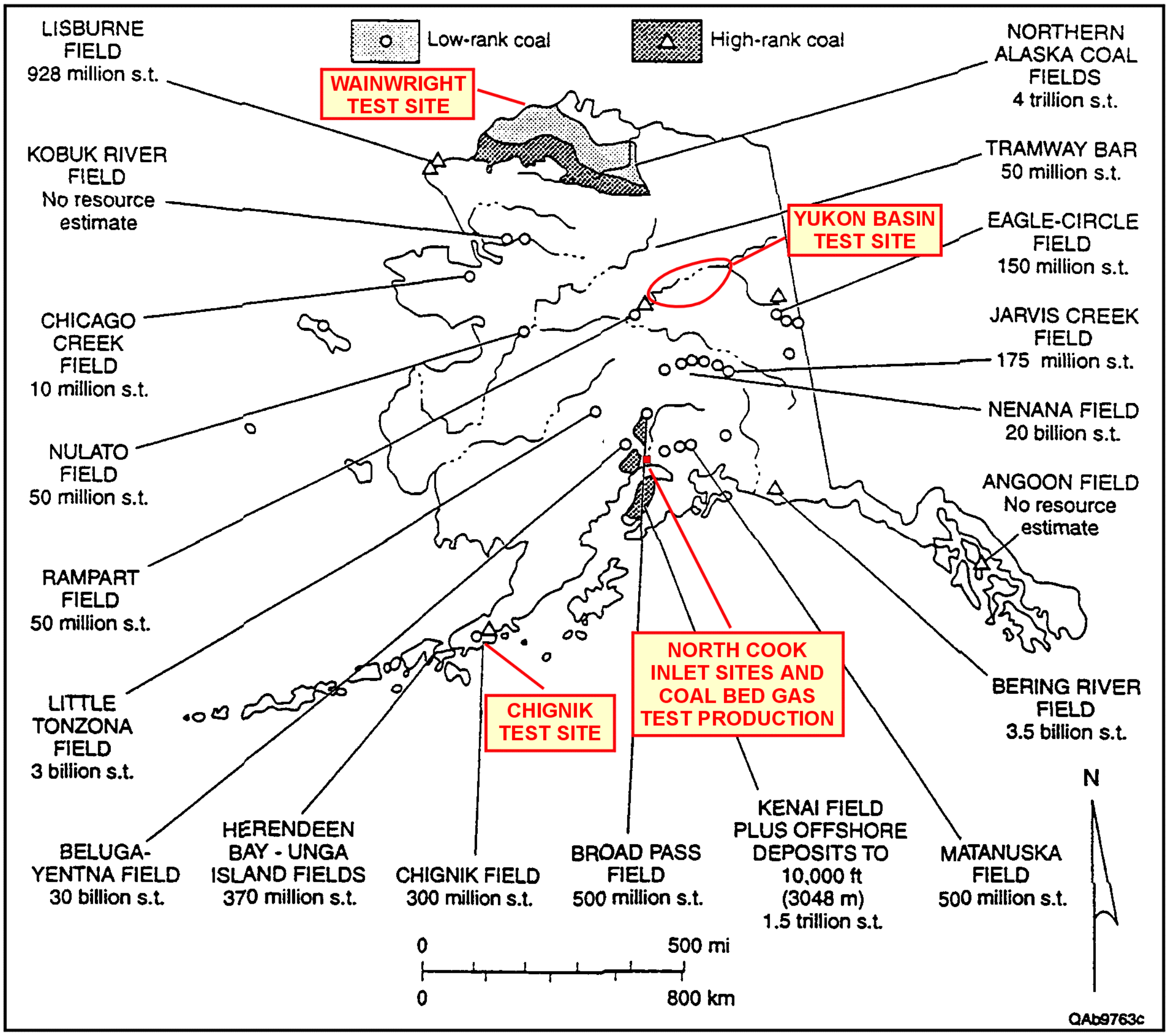


Figure 10: Major coal fields and field resources (s.t. = short tons; 1 s.t. = 0.9078 metric tons). Total tonnage for Alaska is 5.56 trillion tons. Smith (1995) estimated that total coal bed methane resources of Alaska might reach 1,000 tcf. The Potential Gas Committee (PGC, 1999, tbl. 53) estimated the 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).

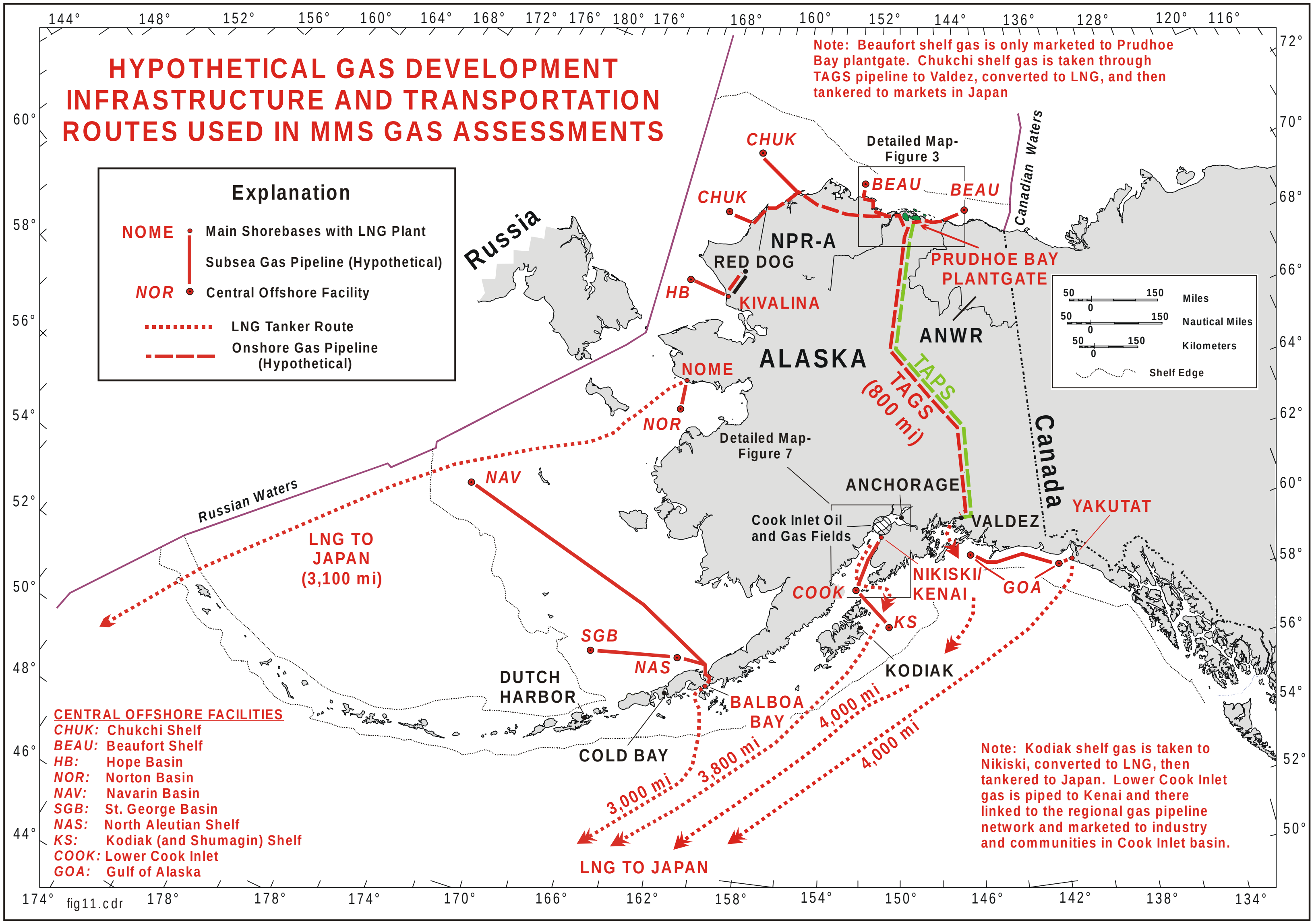


Figure 11: Hypothetical gas development infrastructures used for economic modeling of Alaska Federal offshore in 1995 and 2000 MMS assessments of the Alaska offshore. Central offshore facilities are located near areas of highest potential at hypothetical sites representative of average pipeline distances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

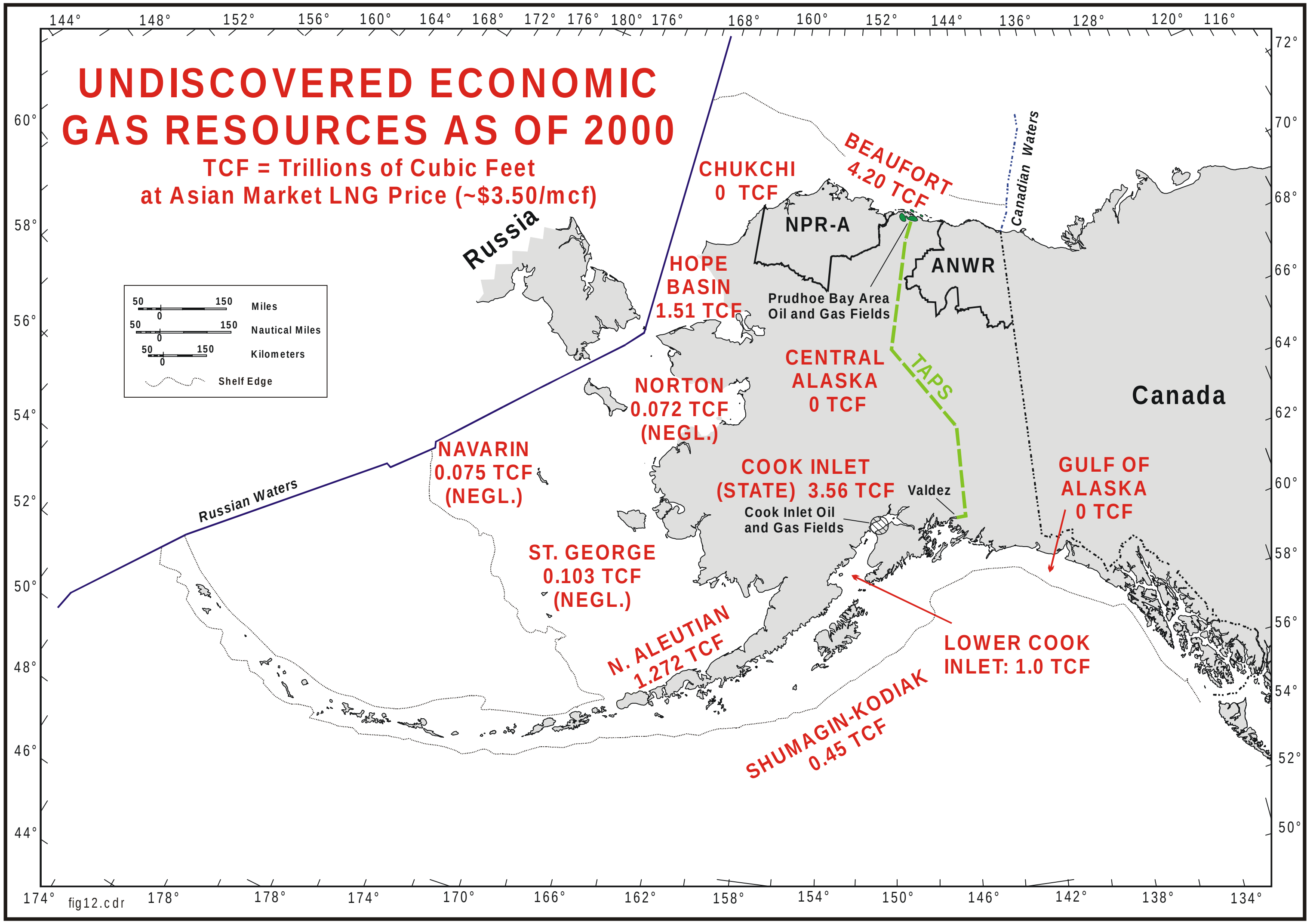


Figure 12: Undiscovered, economically-recoverable conventional natural gas resources of Alaska and Alaska Federal offshore, as of 2000, at gas prices comparable to LNG marketed to Japan ($3.34 to $3.52/mcf). Natural gas in Arctic Alaska (offshore and onshore) is presently stranded by the absence of a 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).

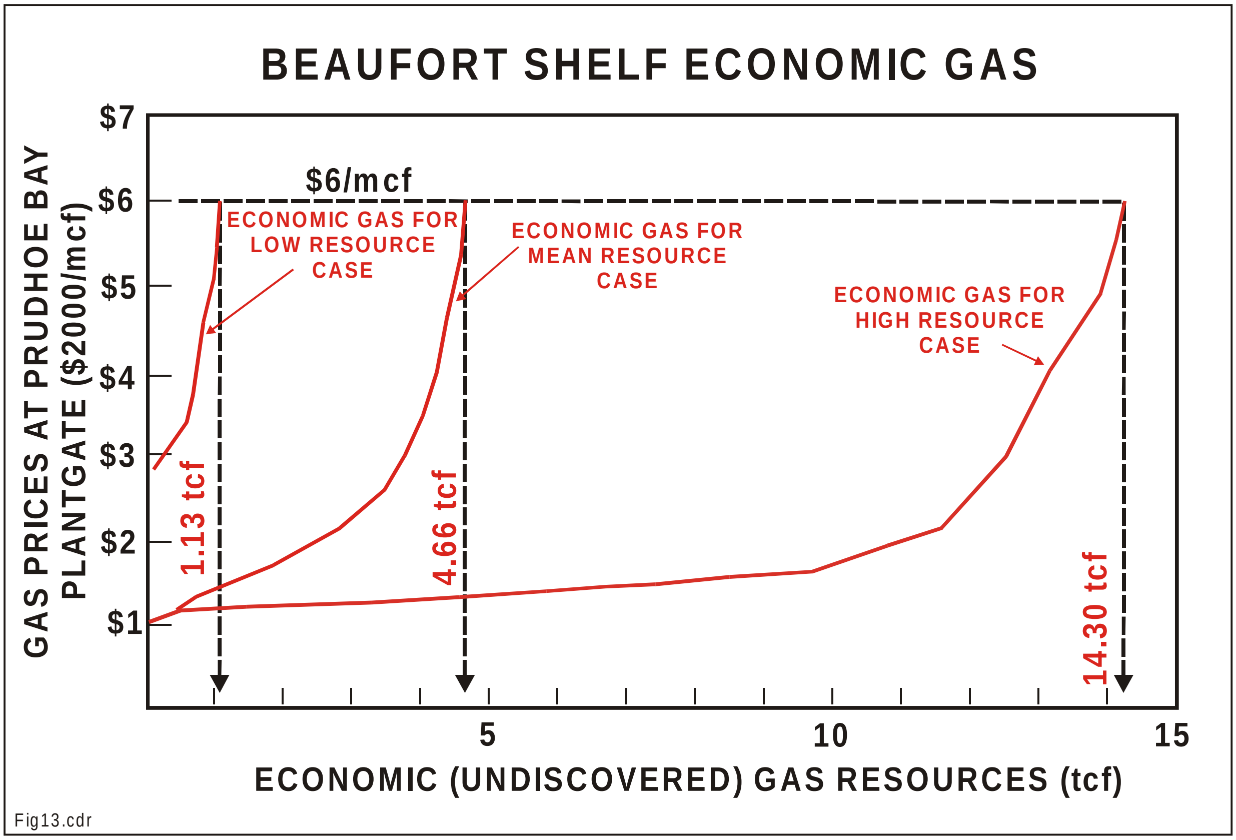


Figure 13: Price-supply curves for undiscovered economically-recoverable gas in Beaufort shelf, delivered to Prudhoe Bay plantgate. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 1.13, 4.66, and 14.30 tcf of gas could be economically recoverable in the low (F95, 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).

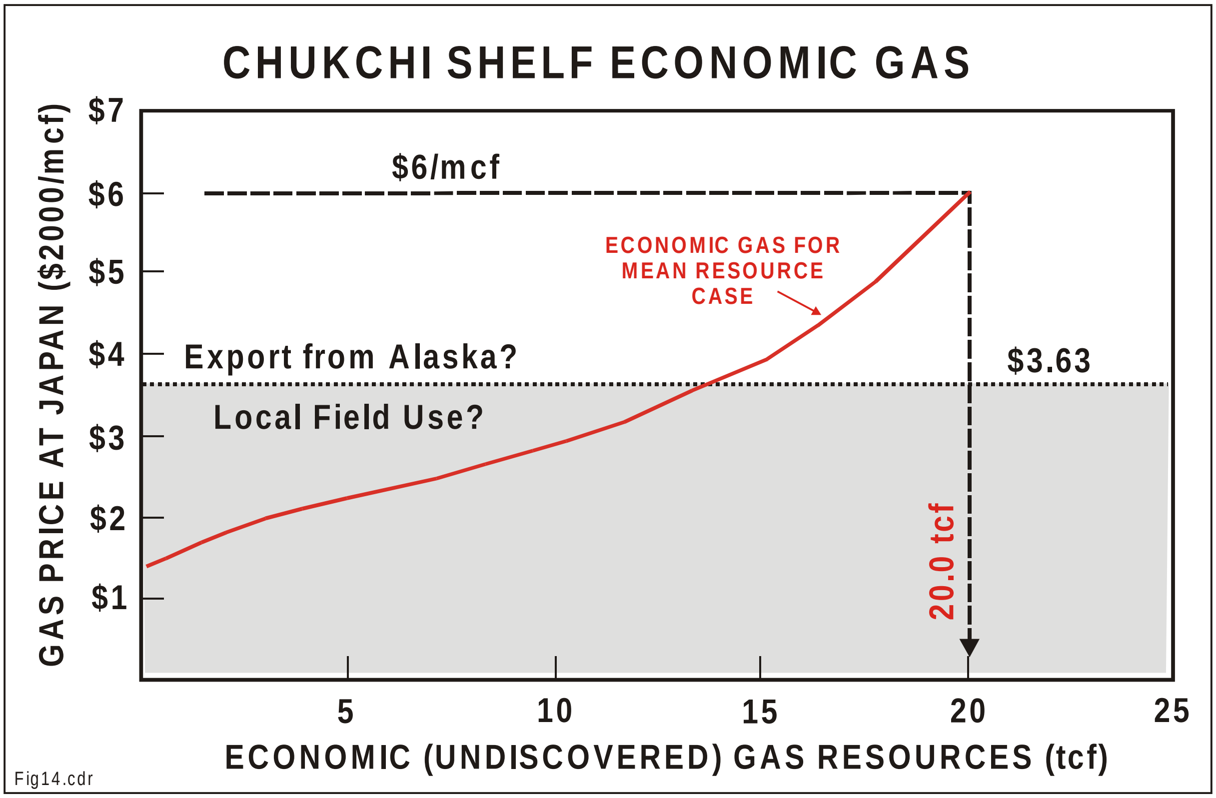


Figure 14: Price-supply curves for undiscovered economically recoverable gas in Chukchi shelf and marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 20.0 tcf of gas could be economically recoverable from Chukchi shelf in the mean resource case, 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).

