ON THE STATE’S CHOICE OF OIL COMPANY: RISK MANAGEMENT AND THE FRONTIER OF THE PETROLEUM INDUSTRY

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About the National Oil Company Research Platform

While the role of the state is declining in nearly every sector of world economic activity, in hydrocarbons the pattern is quite different. State-controlled oil companies—so-called national oil companies (NOCs)—remain firmly in control over the vast majority of the world's hydrocarbon resources. Some NOCs are singular in their control over their home market; others engage in various joint ventures or are exposed to competition. PESD’s study on National Oil Companies focuses on fifteen NOCs: Saudi Aramco, NIOC (National Iranian Oil Co), KPC (Kuwait Petroleum Co), PDVSA (Petróleos de Venezuela), ADNOC (Abu Dhabi National Oil Company), NNPC (Nigerian National Petroleum Corporation), PEMEX, Gazprom, Sonatrach, CNPC, Petrobras, Petronas, ONGC, Sonangol, and Statoil.

These enterprises differ markedly in the ways they are governed and the tightness of their relationship with government. NOCs also vary in their geological gifts, as some are endowed with prodigious quantities of "easy" oil while others must work harder and apply highly advanced technologies; some have sought gas, which requires different skills and market orientation than oil, while others stay focused on liquids. These case studies explore whether and how these and other factors actually explain the wide variation in the performance of NOCs.
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On the State’s Choice of Oil Company: Risk Management and the Frontier of the Petroleum Industry

Peter A. Nolan and Mark C. Thurber

1. Introduction

The record of events that describe the petroleum industry (Parra 2004; Yergin 1991) and the analysis of these events (Adelman 1995; Jacoby 1974; Kobrin 1984) provide a context from which to draw observations about the drivers and evolution of the structure of the industry. Private operating companies are seen to have been employed in the great majority of instances for the exploration and early development of a new “frontier” petroleum province, yet governments have often revisited those choices in favor of nationalization and the transfer of petroleum assets to a state operating company. Most notably, in the early 1970s, nationalizations in a host of countries including all of the major developing world oil producers left three-quarters of the world’s oil reserves in the hands of state-owned companies. Control of a major part of the oil industry — decisions on oil price, production, and investment in reserves replacement — passed from private enterprise to a small group of producer countries.

Conventional wisdom holds that nationalizations are rooted in political motives of the petroleum states, which perceive value in the direct control of resource development through a state enterprise. State motives are inarguably important. At the same time, the argument presented in this paper is that this motive to nationalize, whatever its cause, is in fact severely constrained by both the significant risks associated with the creation of petroleum resources and the capacity of the petroleum state to take these risks.

We argue that constraints of risk significantly affect a state’s choice of which agent to employ to extract its hydrocarbons. Implicit in much current debate is the idea that private, international oil companies (IOCs) and the state-controlled, national oil companies (NOCs) are direct competitors, and that the former may face threats to their very existence in an era of increased state control. In fact, IOCs and NOCs characteristically supply very different functions to governments when it comes to managing risk. For reasons we will discuss, IOCs excel at managing risk while NOCs typically do not. A third type of player, the oil services company (OSC), does not take on the risk of oil exploration and development, but instead supplies needed technology to both IOCs and NOCs. IOCs, NOCs, and OSCs will all continue to exist because their distinct talents are needed by states seeking to realize the value of their petroleum resources. However, the relative positions of these different players have
changed substantially over time, and will continue to do so, in response to the shifting needs of oil-rich states.

Our hypotheses about the role of risk in shaping a state’s choice of agent for hydrocarbon extraction are summarized in the decision tree of Figure 1. This diagram is a stylized representation of how a rational state should choose its agent—private or state—under different conditions; it does not, of course, imply that all states will actually make rational choices. Private operating companies unsurprisingly are employed where oil-rich states perceive no motive for direct control through a state enterprise (A). In the more interesting (and common) cases where states do feel the need for direct control, private companies may nevertheless thrive at the industry frontier, where risks are extreme and the state’s capacity to shoulder these risks is low (B). State operating companies are principally found in proven and more mature petroleum provinces where the risks associated with the extraction of petroleum from developed fields are relatively small. However, they can also thrive where the petroleum state has significant capacity to absorb risk (risk tolerance), or in the rare cases where characteristics of the state-NOC relationship allow the NOC to develop appreciable risk management capabilities.

![Figure 1](image-url)  

Figure 1 The central idea: Petroleum risk and the state’s capacity for risk can constrain state choice of hydrocarbon agent.

Outcomes A and C in the decision tree are relatively stable, but outcome B creates an inherent tension between the state’s desire for direct control and dependence on IOCs to
manage risk. In this situation, a significant alteration in either petroleum risk or in the state’s capacity for risk can herald change. Over the multi-decade life of petroleum ventures, risks and state capacity for risk do change quite profoundly, prompting corresponding changes in the state’s choice of hydrocarbon agent. In some countries this has happened only once, in others multiple times — in some cases resulting in “serial” nationalizations.

In the next section of this paper we develop in more detail the hypotheses expressed in Figure 1, exploring the nature and sources of risk in the petroleum industry, how these risks change over time, the task of managing petroleum risks, and the variable capacity of state and private companies to manage them. In section 3, we apply qualitative and quantitative approaches to test the idea that risk significantly affects the state’s choice of which agent to use for petroleum extraction. First, we review the events leading to the cluster of nationalizations that occurred in the early 1970s and assess whether they were significantly affected by considerations of risk. Second, we explore how well variation in risk and state capacity for risk can explain changing ownership over time within a particular oil province — the UK and Norwegian zones of the North Sea. Third, we use data from energy research and consulting firm Wood Mackenzie to quantitatively test our hypothesis about the key role of risk, looking in particular at the case of oil and gas company exploration behavior. Finally, in section 4, we assess our theory about the role of risk in light of the results of section 3 and speculate about the roles for both private and state operating companies in the oil industry going forward.

2. The constraint of risk

In this section we elaborate on the idea of Figure 1 that considerations of risk significantly constrain a state’s options for using a state-owned entity to extract hydrocarbons, even when motives of control militate in favor of such an approach. The term “risk” has been used by different people to mean different things, which has sometimes introduced ambiguity into discussions around the concept. Therefore, we begin this section by presenting the definitions of risk and the related notion of uncertainty that will be used in this paper before we proceed step-by-step through the logical flow of Figure 1.
2.1. Defining risk

We define uncertainty to be a state in which outcomes are not known. Uncertainty can also be discussed in terms of degree, with uncertainty being smaller where more accurate estimates of outcomes are possible. Risk exists where some of the possible, uncertain outcomes involve a loss. Risk is higher when either negative outcomes are more probable or the losses associated with these outcomes are higher. (Figure 2 illustrates this for petroleum investments.)

The simplest type of risk-weighting for an investment simply multiplies the gain or loss associated with a given outcome by the estimated probability of that outcome and then sums over all possible outcomes (Megill 1988); in other words, it computes the expected value of an investment’s profitability. However, two investments with the same expected value of profitability can have widely different variances, with some investments being much more exposed to large losses (or gains). For this reason, more sophisticated risk-weighting approaches incorporate measures of an investor’s ability to tolerate a loss of a given size (Lerche and MacKay 1999). Our discussion of petroleum risks in this paper is not quantitative, but it incorporates the fundamental concepts above: that risk encapsulates both uncertain outcomes and capital exposed to these uncertain outcomes; and that risk tolerance is a key determinant of who can take on particular kinds of investments.

Risk can be managed in several main ways: by reducing one’s stake in any one investment, by taking on a diverse portfolio of projects to reduce the variance of overall return on investment, and by using knowledge and experience to reduce uncertainty, arriving at better determinations of the probabilities of different outcomes. This last idea merits further unpacking. In his seminal work *Risk, Uncertainty, and Profit*, Frank Knight (1921) divides probability estimates into those “where the distribution of the outcome in a group of instances is known (either through calculation a priori or from statistics of past experience)” and those “where this is not true, the reason being in general that it is impossible to form a group of instances, because the situation is in a high degree unique.”¹ (Knight 1921 p233) As Knight concedes, real-world probability determinations always lie somewhere on a continuum between these idealized extremes of, on the one hand, a fully characterized distribution of possible outcomes derived from perfect analogues to the present situation (what Knight calls “homogeneous classes”) and, on the other, a completely unknowable distribution associated with the absence of any analogues whatsoever that can provide guidance.² A key part of skillful risk management is developing the most accurate possible

¹ Knight suggests that these two canonical types of probability be referred to as “risk” and “uncertainty,” respectively. However, we deliberately eschew Knight’s use of the terms “risk” and “uncertainty” in this specialized way, believing it to be at odds with the common usage of these words and thus more confusing than helpful. (Some authors resolve this dilemma by adding the modifier “Knightian” to indicate these specialized meanings—for example, “Knightian uncertainty” refers to the case where the distribution of outcomes is unknowable.)

² Knight (1921) writes on p225-226: “There are all gradations from a perfectly homogeneous group of life or fire hazards at one extreme to an absolutely unique exercise of judgment at the other. All gradations, we should say, except the ideal extremes themselves; for as we can never in practice secure completely homogeneous classes in the one case, so in the other it probably never happens that there is no basis of comparison for determining the probability of error in a judgment.”
estimates of probability even for relatively unique and unprecedented cases. Models of the workings of physical phenomena—derived from accumulated experience and informed by targeted data collection for the case at hand—can be important tools for refining probability estimates even in the absence of proximate analogues.

2.2. Petroleum state motives and choices

In the stylized decision tree of Figure 1, we concede as a starting point that political considerations around resource control set the basic context that is then modulated by factors related to risk. For the purposes of this paper, we make the following two principal observations about state choices and state motives.

First, there is significant variation in how governments choose to involve themselves in their respective oil sectors. Many petroleum states never seek to control their petroleum industry through a state company. Others have periods of state intervention through a national oil company but at some point revert to control through regulation of private companies (e.g., the UK). In contrast, other petroleum states seek to nationalize their petroleum industry as soon as they can achieve it and still others are “serial nationalizers,” inviting private companies to invest in exploration and field development, then expropriating developed resources, and, at a later date, repeating the cycle.

