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LETTERS AND MEMOS

- 1. Clifton Bowen, U.S. Customs - Letter to Mr. K.M. Hnatiuk, July 28, 1978.**
- 2. Jim Chiles - Memo to all Alaska Statehood Commission Members, "Extrapolating costs of the Jones Act," February 10, 1982.**
- 3. Jim Chiles - Memo to All Alaska Statehood Commissioners, "Restrictions on the Export of Alaska Oil," March 12, 1982.**
- 4. C.R. Elder, Jr. - Letter to Gregg K. Erickson, Erickson & Associates, March 24, 1982.**
- 5. C.R. Elder, Jr. - Letter to Sen. Struglewski, Rep. Barnes, and Rep. Anderson, February 26, 1982.**
- 6. Gregg K. Erickson, Erickson & Associates - Letter to C.R. Elder, Jr., March 3, 1982.**
- 7. Charles L. Logsdon, Petroleum Economist, State of Alaska Department of Revenue - Letter to Jim Chiles, February 9, 1982.**
- 8. Donald W. Lewis, Director, Office of Regulations and Rulings, U.S. Customs - Letter to Governor George R. Ariyoshi of Hawaii.**
- 9. Theodore McCulloch, Vice President and General Manager, Foss Alaska Line - Letter to John de Yonge, December 4, 1981.**
- 10. H.L. Schuyler, Director, Public Affairs, Sealand Service, Inc. - Letter to John de Yonge, December 21, 1981.**
- 11. Everett W. Trout, Vice President, Operations, Totem Ocean Trailer Express, Inc. - Letter to John de Yonge, December 18, 1981.**
- 12. White House - Memo to Oil Exports Working Group, Cabinet Council on Natural Resources and Environment, "Oil Exports Paper," September 24, 1981.**

ALASKA'S ECONOMY AND THE MERCHANT MARINE ACT OF 1920
(The Jones Act)

A Follow-Up and Review of
The Jones Act and its Impact on the State of Alaska
By Simat, Helleisen & Eichner, Inc.
For the Alaska Statehood Commission

20 September, 1982

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EXECUTIVE SUMMARY **(Principal Findings)**

This paper was prepared by Arlon R. Tussing and Associates, Inc. (ARTA) for the Alaska Statehood Commission as a follow-up, review, and interpretation of the analysis and findings contained in The Jones Act and its Impact on the State of Alaska, by Simat, Helleisen & Eichner, Inc. (SH&E). The following are among the most important inferences that readers can draw from the SH&E study and from this review.

1. The "cabotage" laws of the United States, of which the Jones Act is the keystone, impose substantial costs on the US economy, in the form of higher oceanborne freight charges, and the diversion of cargo to more expensive transportation modes.

These costs of the cabotage laws are imposed disproportionately on Alaska. The state's physical separation from the other states makes it depend disproportionately on ocean transport for its interstate commerce. In addition, Alaska's large size and primitive land-transportation network make it depend disproportionately on ocean transportation for its intrastate commerce.

2. Because Alaska's economy is small and distant from major markets, the Jones Act creates a DOUBLE cost penalty for Alaskans. The state is generally a price-taker for both its imports and its exports; thus, the Jones Act adds to the prices of Alaska's imports and subtracts from the prices of the state's exports.

3. The "Jones Act penalty" (the additional cost of using US-built, US-owned, US-registered, and US-manned vessels in place of the lowest-cost transportation) tends to be greatest for commodities having a low ratio of value to weight or to volume.

The cost to Alaska from the Jones Act penalty on the outbound shipment of crude oil probably overshadows all other costs of the Act. SH&E's analysis implies that the law currently reduces the wellhead value of Alaska crude oil by about \$225 million per year. Consideration of the worldwide

surplus of foreign-flag tankers raises this penalty to about \$310 million per year. Taking account of current trends in West Coast oil-price formation increases the potential penalty at the wellhead to \$630 million per year.

The state government's share of increased (or decreased) wellhead revenue is now about 28 percent. This approach yields a direct revenue cost of the Jones Act to Alaska's treasury in the range of \$63 to \$176 million per year.

5. The IMMEDIATE effect of removing either the Jones Act requirements or export restrictions on Alaska crude-oil shipments would probably be minor: The North Slope crude-oil producers have already invested in Jones Act tankers and have made throughput commitments to an oil pipeline across Panama. Also, the incentive of Alaska crude-oil producers to seek transportation-cost reductions is weak, because the combination of royalties and severance taxes, "windfall-profits tax", and federal and state income taxes leaves the producers less than 10 percent of any increase in wellhead prices stemming from lower ocean-transport costs.

Some latitude would remain for non-producers purchasing "in-kind" royalty oil from the state to use lower-cost shipping services.

4. The prohibition on exporting Alaska crude oil depresses its "netback" price (and thereby state oil revenues) more than does the Jones Act; repeal of the prohibition would make the Jones Act nearly moot with respect to crude-oil prices.

Alaska's Congressional delegation might therefore employ its political efforts most effectively in trying to block extension of the oil export prohibitions of the Export Administration Act (which expire in 1983), rather than in mounting new legislation to repeal some of the present Jones Act provisions.

6. The direct cost of the Jones Act to Alaska's PRESENT export industries other than petroleum is probably small. Some of these industries tend to be oriented to overseas markets where the Jones Act is irrelevant. Others can take advantage of low-cost Southbound "backhaul" rates unrelated to the nationality of the vessel.

7. The direct cost of the Jones Act on Alaska's general-merchandise imports is impossible to measure with confidence, but it is probably minor. There is vigorous intermodal competition on routes between the Northwest and Alaska's "Railbelt" (which contains most of the state's population and economic activity).

Transportation costs to and between Alaska ports other than those serving the Railbelt are mostly a function of the small scale and sporadic character of shipments, rather than the nationality of shipping or vessels. A number of methods by which shippers could circumvent Jones Act cost penalties are virtually unexploited; this situation supports the inference that these penalties are insignificant.

8. The largest adverse effects of the Jones Act for Alaska are likely to be IN THE FUTURE, as transportation costs for crude-oil and other minerals can be an important factor determining the economic feasibility of developing specific deposits. Transportation costs between Alaska and the Lower 48 that are higher than those between Alaska and foreign countries also strengthen the tendency of Alaska's resource-industry markets and sources of investment capital to be in the Far East rather than the Lower 48.

9. The most promising Alaska strategy to modify the Jones Act would aim at: obtaining the support of US maritime unions and shipping companies (or at least their neutrality) for allowing foreign-owned and foreign-built ships to operate in the "coastwise" trade, while retaining US labor, safety, and environmental standards.

One basis for this strategy might be the thesis that allowing foreign-built ships in the coastwise trade would increase employment in the US merchant marine. The Jones Act has probably contributed to the virtual disappearance of the US coastwise shipping industry (except for shipments of petroleum by tanker, and service linking Alaska and Hawaii with the mainland).

A first tactic in such a strategy would be for the state to commission a study of the effect of the US-tanker requirement in the Jones Act on US merchant-marine employment.

The SH&E report. The SH&E report is well written, comprehensive, and insightful, and contains little with which ARTA have substantive disagreements. Its quantitative (dollar-denominated) findings about the economic effects of the Jones Act in Alaska suffer from the same disabilities that beset almost every "counterfactual" analysis --- every study that attempts to describe the world that would exist "if only" some circumstance or set of circumstances were different from present reality.

In any analysis of this sort, the investigators have almost infinite discretion in choosing assumptions about which factors to hold constant, and how far to trace the indirect effects of the assumed change. Thus, ARTA probably would have made different assumptions from those employed by SH&E, and emphasized different factors, but we do not thereby mean to fault the SH&E team for the assumptions and methodology they selected. Our object here has been to organize, integrate, and present essentially the same insights as the SH&E report in a way which, we hope, is more directly focused on Alaska's policy choices.

THE JONES ACT AND SHIPPING COSTS: GENERAL

The Merchant Marine Acts of 1920 ("The Jones Act") and 1936 restrict the nation's "coastwise trade" (waterborne commerce between United States ports) to ships (1) built in the United States, (2) manned by US nationals, (3) owned by US nationals, and (4) registered in the US. The following effects of these "cabotage" laws tend to raise the cost of domestic water transportation:

1. Ship-construction costs are relatively high in the United States because of high shipyard labor costs and low labor productivity. SH&E show capital costs for US-flag vessels that are about twice those of their foreign-flag counterparts:

Service	Capital Costs per Ton (Depreciation & Interest)		
	US- Flag	Foreign- Flag	Ratio
VLCC tanker, Valdez-Los Angeles	\$ 1.87	\$0.94	1.98
VLCC tanker, Valdez-Panama	4.00	2.00	2.00
Handy-size tanker, Panama-US Gulf	1.48	.74	2.00
Oil-product tanker, Los Angeles-Valdez	2.92	1.46	2.00
Bulk carrier, Ketchikan-Seattle	1.13	.57	1.98
Containership, Seattle-Alaska	66.60	33.18	2.01
RoRo, Seattle-Alaska	119.01	59.50	2.00
Barge service, Seattle-Alaska	178.34	101.91	1.75

Shipbuilding is a labor-intensive industry that uses a workforce made up primarily of skilled and semi-skilled workers. As a result, the countries that have the greatest comparative advantage in shipbuilding tend to be "low-income developed countries". These are countries with a skilled and disciplined labor force, a moderately high level of technical sophistication, and an effective industrial infrastructure, together with comparatively low wages.

In the early Nineteenth Century, the United States was such a low-income developed country and competed with England for first rank among maritime powers; a similar economic position gave Japan the world lead in shipbuilding during the 1950s and 1960s. More recently Poland, Spain, Portugal, Taiwan, Korea, and Ireland have been able to undersell shipyards in the United States, Japan, and other high-income developed countries.

The comparative disadvantage that a country's high labor costs impart to shipbuilding is not absolute, however. High labor productivity and standards of workmanship have allowed some Scandinavian yards to remain competitive in specialized kinds of shipbuilding despite their high wages. Finland, for example, appears to be the world's leader in icebreaker construction.

Higher capital costs also contribute to higher insurance costs.

2. The United States merchant marine is unionized and US seamen receive exceedingly high wages by world standards. SH&E show manning costs for US-flag vessels that are about twice those of their foreign-flag counterparts:

Service	Labor Costs per Ton (Manning & Subsistence)		
	US- Flag	Foreign- Flag	Ratio
VLCC tanker, Valdez-Los Angeles	\$ 0.72	\$0.39	1.85
VLCC tanker, Valdez-Panama	1.55	0.83	1.88
Handy-size tanker, Panama-US Gulf	1.90	.97	1.96
Oil-product tanker, Los Angeles-Valdez	3.75	1.91	1.96
Bulk carrier, Ketchikan-Seattle	2.06	.99	3.49
Containership, Seattle-Alaska	151.90	88.26	1.72
RoRo, Seattle-Alaska	90.81	52.76	1.50
Barge Service, Seattle-Alaska	99.62	42.80	1.39

Foreign vessels are able to recruit crews from the whole world;

and a seaman's wage one-fifth of the US wage would nevertheless be several times higher than the amount most Pakistani, Somali, or Haitian nationals could earn at home.

3. Ships registered in the United States are subject to comparatively strict standards regarding working conditions, seamen's rights, safety, environmental protection, and insurance. These requirements increase US-flag costs relative to ships operating under "flags of convenience"; i.e., registered in countries like Panama and Liberia chosen expressly because of their more lenient regulations.

4. Ships owned by United States nationals are subject to relatively high levels of taxation. Taxes on ships operating in international trade are lower or non-existent in the flag-of-convenience nations.

5. The absence of foreign-built, foreign-owned, foreign-registered, and foreign-manned vessels from the US coastwise trade limits competition. The fact that US shippers can not draw from the whole world's population of ships and ship operators would tend to keep domestic shipping rates higher even if the US otherwise had relatively low ship-construction and operating costs.

Protection of domestic shipping (1) reduces the incentives for US shipbuilders and shipyard workers to increase productivity and trim costs; (2) increases the influence of maritime unions relative to shipowners and shippers; (3) softens the resistance of shipowners to strict regulation concerning safety and working-conditions, environmental-protection, and liability for accidents, pollution, etc., and (4) makes it easier for operators to cooperate in setting rates.

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6. The strict separation of domestic and foreign waterborne commerce prevents operators from optimizing routes and utilization of vessel capacity.

In general, ships can not carry both domestic and international cargoes on the same trip --- the vessel is either legally excluded from one kind of service or priced out of the other. For example, in order to use a ship most efficiently on each leg of a liner voyage between California and the Orient, a vessel might begin by loading at Long Beach, offloading some cargo in Puget Sound and picking up additional cargo there, offloading at Anchorage, picking up fish at Dutch Harbor; and continuing on the Great Circle route to Yokohama, Taipei, and Singapore. The return voyage might be directly to Puget Sound and/or California, bypassing Alaska ports because of the lack of southbound cargoes.

By precluding such triangular or circular trades, the Jones Act condemns both the coastwise and international trade to the higher costs of empty or underutilized "backhaul" voyages, on any route (e.g., Puget Sound/Anchorage) where a directional imbalance exists.

THE IMPACT OF THE JONES ACT ON ALASKA

The Jones Act Cost Penalty. The Merchant Marine Act of 1920 ("The Jones Act") restricts the "coastwise" waterborne transportation of the United States, including transportation between Alaska and Lower-48 ports and transportation within Alaska, to vessels that are US-built, US-owned, US-registered, and manned by US nationals. Detached from the other states on the extreme Northwest corner of North America, Alaska depends disproportionately on ocean transportation for its economic links with the rest of the nation. The Jones Act has long been a point of contention between Alaskans and other Americans --- it was one of the grievances that motivated Alaska's struggle against "colonialism" and the desire to become a State; 24 years after Statehood some Alaskans still regard the law as a symbol of their state's second-class membership in the American union.

Whatever transportation-cost penalty the Jones Act carries is imposed disproportionately on the Alaska economy. In general, the relatively small size of Alaska's economy makes it a "price-taker" in national and international markets. That is, both the prices of goods exported from Alaska and those of goods imported into the state tend to be set in larger markets outside its borders. Higher transport costs are thus added to the cost of Alaska's imports, and subtracted from the market prices of her exports.

The value of crude oil at Valdez, for example, is a "netback" value that reflects the cost of similar grades of crude oil at Lower-48 refineries, less transportation charges from Valdez to the refinery. Most other commodities produced in Alaska will be valued in the same fashion. Likewise, the prices of most consumer goods in Anchorage are composed of a price determined in some outside market, plus the

transportation cost from that market to Anchorage (and, of course, local distribution markups).

