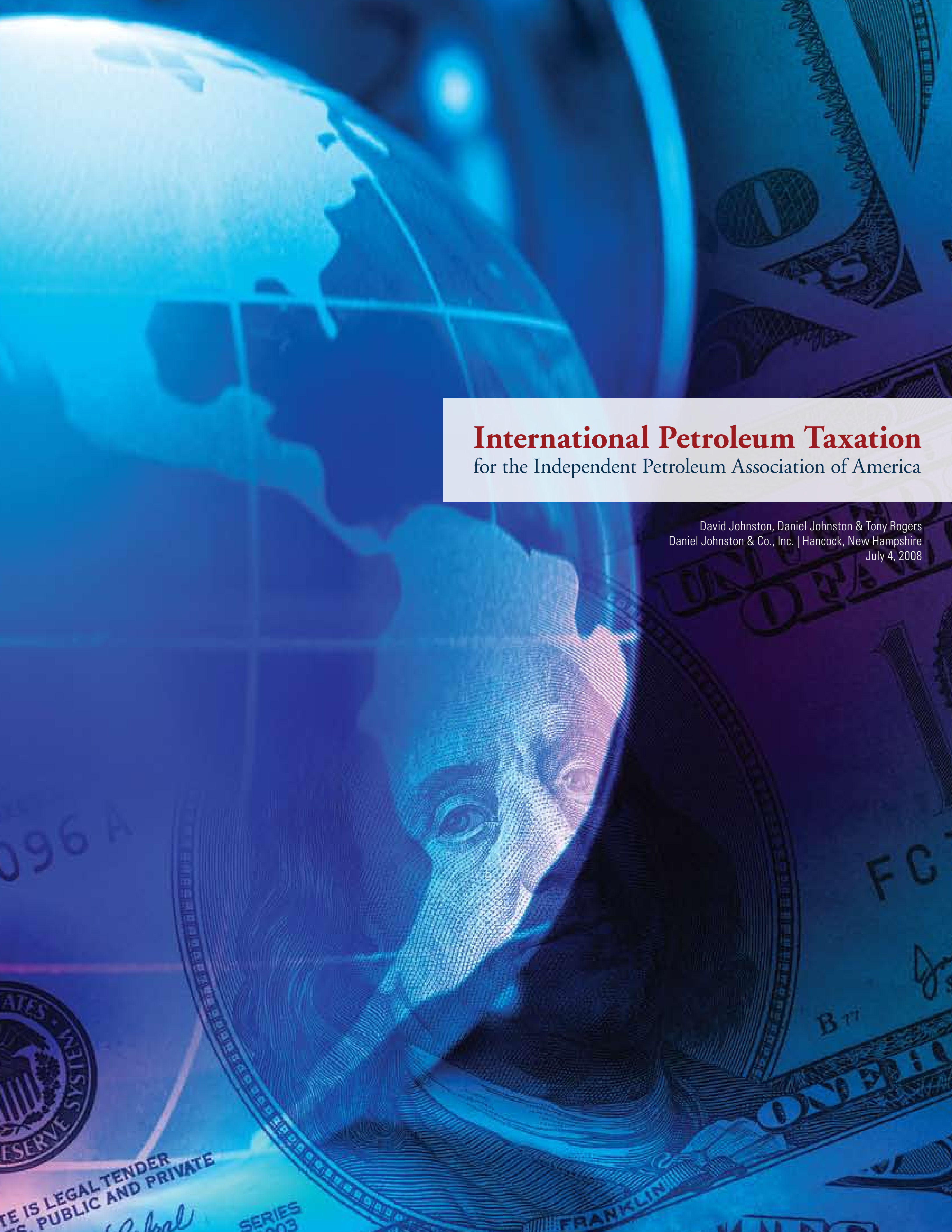

International Petroleum Taxation

for the Independent Petroleum Association of America

David Johnston, Daniel Johnston & Tony Rogers
Daniel Johnston & Co., Inc. | Hancock, New Hampshire

July 4, 2008

Thank You.