Second, governments that depend heavily on petroleum revenues typically express a strong desire for direct control over their respective petroleum sectors. These states are prone to seek mastery over all the key variables that affect their petroleum revenues: the pace of investment, the rate of resource development, the government share of revenues, and of course the price of oil. This mastery has often been pursued through the selection of a state operating company. However, control of the factors that determine state revenue from petroleum does not demand a state company. Licensing and contracts with private firms offer a means to control the pace of investment and rate of development of resources. And, as Adelman (1995) points out, setting a price floor through an excise tax supported by a collective production limit by a producer cartel could influence oil price without the need for a state operating company.

Whatever the real, or perceived, value of direct control through a state operating company, the motive for control among the majority of the larger oil producer-states appears paramount. This motive is, however, constrained by the inherent risks of exercising direct control, as will be discussed in section 2.3. The capacity of a state to absorb hydrocarbon risk—its risk tolerance—is essentially a question of how affected the government and the economy would be by a shortfall in oil revenues relative to expectations or potential. For example, Angola’s MPLA government from 1976 through 2002 critically depended on oil revenues to prosecute a civil war; the government had very little ability to accept risk that these revenues would fall short of potential (see Heller, forthcoming). Countries like Kuwait with small populations and substantial budgetary surpluses, on the other hand, are relatively more able to tolerate the risk of underperformance.
2.3. The nature of petroleum risks

Uncertainty and risk are everywhere in the petroleum industry. In line with the discussion in section 2.1, petroleum investment risks vary in magnitude as a function of both uncertainty and capital invested (Figure 2). Exploration risks tend to be high because of their geological uncertainty despite modest capital exposure. In contrast, field development risk is high because despite reduced uncertainty—oil has been discovered—field development requires significantly greater capital. The magnitude of risk is also a function of the maturity of the exploration and production program, with uncertainty decreasing as knowledge and experience are acquired over time and as unproven (frontier) petroleum provinces are proven commercially and eventually become mature.

Relevant uncertainties are not only geological but also related to future market conditions. At the time of competition for hydrocarbon licenses, when future values are being estimated, investors must also make judgments about future costs and future prices for oil and gas produced. For the vast majority of oil today there is little or no risk associated with connecting oil with a consumer, as most oil can be sold at the wellhead into a global spot market. However, when this is not the case, investment in field development carries the additional commercial risk that demand may not materialize or that necessary infrastructure to connect supply to demand will not be available. We call this risk that hydrocarbons will not be able to find or access customers “market availability risk.” Even today, despite the existence of spot markets for liquefied natural gas (LNG), gas developments can still face appreciable market availability risk, particularly because they require expensive infrastructure and risky investments throughout the value chain. This risk can be especially pronounced in cross-border projects. A converse market risk, “supply risk,” refers to the uncertainty that a downstream investment, for example in a refinery, will receive a sufficient input stream of hydrocarbons to run at capacity over a long period of time as needed to recover costs.
Box 1 Frontier exploration uncertainties

A geological province is a large area, often of several thousand square kilometres, with a common geological history. It becomes a petroleum province when a working petroleum system has been discovered. A commercial petroleum system (or ‘play’) has several major components: a source rock that has a rich carbon content and that has spent sufficient time at required temperatures to convert its organic carbon to petroleum; a sedimentary reservoir rock with sufficient pore space to hold significant volumes of petroleum and sufficient permeability to allow petroleum to flow to a well bore; a non porous sedimentary rock that can be an effective barrier to petroleum migration; a structural trapping mechanism that can combine a reservoir rock and associated barrier/seal rock in a trap to capture and retain petroleum; and fortuitous geological timing such that that trap formation preceded the migration of petroleum. Combinations of these variables that result in the trapping of significant petroleum are rare. This is well illustrated by the USGS World Petroleum Assessment (USGS 2000) which identified 937 geological provinces across the globe. Petroleum has been found in just 406 of these provinces. According to the report, approximately 78% of the petroleum outside the US was found in just 20 geological provinces, with about 50% in just five.
Frontier petroleum activities by definition are those characterized by the highest risk. These can be conceptual oil and gas “plays” yet to be discovered and proved commercial—in other words, cases where only very imperfect analogues are available. The frontier can also include hydrocarbons known to exist but which remain undeveloped because of the significant risk involved in bringing these resources to market (e.g., shale oil and stranded gas). Over many decades, the industry has seen the frontier progress from exploration and development of onshore sedimentary basins through shallow offshore basins and into deep and ultra-deep water basins today. Recent frontiers have included the challenge of deep water as well as that of hydrocarbon activities in the former Soviet Union as it tentatively opened to private investment. Emerging frontiers include the challenge of commercializing vast resources of unconventional oils and gas, known to exist yet plagued by environmental and technical uncertainties and high capital requirements. Another emerging frontier is presented by the world’s large but aging oil fields, which require major new investments for their redevelopment through tertiary recovery. The high-risk frontier always exists, but the nature of its challenges changes over time.

As illustrated in Figure 3, risks change in a characteristic way over the lifetime of a petroleum province. Frontier exploration is characterized by extreme uncertainty. The key ingredients of success are poorly known (Box 1); probability estimates are likely to have significant error. Each exploration well carries not only the uncertainty associated with the specific prospect being drilled but also the uncertainty of the regional petroleum system. A high probability of failure means that many wells might be drilled before success is achieved or the attempt abandoned, and frontier wells can be expensive (a single deepwater well today can cost more than $100 million).

The discovery of a petroleum field begins a process of appraisal and development. Appraisal of a discovery involves drilling many new wells to confirm the extent and properties of the reservoirs and fluids and also to determine whether the range of possible outcomes can be attractive enough to warrant the much larger investment needed to develop the field. The development of the initial fields in a new province is replete with technical uncertainties that will affect the ultimate volume of oil that can be recovered and commercial uncertainties that will affect the value of recovered oil (Box 2).

With the development of one or more commercial fields a frontier becomes “proven.” Subsequent investments in proven provinces benefit from the data and knowledge acquired during the frontier exploration and development phase. Uncertainty about the presence of hydrocarbons and their character is much reduced, and accurate probability estimates are more easily arrived at due to the existence of analogues from the same geological system that can inform subsequent exploration or development activities. The associated reduction in risk often prompts an influx of new entrant companies that were deterred when risks to entry were high but are more able to invest in a lower risk environment. These new entrants can include both state companies and smaller, “independent” private companies.
Finally, as a proven petroleum province is further developed, knowledge continues to grow and uncertainty associated with these hydrocarbon activities is reduced still further. Risks shrink accordingly, and a proven province becomes “mature.”

After substantial oil or gas has been extracted from mature fields, they can benefit from investment in redevelopment. Two phases of redevelopment carry very different risks. The first, “secondary recovery,” involves drilling additional producing wells and injecting water or gas to maintain reservoir pressures if pressures have been depleted as oil is extracted. Secondary recovery carries only moderate investment risk: New well positioning is informed by the extensive reservoir and fluid information gathered during the field’s production history, and the supply of water (or sometimes gas) for injection is often low cost. Investment in “tertiary recovery,” on the other hand, is potentially higher risk. Increased recovery is achieved by injecting a stimulant to oil mobility in the form of chemicals or heat into the reservoir. Tertiary recovery, like other frontier activities, requires the investment of significant amounts of capital and, in contrast to secondary recovery, often has much more uncertain outcomes. Increased knowledge from path-breaking tertiary recovery projects will help reduce uncertainty and risk associated with similar projects in the future.
Field development at the frontier faces significant technical uncertainties. These include the properties of reservoir rock, the fluids it contains, and the fluid dynamics within the rock. The reservoir rock’s porosity, its permeability, its homogeneity, its structure at field and pore scale all contribute to uncertainty of both ultimate recovery and production rates. The reservoir at one location might be vertically or horizontally connected to the fluids in the reservoir at another location. A reservoir might be a single layer of sandstone at one location but made up of many more or less connected layers at another location. Faults at a large or microscopic scale might significantly affect the fluid dynamics of the reservoir. Fractures and pore space might be mineralized, restricting flow to a greater or lesser extent or not at all.

Fluids in a reservoir might be oil or gas or a complex mixture of both. The oil will vary in its API (specific gravity) and also its viscosity. Both oils and gases may contain many impurities (nitrogen, carbon dioxide, and hydrogen sulfide are common). The pressure and temperature of the reservoir fluids will depend on the depth of the reservoir, and this can affect mobility of hydrocarbons. Temperature and pressure change as fluids are produced to the surface, which can cause the complex mixture of petroleum to separate into liquids and gases, often resulting in there being significantly less fluid at the surface than in the reservoir. Oil may have a gas ‘cap’ above it in the reservoir, which may provide valuable energy for pushing oil to the surface. An aquifer at the base of the reservoir might also serve as a key source of energy (pressure) to move oil to the surface.

Uncertainties around each of these field variables translate into uncertainty in ultimate recovery volumes; peak production from the field; the life of the field; well flow rates; the density of wells required; required capacities of production, storage, and export systems; and when secondary and perhaps tertiary recovery might ultimately be appropriate. Adding in the uncertainty of future costs and future prices of oil or gas, the distribution of possible financial outcomes can be quite large.
Figure 3 emphasizes the extent to which risk in the petroleum industry is associated with the “creation of the reserves” — the relatively short time period required to find and develop and where necessary create a market for produced products. By contrast, the capital requirements and risks associated with the extraction of the field’s petroleum are quite low and the time required can span many decades. This dramatic shift in risk once major exploration and development have been completed can alter the bargaining positions of the petroleum state and any private operating company it employs in these initial phases. No longer needing the risk management abilities of private operators, governments may review their options and seek to increase their share of revenues and degree of control over hydrocarbon resources. As Vernon (1971) put it in his study of petroleum nationalization, the original bargain has become obsolete. (The threat in such cases of contract renegotiation or in extreme cases outright expropriation represents a formidable risk for private oil companies; however, this type of “political risk” falls outside of the scope of this paper because our analysis focuses on the risks faced by a petroleum state and how they shape its choice of petroleum agents, rather than on the risks faced by private investors.)

