Securing the Take: Petroleum Litigation in Alaska

By Richard A. Fineberg

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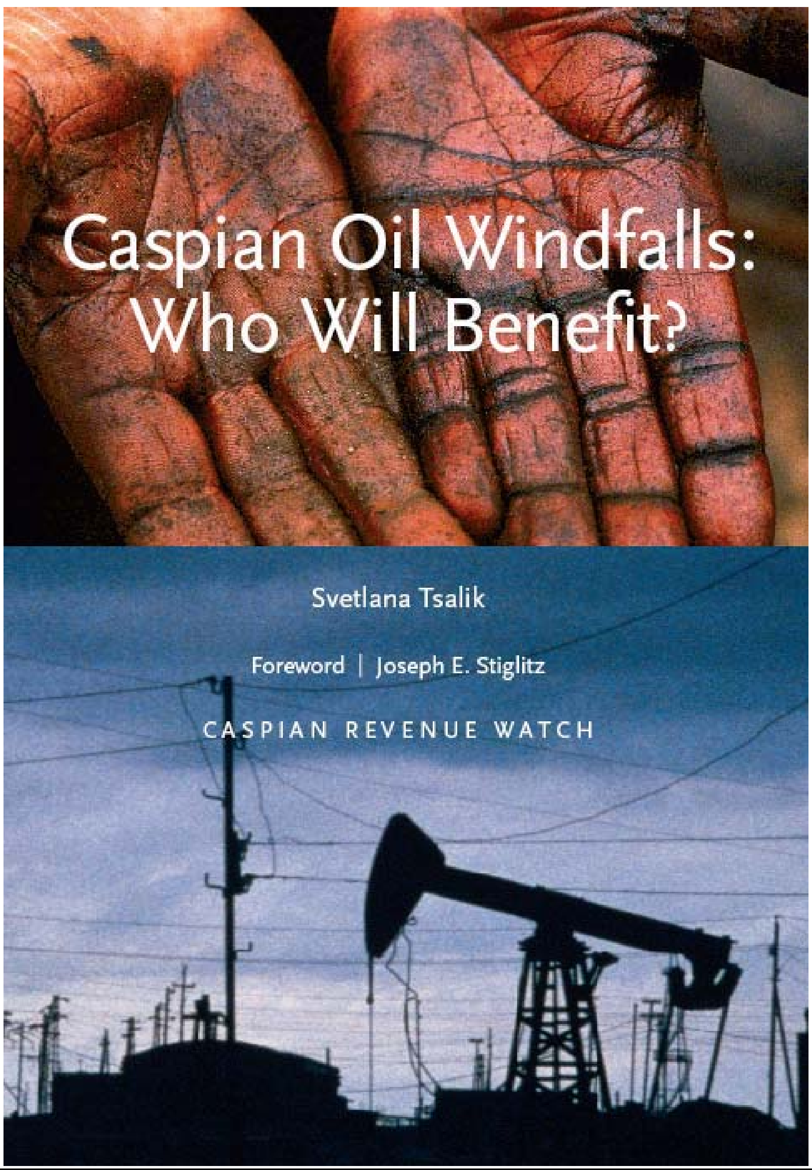

"I was an ARCO employee. Some of the issues being discussed were still being litigated. My plan was to get to retirement. . . . I would not have been there in any capacity had I continued to . . . dissent. . . . I did not get to be a manager and remain a manager being oblivious and blind to signals."

—RETIRED ARCO EXECUTIVE HARRY ANDERSON EXPLAINING IN 1999 WHY HE HAD DEFENDED ARCO'S PRICING PRACTICES IN A 1994 DEPOSITION

3. Securing the Take: Petroleum Litigation in Alaska

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Introduction

The development of major oil fields and construction of pipelines to transport oil to Western markets have ushered in a petroleum boom in the Caspian Basin. The terms of production-sharing agreements (PSAs) between Caspian Basin host governments and the petroleum industry[1] imply great future wealth for the people those governments represent. But public riches from petroleum development are neither guaranteed nor automatic.

In addition to the uncertainties of geology and the inherent volatility of oil prices, the citizens of the Caspian Basin face another major challenge to realizing the full potential of their petroleum resources: ensuring that their governments receive the full value of their share of revenues under the terms of the contracts signed with oil extraction and transport companies. The public share of the net revenue split between host government and industry (sometimes referred to as the "take") can be significantly reduced or delayed by accounting practices used to determine and report key factors such as the price of the oil, the production costs, or the transportation costs charged to each barrel of oil produced and delivered to market.

The tension between host and industry interests is inherent in petroleum development around the world. Consider, for example, the experience of the State of Alaska, another remote region that has developed a super-giant oil field in recent decades.[2] Over the past 25 years, more than one dollar out of every six that Alaska has received from its oil development has been obtained through legal challenges to the industry's original payment.[3] These challenges typically involved disputes over industry reporting of the value of the oil produced and/or the cost of producing that oil and transporting it to distant markets. The importance of these arcane conflicts to the Alaskan commonweal is made evident by this fact: During the 1990s, the fruits of the disputes over industry payment practices became the funding mechanism for Alaska's multibillion-dollar Constitutional Budget Reserve Fund, which was discussed in chapter two.

The lessons learned in Alaska may be particularly relevant for the people of the Caspian Basin, where contracts ostensibly favorable to the host countries are particularly vulnerable because the region's governing systems have little experience regulating current-day corporations and lack a strong tradition of democratic checks and balances. This problem is compounded by the fact that state-owned oil companies are not subject to the financial reporting requirements that govern their publicly traded development partners.[4] In this situation, the extension of the transparency principle (discussed below and in other chapters of this book) from the receipt of revenues to the economics of prospective and actual petroleum development may help the people of the Caspian understand the potential pitfalls associated with that development. To this end, the creation of comprehensive, simplified public economic models for major petroleum reservoirs in the Caspian Basin can provide the basis for evaluating revenues earned, respectively, by the host government and the industry.

Transparency in reporting resource revenue payments to host governments has been proposed by a group of nongovernmental organizations to aid the public in determining whether those payments are properly accounted for and managed.[5] In regions where even basic facts about public budgets are shrouded in secrecy, this is an important first step in public accountability. But disclosures regarding the receipt and disposition of oil revenues do not answer this fundamental question: Do those payments by industry to the host constitute a fair and equitable share of the wealth generated from public resources? To answer this important question, the doctrine of transparency needs to be expanded to include the processes by which payments are calculated and made. The rationale for improving transparency of the process by which oil company payments are determined will be the focus of this chapter.

To further discussion of public petroleum revenue accounting models for the Caspian Basin, the first part of this chapter will look more closely at the underlying background for potential host-industry disputes. The next section examines lessons from the history of

Alaska's petroleum litigation, followed by a discussion of the implications of those lessons for prospective public revenue under Caspian PSAs. The chapter concludes with recommendations for development of comprehensive, simplified models that will help extend transparency from the receipt and expenditure of petroleum revenues to the generation of that wealth.

What Drives Host-Industry Disputes?

The underlying tension between the petroleum industry and its government hosts arises from this fact: Each party seeks to maximize its share of the net revenue, or the difference between gross revenue (total proceeds from oil production) and costs (the industry's expenditures for leasing, exploring, developing the field, producing the oil, and transporting it to market). The timing of revenue receipt is also important. To the investor, whose capital is at risk, a policy of accelerating or "front-loading"[6] cost recovery is attractive. Therefore, in order to encourage development, a prospective host may structure development contracts that give industry the lion's share of initial proceeds.[7]

Investment risk and host risk are different entities. The host government may not wish to assume development risks. On the other hand, the investor provides capital precisely in the hope of receiving compensation. For placing that investment at risk, the investor typically receives a premium that is added into the project rate of return.

In this regard, Caspian Basin PSA terms vary markedly. Royalty payments and cost recovery limits produce significant early payments to the host government under some PSAs; under others, most of the host government share of net income is deferred ("back-loaded") until the industry recoups investment costs.[8] While it may be reasonable under some circumstances to allow the investor to recover costs before the host receives a significant return from production, a policy of accelerated investor repayment has potential negative consequences for the host that should be considered carefully. The host cannot put its share of petroleum revenue to work (for example, providing public services or earning interest) until that money is received. For this reason, the value of a deferred payment is diminished by delay. Moreover, under a deferred payment schedule, by the time the host receives the money, inflation is liable to have eroded its value. Finally, if recoverable reserves turn out to be smaller than originally expected or oil prices slump, the host's share of net revenue may be significantly smaller than anticipated.

Gold-plating and the over-reporting of costs

Some observers have said that front-loading arrangements are inherently prone to gold-plating, or the practice of making unreasonably large expenditures due to lack of cost-cutting incentives.[9] At the same time that front-loaded cost recovery postpones government take, the accelerated repayment provides industry with positive cash flow. These payments to industry may include contractor costs (with a reasonable profit), transportation costs (again including a reasonable profit), and repayment of borrowed capital (with interest). Under a front-loaded PSA, most (or all) of these legitimate payments to industry must be made from the proceeds of production before the producer and the host government begin sharing the net profits from development. In these circumstances, higher costs mean larger up-front profit payments to various industry parties. Therefore, industry may have little or no incentive to reduce those costs. Even a government inclined and staffed to vigorously defend its interests against industry gold-plating may have difficulty suppressing excessive spending by a government oil company.

