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The Political Economy of Oil Production in Latin America

The 1990s witnessed a significant increase in investments in the oil and gas sector in Latin America. In most countries, private investment took the lead after the privatization and liberalization of the sector. In Argentina, Bolivia, Brazil, Ecuador, and Venezuela, private oil investment or some form of privatization (or both) generated significant increases in hydrocarbon production and reserves. In the last five years, however, the region has experienced a new wave of resource nationalism, with increases in the government's take and state control. Oil taxes have risen significantly in Argentina, Bolivia, Ecuador, and Venezuela. In addition, Bolivia and Venezuela have partially nationalized oil projects. We argue that the recent trend is largely the outcome of the rise in the international oil price. Furthermore, we show how the likelihood of expropriation increased after a period of successful investment in exploration and production. At the same time, the timing of these changes and direction in which the sector has evolved varies considerably across the region. In contrast to most other countries in the region, Brazil, Colombia, and Peru have generally strengthened the institutional framework and the property rights of private oil producers. This paper provides a political economy rationale for the divergent evolution.

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The general pattern of development unfolding in the oil sector is not new. Historically, the evolution of oil and gas production in Latin America has seen cycles of investment and expropriation. For example, in Venezuela large oil investments were made throughout the 1940s and 1950s; a process of systematic increase in the government's take then began in the late 1950s. The fiscal take on profits rose from levels around 50 percent in 1943–58 to a maximum of 94 percent in 1974, the year before nationalization.[1] Similar episodes have occurred in Argentina, Bolivia, Ecuador, Mexico, Peru, and other developing countries.[2] Even in some developed countries, governments have reneged on the fiscal and contractual conditions after considerable investments were made. A recent example is the increase in royalty rates in Alberta, Canada.

This paper studies the cycles of investment and expropriation in the context of the Latin American oil sector. In particular, it provides an explanation for the state's difficulties in capturing the oil rents and rationalizes the tendency of governments to periodically renege on their prior agreements pursuing the quasi-rents. The paper does not try to provide a general proposal for the right fiscal and contractual structure, however, as the right structure must be tailored to each country.

Although the discussion on expropriation is typically an emerging-market issue, it is important to emphasize that changes in the tax and contractual framework of the oil sector have not happened only in less-developed or oil-dependent countries. For example, the United Kingdom has instituted important tax modifications, most of which have coincided with oil price changes.[3] Besides the corporate income tax, oil projects in the British North Sea pay a special tax called the petroleum revenue tax (PRT), which is a form of tax on returns. The PRT was originally set at a rate of 45 percent, but it was increased to 75 percent when prices increased in the 1970s. In the 1990s when the North Sea began to be depleted, the PRT was reduced to 50 percent for existing projects and eliminated for new projects.[4] When oil prices increased again in 2002, the British government established a supplementary charge of 10 per-

1. Monaldi (2002).

2. Philip (1989).

3. For a review of the tax regimes in the North Sea, see Moles, Constantinou, and Kretzschmar (2005).

4. Ring fencing of oil projects was also eliminated, allowing the deduction of the costs of new projects from the taxes levied on the profits of mature oil projects. This resulted in a significant reduction of effective taxation.

cent, effectively increasing the tax on upstream profits.[5] A comparable history can be written for oil taxation in the United States and Canada.

The oil industry has some specific features that strongly influence the way the institutional framework and the political economy of the sector evolve. Some of those features are shared with other sectors in different degrees, but the oil industry is one of the few in which their combined importance is significant. First, oil extraction and, to a lesser extent, natural gas extraction generate important rents. Second, oil and gas extraction require major sunk investments. Third, a high proportion of oil reserves are concentrated in countries with weak institutions and high political risks. Fourth, oil exploration involves high geological risks, whereas these risks decline significantly in the field development and production phases. Fifth, oil products are massively consumed and therefore politically salient. Sixth, the oil price in the international markets is volatile, so oil rents are also quite volatile. This paper discusses how these characteristics of hydrocarbon exploitation interact with the institutional and contractual environment to explain the political economy of expropriation.

The characteristics of the oil sector, especially the presence of large rents and considerable sunk costs, are accentuated by the lack of effective and progressive tax systems. Together, they generate episodes of contract renegotiation, particularly when the price of oil increases significantly. The fact that contractual and fiscal systems do not appropriately take into account price contingencies implies that when the oil price rises steeply, an increasing share of oil rents is retained by oil producers. Consequently, governments have powerful incentives for contract renegotiation or nationalization. Moreover, if the government reneges on the contract after large investments have been sunk, the producers would still have incentives to continue operating as long as they can recover operational and nonsunk costs. As a result, industries with high sunk costs, like oil, are tempting targets for expropriation.

The optimal contractual and fiscal system should effectively incorporate price contingencies, allowing governments to capture the oil rents. For example, the fiscal regime could incorporate rates that increase with the oil price—and some recently approved windfall taxes do just that. Achieving an efficient and progressive tax system entails significant difficulties, however. Income taxes are more progressive than royalties, but they provide incentives to overspend and they generate larger distortions since the rate has to be higher than

5. Modifications in the way asset depreciation is considered for tax purposes partially offset the tax increases, however.

a royalty. In addition, more progressive taxation systems require administrative capacities that many countries in the region lack. State ownership could be a solution, but the national oil companies have often been inefficient and easy targets for revenue expropriation. Finally, credible commitment to property rights is difficult in a context of powerful incentives for expropriation and weak institutional frameworks. An option that has recently been implemented to mitigate the time-inconsistency problem, the creation of an independent regulatory agency, may help to provide some credibility without making the system excessively rigid.

The paper is organized as follows. The next section analyzes the economics of oil taxation and the basic characteristics of oil taxation in Latin America. It provides the theoretical foundations for understanding the challenges faced in the fiscal and contractual frameworks. The paper then presents the key characteristics of the oil sector and discusses how they shape the political economy of oil extraction in the region. We include a section on case studies to explore how individual countries in the region have addressed the theoretical and practical problems involved in contract design. The final section presents some concluding remarks.

The Challenges and Inconveniences of Oil Taxation

Resource exploitation is an important part of the economy in developing countries.[6] Governments therefore implement alternative tax and contractual structures to capture as much as they can of the revenues generated by those activities. This is particularly true in oil-exporting countries. Moreover, hydrocarbon reservoirs are the property of the state in most legal frameworks over the world, including all Latin American countries.

In the oil and gas industry, the activity of hydrocarbon extraction generates important rents. In particular, rents arise when the exploited fields are inframarginal in the global context.[7] Rents also arise because the countries with the largest and least costly oil reserves restrict access to them. Given the existence of rents and the state ownership of the resource, states typically apply special taxes to the oil sector. The most common instruments are royalties and special income taxes, although signing bonuses and variable rates are also used. Table 1 presents a summary of the different types of instru-

6. For the countries we are analyzing, fuel exports represented around 13 percent (unweighted average) of their gross domestic product (GDP) in 2004 (World Bank 2007).

7. That is, fields with total costs below the marginal producing field in the oil market.

TABLE 1. Tax Regime for the Oil Sector in Latin America

Country	*Royalty rate on production*	*Income tax rate in excess of other activities*	*Profit tax*	*Other*	*State participation*
Argentina	12 percent for the local government	No	No	Export duties at a rate of 20 percent since 2002	Yes, since 2002
Bolivia					
1990s	18 percent on new fields; 50 percent on old fields	No	12.5 percent—for new fields—on remittances abroad; additional 20 percent on extraordinary utilities		No
2004[a]	18 percent	No	Same as in the 1990's	32 percent direct tax on hydrocarbons. After 2006, 32 percent contribution to YPFB[a] for the largest fields.	Yes
Colombia	20 percent on old fields; variable 8–25 percent on new fields (as of Law 756)	No	7 percent	Pipeline transport fees	Yes
Ecuador	Variable 12.5–18.5 percent, depending on field conditions	100 percent for Petroecuador; 0 percent for all other companies	25 percent	Tax holiday for new fields in exploration phase	Yes
Mexico		5 percent	7.7 percent	Hydrocarbon rights and "privileges" for utilization (up to 60.8 percent)	Yes
Trinidad and Tobago	Royalties at negotiated rates by contract	5 percent ("unemployment tax")	50 percent	Supplemental petroleum tax levied on crude oil sales (less certain allowances) at a sliding rate that varies with the price of oil, the time the development license was granted, and the time production began	No

(continued)

TABLE 1. Tax Regime for the Oil Sector in Latin America *(Continued)*

Country	*Royalty rate on production*	*Income tax rate in excess of other activities*	*Profit tax*	*Other*	*State participation*
Venezuela					
1990s	1.00–16.66 percent	33 percent	State share in earnings (PEG) in exploration phase	Superficial tax (100 ut/km or more); 10 percent tax on own consumption; 30–50 percent tax on general consumption; 4–8 percent reduction in income tax for new investment	Yes, depends on the contract
Post-2000	30 percent for traditional fields; 20 percent for Faja del Orinoco fields; operating agreements specified in individual contracts	16 percent	State share in earnings (PEG) in exploration phase	Same as in 1990s	Yes, depends on the contract
Present	33 percent of oil produced at all fields[b]	16 percent	Windfall tax: surcharge royalty based on prices	Same as in 1990s	Yes, set to a minimum of 51 percent

a. Bolivia nationalized its oil industry in 2004. The new national oil company is the Yacimientos Petrolíferos Fiscales de Bolivia (YPFB).
b. In theory, this rate can be reduced to 20 percent of oil production if the 33 percent rate makes the field unprofitable.

ments used in the Latin American oil-exporting countries. Royalties, which are a form of sales tax, are used in all countries except Mexico, where the state is the owner of the industry, and Trinidad and Tobago.[8] Moreover, Argentina, Bolivia, and Venezuela have recently increased royalties (or introduced them). Most countries also use either a higher income tax rate or a special profit tax to capture extra rents.

Countries also use different contractual regimes for private operators (if the state does not have a monopoly on production). These can be based on concessions (where the producer has ownership rights over the oil field), service contracts (production for a fee), risk service contracts (in which the fee is related to the oil price and increases in production), production-sharing contracts (in which the state receives a share of production), or technical assistance contracts. The nature of the contract has important consequences in terms of the risks taken by the private or international oil company, as discussed later. Finally, other relevant elements of the contractual regime are the duration of the concession or contract, the domestic price of production, the conditions for export, and the dispute resolution mechanisms (for example, whether the contract includes international or multilateral arbitration or whether there are bilateral investment treaties). We focus fundamentally on the taxation issues.