While hydrocarbon activities retain a frontier character, incentives to reduce uncertainty and costs are enormous because such actions translate directly into value. By contrast, there is much less leverage on value through efforts to reduce costs in mature operations where costs are low relative to oil price. It is therefore unsurprising that petroleum states with developed resources, which are characterized by low production costs, seek to maximize their revenue by raising oil price rather than reducing cost as even herculean efforts to improve project performance will have comparatively minor impact.
Together, these observations about the sources of risk and their change with time suggest the following two expectations. First, agents that are able to most effectively manage risk—typically private companies, as we will discuss in section 2.5—will provide more value to resource-holding governments in frontier activities than in mature operations, as the frontier is where costs are more significant relative to oil price. Even at the frontier, governments can choose to employ an agent that might be less able to manage risks, like a national oil company, but only at a potential cost to future revenues. Second, decreases in oil price put a premium on risk minimization in a wider range of hydrocarbon activities, effectively expanding the range of activities that are at the “frontier”; oil prices increases have the opposite effect. One might therefore expect to see oil-price-dependent cycles in the degree to which governments employ the private companies who are best able to manage risk. In sections 2.4 and 2.5 below, we further explore the ways in which oil companies can minimize risk as well as how capable the different types of companies—international oil companies, national oil companies, and oil services companies—are of performing this function.

2.4. The task of risk management in petroleum

Managing risk for a petroleum investor, be it a state or a private company, is about not only maximizing the expected value of net revenue across all investments but also containing its variance— in particular, one’s exposure to losses. Accomplishing this can be achieved by: 1) choosing projects with lower uncertainty, 2) investing in a portfolio of projects so that uncertainties (if well-estimated) will average out, 3) measuring uncertainty better both to identify projects with lower uncertainty and to provide confidence that revenue from a portfolio of projects will converge to the expected value, and 4) reducing the capital exposed to projects with high uncertainty.

Measuring uncertainty as accurately as possible, and progressively refining one’s estimates, is a central function of a petroleum operating company and the source of its competitive advantage. Where the distribution of possible outcomes is well-understood due to the availability of plentiful data from close geological analogues—the type of situation referred to by Knight (1921) as “statistical probability”—the measurement of uncertainty is straightforward and a variety of players can function adequately. Where a petroleum operating company truly distinguishes itself, by contrast, is in developing the best possible probability estimates when close analogues are not available. As described in Boxes 3 and 4, quantifying uncertainty in such cases requires investment in information (most often seismic and well data) and skills in predictive modeling derived from study of geological processes around the world and over many years. Predictive modeling integrates sampled data— informed by global analogues and a deep understanding of the geological processes at work—to predict a probabilistic distribution of hydrocarbons in place at all scales from a petroleum province to a specific field. This process of predictive statistical modeling has become the essence of both province-scale petroleum exploration (Lerche 1997) and reservoir development.
The uncertainty estimates produced by statistical models allow determination of the expected monetary value (EMV) of each investment (Rose 2001) and ranking of investments by attractiveness. Assembling a portfolio of investments allows further reduction of risk through diversification. To the extent that model predictions match the distributions of outcomes that are actually observed in these investments, the net revenue from the portfolio will converge to the overall expected value even though individual investments have highly uncertain returns. However, if major gaps in geological understanding lead to systematic errors in these models that are reflected in investment choices, diversification will not guarantee the expected overall return. The portfolio approach thus offers more risk management value to petroleum operators with superior knowledge, providing yet another motivation for companies to continually work at refining their geological understanding.

Mechanisms to directly reduce capital investment exposed to loss are also important. One strategy is to take a less than 100% working interest in a project, sharing risk among partners. States have sometimes reduced capital exposed to uncertain exploration outcomes by mandating that they receive a carried interest in exploration ventures. Under such an arrangement, states are not required to front any of the capital for exploration activities but are given the option to take a share in an oil and gas field after the presence of commercial reserves has been established.

Another way to reduce the capital exposed to loss is through engineering innovation that drives cost reduction. Petroleum states focused on reducing risk create incentives for innovation and cost reduction on the part of their petroleum agents. Such incentives can be created by competitive bidding, benchmarking of performance, progress bonuses, variable royalty structures, and other means.

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3 As Knight (1921) writes on p233-234 of Risk, Uncertainty, and Profit, “Now if the distribution of the different possible outcomes in a group of instances is known, it is possible to get rid of any real uncertainty by the expedient of grouping of ‘consolidating instances.’”
Exploring for a new petroleum province, or a new ‘play’ within this province, is essentially the process of predicting the presence, characteristics, and location of the key elements needed to form a petroleum province. Success in exploration depends on both geological observations (the data samples) and the ability to construct geological models that incorporate all observations and make useful and accurate predictions about both what might be found and the probability of finding it.

This process of observation, modeling, and prediction of what cannot be observed directly has always been at the center of the exploration business. Well and seismic data are two of the more important inputs that inform exploration. Cuttings from the drilling of wells provide rock samples that offer information on the sedimentary formations penetrated and can provide micro-fossils useful for correlation between wells and even across sedimentary basins. The use of remote tools in wells that can measure the electrical resistivity of fluids in penetrated formations and measure the natural radioactivity of the rocks in the well can provide clues to rock types and the fluids they contain. Cores of rock from wells can provide the opportunity for direct rock measurements. Recording and processing of reflected seismic (sound) waves enables the creation of maps of seismically reflective surfaces which in turn can provide clues as to the depositional environment of the sediments, rock types, and geological structure at depth. Stratigraphic data on rocks and their relationship with each other that is obtained from even a limited number of wells can be combined with seismic information to make extrapolations to a much larger area under the ground.

Geological models can be constructed that predict favorable combinations of source, reservoir and sealing rocks in the subsurface and that consider the timing of trap formation relative to the timing of petroleum generation and migration.
2.5. Company type and capacity to manage risk

We have discussed the nature of the risks associated with creating and extracting petroleum reserves and considered approaches for managing them that can be employed by companies and governments. In this section we consider how the distinctive characteristics of state and private companies with respect to risk management offer governments a choice.

Governments can employ three broad categories of company: privately-owned international operating companies (IOCs), state-owned (or state-controlled) national oil companies (NOCs), and the various oil service companies (OSCs) that provide technical services. While we are centrally interested in the choice between IOCs and NOCs as operating companies, we will also consider the OSCs to highlight both their key role as technology providers and their inability to absorb risk for a petroleum state.

**Box 4 Managing development risk**

Managing field development risk is once again about sampling and prediction, this time at a reservoir rather than province scale and in the context of a specific development scheme. The objective at this stage is to quantify and reduce uncertainties about the ultimate volume of recoverable petroleum and the rate of flow from the field over time. Physical sampling technologies include the drilling of appraisal wells to confirm the presence of petroleum at several reservoir locations, the sampling of both rock and fluid properties at each of these locations, and the testing of wells to determine the flow of oil or gas from the reservoir given local reservoir conditions. Seismic data, collected and processed to provide a very high resolution three-dimensional image of the subsurface, is calibrated to well data. In parallel with data collection a detailed predictive model of the reservoir is gradually built and refined as new information becomes available to include the entire range of variables that might have any material effect on the volume of recoverable petroleum or its rate of production. It is a model with many dimensions and where the majority of variables, despite the high density of well and seismic data, still carry considerable uncertainty. Analogous reservoir/fluid combinations from development projects around the world will once again aid and constrain the predictive modeling of the data. The remaining uncertainty that cannot be eliminated manifests itself in the form of changes to estimates of recoverable reserves over the productive life of a field. Increasing computer capacity has enabled ever more sophisticated simulations of the range of possible behaviors of the modeled fluids within their reservoirs. These models can be applied to a variety of possible development well configurations to investigate individual well productivity and longevity as petroleum migrates through the reservoir pore space into hypothetical well bores cut either vertically or horizontally through the reservoir. A development plan will be constructed based on a statistical reservoir model that predicts a range of ultimate recoverable reserves and a range of potential production rates. Wells will be designed and sited to recover the petroleum in the most economically efficient manner given proper regard for safety and environmental considerations. If uncertainties remain high because of irreducible complexity in the reservoir, then these uncertainties will be reflected in the options built into the development plan, for example the provision for expensive extra space on an offshore production platform that might or might not be required.
An important point to make at the outset of this discussion is that any company is theoretically capable of pursuing any risk management strategy. Just like an IOC, an NOC would be free in principle to manage risk for its government by building a global portfolio of investments around the world or by hiring or developing experts with outstanding capability to quantify geological uncertainty. Indeed, as we will discuss later, the rare NOCs exist that do just this. However, our point in this section is that the fact of being controlled by a state rather than driven principally by profits characteristically causes an NOC not to develop risk management skills on par with IOCs. In the case of OSCs, the salient point is that these specialized companies occupy a particular, profitable market niche that involves providing technology rather than managing hydrocarbon risk.

2.5.1. The International Oil Companies

Unlike NOCs, which can have a range of motivations and responsibilities depending on state goals, IOCs are focused exclusively on profit maximization. The IOC’s particular talent for managing risk stems from this basic orientation. To maximize profits, an IOC must succeed in competition with other oil operators across the globe. A private firm has to compete for the opportunity to invest, compete to attract and retain intellectual capital, and compete for risk capital. To win an opportunity to invest in exploration or development a company must essentially promise value to the petroleum state that exceeds that offered by its competitors. These promises are reflected in bids that are made more attractive to the state through various mechanisms, such as non-refundable cash payments or the commitment to a larger minimum work-program, which if successful promises economic growth and other benefits to the state.4 To create a more attractive bid without sacrificing profitability, a company must be able to predict more value than any other bidder and ultimately to be capable of delivering this value. A company must effectively “see” value that its competitors cannot, such as more in-place petroleum, greater recovery potential, or even the potential of future technologies to reduce costs. A company must get its predictions right more often than it gets them wrong to achieve the long-term performance that enables the private firm to attract risk capital and skills and, critically, to underwrite its promise of higher value to the state.

The skills that a private operating company must develop to survive in the marketplace thus naturally make it ideally capable of managing risk for a resource-rich government. First, an IOC is driven by commercial incentives to refine its ability to predict uncertain outcomes through application of the geosciences. Second, the company can increase its profits by innovating engineering solutions that reduce capital placed at risk. Third, because it is inherently driven to seek out the best opportunities all over the world, a large IOC tends to develop a global portfolio of ventures. As long as project outcomes are uncorrelated and the company’s uncertainty characterizations are good, this portfolio approach dramatically reduces the variance in the expected overall profitability for the IOC.