When development costs are finally repaid, the host may not be on easy street. Specific PSA provisions may actually give the producer incentive to increase reported costs or delay efficient field investments in order to decrease the net revenue that must be shared with the host. One such mechanism found in many PSAs is the large, stair-step increases in the percentage of net revenue payments to the host country as the internal rate of return on investment goes up. An investment that raises the project rate of return to the next stair-step level may increase the host government's percentage take; the corresponding reduction to producer take may create an incentive to increase reported costs or slow development in order to delay reaching the trigger point that will increase the percentage of net profit payments to the host government.[10]

Closely related to gold-plating is the artificial inflation of reported costs. Over-reporting of actual costs cuts government take by reducing the reported profits to be split between government and industry. Again, a front-loaded cost repayment structure will function to increase industry gains from overstated costs. Examples of host/industry conflicts over reported costs can be found in the next section on petroleum litigation in Alaska.

In order to have value, a commodity must be delivered. Because transportation costs must be paid, the typical PSA subtracts the necessary expense from gross revenues before net revenue can be determined. For this reason, the expense associated with the necessary upgrading of old pipelines or the construction of new ones provide fertile grounds for host-investor conflict (stated or unstated) that may result in significant reductions to host country revenues. The pipeline cost element is of particular relevance to the development of remote reservoirs, whose oil must be transported long distances to reach potential markets. The important effect of the transportation costs on production revenues will be discussed in subsequent sections of this chapter.

Sakhalin-II project (Russian Far East)

The Sakhalin-II project in the Russian Far East appears to be an example of a project in which the PSA has failed to deliver on its promise of public revenue. The first phase of Sakhalin-II began producing oil from a single platform in the Sea of Okhotsk in 1999. When that platform was being prepared for installation, a government hungry for revenues was looking at a glossy brochure distributed by the producing consortium. That pamphlet emphasized a long revenue bar, colored bright red, representing net revenue payments to Russia and Sakhalin that appeared to dwarf contractor costs, the small bonus payments, and a 6 percent royalty. But there was a catch: Under the PSA at Sakhalin, the public revenues shown in that long red bar would not materialize until investment costs were repaid. It was not at all clear when (if ever) the limited production from the lone initial platform would repay its costs.

Two years before Sakhalin-II entered production, Pedro Van Meurs, a respected fiscal analyst, observed that the gold-plating effects of the typical Russian PSA "are very difficult to suppress." In fact, Van Meurs said, the rate of return mechanism in the Russian PSA governing the Sakhalin-II project creates a situation in which "the slower a project proceeds, the lower the profit share payable to the government." Therefore, he observed, the PSA for Sakhalin-II "rewards companies for delaying their investments."[11]

By the time the platform began producing in 1999, depressed oil prices were on the rebound. The producers were able to market Sakhalin oil at high prices, retaining almost all of the early-year proceeds as cost reimbursement. In late 2000, the Institute of Sea Geology and Geophysics of the Far East Academy of Science expressed concern that Sakhalin-II would never be profitable. In the view of the Institute scientists, it appeared that oil from the Far East would be produced to be sold abroad while the Far East continued to shiver in darkness each winter. Further, they said, the much larger Sakhalin projects planned for development under the same PSA also appeared likely to have similar inequitable results.[12]

PSAs, audits, and an informed public

In sum, even when oil prices are high enough to sustain profits for industry, creative interpretation of the fine print in the complicated contracts between the host government and the producing companies may result in significant reductions to the government take. When cost repayment is front-loaded, the consequences of increased reported costs are beneficial to the producer and pernicious to public interest in two ways: public receipts are both delayed and reduced. In view of the inevitable tension between the host government and the industry, the importance of auditing both the inputs and the methodology by which the industry calculates its payment to the host government cannot be underestimated. Although auditing of the details of PSA implementation is not readily amenable to public participation, a public that is well informed about the economics of petroleum development is vital to creating a political climate that will encourage and ensure the vigorous defense of the public's share of net petroleum revenue.

Alaska's Petroleum Litigation

To understand the magnitude of the potential conflicts between host governments and the industry regarding revenue generation and sharing, one needs only to examine the experience of Alaska, where protracted battles over arcane accounting issues have produced more than one dollar in additional public petroleum revenue for every five the industry voluntarily paid. Almost all of Alaska's oil revenue comes from production in the vicinity of Prudhoe Bay, located at the northern edge of the North American continent.[13] Since Prudhoe Bay entered production in 1977, three firms—now known as BP, ExxonMobil, and ConocoPhillips[14]—have controlled more than 90 percent of North Slope production and a similar share of the 800-mile Trans-Alaska Pipeline System (TAPS). Alaska has received approximately $70 billion in petroleum revenue from North Slope production, feeder pipelines, and TAPS. This revenue is derived, in the main, from royalties (generally 12.5 percent of the value of oil) and three principal taxes (corporate income, production, and property tax). Additionally, the state receives oil revenues from several minor taxes, as well as lease bonuses and rental payments.[15] The Alaska Department of Revenue has estimated industry and government net income from Alaska production and pipeline operations between 1988 and 2000. The agency analysis is summarized in Figure 1.[16]

FIGURE 1. Allocation of Net Income from Alaska North Slope Production and Associated Pipelines (including TAPS), 1988–2000

Industry Share	41.6%
State of Alaska Share	36.1%
Federal Share	22.3%

Source: Alaska Department of Revenue, "State of Alaska's Oil Revenue Pie (Production and Value Added by TAPS)," March 22, 2000 (in letter from Dan E. Dickinson, Director, Tax Division, to Representative Jim Whitaker, Chair, Special Committee on Oil and Gas, Alaska State House of Representatives).

As noted earlier, Alaska has found it necessary to pursue a path of prolonged and intensive litigation in order to obtain what public officials consider a fair share of the take from petroleum development. Essentially, the State of Alaska found that the industry chronically reduced the bases for calculating royalty, severance, and income tax payments by understating the market value of a barrel of oil at the point of sale. Overstated pipeline shipping charges (tariffs) had the same result.[17] The disputes often turned on differences between the state and industry regarding interpretations of contractual, statutory or regulatory language; many could be chalked up to legitimate differences of opinion, but others could not.

These cases were argued in different institutional forums. Royalty disputes proceeded directly from agency audits to the Superior Court of the State of Alaska's court system; tax settlements resulted from audit findings preliminary to proceedings before an administrative hearing officer of the Alaska Department of Revenue; pipeline tariff issues were handled by the Federal Energy Regulatory Commission (FERC) or the Regulatory Commission of Alaska (RCA, or its predecessors).[18] It was not unusual for the same issue—and even the same set of facts—to be argued separately by different agencies, in different venues, and with different results. In sum, the cases were complicated—and, consequently, costly—to research, brief, and present. In 1994, the Alaska Department of Law reported that since 1977 it had paid contract attorneys and accounting specialists from 30 different firms more than $217 million. But the investment of public revenue paid off; up to that point Alaska had received approximately $2.7 billion in settlements.[19]

By 2001, the Alaska Department of Law reported it had taken in an estimated $6.8 billion to settle charges of underpayments on taxes and royalties since 1977—much of it in statutory interest on long-delayed payments. According to the department, this figure excluded the gains to Alaska from reduced pipeline tariffs that were secured through a separate, extended litigation effort.[20] A closer look at public reports of some of the petroleum litigation suits that have surfaced in Alaska may help the reader grasp the complexity—and the importance—of determining the appropriate net revenue split.

False royalty returns

Alaska's mounting disappointment with industry practices became public in January 1989 when the State of Alaska filed a claim alleging that two of the three major North Slope producers were deliberately filing false royalty returns. According to the complaint, ARCO, one of the original major North Slope producers, committed "fraud and intentional misrepresentation by adopting a hypothetical, posted price for ANS (Alaska North Slope crude oil) that was not based on actual sales and purchases in order to understate the value of its crude oil for royalty purposes." According to the complaint, ARCO structured a small number of visible sales of its oil off the coast of California solely to provide support for this hypothetical posted price, while other producing companies reported a substantially higher value for ANS. The majority of ARCO's oil was not sold on the market, but was transferred to its own refinery; the marker sales at artificially low prices were then used to calculate the value of that oil for royalty and tax payments to Alaska. In addition, the complaint stated, ARCO "wrongfully and knowingly depressed its calculated wellhead value by intentionally inflating the costs associated with transporting ANS to market."[21]

The complaint also alleged that BP affiliate Standard[22] cheated by manipulating the quality or price differential between ANS and other crude oils.[23] For example, the complaint alleged that Standard would deliver one barrel of ANS at its official price of $27.50 per barrel and exchange a second barrel for a barrel of light sweet crude worth $30.00 per barrel in the same transaction. But instead of reporting the sale at a net average of $28.75 per barrel, Standard paid royalties "as though both barrels had been sold at the lower price."[24] To establish the basis for the case that such practices had cost Alaska hundreds of millions of dollars, the state's contract attorneys spent years setting up a filing system that attempted to track every barrel that left Valdez to its destination.