Taxes not only have the capacity to generate revenue for the state, but can also have significant impacts on economic activity. Understanding those impacts is crucial for evaluating the tax structure of a particular country. In terms of the effects of taxes on the resource sector, the recent literature focuses on the market power of resource producers and how to induce efficiency in domestic resource markets. The governments in the region, however, are more concerned with the development of the oil sector and the collection of revenue from the sector. Domestic markets are usually subsidized and only represent a relatively small fraction of total oil production.

Another branch of the literature uses option value techniques to address the volatility of the oil price. Instead, we choose a Hotelling model for two reasons: the Hotelling model includes important tax distortions; and the implications derived from the option value models are less important for the subject of this paper.[9] These implications are ultimately related to the effects of price volatility on investment decisions, which are not central to the study of the recent tax reforms in the Latin American oil sector.

8. The export tax in Argentina is similar to a royalty.
9. See Manzano (2000).

The solution to the problem of the producer of natural resources is developed in the seminal work by Hotelling.[10] The producer maximizes a value function (V) with constraints:

$$\max_{\bar{R},q,T} V = \int_0^T \pi(q)e^{-rt}dt - C(\bar{R}), \tag{1}$$

such that $\dot{\bar{R}} = -q$, $R(0) = \bar{R}$, and $R(T) = 0$, where π represents profits, q the extraction rate, r the discount rate, C the development and exploration costs, and $\bar{R}$ reserves.

In this paper, we define the profit function to be

$$\pi(q) = pq - c(q),$$

which has two implications. First, oil production involves two different types of costs: $C(\bar{R})$, which includes the monetary value at 0 of all past exploration plus development costs, such as the cost of connecting to the distribution infrastructure, and $c(q)$, which represents the costs of oil extraction, such as labor costs and gas injection.[11] Second, this problem assumes that oil companies are price takers—an assumption that is not far from reality, at least not from the point of view of oil companies.[12] The producer chooses the extraction path (q and T) and the amount of reserves that maximizes the profit function subject to the constraint, which implies that the total amount extracted should be equal to the reserves at the beginning of the exploitation.

For the reasons explained above, the government's problem is to try to capture the entire value V. Consequently, it will introduce special taxes in order to obtain it. The first-best solution is an auction of the field for a signing bonus (which would be the only payment received by the government). However, several issues make this solution highly problematic. The political economy issue, discussed in this paper, is that the government cannot commit to not changing the taxes in the future or not expropriating the sector. Another issue

10. Hotelling (1931).

11. There is an important branch of literature on the nature of $c(q)$. In particular, Pindyck (1978) assumes it depends on the amount of reserves present at the time of extraction; he also introduces the possibility of adding reserves through the lifetime of the field. Such models are useful for exploring the effects of the tax system on the timing of extraction and the timing of field development. We return to this point later.

12. While there are few oil reserves, numerous oil companies are exploiting these reserves. We are concerned here with the behavior of these many oil companies, which we assume act competitively.

is that the auctions may not be feasible owing to liquidity or collateral constraints. The most common alternatives to the signing bonus are royalties and income taxes.[13] Consequently, distortions will arise. In equation 1, two margins could be distorted: an extraction margin, which is the difference between the price and the extraction cost, and the development margin, which is the difference between the net income from extraction and the development cost. Taxes could thus affect extraction and development decisions, depending on how they affect these two margins.

The royalty is similar to a revenue tax, but it is called a royalty because the government is the owner of the oil field and collects its royalty from the operator. When we introduce royalty payments to the original formula, the new maximization problem becomes

$$\max_{\bar{R},q,T} V = \int_0^T \left[pq(1-\rho) - c(q) \right] e^{-rt} dt - C(\bar{R}), \tag{2}$$

such that $\dot{\bar{R}} = -q$, $R(0) = \bar{R}$, and $R(T) = 0$, where ρ represents the royalty rate. The effect of royalties is well documented in Heaps and Helliwell and in Manzano, so we merely summarize the results presented there.[14]

As evident in equation 2, the royalty distorts both margins. Consequently, fewer oil reserves are going to be developed. Another consequence is the tilting of the production path, with production shifting from closer periods to further ones. As firms try to minimize the net present value of the tax burden, they postpone production and thereby delay tax payments.

Beyond these results, most of the literature on the topic focuses on the tax burden.[15] We refer to this tax burden as the net present tax rate (NPTR), and we can check it for this case:

$$\begin{aligned} \text{NPTR} &= \frac{\int_0^T pq\rho e^{-rt} dt}{\int_0^T \left[pq - c(q) \right] e^{-rt} dt - C(\bar{R})} \\ &= \rho \frac{\int_0^T q e^{-rt} dt}{\int_0^T \left\{ q - \left[c(q)/p \right] \right\} e^{-rt} dt - \left[C(\bar{R})/p \right]}. \end{aligned} \tag{3}$$

13. Australia and Great Britain use a resource-rent tax (the PRT), which is a form of tax on returns. For a review and study of this type of tax, see Emerson and Garnaut (1984); Garnaut and Clunies-Ross (1975, 1979); Zhang (1997).

14. Heaps and Helliwell (1985); Manzano (2000).

15. For example, Kemp (1987, 1992); Kemp and Rose (1984).

Equation 3 illustrates a result widely reported in this area of the literature: namely, the tax rate will be higher for oil fields with lower value, p, higher production costs, $c_0(q)$, and higher development costs, $C(R)$.

This analysis assumes that the production level is exogenously given. However, firms are likely to adjust their production plan according to the tax scheme they face.[16] Following Manzano, we can derive the change in the amount of reserves developed from the change in the royalty rate.[17] From there, it is possible to compute the change in reserves development for the different parameters of interest:

$$\frac{\partial(dR/d\rho)}{\partial C''(\bar{R})} > 0; \tag{4a}$$

$$\frac{\partial(dR/d\rho)}{\partial c''(q_1)} > 0; \tag{4b}$$

$$\frac{\partial(dR/d\rho)}{\partial p} < 0; \text{ and} \tag{4c}$$

$$\frac{\partial(dR/d\rho)}{\partial c'(q_t)} = 0, \qquad \forall t \neq T, \tag{4d}$$

$$\frac{\partial(dR/d\rho)}{\partial c'(qr)} > 0, \qquad t = T.$$

The results from equations 4a and 4b imply that reserves in fields where costs increase at the fastest rate—whether in production or development—are going to be less affected by the royalty than reserves with more stable costs. A possible reason for this is that the royalty is an additional cost and thus is proportionally less relevant when development or operating costs

16. We therefore cannot draw final conclusions regarding which fields will be more affected based solely on the analysis of the NPTR. This view is relatively valid in a context based on geology. The idea is that each oil field has a maximum efficient recovery rate, such that once a fixed investment is made, the oil field generates a stream of income, determined by geological characteristics. Nevertheless, Black and LaFrance (1998) argue that this not the case. They test data from oil fields and find that oil production follows what would be an economically driven model.

17. Manzano (2000). Livernois (1991) discusses the effects of tax brackets on the production path, including the fact that producers do adjust to the presence of taxes. Jacoby and Smith (1985) also allow producers to adjust, but they parameterize a model for the offshore gas sector in the United States and check the effects of taxes and price regulation.

increase rapidly. Consequently, in terms of the amount of reserves not developed because of the tax structure, inelastic agents will reduce reserves less than more elastic agents. These results are similar to the standard results found in most public finance textbooks concerning inelastic agents. Inelastic agents should bear most of the burden, since they alter their behavior the least in response to the tax.

The result in equation 4c contravenes the conventional wisdom derived from the NPTR. It implies that the reduction in reserves developed in high-value fields, as a consequence of the royalty, is larger than in the case of low-value fields. The reason for this is that high-value fields lose a larger proportion of income relative to the costs of development, leading to a larger reduction in reserves.

Finally, equation 4d implies that the only channel through which the marginal cost affects the value of the derivative is through the marginal cost of q_T. Consequently, the effect is small. If the tax system allows oil producers to deduct all expenses, the optimal solution will not be affected by that system.[18] Most tax codes, however, do not recognize, or allow for, the amortization of these development costs. Instead, they offer a tax credit for them. This means that the oil producer faces the following problem:

$$(5) \qquad \max_{\bar{R},q,T} V = \int_0^T \left\{ \left[pq - c_0(q) \right](1-\tau) \right\} e^{-rt} dt - \left(1 - \tau \cdot t_c\right) C(\bar{R}),$$

such that $\bar{R} = -q$, $R(0) = \bar{R}$, and $R(T) = 0$, where τ represents the tax rate and τ_c the tax credit given.[19] This implies that only the development margin is distorted. As long as $t_c < 1$, fewer reserves will be developed, but there should be no impact on the extraction path. We can also repeat the traditional analysis for tax incidence, which yields

$$(6) \qquad \text{NPTR} = \frac{\int_0^T \tau\left[pq - c_0(q)\right]e^{-rt}dt - \tau \cdot t_c C'(\bar{R})}{\int_0^T \left[pq - c_0(q)\right]e^{-rt}dt - C(\bar{R})}$$

$$= \tau \left\{ 1 + \frac{C(\bar{R})\left(1 + \tau \cdot t_c\right)}{\int_0^T \left[pq - c_0(q)\right]e^{-rt}dt - C(\bar{R})} \right\}.$$

18. In this case, the right-hand side of equation 1 will be multiplied by $(1 - \tau)$, and it will disappear once we set the first-order conditions.

19. This means that the company is allowed to deduct t_c percent of its investment in field development as an expense for income tax purposes.

The tax burden is higher than τ because firms are not allowed to fully deduct their development costs. Fields characterized by a lower value, higher development costs, and higher operating costs pay a higher tax rate. As before, this is a simplistic approach to the problem because it does not take into account the fact that producers will adjust their production plans in response to taxes. We can derive the change in reserves with respect to the tax rate and with respect to the parameters of interest:

$$\frac{\partial(dR/d\tau)}{\partial C''(\bar{R})} > 0; \tag{7a}$$

$$\frac{\partial(dR/d\tau)}{\partial C''(q_t)} > 0; \tag{7b}$$

$$\frac{\partial(dR/d\tau)}{\partial p} < 0; \tag{7c}$$

$$\frac{\partial(dR/d\tau)}{\partial c''(q_t)} > 0. \tag{7d}$$

The results are similar to those in the royalty case. The main difference here is that the marginal cost has a more direct effect than in the case of the royalty. This is because the royalty is based only on price, while the profit tax takes into account the cost of producing oil. This result again contravenes conventional wisdom in the sense that fields with lower marginal costs reduce their level of reserves more in response to the introduction of an income tax than fields with higher costs. The reason is that the ratio of tax to development costs is much larger for fields with lower costs.