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4 Which elements of a bid a host government prefers most depends on factors outside the scope of this study. Some governments might prefer cash or direct payments to favored elites; others might seek visible work programs that create jobs and votes.
allowing it to tolerate below-average financial outcomes, or even a total loss, in a particular project. By shouldering all of the investment risk on such projects, IOCs can transform even frontier projects from ventures that hold enormous risk for host governments into ones that are nearly risk-free for the state.

IOCs have traditionally offered another crucial risk management function to resource-rich governments: the ability to mitigate market availability risk by creating a bridge to sources of demand for products that cannot be internationally traded. Investing upstream without a market commitment or investing in the creation of a market without assured supply would carry enormous risk. The development of stranded gas and its liquefaction for shipment to dedicated international markets is one example. A private company’s willingness to invest private capital in development of oil or gas provides assurance to the resource-holding government that the market is “safe” and to the market that supply can be relied upon.

There is no reason in principle why NOCs could not also attract private capital to projects that require cultivating a demand market, and indeed, a small number do. However, there are several reasons why IOCs are typically better positioned to do this. First, the market-driven track record of IOCs in maximizing returns helps more easily convince private capital that IOCs can deliver in developing profitable markets for stranded oil or gas. Second, connecting supply to demand around the globe requires a truly international focus that is almost inevitably precluded to a greater or lesser degree by home country political constraints faced by NOCs. Even Norway’s Statoil, among the most international and market-driven of NOCs, faces domestic pressures that can distract from its international activities (Thurber and Istad 2010).

2.5.2. The National Oil Companies

The characteristic feature of an NOC is its need to respond to government goals aside from pure profit maximization. The exact shape and function of an NOC can thus vary widely depending on how the government wants to control and benefit from the oil sector. Some IOCs serve regulatory functions in the oil sector (as, for example, in the case of Angola’s Sonangol), some become broader development agencies (as in the case of Venezuela’s PDVSA), and some play the role of administrative vehicles for state participation in oil (Nigeria’s NNPC has this character to a large extent). Many NOCs have operational activities of some kind, but very few are pure hydrocarbon operators. As tools of government, NOCs invariably have a soft budget constraint to some extent—they are never exposed to the risk of takeover or bankruptcy that would threaten a private enterprise that makes unsuccessful investments. On the other hand, NOCs are exposed to political pressures to a greater degree than their privately-owned brethren. These basic conditions under which NOCs operate have fundamental implications for their ability to manage risk as hydrocarbon operators.

First, the close linkages between an NOC and its government can impede the NOC’s ability to raise risk capital or execute other transactions to manage risk, although such
obstacles can sometimes be overcome. Full state ownership precludes equity swaps that might allow an NOC to manage risk by diversifying its assets abroad, but partial privatization can be perceived by governments as weakening their control over the oil sector. Companies funded entirely from government budgetary allocations can face legal constraints on their ability to raise debt on international markets—Mexico’s Pemex was in this situation until the PIDIREGAS scheme was developed to allow it to raise risk capital against the strength of Mexico’s sovereign debt rating (Stojanovski 2008). Most NOCs remain dependent on their own cash flow or government balance sheets to finance their exploration and development projects. This means that a national oil company is putting state rather than private capital at risk; thus risks that the NOC incurs are, in effect, risks to the state.

Second, the relative absence of competitive pressures on the national oil company reduces its incentives to develop the strong risk management capabilities that would be essential to survival in a more competitive environment. NOCs generally have a soft budget constraint and are granted special advantages in their home territory, commonly including a preferential position in the upstream or a monopoly over product sales at home. Lacking strong commercial incentives to do so, NOCs can therefore lag both in development of capability to make accurate geological predictions and in innovation (technological or organizational) that would reduce cost and thus capital at risk. In some cases, the lack of competitive pressures can actively encourage NOCs to take technology risks that IOCs might avoid as imprudent. For example, its monopoly position at home and soft budget constraint probably encouraged Petrobras to be more aggressive at investing in technology-intensive offshore exploration and development than it would have been if the state were not implicitly underwriting these efforts (De Oliveira, forthcoming). Risk taking does not imply risk management on behalf of the state.

Third, both political pressures and their privileged domestic position tend to encourage NOCs to stay at home rather than diversifying abroad to reduce overall risk. Petrobras’ initial partnerships with IOCs and efforts overseas were not politically popular in Brazil (De Oliveira, forthcoming). Norway’s political leadership would probably not have been amenable to an overseas role for Statoil before the 1990s, and the NOC must still weather periodic criticism at home for its activities abroad (Thurber and Istad 2010). A more significant factor in most cases, though, is the simple fact that, as long as plentiful domestic resources remain available, an NOC has every incentive to operate on its home turf where it is not exposed to full competition. This is the main reason why only a minority of NOCs have developed any substantial international portfolio. Those that have internationalized in the face of declining domestic resources—such as ONGC, CNPC, and Petronas—are employed by host governments that in any case no longer have a pivotal need for managing the risks associated with extraction of domestic hydrocarbons.

As discussed above and elsewhere in this volume, governments have many goals beyond managing their exposure to petroleum development risks, and it is the real or perceived ability of NOCs to serve these goals that explains their existence despite characteristically weak risk management capabilities. An NOC in theory offers the state more direct control over resources, including the ability to pursue a depletion policy (rate of
production target) that would be in conflict with maximizing return on investment. An NOC can be used to furnish a wide array of public or private goods, such as employment, financial benefits for elites, fuel subsidies, or development services. Host governments might encourage their NOCs to operate overseas if that yields projects and supplies that are thought to improve the country’s energy security.

At the same time, recognizing the weaknesses of their NOCs at risk management and the sparse inherent incentives for improvement, states do pursue various strategies to try to squeeze more performance out of their state oil companies. These strategies, which are treated in detail by David Hults (forthcoming), can include the introduction of some competition in the home market to benchmark performance.

2.5.3. The Oil Service Companies

A closer examination of what a third entity, the oil service company (OSC), does can help clarify the frequently misunderstood distinction between technology and risk management functions in the petroleum industry. Oil service companies design and provide the physical equipment that IOCs and NOCs alike use to explore, develop, and produce oil and gas. They are essential vendors, but their roles are focused and limited. The role of the oil company, whether state or private, is to know where to explore and what to develop; the role of the oil service company is to provide the technologies that will be used to explore and develop. An oil company might, for example, predict the location of a potential reservoir, but it is the drilling equipment provided by the oil service companies (OSCs) that physically tests the prediction. Unlike operating companies, OSCs do not make predictions or promises about the outcome of an exploration or production venture and do not invest shareholders’ capital in highly uncertain outcomes. The OSCs supply technology but do not assume risk on behalf of a hydrocarbon state.

While the major oil companies formerly developed and owned significant oil exploration and development equipment, today most such technology functions are outsourced because oil companies gain little competitive advantage from keeping them in-house. IOCs compete by convincing oil-rich states of their ability to manage risk, whereas OSCs compete by convincing IOCs and NOCs that they offer better tools to enable the oil industry to take on the next frontier challenge—to go farther and to do it at a lower cost.

As long as resource-rich countries remained dependent on IOCs for both risk management and technology services, they had little prospect of developing state-controlled operating companies. OSCs have played a key role in enabling the development of NOCs by making state-of-the-art technology available to any prospective operating company, even though IOCs retain their advantage in managing risks at the frontier.
2.6. Risk and the state’s choice of agent

Returning to the basic thesis expressed in Figure 1, we expect that the differences discussed above in the characteristic abilities of different hydrocarbon companies to manage risk will constrain a rational state’s choice of agent. In Figure 4, we represent this idea as a set of outcomes according to risk and the state’s capacity for risk, considering only the case of states that have a strong motivation for direct control over hydrocarbons.

For high-risk (“frontier”) ventures in countries with low risk tolerance, the expected agent in petroleum is a private operating company (IOC), as shown in the lower right quadrant of Figure 4. In the most risky frontier activities like exploration, IOCs will most likely bear all of the risk for the state. Once the basic commerciality of a frontier play has been established, states might choose to participate on an equity basis in its development, with the IOC’s willingness to risk private capital providing an important signal to the state that development risks are acceptable and the investment is a good one.

For high-risk ventures in a state that can tolerate risk (upper right quadrant of Figure 4), for example because state revenues are diversified or the government already has a substantial budget surplus, the outcome is often a sector where NOCs dominate as operators and the state takes all of the investment risk. China and several of the large Middle East producer states fall into this category.
Figure 4 The choice of operating company and state participation when the state desires direct control.

Once reserves are created, markets are available, and risks are low, then NOCs can thrive as operators (left half of Figure 4). This situation is characteristic of mature provinces where extraction and maintenance activities dominate. Even so, there may remain cases with significant IOC involvement—for example where institutional weakness and a dearth of technical capability in a country preclude development even of a rudimentary operational NOC that can competently contract technology functions to OSCs. The result might be a national oil company that has no operational role but instead seeks technical service agreements with private companies.

As discussed in section 2.3, oil price can play an important role in shifting the boundary between high-risk and low-risk ventures for resource-rich states. When oil prices rise, minimization of uncertainty and cost becomes a less important part of assuring the desired revenue collection, and resource-rich governments also tend to be more flush with cash that they can pour back into oil (and non-oil) activities. Under these circumstances, a government’s desire for direct control of hydrocarbons is less constrained by considerations of risk, and an NOC is more likely to be the agent of choice. When oil prices drop, on the other hand, governments wishing to maximize revenues will be more likely to need the risk-
minimizing talents of IOCs, which in general can offer lower costs and improved odds of success in resource development. Such a dynamic could in theory lead to a kind of “backward-bending supply curve” for oil, in which higher oil prices actually decrease the rate at which hydrocarbons are found and extracted worldwide.