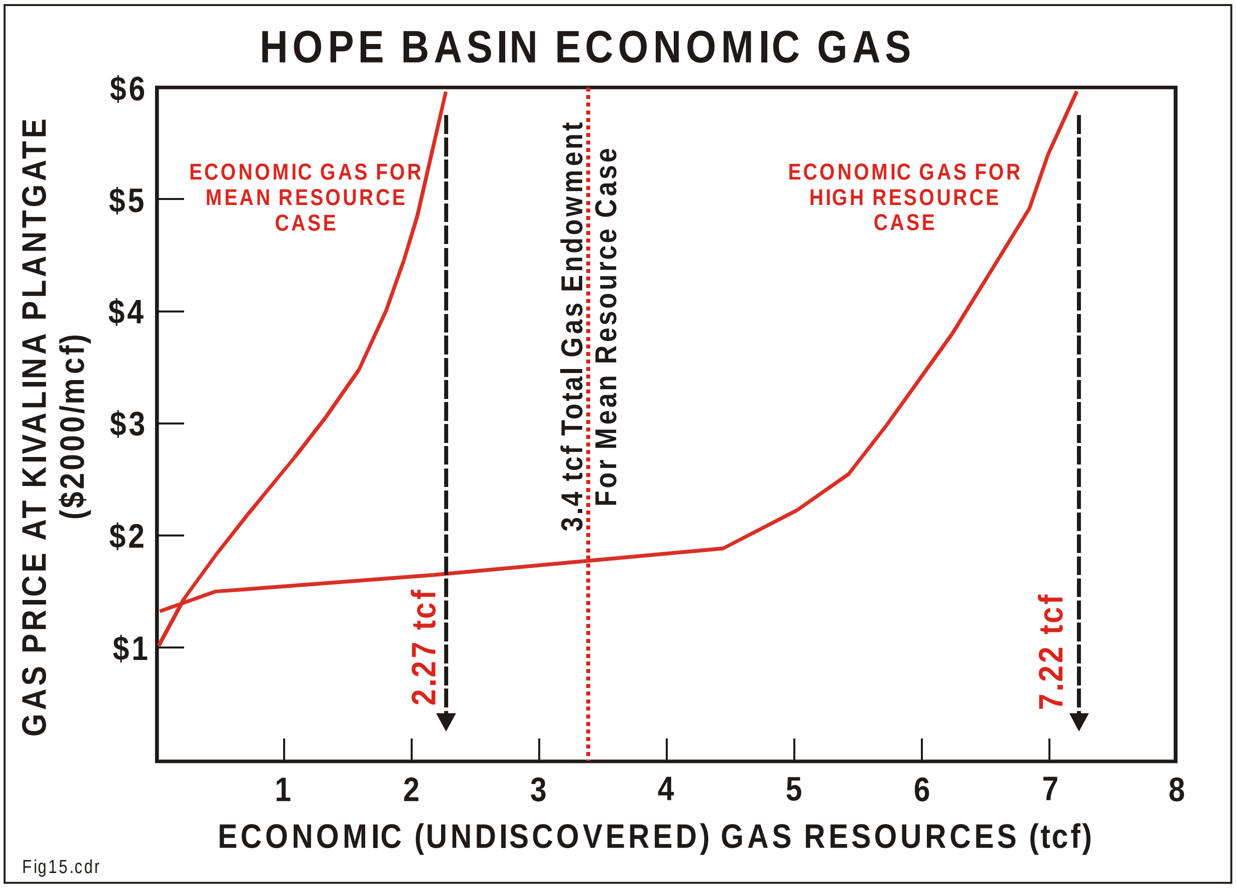


Figure 15: Price-supply curves for undiscovered economically recoverable gas in Hope basin if marketed to a hypothetical industrial complex at the port of Kivalina, Alaska, where Red Dog mine ore is presently stockpiled for shipping to smelters outside of Alaska. At a hypothetical high price of $6/mcf 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).

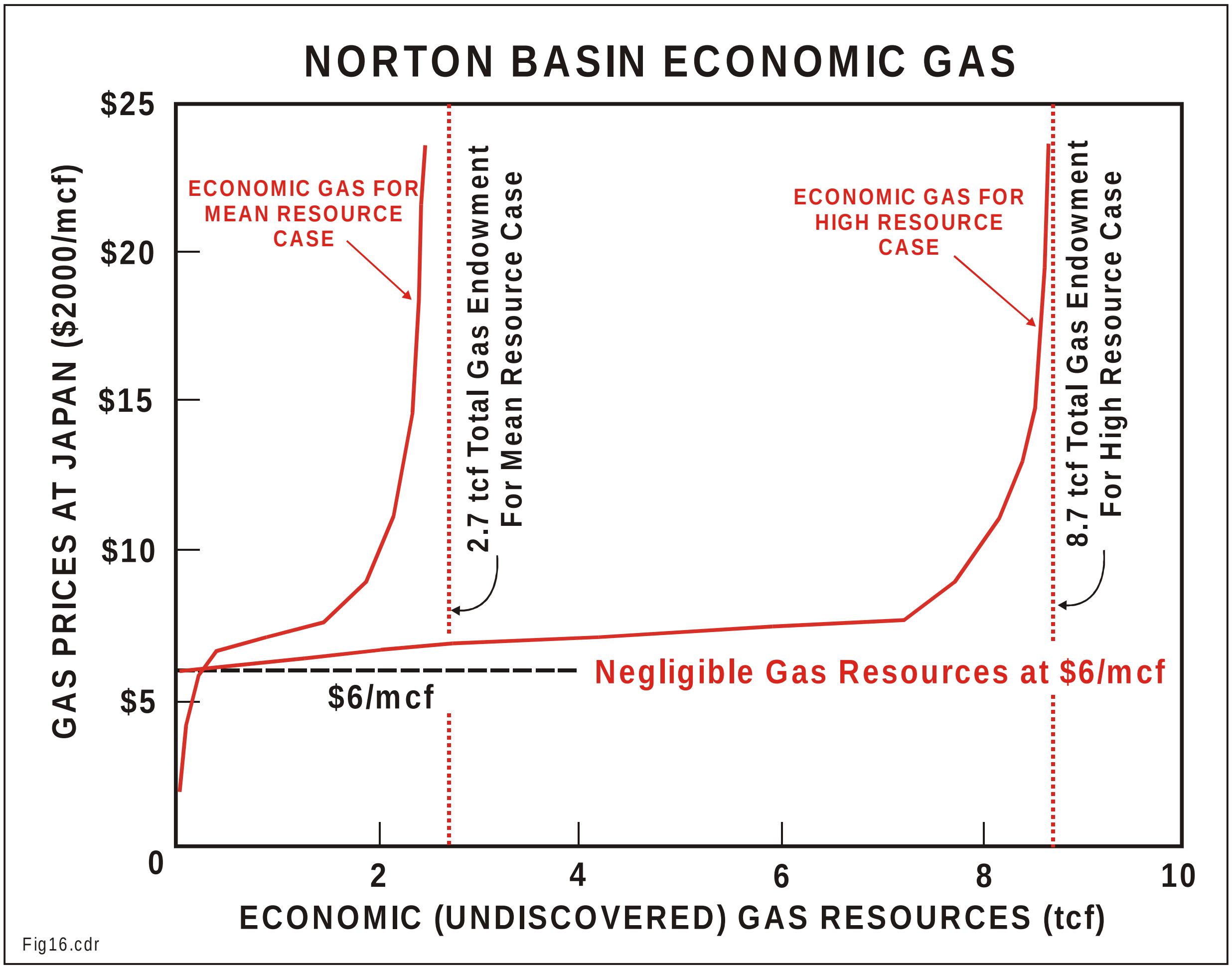


Figure 16: Price-supply curves for undiscovered economically-recoverable gas in Norton basin if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), only negligible quantities of gas could be economically recovered from Norton basin in either the mean resource 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.

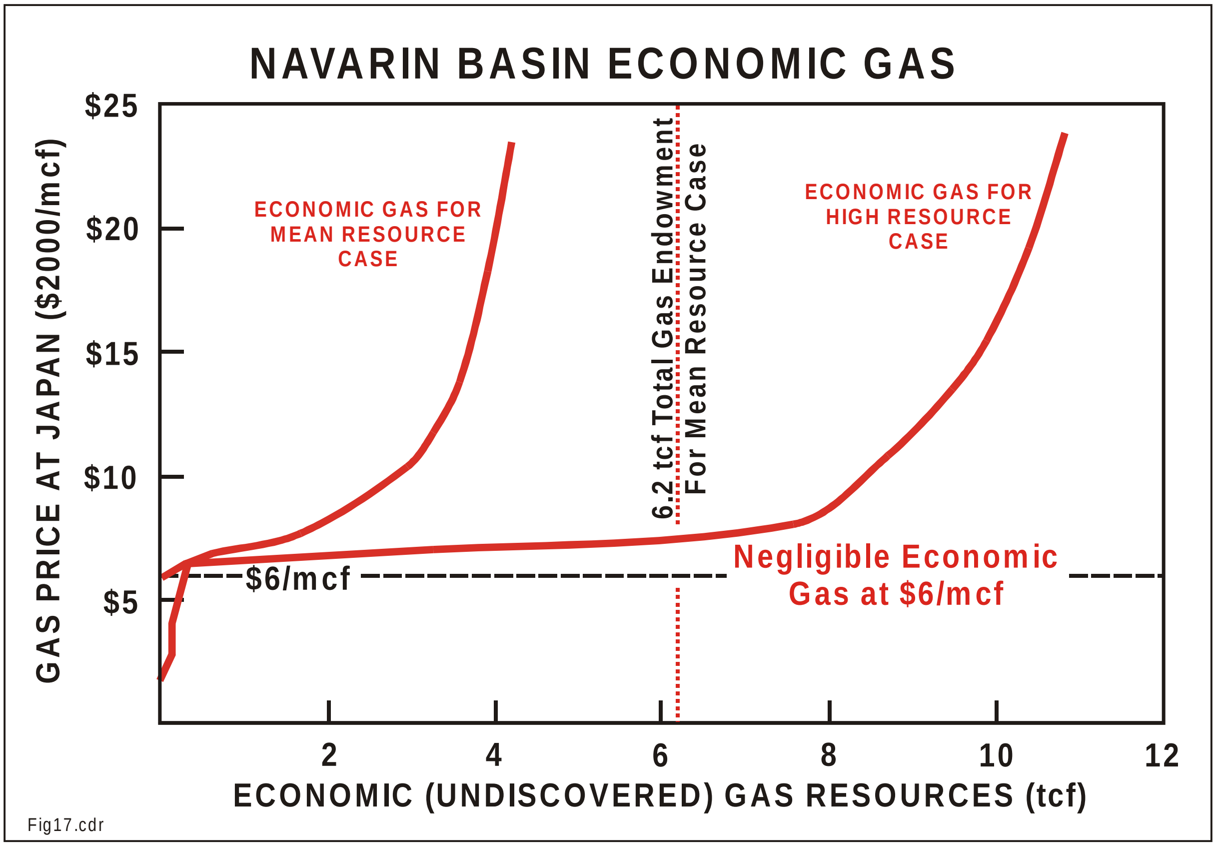


Figure 17: Price-supply curves for undiscovered economically recoverable gas in Navarin basin if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), no gas resources could be economically recoverable at either the mean or the high (F05, or 5% probability of 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.

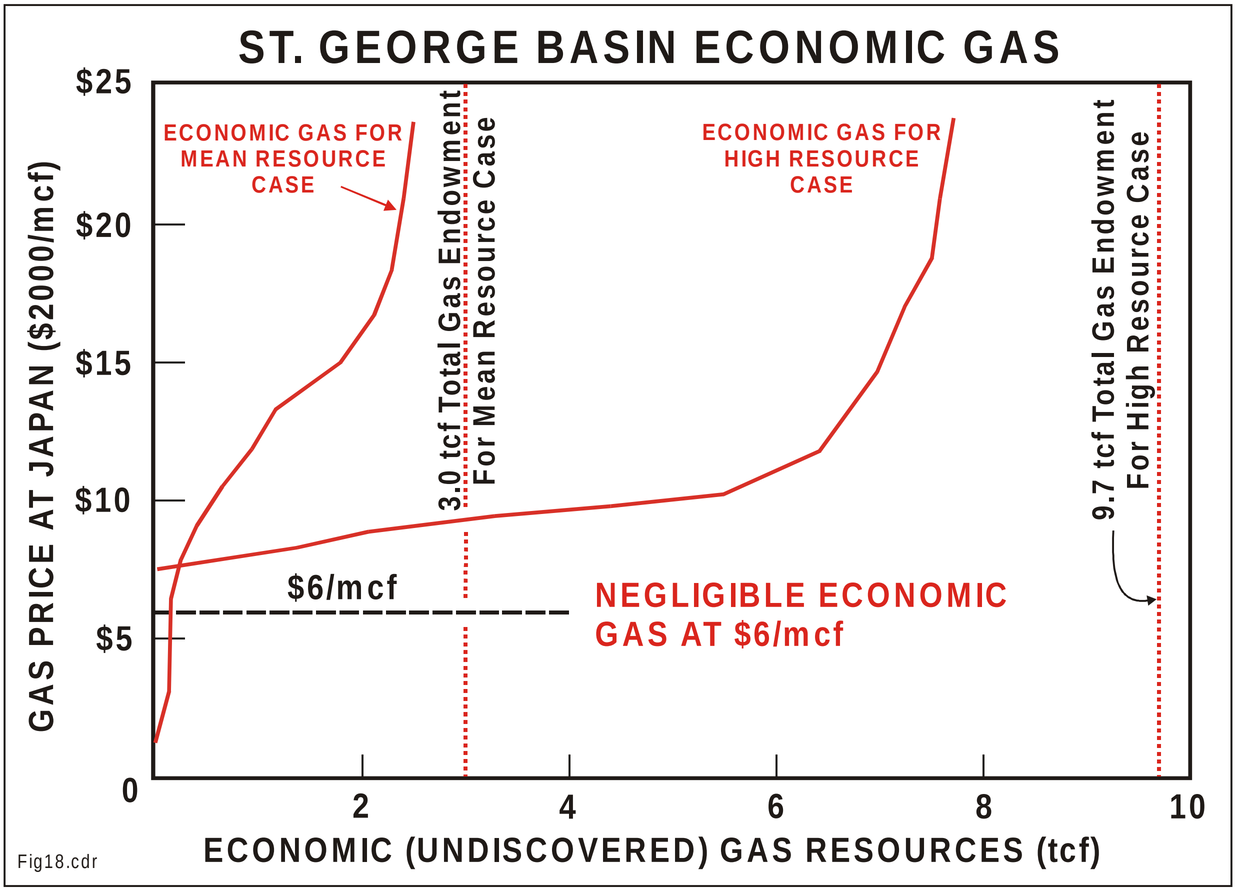


Figure 18: Price-supply curves for undiscovered economically recoverable gas in St. George basin if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), only negligible quantities of gas are economically recoverable from St. George basin in either the mean 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.

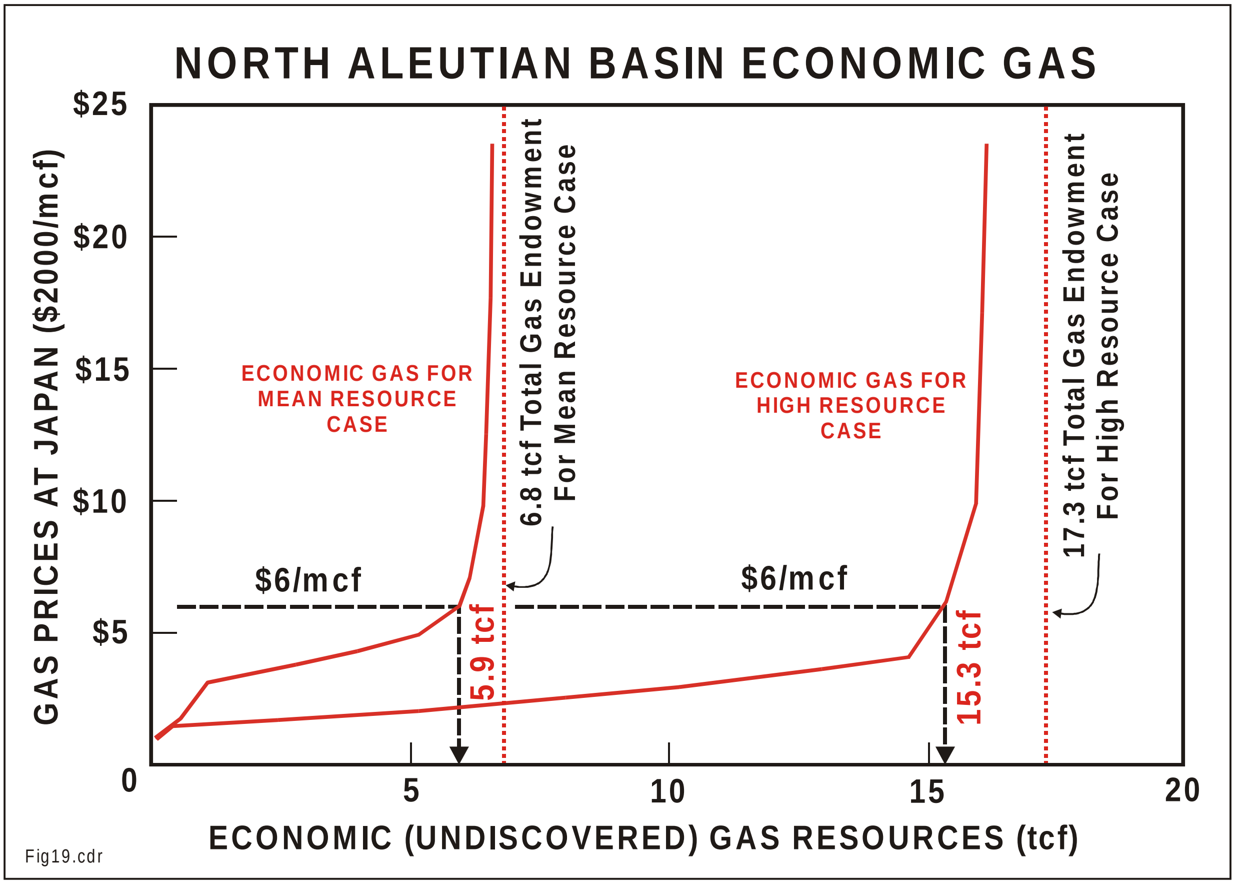


Figure 19: Price-supply curves for undiscovered economically recoverable gas in North Aleutian shelf if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 5.9 tcf of gas could be economically recoverable from North Aleutian shelf in the mean 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.