Alaska's position as a price-taker means that its economy tends to suffer a double penalty from any adverse transport-cost differential. In general, the state's exports to Lower-48 markets will have lower prices at their point of origin than would otherwise have been the case. The most obvious impact of this kind is on the state government's natural-resource royalties and severance taxes, which are keyed to netback prices. Private (e.g., Native-corporation) resource leasing and sales income would be affected by transportation costs in the same way.

An even more important effect of higher transport costs in the long run may be to shift economic margins: Investors might view a certain natural-resource venture (a new oil discovery, for example, or a copper mine) to be economic if the netback value of the crude oil or ore reflected foreign-flag shipping costs, but as uneconomic if the wellhead or mine-mouth return had to absorb US-flag shipping rates. Higher import costs for capital goods and for supplies used by industry may also help shift economic margins, making otherwise economic ventures unattractive to investors.

There is little doubt, therefore, that Alaskans are relatively worse-off because of the Jones Act. The state is not now and is not likely to become a major shipbuilding area; there are few maritime-industry jobs based in Alaska that would not also exist under a more liberal regime. (Indeed, relaxation of the requirement that the coast-wise trade be carried in US-built vessels would undoubtedly result in a greater number of jobs for domestic workers; we take up this point elsewhere in the present review.) Except for some arguable national-defense benefits, therefore, it is hard to conceive of any benefit to Alaska from the cabotage laws.

It is a great leap, however, from (1) concluding that the Jones Act affects Alaskans adversely, (2) to determining which adverse effects are really significant, and (3) from there attaching numbers to these impacts. One step in such an analysis is, of course, a comparison of "required freight rates" (RFR) per unit of cargo for Jones Act vs foreign-flag carriers, as SH&E has conducted. We find no fault in these exercises as they are presented in the SH&E report.

(The RFR is the minimum rate that will cover the vessel's operating costs, amortize its original capital cost over its economic life, and provide a market rate of return on the unamortized capital. In a period of surplus capacity, like the present with respect to foreign-flag oil tankers, actual spot (single-voyage) or time-charter rates may in fact fall below RFR to a level where they cover only variable or "running" costs. Conversely, in a tight market actual rates are likely to be considerably above RFR.)

Although the Jones Act's economic effects are overwhelmingly negative for Alaska, there are few markets or aspects of Alaska's economy for which removal of the Jones Act strictures would make much immediate difference. Except for the Railbelt area (Anchorage, Seward and Whittier, north through the Matanuska Valley to Fairbanks), the cost of ocean transportation is dominated by its seasonality or sporadic character, by the small scale of shipments, and by directional imbalance. For much of Alaska, it is not likely that the potential of competition from foreign-flag carriers would have much impact on costs.

The Railbelt, where most of Alaska's ocean-transportation demand originates, is served by a variety of shipping companies and modes of transportation. For the general mixed-merchandise trade in consumer goods and miscellaneous industrial supplies and building materials,

the transportation business is highly competitive and continually changing. Containerized and roll-on/roll-off trailers seem to be the most efficient mode for most of this business and, as SH&E show, their costs are not strongly related to the nationality of the operations (page 41). Differences in the efficiency of shore-based activities can easily cancel out any difference in capital and manning costs between U.S.-flag and foreign-flag operations. Adding foreign-flag shipping companies to the present mix would in principle strengthen competition, but the true impact is hard to pin down.

The biggest cost impacts of the cabotage laws will be on commodities with low ratios of value to weight or bulk, where there is little practical alternative to oceanborne transportation. Crude oil is of course the outstanding example, and is Alaska's chief export commodity. Other Alaska bulk commodities --- ores, for example, may be seriously affected at some time in the future by the Jones Act cost penalty. Because of the myriad way in which producers, consumers, and investors can adjust to cost differentials, however, the actual impact of the Jones Act will be quite different from the raw comparison of the required freight rates (RFRs) for identical commodities on identical routes in Jones Act and foreign vessels. Several of these differences are worth noting in detail.

Firstly, there are exceptions to the general rule that Alaska is a price-taker in its sales and a price-taker in its purchases. From 1973 to 1980, for example, Alaska-produced crude oil was subject to federal price ceilings at the wellhead. As a result, Lower-48 refinery prices for that oil were cost-plus prices, reflecting the regulated wellhead price plus transportation costs. (North Slope crude oil, however, was actually priced on a netback basis from 1977 through mid-1979 notwithstanding

federal price controls, because the federal ceilings were higher than the market value of the oil.)

Sponsors of projects to deliver Alaska natural gas to the Lower-48, including the El Paso Alaska and PAC-Alaska LNG (liquefied natural gas) schemes as well as the Alaska Highway gas pipeline, have planned for Lower-48 pricing of Alaska natural gas on a cost-plus basis, composed of the sum of a regulated wellhead price and pipeline and/or LNG-tanker costs. These expectations would have been realistic, however, only if there had been a permanent gas shortage in the Lower 48. Under all foreseeable market conditions today, however, a cost-plus price would make Alaska gas unmarketable in the Lower 48.

It is interesting to note that the El Paso Company acknowledged that the need to use Jones Act LNG tankers would have made its proposal to ship North Slope LNG from Prince William Sound to California uneconomic even under the gas-market assumptions that prevailed in 1976, unless the project were able to obtain federal ship-construction subsidies and/or loan-guarantees.

The pricing of petroleum products refined in Alaska is another exception to the rule that the Jones Act means higher prices for Alaska consumer goods. High transportation costs for crude oil exported from Alaska result in lower crude-oil costs for Alaska refiners, and at least potentially, lower petroleum-product prices for Alaska consumers, because the local refiners need only match the price of North Slope crude oil in outside markets less transportation --- as opposed to the combination of Lower-48 prices plus transportation that governs the Alaska prices of most consumer goods.

Those petroleum products produced by two or three of the Alaska refineries (jet fuel and distillate fuel oil) tend to sell in Alaska for less than West Coast prices, while motor gasoline (produced only by Tesoro)

sells at somewhat more than the Los Angeles price, but at less than the Los Angeles price plus transportation costs. For this reason, we doubt whether there is actually a "US-flag premium of \$5.46 per long ton on petroleum products shipped north from Los Angeles." (SH&E, page 54) It is likely that California refiners absorb most or all of this premium --- indeed, it is not clear that Alaska consumers actually bear all of the Northbound transport costs.

There are other instances in which sellers or buyers outside of Alaska may have to absorb all or some of the additional costs imposed by higher freight rates. To the extent that the lowest-cost source of some Alaska import (for example, structural steel or steel pipe from Japan) is not burdened with a Jones Act shipping-cost penalty, competing Lower-48 suppliers may have to absorb whatever additional Jones Act penalty their product bears if they hope to do business in the state. In some cases, they may be willing to accept a lower price, in others they may not.

Likewise, US buyers seeking an Alaska product whose principal outlet is a foreign country must meet the Alaska export price and, in addition, bear whatever additional transport cost is involved. This situation probably applies to occasional shipments of Southeast Alaska logs or lumber to the Lower 48; thus the SH&E report may be in error when it attributes a \$3.41-per-ton Jones Act penalty on Southbound exports of Alaska lumber (p 54). The same situation likely applies to shipments of fresh and frozen king and chum salmon from the Bristol Bay area --- their prices are most likely determined by the offers of Japanese fish-buyers; Lower-48 buyers are price-takers and must absorb whatever the transportation costs to the Lower 48 may be.

Secondly, shippers can avoid the full impact of any Jones Act penalty by using a different transport mode or different routing; and

the new arrangement may or may not involve Jones Act shipping. For example, SH&E refer to exceptions or "provisos" in the Jones Act which constitute potential loopholes in its coverage (pp 4-8). The most important exception is probably the ability to use foreign vessels in the coastwise trade, if the group of carriers, which must include a Canadian railroad, files a through tariff with the Interstate Commerce Commission. Hydrotrain formerly used this exception to ship rail barges from New Westminster, BC to Whittier. Similar arrangements could be imagined involving piggyback trailers carried by rail to Canada, where they would be loaded on Ro/Ro (roll-on/roll-off) or container vessels.

Alternately, the level and structure of Jones Act charges might shift some cargoes from self-propelled Jones Act ships to Jones Act tug-and-barge combinations; and other cargoes from ships to highway transportation; and still others to mixed modes (e.g., by highway to Prince Rupert and thence by Alaska state ferries to Southeast Alaska ports rather than by sea all the way).

Still another pattern exists in the Southeast Alaska tourship industry. In order to use foreign-built, foreign-flag, and foreign-crew vessels in Alaska tourship operations, the operators simply base their operations abroad, and pretend that no passenger both embarks and disembarks in the United States. Numerous passengers do, indeed, join a tour at (say) Seattle, and leave it at (say) Skagway, but no one evidently interferes, in the (probably accurate) perception that if the Jones Act were enforced in this case, there would be no tourships.

Thirdly, Jones Act transport-cost penalties can induce Alaska buyers to shift supply sources. For example, Japan is a net exporter of both steel and automobiles to the United States. Because Alaska is located between US and Japanese producing areas, the state can be expected to import a somewhat larger share of its steel and motor

vehicles from Japan than do other areas of the United States having lower shipping costs from US factories and higher shipping costs from Japan. This would be the case even in the absence of a Jones Act transportation-cost burden on shipments from the United States, because Alaska is further from US producing areas and closer to Japan. The Jones Act penalty on shipments of steel and automobiles from the United States to Alaska would, however, tend to shift the Alaska market balance even further in favor of Japanese goods.

The tendency for shipping costs to alter the choice of supply sources could be readily tested and measured for motor vehicles, on the basis of published statistics on sales and average prices by state and make. If Japanese automobiles are in fact imported directly into Alaska rather than transshipped through Seattle (a factual question we have not investigated), we could compute the Jones Act transportation-cost penalty on motor vehicles with some confidence. With a little ingenuity, the same data could be translated into lost sales by US auto manufacturers and lost jobs for US auto workers. (Unfortunately, the Alaska market is probably too small for such an analysis to have much influence on the position of the United Auto Workers with respect to the Jones Act.)

Researchers could do a similar analysis of the Jones Act's influence on Alaska steel-purchasing patterns, but the necessary data are much more complex and difficult to obtain. Such an analysis would probably be worth while, however, for very large projects using large amounts of steel. For example, was the Jones Act an element in Alyeska's decision to use Japanese-made pipe on the Trans-Alaska oil pipeline (TAPS)? If so, the state's advocates and allies on this issue could counterpose the employment cost of the Jones Act to US

steelworkers against its benefits (if any) to shipyard and maritime workers.

If such an analysis showed that motor-vehicle, industrial-machinery, or steel-purchase decisions in Alaska are indeed sensitive to ocean-transport costs, Alaska might effectively argue for an amendment to the law providing that ---

The Secretary of Commerce may authorize the use of foreign-flag vessels in transport of US-produced commodities to or between Alaska ports if he finds that requiring the use of Jones Act vessels will result in a loss of sales by the US producers of those commodities.

Buying Canadian-made goods is another way in which Alaskans can, at least in principle, circumvent the Jones Act. British Columbia is a net exporter of lumber and newsprint to the United States; thus Canadian prices of these commodities, plus duty, are unlikely to be higher than U.S. prices. It is likely, indeed, that most of the newsprint consumed in Alaska now comes from British Columbia by way of Seattle. Alaska buyers ought to be able to save at least as much on these commodities as the unit difference between US-flag and foreign-flag cargo rates by importing them from Canada rather than from the West Coast of the United States. Similar relationships may exist for Portland cement and other low value-to-weight or value-to-bulk commodities.

The import of motor vehicles from Canada might be a similar opportunity for avoiding Jones Act transportation-cost penalties. The United States and Canada have an agreement to treat the automobile and auto-parts manufacturing industry of the two countries as a single industry. "American" cars bought in the US may well have been manufactured in Canada or vice versa; cross-border sales do not bear

import duties. Thus, "American" motor vehicles made in Canada could be shipped from Vancouver to Alaska in foreign-flag carriers without running afoul of the Jones Act.

Any assessment of the feasibility of arrangements of this type would have to take account of (1) import duties and non-tariff import limitations, (2) economies of scale, and (3) the effect of directionally imbalanced trade. For example, is the Alaska Railbelt's motor-vehicle market large enough to support direct deliveries from Japan or Canada by specialized automobile carriers? And how much, if any, influence does the Jones Act have on outbound or ("backhaul") cargoes of fish, wood products, or other merchandise in view of the excess capacity that exists for southbound water, air and highway shipping?

Nevertheless, the fact that few shippers now seem to take advantage of either (1) their ability to bypass the Jones Act with purchases in Canada or (2) the exception for through shipments over Canadian railroads (and particularly the failure of a British Columbia to Whittier rail-barge service) leads us to a rebuttable presumption that the effective burden of the Jones Act on the Railbelt's general-merchandise imports is not great.

Fourthly, Alaska exports could be redirected away from US markets, where their transportation is burdened by the Jones Act cost penalty, to foreign markets that can be served by foreign-flag carriers. Even without a Jones Act cost differential, the Far East is an important market for Alaska natural-resource products. About three-fourths of Alaska's forest products, and about one-fifth of its seafood products (measured by wholesale value vs the FOB value of exports) are exported; these exports are principally to the Far East. If an Alaska coal-export industry develops, it will surely serve the Far East rather than the Lower-48. Some metallic and non-metallic mining industries,

likewise, would be directed at markets in Japan, Korea, Taiwan, etc. The fact that the Western US and Canada are both exporters of coal, wood products, non-ferrous metal ores and concentrates, and other non-fuel minerals to East Asia is almost conclusive evidence that additional Alaska exports would tend to go East rather than South, even without the Jones Act.

Alaska's single existing petrochemical plant was built to serve the Japanese market, and if further natural-gas or natural-gas-liquids-based petrochemical plants are built in Alaska, a part of their output would surely go to Far Eastern markets. The state's present production of LNG is exported to Japan, and if any prospect exists for further LNG shipments from Alaska, it would almost certainly be an East Asian market, in view of the emerging natural-gas surplus throughout North America.

If Alaska's natural-resource-based industries continue to diversify, there will be a number of industries orienting principally to US markets, and others orienting principally to East Asian or other export markets, but most of them have some potential in both domestic and foreign markets. Alaska's seafood, wood products, oil and gas, coal, non-fuel minerals, and agricultural industries can each be expected to serve both domestic and foreign export markets to different degrees. The effect of the Jones Act will not be measurable with very much confidence in most of these industries, but in each of them, it can be expected to tilt the market balance in some degree away from Lower-48 markets and toward foreign export markets.

The same factors that bias the state's trade toward foreign exports will, moreover, have some tendency to tilt Alaska's resource-extraction and processing industries further in the direction of foreign ownership and management.