3. Testing the idea that risk constrains state choice of oil company

This section of the paper uses three complementary approaches to test the proposition that risk is a significant constraint on state choice of agent in oil. First, we take a high-level look at the most important structural change the industry has seen—the widespread nationalizations of the early 1970s—to see if changes in risk over time had an important influence on events. Second, we examine the effect of risk on state choices of operating company for the particular case of the North Sea, where within one province the behavior of two different countries can be compared. Third, we use exploration well data from Wood Mackenzie to statistically test whether specific frontiers are preferentially explored by private companies as would be expected according to our hypothesis. In particular, we consider exploration in deep water and in sectors that have not had a previous discovery. We also use the same data to test for the expected effect of price—that higher prices result in more use of national oil companies and lower prices in more use of private companies.

In none of these cases do we expect to find a deterministic effect of risk on outcomes; as we have discussed before, there are simply too many different factors that can affect the state’s choice of agent. However, we do expect to see risk emerge as an observable constraint on state choices in hydrocarbons.

3.1. The nationalizations of the early 1970s

In the early 1970s several countries, including all the major producing countries in the developing world, chose to fully or partly nationalize their oil industries and replace private oil companies with national operating companies. Unlike earlier and more isolated nationalizations of private company oil positions—notably in Bolivia in 1937 and Mexico in 1938—which had only modest impact on the industry as a whole, the events of the early 1970s marked a transformation of the structure of the international oil industry. To examine how the constraint of risk influenced these events, we need to look at several factors: the risk characteristics of the emerging international oil industry as WWII drew to a close; the players in the industry and the tools they used to manage these risks; the consequences for the petroleum producer states; and the actions these states took to seize control. Our analysis draws upon the excellent documentation and interpretation of these events by Adelman (1995), Jacoby (1974), Kobrin (1984), Parra (2004), and Yergin (1991).

As oil began to emerge as a key fuel, the United States, Russia, and China were able to transition from indigenous coal to indigenous oil. However, the major industrial countries
of Europe and the Far East were faced with the need to import virtually all of their oil. At the same time, virtually no indigenous markets were available to absorb the oil that was being discovered in the Middle East and elsewhere. This mismatch created a pressing need to connect emerging oil provinces with markets abroad. Risks were high not only in oil exploration and development but also in bringing this oil to new consumers. At this stage, no one knew what hydrocarbons might be found, where they would be found, or what it would take to build the infrastructure to transport oil produced in the Middle East, Venezuela, Indonesia, or other oil provinces to markets in Europe or Japan. Market risks ran in both directions: Upstream development was extremely risky without a stable long-term market, and market development was risky in the absence of assured supply.

For all the appeal of potential oil revenue, oil-rich countries had low capacity to accept the massive geological and market availability risks in the nascent oil industry. They did not in general have the financial capacity to put the requisite capital at risk themselves, nor did they possess sufficient domestic technical capacity to form a state-owned agent that could manage geological risk. (The few countries that eventually developed NOCs with some risk management talents, notably Norway and Brazil, focused early in their petroleum eras on building indigenous technical capability in oil.) As a result, all of these new producer states chose to employ private companies to take on the risks of exploration, initial development, and, critically, the creation of markets for their petroleum. Only a few major international corporations had the know-how and financial risk tolerance required for such an undertaking: American companies Chevron, Exxon, Gulf, Mobil, and Texaco; Britain’s BP; Anglo-Dutch company Shell; and France’s CFP. These companies faced the challenge of finding and developing sufficient petroleum in the Middle East, and later Africa, to support and underwrite vast investments aimed at meeting the rapid growth in demand for petroleum products from Europe and the Far East. Refineries, petrochemical plants, distribution systems, and retail outlets as well as ports, infrastructure, and tanker fleets had to be financed.

The major international companies evolved several strategies for managing the considerable risks of investment in this cross-border oil business: concessions, upstream joint ventures, and vertical integration from supply to consumers. Very large and very long-term concession agreements with producer states, which were to persist until the early 1970s, reduced risk by aggregating geological opportunities and allowing cost recovery over a long period. Joint ventures between oil companies helped spread the political risks of having concessions in a few politically unstable countries. Vertical integration helped keep upstream and downstream investments in harmony, infrastructure at capacity, and consumers content and growing in number. The massive downstream investments required to build refineries and oil transport infrastructure, which were significantly more capital-intensive even than upstream exploration and development, made vertical integration particularly important at this stage of industry development. Without being able to ensure oil supply sufficient to run downstream infrastructure at full capacity, the oil companies would not have been confident in their ability to achieve an adequate return on their downstream investments. Although the major companies were not a cartel in any formal sense, vertical integration and shared upstream JV positions ensured that they shared knowledge and in effect made upstream
decisions within a common interest, further reducing their risk. None of these risk management tools were available to the producer states at this phase of oil industry development.

The risk management strategies of the private oil majors were successful: The necessary investments were made in developing oil supply and delivering it to consumers, and the international oil business grew at an unprecedented rate. However, the producer states perceived this to be somewhat at their expense. Private companies were making all the decisions about investment in exploration, whether and when to develop a discovery, and what production levels to take from each field. The producer states were left with no strategic control over critical factors—including the rate of investment and rate of production—that affected the revenues upon which they increasingly depended. They could increase taxes but only on what was produced. These states therefore had a strong motive to wrest control of the decisions affecting oil revenues from the private companies. However, they were constrained in their ability to do this by their limited capacity to accept risk or to apply the risk management strategies being used by the private oil companies.

The risks of oil operations began to decline as the industry developed. By the late 1950s the big fields had been found and developed in the key Middle Eastern countries (Iran, Iraq, Kuwait, and Saudi Arabia), significantly reducing upstream risk. Transport and refining infrastructure was in place, and the market for petroleum products was growing rapidly. However, the major oil companies still controlled access to customers, creating a residual market availability risk that still precluded effective nationalization by producer states. The inability of Iran, despite formal nationalization of its oil sector in 1951, to gain de facto control over its hydrocarbons illustrated how this market availability risk still gave the major oil companies the upper hand in their negotiations with oil states.

It was the entry of new companies into the international oil business that ultimately helped provide competitive access to oil markets, reducing market availability risks sufficiently for nationalization of a country’s oil sector to be feasible. The rapid growth and profit potential of the international oil industry proved a strong attraction to new entrants, especially once exploration and development risks had fallen and solid demand for oil had been established. More than 300 private companies and 50 state-controlled companies entered or significantly expanded their activities in the international oil business between 1953 and 1972 (Jacoby 1974). These included American “oil independents” in search of lower-cost oil supplies for their downstream positions in the United States as well as companies owned by oil-consuming states that wanted security of supply (Parra 2004). The new entrants pursued oil exploration and development in the already-established provinces of the Middle East and also in new areas in Africa, helping supply stay ahead of demand even in a rapidly growing market. Import controls imposed by the United States after 1957 meant that the US-based independents had to find alternative markets in Europe and the Far East for their crude. As a result, they contributed substantially to the rapid growth of refining capacity in industrial countries of Europe and the Far East and began to create an open market for the trading of crude oil. With infrastructure in place, increasingly open markets, and a multiplicity of both suppliers and consumers—what Jacoby (1974) called an “effective
market” for oil—upstream investments carried reduced market availability risk and
downstream investments carried reduced supply risk. In theory, the risk management role of
the major oil companies had become less important.

Our simple model of Figure 1 predicts that nationalizations could have been expected
as soon as geological and especially market availability risks had declined in this way by the
early to mid 1960s. However, in reality there was some delay before widespread
nationalization actually occurred. The nationalizing trend of the 1970s was indeed enabled
by reduced geological uncertainty and the ready availability of markets, but its exact timing
was affected by other factors. In particular, we speculate that the declining oil prices in the
1960s, themselves the result of increased competition in the oil industry, may have had a role
in affecting state perceptions of risk and re-directing state focus temporarily away from
nationalization. As discussed in section 2.3, lower oil prices effectively increased the risk
that overall revenue would fall short of government targets, placing a greater premium on
minimizing hydrocarbon and market availability risks by employing IOCs. At the same
time, these states turned to cartelization as their own means of reducing the risk to their
revenues. The OPEC cartel was formed in 1960 and made progressively stronger efforts to
control price through coordination. At the outset the OPEC states remained reliant on the
major oil companies to set the price of oil. By 1971 their bargaining position had improved
to the point where they were sharing decisions on price with the major companies. By 1973
their position was sufficiently strong that they could unilaterally set prices above what would
be sustainable in a free market, supported by the coordinated withholding of production
(Adelman 1995). Nationalization before an effective cartel agreement on production restraint
would have opened the door to competition between producer states and depressed crude
prices further. However, once an effective cartel was in place to deal with the price risk to
state revenues, nationalization could follow.

3.2. The North Sea

The North Sea provides an opportunity to examine how two countries, the UK and
Norway, chose their hydrocarbon agents to manage risks within essentially the same
petroleum province. The evolution of hydrocarbon policy in these two countries over the
course of North Sea petroleum development is well-documented by Bowen (1991), Nelsen
(1991), and Noreng (1980). Much of that history is consistent with what our theory would
predict about how risk constrains government actions. At the same time, differences in the
British and Norwegian approaches at particular junctures illustrate that risk is not the only
factor that influences government decisions on hydrocarbon licensing.

Until 1959, with the discovery of the very large Groningen gas field in the
Netherlands, there had been very few discoveries of hydrocarbons of commercial value in
onshore Europe. Once Groningen was known to exist, the major oil companies began
lobbying to open the North Sea for exploration on the theory that the Groningen-like
formations might extend offshore. Norway and the UK had a classic frontier province on
their hands: The geology of the North Sea was promising but it remained highly uncertain whether commercially viable reserves would be found. Because massive investments in exploration would be needed to prove out the province, this uncertainty translated into substantial risk.

As Figures 1 and 4 would predict, both the British and Norwegian governments avoided equity or operational participation in the early exploration and development of the North Sea. Instead, after a process of demarcating political boundaries and putting in place requisite legislation in their respective countries, the British and Norwegian Governments sought to entice the private oil industry to take on the risks of establishing the new province. Both governments allowed private companies to bid for exploration and production licenses. In the UK, the licenses on offer covered not only the southern basin of the North Sea, which was believed to offer the potential for gas in Groningen-like formations, but also extended into the main areas of the North Sea. Both countries took a remarkably similar approach to exploration licensing, with nearly identical license sizes, incentives for exploration of the more frontier areas, relinquishment requirements, work programs, and commercial terms (Nelsen 1991). (We note that, since the Norwegian civil servants in charge of petroleum explicitly sought to learn from their British counterparts, as discussed by Thurber and Istad (2010), this similarity of approach was to some extent the result of deliberate imitation.)