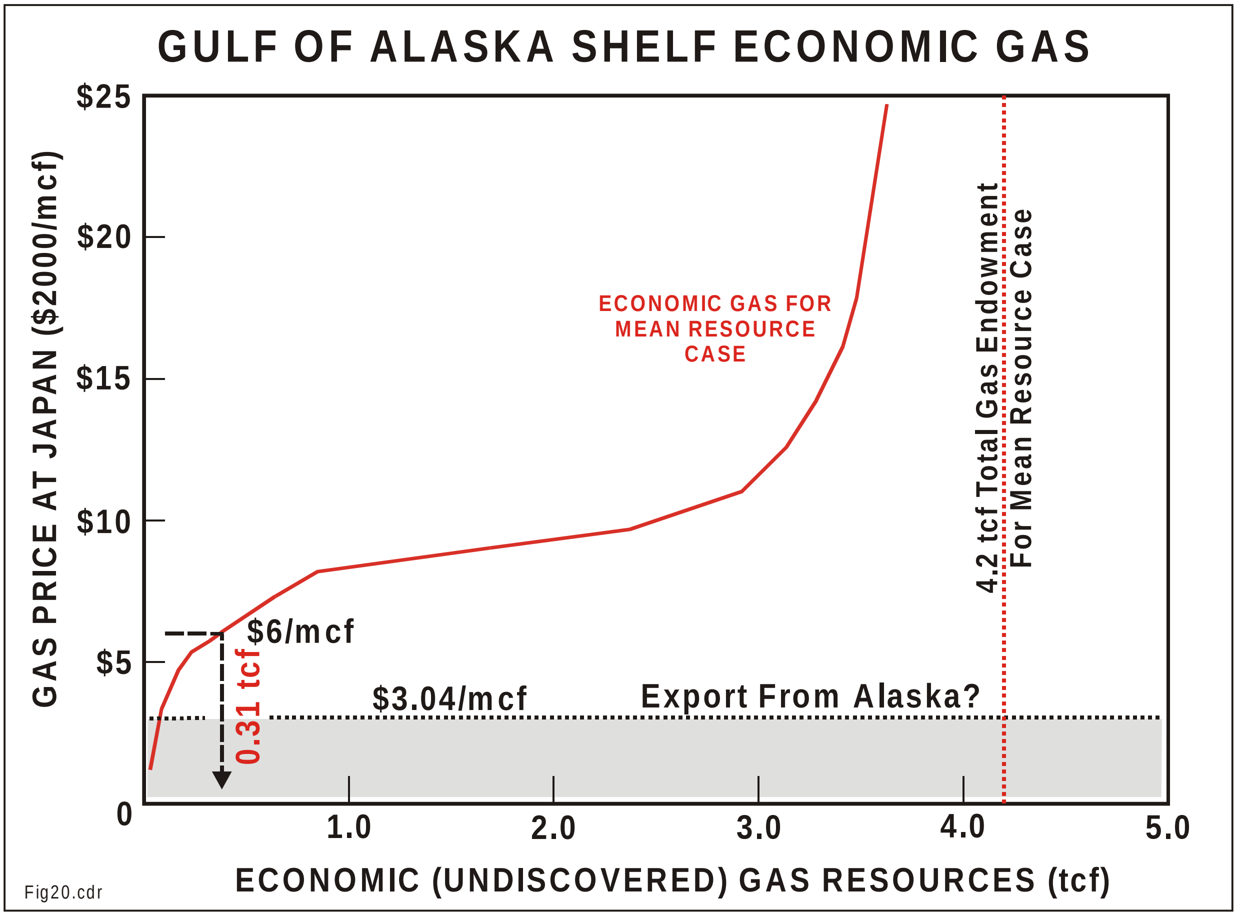


Figure 20: Price-supply curves for undiscovered economically recoverable gas in Gulf of Alaska shelf if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 0.31 tcf of gas could be economically recoverable from the Gulf of Alaska shelf in the 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.

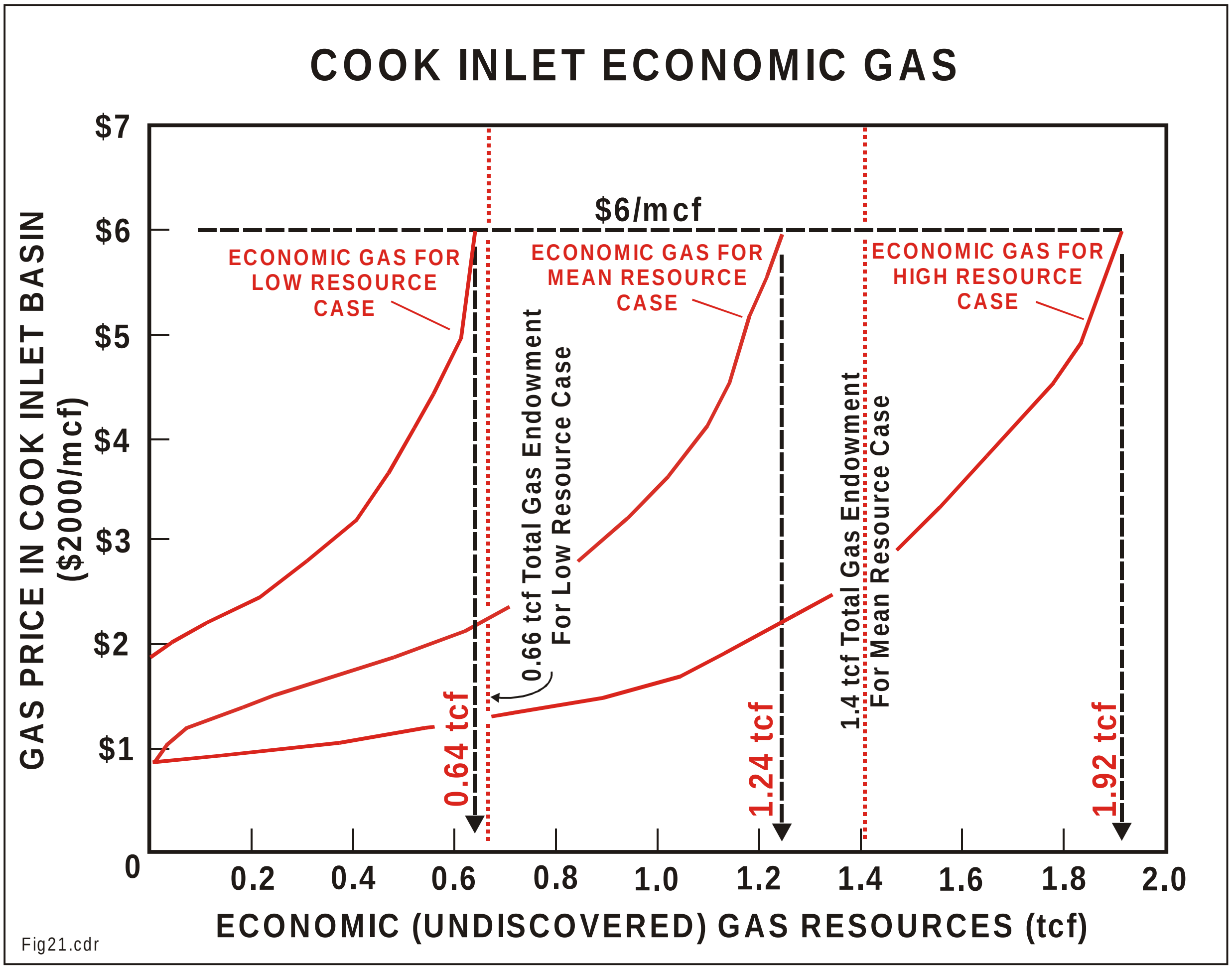


Figure 21: Price-supply curves for undiscovered economically recoverable gas in Cook Inlet (Federal waters) if delivered to local markets within Cook Inlet basin. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 0.64, 1.24, and 1.92 tcf of gas could be economically 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).

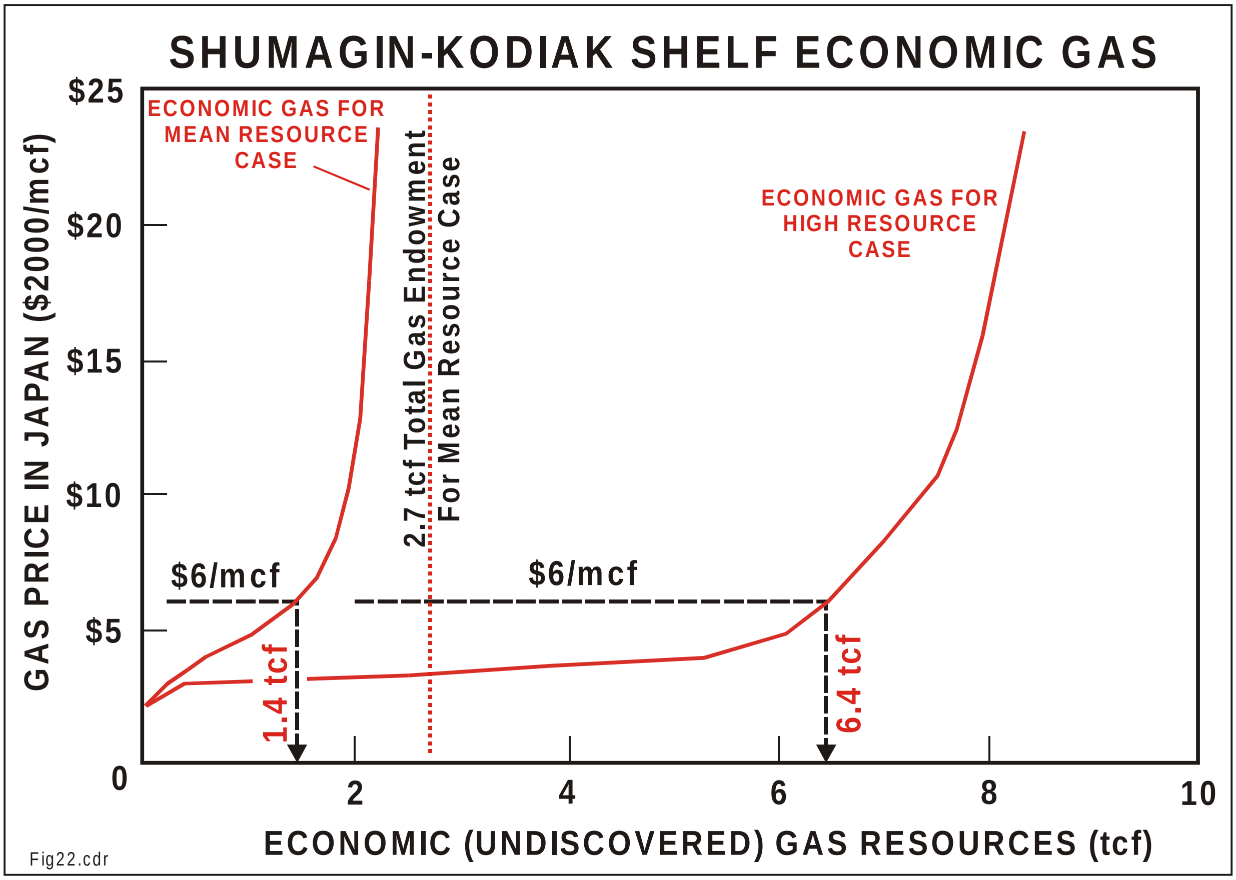


Figure 22: Price-supply curves for undiscovered economically recoverable gas in Shumagin-Kodiak shelf if marketed as LNG to Japan. At a hypothetical high price of $6/mcf in $2000 ($11.05/mcf in $2020), approximately 1.4 tcf of gas could be economically recoverable from Shumagin-Kodiak shelf in the mean 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.

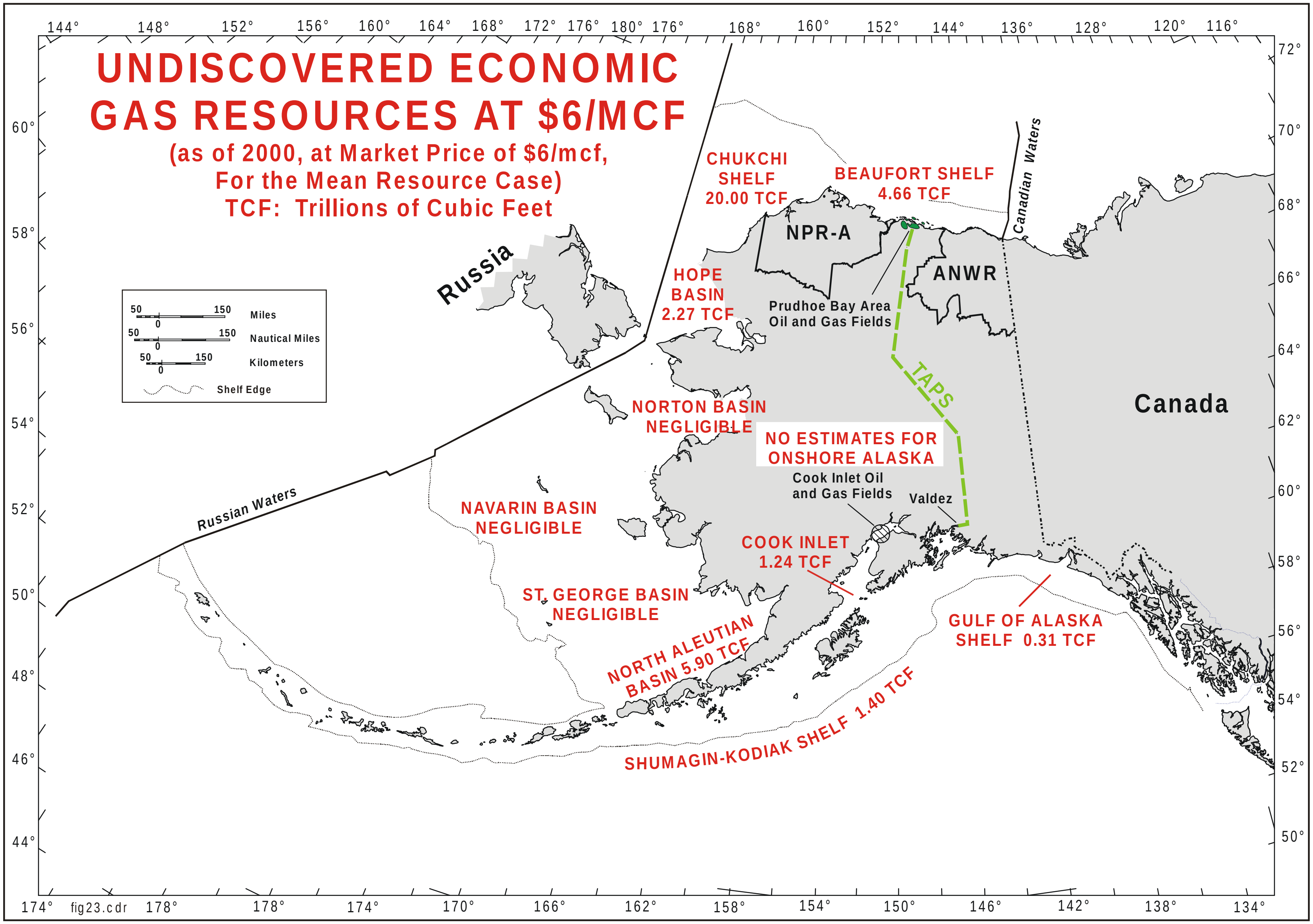


Figure 23: Economic, undiscovered gas resources for Alaska offshore at a price (delivered to various markets) of $6/mcf in $2000 (equivalent to $11.05/mcf in $2020) and at the mean resource case. Offshore economic gas resources at $6/mcf total 35.78 tcf.

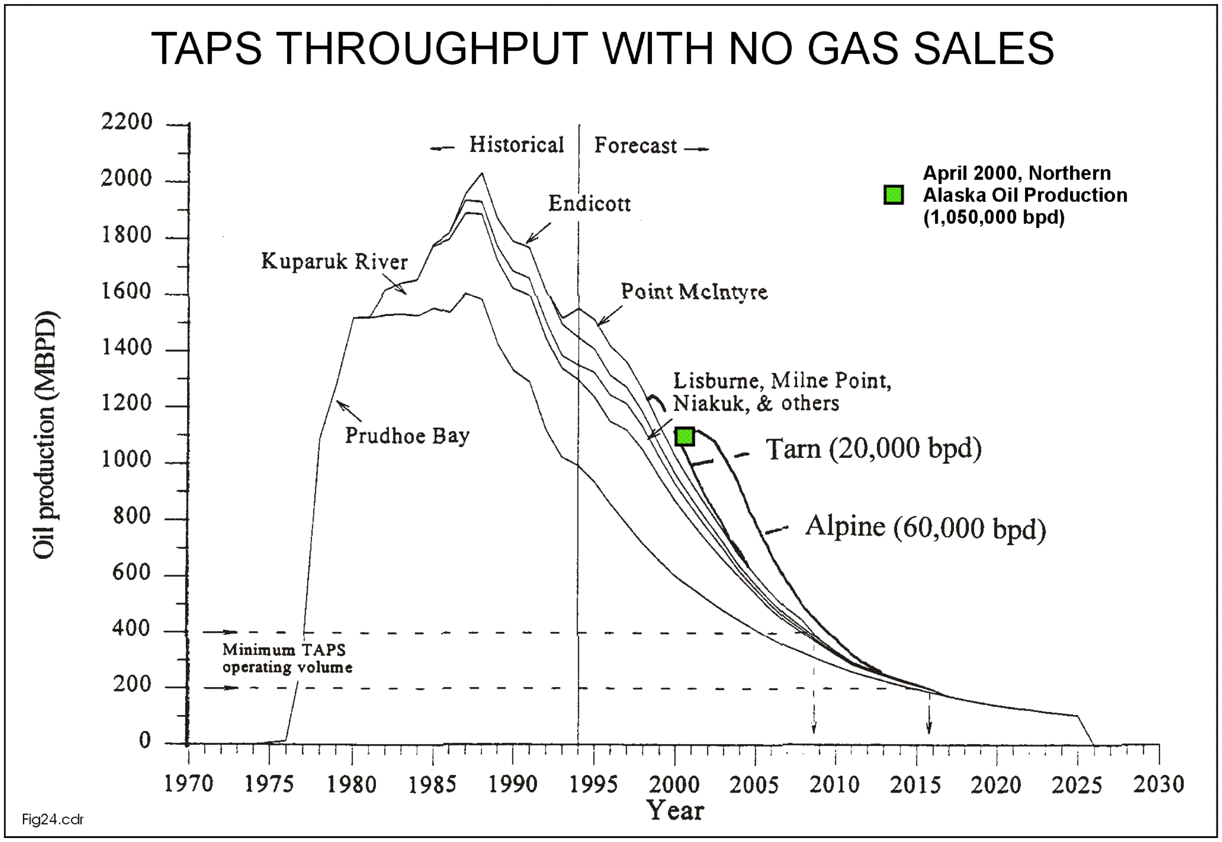


Figure 24: Production decline projections for northern Alaska producing fields in Prudhoe Bay area. Contributions from new fields at Tarn and Alpine have been added as sketches based on estimates for maximum production rates. These new fields, although significant, will not materially prolong the economic 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).