The most important Alaska industry that would be export-oriented, at least in part, is crude-oil production. If the Alaska North Slope (ANS) crude-oil producers faced no legal obstacles in selling their product where it obtained the highest netback price, they would ship a little less to the US West Coast than they do now, and the balance would be sold in the Far East, rather than in the Eastern part of the United States. The Jones Act, by reducing the netback prices from the West Coast relative to netback prices from Japan, would have some influence on this balance --- exports would be greater by some amount than they would have been in the absence of the Jones Act.

This inference is moot today, however, because the Trans-Alaska Pipeline Authorization Act severely restricts the exports of crude oil transported through pipelines crossing federal lands, and the Export Administration Act amendments of 1979 effectively prohibit exports of crude oil transported through the Trans Alaska Pipeline System (TAPS). The joint influence of these export restrictions and the Jones Act are sufficiently important that we have considered them separately in a section on "The Jones Act and the Alaska Crude-Oil Export Ban."

Finally, industrial facilities or processing operations can be located so as to minimize the impact of the Jones Act penalty, or to escape the export prohibition. American-owned refineries have located in the Caribbean, for example, partly because they could receive Middle Eastern or Venezuelan crude oil at those refineries via foreign-flag VLCCs, and then ship the refined products into US ports in smaller foreign-flag tankers. The reader can probably conceive of a number of possibilities of this sort, involving the processing or conversion of some Alaska resource product in Canada or some other foreign country, for reshipment in a new form back to the United States. Both legs of the journey might thereby escape the Jones Act limitations.

ALASKA CRUDE-OIL ECONOMICS: **THE JONES ACT AND THE EXPORT BAN**

The greatest Alaska impact of the Jones Act undoubtedly comes from its influence on the wellhead value of crude oil produced in the state. Alaska's state royalty and production-tax revenues are a direct function of the wellhead price; on some (still non-producing) leases in the Beaufort Sea, the state owns an additional net-profits interest that makes its revenues an increasing function of the wellhead price. The state's corporate income-tax collections on crude-oil production also depend on the wellhead price, and the expected wellhead price is a crucial variable in the oil companies' decision whether and how much to bid on a lease, explore a tract, develop a discovery, or invest in extended or enhanced recovery in a producing field.

The wellhead value of Alaska crude oil is a "netback" value, determined by subtracting transportation costs from the market value of the oil at the receiving refinery. This value at the refinery is, in turn, the price the refiner would have to pay to acquire a similar grade and quality of crude oil from another source. In the world at large, therefore, Alaska-produced crude oil is a price-taker, and higher transportation costs between the field and the refinery are deducted almost penny-for-penny from the wellhead price.

SH&E estimate the reduction in the value of Alaska crude resulting from the Jones Act at about \$225 million per year, based upon present levels of production in Alaska and the recent destinations of Prudhoe Bay crude oil. They obtained this figure by a straight comparison between required freight rates (RFRs) on US-flag and foreign-flag tankers on the Valdez-Los Angeles, Valdez-Panama, and Panama-Gulf Coast routes. While this calculation is a useful starting

point, readers should keep in mind several caveats about these assumptions.

Repeal of the Jones Act would not lead the Alaska crude-oil producers to replace their existing Jones Act tankers overnight with foreign-flag tankers. The companies have already incurred the acquisition costs for these tankers, either for their construction or for term charters, and their decision whether to retire them in favor of other vessels will not be based upon the difference between the RFR of the current fleet and that of the new vessels, but only on their relative running costs. Likewise, the companies have committed themselves to pay the new Panama pipeline's tariff for three years whether or not they actually use it. Thus, the trans-Panama cost is not one that shippers can instantly avoid by using foreign-flag VLCC's (supertankers) around the Horn. In valuing their oil at the wellhead for royalty and tax purposes, moreover, the companies can be expected to keep deducting the costs of the present tanker fleet from the refinery value of the oil until its costs have been amortized, even if some transportation alternative has a lower incremental cost.

It is also important to recognize that the companies' motivation to alter their transportation arrangements in order to increase the wellhead price is very weak. In other words, running-cost savings would have to be exceptionally large to justify any capital outlays for new transportation facilities. This circumstance stems from a combination of royalties and state and federal taxes that leaves the producers less than ten cents out of each dollar in added wellhead revenues at Prudhoe Bay or Cook Inlet. (Production from the Kuparuk field is, however, exempt from the federal windfall profits tax and is subject to a lower state severance tax than Prudhoe Bay production; as a result, the

companies retain about 40 percent of any increase in the Kuparuk wellhead price.)

For these reasons, SH&E's figure of \$225 million is valid only as an hypothesis about the past or the future. It is an estimate of how much higher Alaska wellhead revenues would now be if the Jones Act had not been in effect when the companies made their transportation investments or, alternatively, how much higher they would be after the end of the present Jones Act tanker fleet's economic life, if the Jones Act were repealed or waived today. For the latter purpose, however, SH&E's estimate of the Jones Act premium on the basis of comparing US-flag and foreign-flag RFR's is probably an understatement, for two reasons.

Firstly, the RFR is a valid basis for estimating the life-cycle cost of transportation for new Jones Act tankers that would be built to replace the present tanker fleet, because there is no surplus of unsubsidized, US-flag vessels such as those used on the Alaska run, and none is anticipated. Foreign-flag tankers of every kind, however, are available for purchase or long-term charter for considerably less than their original capital cost. About 40 percent of the world's VLCC's built since 1975 are idle because of the decline in world oil consumption. As this surplus capacity is not going disappear in the foreseeable future, it is more appropriate to compare the RFR on Jones Act tankers with the variable operating costs of foreign-flag tankers. If one makes this adjustment, using SH&E's cost data, the projected Jones Act premium corresponding to the current volume and destination of Alaska crude-oil production rises from SH&E's \$225 million to \$314 million.

Secondly, SH&E's calculations assume that two-thirds of Alaska production goes to the West Coast and one-third to the East Coast, and that the US West Coast and US Gulf Coast markets for Alaska crude oil

are economically separate, so that there are two sets of wellhead prices in Alaska. The higher price in this model is a netback from the West Coast, and the lower a netback from the Gulf Coast. On this basis, SH&E estimated the Jones Act cost premium separately for the two routes and then combined them to yield their total of \$225 million. These assumptions about the market for Alaska crude oil reasonably approximate the market's past operation, but they are unsuitable for projecting future prices. A worldwide buyers' market for crude oil, together with rising production in both Alaska and California, have intensified producer competition for the West Coast market, and are gradually breaking down the two price system. This market is moving in the direction of a system where the Valdez price will be the US Gulf Coast price less transportation charges from Valdez to the Gulf, while the California price will be the Valdez price plus transportation to the California refinery. (A technical appendix to this review, regarding "West Coast Oil Prices" explains how the two-price system operates and why it is breaking down.)

In the emerging one-price system, only the transportation cost between the Alaska and the US Gulf will affect the wellhead price of Alaska crude oil. Because the Jones Act penalty is greater on this longer route, therefore, its depressing effect on Alaska wellhead revenues will be considerably greater than estimated by SH&E. Using Jones Act and foreign-flag tanker RFRs on the Alaska-Panama and Panama-Gulf routes to determine the netback value of all Alaska crude oil would double the estimated Jones Act penalty, from \$225 million to \$450 million. If we also take the world tanker surplus into account, and compare Jones Act RFRs with foreign-flag running costs rather than foreign-flag RFRs, the estimated Jones Act penalty incurred by Alaska crude-oil rises from \$310 million per year to \$630 million.

The state's direct share of additions or reductions in wellhead prices is now about 28 percent, including royalties, production taxes, and state income taxes on profits from crude-oil production and TAPS operations. Thus, depending upon the additional assumptions adopted, the state's direct revenue loss from the Jones Act ranges from \$63 million to \$176 million annually.

Alaska crude-oil production would not have to bear this "Jones Act penalty" that amounts to some hundreds of millions of dollars annually if Congress had not prohibited the export of crude oil carried through TAPS. The Trans Alaska Pipeline Authorization Act of 1973 allows the export of crude oil carried by pipelines across federal lands (other than exchanges with Mexico or Canada) only under specified conditions, which must be certified by the President. In the 1979 "McKinney" amendment to the Export Administration Act, which was intensely lobbied for by the maritime interests, Congress took away the President's discretion on exports of North Slope oil, and effectively outlawed them. Even considered alone, this export restriction costs Alaska considerably more than does the Jones Act.

In the absence of the export ban, most of the Alaska crude oil now shipped to the US Gulf and East Coasts would be exported to Japan and other East Asian countries. The Jones Act would not, of course, apply to these shipments, and the netback value of Alaska crude oil would be its value in Japan (the price at which Japanese refiners could obtain a similar grade and quality of crude oil from another source) less foreign-flag tanker charges from Alaska to Japan.

There have been a number of studies of the cost of the export ban in lower wellhead revenues for Alaska crude oil. Their assumptions vary widely, but most of them conclude that the netback value of Alaska oil exported to the Far East in foreign-flag tankers would be

about the same as the netback value of Alaska oil sold on the US West Coast in competition with similar types of Middle Eastern oil. Japan is closer to the Persian Gulf than California, resulting in a somewhat lower "world-market" oil price there, but this differential just about offsets the greater penalty imposed in the US on North Slope oil because of its sulfur content and "high gravity". And the longer run from Alaska to Japan, compared with the run from Alaska to California just about offsets the Jones Act penalty on the domestic route.

In brief, if exports were permitted, all crude oil shipped from Alaska would have a netback value at least as high as the present West Coast netback price. The Jones Act would therefore no longer affect the third of Alaska's current production that moves beyond the West Coast; and the route to Japan is shorter and less complicated. Over time, an even more important effect of the export "window" would be to limit the competition between Alaska and California crude oils at California refineries, which otherwise threatens to depress all Alaska crude-oil prices to levels that reflect US Gulf Coast prices less Jones Act transportation costs.

Summary. If both the Jones Act and the ban on exporting Alaska oil remain in place, the wellhead value of all Alaska oil will ultimately be the world market price at the U.S. Gulf less pipeline and Jones Act shipping costs between Alaska and the Gulf. If both restrictions are waived, the wellhead value of all Alaska oil will ultimately be the world market price in Japan less pipeline and foreign-flag shipping costs between Alaska and Japan. If exports are permitted and the Jones Act remains unchanged, the wellhead value of Alaska oil will still rise to the world market price in Japan less pipeline and foreign-flag shipping costs between Alaska and Japan, because producers would not be willing to sell Alaska oil into US West

Coast markets unless they got at least as much for it there as they would get by exporting it.

Under the last set of circumstances, California consumers of Alaska oil, rather than Alaska producers, would pay the Jones Act penalty, while California producers would benefit from the resulting higher prices. Assuming that the market value of North Slope crude oil were about the same at both destinations, removing the export ban could ultimately raise Alaska wellhead prices by \$4-6 per barrel, or \$2-3 billion per year, on production at 1.6 million barrels per day --- regardless of whether anything was done about the Jones Act. We saw previously that repealing the Jones Act without allowing exports would ultimately increase wellhead prices for the same 1.6 million barrels per day by "only" \$450 to \$630 million.

The same cautions that we applied to the Alaska benefits of repealing the Jones Act apply here also. Firstly, the hypothetical benefits of oil exports would not appear overnight, as a large part of the transportation costs the shippers of Alaska oil now bear are fixed costs of existing transportation facilities, which have been or will be incurred whether or not the existing vessels, pipelines, and terminals continue to be used. Secondly, the combination of royalties and federal and state taxes has eliminated most, if not all, of the benefits the North Slope producing companies would get from exports. None of the big three (Sohio, Arco, and Exxon) is now advocating liberalization. Arco, which is able to use all of its Alaska crude oil in its own West Coast refineries, is expressly opposed to changing the law; the benefits of liberalization would go disproportionately to competing producers in Alaska (Sohio) or competing refiners on the West Coast (Chevron).

The federal share. An earlier page of this review pointed out that the crude-oil producing companies receive less than 10 cents out of

each additional dollar netted back to the wellhead at Prudhoe Bay or Cook Inlet; they also pay out less than 10 cents out of each additional dollar in transportation expense. We have seen that the government of Alaska captures about 28 cents of each additional dollar, and pays about 28 cents out of each added dollar charged for crude-oil transportation. Combining these numbers leads to a remarkable inference, which is one of Alaska's most promising political assets in any effort to amend the cabotage laws or prevent extension of the "McKinney" amendment to the Export Administration Act: The federal government will capture more than 60 percent of any incremental revenues from Alaska crude-oil production, by means of the "windfall profits tax" and the corporate income tax.

Long-term impacts: shifting the economic margin. The most far-reaching impact of the cabotage and export-licensing laws on Alaska's petroleum economy will be their influence on company decisions whether and where to explore new acreage; whether, when, and how to develop new discoveries; and whether, when, how to invest in enhancing or prolonging the output from producing fields. The minimum wellhead prices needed to justify exploring or developing different oil prospects and discoveries in Alaska are certain to cover a wide range of values; and minimum economic prices measured at an Alaska tanker terminal will reflect the minimum wellhead price plus transportation to the terminal, and will therefore vary even more widely. Five contrasting cases illustrate the significance of destination prices and transportation costs for these decisions.

(1) Established Production: Prudhoe Bay. With TAPS already in place and most of the investment in the Prudhoe Bay waterflood project already committed, variable costs for producing Prudhoe Bay crude oil and moving it through TAPS are very low. Likewise, the incremental

capital costs per barrel for contemplated investments in pressure maintenance are relatively modest. For this reason, it is hard to imagine any economic scenario in which the producers would shut in the field or abandon the already-programmed investments in enhanced recovery.

(2) Established Productions Kuparuk. In 1980, Arco began developing the Kuparuk field's first 20-square mile tract within an initial 210-square-mile development area (out of the field's total 557-square-mile extent). Although this field may be the second-largest oilfield ever to be developed in the United States, and although the incremental cost of transporting Kuparuk oil to tidewater through the nearby TAPS pipeline is minimal, the field's per barrel development and operating costs will be far higher than in the nearby Prudhoe Bay field. Primary recovery from the initial development area will produce only one-tenth of the volume of oil expected from Prudhoe Bay, but it will require almost twice the number of wells.

Drastic events would be needed to induce Arco to shut in the already-developed portion of the Kuparuk field or to cancel the additional drilling now programmed for the initial development sector. The company probably would not have decided to develop this field, however, if it had anticipated two years ago that world oil prices would begin to fall in 1981, or if Congress had failed to exempt Kuparuk from the windfall profits tax. The ongoing decline in world oil prices creates further uncertainty regarding the economics of developing the balance of the field or of undertaking secondary- and tertiary-recovery efforts. Given the present world-oil price outlook, there is a good chance that further development of the Kuparuk field hinges on the range of markets open to North Slope oil and the cost of shipping the oil beyond Valdez.