This analysis suggests that an income tax is better than a royalty, given that it distorts only one margin. Moreover, tax systems might generate fewer distortions as they move to include capital expenditures more appropriately—through depreciation provisions, allowances for some form of capitalization that can be deducted later, and so on. Another alternative that would generate fewer distortions is to make the government a partner, so that the government's take (the tax) is collected through participation in the oil project. Recent contracts in the oil sector have thus introduced alternative forms of government participation, partially reducing the distortions. Some of these provisions include a government share in profits and a tax on the repatriation of dividends. Table 1 lists some of these mechanisms used in the region.

Nevertheless, these instruments end up being a form of rate-of-return regulation. The theory of regulation shows that rate-of-return regulation can induce overinvestment by the firms.[20] Giving the government a share of profits or taxes on dividends may have similar effects. The literature also outlines the perverse incentives that tax brackets may have for the investment decisions of firms in the resource sector.[21]

Alternatively, the optimal taxation of the oil sector could be viewed as a problem of asymmetric information. The oil sector is characterized by relatively good information on oil quality, prices, reservoir depth, and so forth, but governments have less information on the investments and costs required to develop a field. This is similar to the issue of effort in the labor economics literature. For this reason, some governments may have decided to use the royalty more extensively than an income tax.[22]

The main problem with the royalty is that it performs quite poorly in capturing rents. As oil prices rise, a set royalty rate captures less rent than a set income tax rate. Royalty rates are typically lower than income tax rates. If a government wants a specific share of the profits, leaving aside behavioral changes, it needs a higher income tax rate than a royalty rate. Consequently, when prices rise, the share of the government in the increased price is lower with a royalty.[23] An important amount of rents thus remains with the producer, and these rents are procyclical. This is illustrated in table 2, which presents a reference oil price per barrel (the West Texas Intermediate, or WTI) and the average portion appropriated by the government. As the oil price has increased, the average fiscal share has decreased or remained stable. In other words, the tax systems are not progressive.[24]

This could help explain the recent wave of tax increases. Most Latin American countries signed new agreements for exploration and development in the 1990s, when the average WTI price was US$19.96 per barrel. The price context has changed radically since then, yet most of the contracts did not

20. Train (1983).

21. Livernois (1991).

22. See, for example, Mommer (2002), who argues that the use of a royalty could solve the principal-agent problem between the government and the oil firm derived from the asymmetric information on costs.

23. For example, with prices of $20 a barrel and costs of $10 a barrel, a royalty of 25 percent ($0.25 \times 20 = 5$) is equivalent to an income tax of 50 percent [$(20 - 10) \times 0.5 = 5$]. If the price of oil increases to $40, a royalty of 25 percent now captures $10 per barrel, whereas an income tax of 50 percent captures $15 per barrel.

24. Bolivia is a textbook example of rate-of-return regulation. Firms overinvested, and their liability was reduced.

TABLE 2. Fiscal Take per Barrel[a]
Percentage of international price

Country	1996–98	1999–2001	2002–04
WTI (dollars per barrel)	19.0	25.1	32.9
Argentina	n.d.	20	24
Bolivia	37	24	15
Colombia	22	21	22
Ecuador	66	46	51
Mexico	42	38	52
Trinidad and Tobago	37	16	23
Venezuela	51	47	53

a. Our reference price is the West Texas Intermediate (WTI) price, measured as the average price for the period, in U.S. dollars per barrel. The fiscal take for each country is measured as a percentage of that reference price. The estimations for Argentina are based on Scheimberg (2008).
n.d. No data.

include provisions for higher prices. The few that were based on some form of rate-of-return regulation were negotiated in the period of highest investment, so the tax burden was still reduced. Consequently, the royalty rate has increased in Argentina, Bolivia, and Venezuela, and Ecuador and Venezuela have recently approved windfall taxes. Moreover, most of these cases involve inelastic fields. In other words, they are mostly low-value fields or projects with an accompanying sunk investment that serves as a binding constraint.[25] These firms therefore will not change their behavior considerably once taxes are increased. The tax hike might have an effect on the entry of new investment, but production will react very little.

In the 1990s, a number of countries did not fully privatize the national oil company, but selectively opened the sector to private investment. To attract private investors, they offered better fiscal conditions on these inelastic fields, while the national oil companies kept the higher-return fields, including the bigger fields and light crude fields, for themselves. In some cases, the argument for offering the tax incentives was that the existing tax regime was not competitive, but these reforms were mostly driven by a lack of public capital to increase production in the sector. The result of these changes was that production in those countries shifted toward crude generated under these contracts with private investors. This shift had two effects. First, the new production mix is not optimal. The optimal production mix would require producing high-

25. For example, in Bolivia and Ecuador, the installation of pipelines accompanied the investment in exploration and development.

quality, low-cost oil first and then moving on to the lower-quality, higher-cost fields. Second, countries have become fiscally dependent on these new fields. When oil prices began to rise, countries with relatively low taxes on the hydrocarbon sector had incentives to change their tax rates, particularly since most of the privately operated fields were perceived as inelastic.

Oil exploration implies an important agency problem because the government does not have good information on the investments and costs required for oil extraction.[26] A way to solve the informational problem is for the state to exploit the resources itself. This could explain why many countries have national oil companies that operate with a monopoly on the sector or in parallel to international oil companies. The main problem with this arrangement is that a distributive conflict arises between governments and national oil companies with regard to diverting resources to the government versus fulfilling the company's investment plans.[27] As explained later, the national oil companies are often vulnerable to expropriation of revenues by the state through different mechanisms. Examples include Petróleos de Venezuela (PDVSA), which directly undertakes significant social investments (before paying taxes), Petroecuador, which has difficulties fulfilling its investment plans because the government's Treasury directly receives payments for the oil exports, and Petróleos Mexicanos (PEMEX), whose exports have been extensively used as collateral for the issuing of government debt.

A final point is the relationship between taxes and economic volatility. Price volatility is generally expected to have a negative impact on investment, especially in the case of projects such as oil exploitation.[28] However, the fact that tax instruments do not take price volatility into account—that is, they are not contingent—adds a second element of volatility. Firms might include the uncertainty of tax changes in their evaluation of different projects. Moles, Constantinou, and Kretzschmar find that including tax volatility

26. The amount of information coming out of the oil sector has increased since the oil crises of the late 1970s and early 1980s. Governments know oil quality, reservoir depth, pressure, and so forth. However, oil companies still have an amount of private information, which is not available to the government. As argued before, this is similar to the literature on workers' effort in the field of labor economics.

27. For example, in Venezuela in the 1990s, the oil industry's average investment in the production phase alone averaged around 3.4 percent of GDP. During the same period, the fiscal deficit averaged around 1 percent—not including the cost of the financial crisis. The government thus has alternative uses for these resources.

28. An important literature uses real option valuation techniques to assess these issues in the oil sector; see Moles, Constantinou, and Kretzschmar (2005) for a review.

in a model for the North Sea reduces the valuation of the assets involved in this activity by up to 20 percent.[29] This could lead to decreased investment in the sector.

In summary, the instruments used for taxing the hydrocarbon sector in the region tend to have the problem of leaving rents with the producing firms. These rents are procyclical, and they give the governments incentives to enter into an expropriation cycle. This tax volatility compounds the effects of oil price volatility and reduces investment in the sector below the optimal level.

The Political Economy of Taxation and Contracting in the Latin American Oil Industry

Economic and political economy factors help explain the patterns of development in the oil industry. We start by presenting the main characteristics of the oil industry that make it particularly susceptible to changes in the tax and contractual conditions. In the last section, we argued that tax systems are relatively ineffective at capturing rents, particularly when prices rise, and they typically generate significant distortions. This section extends that analysis to the political economy of oil taxation and contracting in the region.

A Primer on the Oil Industry's Characteristics and the Sources of Expropriation

Oil exploitation generates significant rents. For example, the cost per barrel in the region (and the world) typically varies from as low as US$1 to as high as US$15. When the oil price recently rose above $70 dollars per barrel, rents skyrocketed. In theory all rents can be captured by the state—which typically has sovereign control and property rights over oil reservoirs—without affecting long-term production.[30] In practice, the producer often keeps significant rents. The problem arises from the fact that tax and contractual frameworks are typically not very progressive. As a result, when there is a large increase in the international oil price, the government has incentives to renege on

29. Moles, Constantinou, and Kretzschmar (2005).

30. One definition of rent is the excess revenue above the opportunity cost of the reproducible factors of production (that is, labor and capital). Mineral rents can result from the naturally lower costs of extraction or higher quality of certain mineral reservoirs, relative to the marginal producer; these are known as differential rents. Rents can also arise from monopolistic restrictions on accessing the mineral reservoirs or from output restrictions by cartels.

deals made when prices were lower.[31] In addition, some rents are typically captured by other groups, including the oil workers, local actors, and domestic consumers.

Oil investment is characterized by a time-inconsistency problem. A large proportion of the investments in oil production are sunk costs, that is, assets that are immobilized before revenues start being collected. Examples of sunk investments include seismic studies, exploration and production wells, and pipelines. Once deployed, the ex post value of these assets in alternative uses is very low, which opens the door to the appropriation of significant quasi-rents.[32] The operating firm benefits from continuing to operate as long as it can recover operational and nonsunk assets, even if it cannot recover the sunk costs. As a result, the government, or other actors, may expropriate the quasi-rents by opportunistically changing the conditions of investment, through taxes, regulations, or the domestic oil price. The political benefits of opportunistic reneging are high. In the short term, the government can extract significant fiscal resources or transfer them to domestic energy consumers, without a significant impact on oil production. The expropriation of revenues from state-owned enterprises can also be a significant problem, depending on their governance structure, among other variables.[33]

In addition to the appropriation of quasi-rents, hydrocarbon production is risky because world oil reserves are concentrated in underdeveloped countries with weak institutions and high political risks. These governments have trouble committing to allow private investors or state-owned enterprises to recover their sunk investments. If the political benefits of reneging are high and the short-term costs are low, then only strong domestic institutions or external enforcement would provide credible property rights. In fact, external enforcement has played a more significant role than domestic enforcement throughout the history of oil and mineral investment in developing countries. This was the case, for example, when a cartel of oil multinationals coordinated punishment and the hegemonic powers enforced international property

31. In this case the increase in the government's take may only be capturing the additional rents provided by the increase in oil prices and not expropriating the quasi-rents (see below). Still, the prospect of contractual changes increases the risk for investors.