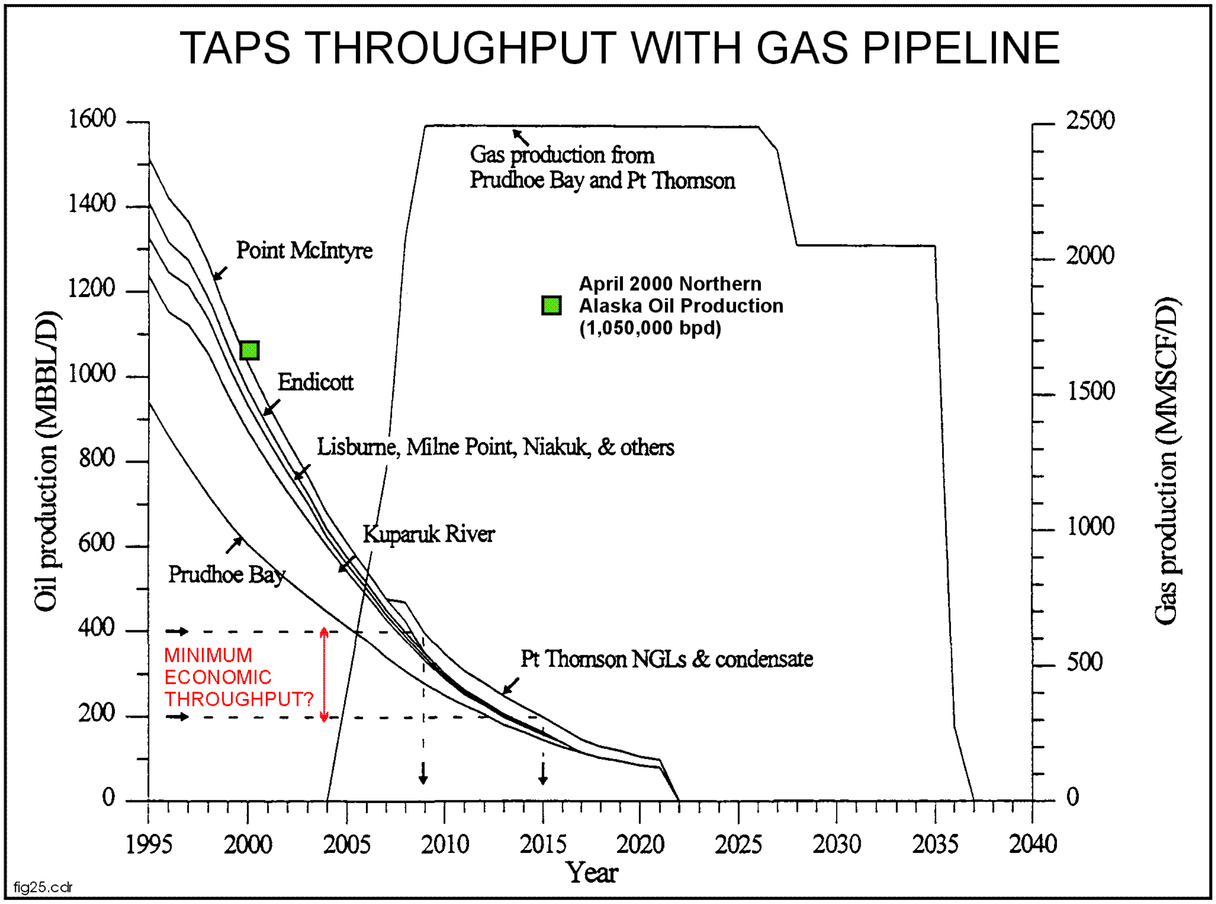


Figure 25: Model for TAPS (oil pipeline) throughput if gas is conveyed through a separate gas pipeline for export from southern Alaska. The economic life of TAPS is shortened about 1 year (to year 2015) at the 200,000 bpd threshold (compare to fig. 24). Diagram adapted from Thomas and others (1996, fig.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

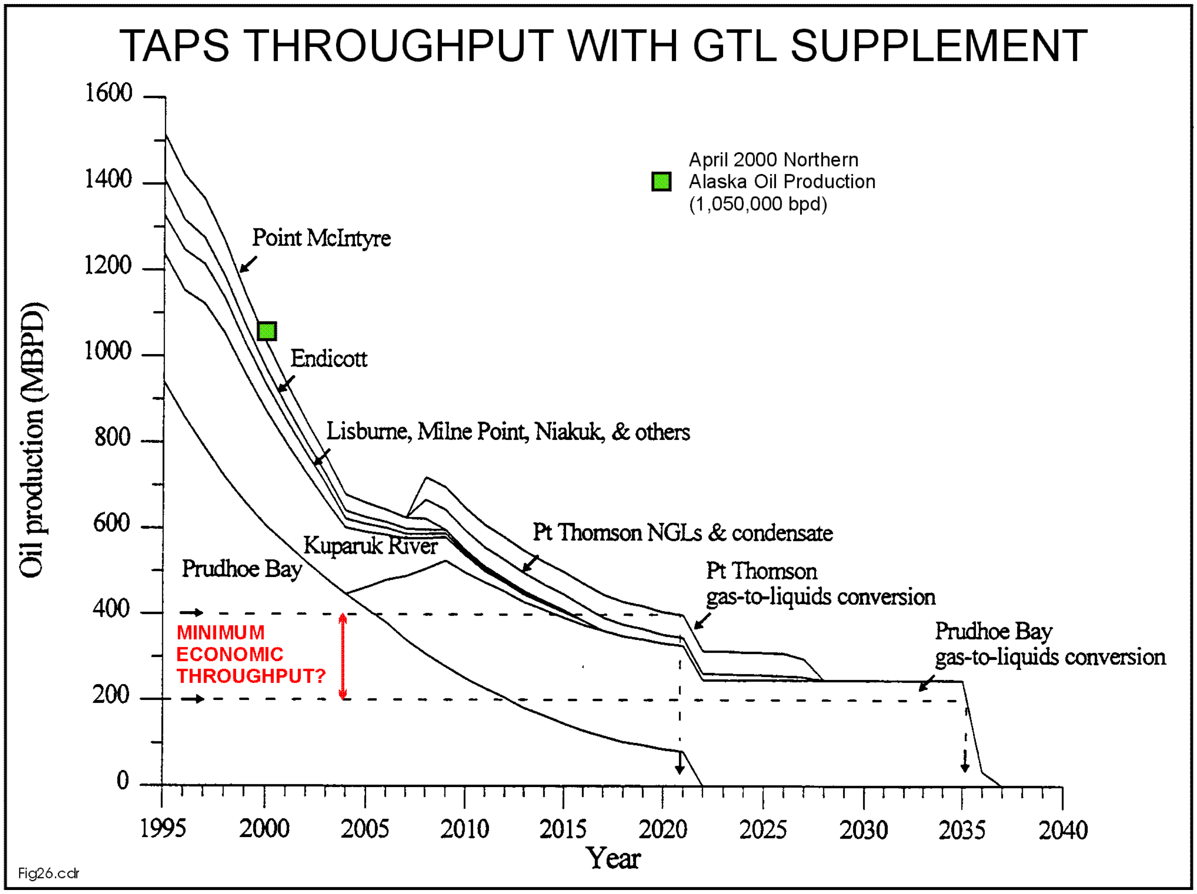


Figure 26: Model for TAPS (oil pipeline) throughput if gas is exported as GTL liquid conversion product through the TAPS line to the tanker facilities at Valdez. The economic life of TAPS is extended by about 20 years over other gas export options at the 200,000 bpd throughput threshold. Diagram from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

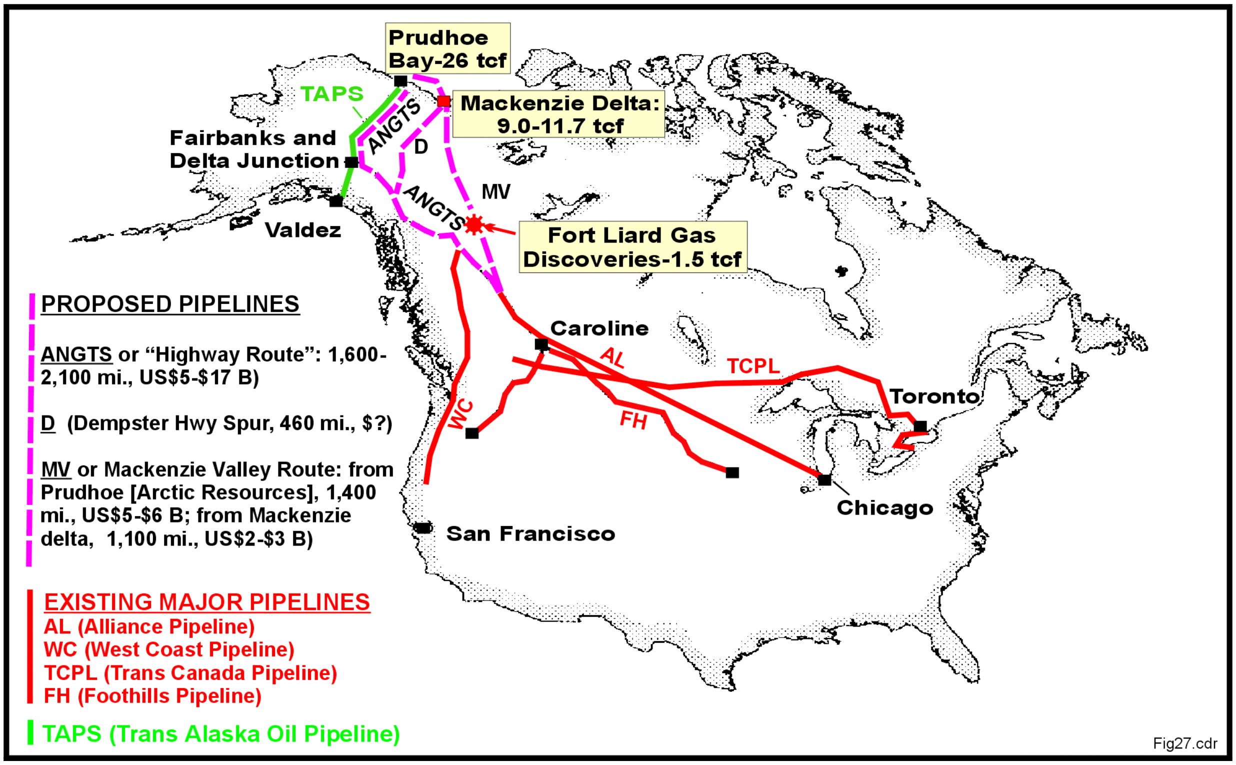


Figure 27: Routes of proposed "ANGTS" (Alaska Natural Gas Transportation System, now referred to as the "highway route"), "MV" (Mackenzie Valley), and "D" (Dempster highway spur) gas pipelines proposed for transportation of natural gas from Prudhoe Bay (26 tcf) and Mackenzie delta (9 to 11.7 tcf) fields 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).

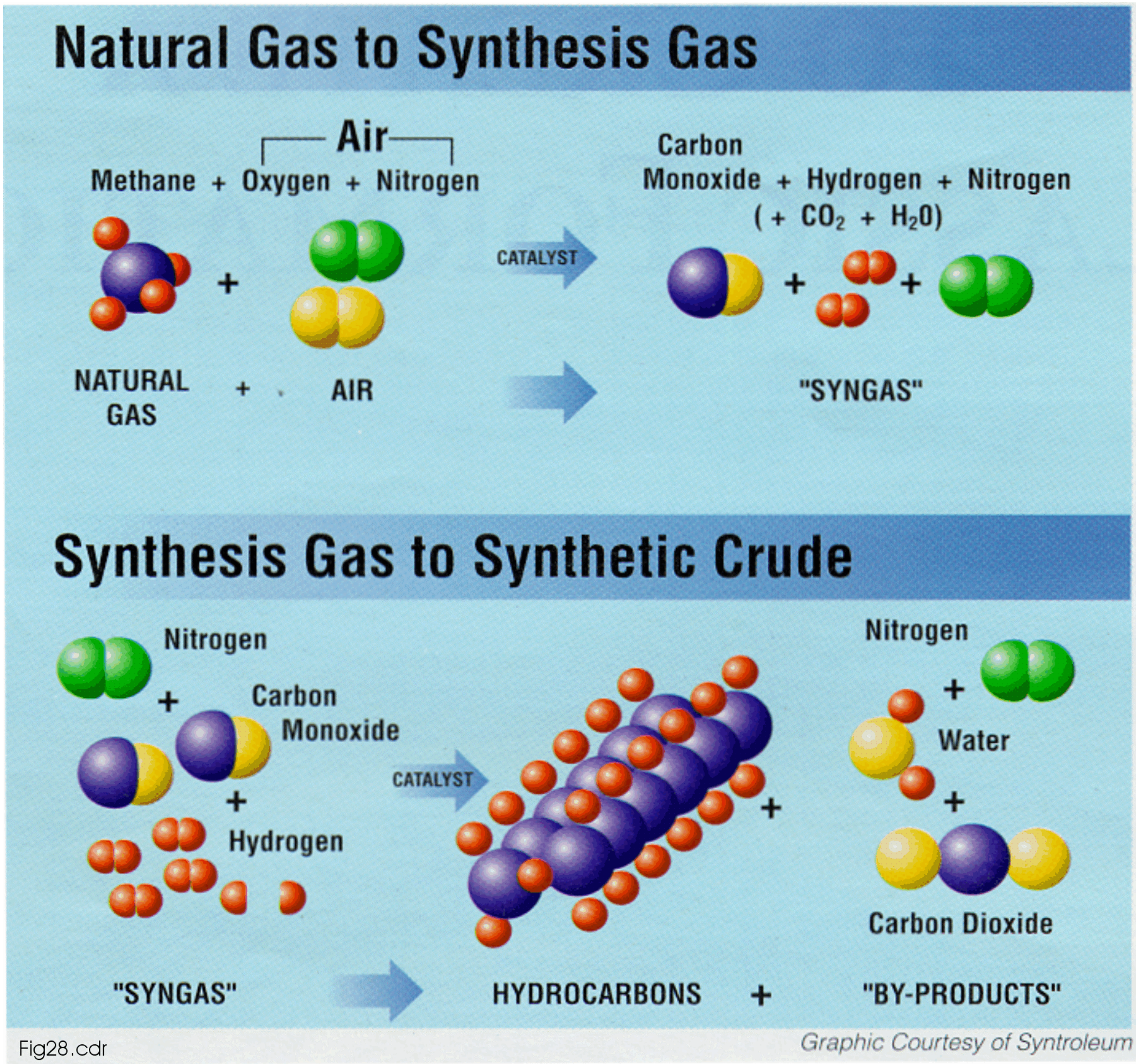


Figure 28: ***Gas-to-Liquids, Fischer-Tropsch Process, or "F-T Process".*** **This schematic shows the basic steps in converting methane or natural gas into synthetic liquids. First, methane is broken into hydrogen and carbon, the latter united with oxygen to create carbon monoxide. The mix of hydrogen 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).**

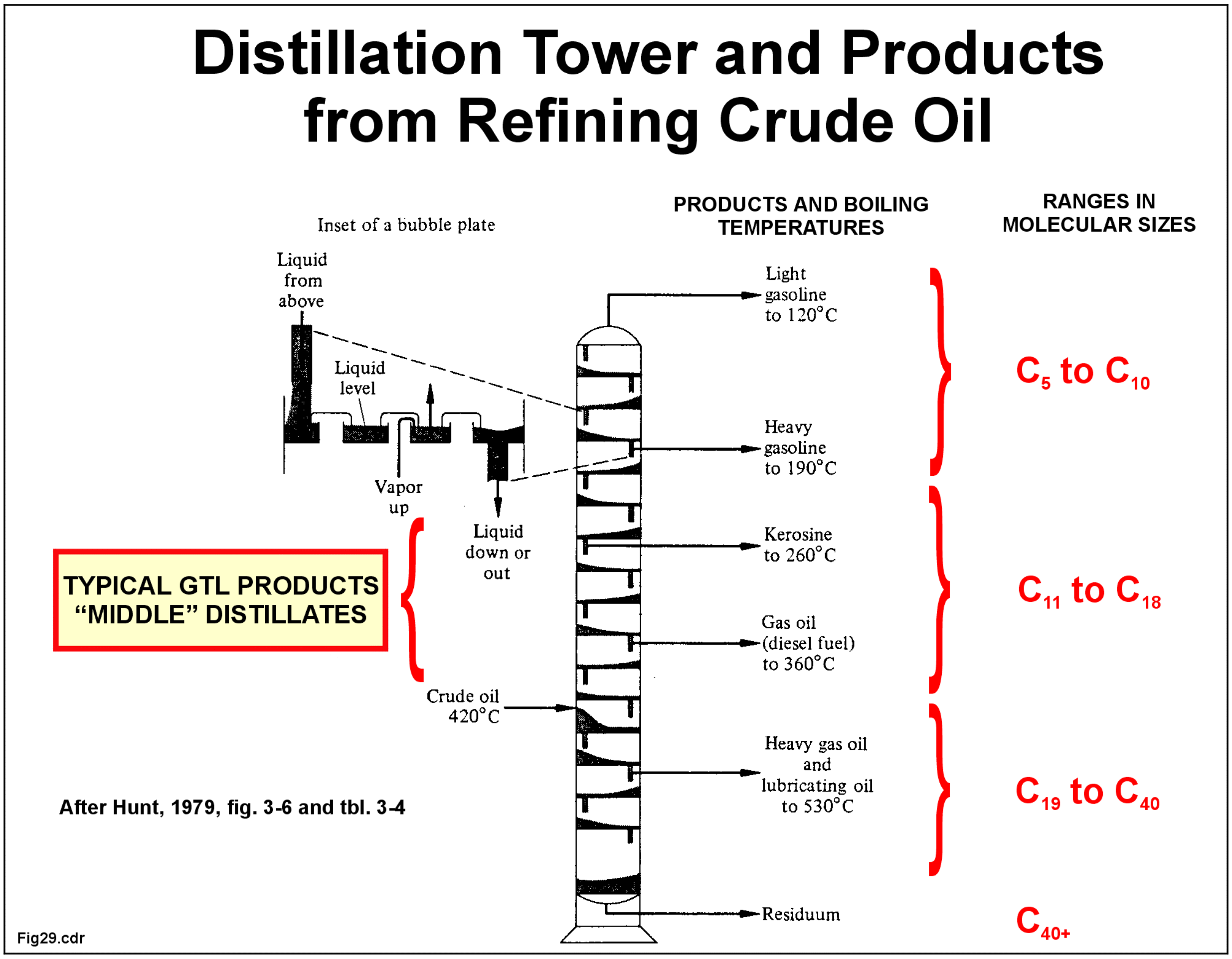


Figure 29: Sketch of distillation tower and products from refining of crude oil. Bubble plates separate liquids on basis of density and molecular size, which controls boiling (vaporization) points. Gas-to-liquids or GTL conversion typically produces fuels in the gasoline to diesel range, corresponding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