(3) A new field with low development costs and low intrastate transport costs. A giant oilfield located near an ice-free port, on Cook Inlet perhaps, might be economic to develop at a wellhead price as low as \$3 per barrel in 1982 dollars. Its product could conceivably be gathered, treated, loaded into a tanker and --- because it had not moved through TAPS --- exported to Japan in foreign-flag tankers at a additional cost of less than \$1 per barrel. This field would be a profitable investment, therefore, even if world crude-oil prices fell as low as \$5.00 per barrel, and neither the export ban nor the Jones Act would be an issue.

(4) A new field with low development costs and high intrastate transport costs. A geologically similar field located in a remote section of Northwest Alaska might be economically feasible to develop at a wellhead price as low as \$6 per barrel (reflecting the higher field-development and operating costs in the Arctic), yet remain unexploited even if world prices remained around \$30 or more, because the cost of of the necessary pipeline and tanker terminal, or of a pipeline connecting with TAPS plus the TAPS tariff, plus Jones Act tanker charges to a Louisiana port, were expected to exceed \$25 per barrel. Industry's decision whether on not to develop this prospect would, therefore, depend directly on the destinations to which they could legally ship the oil and the cost of tanker transportation to those destinations.

(5) A new field with high development costs and low intrastate transport costs: Ungu. If the Ungu heavy-oil deposit that overlies and extends beyond the boundaries of the Kuparuk unit proves to be commercial, it is likely to displace Prudhoe Bay as the largest oil field ever found in the United States or Canada. Industry geologists are confident that Ungu contains at least twice as much "oil-in-place" as Prudhoe Bay; some of them indeed suspect it to be several times larger.

The Ungu crude oil has an API "gravity" ranging from 11° to 22°, however, which means an "extremely heavy" to "heavy" oil that is comparatively troublesome and expensive to extract, comparatively troublesome and expensive to transport, and comparatively troublesome and expensive to refine. Each well may produce two orders of magnitude less oil per day than the average Prudhoe Bay well, and once the substance has been extracted and shipped out of Alaska, refiners will deem it an inferior product worth several dollars per barrel less than Prudhoe Bay oil.

Similar, smaller, heavy-oil deposits have been exploited for decades in California's San Joaquin Valley but, given the high cost of almost everything associated with petroleum development in Arctic Alaska, that fact does not establish a presumption that Ungu can be developed profitably. Even in California, heavy-oil fields requiring steam-or solvent-injection is needed to extract the oil have development and operating costs ranging from \$7 to \$20 per barrel. One indication how critical wellhead prices have been to the economics of this resource is the fact that nearly one-fourth of the proved reserves of heavy oil in California at the end of 1981, had been booked into the "proved" column only after the deregulation of heavy-oil prices in 1978 allowed their prices to rise into the \$19 to \$25 range.

The Ungu heavy-oil deposit has the advantage of proximity to TAPS, and it may in fact have two advantages over California heavy-oil fields. One is the huge size of the North Slope resource, which is likely to attract considerable scientific and engineering attention and considerable risk capital, if only for the purpose of investigating whether there is any economically feasible way to develop the field. The second is its likely access to very cheap energy for

steam-generation or down-hole combustion, in the form of otherwise unmarketable natural gas and/or natural-gas liquids.

At this pass, any judgment about the minimum wellhead price that justifies developing this potential "supergiant" would be little more than a hunch, and the world crude-oil price outlook is especially cloudy. Notwithstanding these uncertainties, it should not be a surprise to discover that the economic feasibility of producing oil from what may turn out to be the largest known field in North America depends upon the destinations to which it may be shipped and/or the nationality of the tankers that carry it.

Four generalizations stand out about this menu of prospects and discoveries:

- (1) Only the largest, most prolific, and/or most favorably located oil discoveries in Alaska will prove to be commercial.
- (2) The high cost of transportation within and from Alaska means that, in most places, a field must have a finding and development cost at the wellhead in the \$0 to \$20 range, even if constant-dollar world oil prices remain at their recent high levels.
- (3) Because the wellhead value of Alaska crude oil is determined by subtracting transportation costs from market prices elsewhere, a small percentage change in the world price, or a transportation-cost disadvantage that seems small relative to the refinery value of crude oil has a greatly magnified effect on wellhead values. If today's \$30 world price nets back to a seemingly adequate wellhead price of \$8 per barrel for some remote Arctic prospect, a 13-percent fall in the world price to \$26 would reduce the actual wellhead price by half.

Under the same conditions, a \$4 difference in the Alaska netback price of oil shipped to Japan in foreign-flag vessels, and

the Alaska netback price of oil shipped to Louisiana (or anywhere in the US, for that matter, because the West Coast price will probably be determined in Louisiana) would be 50 percent of the expected wellhead price. And the lower an oil prospect's minimum economic price at the wellhead, the more sensitive its development-feasibility will be to the crude-oil's destination prices and transportation costs.

- (4) The economic-feasibility thresholds for Alaska's crude-oil discoveries and prospects are certain to occupy a wide and nearly continuous spectrum of prices. Any event or institution that adversely affects netback values --- even by "only a dollar or so" per barrel --- carries the risk of bumping some Alaska oilfield out of the "commercial" into the "non-commercial" category. The depressing effect of the Jones Act and the export prohibition on wellhead prices is sure sooner or later, to prevent development of some major discovery in Alaska.

Granted, the course of world oil prices and industry's expectations regarding world oil prices are just as crucial as transport costs to the economics of petroleum development in Alaska. At any plausible world oil-price level, nevertheless, there is bound to be some oil in Alaska that is worth developing if it can be exported in foreign-flag tankers, but which will be uneconomic to develop for shipment to the US Gulf or East coasts in Jones Act Tankers. Different expectations about world oil prices will change the names of those borderline prospects, but some Alaska oil will always be on the economic margin.

HISTORICAL PERSPECTIVE ON THE JONES ACT: BOOM AND BUST IN THE US MERCHANT MARINE

The United States merchant fleet more than tripled in tonnage during World War I. Domestic shipyards had mass-produced literally thousands of new freighters and tankers: first to replace foreign vessels diverted to Europe from service between North American ports; then to provision the combatants and replace merchant vessels lost in the war; and finally to move and support American forces in Europe. (See Table 1.) Thus, the US-owned fleet grew from 5.8 million tons in 1915 to 16.0 million tons in 1920, and from 12 to 28 percent of the world's merchant shipping capacity. (See Table 2) Over the same years, the American fleet captured an even larger share of the traffic through domestic ports; US-flag vessels, which provided only 20 percent of the tonnage entering US seaports in 1915, accounted for more than half of it in 1920.

Such was the economic background to passage of the Jones Act. While the national-defense considerations described in the SH&E report (page 4) dominated Congressional debate, the concern that the US might once again be left in wartime without cargo ships could have been served just as effectively by measures that assured the existence of a US-controlled merchant fleet. This end could have been accomplished, for example, by allowing US-owned and manned, foreign-built vessels in the coastwise trade. It is reasonable to suspect that the reasons Congress reserved the coastwise trade to US vessels focused on finding a way to preserve some kind of market for a big domestic merchant fleet and a domestic shipbuilding industry, both of which had been created nearly overnight, and neither of which was really cost competitive in international trade.

Table 1: INDICATORS OF UNITED STATES SHIPBUILDING ACTIVITY

Jones Act
09/20/82
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Notes to Table 1

- a SIC 373: Employment in Ship and Boat Building and Repair. From US Department of Labor, Bureau of Labor Statistics, Employment and Earnings in the United States, 1909-1971, and 1975 and 1980 Statistical Abstract of the United States.
- b Total includes "passenger and combination" (not shown on this table), "cargo vessels", and "tankers". From US Department of Commerce, Bureau of the Census, Historical Statistics of the United States: Colonial Times to 1970, Series Q442-448; 1975 and 1980 Statistical Abstract of the United States.

Employment attributed to US merchant shipbuilding was estimated by ARTA using overlapping 15-year regression of total SIC 373 employment for year t against tonnage of ships launched in each of the three classes for year t and $t+1$.

**Table 2. THE US MERCHANT MARINE
BOOMS AND BUSTS --- TWICE**

	Tonnage of Merchant Vessels			Vessels Entering US Seaports			Seamen Empl on US-Flag Merch't Vessels
	World Total	US- Owned	as % of Total	US US	Foreign reign	US as % of Total	
	(million tons)			(million tons)			('000s)
1915	49.2	5.8	11.9%	6.8	26.8	19.5%	n.a.
WW I	-	-	-	-	-	-	-
1920	57.3	16.0	27.9%	26.2	25.3	50.9%	n.a.
1930	69.6	15.9	22.9%	24.6	41.8	37.0%	64.2
1939	64.4	11.8	17.1%	14.5	43.4	25.1%	52.0
WW II	-	-	-	-	-	-	-
1948	69.4	29.1	36.4%	43.2	33.6	56.3%	82.1
1978	406.0	16.1	4.2%	34.0	389.	8.0%	19.9

Sources:

US Department of Commerce, Bureau of the Census,
Historical Statistics of the United States, 1789-1970,
tables:

Q480 Q476 Q510 Q511 Q414

US Department of Commerce, Bureau of the Census,
1980 Statistical Abstract of the United States, tables:

1191 1179 1188

The Jones Act therefore reserved domestic waterborne carriage to vessels that were US-built, owned, registered, and manned, but the comparative economic disadvantage of the United States on a world scale nevertheless caused a steady attrition of US-owned and US-registered tonnage as existing vessels were scrapped, sold to foreign operators, or registered under flags of convenience. Between 1920 and 1939, the US-owned fleet contracted from 16.0 million to 11.8 million tons; and its share of the world total fell from 28 to 17 percent. The number of seamen employed on US merchant vessels fell 22 percent, from 63.8 thousand in 1929 (the first year for which comparable data are available) to 49.8 thousand in 1940.

The Second World War repeated the experience of the First on an even larger scale. Newly mobilized shipyards turned out thousands of "Liberty Ships" and tankers to replace US and foreign tonnage lost in the war, and to supply US forces and the Allies with military materiel and civilian supplies. By 1948, the tonnage of the United States fleet had nearly tripled its prewar level, and its share of world cargo tonnage had more than doubled, to 36 percent from the 17 percent it occupied in 1939. US-flag carriers accounted for more than 56 percent of the cargo-vessel tonnage entering US seaports in 1948, up from 25 percent in 1939.

Once again, however, the high comparative costs of building and manning ships in the United States took their toll. US merchant-ship tonnage fell steadily from 29 million in 1948 to 16 million in 1978, the same level as in 1920, while the world's total tonnage multiplied almost sixfold, from 69 to 406 million tons. The US share of the world market shrank from 36.4 to 4.2 percent, and the nation's share of merchant tonnage entering its own seaports fell from 56.3 to 8.0 percent. The contraction of the merchant-marine workforce was even more drama-

tic, as high labor costs impelled operators to automate shipboard operations. From a 1945 high of 160 thousand, the number of persons employed on US-flag merchant vessels was about halved to 82 thousand by 1948; halved again to 39 thousand in 1965; and halved once more to less than 20 thousand in 1979.

Thus, the determination of US shipping interests (and particularly the maritime unions) to preserve their Jones Act monopoly in the one piece of the world market where their presence still counted sprang from the economic decline of the American shipping industry and from the fact that, in every year since 1948, there have been more unemployed and former merchant seamen and officers than currently employed seamen and officers. The figures we have cited here actually understate the potential surplus of maritime workers in the United States, because they exclude the tens of thousands of former Navy personnel who have had the necessary skills and the desire --- if jobs had been available --- to remain on the sea.

Thus, the campaign of American shipowners and maritime unions to preserve the cabotage laws, and to obtain construction loan guarantees and construction and operating subsidies, has been more than a struggle for markets, jurisdiction, or dues-payers, but a battle for industry and union survival. The dedication and financial resources that America's merchant seamen and officers have put at the disposal of their lobbyists have reflected the fact that, on the whole, this battle has been a losing one.

The combination of cabotage laws, construction-cost, and operating-cost subsidies has been somewhat more successful in maintaining shipyard employment than shipboard employment. While the actual tonnage of ships launched has tended to fluctuate violently from year to year, Table 1 shows shipyard employment in the mid-1970s relatively

stable at 170-180 thousand workers. About half of these jobs can be attributed to construction of US-flag merchant ships. The bulk of that work was, indeed, tanker construction --- mainly for the Alaska trade.

Since World War II, the legislative efforts of domestic maritime interests have not only been exceptionally dedicated but, considering the small economic interest they represent, they have also been exceptionally effective. Although the shipbuilding labor force has tended to outnumber shipboard personnel several-fold, it is the maritime unions who have been the heart and backbone of the effort to preserve and extend the cabotage laws. The success of the US shipping lobby has been possible, in large part, because of the distinctive sociology of maritime labor and the distinctive political history of the maritime unions --- fascinating issues that do not concern us here.

An important heritage of this history, however, is the highly political orientation of the union leadership; their ability to use its apparatus as an "organizational weapon"; and the members' willingness to contribute heavily in time and money to the cause. The maritime unions have shown persistence, cohesiveness, and political sophistication that outshines the shipowners and both management and unions in the shipbuilding industry, not to mention shipper, consumer, or taxpayer interests.

The power of the industry, and especially the unions, is now probably at the lowest point since World War II. Most of the old union leaders are gone; their most reliable political servants (e.g., Garmatz and Murphy) have succumbed to age or Abscam. By and large, the American seaman and the American merchant marine have both disappeared from the stage. The only important domain left to them is the coastwise tanker trade. Only the shadow of their former political sophistication and power survive.

There is irony in this history of the American merchant marine under the Jones Act. The United States coastwise trade and the number of American nationals engaged in that trade is probably smaller than it would have been if the Jones Act requirement of US-built carriers had not been in effect. For it tends to be construction cost for American vessels, more than domestic labor costs or safety and environmental standards, which have made the US fleet non-competitive. In the coastwise trade, the Jones Act has indeed prevented competition from diverting business to foreign vessels. High costs have, instead, diverted traffic to the rails, to the highways, and to pipelines. They have led investors to locate industrial facilities (e.g., Caribbean oil refineries) expressly to avoid the need to use Jones Act shipping.