The only major North Slope producer that was not accused of fraud in the 1989 royalty complaint, ExxonMobil, was the last to settle its royalty disagreements with Alaska. The ExxonMobil dispute was settled in 1992, on the morning that its trial in the ANS royalty litigation was finally scheduled to begin; it would have been the first and only royalty trial. None of the companies admitted fraud. However, ExxonMobil's payment of $128 million brought the total collected on royalty litigation over a 15-year period to $631 million. Subsequent royalty settlements bring the total for royalty oil settlement payments between 1977 and 2000 to $979 million.[25] The major settlements included an agreement by ExxonMobil to price their ANS in the future using a basket of six crude oils that were listed daily and electronically on the open market. Formulas were also established for tanker costs.[26]

ExxonMobil was charged with fraud in a state income tax dispute running from 1979 through 1986. More than a decade later, the state and ExxonMobil fought this battle in an administrative proceeding before a special hearing officer that lasted for over a year. The state initially sought over $1 billion[27] but the hearing officer, who dismissed the fraud charge, awarded the state $254 million ($62 million in tax and $192 million in interest). When the case was settled in 1998, it was described as the last of Alaska's major tax cases from the 1970s.[28]

Inflated pipeline tariffs

Pipeline tariffs compensate the owner for construction, operating and dismantling costs, profits, and taxes. One of the principal reasons for determining correct pipeline tariffs is to ensure that pipeline owners do not over-charge shippers. In the case of an isolated, producer-owner pipeline such as TAPS, excessive tariffs could inhibit competition from nonowner shippers who must pay that tariff out-of-pocket, as opposed to the producer-owner, for whom the pipeline tariff is actually a transfer payment.[29] From a state fiscal standpoint, an appropriate pipeline tariff is important for another reason: A $1.00 increase in transportation costs reduces Alaska state revenues on production by approximately $0.21 (and vice-versa).[30] Because transportation costs are subtracted from the price of oil to determine production tax and royalty payments, all else being equal, the producer-owner would prefer higher pipeline tariffs. Producers or shippers who do not own a share of the pipeline, along with the State of Alaska, find themselves in exactly the opposite position.

These conflicting interests have led to protracted litigation involving the State of Alaska, pipeline shippers, and the TAPS carriers over correct pipeline charges. At the core of this battle, which has been described by the Alaska Department of Law as the largest and most complicated ratemaking case in the history of the United States,[31] were issues that included: the actual costs of designing, building, and operating the pipeline; the correct amortization period, methodology, and rate; interest rates; rates of return; ultimate throughput; and a host of other financial and economic issues.[32] In 1985, the TAPS carriers and the state sought to end 10 years of litigation with a settlement agreement establishing a novel and complex formula for determining maximum annual tariffs. The settlement was adopted at the FERC and was accepted provisionally by the RCA, which has jurisdiction over tariffs on oil that does not leave Alaska (approximately 8 percent of all TAPS oil).[33]

Alaska's attorney general has estimated tariff reductions due to pipeline tariff battles have resulted in the State of Alaska's collection of an additional $3.8 billion in postsettlement severance tax and royalties.[34] Nevertheless, extensive litigation over implementation of the agreement has continued before both regulatory bodies.[35] In 2002, the RCA upheld intrastate shipper challenges to TAPS tariffs filed under the 1985 settlement ceiling by nonowner shippers of oil destined for Alaska refineries. The commission found that between 1977 and 1996 the settlement allowed TAPS owners to overcharge TAPS shippers by nearly $10 billion dollars, and that tariffs in recent years were more than 50 percent too high.[36] While the state commission's decision appears to affect only the portion of TAPS oil shipped to in-state refiners between 1996 and 2000, state officials said that if the commission's order were applied to all future TAPS shipments, the state would receive an additional $110 million per year in increased royalty and production tax payments.[37]

According to the state commission, its 486-page decision marked "the first time in more than twenty years . . . that a regulatory agency has reviewed TAPS rates for consistency and statutory standards."[38] The TAPS owners have challenged the RCA order in court[39] and the state commission, as noted, has jurisdiction over a small percentage of the oil shipped on TAPS. Therefore, the ultimate outcome of this case is not clear; nevertheless, this decision appears to confirm charges that Alaska's negotiated TAPS tariff settlement cost the state billions of dollars in public revenue. These overcharges occurred despite the fact that the 1985 settlement reduced later-year tariffs to approximately $3.00 per barrel, compared to early-year filed tariffs of approximately $6.00 per barrel.[40]

By the end of 2000, Alaska had collected settlements in 29 North Slope royalty cases, 104 separate tax cases, and eight tariff proceedings at the FERC. The Alaska Department of Law reported that this litigation effort had produced an estimated $10.6 billion in additional revenue. This figure included $6.8 billion in direct payments for taxes and royalties, plus $3.8 billion in increased taxes and royalties attributed to reduced pipeline tariffs resulting from the 1985 TAPS tariff settlement.[41] This amount does not represent the total increase in government take due to petroleum litigation because it does not include efforts by the federal government to secure that government's portion of the income from North Slope petroleum development.[42]

North Slope crude prices and California's oil price dispute

Ripples from North Slope crude oil accounting, pricing, and transportation litigation extended far beyond the State of Alaska's coffers. In 1999, ExxonMobil was once again the lone holdout in a set of long-running oil price disputes its partners had settled long ago. This one involved the price of oil from the Wilmington field in Long Beach Harbor, California. Previously, various companies in the California producing consortium had paid an estimated $320 million to settle charges of underpricing their crude.[43] In that case, the State of California and the City of Long Beach argued that ARCO, a producer at Long Beach and on the North

Slope, had underpriced its California oil by $4 to $5 per barrel to support the artificially low price it reported in Alaska on its much larger volume of ANS, thereby reducing its Alaska royalty and severance taxes. ARCO presumably made up the difference in the resulting increased refinery profits, on which royalty and severance tax payments did not apply.

In the California case, the testimony of retired ARCO executive Harry Anderson was of particular interest. In a 1994 deposition, Anderson had defended ARCO's pricing practices. But at the trial, under cross-examination, the former oil company official testified that internal company analysis demonstrated that ARCO's posted price for ANS was $4 to $5 per barrel too low, that ARCO knew Chevron was paying Standard the higher figure for ANS on the West Coast, and that the posted price ARCO used for ANS royalty simply did not represent fair market value. Asked why his 1999 testimony contradicted his affidavit five years earlier, Anderson explained the difference this way:

> I was an ARCO employee. Some of the issues being discussed were still being litigated. My plan was to get to retirement. . . . I would not have been there in any capacity had I continued to . . . dissent. . . . I did not get to be a manager and remain a manager being oblivious and blind to signals.[44]

Industry settlement payments to Alaska, California, and Long Beach do not represent the totality of underpayments by the North Slope producers. In efforts similar to those of Alaska, the U.S. government also secured additional tax payments by demonstrating that the producers had under-reported the value of their profits on ANS in their federal income tax reports.[45] Even with the inclusion of the federal component, settlement sums do not necessarily represent the amounts by which payments by producers fell short of their obligations to their host. Settlements typically reflect a compromise acceptable to both parties at the time of the agreement. But the outcome of any given settlement may not reflect the actual costs and values at issue.[46]

Most of the Alaska disputes were settled in quasi-judicial forums before they went to trial; few cases were actually heard in a court of law. Nevertheless, the courts played a major role in enabling the public to obtain this significant portion of petroleum revenue. A strong and stable court system provided assurance that disputes over the administration of the terms of development could eventually be decided, if necessary, in a carefully structured proceeding. In contrast to the importance of the courts, input from legislative bodies and the public on petroleum litigation matters has been limited. Although it is the executive branch that represents the state in dealing with the petroleum industry, the State Legislature does receive occasional settlement briefings, with key information typically disclosed only behind closed doors.[47]

With a few notable exceptions, the critical details of the important arguments between Alaska and the North Slope producers have taken place behind a veil of confidentiality. In most cases, public information about a settlement is limited to the totals received, without quantification or discussion of specific issues or their resolution. Occasionally, the public learns of a dispute only when its final settlement is announced. Definitive information is generally unavailable through freedom of information challenges due to laws protecting taxpayer confidentiality and corporate assertions that such information would aid competitors. The result, by and large, is to leave the public in the dark regarding these matters.

Despite these barriers to public reporting on petroleum revenue disputes, the tradition of public disclosure of government activities in Alaska assures that the broad dimensions of petroleum litigation issues are at least partially visible, with detailed information emerging on a sporadic basis. Alaska's experience indicates that the compilation and publication of aggregate data on petroleum litigation issues can provide interested members of the public with the information necessary to understand the broad dimensions of salient economic issues affecting petroleum development without infringing on taxpayer confidentiality or threatening commercial positions.

Caspian Basin Development

The development of significant reserves in the Caspian Basin present the oil-consuming nations of the world with an enticing alternative to the Persian Gulf, where five nations possess more than 60 percent of the world's proven reserves. In March 2002, an article in *Foreign Affairs* magazine reported that new forecasts showed that the Caspian shelf held 75 billion barrels of oil—115 percent more than the *BP Statistical Review of World Energy* credited to the entire Commonwealth of Independent States in 2000. The article enthused that Kazakhstan's Kashagan field, recently discovered in the shallow north Caspian, looked to be even larger than its older, on-shore twin, Tengiz, just a few miles to the east. However, the same article warned, similar bright promise also beckoned a decade ago, only to vanish as "investors bogged down in a swamp of corruption and the difficulties of doing business in rapidly changing economies."[48]

While the prospect of vast wealth from petroleum beckons to the people of the Caspian Basin, the brief history of the petroleum industry is littered with broken dreams, and the Caspian region has lived both sides of this story. With the hopes of impoverished populations hanging in the balance, a clear understanding of the prospects for Caspian oil development is imperative.[49]

According to petroleum financial analysts Daniel and David Johnston, Kazakhstan government target returns from the PSAs for Tengiz and the more recently discovered Kashagan should be approximately 83 percent of net revenue over the life of those fields.[50] Elsewhere, Daniel Johnston also estimates that two Azerbaijan PSAs result in host government take to be between 64 percent and 70 percent of net revenue.[51] According to Johnston, these estimates of the government take compare to world averages of 78 percent for the government take for PSAs in more favorable regions.[52]

The target percentages that host governments expect from Caspian Basin development—64 to 83 percent—are significantly greater than the estimated 58.4 percent state and federal government share of net income from Alaska production and pipeline operations between 1988 and 2000 indicated in Figure 1, above.[53]

The Caspian region is still undergoing major social, political, and economic transformations associated with the end of Soviet power. Moreover, transportation systems to deliver oil to market have yet to be fully developed. Alaska, on the other hand, is a relatively stable region with a major transportation system in place. In view of these factors, one might expect that Alaska's producers might pay a premium over the Caspian. Instead, it is the other way around.