32. Klein, Crawford, and Alchian (1978); Williamson (1996). One definition of quasi-rent is the difference between the ex ante and ex post opportunity cost of the production factor. In contrast to rents, if the quasi-rents are taken from the producer, long-run production would be affected. The company would continue operating in the short run as long as it can recover operational and nonsunk costs, but it would not redeploy sunk assets, that is, it would not invest.

33. Monaldi (2002, 2005).

rights.[34] More recently, multilateral arbitration, investment treaties, and loans guaranteed by oil export receivables have provided some degree of external enforcement.[35] In a few cases, however, such as Brazil, Chile, and Norway, domestic political and regulatory institutions have provided credible commitments to foreign investors in sectors characterized by high sunk costs.[36]

The reputational costs of reneging on commitments are high when the government is eager to attract new foreign investment (particularly in the same sector). The likelihood of expropriation thus declines when a new investment cycle is being initiated, because production is just starting, because there has been a long period of disinvestment (possibly as the result of previous expropriation), or because the government does not have the necessary fiscal resources to invest. In contrast, the likelihood of expropriation increases after long periods of high investment and rising revenues (and reserves) and when the government has plentiful financial resources.

The incentives for governmental reneging also depend on the politicians' discount rate. In the presence of weak institutional frameworks, episodes of economic and political instability induce high discount rates, which make the reputational costs of reneging less relevant. The short-term benefits of expropriating the oil industry, combined with high discount rates, have made the oil industry a very tempting target in the past. For example, the Argentine government reneged on oil contracts following the economic crisis of 2000–02.

The existence of high geological risks in the exploration phase provides incentives for governments to offer attractive deals to private investment. When exploration is highly successful, however, the government has significant incentives for ex post renegotiation. Contracts typically do not incorporate clauses that allow the government to capture all the large rents that arise after significant new discoveries. As a result, even in the initial phase of production, governments often change the fiscal and contractual conditions following the discovery of major hydrocarbon reserves that significantly increase the net present value of the project.[37] Similarly, because fiscal and contractual

34. Lipson (1985).

35. Monaldi (2002).

36. Levy and Spiller (1996). They identify three conditions required for institutional commitment: the existence of substantive legal restrictions on government's reneging, the existence of higher-level procedural restrictions on changing the legal restrictions, and the existence of credible institutional mechanisms for enforcing the first two types of restrictions (such as an independent judiciary). They present the case of Chile's management of the electricity sector as an example of credible commitment supported by domestic institutions.

37. Vernon (1977) calls this phenomenon the obsolescing bargain.

frameworks are typically not progressive with respect to increases in oil prices, there has been a tendency to raise taxes in periods of high oil prices.[38]

The massive consumption of oil and gas products (including gasoline and residential gas) has made domestic pricing a charged political issue. Politicians are therefore pressured to avoid significant increases in domestic energy prices. Some exporting countries have regulated domestic prices below the opportunity cost of exports, especially during periods of international price hikes. In contrast, since the demand for oil products is highly inelastic, some countries prefer to use consumption taxes to obtain fiscal revenues.

Volatile oil prices generate volatile oil rents. We have already argued that fiscal systems have a hard time capturing oil rents in different price scenarios; price volatility is particularly problematic as a result. In the case of oil-dependent exporters, volatility may create macroeconomic and fiscal instability unless stabilization mechanisms are effectively implemented, which typically has not been the case. Oil-dependent governments might therefore be tempted to renege on oil companies, particularly state-owned companies, when the oil prices fall and the government faces a fiscal crisis. If government officials face a high discount rate, partly induced by the high volatility of oil income, the reputational costs of reneging could be less relevant during a fiscal crisis. A fiscal crisis produced by something other than an oil shock could also make the oil industry a tempting target.

Actors and Incentives

In general, governments have incentives to attract oil investments because they benefit from the development of oil projects and oil production in their territory. The economic activity generated and the taxes collected provide authorities with both fiscal resources and political support from constituents. Governments might have incentives to renege on previous oil deals, however, once investments have been deployed and production is ongoing. In particular, they might have incentives to increase the government's take or regulate the domestic price of oil products.

The governments' incentives also depend on the extent to which the country is a net exporter or a net importer of oil. If the country is a substantial net exporter, one key issue is whether oil revenues can represent a significant source of fiscal income. In that case, policymakers have powerful incentives to maximize generation and the appropriation of rents from oil exports.

38. Monaldi (2005).

Depending on the politicians' discount rate, the level of the country's oil reserves, and future market expectations, this rent maximization could imply a strategy focused on short-term fiscal revenue extraction or one oriented toward increasing long-term production.[39] Net exporters are typically more reluctant than net importers to privatize national oil companies, because national oil companies can be more easily used as cash cows or piggy banks than private companies. In addition, since they capture mineral rents, the national oil companies tend to be less deficit prone and debt ridden than other state-owned companies, making the rationale for privatizing them politically less compelling.[40] Moreover, given that oil taxation inevitably introduces distortions, state ownership might seem a less distortionary alternative than having high marginal taxes on private operators, particularly when the oil price is high.

When governments are willing to offer foreign investors access to their oil reserves, net exporters with substantial oil reserves generally have the upper hand in their negotiations with international oil companies, given that these companies have few alternatives for increasing their reserves. These countries typically open the projects with lower rent generation first. When the price of oil in the international market rises significantly, net exporters are in the best position to negotiate, whereas international oil companies with existing sunk assets in the country have a particularly weak bargaining position if the government attempts to change existing conditions. As a result, resource nationalism and tax increases are common among net exporters when the price of oil rises substantially.

In the case of net oil importers, the incentives are skewed toward increasing investment and production. Rent extraction from upstream activities becomes less relevant. Given that production is domestically consumed, rents are not generated in the international markets; rather they are extracted from political constituents. Moreover, oil imports can be very costly when oil prices are high, generating high political and fiscal costs and external-account problems. Consequently, net importers typically provide more attractive terms for oil exploration and extraction (although this can also result from the lack of attractive geological prospects). Nevertheless, the governments of net importers could renege on oil deals in the event of an oil price hike, an external shock, or a high political discount rate. For example, the domestic price of natural gas or oil products might be regulated down, or the existing exports

39. If the country is a relevant player in the international oil market, the government also has to decide whether to belong to OPEC and, if so, whether to respect the cartel production quotas.

40. A counterexample is YPF, the national oil company of Argentina, which incurred significant deficits before being privatized. However, Argentina was not a significant oil exporter.

might be heavily taxed or forbidden, to benefit domestic consumers and obtain constituent support.

Net oil importers also typically offer fewer subsidies on domestic energy consumption. Since they do not have external oil rents to cover for these subsidies, they would have to finance them with cross-subsidies, other taxes, or inflation. In addition, net importers facing fiscal deficits or the need for large investments in oil are typically more willing to privatize their national oil companies. Since national oil companies do not obtain external rents in this case, they can more easily generate net losses.

In general, governments with oil and gas reserves are in a better position to increase the government's take and control if they have higher oil reserves and higher prospectivity (that is, the likelihood of finding oil and gas in exploration) since international oil companies would be interested in entering and staying in this type of country; if they have the financial resources to finance the needed oil investment, based on high oil revenues or access to international financial markets (whereas international oil companies are necessary when governments are in dire need of financial resources); if they are at the end of an asset deployment cycle or a successful investment period, when there are significant sunk assets and little new investment is required; and if the price of oil and gas in the international market is quite high.

The managers of the national oil companies may have different incentives from their governments. For example, they typically prefer to keep resources in the company, rather than pay taxes. The managers' incentives largely depend on the institutional and governance structure regulating the national oil company. For example, if the company is highly politicized, it could become a clientelistic vehicle of the ruling party, in which rents and quasi-rents are used to overemploy and overpay party supporters.

The political costs, for the government, of expropriating revenues from the national oil company will depend on how autonomous and institutionalized the company is and how discretional the fiscal regime is. If the ministry of finance or the executive office can discretionally decide the government's take on oil revenues or fully control the national oil company's budget, then the costs of expropriation are low. In general, extracting revenues from the national oil company is typically less costly than extracting revenues from a private company. The cases of Petroecuador, PEMEX, and PDVSA today are clear examples. However, systematic expropriation has been avoided in cases of financially autonomous national oil companies, such as PDVSA in the 1990s and Brazil's Petrobras. One mechanism to reduce the likelihood of expropriation of a national oil company is the introduction of private shareholders and the listing of the company on the stock market, as in the case of Petrobras and Norway's Statoil.

The international oil companies are the other key player in the oil business in Latin America. Only a few, relatively small domestic oil companies operate in the region.[41] The international oil companies maximize global profits, typically with longer horizons than those of the developing countries' governments. They provide capital, know-how, technology, and human capital in exchange for oil profits. In the era of the so-called seven sisters cartel of multinational oil companies, they were able to coordinate to impose high costs on reneging governments. Their capacity for external enforcement diminished greatly, however, after the rise of the independent oil companies and the increase in the sovereignty of many developing oil-producing areas in the 1960s. The ensuing nationalizations of the 1970s dramatically changed the structure of the oil market, making the national oil companies of exporting countries very powerful players.

The Latin American Oil and Gas Sector

Latin American countries differ in many of the endowment and institutional dimensions that shape the governments' incentives. Accordingly, their oil sectors have followed relatively different trajectories. Still, the evolution of the oil sector in the region does display some common trends. In particular, the institutional framework of the oil and gas sector has undergone extensive changes over the past two decades throughout the region.

The countries in the region vary dramatically in terms of their oil reserves (see table 3). Venezuela's reserves are by far the largest and have been growing in the last two decades. Mexico has the second-largest reserves, but they have been revised down significantly over the period.[42] Brazil has the third-largest reserves, which have been increasing. While they still are not that significant relative to the country's consumption and population, very recent discoveries promise to make Brazil a future exporter. Ecuador ranks fourth, with increasing reserves, which are significant both in per capita terms and relative to domestic consumption.