IPAA would like to extend its gratitude to David Johnston, Daniel Johnston and Tony Rogers for putting this study together. IPAA continues to supplement the *International Primer* that was released in 2002 with detailed studies of particular issues of interest. IPAA has worked with the authors to provide further substance on the chapter in the *International Primer* dealing with contracts, financial terms and taxation. Follow-up IPAA international surveys over the past few years indicated that members were particularly interested in additional details on this important area. The Committee believes that this study will support our Committee's mission of "providing educational and information services to IPAA members engaged in or interested in international business opportunities."

IPAA would also like to thank the members of the International Steering Committee for their continued dedication to the issues that have been delineated by IPAA membership. The Committee's Chairman and Vice Chair along with Steering Committee members have generously provided their valuable time for these projects, which will help with planning on upcoming events such as the NAPE® International Forum that are directed at internationally-oriented independent producers. Should you have comments or recommendations regarding future topics of interest, please do not hesitate to contact us.

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Introduction

Compared to petroleum industry in the United States, the international sector is characterized by (1) significantly greater geopotential (than the super-mature US basins), (2) various and diverse petroleum fiscal systems, and (3) diverse means by which governments allocate license rights to IOCs. The larger field-size distribution overseas is attractive but many independent oil companies are hesitant to confront strange and complex fiscal systems and governmental relationships.

Geopotential Around the World

By any measure the US basins that are open (unlike the Offshore along the East Coast, Florida and California as well as much of the Alaska Arctic) are beyond comparison with the rest of the world in terms of exploration and development maturity. This is illustrated to a certain extent with a summary/comparison of drilling density around the world as shown in Figure 1. By world standards most of the US is super-mature and field-size distributions overseas are orders-of-magnitude greater than much of what is available domestically. For example, average discovery size worldwide the past 10 years or so has been around 100 MMBOE. Test rates per well in the various international discoveries worldwide average around 4,000 to 5,000 BOPD for oil discoveries and 20-30 MMCFD for gas discoveries.[1]

Licenses are also larger overseas with average block size of around 500,000 acres. Frontier blocks are typically on the order of 3-4 million acres or more.[2] Historically there have been some very large licenses granted but generally speaking these numbers are fairly typical.

Cost of doing business is unsurprisingly higher in the international sector but with the economy-of-scale that comes with larger discoveries the cost-per-barrel is often quite attractive.