Before tackling this apparent anomaly, a brief discussion of background factors affecting comparison between Alaska's actual rewards and the projected returns from Caspian Basin development may be of use. There are striking similarities between Alaska and the Caspian Basin: both belong to the exclusive club of regions possessing super-giant fields; the oil from both provinces must find its way in a global market dominated by oil from the Persian Gulf; finally, to reach tanker connections to world markets, production from these remote reservoirs must bear the cost of long overland pipelines. Ranged against these broad similarities are significant differences between these two petroleum basins. For example: Alaska's principal development terms were forged approximately 30 years ago, in a different economic environment; did the emerging need for non–Persian Gulf oil supply that propelled the development of the North Slope prevent the United States and Alaska from securing terms comparable to those achieved by the Caspian nations three decades later? It should also be noted that North Slope development faced significant physical challenges posed by Arctic and subarctic environments; did the original investment risk translate into a premium that should continue to augment industry's share of net revenues 30 years later, even though Alaska development is no longer risky from a physical standpoint?

With these background observations and questions in mind, we turn now to three principal factors that partially explain why the government share of the income from Alaska's North Slope operations appears to be significantly smaller than the government take under the Caspian Basin PSA projections.

Government participation. The Caspian host government often holds an investment interest in the project as a member of the contracting group. The government take therefore includes not only royalties and taxes, but also the government share of return on risked investment. At Tengiz, for example, the government of Kazakhstan holds a 20 percent financial stake.[54] To compare to Alaska, it is necessary to transfer the profit on the Kazakhstan government investment shares to the industry side. A simplified calculation indicates that at Tengiz the industry share of net revenue would increase to 21 percent, resulting in a 79 percent government take.

Timing of cost recovery. A second significant difference between Alaska's returns and projected returns for the Caspian Basin is the timing of the payment of oil revenue to investors and to the host country. As discussed in the second section of this chapter, under some PSAs, most of the host government returns are deferred until investment is repaid, resulting in accelerated return of investment to the producer. This policy is attractive to investors, but the value of the payments to government is diminished during the corresponding delay. In the long run, the host government receives a larger percentage share as compensation for deferring its share of the net revenue. But the host government now shares a significant portion of the oil price risk (if oil prices remain unexpectedly low, the anticipated net profits might not materialize). Consider in this regard the Kashagan development: According to the Johnstons, in the early years of Kashagan development the contracting group will retain 98 percent of all revenue from Kashagan, leaving the host government with 2 percent. The Johnstons estimate that this extremely high back-loading of the government take (and the corresponding front-loading of investment costs) will continue until investment costs are recovered—perhaps until Kashagan has produced one billion barrels of oil.[55] During this period, the producers retain almost all of that revenue as repayment of costs instead of sharing it with the host as net profits.

Pipeline arrangements. A third explanation for the significant difference between returns realized in Alaska and those projected for the Caspian is that the Alaska data include pipeline operations; the PSA estimates for the Caspian projects do not. The State of Alaska analysis summarized in Figure 1 estimated that Alaska pipeline operations—principally TAPS—provide, on average, approximately one-quarter of the industry's net revenue from its Alaska operations. Under the Alaska system, pipeline operators pay only property and income taxes to the host governments; the producing companies must pay royalty and severance taxes to the host in addition to (and before calculating) property and income taxes. It is therefore reasonable to assume that inclusion of TAPS in the Alaska analysis increased the industry's percentage share of the net revenue take.[56] Inclusion of the transportation arrangements in Caspian calculations would similarly reduce the host government's percentage share.

After years of uncertainty, transit routes from the landlocked Caspian are finally under construction. Two major pipeline links to European and world markets are being developed, older pipelines through the former Soviet Union are slated to receive costly upgrades, and other projects are being considered.[57] Alaska's experience suggests that who will transport Caspian Basin oil and the terms on which that oil is shipped will play a significant role in determining who reaps the riches from that development. The principal transportation links and the regulation of their costs therefore deserve closer scrutiny.

The Caspian Pipeline Consortium (CPC) system, running nearly 1,000 miles from the Tengiz oil field to Novorossiysk on the Black Sea, pumped its first oil in October 2001. (see map at front of book) Start-up was delayed by five months while Kazakhstan negotiated various aspects of the pipeline charges with Russia.[58] At the end of 2002, CPC pipeline tariffs were essentially unregulated because that pipeline was shipping oil belonging only to the pipeline owners.[59] Initially, the CPC pipeline was able to carry slightly over half a million barrels per day (bpd); it is expected that between now and 2015 the CPC pipeline will be expanded to carry 1.34 million bpd from the super-giant Tengiz and other western Kazakhstan fields.[60] Governments hold 50 percent participation in the CPC—Russia (24 percent), Kazakhstan (19 percent) and Oman (7 percent). The remaining 50 percent is divided between a number of companies, including Chevron (15 percent), LukARCO (12.5 percent), ExxonMobil and Shell/Rosneft (7.5 percent each).[61]

During the summer of 2002, construction began on another major pipeline link to Western markets, the one million bpd BTC Pipeline, which will run from Baku through Tbilisi (Georgia) to Ceyhan (Turkey) on the Mediterranean. Although final approvals from Georgia were not in place when construction began, completion was anticipated in 2004.[62] BTC pipeline tariffs are spelled out in the construction agreement rather than in regulations; these arrangements include discounts for shipper-owners and a fixed fee for the Turkish portion.[63] The principal owners of the pipeline were BP (38.21 percent) and the State Oil Company of Azerbaijan (25 percent), with six other companies holding smaller interests. Initially, the BTC line will carry oil from the Azeri-Chirag-Gunashli field, in which BP holds a major stake.[64] Some observers have suggested that the line might carry oil from Kashagan, the recently discovered super-giant field scheduled for production in 2005 but still looking for a transport route.[65]

As mentioned above, with these projects underway, proposals for other major oil and natural gas pipelines from the Caspian Basin are competing for capital with other proposed projects that would bring oil and gas from other regions of the former Soviet Union to markets in both Europe and Asia.[66]

Conclusion and Recommendations

The people of the Caspian Basin and their governments face many challenges in the quest to ensure that they receive fair and full compensation for their petroleum resources. To understand the dimensions of these problems, this chapter examines the experience of another remote oil province with a super-giant field linked to world markets through a long pipeline connection—the state of Alaska. The resulting analysis of potential revenue issues related to Caspian development suggests important public policy issues in two areas.

One set of questions arises from the disparity between the terms the industry has offered to pay in the Caspian Basin and in Alaska. As noted in the preceding analysis, the industry will pay its hosts in the Caspian an estimated 64 to 83 percent of net revenue, compared to approximately 58 percent actually paid in Alaska. The disparity between the terms of development in two remote provinces with super-giant petroleum reservoirs brings to mind an adage frequently employed by investment advisors: If a deal sounds too good to be true, it probably is.[67] This concern may have particular relevance where people looking to improve their living conditions have been asked to postpone the major portion of that revenue while assuming the economic risks associated with deferral.

A second significant problem identified through consideration of Alaska's experience is that differences in the accounting for price received, production costs, and transportation charges, as well as other accounting practices, can significantly reduce the public's share of the revenue split between the host government and the industry. To deal with these conflicts, Alaska has had to engage in litigation efforts that have increased its take on North Slope development from $59.4 billion to approximately $70 billion, an increase of approximately 18 percent.[68]

Receipt of these additional revenues was tedious and administratively burdensome, with the additional payments often lagging behind the original payments by more than a decade. Despite the existence of democratic institutions in Alaska, including a strong court system and tradition of public accountability, important facts pertinent to the government/industry split of net revenue are generally not part of the public record, in Alaska or elsewhere.

Due to the nascent character of public accountability in the Caspian states, the challenge of securing fair and full public compensation is even more daunting than that faced by Alaska. In the absence of well-developed audit institutions and a court system, Caspian nations probably cannot place their reliance on a litigation effort such as that employed by Alaska. Nevertheless, as development issues unfold, it would be fatuous to suggest that industry representatives will not seek to maximize profits—or that corporate objectives are not liable to conflict with public interests. With amounts potentially totaling billions of dollars at issue, the citizens of the Caspian have a fundamental interest in assuring that government officials exercise their stewardship responsibilities vigorously to assure prompt receipt of the public share of petroleum resource revenue.