41. Argentina has had the more relevant domestic private companies. The largest, Perez Companc, was bought by Petrobras.

42. PEMEX reserves were reduced after the company was audited according to the U.S. Securities and Exchange Commission's (SEC) rules. The reserve certification was required because of the Mexican government's use of the oil receivables from PEMEX exports as debt collateral.

TABLE 3. Proven Conventional Oil Reserves
Billions of barrels

Country	1986	1996	2006
Argentina	2.2	2.6	2.0
Bolivia	0.0	0.0	0.0
Brazil	2.4	6.7	12.2
Colombia	1.7	2.8	1.5
Ecuador	1.2	3.5	4.7
Mexico	54.9	48.5	12.9
Peru	0.5	0.8	1.1
Venezuela	55.5	72.6	80.0
Total	118.4	137.5	114.4

Source: *BP Statistical Review of World Energy 2007.*

Table 4 presents the region's natural gas reserves. Venezuela ranks first, but 90 percent of its gas is associated with oil production, which is generally used for reinjection to increase oil production. Bolivia has the second-largest gas reserves, which are not associated with oil production and thus are available to export. Argentina and Mexico are next in natural gas reserves, while Brazil and Peru have made important recent discoveries. The rest of the countries in the region, with the exception of Guatemala, have negligible levels of oil and gas reserves.

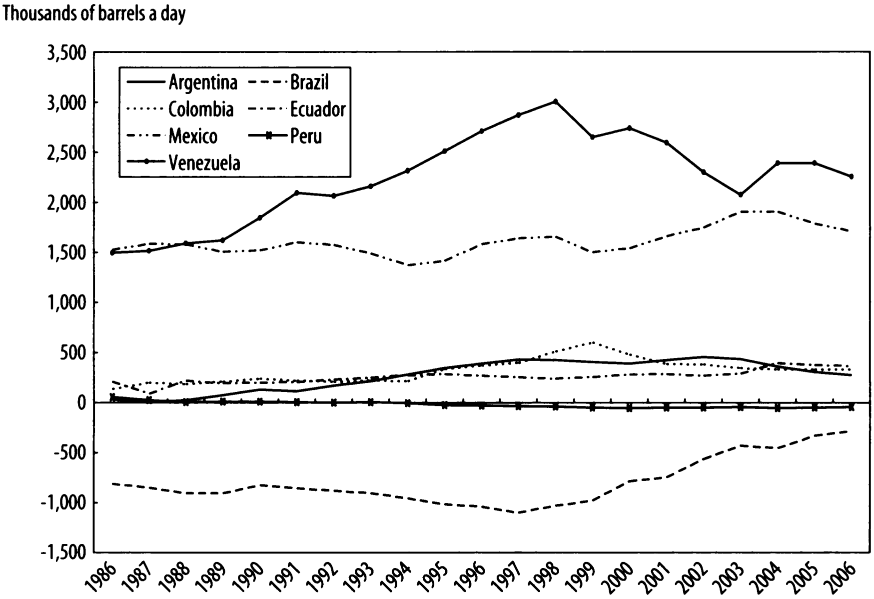
Venezuela and Mexico are the largest net oil exporters (see figure 1). Ecuador is next, with increasing exports of around 400,000 barrels a day. In per capita terms, however, Ecuador's oil exports are the second largest in the region, behind Venezuela's. Colombia and Argentina have become relevant

TABLE 4. Proven Natural Gas Reserves
Trillions of cubic meters

Country	1986	1996	2006
Argentina	0.7	0.6	0.4
Bolivia	0.1	0.1	0.7
Brazil	0.1	0.2	0.4
Colombia	0.1	0.2	0.1
Ecuador	0.0	0.0	0.0
Mexico	2.2	1.8	0.4
Peru	0.0	0.2	0.3
Venezuela	2.6	4.1	4.3
Total	5.8	7.2	6.6

Source: *BP Statistical Review of World Energy 2007.*

FIGURE 1. Oil: Net Exporters and Net Importers[a]



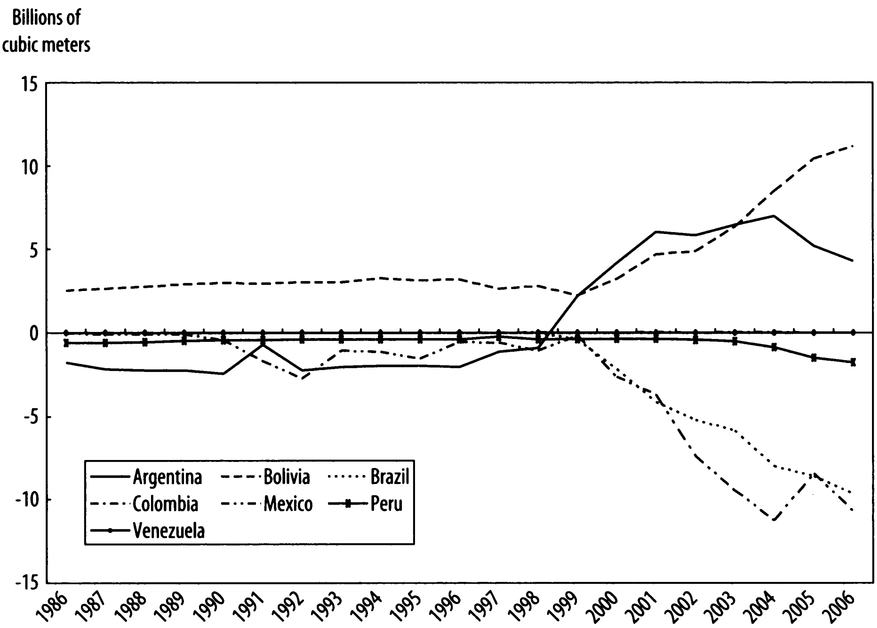
Source: *BP Statistical Review of World Energy 2007.*
a. Positive values indicate net exports; negative values indicate net imports.

net exporters in the last two decades, but production has declined in both countries over the last few years. Brazil and Peru have been net importers of oil. Brazil has been able to significantly decrease its dependence on imported oil and become self-sufficient, while Peru has not had much success in increasing production.

Argentina and Bolivia are the region's main natural gas net exporters (see figure 2). Venezuela has enormous reserves, but it consumes the gas domestically, mainly as an input for oil extraction. Other countries, in particular Brazil and Mexico, are net importers of natural gas.

Institutional variables also display significant variation in the region, for example, in the degree of state and private participation in oil and gas production. At one extreme is Mexico, where oil production has been a state monopoly for seventy years and where the government has only recently begun a timid opening to the private sector. Next come Brazil, Colombia, Ecuador, and Venezuela, which are all characterized by a dominant state-owned company. In Brazil, Petrobras was partly privatized, and the major-

FIGURE 2. Natural Gas: Net Exporters and Net Importers[a]



Source: *BP Statistical Review of World Energy 2007.*
a. Positive values indicate net exports; negative values indicate net imports.

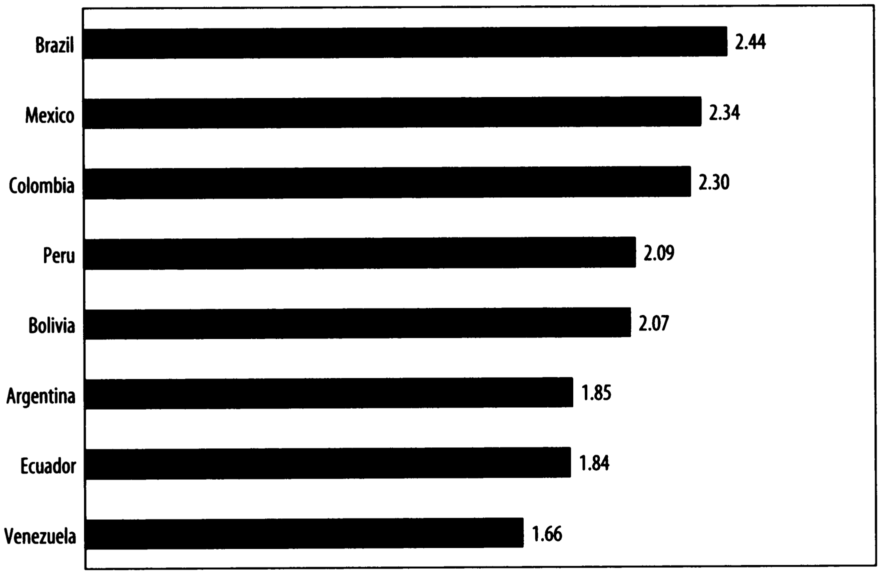
ity of the stock is now in private hands although the state maintains control through shares with special voting rights. Colombia followed Brazil's path in 2006, with the privatization of a minority share of Ecopetrol stock. In Ecuador and Venezuela, the national oil companies have not sold stock on the market. Nevertheless, private operators became increasingly relevant in both countries over the last decade, coming to produce over 40 percent of the total oil extracted. At the other extreme are the cases of full privatization in the 1990s in Argentina, Bolivia (through so-called capitalization), and Peru. However, Bolivia has dramatically reversed privatization in the last two years, with the recent nationalization of the natural gas industry and the oil refineries.

The regional trend toward privatization and the opening to private investment in the 1990s was partially the result of the market reforms induced by the fiscal crises of the 1980s. Moreover, the decline in oil prices implied that there were less rents to finance oil investments. However, the net exporters, like Ecuador, Mexico, and Venezuela, did not privatize because these states tend to be fiscally and financially dependent on their national oil companies (for example, they use the companies as collateral for debt issues). In contrast, privatization prevailed in net importers (like Brazil and Peru) and small per capita exporters (such as Argentina), some of which had deficit-ridden oil companies.

Recent trends in regulatory and tax reform also vary among countries. Argentina, Bolivia, Ecuador, and Venezuela have reneged on oil contracts and increased the government's take on oil and gas private production over the last five years. In these countries, private investors were partially the victims of their own success. The large private investments in the previous decade resulted in increased reserves and production. The large sunk investments and the recent increase in international oil and gas prices together provided a perfect opportunity for the governments to renegotiate the contracts. In contrast, Brazil, Colombia, and Peru have strengthened the credibility of their regulatory framework in the last few years and generally moved in the direction of promoting private participation. Brazil and Peru have been net importers eager to obtain more oil and gas investment. In Colombia, the decline in reserves and production promised to transform the country into a net importer in the next decade if radical actions to promote investment were not taken.