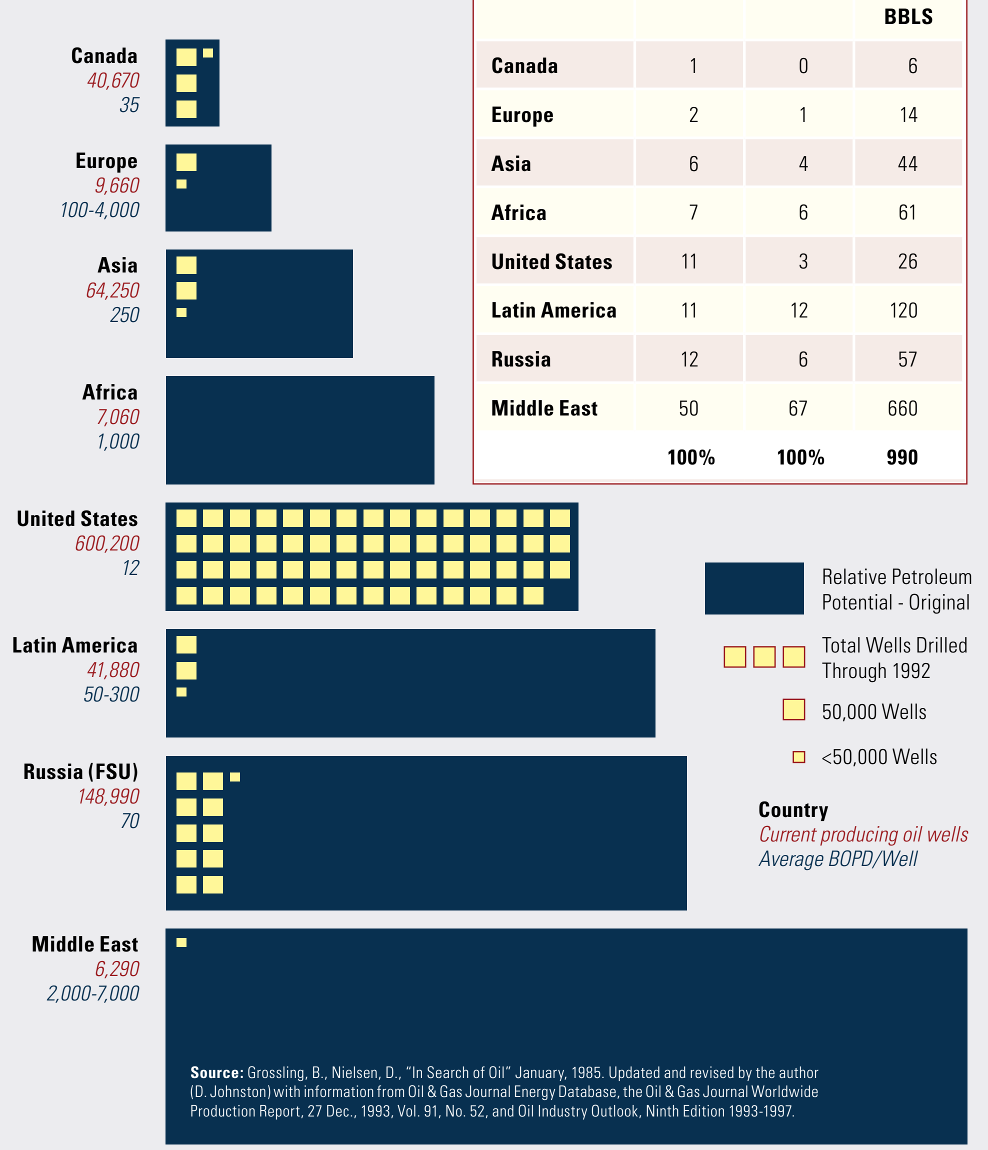
Political/commercial risks take on a new dimension overseas especially with such diverse cultural and social differences that exist. Additionally, the ubiquitous distrust of oil companies in the US is also found overseas and sometimes magnified by cultural, economic, and religious dynamics.

Petroleum Fiscal Systems Around the World

Petroleum fiscal/contractual systems or regimes around the world have for many years been classified into two main categories.

The basis of this classification is legal regarding transfer of title to hydrocarbons to the oil company. Unlike the US and Canada, the law in other countries grants the State title to all hydrocarbons or mineral rights. Within the framework of various agreements between international oil companies (IOCs) and governments IOCs can sometimes obtain title to at least a portion of the hydrocarbon production. There are two main families of agreements between governments and IOCs:

Figure 1



Recoverable Conventional Oil

Region	Original %	1992 %	(1992) Billion BBLS
Canada	1	0	6
Europe	2	1	14
Asia	6	4	44
Africa	7	6	61
United States	11	3	26
Latin America	11	12	120
Russia	12	6	57
Middle East	50	67	660
	100%	100%	990

Source: Grossling, B., Nielsen, D., "In Search of Oil" January, 1985. Updated and revised by the author (D. Johnston) with information from Oil & Gas Journal Energy Database, the Oil & Gas Journal Worldwide Production Report, 27 Dec., 1993, Vol. 91, No. 52, and Oil Industry Outlook, Ninth Edition 1993-1997.