The public policy choice in this regard is simple: Citizens of the Caspian Basin can assume that whatever revenue they receive from petroleum development is the correct amount, or they can explore the best ways to evaluate in a timely manner the complicated cost, accounting, and pricing mechanisms that may be used by industry to enhance its returns at public expense. The assumption that petroleum revenues paid voluntarily represent the total amount due ignores the Alaska experience and flies in the face of common sense. Because the complicated economics of petroleum finances are not readily amenable to public analysis, the people of the Caspian would benefit greatly from clear reports that delineate how major petroleum development projects are being translated into private and public wealth. To this end, the people of the Caspian Basin can do three things:

- ***Create comprehensive, simplified economic models for evaluating potential petroleum earnings.***

  The creation of comprehensive and transparent economic models for specific petroleum reservoirs can be of assistance in dealing with these problems by providing the basis for evaluating potential petroleum earnings. In the absence of transparent development models, whether a project should go forward and, if it does, the actual results for the producers and their host governments remain matters of mystery and conjecture to the public. Information gained from a simplified simulation of the physical and economic performance of large Caspian Basin petroleum reservoirs and the associated infrastructure can help the public and policymakers to get a realistic fix on the promises and the pitfalls of proposed development projects. As those projects unfold, comprehensive public models can assist in determining whether actual payments, as reported in government documents and Publish What You Pay reports, constitute fair and appropriate compensation to the host government for the right to extract public resources. A tracking model has already been developed for the government of Kazakhstan with the assistance of the World Bank and the International Monetary Fund, but it is confidential. Because they concern such a large portion of public finances, information about these models should be made public.

To avoid issues of confidentiality, the public model for specific development should use publicly available estimates of (a) production, (b) price, (c) operating and capital costs and (d) transportation costs. The model should distinguish up-front government payments, such as royalties and bonuses, from net revenue payments. Using the formulas established by the governing PSA, costs would be subtracted from the gross production revenues to determine net revenue available for the split between the host and the producer.

- ***Monitor expenses for excessive costs that reduce net share payments.***

As noted earlier in this chapter, front-loading of industry cost recovery increases the potential for aggressive cost reporting that delays or reduces host government receipt of production revenues. Understanding the complicated economics of petroleum development becomes more difficult when state-owned oil companies are involved. The subjects discussed in this chapter that provide empirical support for these concerns include Alaska's litigation history, the Sakhalin-II experience, and the disparity between Alaska and projected Caspian returns. In combination, these factors suggest that careful monitoring of Caspian Basin development costs and payouts is warranted.

- ***Carefully analyze pipeline costs.***

Transportation charges take on particular relevance because these costs must be calculated before a producing reservoir earns net revenue that will be divided between producer and host. When a producing company is also invested in a pipeline that carries its own oil, transportation expenditures may remain with that company while simultaneously decreasing net production revenue available for sharing, and stifling competition. From this theoretical perspective, the Caspian Basin host nations should look closely at pipeline financial arrangements to ensure that excessive costs and shipping requirements do not reduce payments to producer host governments. In Alaska, even though a 1985 settlement reduced per-barrel pipeline tariffs on TAPS, a recent regulatory decision found that those tariffs are still too high when compared to tariffs calculated using standard economic formulae; excessive TAPS tariffs reduce state production revenue and inhibit competition.

The importance of pipelines to development in both Alaska and the Caspian was evident in the experience of Conoco after the company left Alaska's North Slope in 1993.[69] At the time, Conoco was the only company operating a field on the North Slope without a share of the super-giant Prudhoe Bay or TAPS. When Conoco sold its North Slope interests to BP during a period of relatively low oil prices, the guaranteed profits from pipeline ownership might have kept the company afloat until oil prices rose again.[70] Later, reflecting on his company's departure from Alaska, Conoco Chairman and CEO Archie Dunham said, "It broke my heart to trade Milne Point, but we had to do it. All the value of that property was taken away from us in the pipeline tariffs. It was a valuable strategic lesson—just look at why the producers in the Caspian Sea are so worried."[71]

The development of models that simulate the economic performance of major petroleum reservoirs can help citizens of host countries to understand and control their own destinies. In sum, creation of comprehensive, transparent, simplified petroleum revenue models to supplement the information produced under the Publish What You Pay doctrine will increase public understanding of the risks and rewards of petroleum development in the Caspian Basin.

Appendix 3

Oil Production (Thousand Tons):

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Total Oil Production	12,501	11,703	11,084	10,295	9,563	9,161	9,300	9,071	11,423	13,806	14,086	14,897	15,330
Including:													
— SOCAR	12,501	11,703	11,084	10,295	9,563	9,161	9,300	8,556	8,585	8,328	8,376	8,254	8,181
— JV and PSA (onshore)								465	467	664	637	746	763
— AIOC								50	2,371	4,814	5,073	5,897	6,386

Source: SOCAR, AIOC, Turan News Agency

Gas Production (Million Cubic Meters):

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Total	9,926	8,621	7,872	6,805	6,379	6,644	6,305	5,964	5,590	5,999	5,658	5,547	5,151
Including:													
— SOCAR	9,926	8,621	7,872	6,805	6,379	6,644	6,305	5,913	5,192	5,264	4,936	4,563	4,097
— JV and PSA (onshore)								51	47	92	78	84	95
— AIOC									351	643	643	899	959

Source: SOCAR, AIOC, Turan News Agency

Appendix 4
Azerbaijan's Expected Revenues from the Sale of Profit Oil Under the PSA for Development of the Offshore Block, Azeri-Chirag-Gunashli

Table A-1 below contains anticipated (2003-2010) oil production data from the Azeri-Chirag-Gunashli block of fields.

TABLE A-1: Azeri-Chirag-Gunashli Oil Production, 1997–2010, million barrels

Year	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Production	0.4	17.3	35.1	37.0	43.0	47.5	47.5	63.9	89.0	140.5	224.5	352.5	434.4	452.6

Source: "AIOC Azeri, Chirag and Deep Water Gunashli Full Field Development. Environmental and Socio-Economic Overview. BP, 2000"; Presentation by BP during the annual oil and gas show, Baku, June 5, 2002.

Table A-2, below, contains calculations of predicted earnings from profit oil from the ACG.

TABLE A-2: ACG Profit Oil Calculations, 1997–2010

		1997–2002	2003	2004	2005	2006	2007	2008	2009	2010
Production in Year, mln. barrels										
	A		47.4	63.9	89.4	140.5	224.5	352.2	434.4	452.6
Cumulative Production, mln. barrels										
		180.2	227.6	291.5	380.9	521.4	745.9	1098.2	1532.5	1985.1
Price of Crude Oil, $/b										
high	B		25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
low	C		18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Value of Annual Production, mln USD										
high	D		1185.0	1597.0	2235.8	3513.3	5612.0	8805.8	10858.8	11315.0
low	E		853.2	1149.8	1609.7	2529.5	4040.6	6340.1	7818.3	8146.8
Operating Cost, $/barrel										
	F		1.8	1.8	1.9	2.0	2.0	2.0	2.0	2.0
Cumulative Oper. Cost, mln. USD										
	G		85.3	115.0	169.9	281.1	449.0	704.5	868.7	905.2
Value of Production after Operating Cost, mln USD										
high	H		1099.7	1482.0	2065.8	3232.2	5163.0	8101.3	9990.1	10409.8
low	I		767.9	1034.9	1439.8	2248.5	3591.7	5635.7	6949.6	7241.6
To Recover Capital Cost, mln USD										
high	J		549.8	741.0	1032.9	1616.1	2581.5	4050.6	4995.0	
low	K		383.9	517.4	719.9	1124.2	1795.8	2817.8	3474.8	3620.8
cumulative high	L	1893.5	2443.3	3184.3	4217.3	5833.4	8414.9	12465.5	17460.5	
cumulative low	M	1893.5	2277.4	2794.9	3514.8	4639.0	6434.9	9252.7	12727.5	16348.3
Profit Oil $ mln										
high	N		549.8	741.0	1032.9	1616.1	2581.5	4050.6	4995.0	10409.8
low	O		383.9	517.4	719.9	1124.2	1795.8	2817.8	3474.8	3620.8
Cummul. Profit Oil mln USD										
high	P	1893.5	2443.3	3184.3	4217.3	5833.4	8414.9	12465.5	17460.5	27870.3
low	Q	1893.5	2277.4	2794.9	3514.8	4639.0	6434.9	9252.7	12727.5	16348.3
Profit Oil of Azerbaijan, $ mln										
high	R		165.0	222.3	309.9	484.8	1419.8	2227.9	2747.3	8327.8
low	S		115.2	155.2	216.0	337.3	987.7	1549.8	1911.1	1991.4
Cummul. Profit Oil of Azerbaijan, mln USD										
high	T	568.1	733.1	955.4	1265.2	1750.1	3169.9	5397.7	8145.0	16472.9
low	U	568.1	683.3	838.5	1054.5	1391.8	2379.5	3929.3	5840.4	7831.9
Profit Oil of Contractor, $ mln										
high	R		384.9	518.7	723.0	1131.3	1161.7	1822.8	2247.8	2082.0
low	S		268.8	362.2	503.9	787.0	808.1	1268.0	1563.7	1629.4
Cummulative Profit Oil of Contractor, mln USD										
high	V	1325.4	1710.3	2229.0	2952.0	4083.3	5245.0	7067.8	9315.5	11397.5
low	W	1325.4	1594.2	1956.4	2460.3	3247.3	4055.4	5323.4	6887.1	8516.4

Notes to Table A-2:

1. Lines B and C contain optimistic and pessimistic scenarios of crude oil prices in world markets. The estimated value of oil production by the year has been calculated on this basis. The estimated value is provided in lines D and E.

2. Line F displays estimated operating cost per barrel of oil produced from the Azeri-Chirag-Gunashli contract territory. The data for 1997-2002 have been taken from AIOC and SOCAR reports, while the data for 2003-2010 are a forecast based on an assumption of gradual increase in cost as later stages of development present greater geological challenges.

3. Line G displays annual operating costs, which are found by multiplying Line A by Line F.

4. Lines H and I indicate the value of annual production net of transportation and operating costs. Lines H and I subtract operating costs (line G) and transportation costs ($3/barrel) from the value of annual production (line D). Thus, we subtract the quantity of oil necessary to cover operating cost from the revenue derived from yearly oil output.