The results of this initial exploration licensing round emphasized the central role of risk in several ways. First, exploration blocks perceived to have less uncertainty regarding the presence of hydrocarbons were, unsurprisingly, more likely to receive bids. The vast majority of the blocks near the known gas formation of Groningen were licensed, whereas few of the blocks in the more remote Central North Sea and none of the blocks in the more remote Northern North Sea were bid for. Second, companies shared risk by bidding in consortia. For example, over half of the initial licenses issued by Norway were awarded to partnerships of more than one company (Norwegian Petroleum Directorate 2010). Third, licenses were concentrated among the most established oil companies, reflecting their superior ability to manage the risks of frontier exploration. In this case these frontier risks were associated with both geological uncertainty and uncertainty that suitable technologies for offshore operations in harsh conditions could be developed.

Uncertainty was gradually reduced over time as discoveries followed the early license rounds in both Norway and the UK. In 1965 the West Sole gas field was discovered, which confirmed expectations that the Groningen-like gas extended into the southern basin under the North Sea. The pace of exploration was slower in the more frontier areas of the Central North Sea and the Northern North Sea. In total 14 wells were drilled in the UK sector of the Central North Sea before the first modest oil discovery, the Montrose field, was made by Amoco in December 1969. The first major oil find (Ekofisk) in the Central North Sea was made in Norwegian waters by Phillips in December 1969, although its size was not

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5 This first round of UK licenses covered virtually the whole of the offshore continental shelf from the Dover Strait to the northern limits of the Shetland Islands (Bowen 1991).

6 This example implicitly points to a driver of government policy that falls outside of our simple theory about risk and desire for control: the way that governments can be influenced by the actions of other countries.
appreciated at the time because of the field’s geological complexity. The discovery of the giant Forties field by BP in December 1970, however, left no doubt as to the commercial potential of oil in the North Sea. Just a few months later, in June 1971, another exploration well operated by Shell discovered the Brent field in the far north of the province. These three large oil discoveries, once established to be commercial, essentially proved a major new oil province and significantly reduced the risks associated with any further exploration and development in the central and northern parts of the North Sea system.

These decreasing risks were reflected in the fourth UK license round, held in June 1971, which attracted a great deal of competitive attention from exploration companies. Four times more companies made applications than in any of the first three license rounds. The high level of exploration commitments made in these next bidding rounds, which reflected rising confidence and falling risks, yielded a string of significant discoveries in both the Central North Sea and Northern North Sea areas. In just a few years, by 1977, the discovery rate (measured in barrels found per well drilled) was already in decline in UK waters (Bowen 1991). The province was entering a more mature phase characterized by much higher activity levels and reduced volumes discovered per well.

As expected according to Figure 4, both countries shifted to a more participatory approach to hydrocarbon development as risks declined. Increased state involvement was intended to provide the government with more information about operations and greater influence over key operational decisions. In Norway’s second license round in 1969, state participation was mandated, in a number of cases in the form of a “carried interest” in exploration blocks. Carried interest meant that the state held an option to participate in development and production activities in the event of a discovery that was determined to be commercially viable. As discussed earlier, this kind of provision meant that the state took none of the risk of failure from exploration or appraisal wells and only participated in development where remaining risks were effectively underwritten by the willingness of the operating company to invest private capital in the project.

During the 1970s, as risks continued to fall, both countries expanded their direct involvement in hydrocarbon activities through the creation of national oil companies—initially, to manage the state’s equity share in development investments, and later, to take on operatorship of new exploration, development, and production licenses. Norway led the way in nationalizing resource holdings, creating national oil company Statoil in 1972, not long after the size and commercial viability of the Ekofisk field had been established. The company initially served as the investment vehicle for state participation in petroleum, and by 1974 it was being given a minimum 50% carried interest in all new exploration blocks. The government also increasingly took steps to help Statoil develop into an operator, reserving highly prospective blocks for the NOC as well as granting licenses to experienced international companies with the provision that they relinquish operatorship to Statoil a specified number of years after the commencement of production (Thurber and Istad 2010).

Britain moved more slowly than Norway but eventually followed suit in creating a national oil company. A 1974 white paper announced the government’s determination to
build up production as quickly as possible and assert greater public control over national hydrocarbon interests, using carried interest provisions to avoid government exposure to exploration and appraisal risks. The vehicle for this new state interest was the British national oil company BNOC, which was formed in 1975 and given the right to acquire up to 51 percent of produced petroleum at market prices.

After tracking each other from the outset of North Sea petroleum activities through the 1970s, British and Norwegian policy clearly diverged in the early 1980s. Britain ended its state participation in oil field developments and began the process of full privatization of both the national oil company (BNOC) and the national gas company (BGC). Norway made no such reversal of policy and continued to assert state control of the oil sector through its national oil company.

The ideas about risk presented here cannot entirely explain why Britain reversed course and privatized its state industry, emphasizing that risk is far from the only determinant of outcomes. The UK’s larger economy and population made oil and gas a relatively less disruptive force and, in line with Figure 1, may have reduced the perceived imperative to exert direct control over petroleum development. However, it is also likely that other factors internal to Britain’s politics during those years were important. The UK may simply have had a lower political tolerance for government intervention in the economy. Britain had dithered on whether to create a national oil company in the first place, remaining content with the initial licensing system well into the 1970s. However, OPEC’s success in dramatically raising oil prices in 1973 and the perception that oil companies were reaping extra-normal profits had generated political impetus towards nationalization. Additional momentum in favor of creating a British national oil company was generated by Labour’s election victory in 1974, which ousted a more market-oriented conservative government. However, the political will behind direct national control over hydrocarbons could not be sustained when oil prices tumbled in the 1980s, and Britain privatized BNOC and the state gas company (BGC) and reverted to the model that had existed until the early 1970s: government regulation of competing private firms. Even in Norway, political factors—notably including the accession of a Labour government in 1971—had important influence over the exact timing of Statoil’s creation, the form it took as a 100%-state-owned enterprise, and its eventual partial privatization in 2001 (Thurber and Istad 2010).


Data on exploration wells around the world from energy research and consulting firm Wood Mackenzie provide an ideal means of testing the hypothesis that risk is an important driver of industry structure. We examined two possible frontiers: exploration in deep water, which is characterized by massive capital requirements and significant technological uncertainty, and exploration in areas where there have been no previous discoveries, for which capital requirements may be lower but geological uncertainty is high. We also tested
the possibility, proposed in section 2.3, that oil price might be an important determinant of whether NOCs or private firms predominate in hydrocarbon activities.

The specific hypotheses that we tested were the following:

Hypothesis #1: Governments will preferentially use national oil companies for exploration in high price environments, where risk minimization is less important.

Hypothesis #2: Governments will preferentially use their national oil companies in onshore or shallow-water exploration, where risks are lower than in deep water.

Hypothesis #3: Governments will preferentially use their national oil companies in territories where previous discoveries have already been made, rather than in territories where no previous discoveries have been made and risks are therefore higher.

We used the following linear regression model to simultaneously test these three hypotheses:

\[
\text{NOCFRACTION}_{ijt} = \beta_0 + \beta_1 \text{PRICE}_t + \beta_2 \text{NOFINDS}_{jt} + \beta_3 \text{WATERDEPTH}_{jt} \quad (\text{Eq. 1})
\]

Where:

\[
\text{NOCFRACTION}_{ijt} = \text{Fraction of exploration wells spudded in country } i \text{ and basin/sector combination } j \text{ in year } t \text{ which are operated by the national oil company of country } i.
\]

\[
\text{PRICE}_t = \text{Average of Brent oil price (2008 US$) for 5 years prior to year } t, \text{ normalized by highest price during entire time period (1970-2008)}.
\]

\[
\text{NOFINDS}_{jt} = 0 \text{ if a commercial discovery has been made in basin/sector } j \text{ prior to year } t
\]

\[
= 1 \text{ if no commercial discovery has been made in basin/sector } j \text{ prior to year } t
\]

\[
\text{WATERDEPTH}_{jt} = \text{Average water depth of wells completed in basin/sector } j \text{ in year } t \text{ and two prior years, normalized by the 90th percentile water depth of offshore wells drilled in that year worldwide. The 90th percentile water depth frontier is shown in Figure 5; however, note that for the purposes of the regression model, the frontier value used for normalization is not allowed to decline below the previous high, as the “frontier” depth is intended to reflect knowledge about deepwater operations accumulated up to that point.}
\]

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7 A basin is a geological depression that could contain hydrocarbons. The Wood Mackenzie PathFinder database further divides basins into sectors, typically according to region within the basin although sometimes based on other distinctions like whether an exploration area is onshore or offshore. For the purposes of this analysis, the basic geological unit we characterize is the basin/sector combination—the inclusion of the sector as well as the basin enables us to better resolve differences in characteristics of the area being explored. Our analysis dataset includes a total of 400 basin/sector combinations.
Figure 5  Water depth of the 90th percentile offshore exploration well worldwide that was spudded in the given year. (In other words, 90% of offshore exploration wells were in shallower water.) Data source: Wood Mackenzie PathFinder (2010).

The basic logic of this model is that NOCFRACTION—the fraction of wells in a given basin/sector operated by the home country’s NOC—is a proxy for the state’s choice of whether to employ an NOC or IOCs. Clearly, there are many factors besides an explicit state choice that could influence this fraction. A state may not have an NOC, for example, or a state may desire to employ an IOC to explore in a given area but find that IOCs are not interested. However, our assumption is that over the long run states can put in place policies (including the establishment of an NOC) and create incentive structures that will favor either NOC or IOC exploration activity. Thus, the value of NOCFRACTION should at least implicitly reflect state choices. Because we are focusing on the degree of risk a state is willing to accept, we chose to examine the fraction of wells operated by the home NOC. The decision to employ the home NOC as an operator entails more risk (but may also be perceived to afford more control) than simply taking an equity share in an IOC-operated exploration well.