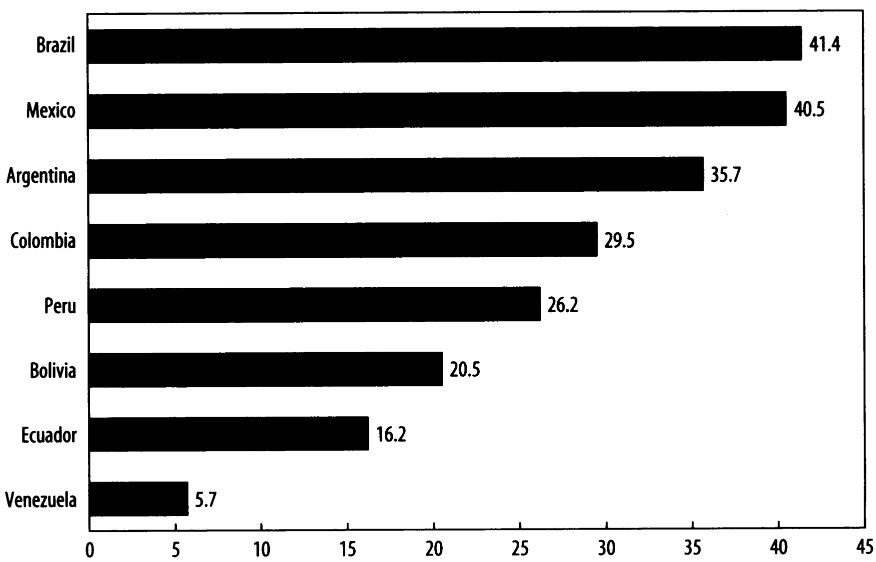
Oil and gas sector regulations are framed within the larger set of domestic political institutions. Brazil and Colombia, which have strengthened the institutional framework governing the oil sector, have relatively good ratings in different subjective measures of institutional strength and rule of law that are not based on the energy sector, such as those compiled by the World Bank and the Inter-American Development Bank (see figures 3 and 4). In contrast, the countries in which the governments have changed the rules of the game with respect to the oil tax and contractual frameworks generally also have relatively low ratings in these measures. For example, a country with the current institutional endowment of Venezuela would have difficulty committing to contracts based on domestic institutional guarantees. At the same time, Bolivia had a relatively good standing in these measures before becoming one of the leading resource nationalists. Moreover, contracts were respected in the 1990s in countries like Argentina, Ecuador, or Venezuela, despite considerable institutional weaknesses, and reneged on later, showing that the timing of reneging cannot be attributed just to the relative strength of domestic institutions. Finally, changes in oil taxes and contracts have been common elsewhere, even in developed and highly institutionalized countries such as Great Britain, Canada, and the United States.

FIGURE 3. Overall Policy Index, 2005



Source: Inter-American Development Bank (2006).

FIGURE 4. Rule of Law Index, 2006[a]



Source: Kaufmann, Kraay, and Mastruzzi (2007).
a. The index provides a percentile ranking of the countries.

Country Cases

This section briefly presents the country cases of the region's relevant oil and gas producers, analyzing the political economy factors that have affected the institutional and economic evolution of the sector. We start with the most important oil producers in the region and continue with the smaller, more recent participants. We end the section with a brief comparison of the different cases in light of the theoretical framework presented earlier in the paper.

Venezuela

The case of Venezuela exemplifies the dynamics of investment and expropriation cycles. The periods of contract renegotiation have coincided with the end of successful cycles of investment, and nationalizations have occurred during oil boom periods. The country has generally behaved as a typical significant net exporter with short-term horizons, maximizing short-term rents and heavily subsidizing the domestic oil products market.[43]

Venezuela is the second-largest producer and the largest exporter in the region, and it has by far the largest hydrocarbon reserves.[44] It is also the only founding member of the Organization of the Petroleum Exporting Countries (OPEC) in the region. Oil has been Venezuela's main source of fiscal revenues (around 50 percent) and exports (above 80 percent) for decades.

After decades of high investment, the taxation of the international oil companies was increased significantly in the 1960s and 1970s, and oil concessions were not renewed. Oil investment therefore declined from 1958 to 1976. In contrast, oil production capacity continued to rise until the early 1970s; it then fell abruptly, but with a significant lag. The oil industry was eventually nationalized in 1976. After nationalization, PDVSA, the national oil company, increased investments dramatically, taking advantage of the prevailing high oil prices. The governance of the national oil company was designed to minimize political interference and rent extraction.[45]

43. Domestic subsidies (with respect to the opportunity cost of exporting) exceeded US$10 billion in 2006.

44. If the unconventional hydrocarbons of the Orinoco Belt are included, Venezuela could claim to have the largest crude reserves in the world, with total reserves of over 300 billion barrels.

45. Monaldi (2005).

By the early 1990s, large new investments were needed to increase production. PDVSA significantly increased capital expenditures.[46] At the same time, the government's fiscal difficulties induced the opening of the oil sector to private operators using a special contractual framework that provided some credibility against government reneging, by using PDVSA and its foreign assets as a guarantee. The projects offered to private investors involved lower rent generation, mature or abandoned oil fields (high costs), extra-heavy crude that requires expensive upgrading (high costs), and exploration. Consequently the contracts with private operators generally lowered the implicit tax rates.[47]

Private investment thus increased substantially in the late 1990s, raising production by 1.2 million barrels a day by 2005. After 1998, the government increasingly extracted more resources from PDVSA. The revolutionary government of President Hugo Chávez honored the private contracts until late 2004, despite having changed the constitution and the oil law to increase government control over the oil sector. The externally enforceable contractual framework, the institutional autonomy of PDVSA, and the fact that significant private oil investments were being deployed in 1997–2003 provided protection for the investors' property rights.

The evolution of the Venezuelan government's take in the sector reflects the composition effect, that is, the relative increase in privately operated production with a lower implicit tax, combined with a reliance on royalties. PDVSA's production declined in 1998–2003, while privately operated production increased until 2005. The share of private production therefore increased. Moreover, the government's take on private sector production was lower than its earnings from PDVSA. The government's share of total oil revenue actually decreased even though the fiscal take per barrel increased in absolute terms from 1996–98 to 1999–2001 (see table 2).[48] As discussed earlier, systems based on royalties, which are not progressive, tend to have this effect.

In 2002–03, the government's attempt to eliminate the autonomy of PDVSA resulted in a massive oil strike that dramatically diminished oil investments

46. Venezuela's production was limited by OPEC quotas in the 1980s, making investments in exploration and production relatively unnecessary. In addition, after the debt crisis the government began discretionally extracting revenues from PDVSA. When OPEC eliminated quotas in the late 1980s, PDVSA was able to increase production using its spare production capacity.

47. Monaldi (2005). For example, the extra-heavy oil projects of the Orinoco Belt had a 1.00 percent royalty and a 34.00 percent income tax, compared with the 16.66 percent royalty and 67.00 percent income tax rate charged to PDVSA at the time.

48. From around US$9.70 to US$10.30 per barrel.

and production. The government fired half of the oil workforce and most of the management, taking complete political control of the company. By 2004, the private oil investment cycle had concluded, and the higher oil price provided incentives and opportunities for renegotiating the oil contracts. The contractual framework of the oil opening changed significantly over the next two years, considerably increasing the government's take and control over private investments. By 2007 the government had nationalized the oil industry, taking majority control of all privately operated projects without providing market compensation. The weakening of the domestic institutional framework has resulted in a new cycle of expropriation. In sum, Venezuela has engaged in contract renegotiation and expropriation more than once. The evidence seems to suggest that these renegotiations occur during periods of increasing rents and after high investment has been sunk.

Mexico

The case of Mexico exemplifies the use of the national oil company as a fiscal, financial, and political tool in a net exporting country. If the regulatory framework is not reformed, the country will probably face declining production and reserves in the future. Mexico is the largest oil producer in the region and the second-largest country in terms of exports and reserves. However, reserves declined dramatically in the last decade. Mexico became a significant oil exporter in the early part of the twentieth century. Oil was nationalized in 1938, and Mexico then ceased to be a relevant net oil exporter until the 1970s.[49] Important reserve additions in the 1970s allowed a significant increase in production and exports, financed by the high oil prices. The proportion of oil in total exports (about 10 percent in 2004) is not nearly as relevant as in Venezuela (85 percent), Ecuador (50 percent), or even Colombia (30 percent). This contrasts sharply with the 1970s, when oil exports represented more than 70 percent of the total. Nevertheless, oil fiscal revenue is still very relevant for the Mexican government (over a third of the total). Only in Venezuela and Ecuador is oil fiscal dependence higher.

The Mexican national oil company, PEMEX, does not have financial autonomy from the government, and it has generally been used as a clien-

49. The decline in Mexico's oil export capacity can largely be attributed to geological factors. Although Mexico was initially punished by the international oil companies for nationalizing the oil industry, the decline in production can be traced to lack of exploratory success. In the 1970s, offshore oil discoveries increased the Mexican oil reserves, allowing the country to become a net exporter again (Haber, Maurer, and Razo 2003).

telistic tool of the ruling party (until 2000, the *Partido Revolucionario Institucional,* or PRI, was the only ruling party). It has also been systematically used as a vehicle to guarantee government debt.[50] PEMEX's budget is part of the government's budget approved by congress, so macroeconomic considerations have generally prevailed in its design.[51] The Mexican government's excessive fiscal dependence on PEMEX has required a government take of more than 60 percent of oil profits in the last decade, which is significantly higher than in Venezuela or Ecuador.

The lack of financial autonomy has limited PEMEX's own investment capacity, causing the company to become highly indebted and to use an off-budget mechanism of deferred payment of projects (*Proyectos de Impacto Diferido en el Gasto,* or PIDIREGAS) to finance the expansion of production.[52] Until recently, oil production was sustained by the very large Cantarell field, which has started to fall. The drop in oil production is therefore expected to continue in the next few years. The Mexican oil and gas sector urgently needs an increase in investments to avert the dramatic decline in reserves and sustain the falling export volume.

PEMEX has traditionally been one of the more inefficient national oil companies. The use of the company as a clientelistic tool has implied the appropriation of oil rents by the labor unions and the PRI.[53] Still, due to its favorable endowment, PEMEX has been able to provide significant rents to the state, and Mexico has been a significant net exporter with fewer fiscal difficulties than Argentina, Ecuador, or Venezuela. As a result, it has been able to postpone privatization or opening to private oil investment.[54] In sum, the institutional framework based on a state monopoly with little autonomy has allowed the government to capture the increasing rents, but the expropriation of revenues has left the national oil company with high debt and little investment capacity.