5. Then in Lines J and K, under the terms of the production sharing agreement, 50 percent of the amounts in lines H and I is calculated for payment to reimburse capital costs at high and low forecast oil prices. The remaining 50 percent is the profit petroleum to be shared between Azerbaijan and the contractor. Lines J and K contain the anticipated yearly volume of crude oil covering the capital costs, depending on high and low oil prices.

6. Lines L and M contain cumulative amounts of crude oil directed to covering the capital cost. Note that the cumulative amounts used for covering capital costs under the high price scenario will amount to about $17.5 billion by 2009, which exceeds the forecasted investment for all phases of the project with inflation and cost of capital figured in.

7. Since the total volume of capital expenses on the development of the Azeri-Chirag-Gunashli contract territory is forecast at the level of $13 billion (including expenses on financing, i.e. interest stakes on credits), the process of reimbursing the capital cost ends in 2009 or 2010 depending on crude oil prices.

8. In lines N and O, we calculate profit oil to be shared between the government of Azerbaijan and the contractor. Before 2009 (or 2010 in the event of low crude oil prices) the profit oil in Lines N and O is half of the amounts in Lines H and I, respectively. After all capital costs have been recovered, (starting in 2010 in the high price scenario and 2011 in the event of low crude oil prices) all revenue net of operating costs is available for distribution as profit oil.

9. Lines P and Q contain cumulative data on profit oil.

10. The profit-sharing mechanism of the ACG PSA allows us to calculate earnings for Azerbaijan and for the contractor from their split of profit oil. At Lines R and S, Azerbaijan's profit oil revenue is calculated for the high and low crude oil price scenarios. These lines cover three periods: 1997-2006, 2007-2009 and 2010, which differ from each other by the percentage of profit oil. According to the Azeri-Chirag-Gunashli PSA, depending on the rate of return on capital costs (see Table 4, Section 1), Azerbaijan will receive 30 percent, 55 percent or 80 percent of the proceeds from profit oil. From 1997 through 2006, profit oil was calculated on the assumption of a 30 percent share for Azerbaijan. Data for 2007-2009 was calculated on the assumption of a 55 percent share for the government. Finally, the data for 2010 was calculated on the assumption of an 80 percent share for Azerbaijan. These predictions have been based on expert assessments because exact information about the sale of crude oil (volume and price), and operational and capital expenses for every calendar quarter are not publicly available. According to the relevant PSAs, all production sharing calculations are made on a quarterly basis.

11. Lines T and U contain cumulative Azerbaijan profit oil totals for both high and low pricing scenarios. If the high price scenario materializes, then Azerbaijan's total receipts from ACG profit oil from 2003 to 2010 will exceed $15.9 billion, as Table A-2 indicates. Under the low price scenario, Azerbaijan's total earnings for that same period amount to $7.2 billion.

12. It is indicative that profit oil constitutes a considerable portion of Azerbaijan's oil revenues from PSAs, though, there are other revenue items in PSAs. It is also worth noting that all the calculations have been performed in the present value of money without inflation-related discounting.

TABLE A-3: Profit Tax Government Earnings from ACG, 2003-2010, in $ million USD

	Crude Prices, $/barrel	2003	2004	2005	2006	2007	2008	2009	2010	Total 2003-2010
Profit Oil of Contractor	25	384.9	518.7	723.0	1131.3	1161.7	1822.8	2247.8	2082.0	**10072.2**
Net Profit including:		346.4	466.8	650.7	1018.2	1045.5	1640.5	2023.0	1873.8	**9065.0**
to SOCAR		34.6	46.7	65.1	101.8	104.6	164.1	202.3	187.4	**906.5**
to Foreign Investor		311.8	420.1	585.6	916.4	941.0	1476.5	1820.7	1686.4	**8158.5**
Profit Tax from Foreign Investor		77.9	105.0	146.4	229.1	235.2	369.1	455.2	421.6	**2039.6**
Profit Oil of Contractor	18	268.8	362.2	503.9	787.0	808.1	1268.0	1563.7	1629.4	**7191.1**
Net Profit Including:		241.9	326.0	453.5	708.3	727.3	1141.2	1407.3	1466.5	**6472.0**
to SOCAR		24.2	32.6	45.4	70.8	72.7	114.1	140.7	146.6	**647.2**
to Foreign Investor		217.7	293.4	408.2	637.5	654.6	1027.1	1266.6	1319.8	**5824.8**
Profit Tax from Foreign Investor		54.4	73.3	102.0	159.4	163.6	256.8	316.6	330.0	**1456.2**

To calculate government profit tax earnings, we began with the calculation of contractor profit oil derived from Table A-2 above. We estimated transport, insurance, and other expenses at 10 percent of profit oil and deducted this amount. Hence, the taxable base was 90 percent of profit oil. The profit tax was calculated at the rate of 25 percent.

Endnotes

3. Securing the Take: Petroleum Litigation in Alaska

Chapter 3

[1] In this chapter the term "industry" refers to petroleum producers, their contractors, investors, and other associated companies and governments operating as project developers. These parties are typically identified in PSAs as "contractors."

[2] The term "super-giant" is usually reserved for oil fields estimated to contain at least 5.0 billion barrels of recoverable oil. In 1993 there were only 42 such fields in the world. See L.F. Ivanhoe and G.G. Leckie, "Global Oil, Gas Fields, Sizes, Tallied, Analyzed," *Oil & Gas Journal* (Feb.15, 1993): pp. 87-91. Alaska and the Caspian Basin are among the relatively few regions outside the Persian Gulf that possess super-giant oil reservoirs.

[3] This figure understates the total share of public revenue obtained through litigation because it does not include amounts secured by the federal government of the United States through Internal Revenue Service challenges to producer payments.

[4] It should be noted that the conduct of state-run oil companies can have significant impact on environmental issues beyond the purview of this chapter.

[5] The "Publish What You Pay" campaign was launched June 13, 2002 by financier George Soros with Global Watch and a coalition of more than 30 other non-government organizations See Nicholas Shaxson, "Soros aims to stop graft in mining and oil projects: Developing Countries Campaign to Make Companies Break Down Payments to Governments," *The Financial Times,* June 13, 2002, p. 6.

6. In the oil patch, early industry payments to a host government for purposes other than investment recovery (for example, bonus and royalty payments) are sometimes identified as front-loaded. In recognition of the importance of cash flow considerations to oil field development, in this chapter the term front-loading refers specifically to industry investment recovery.

7. Terms that front-load industry cost recovery are often used to induce development in provinces where prospects might not attract investment otherwise. For discussion of cash flow under various contracts, see Daniel Johnston, "International Petroleum Fiscal Systems," workshop workbook, Empire Hotel and Country Club, Brunei, January 16-18, 2002, p. 9-18.

8. Kazakhstan's Kashagan PSA is an example of a super-giant field whose investment recovery is heavily front-loaded. See Daniel Johnston and David Johnston, "Kashagan and Tengiz — Castor and Pollux," *Petroleum Accounting and Financial Management Journal* (fall-winter 2001): Figures 4 and 5.

9. See, for example, Pedro Van Meurs, *Suggestions for New Terms for the Alaska North Slope LNG Project: Background Report*, report prepared for the Alaska Department of Revenue, February 12, 1997, 75.

10. Under the terms of the PSA between the State Oil Company of Azerbaijan and the investors in the Azeri-Chirag-Gunashli Caspian production area, when the after-tax rate of return on investment rises above 16.75 percent, the government share of net revenue take jumps from 30 percent to 55 percent; the producer take therefore declines from 70 percent to 45 percent. See "Contractor's Recovery of Petroleum Costs and Production Sharing," *Agreement on the Joint Development and Production Sharing for the Azeri and Chirag Fields and the Deep Water Portion of the Gunashli Field in the Azerbaijan Sector of the Caspian Sea* (November 1994): art. XI. These terms are typical of Azeri PSAs. See Table 3 of Chapter 5. In the following simplified example, peripheral aspects of the PSA have been removed to demonstrate the essential economic effects of a potential investment when (1) the project operates for five years, (2) net revenue without additional investment is $100 million per year, (3) the rate of return is approaching the 16.75 percent threshold. For an investment of $100 million to increase net revenue to $150 million per year over five years, the annual rate of return on the new investment would be approximately 20 percent per year—significantly higher than the rate of return without the investment. But when the higher rate of return on the new investment raises the overall rate of return above the 16.75 percent trigger point, the investor's share of net income decreases due to the increase in host share of net income from 30 percent to 55 percent. The following simplified example compares the results of investment versus non-investment:

	Net Revenue ($ Millions)				
Investor Share with and without Additional Investment*	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
No Additional Investment Case (ROR < 16.75%)	($100 *[1 - 0.3]) = $70.00	$70.00	$70.00	$70.00	$70.00
Additional Investment Case (ROR > 16.75%)	($150 *[1-0.55]) = $67.50	$67.50	$67.50	$67.50	$67.50

* *Simplified example.*

11. Van Meurs, *Suggestions for New Terms for the Alaska North Slope LNG Project: Background Report.*

12. "Appeal of the Institute of Sea Geology and Geophysics of the Far East Academy of Science to the President V. Putin, Speaker G. Seleznyov, the Chief of Soviet Security S. Ivanov, the President of Academy of Science Y. Osipov, the Chief of Presidium of Far East Academy of Science G. Elyakov, the Chief of Auditing Chamber of Russia S. Stepashin," declaration by Pacific Environment, February 4, 2001.