Oil price expectations were represented in a simple-minded way by averaging the Brent benchmark price for the previous five years.\(^8\) Averages of one and three years were also tried; they unsurprisingly showed similar (though noisier) regression results compared with those presented in Tables 1 and 2.

NOFINDS is a dummy variable that in a coarse way groups exploration areas into putative geological frontiers—those with no previous commercial discoveries as classified by

\(^8\) A futures price might have been more appropriate in theory, but the oil derivatives market did not develop until the 1980s. We are doubtful in any case that the use of a futures price would have added significant value to the analysis.
Wood Mackenzie—and areas that should have lower geological uncertainty because a previous commercial discovery has been made in the specified basin/sector. A sophisticated case-by-case analysis of the geological uncertainty faced by each exploration well along with its potential upside would have been a superior approach to characterizing risk, but such an approach was not feasible for this kind of large-sample regression.

WATERDEPTH is intended to capture the challenge and risk posed by the characteristic water depth in a given basin/sector. Because the frontier has advanced over time as shown in Figure 5, this variable is normalized by a measure of the “frontier” water depth in a given year.

Our analysis dataset included all exploration wells in Wood Mackenzie’s PathFinder database, except those in China and Russia, that were spudded between 1970 and 2008. China and Russia were specifically excluded because of known data gaps for these countries which could introduce systematic error, for example because wells with international participation were more likely to be recorded than those without international participation. With these two nations removed, a total of 89 countries were covered by the sample.

The full data table for 1970 through 2008 had a total of 8602 observations, with each observation representing a basin/sector in a given country in a given year. As part of creating the data table, it was necessary to classify every company operating a well over the sample period as either an IOC or an NOC in each year, and also to identify the home country of a given NOC in order to distinguish its operations at home from those abroad. This classification was performed based on a variety of sources, including the case studies in this volume, the World Bank’s 2008 survey of national oil companies (World Bank 2008), and company websites. Companies with majority state ownership were considered to be NOCs, as were those for which the government was a minority shareholder but retained control through special shareholding arrangements. Operating companies that were partnerships between the home NOC and other private companies or foreign NOCs were generally not classified as home NOCs, with the rationale that the other companies could be providing all of the expertise in risk management for the partnership.

To test the three hypotheses above, an ordinary least squares regression was performed on the data, using robust standard errors to account for heteroskedasticity. Results are shown in Table 1, first for the entire sample period (model 1) and then for the periods 1970-1979, 1980-1989, 1990-1999, and 2000-2008 in models 2-5, respectively. Interpretation is simplified by the fact that price has been normalized to 1 at its highest value in the sample period (in 1984) and water depth is normalized to 1 at the “frontier” in a given year, as measured by the 90th percentile water depth worldwide. Thus, for example, the

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9 The exclusion of Russia and China turned out to have only a minor effect on regression results.
10 In a study that is focused on measuring the effect of state ownership per se on company performance, it might make more sense to distinguish only between majority-state-owned and majority privately-owned companies, irrespective of where the company is operating. In this work, however, we are focusing on a state’s choice of whether to use its own NOC to develop domestic resources or to rely on outside companies, be they private or owned by other states. Therefore, it was more logical to draw the line between the home NOC and any other operator.
constant term in Table 1 (e.g., 0.218 for model 1) represents the expected fraction of NOC-operated wells at zero price and zero water depth (e.g., an onshore sector), for an exploration province that has already seen a commercial discovery. If the average price for the last five years is at its maximum value, on the other hand, model 1 predicts the fraction of NOC-operated wells will be 0.065 higher. If the water depth of wells drilled in the region over the past three years (including the current year) is exactly at the 90th percentile “frontier” for the current year, model 1 predicts the fraction of NOC-operated wells will be 0.136 lower.

Table 1  Regression results for coefficients of the independent variables in equation (1) and their statistical significance.

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<tbody>
<tr>
<td>Average oil price, Brent (2008 US$), norm. - previous 5 yrs</td>
<td>0.065*** (0.018)</td>
<td>0.089 (0.054)</td>
<td>-0.019 (0.053)</td>
<td>0.066*** (0.189)</td>
<td>-0.086 (0.082)</td>
</tr>
<tr>
<td>No previous finds (1 = no previous discoveries in sector)</td>
<td>0.008 (0.017)</td>
<td>0.011 (0.024)</td>
<td>-0.024 (0.032)</td>
<td>-0.088** (0.041)</td>
<td>-0.020 (0.088)</td>
</tr>
<tr>
<td>Water depth, normalized</td>
<td>-0.136*** (0.016)</td>
<td>-0.286*** (0.027)</td>
<td>-0.210*** (0.037)</td>
<td>-0.045 (0.035)</td>
<td>-0.005 (0.033)</td>
</tr>
<tr>
<td>Constant</td>
<td>0.218*** (0.010)</td>
<td>0.298*** (0.019)</td>
<td>0.317*** (0.043)</td>
<td>-0.022 (0.066)</td>
<td>0.182*** (0.034)</td>
</tr>
<tr>
<td>Observations</td>
<td>8602</td>
<td>2145</td>
<td>2384</td>
<td>2233</td>
<td>1628</td>
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Robust standard errors in parentheses
***Significant at 0.01 level, **Significant at 0.05 level, *Significant at 0.1 level

Model 1, covering the entire period from 1970 through 2008, supports hypothesis #1 (higher oil price increases the likelihood that states will use NOCs for exploration) and hypothesis #3 (states tend to use their NOCs to a lesser degree for exploration in deeper water). The coefficient for NOFINDS in model 1, on the other hand, is not statistically significant, meaning that overall there is no support either positive or negative for hypothesis #2 that states are less likely to employ NOCs in territories where no previous discoveries have been made.

The breakdown by time periods in models 2-5 reveals a more complicated picture. The hypothesis that states will preferentially employ companies other than their NOCs in deeper water is strongly borne out for the period from 1970 through 1989, but the effect disappears for the later periods. All of the price effect for the period from 1970 through 2008 is accounted for by a large price coefficient from 1990 to 1999. A statistically significant though smaller effect associated the presence or absence of previous commercial discoveries also emerges for 1990-1999, although in the opposite direction to that expected by hypothesis #2. We will discuss each of these findings in turn.
The finding that states preferentially avoided employing their NOCs as operators for deeper water wells between 1970 and 1989 is the most unambiguous and strongly supported by our regression. Figure 6, which plots the fraction of wells operated by NOCs at different depths relative to the frontier in the time period from 1970 to 1989, clearly illustrates this effect.

**Figure 6** Fraction of exploration wells operated by home NOC as a function of the water depth of the basin/sector relative to the “frontier” (columns), along with the sample size for each depth bin (line). Since the frontier is defined by the 90th percentile water depth in a given year, depths of greater than 100% of the frontier are possible. Data source: Wood Mackenzie PathFinder (2010).

Further analysis (including inspection of the raw data table) suggests that the disappearance of the deepwater effect on NOC vs. IOC operatorship since 1990 is due almost entirely to the influence on the results of Brazil’s Petrobras and Norway’s Statoil—two NOCs that have developed substantial skill at operating and managing risks in deep water. In Table 2, we re-run the same regression models as in Table 1, but removing Brazil and Norway from the dataset. When we do this, the strong preference against NOCs in deeper water is roughly consistent across all four time periods. This result suggests that Petrobras and Statoil have truly become “IOC-like” in their ability to operate and shoulder risks for their respective governments in deep water, which is not a surprise in light of the findings of Thurber and Istad (2010) and De Oliveira (forthcoming).
Considering all of the evidence in Tables 1 and 2 together, it is difficult to find any support either positive or negative for the idea that states might preferentially use IOCs to explore regions that have not seen previous commercial discoveries and are therefore riskier. Several explanations for this are possible. First, it may be that the presence or absence of a prior commercial discovery in a basin/sector is simply too coarse and imperfect a measure of geological risk. Second, this measure says nothing about the potential upside of a territory with no previous discoveries—it may be that IOCs stay away from a basin/sector with no previous discoveries precisely because they do not consider it to be very prospective. Third, a countervailing factor that could cause NOCs to explore virgin territory even if there have been no previous discoveries is the simple fact that it is on their home turf. (As will be discussed further in section 4.1, NOCs in some cases might have incentive to pursue local exploration precisely because the state is shouldering the risk.) Fourth, even if the region is not highly prospective and uncertainties are high, capital outlays can be relatively low in the case of onshore exploration wells, meaning that the risk might be tolerable for certain states.

At first glance, the price effect in model 1 of table 1 seemed to confirm our hypothesis that high oil prices effectively reduce state risk and the need to employ IOCs. However, further inspection reveals that the price effect is almost entirely associated with the period from 1990 to 1999, although when Brazil and Norway are excluded in the analysis of Table 2, a statistically significant though smaller effect is also observed between 1970 and 1979. Figure 7 suggests that the strong price effect in the 1990s might actually come from the correlated decrease in the overall fraction of NOC-operated exploration wells and the oil price over this period. Because this correlation could be random, we view the implications of the analysis for hypothesis #1 as inconclusive. At the same time, one could plausibly make the broader argument that the flurry of privatizations in the 1990s was related in part to the

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<tbody>
<tr>
<td>Average oil price, Brent (2008 US$), norm. - previous 5 yrs</td>
<td>0.062*** (0.018)</td>
<td>0.123** (0.054)</td>
<td>-0.035 (0.053)</td>
<td>0.789*** (0.179)</td>
<td>-0.068 (0.076)</td>
</tr>
<tr>
<td>No previous finds (1 = no previous discoveries in sector)</td>
<td>0.028* (0.017)</td>
<td>0.019 (0.024)</td>
<td>-0.036 (0.032)</td>
<td>-0.050 (0.036)</td>
<td>0.019 (0.087)</td>
</tr>
<tr>
<td>Water depth, normalized</td>
<td>-0.215**** (0.024)</td>
<td>-0.283*** (0.028)</td>
<td>-0.273*** (0.037)</td>
<td>-0.213*** (0.024)</td>
<td>-0.150*** (0.036)</td>
</tr>
<tr>
<td>Constant</td>
<td>0.192*** (0.010)</td>
<td>0.253*** (0.019)</td>
<td>0.302*** (0.043)</td>
<td>-0.080 (0.064)</td>
<td>0.154*** (0.032)</td>
</tr>
<tr>
<td>Observations</td>
<td>7922</td>
<td>1994</td>
<td>2184</td>
<td>2054</td>
<td>1496</td>
</tr>
</tbody>
</table>

**Table 2** Regression results for coefficients of the independent variables in equation (1) and their statistical significance, this time excluding Brazil and Norway from consideration.