50. PEMEX debt has increased from US$21 billion in 1998 to more than US$50 billion in 2005 (see www.pemex.com).

51. Campodónico (2004).

52. PIDIREGAS is an off-budget mechanism that allows the company to grant projects to private contractors and pay them when the project is finished, using the new assets to guarantee loans (Campodónico 2004).

53. In 2002, PEMEX employed three times as many workers as PDVSA in relation to production. The labor unions have obtained significant rents through contracting assignments.

54. Palacios (2003). The only attempt to open the hydrocarbon sector thus far has been the offering of multiple service contracts in natural gas exploitation. This mechanism represents a very minor source of investments. As mentioned, Mexico is a significant net importer of natural gas; this condition and the existence of relevant gas reserves would probably provide incentives for further reform in this sector.

Ecuador

Ecuador has had one of the most volatile oil policies in the region, partly a reflection of the high political volatility in the country. The recent trend points toward contract renegotiation, higher taxes, and expropriation, as was the case with other net exporters that were able to increase investments and production in the 1990s. Ecuador is the third-largest exporter in the region and has the fourth-largest oil reserves. More than a third of the country's fiscal revenues and close to half of its exports have been generated by oil. The national oil company, Petroecuador, produces more than half the country's oil, but an increasing share has been extracted by private companies.

Like PEMEX, Petroecuador has very limited financial autonomy. The government collects the oil revenues and gives Petroecuador back very limited resources for reinvestment. The company has therefore had persistent difficulties fulfilling its investment plans. Because of the company's financial difficulties and the decline in oil prices, private investors were given progressively more attractive conditions in the 1990s. Production-sharing contracts were established in 1993 and joint ventures in 1999. The reforms of the 1990s were successful in attracting an increased flow of investments. In the early 1990s, annual foreign investment in oil was below US$200 million; by the early 2000s it had surpassed US$1 billion.[55]

In the case of Ecuador, the evolution of the government's take in the sector also reflects the composition effect. Petroecuador has made little investment in the last few years, and its production has declined as a result. In contrast, private sector production has been increasing, causing the share of private production in total production to rise. As shown in table 1, the implicit tax rate on private production is lower than in other countries. The government's share of oil revenues was thus relatively constant, despite the rise in oil prices (see table 2).

In the last few years, legal reforms increasing the government's take have been approved, and the government reneged on an oil contract with Occidental Petroleum. The 2006 election of President Rafael Correa, on a resource-nationalism platform, prompted further increases in government control and taxes. As in Venezuela, Ecuador's success in attracting private investment in the 1990s, combined with the recent increase in the price of oil, has provided

55. Campodónico (2004). In 2003, the national oil company's financial difficulties led President Lucio Guitiérrez to decree additional reforms to favor private investors and reduce the role of Petroecuador, but these reforms were never formally passed by Congress. After Gutiérrez was removed from office, a new cycle of resource nationalism began.

the incentives and opportunities to renege on the original deals.[56] As in Mexico, the governance structure of the national oil company has induced excessive expropriation of revenues and a lack of state investment in the oil sector.

Colombia

Colombia is a net exporter, but its production, exports, and reserves have been declining in the last few years. As a result, Colombia has defied the trend of net exporters in the region, strengthening the regulatory framework, providing more attractive conditions for foreign investors, and partially privatizing the national oil company. Oil became a relevant source of exports and fiscal revenues in the late 1980s and 1990s and currently accounts for more than 20 percent of the total fiscal revenues and close to a third of exports. Ecopetrol, the national oil company, produces—either directly or in association—more than half of the oil extracted.

As in most countries in the region, conditions for private investments were improved in the 1990s. In 1999, a system of variable royalties made private investment in marginal fields more attractive. The addition of new oil reserves was not very successful, however, despite the attraction of new private investments. Since 2005, the Colombian government has implemented some additional reforms to induce more investment. These reforms are aimed at improving regulatory credibility, providing a more flexible tax regime, and making Ecopetrol more accountable and financially autonomous.[57]

In contrast to Bolivia, Ecuador, and Venezuela, the investment cycle of the 1990s did not generate either an increase in production and reserves or the subsequent incentives for expropriation. Colombia could become a net importer in the next decade if the new reforms fail to significantly increase investment and the successful addition of reserves.

Argentina

Argentina's success in obtaining investment in the 1990s created the conditions for contract renegotiation following the dramatic economic crisis of 2002. Argentina has the fifth-largest proven oil reserves in the region, but the

56. Moreover, the political instability that has plagued the country has generated an environment of significant legal uncertainty.

57. One key reform was the creation of an independent regulatory agency to supervise the oil and gas sector. Another recent reform was the partial privatization of Ecopetrol in late 2006.

country was barely self-sufficient until the 1990s. It implemented one of the most radical privatization, liberalization, and opening programs starting in 1989, and it was very successful in attracting foreign investment in oil and gas and significantly increasing production. Foreign investments in the oil sector exceeded US$27 billion in 1992–2002, accounting for more than 35 percent of total foreign investment in the country. As a result, the country became a net exporter of both oil and natural gas.[58]

After the economic crisis exploded in 2002, the government implemented some emergency measures, including a new oil export tax of 20 percent and the regulation of domestic prices. The success of the liberalization of the 1990s and the fact that the country became a net exporter have allowed the current administration to significantly worsen the conditions for foreign investors.

Brazil

Brazil is an example of a net importer successfully becoming self-sufficient. The institutional framework has provided credibility to investors and prevented the expropriation of the national oil company. Despite being the region's third-largest producer, Brazil has until recently been a net importer of oil. It has successfully reduced its import dependence over the last decade. The oil sector was opened to private investment in 1995–97, eliminating the constitutionally sanctioned monopoly of the national oil company, Petrobras. To provide regulatory credibility to private investors, an independent regulatory agency was created to oversee the oil sector. In addition, Petrobras has been partially privatized. Although the state maintains control of voting shares, the majority of the company's capital is now in private hands.

The institutional autonomy and accountability of Petrobras contributed to a dramatic increase in its levels of investment and production, directly, in joint ventures with international oil companies, and through project finance mechanisms. Petrobras's investment exceeded US$46 billion in 1992–2002. The country has also held five auctions of oil areas for private investment.[59]

58. The oil sector reforms were part of the market-oriented reforms of the Menem administration. The tax and contractual regime for private investment in oil became the most liberal in the region, and domestic oil product prices were deregulated. YPF, the deficit-ridden national oil company, was privatized in 1993. YPF was highly inefficient and not a net exporter, unlike PEMEX and Petroecuador, which made it a propitious target for privatization. The Spanish company Repsol eventually obtained majority control of YPF. After the 2002 crisis, the Brazilian oil company, Petrobras, bought Perez Companc, a private Argentine oil company.

59. The country has been less successful in attracting interest in the recent auctions than in the projects in partnership with Petrobras.

As a result, Brazil has significantly reduced its dependence on foreign oil and gas, and it has become nearly self-sufficient.

The reform of Petrobras and the Brazilian oil sector contrasts sharply with the lack of reform in PEMEX and Petroecuador and the politicization of PDVSA, the net oil exporters that rival the Brazilian oil company. The fact that Brazil and Petrobras are net importers has provided incentives to increase oil investments in order to reduce import dependency and to maintain domestic prices closer to international prices (compared with the net exporters in the region). The recent large discoveries of offshore oil reserves promise to make Brazil a net exporter in the future, possibly changing the political economy of the sector.

Bolivia

Bolivia represents the prototypical case of a country that has succeeded in attracting investments and increasing production and reserves of natural gas, under a nonprogressive tax framework designed in a period of low commodity prices. As a result, the government had powerful incentives for contract renegotiation and nationalization after the international price of gas rose and large investments in gas infrastructure were sunk.

Bolivia has no relevant oil reserves and a very small oil production. In the last decade, however, it became the largest net exporter of natural gas, with the second-largest proven reserves in the region. In 1996–97 the government implemented an innovative process for privatizing the national oil company, YPFB, in which it capitalized the country's pension funds and attracted private international oil companies into natural gas exploration and production by making the tax and contractual framework more attractive. As a result, Bolivia was extremely successful in increasing foreign investment, production, exports, and reserves in the natural gas sector. Foreign direct investment (FDI) in hydrocarbons reached US$2.5 billion in 1993–2002, representing 40 percent of total FDI in the country.[60] Proven natural gas reserves increased sevenfold and net exports fourfold.

The source of the Bolivian government's take changed in 1999. Before the country began exporting natural gas to Brazil, a large proportion of the government's take originated in the domestic market. As a result, local political pressures imposed little adjustment on the dollar value of domestic taxes. Nevertheless, most revenues have come from gas exports since 1999.

60. Campodónico (2004).

The Bolivian system had some provisions that reduced its progressiveness. For example, windfall taxes were set at the dividend level, so firms generally chose to borrow from their parent companies, and revenues were sent back through that channel. The system also had provisions that allowed for the recovery of capital expenditures. Consequently, when prices rose, firms deducted these expenditures in their tax returns.

The recent increase in international prices and the existence of high sunk investments provided incentives and opportunities, first for a significant increase in the government's take, and later for the outright nationalization of the natural gas industry. The royalty was increased from 18 to 50 percent, and the government gained majority control of all oil and gas projects. Again, as in the case of Argentina, Ecuador, and Venezuela, foreign investors have been the victims of their own success by generating an increasing stream of export revenues that in the short term is not affected by an increase in government revenue extraction.

Peru

Peru has significantly increased its oil investment in the last decade, but it has had little success in expanding oil production, furthering its status as a net importer. Of all the oil-producing countries in the region, Peru has gone the farthest in privatization and liberalization. It has also been one of the countries, along with Brazil and Colombia, that has done the most to increase regulatory credibility by establishing contracts with stable tax conditions. However, the discovery of the large Camisea natural gas field has opened new prospects for potential exports. As a result, there have been recent announcements of increasing the government's take on this project.

Are the Case Studies Consistent with the Theory?

In this section, we briefly compare the different cases presented above in light of the theoretical framework described earlier in the paper. All the cases display issues regarding taxation and the political economy of the sector. As we pointed out in the introduction, we do not attempt to propose an optimal tax and contractual framework. In fact, one of the main findings of the paper is that the countries have particular issues that require frameworks with different characteristics.