1 Johnston D., "International Exploration Economics, Risk and Contract Analysis" PennWell Books, Tulsa, 2003

2 Johnston D., Johnston D., "International Petroleum Fiscal Systems and PSCs" Course Workbook, 2008

While these various categories reflect contracts or systems of different styles, there is often substantial variation between contracts or systems within a given category. Some systems are considered to be "hybrids" which have characteristics of more than one category. For example many PSCs (like those in Indonesia, Nigeria, Malaysia, India, China and Russia) also have royalties and/or taxes included in their standard agreements.

From a financial point of view the similarities can easily outweigh the differences between these various categories. From an economic or financial perspective the same objectives can be achieved under all systems.

Concessions or Licenses

Royalty/Tax Systems

A Concession (or License) is an agreement granting an IOC or consortium the exclusive right to explore for and produce hydrocarbons within a specific area (License Area or Block) for a given time period. In exchange for these rights the IOC may have paid a signature bonus or a license fee to the Host Government. The Host Government's compensation will typically include royalty and tax payments if hydrocarbons are produced. This type of system is used, for example, in the US, UK, France, Norway, Australia, Russia, New Zealand, Colombia, South Africa, and Argentina. Nearly half of the countries worldwide use a concessionary (or royalty/tax) system. Within this group of countries there is considerable diversity with regard to various fiscal devices, royalty and tax rates, number of layers of tax and other features such as "incentives" like investment allowances and credits.

Production Sharing Contracts

Production sharing contracts or agreements (PSCs or PSAs) give an IOC or consortium (known as the Contractor) the right to explore for and produce hydrocarbons within the Contract Area or Block for a specified time period-much the same as a R/T license. The IOC assumes all exploration risks and costs in exchange for a share of the oil and/or gas produced.

Under this type of system, as with a License, if the IOC's exploration efforts do not yield a commercial discovery, the IOC is not reimbursed by the Host Government. However, in the event of commercial discovery, production is split between the parties according to formulas in the PSC that are either statutory (fixed), negotiated, or secured through competitive bidding.

Unlike a License, the Host Government typically receives a large share of oil and/or gas, which can be commercialized and monetized according to the Host Government's development programs and economic needs. These agreements were introduced in Indonesia in the mid 1960s and for many years became the fiscal-system-of-choice for many countries. They are now also used in Malaysia, India, Nigeria, Angola, Trinidad, the Central Asian Republics (of the FSU), Algeria, Egypt, Yemen, Syria, Mongolia, China, and many other countries. Slightly over half of the governments with hydrocarbon production worldwide use PSCs.

Risk Service Contracts

A Risk Service Contract is a type of agreement whereby an IOC performs exploration and/or production services for the Host Government within a specified area for a fee. At all times the Host Government maintains ownership of the hydrocarbons produced and usually the IOC (Contractor) does not acquire any rights to oil and or gas, except where a Contractor is paid its fee in kind (oil and or gas) or is given a preferential right to purchase production from the Host Government. Pure service agreements are rare between an IOC and a foreign government but some do exist like the Iranian buy-backs, which are very similar to an engineering procurement and construction (EPC) contract. Other countries that use service agreements include Saudi Arabia, Philippines, and Kuwait. True pure service agreements are like those between a service company (Schlumberger or Halliburton) and an IOC.

Evolution and Development of the Indonesian PSCs and RSAs

Indonesia holds a special place in the industry when it comes to international petroleum exploration and fiscal design. In the 1960s and 1970s, Indonesia was at the center of the international exploration industry. At that time there were many fewer countries granting exploration rights to foreign companies than there are now. Back then, Southeast Asia was one of the most active and established regions in the international oil patch. Indonesia represented nearly half of that activity in terms of drilling activity, contracts signed, and production. Almost anyone involved in international exploration in the 1970s and early 1980s had some experience with Indonesia and the Indonesian-type contracts.

The early Indonesian PSCs were relatively simple. The contractor could recover costs out of gross production (usually with some limit known as a cost recovery limit). This was called "cost oil." After cost recovery and remaining oil (known then as "equity oil" now called "profit oil") was "shared" between the State and the contractor. Unrecovered costs would be carried forward and recovered in later periods depending on production rates and prices. Many countries followed Indonesia's lead but modified their systems to include royalties and income taxes to be paid directly. Later Indonesia also modified their system to include taxes paid directly by the Contractor.