Robust standard errors in parentheses

*** Significant at 0.01 level, ** Significant at 0.05 level, * Significant at 0.1 level
decrease in oil prices and price expectations—in line with our argument about risk effectively being higher in low price periods.

Figure 7 Average fraction of exploration wells operated by NOCs from 1970 through 2008, plotted alongside the Brent benchmark oil price for both the previous year and for the average of the previous five years. Data sources: Brent oil prices from BP (2009); NOC-operated fraction of wells derived from Wood Mackenzie PathFinder (2010).

While our statistical analysis was unable to conclusively demonstrate a price effect on states’ preferences for NOCs or IOCs, and it also failed to discern an effect based on our simplistically-defined “frontier” of territories without previous discoveries, it did find clear support for the thesis about risk and state choices in patterns of exploration as a function of water depth. At the same time, it is important to point out that the model of equation (1) only explains a small percentage of the overall variation in the state’s choice of an NOC or IOC. The model showed the most explanatory power for the period from 1970 to 1979, but even then the R² was only about 0.05—the result not only of the coarseness of our ability to assess risk but also the fact that risk is but one constraint on the choices of the state. The simple regression model in this section did not attempt to characterize the other major dimensions in the framework of Figure 1—the state’s relative desire to control petroleum and the capacity of a given state to take on risk. In addition, there are likely to be a whole host of other idiosyncratic drivers of state choices, including the characteristics of different political systems.
4. Conclusion

The central argument in this paper is that industrial structure, defined by a state’s choice of private or state operating company, is to a significant degree a function of just three variables: the petroleum state’s motive for direct control through a state company, the inherent risks of doing so, and the capacity of the state to take these risks. Both state-owned and private companies can in theory manage risks for the state, but the very nature of the state-owned company as a tool for government goals beyond the commercial tends to make it a poorer risk manager than its private counterparts. Governments thus have strong incentives to employ private companies in cases involving high risks or in situations where they have little or no desire for direct control of the sector and can achieve state goals through industrial regulation. But these latter settings are rare in the major petroleum provinces; more common is an acute interest in control with a highly varied exposure to risk and equally variable capacity to manage it.

In section 3 of this paper, we considered the success of this basic model in predicting how the agents most commonly employed by hydrocarbon states shifted as the oil and gas industry developed; which kinds of companies Norway and the UK chose to find and extract North Sea oil and gas; and whether different kinds of exploration frontiers (deepwater and virgin territory) would be preferentially occupied by state or private companies. Broadly, the outcomes in these cases supported our thesis that private companies play a central role as risk managers at the frontier; however, other factors also emerged as having some bearing on the state choice of hydrocarbon agent.

4.1. The influence of non-risk factors on agent choice

Political factors can play a particularly important role in what kind of company the state employs in oil and gas and the exact timing of when the state involves itself directly. For example, this factor appears to be relevant in explaining why the UK privatized its national oil company BNOC relatively quickly after its formation whereas Norway preserved Statoil as a fully-state-owned company for much longer and has left it as a majority-state-owned entity to the present day. In some cases, NOCs may be difficult to privatize or dismantle even after the risk environment has changed such that an IOC would be a more logical choice for a state. Leaders may value the ability of an NOC to provide private benefits to elites or broader public benefits that help them retain their legitimacy among the population.

Political considerations and the non-hydrocarbon benefits of NOCs likely explain many “mistakes” in which states persist in employing a state operating company even when it is unable to adequately assess or manage the risks the state will be exposed to. Mexico and Venezuela today are two countries that retain state companies in the face of mounting risks to state investment intended to open new frontiers in these countries. Other “mistakes” may
instead be cases in which the state is able to tolerate the risks involved in frontier activities, at least for the time being. For example, India’s national oil company ONGC compiled a woeful performance record in exploration activities (Rai 2010), but these failed investments may not have loomed as large in a diversified economy like India’s as they would have in a state like Nigeria in which oil revenues are critically needed to close the state budget. (And in any event, the Indian government in recent years has attempted to benchmark and improve ONGC’s performance, including through the introduction of competition.)

The Indian example may also reflect the ironic outcome that NOCs can end up taking on significant risks, even if not prepared to adequately manage them, precisely because they are gambling with state money. This is likely part of the explanation for why IOCs did not systematically emerge in section 3.3 as the dominant explorers in hydrocarbon basins without previous discoveries. As discussed in section 2.5.2, Petrobras was likely more aggressive in taking on the technological risks of offshore development than it would otherwise have been because the state was shouldering the risk of failure. Similarly, Statoil was free to take a more long-term approach to research and development than commercial players because of its implicit support from the state. As Statoil has progressively separated from the state, notably through partial privatization in 2001, it has appeared to move toward a more commercial mode of managing technology development and risk (Thurber and Istad 2010).

As the Petrobras and Statoil cases demonstrate, state support for capability development within national oil companies can in rare instances lead to long-term benefits for the state, even if it does result in sub-optimal risk management in the short term. It can also lead to NOCs eventually developing some risk management skills themselves. As suggested by the results of section 3.3, Petrobras and Statoil by the 1990s were able to play an IOC-like role for their respective governments in taking on the risks of deepwater exploration. Their development of risk management capabilities within these NOCs was facilitated by the atypically limited demands of their host states for non-hydrocarbon functions.

A final factor that emerged as a qualification to the basic framework of state agent choice was the effect of oil price. By altering the relative contribution of produced quantity, production cost, and selling price to net revenue for the state, price changes effectively shift the location of the frontier by making given resources more or less economic. We expect lower price environments to place a greater premium on the risk management skills that IOCs bring to the table. As discussed in section 3.3, decreasing oil price in the 1990s did broadly track a decrease in the use of NOCs in exploration, although further work would be needed to confirm a causal result. Another way of thinking about price fluctuations is as an independent source of revenue risk to the state that private companies are not able manage on its behalf. The significance of price risk may help explain the observation in section 3.1 that oil-rich states turned to cartelization before nationalization, even after the geological and market availability risks of the oil industry had been substantially reduced.
4.2. Industry structure and the next frontier

With such a large share of the world’s petroleum reserves under the control of state companies today, it is often suggested that the days of the private operating company are over, and that state companies and oil service companies will increasingly control oil in the future. Based on the theory of risk and the structure of the petroleum industry that we have described here, we are skeptical of such arguments, for several principal reasons. First, the oil service companies do not compete with private operating companies. Rather, they perform fundamentally different roles, with only the private operating companies managing risk as a fundamental part of their business models. Second, most state companies are not well equipped to manage extreme risks on behalf of their respective governments. Because of a lack of competitive pressures at home, their responsiveness to government goals beyond the commercial, and other domestic political factors, only the rare NOC can accumulate the necessary elements of risk management such as strong geosciences capability, the ability to innovate while holding down costs, and a global portfolio of investments. Third, there will remain a new high-risk frontier to be conquered as long as there is a petroleum industry. That being said, the changing nature of the frontier will have implications for the opportunities available to private operating companies going forward.

Previous frontiers have largely been about exploration and development in new geographies, and the private operating companies, of all sizes, have become skillful at managing these risks. We can see that major new exploration geography is limited: The industry has already explored accessible onshore basins, offshore basins, and now deepwater basins. Today’s frontier opportunities mostly do not involve new geography per se, but like all frontiers they are characterized by high uncertainty and massive capital requirements. Today’s frontiers encompass vast volumes of unconventional oils (for example, tar sands, only 20 percent of which can be extracted with today’s surface mining technology) as well as unconventional gas in tight sands, in tight shale source rocks, as coal bed methane, and in hydrates. Even conventional natural gas development can retain a high-risk character due to the capital intensity of gas transport infrastructure, the complex and frequently cross-border value chains associated with gas, and the requirement that reliable demand be established at prices that can enable cost recovery. For this reason, IOCs continue to dominate in the gas arena. Other frontiers include exploration in ultra-deep waters, particularly where mobile salt provides a substantial obstacle to the identification and mapping of drillable prospects, as well as exploration of the remote Arctic with its challenges of both static and mobile ice.

Success at these frontiers will depend, as always, on the ability to manage risk through the development of increasingly accurate measurements of uncertainty. It will require the use of innovative data collection methods and accumulated geological knowledge to make skillful predictions of exploration or development outcomes even when an absence of precedent makes these outcomes seem unknowable. It will also demand continual innovation to reduce capital cost. Several broad uncertainties exacerbate the risks of today’s frontiers, notably those around climate policy and the direction of future oil prices—the latter being a function in part of how large resource (and spare capacity) holders like Saudi Arabia
might try to use production rates to influence oil price so as to undercut any emerging threats to petroleum’s dominance.

Because of this ongoing need for risk management at the frontier, the role for private operating companies in the petroleum industry will not disappear; of course, there is no guarantee that these companies will be able to maintain or expand their current share of the market. More certainty in both climate policy and oil price—the latter created, for example, by taxation to create oil price floors in consuming countries—might help in reducing the market risks that private companies are unable to manage themselves, and thereby assist these companies in venturing out more aggressively into new frontiers.

State companies will continue to thrive where there are low-risk and low-cost hydrocarbons to manage. Whenever risks become higher or cost performance becomes more critical to state revenues, their dominance is likely to wane at least for the moment. One high-risk activity on the horizon for oil-rich governments with maturing resources is the redevelopment of large maturing fields through tertiary recovery. Other frontiers that are closed today for political reasons may open as a result of political change, as has occurred in Iraq, or when the true risks of investment and the limited ability of the state to absorb risk are better understood, as in the case of Mexico deep water or Venezuela extra-heavy oil.

It may be that more NOCs over time will follow the lead of Statoil and Petrobras in starting to develop a global portfolio and competitive risk management capabilities. However, in most cases this only seems to happen when domestic resources begin to dwindle; until this point, governments tend to ask NOCs to fulfill too many ancillary goals, while NOCs find themselves too comfortably sheltered at home to become truly competitive at managing risk.
References