The Jones Act may thus have made a major contribution to the near disappearance of the US coastwise trade, except for petroleum; even for petroleum, domestic waterborne cargoes are probably considerably smaller than they would otherwise be. If foreign-built ships, registered in the United States, subject to US labor and environmental laws, and manned by US nationals, were permitted in the coastwise trade, more domestic cargoes would certainly move by water than they now do. We can not say what kinds and volumes of cargo would be made sufficiently cheaper to shift from land to waterborne transport if foreign-built vessels could be used between United States ports. It is conceivable, however that US-owned, licensed, and manned, foreign-built container ships could command a substantial portion of the container and piggyback loads now on the highways and on the rails. A strategy emphasizing this possibility might split the maritime unions, who have been the most effective part of the Jones Act coalition, away from the shipbuilders.

APPENDIX

The following material on West Coast oil prices is extracted from the technical appendix to a report ARTA prepared in 1981 for West-coast Transmission Company and Petrocanada in connection with their application to the British Columbia Utilities Commission for a license to build and operate the "Rimgas" LNG-export facility.

1. WEST COAST OIL PRICES

World oil-price levels. World crude-oil markets are now [June 1981] in the process of rationalizing themselves around the \$32.00 (U.S.) official price of Saudi Arabian "marker" crude. The Saudi government's current strategy is to maintain a global crude-oil surplus until competitive forces have squeezed out all price premiums and disparities that do not reflect quality or transportation-cost differentials, and thereafter to use Saudi Arabia's market power to decide whether, when, and in what direction the whole complex of world oil prices will move.

No one can forecast the actual direction of world oil prices over the next decade with any confidence, however. On the one hand, a new Middle Eastern political or military upheaval might be followed by a third great surge in world oil prices that would leave the Saudi government's current wishes and plans almost irrelevant. On the other, it is not clear that even large cutbacks in Saudi production could prevent the global price structure from sinking to a floor substantially below \$32, if oil companies and traders started desperately unloading their existing crude-oil inventories in the belief that a price collapse was imminent. Finally, there is no consensus among the experts (and most likely none in the Saudi government itself) about the long-term policy which that government would or should pursue if it did gain undisputed control over world oil prices.

Regardless whether oil prices are stabilized in nominal dollars or in real dollars, surge upward once more, or collapse to, say, 1970 levels, it is almost certain that Persian Gulf crude oil will be the world's marginal supply, and that petroleum prices worldwide will therefore reflect

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export prices at the Persian Gulf (most likely for Arabian Light crude oil), plus transportation costs from the Persian Gulf "basing point", and an adjustment (plus or minus) for the grade and quality of the crude oil.

U.S. and West Coast crude-oil prices. A similar process of rationalization is under way in the United States as the February 1981 ending of oil-price controls and the entitlements system permits market forces to realign domestic crude-oil prices on the basis of quality and location. In a fully rationalized market, crude-oil prices on the West Coast of the United States would be significantly lower than those for comparable grades of oil East of the Rockies, despite slightly higher tanker charges from the primary basing point in the Persian Gulf.

The reason for lower prices in PAD District V (Alaska, Washington, Oregon, California, Arizona, and Hawaii) is that the District's refinery demand for crude oil is less than its crude-oil production (which is almost entirely from Alaska and California). District V's net exports of crude oil in 1980 were about 45 million barrels or 123 thousand barrels per day (mb/d); because of increased production and reduced demand, net exports have now [June 1981] risen to about 400 mb/d and can be expected to continue growing until at least 1986-87, when output from Prudhoe Bay will begin to decline. [See Table 1.]

The crude oil exported from the West Coast states is mostly Alaska North Slope (ANS) oil, carried in large tankers (VLCCs) from Valdez, Alaska to Panama, where it is transferred to smaller tankers that transit the Canal to Gulf Coast, Atlantic, and Caribbean refineries. After oil markets have had an opportunity to adjust to decontrol

**Table 1. U.S. West Coast Crude-Oil Exports and Imports
(PAD District V, 1979-80, thousand barrels per day)**

	1979	1980	
	Jan-Dec	Jan-Nov	Dec
Exports (mainly ANS crude) to:			
U.S. Gulf	131.4	274.8	252.8
U.S. Atlantic Coast	47.8	83.2	113.9
Other (mainly U.S. possessions)	159.4	192.2	234.5
<u>Total Exports</u>	<u>338.6</u>	<u>539.0</u>	<u>601.2</u>
Imports from:			
Indonesia	324.7	282.4	159.3
Malaysia	51.9	61.6	44.8
Persian Gulf	107.6	45.2	26.1
Others	43.7	44.1	6.9
<u>Total Imports</u>	<u>527.9</u>	<u>437.5</u>	<u>244.9</u>
<u>NET EXPORTS (IMPORTS)</u>	<u>(189.3)</u>	<u>101.5</u>	<u>356.3</u>

Source: U.S. Department of Energy, Energy Data Reports:
Crude Petroleum, Petroleum Products, and Natural Gas
Liquids (December, 1980).

and the growing West Coast surplus, ANS crude oil will become the "marker" crude and Valdez will become the basing-point for all West Coast oil prices. Table 2 shows the way in which the "netback" value of ANS crude oil at Valdez would determine the wellhead price of a hypothetical California heavy crude oil (CHCO) might be determined, on the basis of approximate current values.

The two-price system for ANS crude oil. Thus far, however, the ANS producers have been able to maintain two prices at Valdez --- a netback price from the U.S. Gulf determined essentially as described in Table 2, and a higher netback price for shipments to West Coast refineries that is established by reference to the price of Indonesian imports in California, with adjustments for quality and transportation-cost differentials.

Table 2: Determination of California Heavy Oil Price

Arabian Light (AL) price FOB Ras Tanura	\$32.00
+ Tanker charge, Ras Tanura to LOOP	1.25
= AL price CIF LOOP	33.25
- Quality penalty ANS vs. AL	(.35)
= ANS value CIF LOOP	32.85
- Tanker charges, Valdez to LOOP	(5.85)
= <u>ANS price FOB Valdez</u>	<u>\$27.00</u>
ANS price FOB Valdez	\$27.00
+ Tanker charge, Valdez to Long Beach	1.75
= ANS price CIF Long Beach	28.75
- Quality penalty CHCO vs. ANS	(2.80)
= CHCO value CIF Long Beach	25.95
- Pipeline charge Kern Co. - Long Beach	(.55)
= <u>CHCO wellhead value @ Kern Co.</u>	<u>\$25.40</u>

Explanation: all parties in the table, except Petromin (the Saudi government oil company) are price-takers; they can sell all the oil they wish at the given price. Saudi Arabia may set the price because it is the marginal producer, but only if it delivers whatever the market demands at that price, no more and no less. Sohio is a price-taker at the U.S. Gulf, but until recently at least, it has been the marginal producer and therefore the price-maker on the U.S. West Coast in the same sense that Saudi Arabia is the global price-maker. In the near future, however, Sohio will share this role with other companies, and competition will align West Coast crude-oil prices in the manner shown here.

Moving up the table, Kern County is a net exporter of heavy oil; producers there can sell as much as they wish by "backing out" ANS crude from Los Angeles basin refineries; to do so, they must pay (55 cents per barrel) for pipeline transportation, and accept a price discount (\$2.80) relative to the CIF price of ANS crude (\$26.75) that corresponds to the higher cost of refining the heavy crude, and the lower value of the products produced from it. Los Angeles basin refiners, in turn, can obtain as much ANS crude oil as they want, by paying tanker charges from Valdez (\$1.75) plus an FOB price (\$27.00) equal to what the producer would get for it CIF at the U.S. Gulf (\$32.85) less the cost of shipping it there (\$5.85). The FOB value of ANS crude oil at the U.S. Gulf is the CIF price at which refiners can get Arabian Light (33.25), less a penalty for the lower quality of ANS crude (35 cents); and the CIF price of Arabian Light is the FOB Persian Gulf price (\$32.00) plus tanker-transport costs (\$1.25).

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Lower prices for ANS crude would have allowed the ANS producers to sell more oil in District V by accelerating the substitution of ANS oil for imports and by retarding the development of high-cost heavy-oil production in California. But such price reductions by one ANS producer would have met with comparable reductions by other ANS and California oil producers. The increase in the number of barrels of District V crude oil refined on the West Coast would have been relatively small, so that the total revenues of all West Coast producers would have declined. It has been in the interest of the ANS and California producers, therefore, that West Coast crude-oil prices remain above the levels that would prevail in a competitive, rationalized market.

A special factor that dampened producer competition for West Coast petroleum markets was the price control system which, from about July 1979 until February 1981, made producers of price-controlled ANS oil indifferent to its transportation cost and, beginning in 1974, had made a large proportion of California's heavy oil uneconomic to produce.

Finally, the Windfall Profits Tax (WPT), which was imposed on decontrolled crude oil in January 1980, drastically reduces the incentive of individual ANS producers to optimize their transportation and marketing arrangements in order to maximize wellhead revenues. The WPT leaves the ANS producers only 8 cents out of each dollar's increase in the wellhead price after payment of royalties, State severance taxes, and State and Federal income taxes. An effective marginal tax rate of 92 percent on oil-production revenues clear / invites integrated oil companies to find means of shifting some of their profits from crude-oil production to their refining or transportation operations, which are taxed at much lower rates.

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Where a producer's marginal tax rate is 92 percent, the WPT creates an incentive, for example, for the producers to ship their crude oil to affiliated refineries at an artificially low "transfer" price, or to arrange exchanges with other integrated companies that have a similar incentive to understate the value of their crude oil, even when doing so requires otherwise unnecessary transportation expense that reduce netback prices at the wellhead.

Despite the interest of all West Coast producers in preserving the two-price system for ANS crude oil, it has been able to survive until now only because one company, Sohio, was the marginal supplier of domestic oil to West Coast refineries, and the main exporter of West Coast oil to the Gulf and Atlantic coasts. Since 1977, that position has given Sohio the power to determine District V oil prices within a wide range, by deciding how it will allocate its ANS crude oil between West Coast refineries and refineries East of the Rockies. Understandably, the company has not chosen to "spoil" its own District V market (and everyone else's) by competing vigorously for a slightly larger share of that market.

End of the two-price system. Price controls and the entitlements system are gone, and Sohio is losing (if it has not already lost) its special ability to support West Coast oil prices; thus, the two-price arrangement for ANS crude oil at Valdez is unlikely to survive the intensified competition for market shares that will occur in the 1980's.

Because of the general decline in petroleum-products consumption and the growth of ANS and California heavy-oil production, ARCO and Exxon (as well as Sohio) are already having to ship substantial amounts of ANS crude oil East of the Rockies. ARCO will begin producing from the Kuparuk

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River formation at Prudhoe Bay in 1982; year-end production will be about 80 mb/d, and may rise to as much as 200 mb/d by 1985. The anti-trust laws forbid the producers from coordinating their decisions on allocation of ANS crude oil between District V and other markets, but without such coordination, Sohio, Exxon, and Arco are doomed to compete with one another trying to sell crude oil to Chevron, Union, and other West Coast refiners.

The State of Alaska may also aggravate the downward pressure on District V prices by its policy of selling royalty oil independently of the ANS producers, at a price that it sets (perhaps unwittingly) below the market value of the crude oil. In April 1981, for example, a Charter Oil subsidiary withdrew from a contract with Alaska in which it was lifting 75 mb/d of ANS royalty oil at the "in-value price" --- a price equal to the royalty the State could have received in cash from the producers for the same oil. Unlike the producers' own crude-oil, however, State royalty oil is not subject to severance tax; thus, Charter received crude oil for more than two dollars per barrel less than it would have had to pay one of the producers for identical oil. (Ironically, Charter withdrew from the purchase contract mainly because it was losing money on the transaction despite this discount).

Finally, California heavy-oil production continues to grow. The biggest producers are Getty and Shell. Getty has only about 5 mb/d of ANS production and Shell has none; thus they will have no reason not to price their California product at whatever levels clear the market --- at the expense of ANS sales to California refiners. All in all, the outlook is for vigorous price competition throughout District V in the 1980's, and a rapid rationalization of prices in the District around the price of ANS crude oil at Valdez.

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The ANS producers could still forestall the erosion of West Coast oil prices relative to the price of Middle Eastern imports, if they were permitted to ship ANS crude oil to the Far East: the highest attainable netback value at Valdez, would probably result from foreign-tanker shipments to Japan, where its value is equal to or higher than that of Arabian Light. The relative value of West Coast petroleum would also increase if a large-volume crude-oil pipeline system connected District V with the Midwestern States (but only if that pipeline were utilized at or near its design capacity). However, the Export Administration Act forbids overseas exports of ANS crude oil, and the near-term outlook is not favorable either for liberalization of exports or for construction of a new transcontinental pipeline system along the lines of those proposed by Trans-Mountain, Northern Tier, or Foothills.

These conditions mean that competition will press the entire structure of PAD District V crude-oil prices toward a level three to four dollars below those of the Gulf and Atlantic coasts. The April 1981 appearance of a West Coast spot price for ANS crude oil (\$31.00) three dollars below the average Gulf Coast contract price (\$33.97) and more than two dollars below the Gulf Coast spot market price (\$33.30) may be evidence that sufficient price competition already exists to bring about this result.

West Coast crude-oil grade and quality vs. product-slate trends. The effect of the West Coast oil surplus on the crude-oil price structure is complicated by a mismatch between the mix of crude oil that District V produces and the slate of petroleum products it consumes. Relative to other parts of the United States, the West Coast's petroleum-product demand is concentrated in lighter products --- gasoline, jet fuel, and middle distillates (diesel and

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heating oil)), as opposed to heavy fuel oils. Also, air-quality considerations demand a lower average sulfur content in fuel oil than in other regions, but the producing fields in Alaska and California are, unfortunately, comparatively rich in both the heavier crude-oil fractions and sulfur.

The average District V refinery feedstock is, therefore, relatively costly to process into the product slates demanded by West Coast consumers. In addition, the value of different West Coast crude oils in, say, the Los Angeles area, varies over a range of more than six dollars per barrel, depending largely upon the proportion of low-valued residual oil in each of them or (what is essentially the same thing) the relative cost of processing them into higher-valued refined products.

Because of a progressive shift of District V production toward "lower-gravity" (higher-residue) and higher-sulfur crude oils, and a simultaneous decline in the demand for residual oil (particularly high-sulfur residual oil), disposal of residual oil is a chronic problem for West Coast refineries. A refiner has five fundamental options for coping with this problem:

- 1) To change the crude-oil feedstock mix in the direction of crudes that produce less residual oil, and/or contain less sulfur, but at a higher raw-materials price per barrel.
- 2) To ship the surplus residual oil into another market where it is worth more.
- 3) To adjust the refinery's operations to produce less residual oil, but at a higher operating cost per barrel, and with a reduction in the refinery's effective capacity;

- 4) To invest in additional cokers, hydrocrackers, vis-breakers, and/or hydrotreaters, in order to upgrade residual oil into higher-value products; and
- 5) To sell the residual oil in existing local markets (including the market for ship's bunkers), at whatever price it will command.