The case of Venezuela combines both issues: the political economy problems of the sector and the taxation issues. With regard to the latter, tax breaks were given precisely to the areas where the dead weight losses were lowest, skewing the fiscal contribution toward fields with smaller rents and lower fiscal contribution. Additionally, the system was not progressive. Once oil prices increased, the marginal tax rate was equal to or lower than the average rate, and there were limited contractual provisions for increasing the government's take. However, Venezuela has also had the ingredients for opportunistic expropriation. There was a national oil company that had cash flow problems as a result of government pressure to increase fiscal contributions in the context of low oil prices. Regulatory changes were made to attract international oil companies to the country to develop new oil production in joint ventures with the national oil company. Once the investment was already sunk, the government forced the renegotiation of the contracts to increase the government's take. It also forcefully acquired a controlling stake in the joint ventures. It is difficult to say whether a more progressive and efficient tax regime would have prevented the forced regulatory changes. It is hard to determine which factor was more important: the regressive tax system or the incentives to expropriate.

Mexico is a net exporting country that has used the national oil company as a fiscal, financial, and political tool. The government has not had enough incentives to change the regulatory framework before a major crisis hits the country, such as an external shock or the prospect of the country's becoming a net importer. The latter already could be the case. Oil production is declining and consumption is growing, increasing the probability that Mexico will become a net importer. In this context, the current government has introduced legislation to allow some form of private participation in the sector.

Argentina, Bolivia, and Ecuador seem to be closer to the typical case of political expropriation cycles. The three countries had some experience producing and exporting hydrocarbons, but they lacked the resources to invest in the sector as a result of the debt crises and the structural adjustment programs. This problem was more evident in the case of Bolivia and Ecuador because both countries needed investment to develop not only reserves, but also the necessary transportation infrastructure. Consequently, important regulatory changes were made to attract international oil companies to the country, and Bolivia and Argentina fully privatized their national oil companies. Nevertheless, once the investments were made, the governments changed revenue-sharing rules and reneged on contracts—including, in the case of Argentina, contracts on the price of domestic supply. Although there were also problems in that the contracts were not progressive in Bolivia and Ecuador, it seems that the regulatory changes were mostly a result of the incentives to expropriate. Furthermore, both Argentina and Bolivia created new national oil companies.

Brazil, Colombia, and Peru are clear cases of countries that either were or are becoming net importers. These countries implemented reforms to attract international oil companies, and they privatized their national oil companies or opened the sector to private capital. In addition to improving the general credibility of property rights, the three countries established a new institutional arrangement for the sector aimed at attracting new investments. The issue of taxation has been discussed in these nations in light of the recent increase in oil prices, but it seems that the renewed importance of property rights, as well as the pressure to generate more oil production, has thus far allowed the countries to uphold stable revenue-sharing rules. The governments have only engaged in either reforms that allow for price-contingent royalties, but apply only to new projects; or voluntary renegotiations with private investors. In the case of Brazil, the new oil discoveries could represent a challenge for maintaining the credible regulatory framework, as incentives for expropriation rise in the future. Similarly, renegotiation pressures could eventually increase in the case of the Camisea natural gas field in Peru.

Concluding Remarks

This paper has discussed some of the main factors that help explain the recent wave of nationalizations and tax hikes in the Latin American hydrocarbon sector. A key force behind these trends is the distributive conflicts that arise between the governments and the producing firms. These conflicts occur, to a large extent, because the tax systems used in the region have not taken into account fundamental contingencies—in particular, price changes. As a result, the producers retain an increasing share of oil rents when oil prices rise significantly. This generates powerful incentives for governments to renegotiate, renege on contracts, or nationalize the sector.

The optimal contract properly should include price contingencies. The policymaker may consider tax and royalty rates that vary according to the price, but implementing such a scheme is not easy. On the one hand, taxes based on net revenues—like the income tax—will generate incentives to overspend or overinvest. Furthermore, an income tax could generate greater distortions than a royalty since the tax rate must be higher for an expected amount of revenue. On the other hand, taxes based on sales—like the royalty—will give incentives to shift production to other periods. There are fewer distortions, however, because royalty rates would be lower.

These incentive problems are compounded by agency problems, that is, firms not revealing their true costs and investment needs. For the fiscal system to work, the contracts should incorporate not only price contingencies, but also a tax structure customized for each field and cost regulations. These incentive problems are, to some extent, the source of the reluctance on the part of the governments in the region to implement progressive tax frameworks.[61] These requirements might imply an administrative capacity that most of the countries in the region lack. Simpler systems, such as those based on a royalty, are thus preferred for implementation reasons, even though they increase the probability of future renegotiation.

An alternative to the agency problem is for the state to control all or a significant part of the country's oil production. However, the sector requires significant resources that may not be available in a context of fiscal imbalances. At the same time, the traditional agency problems may arise between the state and the bureaucracy in charge of managing the national oil company. Moreover, state-owned enterprises have typically been easy targets for quasi-rent expropriation, via regulatory and tax appropriation, prices set below opportunity cost in the domestic markets, and the clientelistic political use of overpaid and oversized bureaucracies.

Another issue with implications for both national and international oil companies is the problem of credible commitment in the face of powerful incentives for ex post renegotiation, particularly in net exporters in which large investments have been sunk. Even if the tax structures are progressive and fully capture the rents, the quasi-rents could be a tempting expropriation target. As a result, the credibility of the institutional framework is crucial for developing the potential of the oil sector.

To gain credibility, some countries have used external enforcement mechanisms such as international arbitration, bilateral investment treaties, and multilateral agency enforcement, to guarantee the stability of tax rules. These credibility devices have often been ineffective at deterring renegotiation at high prices. When they are effective, they may limit the adaptability to price contingencies if combined with nonprogressive taxes.

61. The lack of a progressive tax system also has potential disadvantages from the perspective of the oil companies, because it provides incentives for governmental renegotiation and makes contracts obsolete and because contracts signed under high price levels become uneconomical when the price falls. Companies might be willing to continue operating, however, because of the high sunk costs. Nevertheless, some company executives prefer nonprogressive tax systems signed at low prices because they can make handsome profits before contracts are renegotiated.

To provide credible commitment, some adaptability in the fiscal conditions, and a level playing field between national and international oil companies, some countries, like Brazil and Colombia, have created autonomous regulatory agencies to oversee the oil industry. This solution requires a relatively stable and credible set of political institutions to support it. Otherwise, all the restraints against expropriation can easily be removed, as occurred in Bolivia, Ecuador, and Venezuela.

Comment

Federico Sturzenegger: With the price of oil exceeding US$100 a barrel through much of 2008, the issue of taxation of oil production has become particularly sensitive, as oil-exporting countries debate how to react to the price increases while oil importers assess how to cope with the large swings in oil prices. This is particularly important in Latin America because the region includes a number of oil and gas producers and exporters, such as Bolivia, Ecuador, Mexico, Trinidad and Tobago, and Venezuela, as well as importers such as the Central American countries. This paper, written by two knowledgeable economists who work on energy issues, provides a discussion of the determinants behind the different forms of taxation in the region. It is a welcome effort. However, while the authors successfully map out the main issues that are relevant for the problem, they are somewhat less successful in comprehensively tying their analytical framework to actual experiences. Granted, such a comprehensive approach may, in fact, be virtually impossible given the diversity of problems that need to be solved in setting up the best tax system, but I suggest a way this could be done below.

The main problems when one thinks about oil production contracts can be summarized as follows. First, there are rents associated with the production of oil and gas, so a tax system needs to appropriate these rents without distorting productive objectives too much. Second, there is a time-inconsistency problem, because the government cannot commit not to change taxes later on. Third, there is a problem of asymmetric information between the operator and the state, which creates problems when an optimal contract is designed. Finally, there is an agency problem with state production itself. The interplay of these different problems makes the writing of a successful contract very difficult. To solve the distortion problem, the best solution is to auction off the fields for an initial lump sum with no taxes thereafter, but this maximizes the expropriation risks, particularly if exploration is successful or prices increase. To reduce expropriation risks and asymmetry of information, government production would be best, but this typically creates important agency problems. In addition, governments generally bring in multinational companies because they lack the capital to pursue the investments themselves, so the problem is linked to imperfections in capital markets.

Because the optimal solution differs according to how acute each of the four problems is, countries have pursued a wide range of paths. Outcomes differ even for countries that take the same path, depending on the specific constraints faced by each country. Brazil, for example, focused its strategy on its national oil company, but the government not only allowed for partial privatization, but also forced the company to compete in the local market for new fields. This fairly reasonable institutional framework led to a successful expansion of Petrobras and of the oil sector generally. Ecuador's reliance on a national oil company led to failure, however, as the company found itself mired by governance problems and lack of funding. Argentina and Bolivia auctioned off their reserves but then decided to change taxation when prices increased, whereas Colombia kept the terms of engagement of the private sector virtually unchanged.

The description of these complexities makes this paper interesting, although the authors do not provide a synthesis of how the complexities are linked to analyzing the optimal system for each country. Should Argentina and Bolivia have taken a different path? Given that the authors have clearly identified the fundamental problems, there should be a way to construct a matrix in which institutions, agency problems, management effectiveness, field characteristics (in terms of the steepness of the cost function), and the uncertainty of oil prospects can be integrated to suggest the right framework given these considerations. Then, once the mapping has been laid out, how do the data fit the model? For example, a country with credible institutions, poor government management, and certain prospects on very productive fields should go for a one-off auction of the resources, because time inconsistency or risk premiums will not be a large problem, government production is out of the question, and income taxes or royalties would be very distortionary. On the other hand, a country with high exploratory uncertainty, very productive fields, good management, and good institutions should opt for government production.

The question is whether reality fits this framework. Unfortunately, the case studies focus on a descriptive history, rather than on mapping the constraints identified by the theory into policy outcomes, thus leaving the reader uncertain as to how to tie the conceptual framework to the data. For example, the authors point out that with royalties, the government's take falls as the oil price rises, which exacerbates the expropriation risk. Why are contracts written this way to begin with? Is it because of the other constraints?

The authors do provide some clues, however. For example, a formal model compares royalties to an income tax. The model strongly favors an income tax (leaving unexplained why royalties are so prevalent) and illustrates why the distortions are smaller in marginal fields (where the supply curve is more inelastic). This result sheds some light on why the recent price increases have led to royalty hikes in Argentina (typically with marginal fields) and in Venezuela's marginal fields, but not elsewhere. It does not explain why royalties have increased for Bolivia's giant gas fields. Once again, the devil is in the interactions between the different problems that need to be addressed.

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