Comparative Analysis

Service Agreements - R/T Systems - PSCs

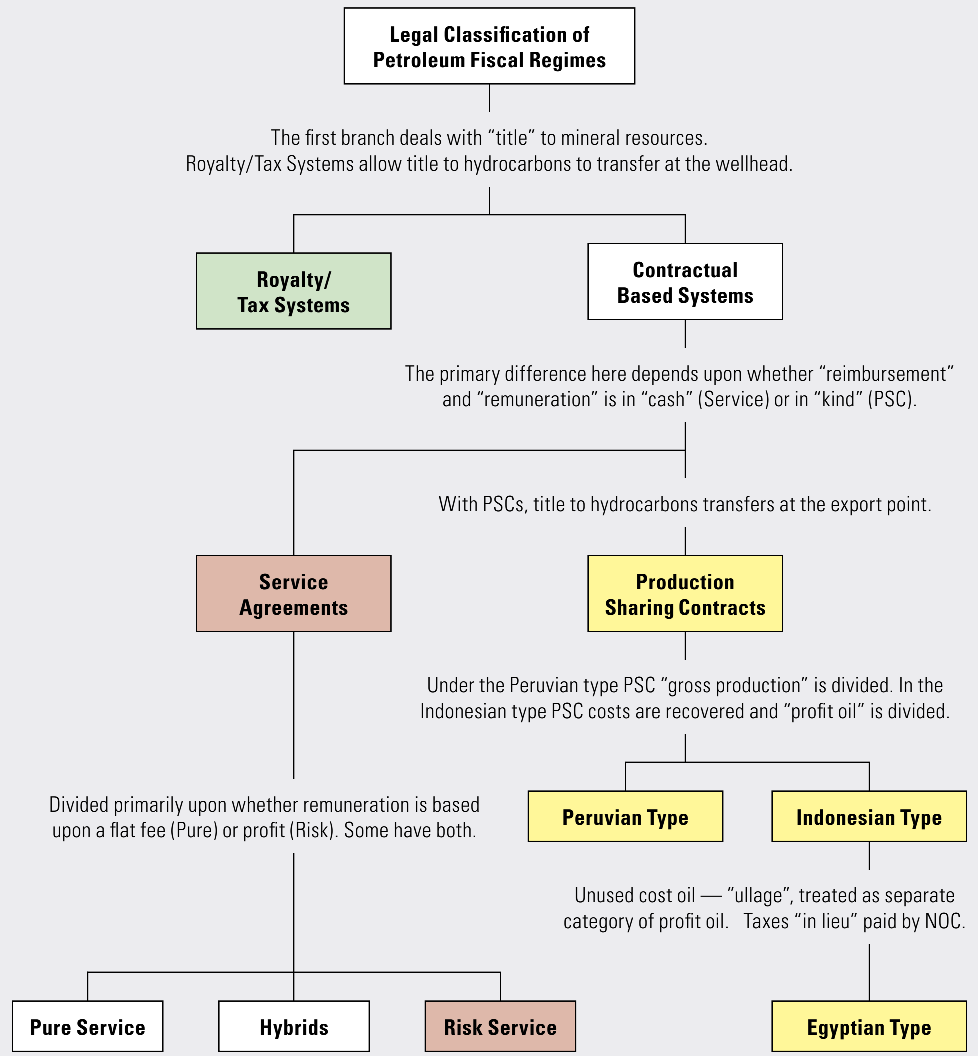
From a mechanical point of view there are practically no differences between the various systems. The hierarchy of arithmetic such as (1) generation of production and revenue followed by (2) royalty or royalty equivalent elements, followed by (3) cost recovery, tax deductions or reimbursement, etc. and (4) profits-based mechanisms such as profit-oil sharing and/or taxes are for all practical purposes found in almost all systems.