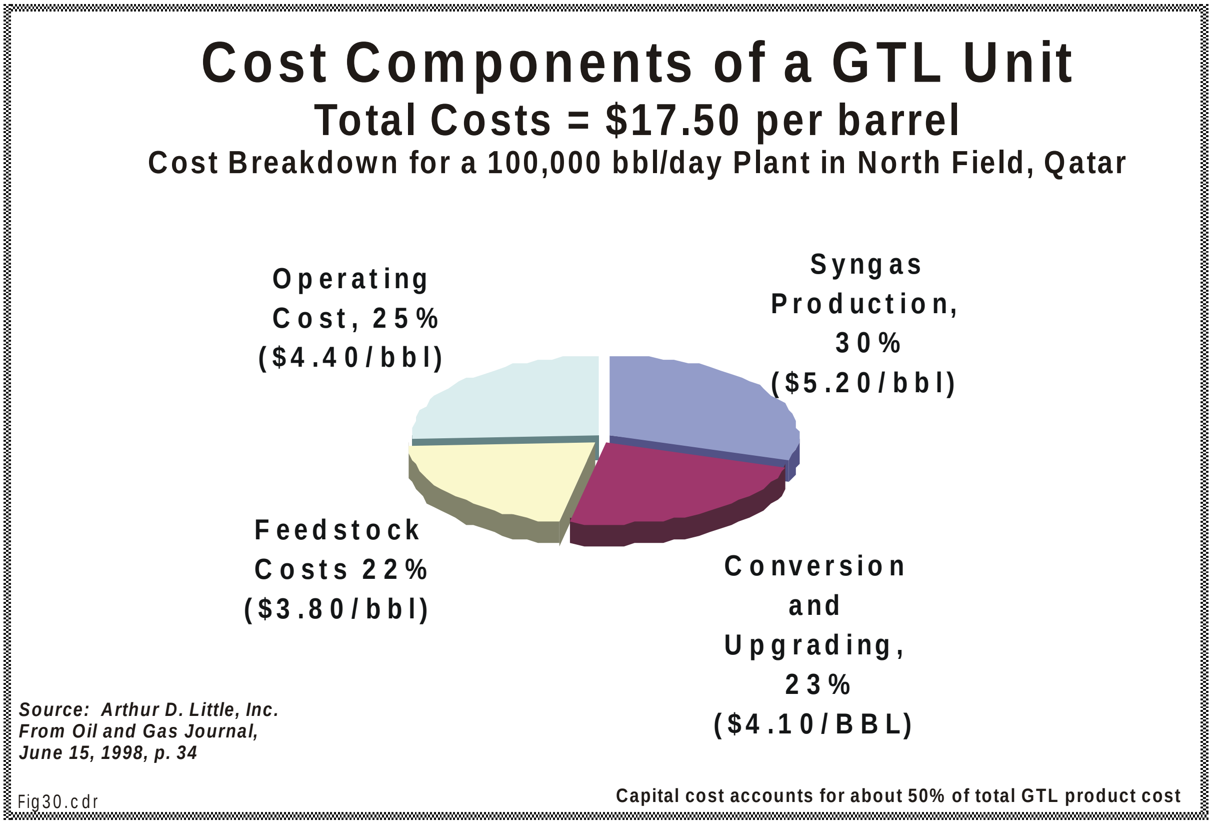


Figure 30: Cost components of a gas-to-liquids facility at output scale of 100,000 barrels of product per day, located in Qatar. Feedstock costs of $3.80 per barrel of conversion liquid are approximately equivalent to $0.38/mcf of feedstock gas. Diagram redrawn from O&GJ (1998, p. 34).

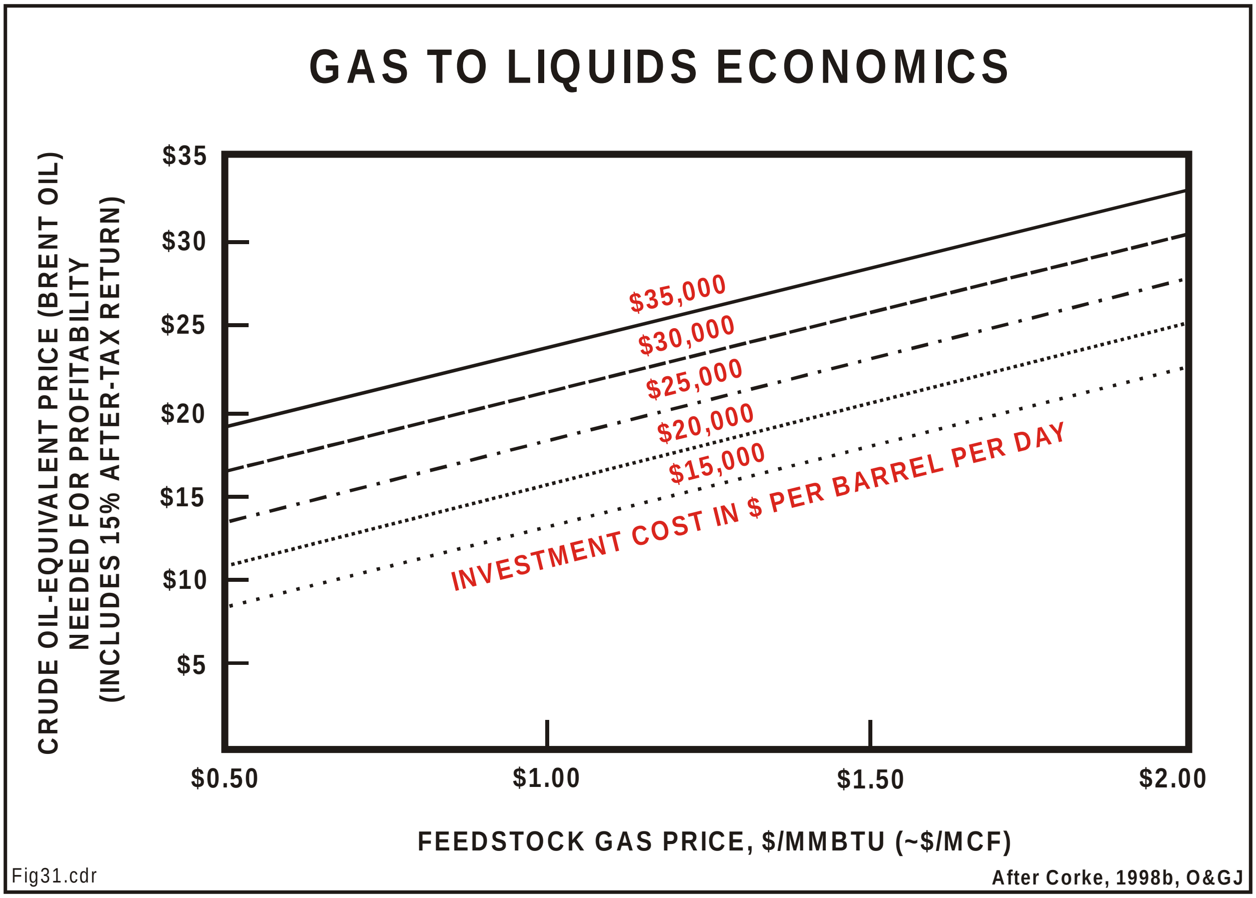


Figure 31: Economics of GTL projects and relationship to feedstock gas costs. $0.50/mcf roughly translates to $5.00 per barrel of liquid GTL product. Investment costs for plant construction are represented in dollars per barrel of daily plant output and are determined by plant scale. Larger plants benefit 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.

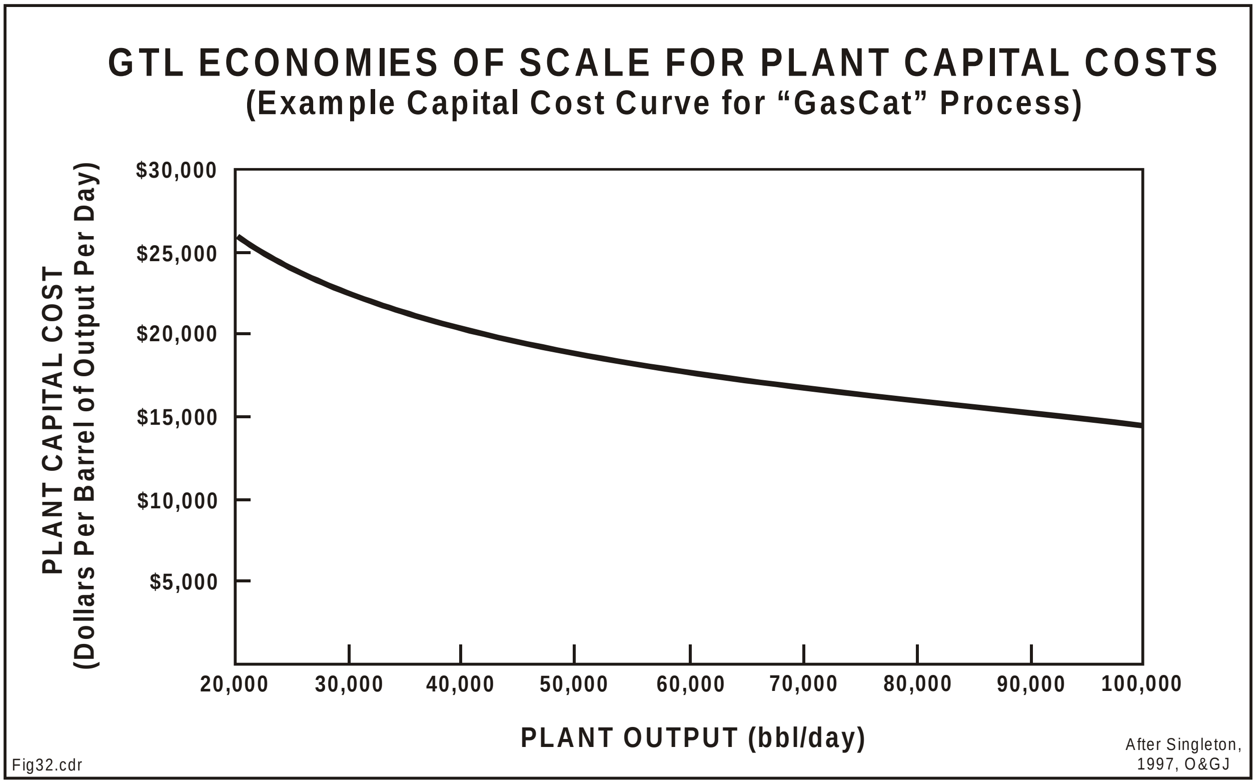


Figure 32: Example from "GasCat" process showing how larger GTL plants benefit from economy of scale and can produce liquids from gas more cheaply. For example, capital costs for this type of GTL plant, when designed for an output capacity of 100,000 barrels of liquid product per day, are only $15,000/barrel/day,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

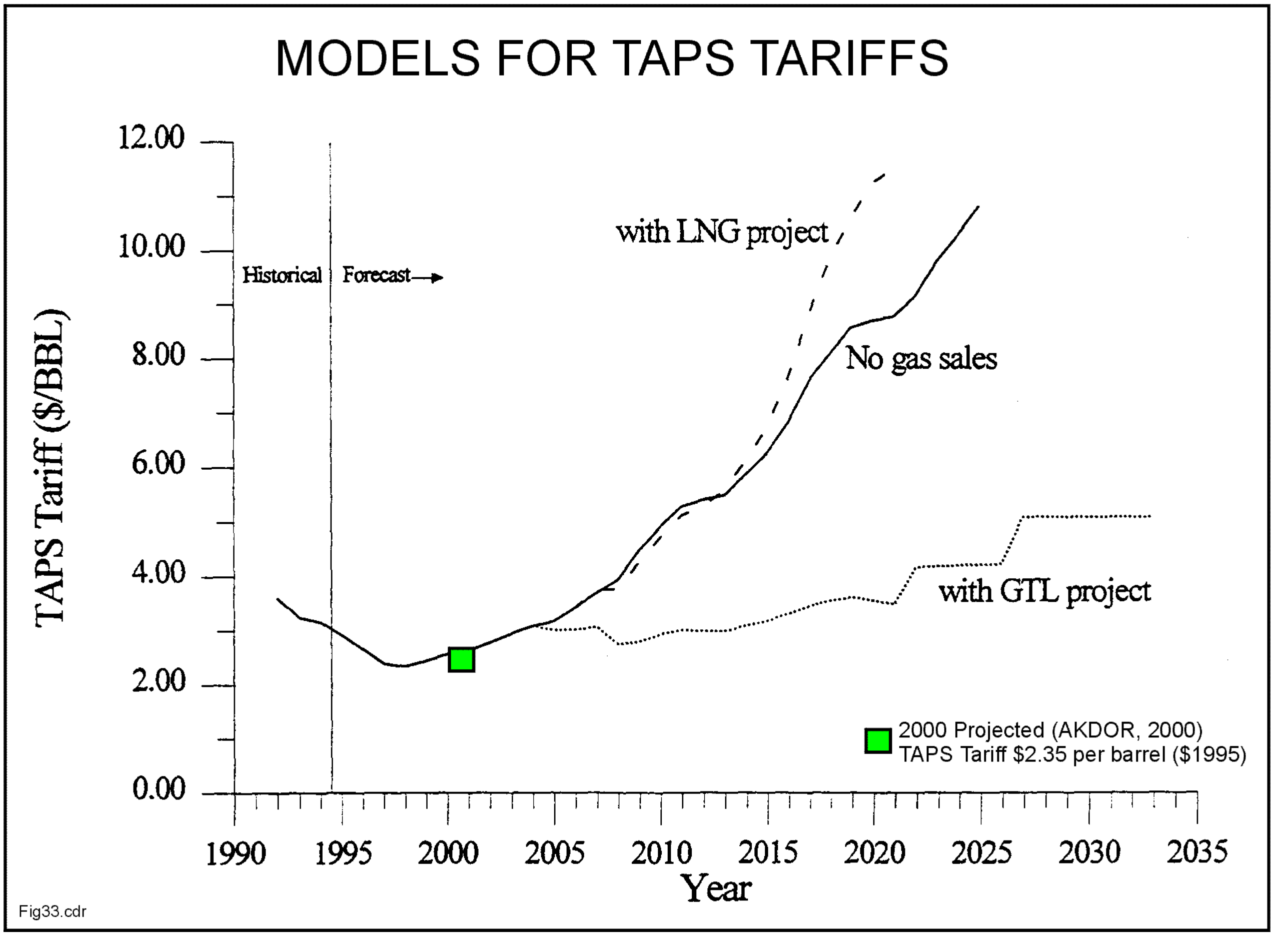


Figure 33: Trans-Alaska oil pipeline (TAPS) tariff projections to year 2035, shown in $1995. A gas-to-liquids (GTL) project will add to pipeline throughput and will moderate future tariff increases, potentially allowing small future oil (and gas?) discoveries to be economic to produce. A liquified-natural 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).

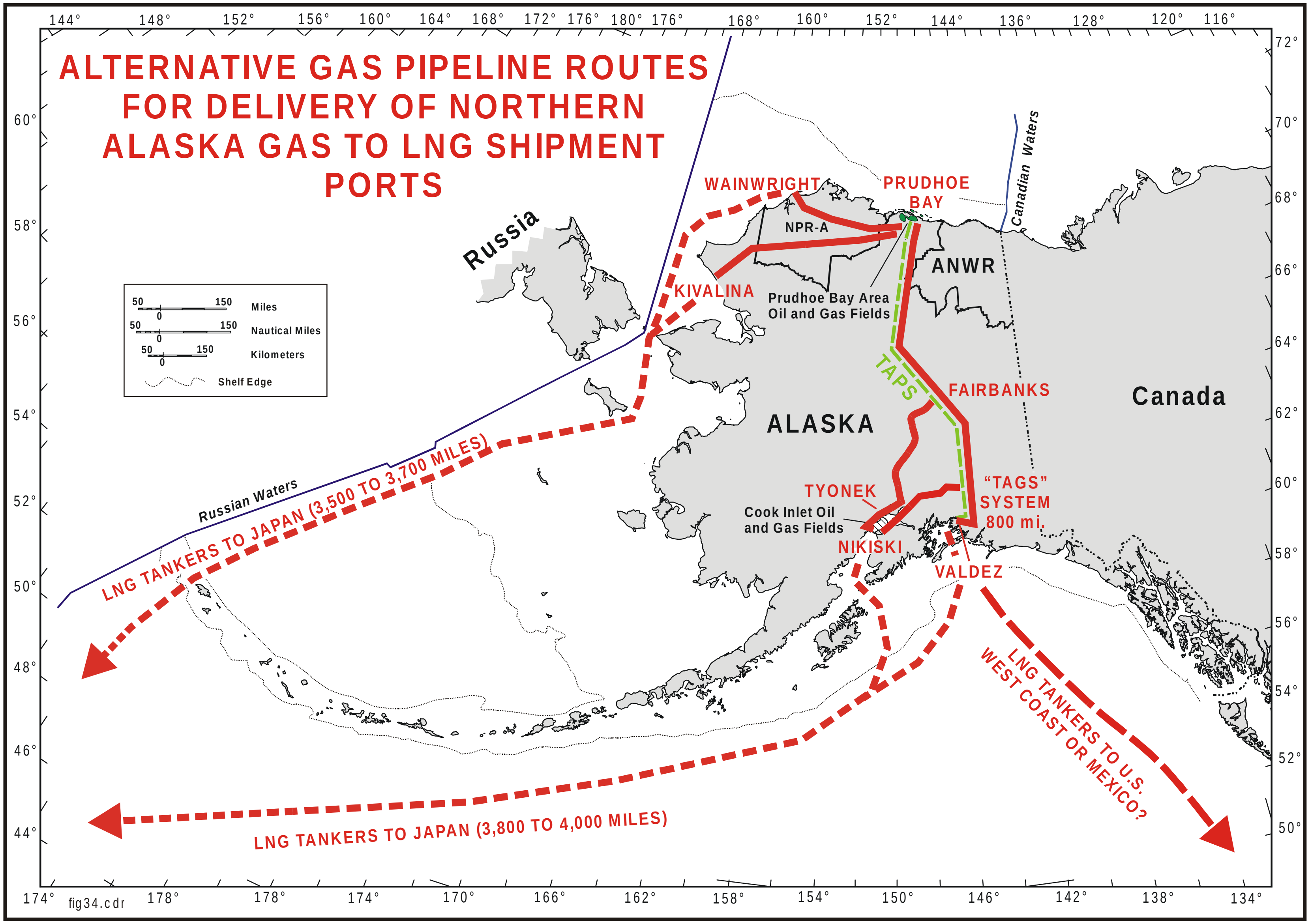


Figure 34: Proposed routes for gas pipelines carrying northern Alaska gas to LNG facilities at Alaskan shipping ports. The Yukon-Pacific Corporation "TAGS" system carrying gas 800 miles from Prudhoe Bay to Valdez forms the traditional route, although a lines to export terminals in Cook Inlet are also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