13. Prudhoe Bay was discovered in 1967 and entered production in 1977 to become the largest oil field ever developed in North America. Alaska North Slope (ANS) production peaked at 2.0 million barrels per day (bpd) in 1988 and was approximately 1.0 million bpd in 2002. Output from the complex is expected to remain at current levels through 2010, dropping to approximately half that level by 2034. In terms of total production, the Prudhoe Bay reservoir is expected to produce approximately 14 billion barrels of oil, with the outlying reservoirs contributing an additional six billion barrels of oil. See Alaska Department of Revenue, *Revenue Sources: Forecast and Historical Data* (spring 2002): 29; L.D. Maxim, "Appendix A: Trans Alaska Pipeline System Throughput Analysis," in *Draft Environmental Report for the Trans Alaska Pipeline System Right-of-Way Renewal* (Trans Alaska Pipeline System Owners; February 15, 2001): A-2.

14. Mergers and acquisitions have changed the corporate names of the three dominant companies on Alaska's North Slope. BP's U.S. subsidiary merged with the Standard Oil Company of Ohio (Sohio) in 1970 and formally took over management of its Alaska partner in 1987; ExxonMobil represents the combined interests of the former Exxon and Mobil Corporations; ConocoPhillips is the third major North Slope player by virtue of Phillips Petroleum's acquisition of ARCO's Alaska properties in 2000. (BP was required to divest those properties as a condition of its global merger with ARCO; Phillips subsequently merged with Conoco, which had previously held smaller interests on the North Slope before trading them to BP and leaving Alaska in 1993.)

15. From Alaska Department of Revenue, *Revenue Sources: Forecast and Historical Data* (spring 2002): 165, and Alaska Permanent Fund Corporation data.

16. The Alaska agency analysis used production and lifting cost estimates from the author's 1998 report, *How Much Is Enough? Estimated Industry Profits from Alaska North Slope Production and Associated Pipeline Operations, 1993–1998* (Oilwatch Alaska, 1998), available at: http://www.alaskaforum.org

17. Gordon S. Harrison, "RE: Overview of Oil and Gas Disputes: Update, August 1994," Alaska State Legislature, Legislative Research Agency, Research Request 94.207, August 12, 1994.

18. Ibid.

19. Letter to Representative Ron Larson, co-chair, House Finance Committee, Alaska State House of Representatives, from Bruce M. Botelho, Alaska attorney general, February 17, 1994. The $217 million estimate did not include the staff time, expenses, and administrative overhead of the auditors, other agency personnel and the time and costs of the administrative overhead for approximately five staff attorneys within the Attorney General's Office. At that time, the Alaska Department of Law estimated that approximately $8.0 billion in claims against the industry were still outstanding.

20. From "Oil and Gas Settlements," attachment to letter from Bruce M. Botelho, Alaska Attorney General, to Representative Eric Croft, Alaska State House of Representatives, February 7, 2001.

21. *State of Alaska et al. vs. Amerada Hess Corporation, et al.*, Third Amended Complaint for Declaratory Judgment and Damages, State of Alaska, Civil Action No. 77-847, January 10, 1989, p. 25-29 (henceforth: Third Amended Complaint).

22. "Standard" refers to the former Standard Oil Company of Ohio (Sohio), which merged with BP in 1970.

23. Different crude oils have different physical characteristics that affect their market value. For example, ANS trades at a discount to the benchmark West Texas Intermediate (WTI) because ANS is heavier and contains more sulfur.

24. State of Alaska, Third Amended Complaint, 30.

25."Oil and Gas Settlements."

26. See "ANS Royalty Litigation Settlement Agreement (between BP Exploration [Alaska] Inc. and State of Alaska)," December 31, 1991, Exhibit A to Joint Motion and Memorandum Supporting Entry of Final Judgment Resolving All Claims between the State and BP Exploration [Alaska] Inc. in the matter of: ANS Royalty Litigation, January 23, 1992.

27. See *ExxonMobil Corporation v. State of Alaska,* Memorandum in Support of Emergency Motion for Stay, Civil Action no. 3AN95-1168CI, February 8,1995, p. 1.

28. Office of the Governor of Alaska, "ExxonMobil Pays State $254 Million to Resolve Tax Dispute," E-News Release 98049, March 10, 1998; "ExxonMobil, State Settle Tax Fight," *Anchorage Daily News,* March 11, 1998, F-1.

29. For summary discussion of competition issues on TAPS, see Anthony Scott, *The Trans-Alaska Pipeline System: The Causes and Consequences of Regulatory Failure,* Master of Science thesis in resource economics, (University of Wisconsin, 1996); and Richard A. Fineberg, *The Big Squeeze: TAPS and the Departure of Major Oil Companies Who Found Oil on Alaska's North Slope* (Oilwatch Alaska, 1997), available at *www.alaskaforum.org.*

30. Personal communication with Charles Logsdon, senior economist, Division of Oil and Gas Audit, Alaska Department of Revenue, December 2002. For a simplified example of the state-industry fiscal relationship, see *The Big Squeeze,* Tables 1.1 and 1.2. In a 1978 decision affirming the interest of the State of Alaska in TAPS tariffs, the United States Supreme Court noted that the State of Alaska loses $0.23 for every dollar of excessive TAPS tariffs. See *Mobil Alaska Pipeline Company, et al. v. United States et al.,* Trans Alaska Pipeline Rate Cases, 436 US 631 (1978).

31. The Alaska Department of Law described the case as "the largest" in budget and other presentations to the Alaska State Legislature, October 20, 1983, February 6, 1984 and January 24, 1985.

32. The complexity of the TAPS tariff formula is compounded by the fact that each of the TAPS carriers files a separate tariff. Moreover, individual company tariff data are shrouded in confidentiality.

33. *Settlement Agreement between The State of Alaska and ARCO Pipe Line Co., BP Pipelines Inc., Exxon Pipeline Co., Mobil Alaska Pipeline Co., Union Alaska Pipeline Co. with Respect to the Trans Alaska Pipeline System,* Federal Energy Regulatory Commission Docket OR 78-1, June 28, 1985. Through most of its life, the TAPS carriers without exception filed the maximum allowable tariff. Although some carriers have filed reduced tariffs in recent years, published settlement data indicates that these reductions constitute less than one percent of total tariff revenues.

34. "Oil and Gas Settlements."

35. For a summary of TAPS litigation issues subsequent to the 1985 settlement, see *The Big Squeeze,* 5.1 - 5.23.

36. Regulatory Commission of Alaska, *Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; And Outlining Phase II Issues,* Order no. 151 in Docket no. P-97-4, November 27, 2002, 1-9. As noted above, for every $1.00 of excessive TAPS tariffs, the State of Alaska loses approximately $0.21 in reduced royalty and severance tax payments. Therefore, overcharges of $10 billion, although largely transfer payments among shipper-owners, reduced Alaska's royalty and production tax receipts by approximately $2.1 billion.

37. Allen Baker, "State Weighs Pipeline Fees — $110 Million: If Rates are Cut, Alaskans, Small Producers Benefit," *Anchorage Daily News,* December 31, 2002, A-1.

38. Regulatory Commission of Alaska, "The Regulatory Commission of Alaska Rejects Rates for the 1997-2000 Intrastate Trans-Alaska Pipeline System, Sets Just and Reasonable Rates, and Requires Refunds and Filings by the Carriers," press release accompanying Order no. 151 in Docket no. P-97-4, November 27, 2002.

39. *Amerada Hess Pipeline Corporation, BP Pipelines (Alaska) Inc., ExxonMobil Pipeline Company, Mobil Alaska Pipeline Company, Phillips Transportation Alaska, Inc. and Unocal Pipeline Co. v. Regulatory Commission of Alaska,* Indicated TAPS Carriers' Statement of Points on Appeal, Superior Court for the State of Alaska, Third Judicial District, Case no. 3AN-02-___ CIV, December 6, 2002.

40. State of Alaska and U.S. Department of Justice, *Explanatory Statement of the State of Alaska and the United States Department of Justice in Support of Settlement Offer,* Federal Energy Regulatory Commission Docket no. OR 78-1, June 28, 1985, App. 6-7.

41. "Oil and Gas Settlements."

42. Although the U.S. Internal Revenue Service has received significant settlement payments from the major North Slope producers, comprehensive figures on its legal battles to are not available to the public.

43. As part of the California settlement, the companies also agreed to open previously closed West Coast pipelines to competitors. See: "Unocal to Settle Price-Fixing Suit for $78 Million: The Firms Admit no Wrongdoing in the Proposal, One of the Largest Settlements Reached in a State Antitrust Action Against the Oil Industry," *Los Angeles Times,* February 7, 1991, p. D-1; "Oil Giants Settle Suit With State: Chevron, Others to Pay Nearly $220 million," *San Francisco Chronicle,* August 17, 1991.

44. See testimony of Harry R. Anderson in Long Beach Antitrust Case, July 6-7, 1999, quoted in Eric Umansky, "Shooting the Whistleblower: How Congress is Sabotaging an Effort to Stop Oil Companies from Cheating Taxpayers," *The Washington Monthly,* vol. 31, Issue 8; and Morton Mintz, *Tompaine.com*, December 29, 1999, available at *www.tompaine.com*

45. Scattered news reports only hint at the magnitude of the amounts at issue in litigation by the U.S. Internal Revenue Service (IRS). The value of ANS crude was not the only issue in the federal challenges. For example, in May 2000 the *Houston Chronicle* reported that the U.S. Tax Court denied ExxonMobil $228 million in tax deductions ExxonMobil had sought future Prudhoe Bay dismantling expenses for the years 1979 through 1982 under a tax loophole closed in 1984. Since ExxonMobil holds a 20 percent interest in Prudhoe Bay, the total deduction at issue for that field was approximately $1.0 billion. According to the article, the Prudhoe Bay case was one part of a larger, global claim against ExxonMobil in which the IRS was seeking a total of $6.8 billion in alleged tax underpayments from ExxonMobil; on many of the major issues, the tax collectors did not prevail. See "Tax Court Denies Exxon Mobil Case," *Houston Chronicle,* May 5, 2000.