The distinguishing characteristic of

each is where, when and if ownership of the hydrocarbons transfers to the oil company. Numerous variations and twists are found under both the royalty/tax (concessionary) systems and the contractual-based themes (PSCs and RSAs). The taxonomy of petroleum fiscal systems is outlined in Figure 2.

Figure 2

The legal classification of petroleum fiscal regimes is the most common. However, legal aspects are secondary to a nation's philosophical attitude toward their mineral resources.



Source: Johnston, D., "International Exploration Economics, Risk, and Contract Analysis" PennWell Books, 2003 pg 10.

Key Differences

Transfer of Title of Hydrocarbons

- With Royalty/Tax systems title transfers at the wellhead the IOC takes title to gross production less royalty oil
- With PSCs title transfers at the export point or "fiscalization point" the IOC takes title to cost oil and profit oil
- With Service Agreements title does not transfer

The philosophical differences between the two main families (PSCs and R/Ts) are evident in the contract language and management structure found. With PSCs and RSAs the term "contractor" is used to represent the IOC or consortium of IOCs. The term is used in the same context as the terms "tenant" or "sharecropper".

There Are Numerous Similarities

While the differences between the various fiscal/contractual arrangements are extremely important, they become even more important when considering what constitutes a modern petroleum agreement between an IOC and a host government. For all practical purposes it does not matter whether the agreement is a PSC, RSA or R/T system. As a practical business matter the following issues must be addressed either in the agreement itself or in the petroleum and/or tax laws and regulations of the country.

Provisions Common to All Systems (in one fashion or another)

- Initial License Area and Relinquishment Provisions
- Minimum Work Program and Expenditure Obligations
- Term, Termination, and Force Majeure
- Currency Exchange Controls and Repatriation of Proceeds
- Investing Entity and Parent Company Guarantees
- Fiscal Incentives and Disincentives
- Health, Safety and Environment
- Stability and Legal Status of the Agreement
- Applicable Law and Forum
- Rules and Procedure regarding Establishment of Commerciality
- Allocation of Production
- Measurement and Valuation of Hydrocarbons
- Non-Arms-length Sales
- Considerations for Natural Gas
- Communications and Language
- Reports and Studies
- Use of Infrastructure
- Training and Transfer of Technology
- Importation and Immigration Considerations
- Confidentiality
- Assignment of Interests
- Abandonment/Site Restoration Provisions and Procedures
- Control of Operations

- Hydrocarbons Ownership and Ownership Transfer
- Ownership of Assets
- Dispute Resolution Mechanisms
- Export and Sale of Production

When it comes to treatment of these various elements, each of the various approaches can be similar although many differences exist. There is no reason why there would necessarily be a big difference.

Accounting Aspects

Basic accounting principles are virtually universal across the full range of petroleum fiscal systems. Almost all systems have at least one "profits-based" mechanism which could include such things as profit oil sharing as well as special petroleum taxes and/or corporate income taxes. Profit-based mechanisms like these require measurement and accounting for both revenues and/or production as well as the costs associated with exploration, development, and operations.

The budget process, procurement practices and regulations, authorization-for-expenditures, reporting requirements, auditing, and the approvals process can be similar from one system to another. Also, while there are numerous conventions for capitalizing costs (amortization and/or depreciation) such as straight-line, unit-of-production, and declining-balance, for example, these are found in many systems.

Division of Revenues and Profits

The division of profits is a key aspect of any contract. This is determined prior to contract signing like so many elements either through (1) competitive bidding, (2) negotiations, or (3) through statutes (by law i.e. "fixed terms"). In fact, it is usually the first thing agreed upon. While much of the discussion of the division of profits focuses on "economic" profits (gross revenues less costs associated with obtaining those revenues), timing is everything.