The tradeoffs among these options are crucial to any projection of short- and long-term price differentials between residual oil and distillate fuel oil; high-sulfur and low-sulfur residual oil; and petroleum products and crude-oil. These price differentials also depend on the array of crude-oil grade and quality differentials, while the crude-oil price structure reflects, in turn, the structure of petroleum-product prices. All of these price relationships are also functions of demand conditions for various petroleum products, the relative abundance of different types of crude oil, and the technical characteristics of the existing District V refinery stock.

A rigorous analysis of all these factors would require a sophisticated model that, as far as we know, does not exist today and whose precision, moreover, would be swamped by uncertainty about several important input variables. For the purposes of this report, a few basic principles may be adequate to forecast some important limits to the range of West Coast fuel-oil prices.

Bracketing the industrial fuel-oil price: (1) Maximum prices. Industrial fuel-oil prices can not long exceed the prices of their caloric equivalents in crude oil of comparable sulfur content. If the price of high-sulfur residual oil were higher than the price at which the cheapest high-sulfur California heavy crude oil could be brought to tidewater, ship operators would buy the heavy crude oil in place of residual oil for their bunkers.

For example, if a 14° API, 2.5-percent sulfur crude oil sold at tidewater in the Los Angeles basin for \$5.79 per barrel less than the CIF price of ANS crude (as suggested by the price coefficients on page 16), it is unlikely that the price of 3-percent residual oil at Seattle would persistently exceed the ANS price in Los Angeles, less \$5.79, plus tanker charges from Southern California to Puget Sound. Likewise, if the price of 1-percent-sulfur residual oil in the San Francisco Bay area exceeded the price of ANS crude oil, industrial consumers who were allowed to use 1-percent fuel oil would burn ANS crude instead.

Any desired proportion of residual oil in a crude-oil feedstock can be obtained by blending, so the relation between the percentage of residue in crude oils and their prices will be almost linear. Likewise, because any desired sulfur content in heavy fuel oil can be obtained by blending, the relationship between the sulfur content of residual oils or heavy gas oils and their market value also tends to be linear. Thus, the price of low-sulfur (maximum 0.3 percent S) fuel oil is not likely to rise above either the cost of a mixture containing 77 percent Indonesian Minas crude oil (0.08 percent S) and 23 percent ANS crude (1.05 percent S), or a that of a mixture containing 70 percent sulfur-free gas oil or distillate oil and 30 percent ANS crude or 1-percent-sulfur residual oil.

(2) Minimum prices in the short-term. The lowest price that can be sustained for an industrial fuel oil of a given sulfur content is the price that clears the market, because it is low enough (1) to offset the added cost of adjusting the operations of existing refinery equipment to produce a smaller volume of residual oil and/or high-sulfur oils, and a larger volume of higher-valued products; (2) to overcome transport costs to other markets that have a less acute

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surplus of residual oil (e.g., the Atlantic Coast or the Far East); (3) to persuade industrial consumers that have dual or multi-fuel capabilities to use oil instead of natural gas or coal; and/or (4) to attract ships from their usual routes in order to save money on bunker oil.

Refinery operations. Authoritative studies published in 1979 and 1980 (e.g., Bonner & Moore's, 1985 California Oil Senario Study [1979], Purvin & Gertz's Analysis of the Potential for Upgrading Domestic Refining Capacity [March 1980], and the National Petroleum Council's Refinery Flexibility Study [December 1980]) pointed to the need for great investments in refinery modification during the 1980's to deal with the worsening mismatch between the mix of refinery feedstocks and the mix of product demand.

Overall petroleum-product consumption in the United States has declined more than 24 percent (on a comparable-month basis) since 1978, when most of the work was done on these studies; subsequent forecasts of West Coast, U.S., and world petroleum demand in 1985, 1990, and 2000 have fallen correspondingly, and made much of the analysis obsolete. The present excess of refinery capacity has enhanced the ability of refiners to modify their operations to produce less residual oil and lower-sulfur products from a given feedstock without major capital expenditures. Thus, Booz-Allen, in a draft update of the 1979 Bonner & Moore study [Residual Oil Marketing and Heavy Crude Refining Operations, February 1981], concludes that the existing California refinery stock and the modifications now under way will be sufficient until at least 1992, to accomodate both the shift in product slates and an acceleration of California heavy-oil production.

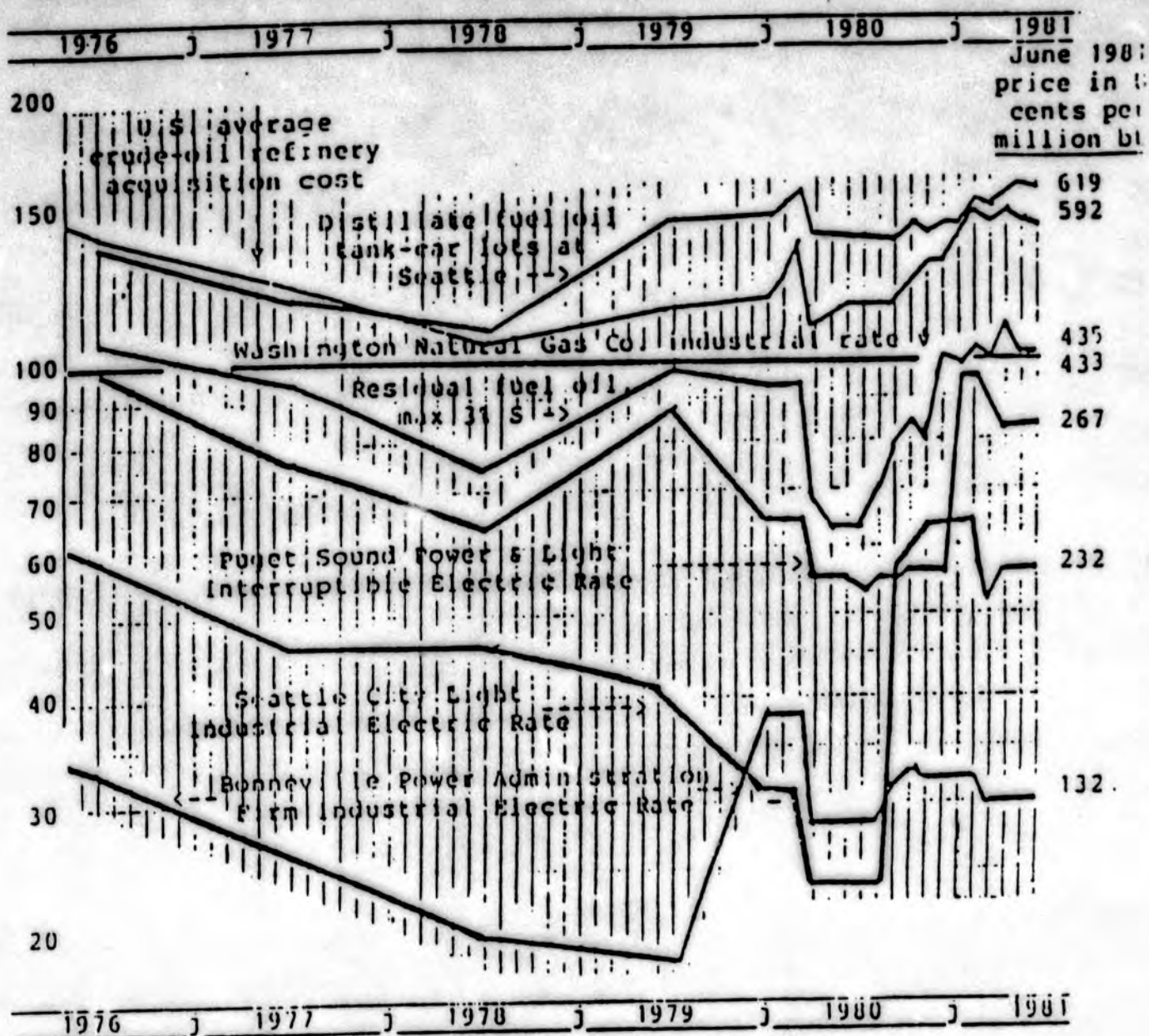
Lower consumption both takes some of the anticipated pressure off remaining reserves of high-gravity and low-

sulfur feedstocks, and increases the flexibility of existing refineries to shift feedstocks and product mix. For example, the heavy gas oil or residual oil produced by an existing cracker or coker can be "cycled to extinction" by running it back through the same unit again and again, rather than putting them on the market directly as industrial or bunker fuels.

Because this recycled heavy oil displaces an equal volume of feedstock that would otherwise be coming to the coker or cracker from the fractionating tower or vacuum-distillation set, the effective capacity of the cracker or coker will be reduced proportionally, and its fuel-consumption per unit of production similarly increased. The additional flexibility created by excess capacity is thus available only at an added cost which, as crucial elements of the refinery are used more intensively, at some point exceeds the unit cost of either (1) replacing some domestic high-sulfur, heavy oil with higher-quality (and more expensive) imported crude, (2) dumping the excess residual oil into the market for whatever it will get, or (3) investing in new residual-oil upgrading capacity.

Local and distant markets. One option for disposing of excess high-sulfur residual oil is to ship it to another market where it is allowed to be burned, and where relative prices are more favorable to residual oil generally or to high-sulfur fuels. For example, the Pacific Northwest is an important "dump" for high-sulfur residual oil that air-quality regulations make unusable in Southern California. In the winter, high-sulfur residual-oil prices in the Northwest states appear to settle at a price just low enough to persuade owners who can use either fuel to burn oil instead of gas. In the last three summers, however, when electric-utility and heating-fuel demand were seasonally

Figure 1 COMPARISON OF NORTHWEST INDUSTRIAL ENERGY RATES:
Ratio of price per btu to industrial gas price, Washington Natural
Gas Company, Seattle (Natural-gas price = 100)



Notes: 1976-1979 data are annual averages. Gas price is average interruptible charge from Washington Natural Gas Company Tariff Book Information Bulletin: Chronology of Rate Changes [10-1-1980]. Crude oil acquisition costs are from Monthly Energy Review and telephone inquiry to Energy Information Administration. Distillate fuel oil and residual fuel oil prices are median annual or monthly low quotations from Platt's Oilgram Price Report and Oilmanac; distillate oil was converted at 138 mbtu per gallon, and high-sulfur residual oil at 6,325 mbtu per barrel. Electric rates are lowest energy charge, converted at 3,124 btu per kwh, from current utility rate sheets; 1976-79 rates calculated at midpoint of summer and winter rates.

depressed, residual-oil prices fell low enough in California to attract ships from as far away as Panama, and low enough in the Pacific Northwest to displace some electricity from the region's industrial markets. [See Figure 1.]

The large excess of crude-oil processing capacity that exists in District V and nationally means that the least economic refinery unit still in operation (or the next one to be shut down) is barely breaking even on its feedstock costs. In other words, the composite barrel of petroleum products which that refinery produces will have a value about equal to the average cost of the crude oil processed. If residual-oil prices are low relative to crude-oil prices, because of weak demand and an inflexible refinery stock, distillate fuel-oil and gasoline prices will have to be comparatively higher, if the marginal refiner is to avoid an operating loss and a decision to shut down. This relationship is part of the reason prices of refined petroleum products in District V remained stable or continued to rise during the second quarter of 1981, despite falling crude-oil prices everywhere, and falling petroleum-product prices everywhere but the West Coast.

(3) Minimum prices in the long run: Refinery modifications. While the refinery studies cited above may be largely obsolete with respect to forecasting the absolute amount of investment in refinery modifications that will be necessary or economic, the Bonner & Moore report is especially valuable as a framework for calculating the cost of adding capacity to produce an additional barrel per day of sulfur-free industrial fuel oil or additional barrel of distillate fuel oil in place of a corresponding (but not exactly equal) amount of high-sulfur residual oil); or to substitute a barrel per day of ANS crude oil for Indonesian

imports, or a barrel per day of California heavy crude for ANS crude, while maintaining the same product slate.

Desulfurization. The differences between Bonner & Moore scenarios 7 and 8 (for complex refineries and the "expected-gas" case) show that 303 mb/d of residual oil can be reduced in average sulfur content from .78 to .48 percent at a capital cost of \$1,014 per daily barrel.

This figure implies a cost of \$10,277 in 1981 U.S. dollars (as inflated by the Nelson Refinery Cost Index) to add the capacity to produce one barrel per day of zero-sulfur heavy fuel oil in place of 3-percent residual oil. A levelized fixed charge of \$5.78 per barrel is, therefore, needed to generate a 20-percent rate of return on this investment over a 20-year plant life; additional operating costs come to \$3.33 per barrel. If the ability to blend fuels makes the cost of desulfurization proportional to the amount of sulfur removed, we can use the resulting total of \$9.11 per barrel either as the cost of totally desulfurizing one barrel of residual oil or as the cost of, say, producing six barrels of 0.5-percent in place of a similar amount of 1.0-percent residual oil.

Similarly, a comparison of Bonner & Moore's scenarios 8 and 12 shows an incremental capital cost of \$2,397 per barrel per day in 1978 dollars to replace 413 mb/d of imported crude oil with ANS and California heavy crude. This substitution would reduce the average gravity of California refinery feedstocks from API 27.0° to 23.9°, and increase their average sulfur content from 0.95 percent to 1.21 percent. These scenarios, together with scenario 10, which replaces a specified volume of ANS crude oil with California oil, produce a "shadow" price-penalty of \$3.03 per barrel for each percentage-point of sulfur content.

The same coefficient of \$3.03 per percentage-point of sulfur-content per barrel applies (within a few pennies) to sulfur in both crude oil and industrial fuel oils. Comparisons among the various scenarios also produce a shadow price-premium of 10.6 cents per degree of API gravity per barrel, and imply that the fixed and operating costs of producing an additional barrel of No. 2 distillate oil in place of high-sulfur residual oil are \$9.50 per barrel, composed of \$7.14 for residual-oil destruction plus \$2.36 for desulfurization.

If these numbers are reasonably valid, they mean that refiners will invest in desulfurization facilities if and only if they expect the price penalty for both high-sulfur fuel oil and high-sulfur crude oil to remain at least \$3.00 per percentage-point of sulfur content. (Both differentials are necessary: if the difference in price between 0.5-percent sulfur residual oil and 3-percent residual oil is greater than \$7.50 (\$3.00 per barrel-percent), but the sulfur penalty in the crude-oil market is, say, only \$2.00 per percentage-point per barrel, it is cheaper for the refiner to buy a lower-sulfur feedstock than to invest in refinery modifications.)