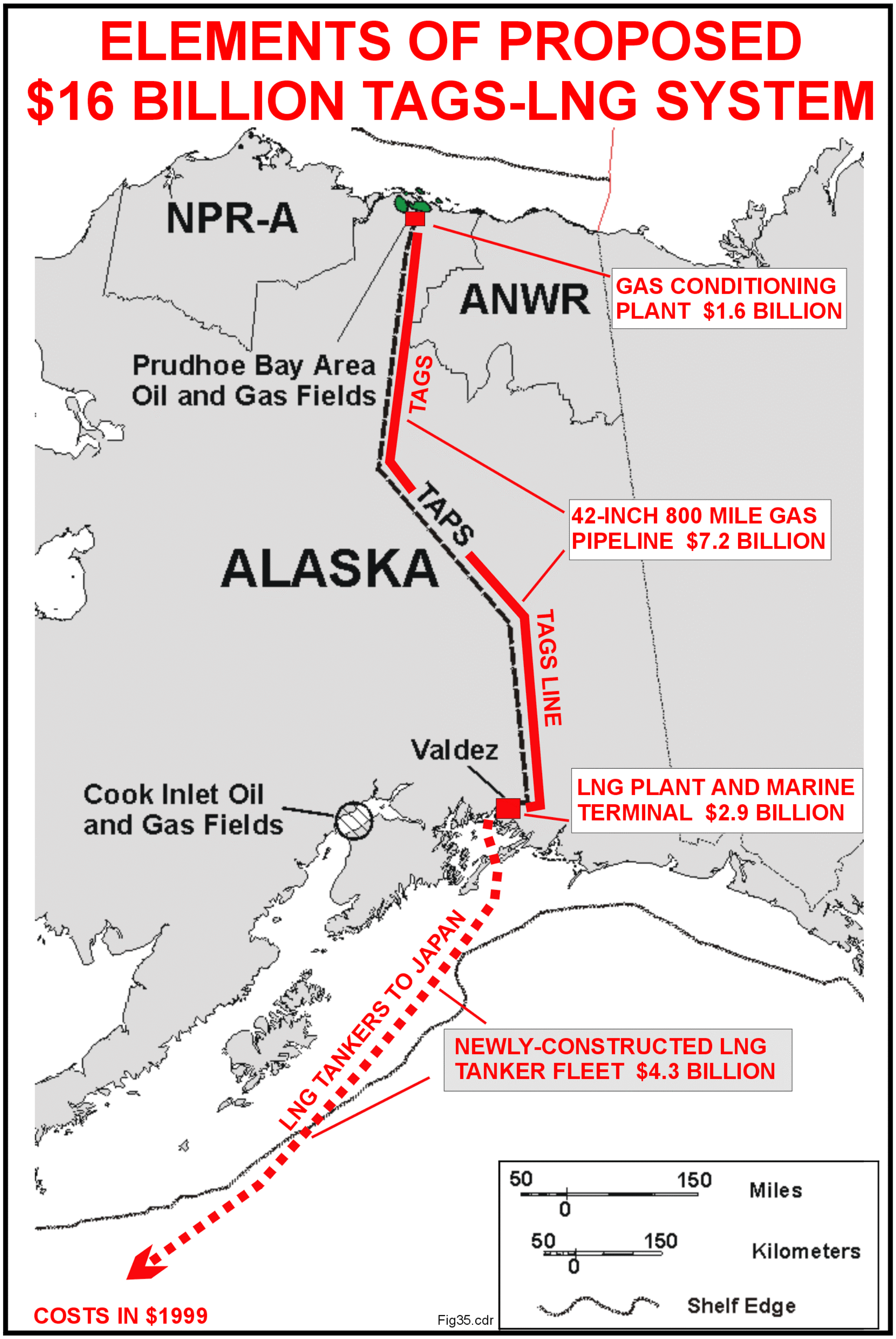
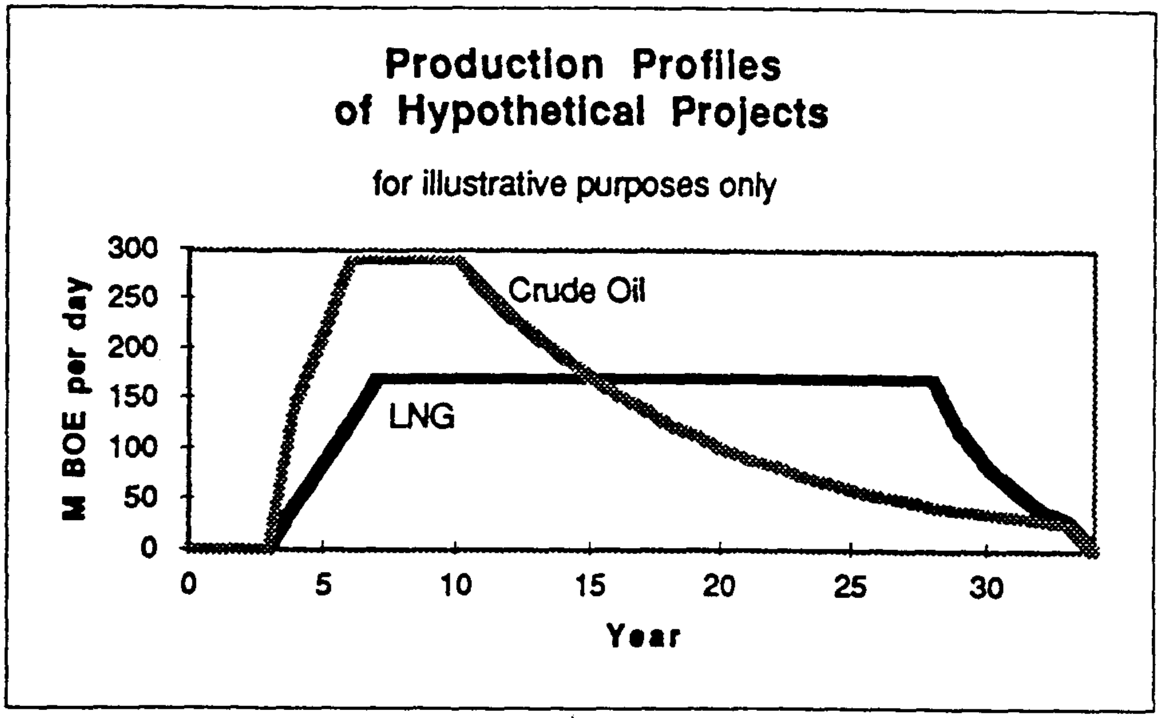


Figure 35: Elements of proposed TAGS-LNG gas transportation system requiring capital outlays for initiation of project. Cost estimates for 14 million metric ton (0.7 tcf) per year project from Thomas and others (1996, p. B-20 to B-21), with reported $1995 costs adjusted to $1999.



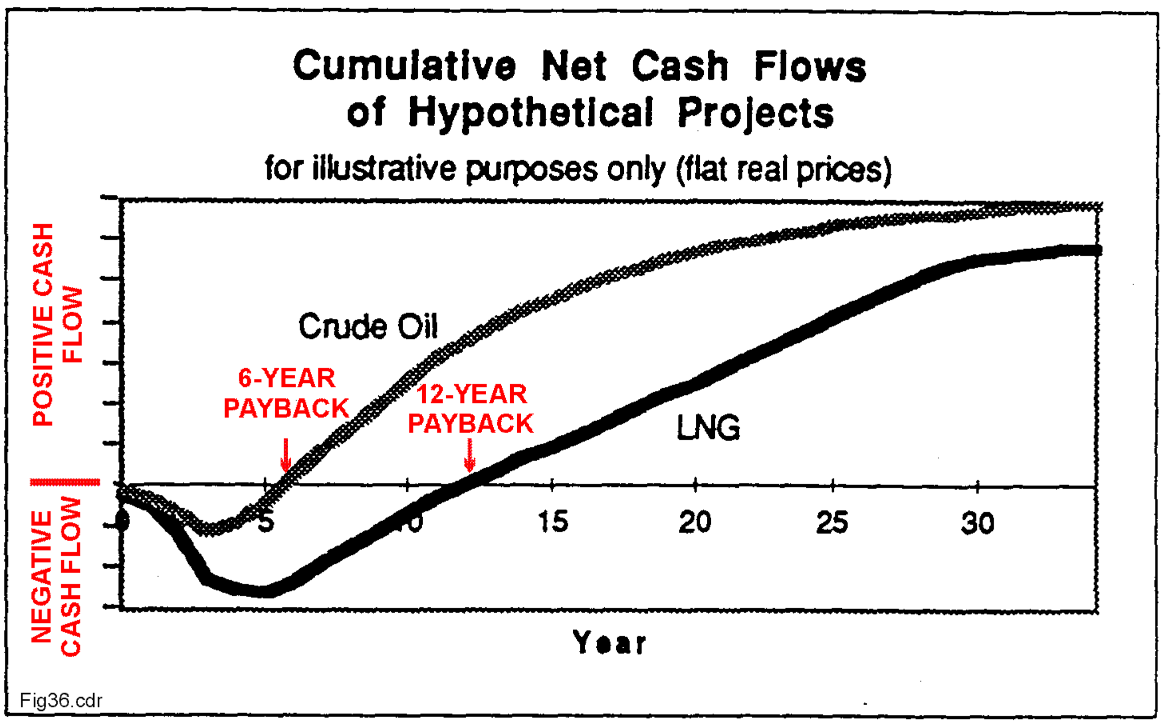


Figure 36: Comparison of production profiles for crude oil and LNG projects showing the effects of the time interval for "ramp-up" to maximum production on overall project economics. Because of the longer ramp-up and flat production profile, cash flows remain negative much longer for the LNG project, 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).

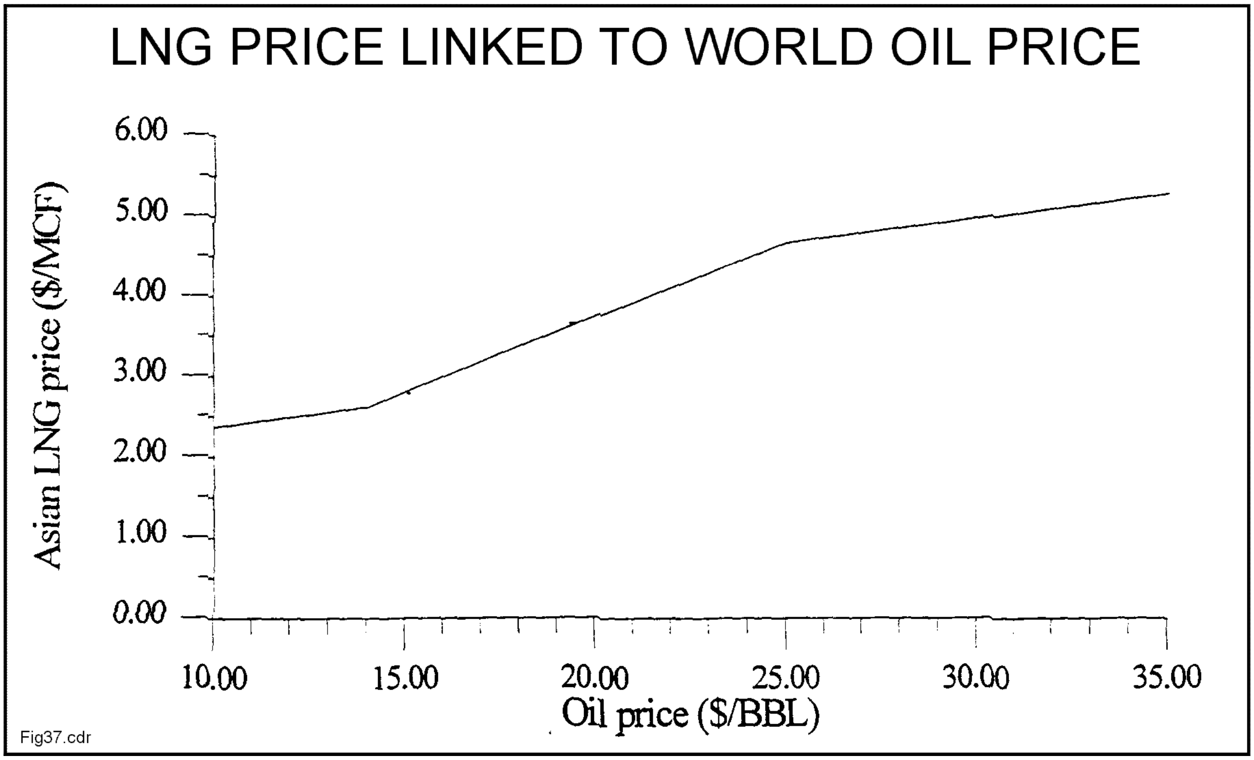


Figure 37: Example of relationship of LNG prices to world oil prices in long-term sales contract. The relationship is drawn so that the LNG provider is contractually protected from financial harm resulting from low (<$15/bbl) oil prices, while the LNG buyer is protected from financial harm resulting 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).

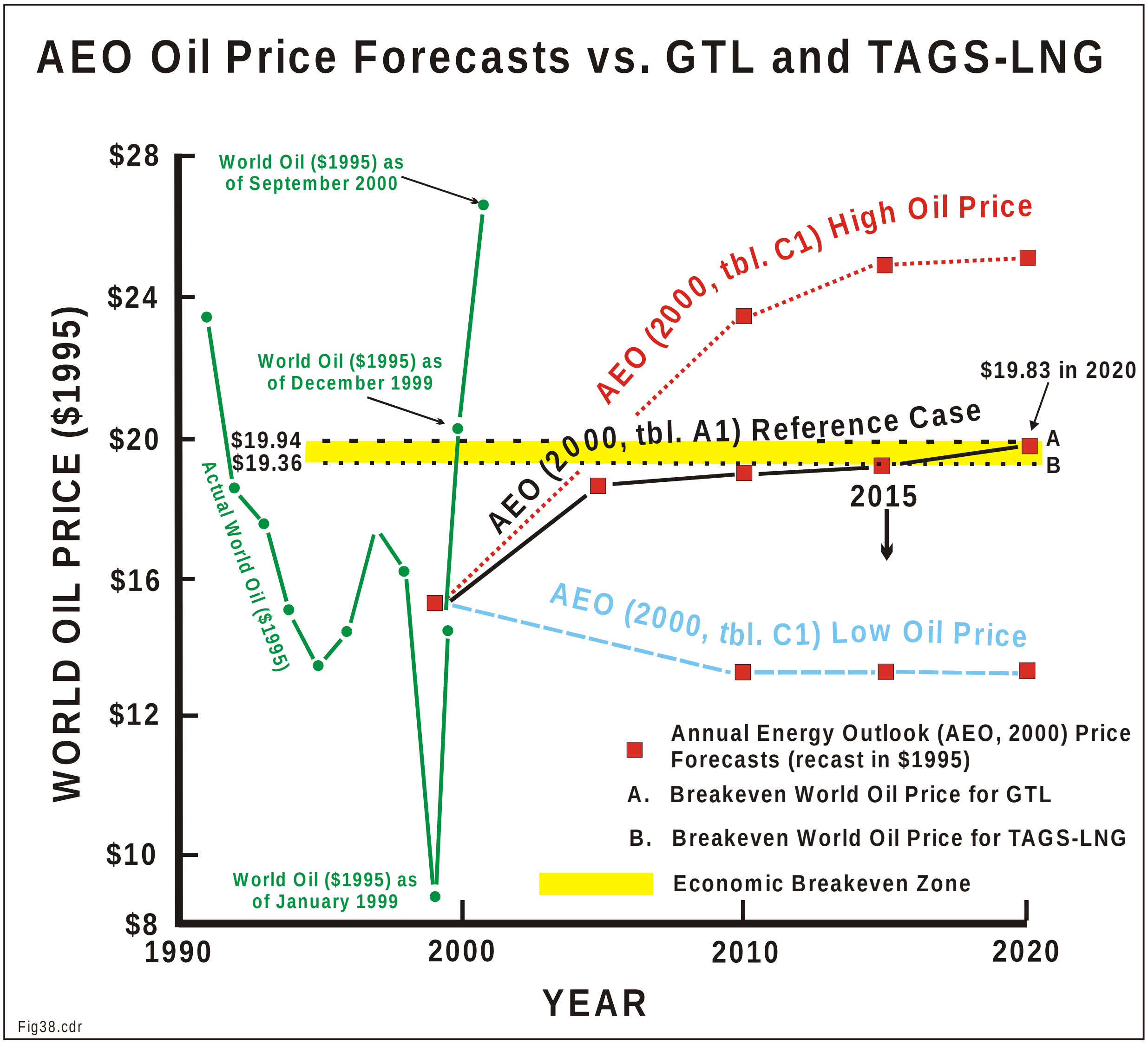


Figure 38: AEO *Energy Outlook 2001* (AEO, 2000) forecasts for world oil prices and 1995 DOE results for breakeven ($NPV_{10} = 0$) flat oil prices ($1995) for GTL ($19.94/bbl) and TAGS-LNG ($19.36/bbl) projects for northern Alaska natural gas, as reported in a 1995 DOE study by Thomas and others (1996, 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.

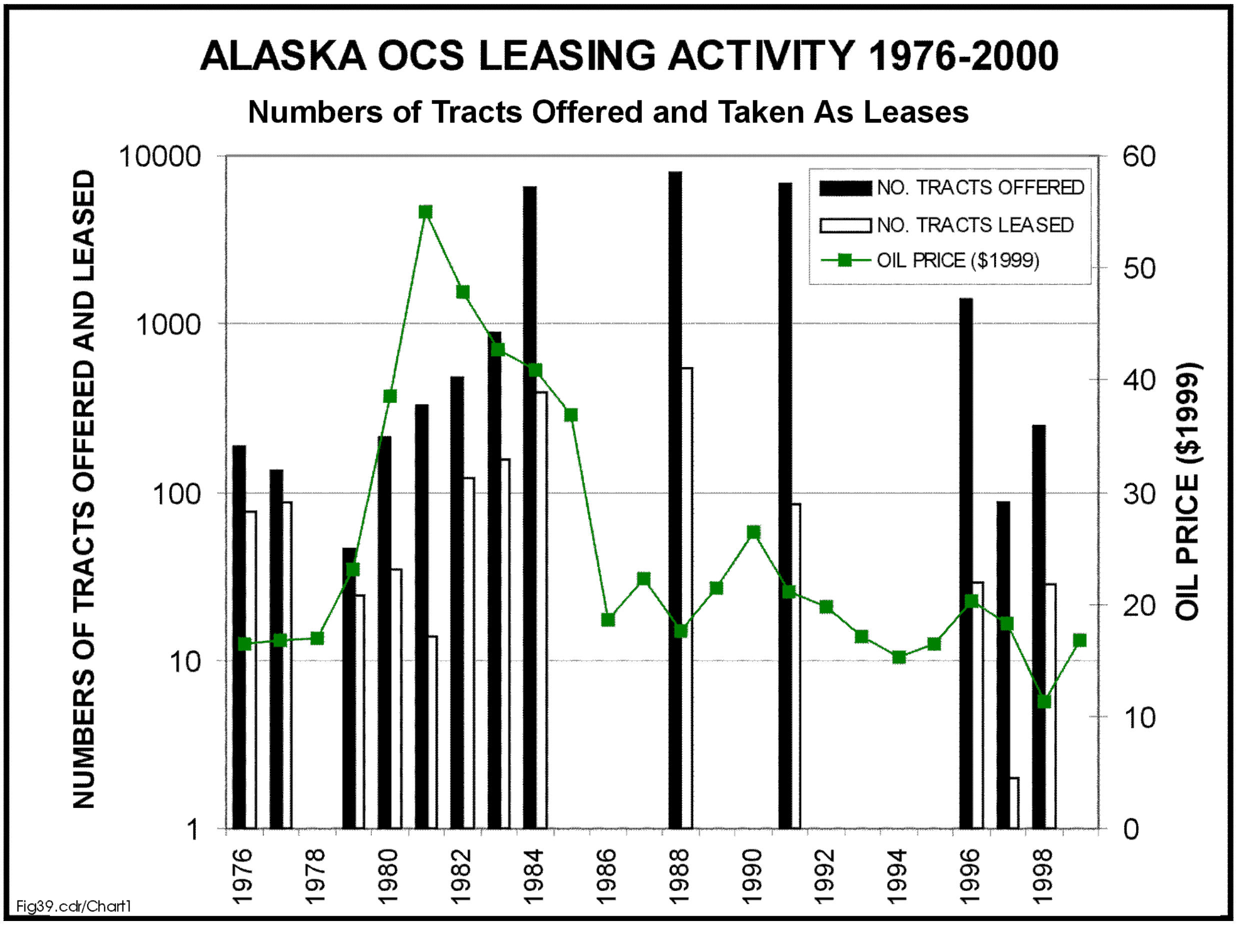


Figure 39: Bar chart for numbers of tracts offered and leased in the Alaska Federal offshore in the years from 1976 to 2000, with world oil prices adjusted to 1999 dollars. A total of 25,289 tracts were offered and a total of 1,598 (or 6.3%) were leased. Some of the largest lease sales in terms of numbers 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).