46. The data released by the State of Alaska to the State Legislature in 1994 indicated that the net financial benefit of protracted litigation far outweighs the cost (see "Oil and Gas Settlements"). Therefore, it is reasonable to assume that industry will prefer continued litigation to settlement unless the settlement preserves a significant portion of potential gains or prevents potential losses. In contrast to industry's primary focus on retaining its gains, host government decisions are made in a broader context by public officials (for example, to raise revenue to provide public services, or to induce further development).

47. Under Alaska's Constitution, the legislature functions as the overseer of public policy; the execution of the tasks established by the legislature is the domain of the agencies of the executive branch.

48. Edward L. Morse and James Richard, "The Battle for Energy Dominance," *Foreign Affairs* (March/April 2002): 23.

49. The prospects for oil development in Azerbaijan and Kazakhstan will be discussed in Chapters five and six.

50. See Johnston and Johnston, "Kashagan and Tengiz—Castor and Pollux."

51. The EDPSA and AIOC agreements are shown in Daniel Johnston's unnumbered figure, "Government Take (for Oil)," in International Petroleum Fiscal Systems Workbook.

52. Ibid., 19.

53. The disparity between the results reported by the State of Alaska for 1988-2000 and the estimates for the Caspian Basin developments is even wider than these numbers indicate for the following reasons:

(1) Oil prices were relatively low during the period covered by the Alaska estimates, but the Alaska industry percentage take increases as oil prices rise and average oil prices were significantly higher during the first decade of North Slope production than during the 1988-2000 period;

(2) The Alaska producer take in earlier years would be higher than the 1988-2000 period because smaller (and hence less profitable) fields were not in production during the earlier years of North Slope operation; and

(3) The Alaska estimates overstate the federal take by using the nominal federal income tax rate, which the industry seldom pays.

An accountancy analysis of Alaska operations between 1977 and 1987 reported industry take of 48.1 percent, with 51.9 percent going to the state and federal governments. (Edward B. Deakin, *Oil Industry Profitability in Alaska, 1969 through 1987,* Alaska Department of Revenue (1989): Appendix E.

54. U.S. Energy Information Agency, "Kazakhstan: Oil and Natural Gas Projects" (January 2002): Table 2.

55. Johnston and Johnston, figures 2 and 4. The environmental and technical challenges associated with Kashagan development will be discussed in Chapter six.

56. For discussion of the relationship between North Slope and pipeline profits, see Fineberg, *How Much Is Enough? Estimated Industry Profits from Alaska North Slope Production and Associated Pipeline Operations, 1993–1998.*

57. See Orhan Degermenci, "EU Study of Caspian Area Oil, Gas Pipelines Compares Routes, Costs," *Oil & Gas Journal* (November 2001): 68-79; U.S. Energy Information Agency, "Caspian Sea Region: Reserves and Pipeline Tables" (July 2002) and "Kazakhstan: Oil and Natural Gas Projects" (January 2002).

58. U.S. Energy Information Agency, "Kazakhstan" (January 2002): 3.

59. "Russian Regulator Delays Deeming Caspian Pipe a Monopoly," *Wall Street Journal,* December 16, 2002.

60. "Caspian Sea Region: Reserves and Pipeline Tables," Table 4.

61. Johnston and Johnston, Table 2.

62. "Caspian Sea Region: Reserves and Pipeline Tables," Table 4.

63. Information from personal communications with SOCAR and Turkish government officials, November 2002.

64. "Baku-Tbilisi-Ceyhan Pipeline Company Formed," press release, August 1, 2002, available online at http://www.unocal.com

65. Johnston and Johnston, Table 2.

66. See "Caspian Sea Region: Reserves and Pipelines Tables."

67. It has been suggested that Alaska, as host, gives up a premium for the risk of investing in Arctic and sub-arctic Alaska. While a risk surcharge may have been warranted in early years, Alaska's North Slope has operated with few interruptions for more than two decades and by 2002 had produced approximately 1.5 times more oil than originally anticipated. New developments now make up an increasing portion of Alaska's production. For these reasons, the original risk premium cannot explain the disparity between the public share from Alaska petroleum development and Caspian Basin target returns.

68. As noted previously, these figures underestimate the total share of public revenue secured through litigation because they do not include amounts secured by the federal government through similar efforts, for which no public totals are available (see Section 2, above).

69. Conoco, later acquired by Phillips Petroleum, is now a part of ConocoPhillips (see endnote 14, above).

70. For the effect of pipeline costs on Conoco's profitability during its final year of operation in Alaska, see *How Much Is Enough?* 27-35.

71. For Dunham's statements see "Getting to the Future First," *Hart's Oil and Gas Investor* (August 1996): 41.

About the Contributors

Author

Svetlana Tsalik is the director of the Caspian Revenue Watch, a program of the Open Society Institute's Central Eurasia Project. As such, she conducts research, works with local activists, and conducts advocacy in support of improved transparency and accountability in the management of petroleum revenues in developing countries. Prior to this she worked as a management consultant for A.T. Kearney in New York. In 2000, she graduated with a Ph.D. from the Department of Political Science at Stanford University, with a focus on center-regional relations in post-Soviet Russia.

Editor

Robert Ebel is director of the Energy and National Security Program at the Center for Strategic and International Studies. Formerly vice president for international affairs at Enserch Corporation, he advised the corporation on global issues. Ebel traveled to the Soviet Union in 1960 as a member of the first U.S. petroleum industry delegation, and in 1971 with the first group of Americans to visit the oil fields in Western Siberia. He is co-editor of *Energy* and *Conflict in Central Asia and the Caucasus* (2000) and author of *Energy Choices in the Near Abroad: The Haves and Have-nots Face the Future* (1997) and *Energy Choices in Russia* (1994).

Contributors

Ingilab Akhmedov is the founder and director of the analytic information agency Trend in Azerbaijan. He also heads the Public Finance Monitoring Center in Azerbaijan. Akhmedov served as an advisor to the Ministry of Economy of Azerbaijan from 1998 to 1999. Prior to that, he taught at the Azerbaijan Institute of Oil and Chemistry from 1991 to 1992. He holds a Ph.D. from the St. Petersburg State University of Economy and Finance.

Sabit Bagirov is the chairman of the board of Transparency International in Azerbaijan and president of the Entrepreneurship Development Foundation and the Center for Economic and Political Research in Baku, Azerbaijan. From 1992–1993, he served as the state advisor on strategic programs to the president of Azerbaijan, helping establish state committees on antimonopoly policy and support for entrepreneurship, privatization of state property, land reform, and foreign investment. During that time, he was also president of the State Oil Company of Azerbaijan (SOCAR), during which he restructured the company for greater efficiency and was responsible for contracts with foreign investors for the development of oil and gas.

Richard A. Fineberg brings experience from academia, newspaper reporting, and government service to his independent analysis of economic and environmental issues related to Alaska and global petroleum development. His research reports on Alaska cover topics such as: the profitability and long-term production prospects of Alaska's North Slope oil complex; state and federal petroleum receipts; operational and safety issues on the Trans-Alaska Pipeline System (TAPS); the economics of that system; and the causes and effects of the 1989 *Exxon Valdez* oil spill. His newspaper coverage of the construction of TAPS and a proposed natural gas line earned both state and national awards. Between 1986 and 1989, Fineberg served as a senior advisor to the governor of Alaska on oil and gas policy issues. Since that time he has consulted and prepared reports for nonprofit organizations, government agencies, independent developers, and private investors.

Rick Steiner is a professor, conservation specialist, and associate director of the University of Alaska Marine Advisory Program in Anchorage, Alaska. As the University of Alaska's marine advisor for the Prince William Sound region of Coastal Alaska from 1983–1997, he was intimately involved in oil issues, and became a local leader in the response to the *Exxon Valdez* oil spill in 1989. His work after the oil spill—proposing the establishment of the Regional Citizens Advisory Councils, helping to craft the U.S. Oil Pollution Act of 1990, and proposing that the governments and Exxon settle their damage claims, which led to the historic $1 billion settlement—received several awards and international recognition. He has also been producer and host of the Alaska Resource Issues Forum public television show since 1986.

Joseph E. Stiglitz, a Nobel Prize winner in economics, is professor of economics and finance at Columbia University in New York City. He has taught at Princeton, Stanford, and MIT, and was the Drummond Professor and a fellow of All Souls College, Oxford. He was a member of the Council of Economic Advisors from 1993–95 and CEA chairman from 1995–97. Stiglitz served as chief economist and senior vice president of the World Bank from 1997–2000. His work has helped explain the circumstances in which markets do not work well, and how government intervention can improve their performance. He helped create a new branch of economics, "The Economics of Information." His most recent book is *Globalization and Its Discontents*.

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For more information, contact:
Caspian Revenue Watch
Central Eurasia Project
Open Society Institute
Tel: 1 212 548 0600
Fax: 1 212 548 4607
stsalik@sorosny.org
http://www.eurasianet.org/policy_forum/crw.shtml
http://www.soros.org

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