Conclusion: Price differentials between high-sulfur residual oil, distillate fuel oil, ANS crude oil, and crude-oil import prices. The preceeding analysis leads us to believe that the long-term floor price (and the most-likely long-term average price) for high-sulfur residual oil (3.0 percent and Bunker C) on the West Coast will be about \$9.00 to \$10.00 per barrel less than the price of zero-sulfur fuel oil, either distillate or heavy gas oil. Average prices of other industrial fuel oil grades will be arrayed between these extremes in inverse proportion to their sulfur content. Prices will swing seasonally, and ~~James~~ no reason to expect much change from the current

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pattern in the Pacific Northwest, where high-sulfur residual-oil prices are just low enough in winter to capture the swing industrial market from natural gas, but where summer prices are even lower, competing with "hog-fuel" (sawdust and chips) in the wood products industries, and with the energy charges in industrial electric rates.

The marginal District V refinery will be a refinery that processes the marginal West Coast crude oil (ANS crude) to produce a product slate that is 25 to 30 percent high-sulfur residual oil. Such a refinery will just break even on its crude-oil costs with this product mix. With a price differential between distillate fuel oil and high-sulfur residual oil that must be \$9 to \$10 per barrel in order to justify any refiner's investing in new facilities to process residual oil into higher-value products, the expected price differential between residual oil and ANS crude oil will be between \$6.30 per barrel (if the output of the marginal refinery is 30 percent residual oil, and the expected price differential between distillate and residual fuel oil prices is \$9.00 per barrel) and \$7.50 per barrel if the residual-distillate price differential is \$10.00 and residual oil 25 percent of output).

Given the present export restrictions and the absence of a transcontinental crude-oil pipeline, ANS crude oil will in turn be three or four dollars per barrel below the landed price of Arabian Light in North America. These considerations imply that average residual-oil prices in Puget Sound will remain very low relative to the cost of imported crude oil --- moving toward a difference of perhaps \$9 to \$11 per barrel or more in 1981 U.S. dollars.

The same calculations suggest that the long-term prices of distillate fuel oil and zero-sulfur gas oil on the U.S.

West Coast will tend to be on the order of \$2.50 per barrel higher than the price of ANS crude oil, making its price a bit less than the landed price of Arabian Light in North America. Table 2 shows the price-spread for industrial fuel oils on the Pacific Coast implied by this analysis and by the crude-oil pricing scheme illustrated in Table 2.

Table 3. West Coast Industrial-Fuel Price Scenarios

	\$/bbl	\$/mmbtu	percent of CIF price, Arab Light
ARABIAN LIGHT (AL) FOB Ras Tanura	\$32.00		
+ Tanker charge, Ras Tanura to LOOP	1.25		
= Arabian Light price CIF LOOP	33.25	\$5.73*	(100.0)
- Quality penalty ANS vs. AL	(.35)		
= ANS value CIF LOOP	32.85	5.66	
- Tanker charges, Valdez to LOOP	(5.85)		
= ANS PRICE FOB Valdez	\$27.00	4.65	
ANS PRICE FOB Valdez		\$27.00	4.65
- Tanker charge, Valdez to Long Beach	1.75		
= ANS price CIF Long Beach	28.75	4.95	
+ Refinery margin, zero-sulfur fuel oil	2.50		
LOS ANGELES INDUSTRIAL FUEL OIL	\$31.25	5.02*	(87.6)
ANS PRICE FOB Valdez		\$27.00	4.65
+ Tanker charge, Valdez to Benecia	1.50		
ANS Price CIF Benecia	28.50	4.91	
+ Refinery margin <0.3% S residual	.95		
S.F. BAY AREA INDUSTRIAL FUEL OIL	\$29.45	4.73*	(82.6)
ANS PRICE FOB VALDEZ		\$27.00	4.65
+ Tanker charge, Valdez to Anacortes	1.10		
ANS price CIF Anacortes	28.10	4.84	
- Refinery discount >2.0% residual oil	(7.50)		
PUGET SOUND INDUSTRIAL FUEL	\$21.60	3.41*	(59.6)

*) Conversions used were 5800 btu per barrel of crude oil, 6000 for heavy gas oil, 6225 for low-sulfur residual oil, and 6325 for high-sulfur residual oil.

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Tighter air-quality regulations will make even low-sulfur residual oil generally unacceptable as boiler fuel in Southern California by 1985, but low-sulfur residual oil will remain the standard industrial fuel oil in Northern California. Sulfur content will not limit most industrial fuel-oil uses in the Pacific Northwest or the market for ship's bunker fuels. As a result, we foresee prices for industrial fuel oil in Southern California, Northern California, and the Pacific Northwest on the order of 88 percent, 83 percent, and 60 percent, respectively, of the CIF price of Arabian Light crude oil at the U.S. Gulf.

The reader should recognize that the implicit model behind this table is much simpler than the reality it tries to simulate, and that several of its assumptions are arbitrary or speculative. Some of them depend not so much on objective facts, but what people believe and how they are likely to act on their beliefs. For example, if refiners as a group overestimate the long-term price differential between distillate and residual fuel oils, as a group they will overinvest in cokers, visbreakers, etc., and cause the price differential to be narrower than the forecast, and narrower than it would have actually been without the investment.

THE FOLLOWING PAGES WERE TREATED AS
A UNIT IN THE ORIGINAL FILE.

REPORT TO CONGRESS ON ALASKAN OIL



**SECTION 126
OF THE
EXPORT ADMINISTRATION AMENDMENTS ACT OF 1985**

JUNE 1986

OVERVIEW

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- II. CURRENT STATUS
- III. EFFECTS OF CHANGES IN INCENTIVES FOR ANS PRODUCTION
- IV. POLICY OPTIONS PERTAINING TO THE LIFTING OF EXPORT RESTRICTIONS
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SECTION 126 STATUTE.....F-1

EXECUTIVE SUMMARY

I. STATUTORY BACKGROUND

Section 126(a) of the Export Administration Amendments Act of 1985 requires the President to undertake a comprehensive review of issues concerning (1) possible changes in the existing incentives to produce crude oil from Alaska's North Slope (ANS) including changes in taxation, pipeline tariffs and leasing policies; (2) possible changes in existing distribution of ANS crude oil at free market levels and at levels of 50,000, 100,000, 200,000 and 500,000 barrels per day (MB/D); and (3) the appropriateness of continuing existing controls.

Section 126 further requires that these possible changes be evaluated in light of the impacts on the following:

- Energy and national security of the United States and its allies;
- U.S. foreign policy;
- Employment in the maritime, oil and related industries;
- Consumers and refiners;
- Revenues and expenditures of the Federal Government and the State of Alaska;
- Incentives for oil and gas exploration and development in the United States; and
- U.S. trade relations in general and with individual countries in particular.

II. INTERAGENCY STUDY PROCESS

Responsibility for developing this report was delegated to the Department of Commerce (DOC). Analysis of all the above issues is based on input from a DOC chaired interagency task force that included the Departments of Energy, Defense, State, Labor, Transportation, Treasury, and Interior, as well as the National Security Council and the Office of Management and Budget.

The report is based on a number of agreed economic assumptions regarding future ANS crude oil production, crude oil price levels, domestic and foreign shipping rates, as well as a number of factors such as economic growth rates and inflation.

The main body of the report was developed before the recent decline in world oil prices. Petroleum industry experts cannot project reliably how long these low prices will prevail. Nevertheless, it was agreed that this study should include an additional chapter which highlights any changes to the previous analysis based on \$15 per barrel oil prices through 1990.

This report also incorporates comments submitted by interested parties in response to a December 9, 1985 DOC Federal Register Notice.

III. CHANGES IN EXISTING INCENTIVES TO PRODUCE ANS CRUDE OIL

Any change that directly or indirectly raises the profitability of production would potentially increase incentives to explore for and produce ANS crude oil. The analysis in this study focused on the following examples of possible changes to the existing incentives to produce ANS crude oil:

- Reduced pipeline tariffs based on the Trans-Alaska Pipeline Settlement (TAPS) of October 1985;
- Exemption of ANS crude from the Federal Windfall Profits Tax;
- Reduction of the State of Alaska severance tax rate by 25 percent and 50 percent;
- Reduction of the Federal royalty rate by 25 percent and 50 percent.

Between 1987 and 2000, increases in production stemming from the incentives listed above would be almost entirely due to increased recovery from existing wells. Given the long lead times to develop new fields on the Alaskan North Slope, new wells from new fields would not begin producing until at least the late 1990's.

Of the incentives noted above, the TAPS Pipeline settlement is projected to have the largest impact on production. Assuming a mid-point price path (i.e., \$32.50 in the year 2000), increased production would likely be about 75,000 barrels per day (B/D) by 2000. This amounts to about a 5 percent increase in production.

The TAPS Settlement also has a significant revenue impact. It is estimated to reduce Federal revenues through the year 2000 by about \$3 billion but is projected to increase the State of Alaska's revenues by about \$8.6 billion. The marked disparity in revenue impacts arises from the substantial increase in State of Alaska royalty and severance taxes.

Reduction of the State of Alaska severance tax rate would significantly reduce state revenues, but would not have a large impact on production. A 50 percent reduction in the tax rate would reduce state revenues by \$9 billion but would result in additional production of only 24,000 B/D by 2000.

Significant oil production from Federal leases is not expected to occur before 2000 regardless of the incentives to produce. Therefore, reductions in the Federal royalty rate would not have a large impact on producer revenues or production between 1987 and 2000.

Because the production responses would be small, other economic impacts from these incentives (on shipping, producers, consumers, etc.) would also be small.

It is also important to note that, under low oil prices, incentives to produce ANS crude would have a greater impact on preserving existing production than on new exploration and development.

IV. POLICY OPTIONS PERTAINING TO ANS EXPORT RESTRICTIONS

At present, ANS crude oil production of about 1.8 million barrels per day (MMB/D) is consumed in the United States due to the statutory export ban. Of this total, 1000 MB/D of ANS production is shipped to the West Coast; 630 MB/D is shipped to the East and Gulf Coasts, and 128 MB/D is shipped to the Virgin Islands and Puerto Rico.

This section examines the oil flow redistributions and economic/policy impacts that such redistributions would have if the export ban were removed. This section also examines the impact of partial export decontrol at levels of 50, 100, 200 and 500 thousand barrels per day (MB/D).

A. Trade Flows

The actual level of exports will be determined by demand for ANS crude in U.S. West Coast and Pacific Rim markets. Export levels projected in this study represent maximum volumes based on the DOE Oil Trade Model. Actual export levels could be more or less depending upon market circumstances.

If the export ban were removed, shipments to the West Coast would remain relatively stable declining to a low of 830 MB/D in 1990 and increasing to 1040 MB/D by the year 2000. However, shipments to other U.S. destinations would be phased out by 1990 and the rest of ANS production would be exported to Pacific Rim countries.

It is anticipated that peak exports would reach 870 MB/D by 1990 and decline significantly after that due to falling ANS production and increased West Coast demand for ANS crude. By the year 2000, exports are projected to be about 360 MB/D.

B. Economic and Policy Impacts

This study examines the general economic efficiencies as well as sectoral/public policy impacts of removing the ban on ANS crude oil exports. Overall, a lifting of the ban would reduce government caused economic distortions and inefficiencies, and result in general welfare gains, but would have a negative impact on several particular sectors.

-- Petroleum Industry

At present, petroleum producers ship ANS crude to U.S. destinations only on American flag vessels as required by the Jones Act. Removal of the ban would permit producers to use foreign vessels to export ANS crude. This would reduce transportation costs significantly because (1) foreign shipping rates are lower than U.S. rates, and (2) Pacific Rim markets are closer to Alaska than the U.S. Gulf and East Coast markets. The savings from reduced transportation costs would translate into higher wellhead prices for producers.

ANS crude oil exports would also increase the value of California crude that is currently depressed due to the surplus in that market. At present, ANS crude sells at a discount on the West Coast to be price competitive. With other markets available for ANS crude, the "West Coast Discount" would disappear and prices of all oil would rise.

Using a mid-point price estimate for crude oil, the removal of the export ban would increase producer profits by \$3.7 billion in Alaska and by \$4.0 billion in California over the 1987-2000 time frame. If current low oil prices prevail, the transportation component will represent a larger part of the wellhead price. Lifting the export ban and increasing the wellhead price by approximately \$1.75 per barrel will provide important economic incentives for some current ANS as well as California oil production. It may prevent some producers from having to shut-in crude oil production.

If oil prices recover and reach the levels projected in this study, higher FOB netback prices would also provide some incentives for increased production in California and Alaska. This study estimates that, by 2000, increased production responses to the removal of the export ban could be at least 5-15 MB/D in Alaska and 12-24 MB/D in California. Beyond 2000, production responses could be higher.

-- Refining Industry

At present, West Coast refiners benefit from the captive supply of ANS crude which also serves to depress the price of California crude oil. A lifting of the export ban will raise the refiners' crude oil acquisition costs.

Some government analysts project long-term benefits to the refinery industry if they import light crude to replace heavy ANS supplies. This will lead to greater refinery efficiencies and processing gains. Further, refiners would be able to forego the additional expenses of converting their facilities to continue processing California heavy as well as ANS crude.

-- Consumers

In the short run, it is anticipated that the decontrol of ANS crude exports would raise petroleum product prices, particularly for residual fuel oil, on the West Coast consumers. Refiners would pay more for crude oil on the West Coast and would pass those costs along to consumers. Consumers on the Gulf Coast are unlikely to be adversely affected.

Some government analysts believe that consumers would benefit in the long run. As previously noted, market forces will increase the price of ANS and California crudes and thereby provide incentives for increased production. This would tend to depress world oil prices over time and result in lower petroleum products prices for U.S. consumers.

-- Federal and State Revenues

Removal of the export ban will increase the wellhead price of crude oil in Alaska and California and thus increase both Federal and State tax revenues. This study projects that Federal revenues will grow by \$4.6 billion; Alaskan revenues by \$4.0 billion; and California revenues by \$1.6 billion during the 1987-2000 period. (These revenue projections would be reduced under partial decontrol scenarios and/or if current low oil prices persist.)

-- Maritime Industry (Including Militarily Useful Tankers)

The removal of the export ban would have a significant negative impact on the U.S. flag tanker fleet and the industries that support it.

Of the 10.7 million deadweight tons (DWT) of tankers active under the U.S. flag as of October 31, 1985, about 60 percent were employed in the distribution of ANS crude. This study estimates that removal of the export ban will lay-up over 30 tankers totalling over 4 million DWTs, exposing approximately \$382 million of Title XI Federally guaranteed mortgages to default.