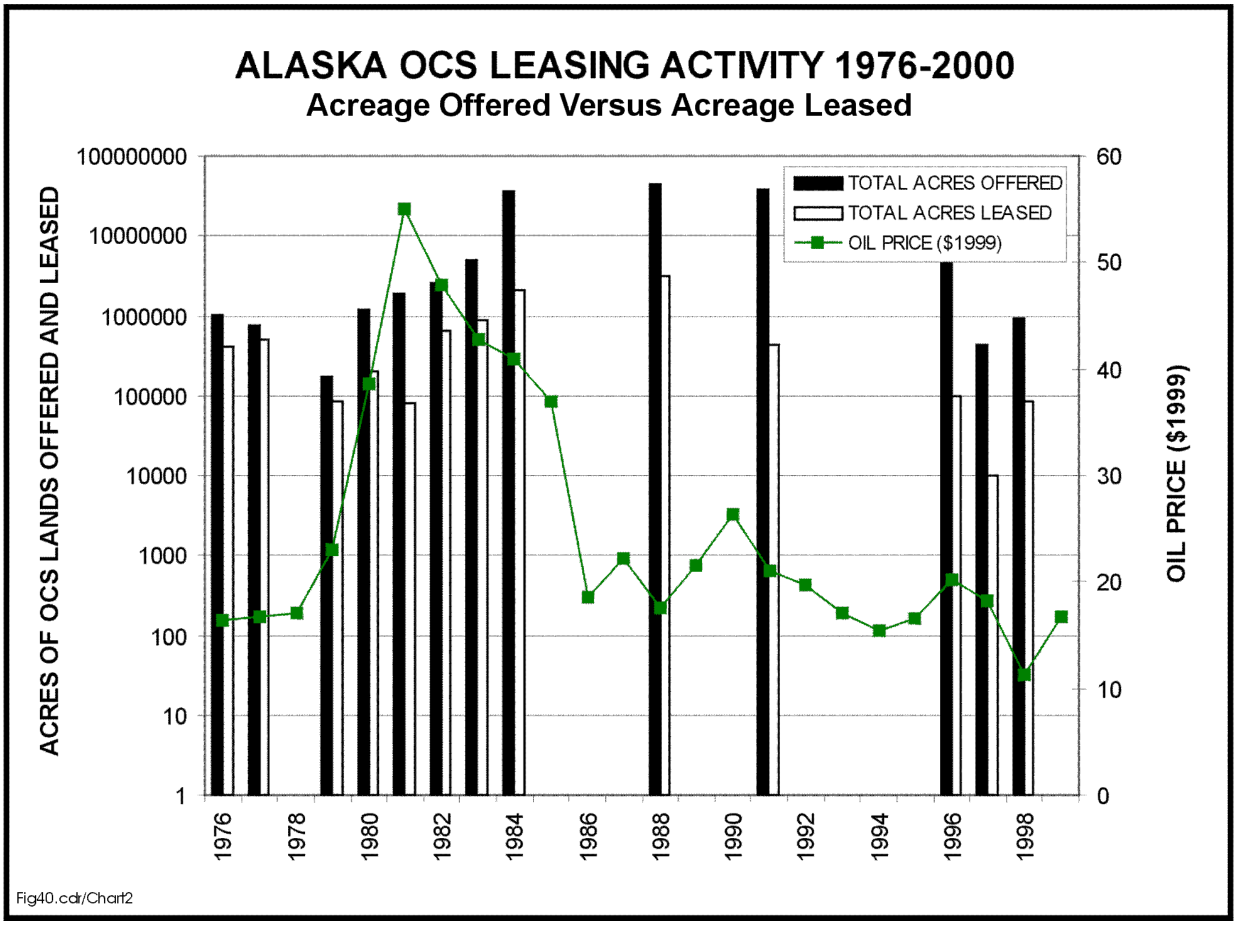


Figure 40: Bar chart for numbers of acres offered and leased in the Alaska Federal offshore in the years from 1976 to 2000, with world oil prices adjusted to 1999 dollars. A total of 138,588,002 acres were offered and a total of 8,663,685 acres (or 6.3%) were leased. Some of the largest lease sales in 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).

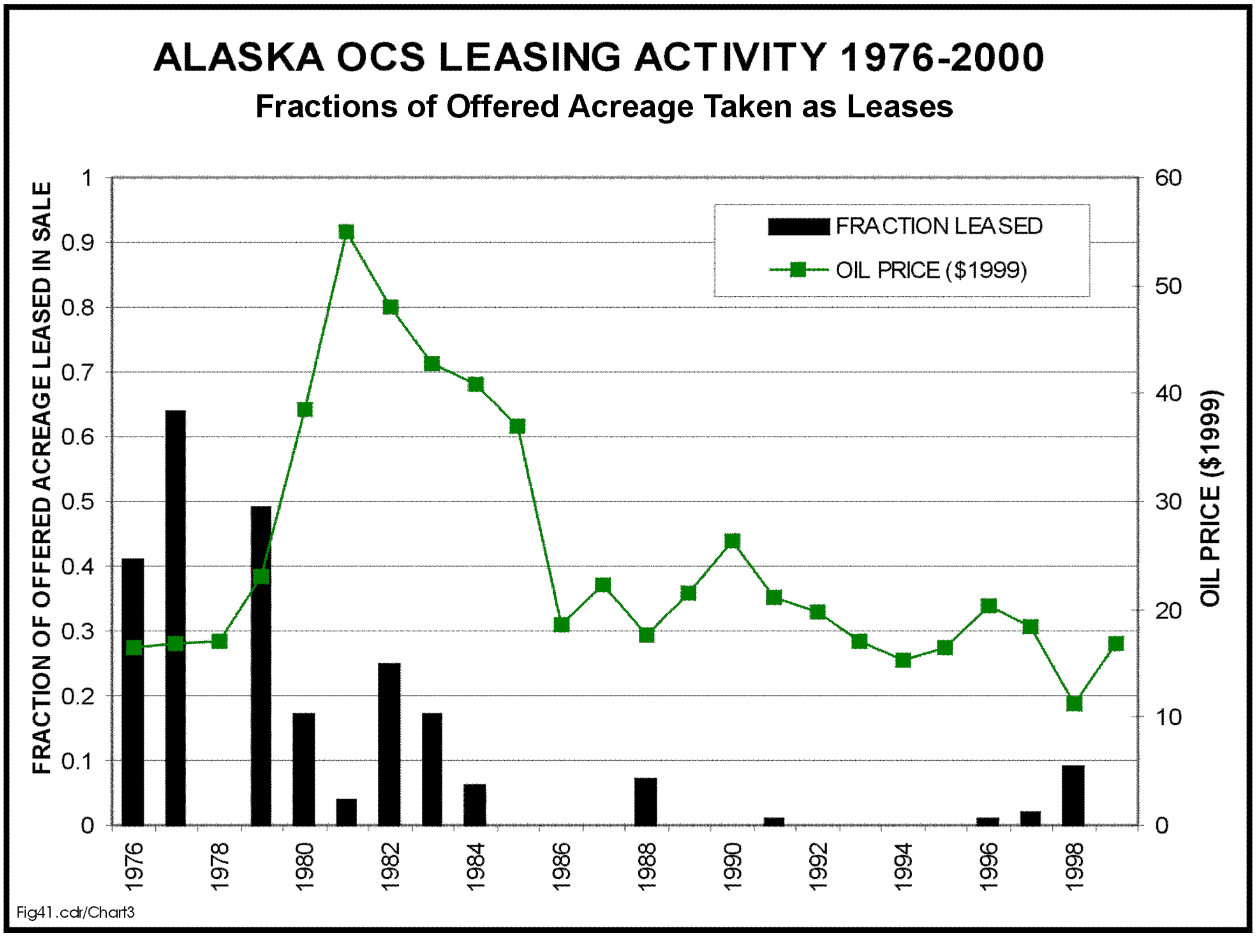


Figure 41: Bar chart for fractions of offered acreage actually leased in lease sales in the Alaska Federal offshore in the period 1976 to 2000, with world oil prices adjusted to 1999 dollars. In early lease sales, over 40% of the lands offered were leased. However, the lease strategy moved to area-wide 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.

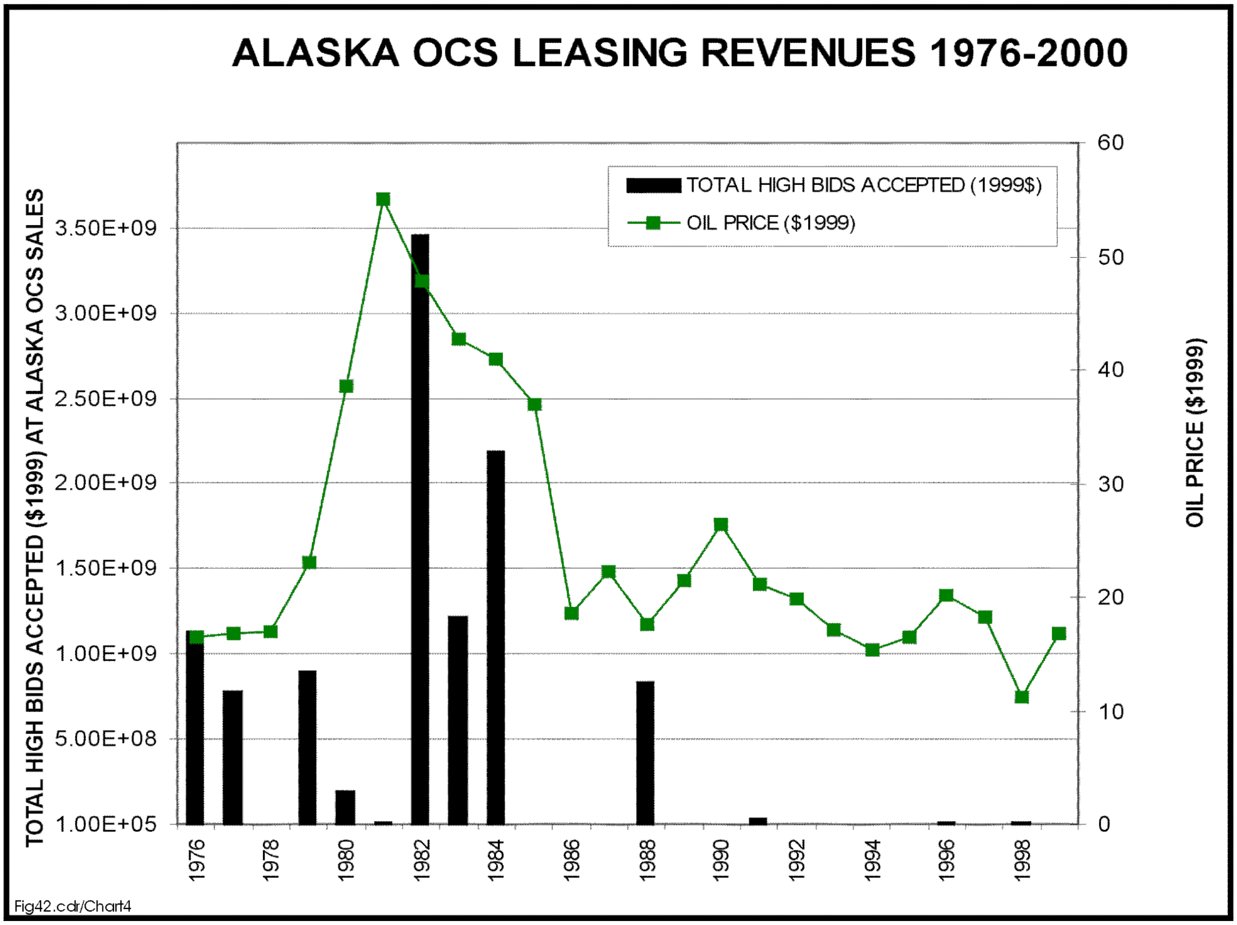


Figure 42: Bar chart for total high bids (adjusted to 1999 dollars) accepted in lease sales in the Alaska Federal offshore in the period 1976 to 2000, with world oil prices (also adjusted to 1999 dollars). Bonus (lease bid amount) revenues nearly reached $3 billion in 1982 but declined sharply following 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).

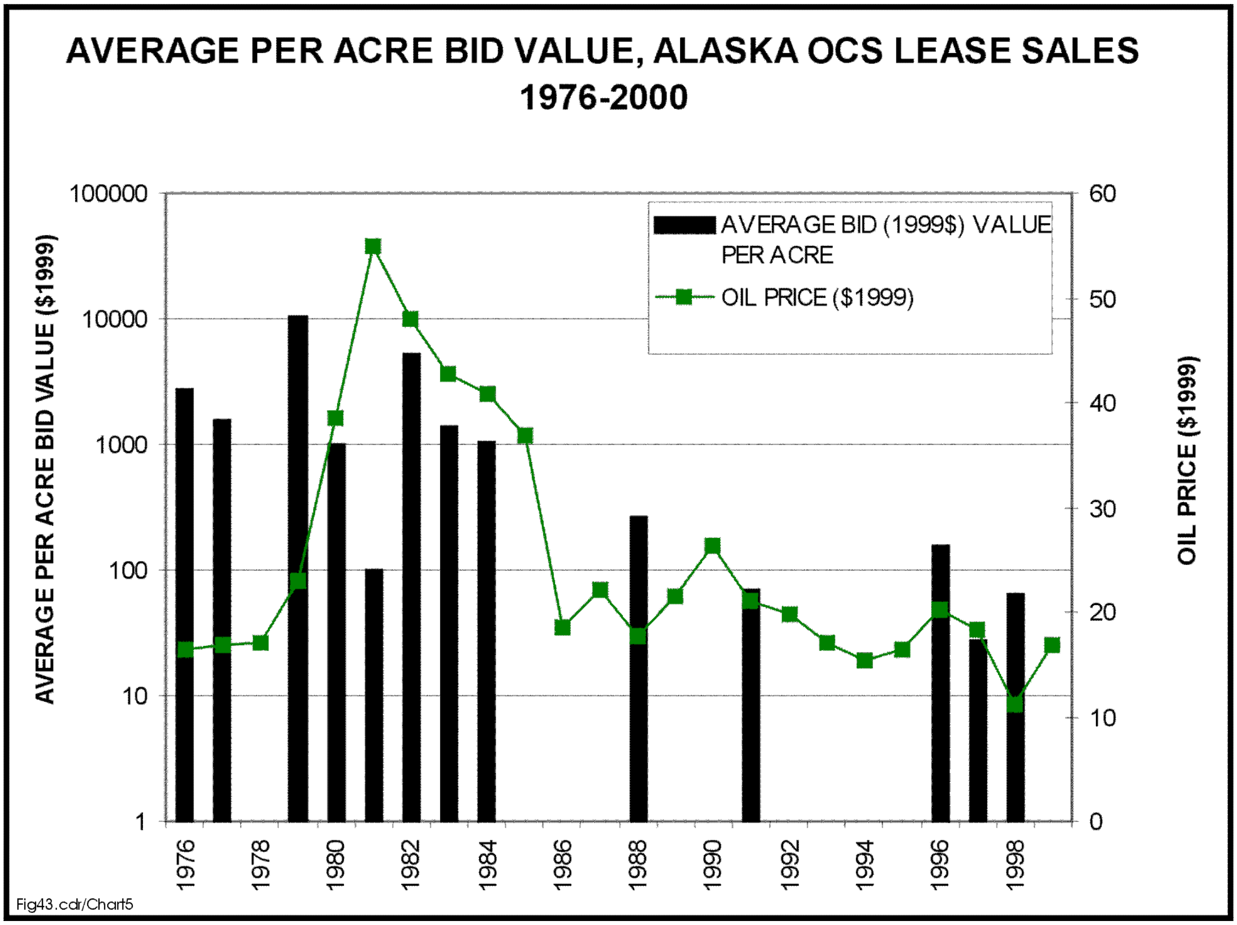


Figure 43: Bar chart for average bonus bid values (adjusted to 1999 dollars) per acre for leases sales in the Alaska Federal offshore from 1976 to 2000, with world oil prices (in $1999) also shown. The opening of unexplored basins to leasing during the early 1980's, coupled with high expectations for 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.

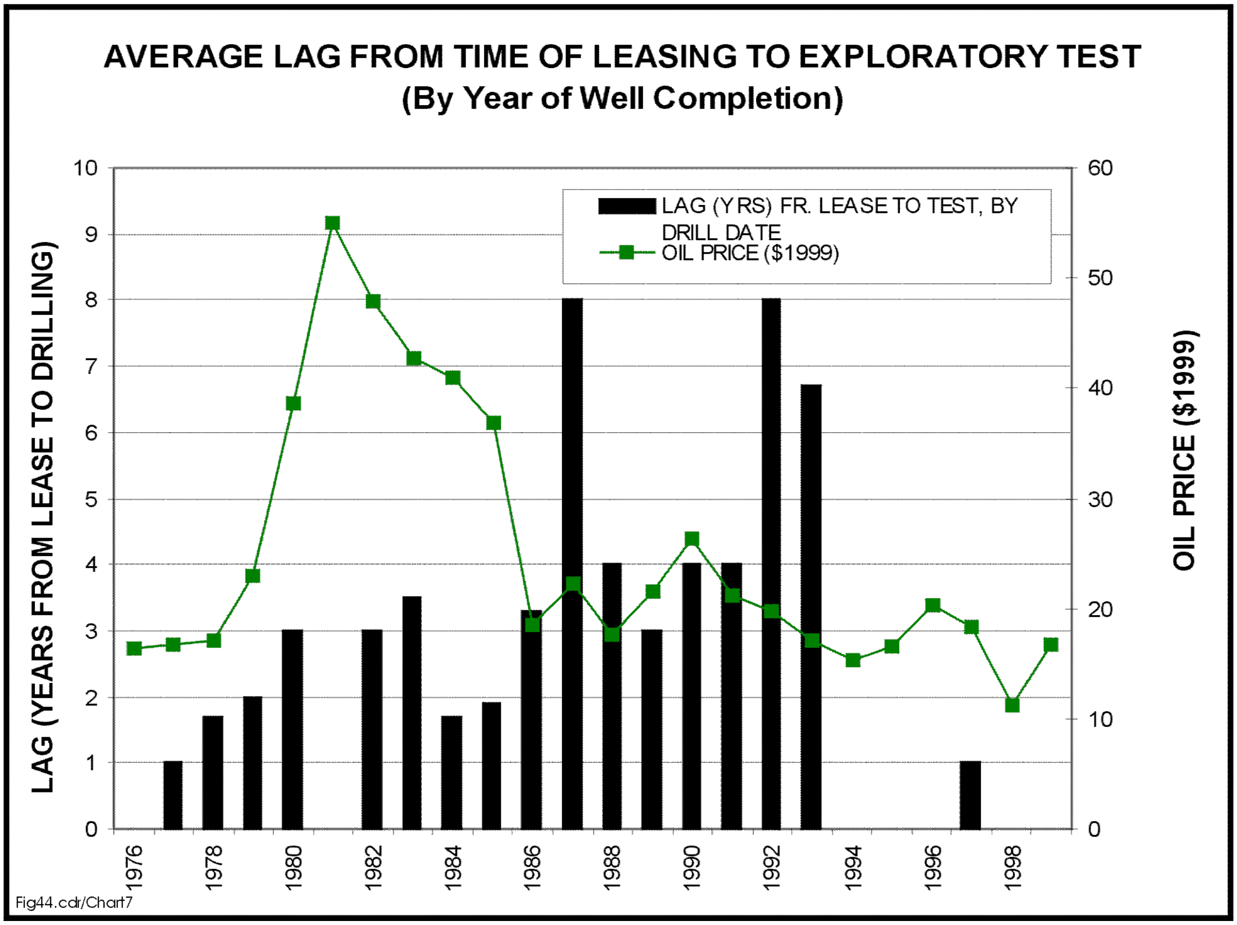


Figure 44: Bar chart for average time lag (in years) between the dates that leases were acquired and the dates when the first exploration wells were drilled, indexed to year that the well was completed. Most leases were never drilled. Only 83 exploration tests were drilled in the Alaska Federal offshore, 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.

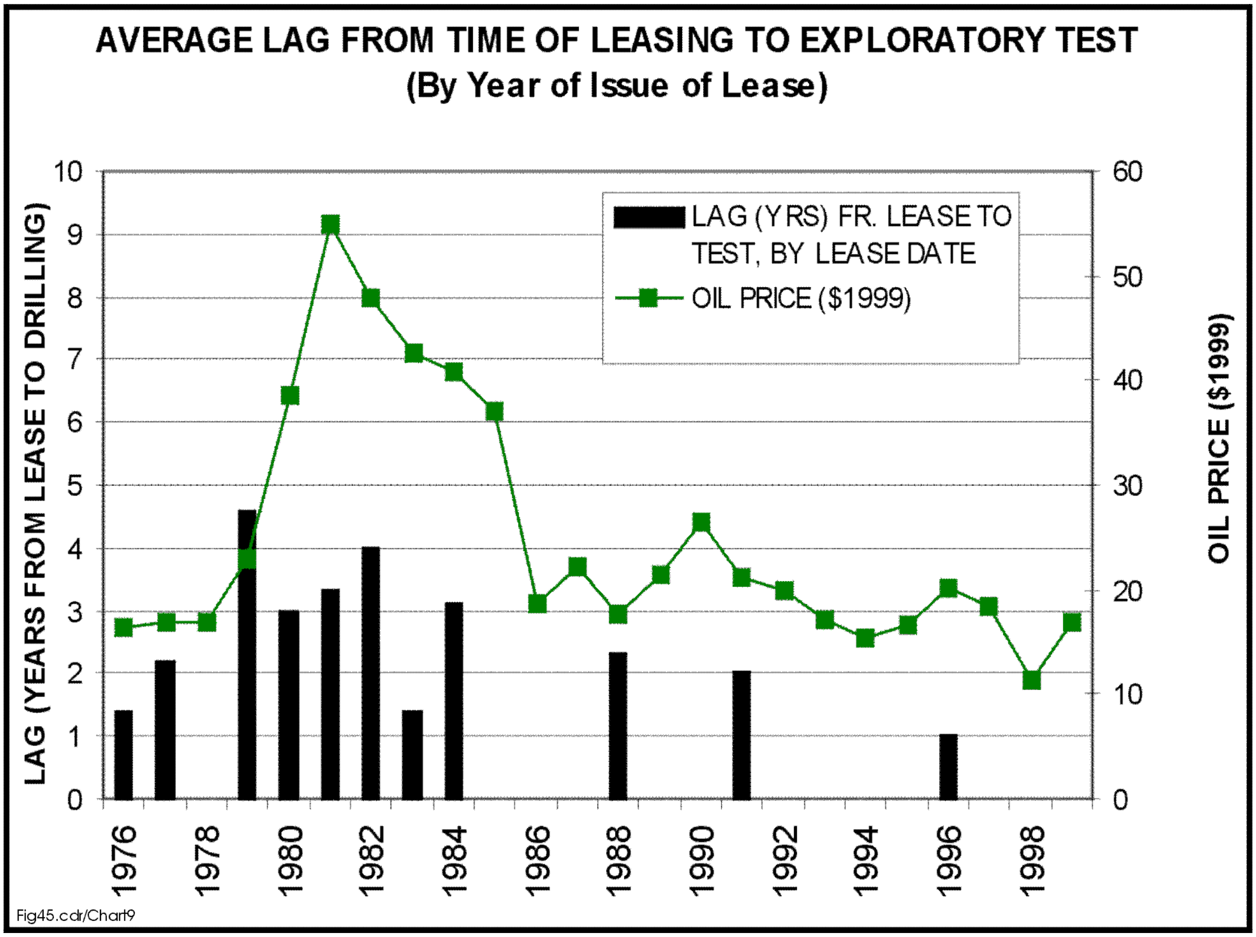


Figure 45: Bar chart for average time lag (in years) between the dates that leases were acquired and the dates when the first exploration wells were drilled, indexed to year that the lease was acquired. Most leases were never drilled. Only 83 exploration tests were drilled in the Alaska Federal offshore, 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.

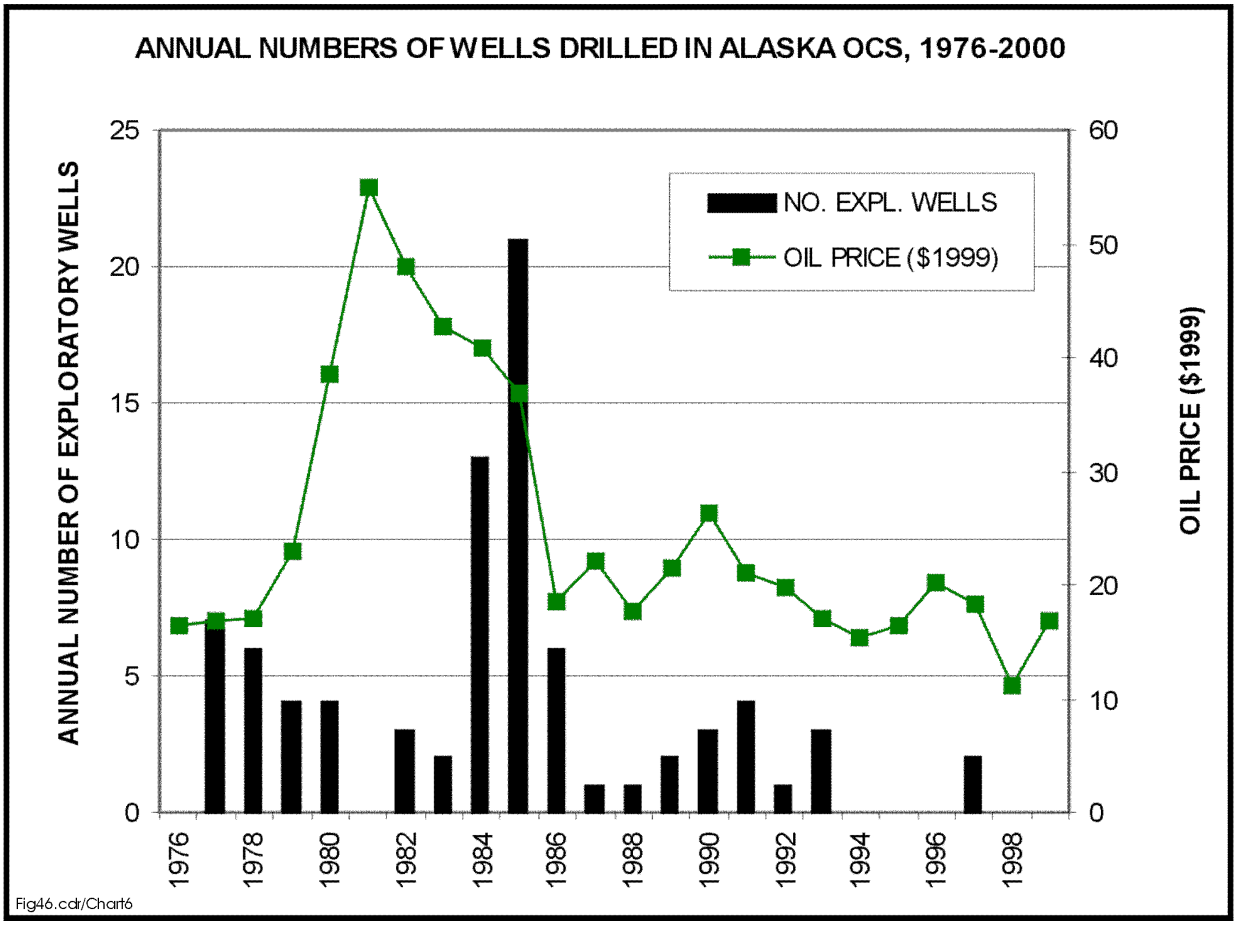


Figure 46: Bar chart for numbers of exploratory wells drilled annually in Alaska Federal offshore from 1976 to 2000, with world oil prices ($1999) also posted. A total of 83 exploratory wells have been drilled in the Alaska Federal offshore. The largest spikes in drilling activity, when 10 to 20 wells 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.

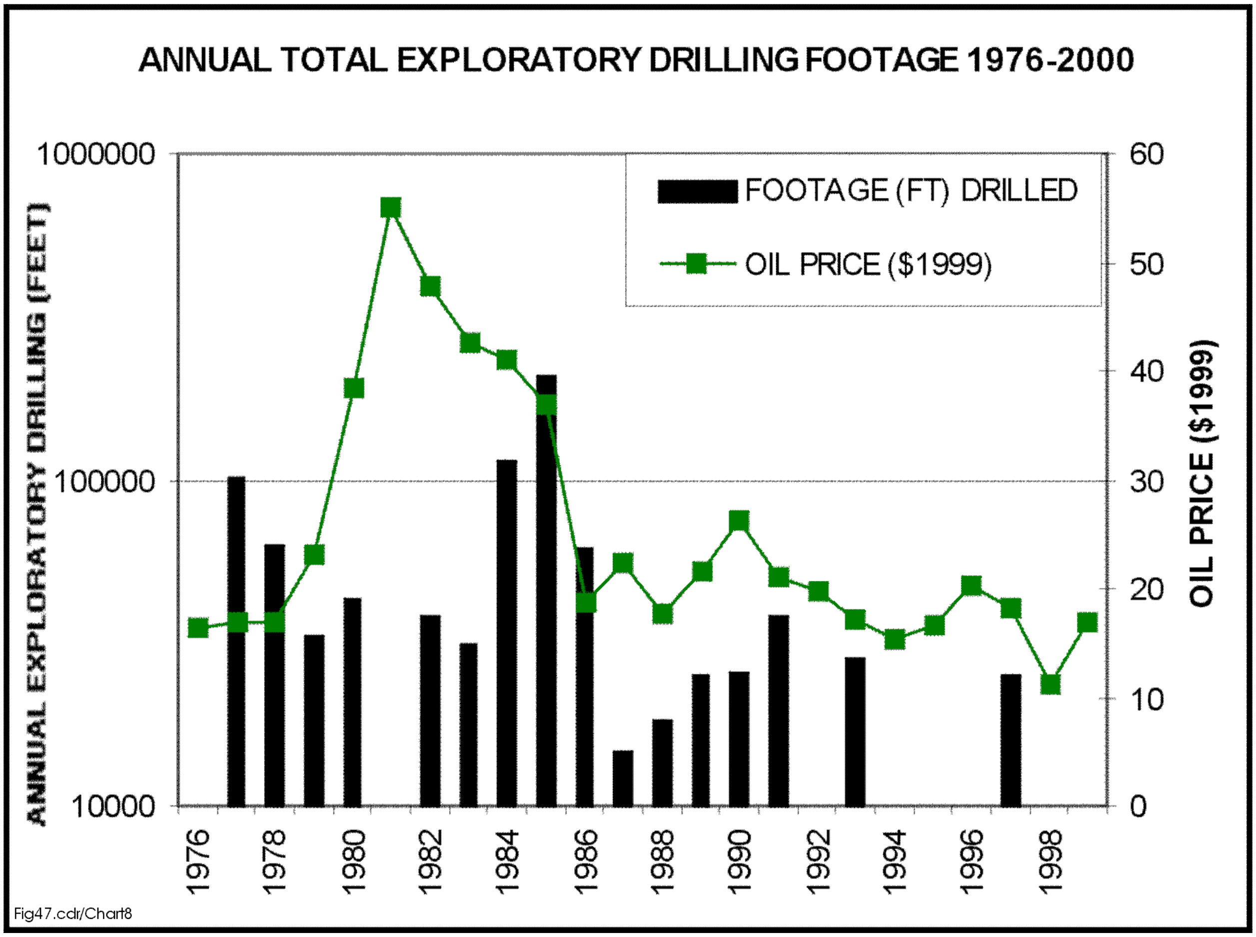
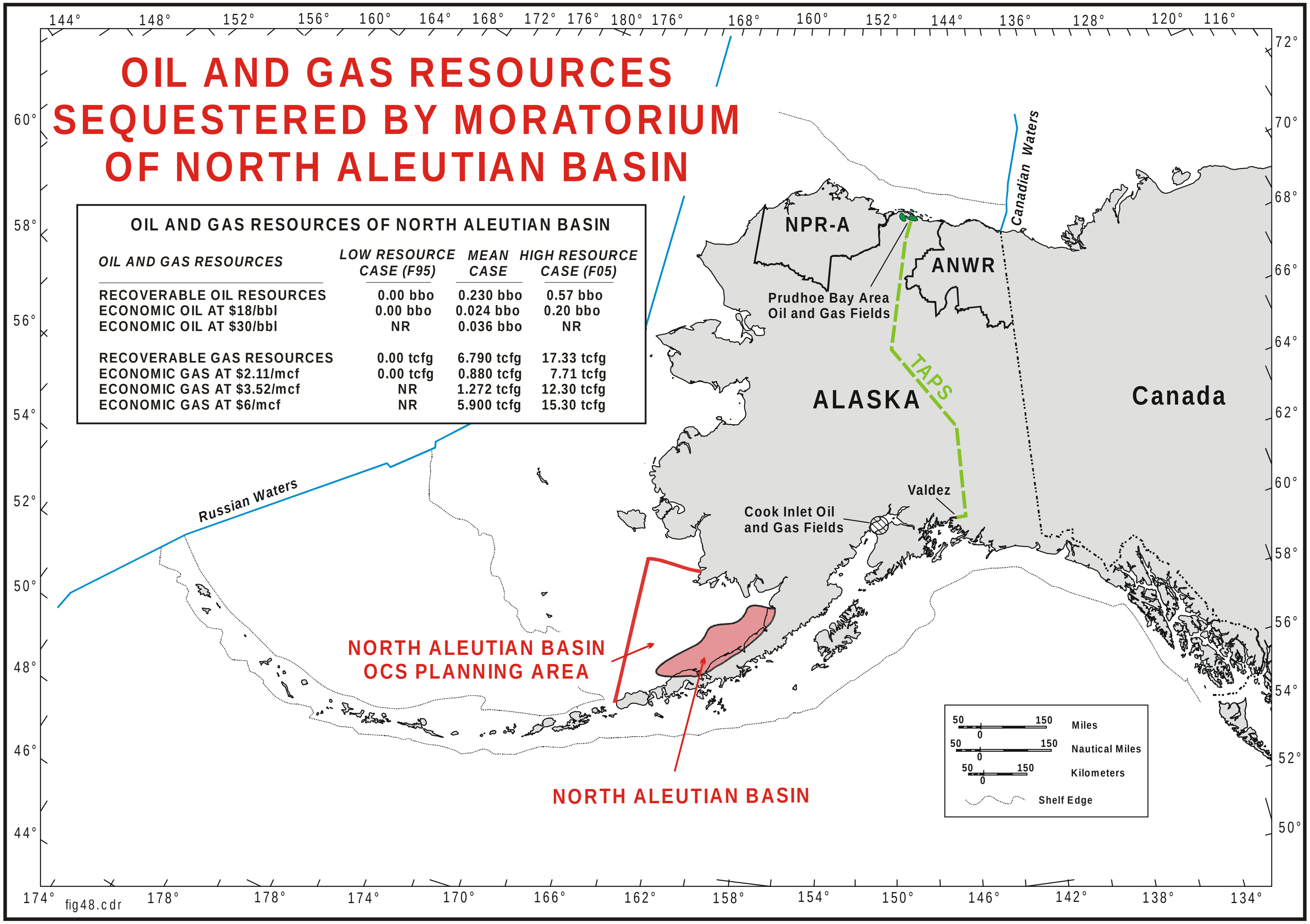


Figure 47: Bar chart for aggregate annual footages for exploratory wells drilled in Alaska Federal offshore from 1976 to 2000, with world oil prices ($1999) also posted. A total of 83 exploratory wells have been drilled in the Alaska Federal offshore with aggregate penetration footage of 875,915 feet. 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.



OIL AND GAS RESOURCES OF NORTH ALEUTIAN BASIN

OIL AND GAS RESOURCES	*LOW RESOURCE CASE (F95)*	*MEAN CASE*	*HIGH RESOURCE CASE (F05)*
RECOVERABLE OIL RESOURCES	0.00 bbo	0.230 bbo	0.57 bbo
ECONOMIC OIL AT $18/bbl	0.00 bbo	0.024 bbo	0.20 bbo
ECONOMIC OIL AT $30/bbl	NR	0.036 bbo	NR
RECOVERABLE GAS RESOURCES	0.00 tcfg	6.790 tcfg	17.33 tcfg
ECONOMIC GAS AT $2.11/mcf	0.00 tcfg	0.880 tcfg	7.71 tcfg
ECONOMIC GAS AT $3.52/mcf	NR	1.272 tcfg	12.30 tcfg
ECONOMIC GAS AT $6/mcf	NR	5.900 tcfg	15.30 tcfg

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.