In addition, the private sector (oil companies owning tankers and private tanker owners) could be subject to an additional default of approximately \$540 million.

The Federal Government might also have additional costs associated with assuring adequate tankers for national defense of as much as \$34 million to purchase displaced militarily useful tankers. Absent these acquisitions, the shortage of U.S. flag tankers that would transport military mobility fuels during a crisis would increase.

Removal of the export ban could likewise have a negative impact on the U.S. shipbuilding and repair industry. Future ship construction opportunities could be reduced by about \$1.5 billion and maintenance and repair operations could be reduced by about \$392 million during the 1987-2000 time frame.

-- Trade

The balance of trade implications of ANS crude oil exports depend on a number of economic variables.

On the one hand, the U.S. could realize a net positive change in its trade balance if crude oil exports are not replaced on a barrel for barrel basis with imports. Under such a scenario, lifting the ANS ban provides economic incentives for producers to export crude rather than discounting ANS crude on the West Coast. Not only is it more profitable for ANS producers to export crude oil, West Coast refinery operations would be made more efficient by reducing heavy oil supplies. (At present, residual fuel exports are permitted while crude exports are restricted.) This will result in less residual fuel production on the West Coast which leads to higher prices. Higher residual fuel prices will reduce domestic demand by about 60 MB/D in 1995. Further, imports of light crudes rather than heavy oils result in large West Coast refinery processing efficiencies that reduce the need to replace exports on a barrel for barrel basis.

On the other hand, there are factors which could lead to a net negative change in the trade balance. This scenario is based on the presumption that oil exports are sold on an FOB Valdez, Alaska basis and carried on foreign vessels. This oil is replaced on a barrel for barrel basis by oil imports that are carried on foreign tankers. Thus, the United States would lose the transportation costs of each transaction. (This transportation based deficit would be reduced if the ban were partially lifted and/or if U.S. vessels carried part of the oil.)

-- Employment

Removal of the export ban would have the greatest impact on seafaring employment. This study estimates that displacements could be as high as 52 percent of the U.S. tanker workforce (about 2000 workers). Displaced seafarers would have difficulty finding work in other types of shipping since employment opportunities in the U.S. Merchant Marine at large are poor. There would also be major displacements in the shipbuilding and repairing industries. Some of these negative impacts may be offset by employment gains in the oil and gas extraction and supporting industries. If low oil prices persist, lifting the ban could prevent the shut-in of ANS and California oil production and thereby preserve existing oil production related jobs.

-- Foreign Policy

The Administration has strongly urged the International Energy Agency to support an open trading system in which market forces determine prices and the movement of goods internationally. The International Energy Agency has developed a consensus that reliance on market forces is an effective means to promote stability and energy security. Lifting the ban on ANS crude oil exports would be consistent with these objectives.

Crude oil exports could improve bilateral trade balances with Pacific Rim countries.

ANS exports could contribute to obviating the need to transship crude through the Panama pipeline depending upon the strength of Gulf Coast demand for ANS crude. However, lifting the ban would increase oil export opportunities for other Latin American countries. The impact on the Panamanian economy would be negative, but the impacts on Ecuador, Venezuela, and Mexico would be positive.

-- National and Energy Security

Lifting the ban diversifies oil imports and could improve the energy security of Pacific Rim countries which are heavily dependent on Persian Gulf supplies. It might also provide incentives for these countries to expand overall energy and trade cooperation with the United States.

However, large ANS crude oil exports during the 1990s could require offsetting oil imports and increase U.S. dependence on OPEC sources. While the sources and reliability of U.S. oil supplies would change, lifting the ANS ban could result in a slight decline in net oil imports because of increased domestic oil output.

If the export ban is lifted, a number of U.S. flag tankers would be forced out of business. This would aggravate the shortage of militarily useful U.S. flag tankers to carry clean petroleum products for the military during national emergencies.

V. APPROPRIATENESS OF CONTINUING EXPORT CONTROLS

The Administration believes that reliance on market forces is the most effective means to promote U.S. energy security. While lifting the ban on Alaskan crude oil exports would be in line with this objective, some government analysts point out that a number of other factors must be taken into consideration when making such a determination.

Lifting the ban on Alaskan crude oil exports would have consequences for a number of domestic interests and should also be evaluated based on institutional considerations that have developed since the Congress passed the Trans-Alaska Pipeline Authorization Act in 1973.

A partial lifting rather than full lifting of the ANS crude export ban could pose a number of administrative and commercial difficulties. The U.S. Government would find itself in the position of allocating limited export volumes rather than allowing the market to make these determinations.

Finally, it is important to note that this study only evaluates the implications of removing or modifying export controls on ANS crude oil -- it does not address the costs and benefits of export controls on other domestically produced crude oil. From a public policy perspective, removal or modification of export controls on ANS crude should be considered in the context of overall restrictions on crude produced in the lower 48 states.

VI. RECOMMENDATION

An interagency review has been conducted of the analytical and technical findings of the study and the following is recommended: that the appropriate Federal agencies continue to review the prospects for Alaska North Slope exports, in light of changing energy market conditions. During this continuing review process, the appropriate Federal agencies will consult with the owners of the oil, including the State of Alaska, the maritime industry, and other interested parties.

II. CURRENT STATUS

This chapter provides a background discussion of the current situation with respect to Alaskan North Slope (ANS) oil production, transportation and use. Note that the discussion throughout this report pertains only to ANS crude oil. Crude oil production in southern Alaska -- primarily in the Cook Inlet area -- is excluded from the discussion and analysis.

A. PETROLEUM ECONOMICS: GENERAL BACKGROUND

1. The Origin of ANS Export Controls

The discovery of oil in the Prudhoe Bay region of northern Alaska in 1968 revealed the presence of the largest field ever found in the United States. The field contained approximately 10 billion barrels of recoverable oil, an amount that would substantially help stem rising oil imports and offset declining production in the lower 48 States. However, to achieve these economic benefits, the oil would have to be transported to the marketplace. A controversy, therefore, arose over the route by which the oil would be transported.

Two competing proposals were advanced for transporting ANS crude to the domestic market. One was a pipeline across Canada into the midwestern United States. The second was an all-Alaska line to carry oil from Prudhoe Bay to a terminal at Valdez, Alaska, for tanker shipment to U.S. markets. It was also envisioned that, after shipment from Valdez, some of the ANS crude could be moved by pipeline from Washington State to markets in the Midwest. This proposed West-to-East pipeline, the Northern Tier pipeline, was never built.

The proposed land route from Alaska and across Canada was considerably more expensive and had potentially more severe environmental impacts than the all-Alaska route to Valdez (the Trans-Alaska Pipeline System - TAPS). Therefore, Congress decided on the Prudhoe Bay to Valdez route when it passed the Trans-Alaska Pipeline Authorization Act in 1973.

In order to obtain Congressional support, the TAPS bill was amended to make ANS crude available only for domestic consumption. There were significant concerns by many who thought that a pipeline to Valdez would provide an incentive for ANS crude to be exported to the Far East rather than transported to domestic markets. The ANS export restriction satisfied the concerns of those who had experienced serious shortages during the Arab oil embargo and who wanted to ensure the availability of ample, reasonably-priced petroleum supplies. Subsequent legislation strengthened the export

restrictions and no ANS crude oil has ever been available for export. However, petroleum products refined from ANS crude have been and remain eligible for export.

The export controls imposed on ANS crude provided incentives for several North Slope oil producers to purchase their own U.S. flag ships. Since the Merchant Marine Act of 1920 (commonly known as the Jones Act) requires that all cargo between U.S. ports be transported on U.S. vessels, all foreign tankers are excluded from the ANS crude trade. (Foreign flag tankers are allowed in the ANS trade to the Virgin Islands under Section 21 of the Merchant Marine Act, 1920.) Thus, several domestic producers have also become shippers and have developed institutional trading relationships with various U.S. consumers.

2. ANS Crude and the Current World Oil Market

Both international and domestic oil markets are substantially different today from what they were in the 1970s when restrictions were imposed on ANS oil exports. Internationally, we have moved away from a world oil market dominated by the Organization of Petroleum Exporting Countries (OPEC) and characterized by tight supplies and sharp oil price hikes. Today's market, by contrast, has excess production capacity and falling oil prices. OPEC no longer has a stranglehold on crude oil trade, having seen its share of world crude oil production fall from 56 percent in 1973 to about 30 percent in 1985. Non-OPEC production increased by 50 percent over the same period.

Domestically, we have shifted from an era of government price regulations and supply allocations to one of oil price decontrol and distribution according to market forces. Since the removal of U.S. crude oil price controls in January 1981, crude oil prices have declined significantly and domestic production has modestly increased.

In addition, our energy security has been enhanced by the storage of about 496 million barrels of crude oil in the Strategic Petroleum Reserve (SPR). With net crude oil and product imports now at about 4 million barrels per day, the SPR could replace our import requirements for about 120 days -- a considerable improvement over conditions in 1973-74 when we had no oil in strategic storage.

Despite the changing world oil market and U.S. energy security considerations, ANS crude remains subject to export restrictions. In the case of ANS production, the crude oil must first move by pipeline to Valdez (small quantities are taken out of the pipeline for local refineries near Fairbanks and Anchorage), where it is loaded on tankers. Any crude oil not processed in Alaska must then be shipped to other ports in the United States. As a result of the ban on exports, tanker transportation costs are an important factor in the delivered price.

As previously noted, the Jones Act requires that all shipping between U.S. ports must be transported by U.S. flag carriers, whose rates are substantially higher than foreign tanker rates on comparable routes. If there were no restrictions on exports, those producers of ANS oil who do not own U.S. flag vessels would normally seek to maximize profits by selling crude oil in nearby foreign markets, where transportation costs would not put them at a disadvantage. However, the ban on exports denies ANS producers some nearby markets along the Pacific Rim and obliges them to use costly U.S. flag carriers. Of necessity, the ANS producers have had to ship their crude farther and at a greater per barrel cost than they would under free market conditions. These two factors have reduced the prices received by producers (see Table A-1). Moreover, the flow of ANS oil into the California market has created an oversupply that has depressed the value of both Alaskan and Californian crude.

TABLE A-1WELLHEAD PRICE OF ALASKANNORTH SLOPE CRUDE

(1985 DOLLARS/BARREL)

<u>Estimated 1985</u>	<u>California/West Coast</u>	<u>Gulf Coast</u>
DELIVERED AVERAGE PRICE NORTH SLOPE CRUDE OIL	\$ 24.28	\$26.98
<u>LESS:</u>		
SHIPPING COST	<u>\$ 1.30</u>	<u>\$ 4.46</u>
VALDEZ F.O.B. PRICE	\$22.98	\$22.52
<u>LESS:</u>		
TAPS PIPE LINE TARIFF	<u>\$ 6.11</u>	<u>\$ 6.11</u>
NORTH SLOPE NETBACK WELLHEAD PRICE *	\$16.87	\$16.41

Source: Petroleum Intelligence Weekly, Vol. XXIV, No.25, June 24, 1985, p.2

* Price at Pump Station #1

B. EXPLORATION AND DEVELOPMENT

1. Difficulties of ANS Exploration and Development

The Alaskan North Slope is one of the world's harshest environments for crude oil exploration and development. Normal temperatures vary from -6 to -24 degrees Fahrenheit (F) on the North Slope and extremes in temperature vary between -50F to +30F. In addition to the extreme cold, the winter months are always dark because the sun sets in late November and does not rise again until the end of January.

Despite the harshness of the cold weather months, most exploration and development activity has to take place in winter for the following reasons:

- o No drilling or movement of equipment on the tundra is allowed between late April and late November because the permafrost, which softens in the warmer temperatures, might be damaged.
- o No offshore activities are allowed during April and September because of the possibility of adverse effects on the migration of bowhead whales.
- o No onshore activities are allowed during mid-May to mid-July to avoid disturbing the caribou during calving season.

Also, there are a number of other regulations by the Environmental Protection Agency and State fishery and wildlife groups that also restrict oil exploration and development.

As a result of the harsh climatic conditions and government restrictions on exploration and development of the North Slope, there is a 10 to 15 year average delay between the discovery of an oil field and the start of production. For example, Prudhoe Bay (the Sadlerochit Reservoir) was discovered in 1968, but significant production did not start until 1978.

Due to the harsh environment, North Alaskan exploration and development costs are significantly higher than in other parts of the United States. Section III of this report evaluates a variety of incentives to overcome these difficulties and to increase North Slope oil production.

2. Status of Discoveries

Table B-1 shows estimated crude oil reserves on the North Slope by major field and year of discovery. Current proven reserves equal nearly 7.9 billion barrels, with about 75 percent in the Sadlerochit Reservoir of the Prudhoe Bay Field. It is estimated that between 5.8 to 18.0 billion barrels remain to be discovered in the North Slope area.

In 1984, the most recent year for which data exist, crude oil reserves for Alaska increased over 250 million barrels, primarily due to positive revisions in reported reserve estimates for North Slope fields. Most of these revisions were the result of increased secondary recovery projects in producing fields, including expansion of waterfloods and the construction start-up of a miscible-phase gas injection project in the Sadlerochit Reservoir of the Prudhoe Bay Field. Other significant additions to reserves were reported in older fields for which development plans had been uncertain until 1984.

Discovery of the "giant" Seal Island Field, in 40 feet of water, five miles offshore in the Beaufort Sea, was announced in January 1984. The field is about one mile northwest of the Prudhoe Bay Field, with reserves expected to reach about 300 million barrels.

Seal Island was the first commercial discovery reported in the Beaufort Sea. Its operator hopes to begin production by 1992.

Plans were announced in 1984 to drill up to 180 wells and fully develop the Lisburne Reservoir, which was discovered in 1968 by the same well that discovered the Prudhoe Bay Field. The Lisburne Reservoir underlies the main Sadlerochit Reservoir in the Prudhoe Bay Field. Production on a large scale is planned for late 1986 or early 1987, increasing to about 100,000 barrels of oil per day in 1987. Ultimate recovery from Lisburne is estimated at 140 million barrels, a small fraction (about 5 percent) of the estimated 3 billion barrels of original oil-in-place.

Planned development of the Endicott Reservoir was also announced in 1984. The reservoir is in the Sag River-Duck Island Unit east of the Prudhoe Bay Field. Reserves are estimated at up to 375 million barrels and production should start-up in 1988 at about 100,000 barrels of oil per day. Producers at Milne Point, a 1980 discovery, have put a hold on the second phase of development due to lower oil prices. It is an extension of the Kuparuk River and West Sak formations north of the Kuparuk River Fields, located on State lands about 35 miles northwest of the Prudhoe Bay Field. A pipeline will connect the unit's production to the Trans-Alaska Pipeline