There are four main means by which governments get a piece of the pie ("take") or as it is also commonly called "rent":

1. Signature Bonuses
2. Royalties
3. Profits-based elements (profit oil split and/or taxes)
4. Government Participation

The general view is that unless a government is desperately in need of upfront cash it is better off in the long run obtaining its share of production or revenues (or rent) with back-end-loaded elements like profit oil, taxes or government participation. While the more regressive elements (bonuses and royalties) will ensure that some of the government's take comes sooner (rather than later) the government is likely to end up with less if the system is too heavily front-end-loaded (i.e. regressive).

Signature Bonuses

Nearly half of all countries with hydrocarbon fiscal systems use signature bonuses as part of their system. In the US, signature bonus bidding is the means by which the Federal Government allocates licenses. Signature bonuses usually contribute a small part of the overall government take (or rent). For example, in the cash flow model in Table 2 a $40 million bonus would amount to just half of one percent of gross revenues.

In the following cash flow model and flow diagrams bonuses are not included. There are many other kinds of bonuses such as those triggered by a discovery, or attainment of commercial status, production startup, commissioning of facilities or achievement of certain production thresholds such as accumulated production or specified production rates. These other bonuses are also usually relatively insignificant but unlike a signature bonus which constitutes part of the "risk capital" the other bonuses are part of the "reward side of the equation."

Signature bonuses can range from as little as $20,000 to over $1 billion. It is difficult to estimate an "average" but there are some trends. For example, where signature bonus bidding is the sole criteria for license allocation bonuses can often be quite large. When

Table 1: Fiscal System Comparison

	R/T System	PCSs	RSAs
Type of Projects	All types: Exploration, Development, EOR	All types: Exploration, Development, EOR	All types but often non-exploration
Ownership of Facilities	International Oil Company	Government NOC	Government NOC
Production Facilities Title Transfer	No transfer	"When landed" or upon commissioning	"When landed" or upon commissioning
IOC Ownership of Hydrocarbons (Lifting entitlement)	Gross production less royalty oil	Cost oil + profit oil	None may have preferential right to purchase
Repatriation of Service Company Equipment	Yes	Yes	Yes
IOC Lifting Entitlement (%)	Typically around 90%	Usually from 50-60%	None (by definition)
Hydrocarbon Title Transfer	At the wellhead	Delivery Point Fiscalization Point or Export Point	None
Financial Obligation	Contractor 100%	Contractor 100%	Contractor 100%
Government Participation	Yes | Not common	Yes | Common	Yes | Very Common
Cost Recovery Limit	No	Usually	Sometimes
Government Control	Low Typically	High	High
IOC Control	High	Low to Moderate	Low

bonuses are not the only bid parameter they are usually smaller i.e. less than $5 MM. There are many famous bonuses such as the $300 MM bonuses each for the first three ultra-deepwater licenses (Blocks 31, 32 and 33) in Angola. All other bonuses are typically contingent upon some measure of success and therefore oil companies usually only hope they will be able to pay these bonuses. Signature bonuses, because they are part of the risk capital, are not popular.

Government Participation

One unique element found outside of North America is what is known as government participation (or "government carry" or "government risk-free carry"). Nearly half of the governments worldwide use this option as part of their system. Typical government participation is where a national oil company (NOC) or the equivalent has the right and/or option to take up a working interest in a discovery if it is deemed to be commercial. It is not a popular thing with IOCs but it is a fact-of-life. In about half of these arrangements the NOC will reimburse its share of "past costs" at the point at which it "backs-in". Past costs include all costs incurred from the effective date of the agreement to the commerciality date. The other half of the countries do not reimburse past costs but they do allow these costs to be cost recovered and/or tax deducted (usually). Typically from the moment the NOC "backs-in" (at the commerciality point) it "pays-its-way" or is said to be "heads up" or "straight-up" just like any other working interest holder (except that it represents the Host Government).

Government participation is one of the more dramatic elements of a fiscal system when it comes to such issues as: (1) control and (2) technology transfer. Being a working interest partner usually means that the NOC (if that is the entity participating) has better access to data and information and the NOC personnel can attend Operating Committee Meetings and Technical Committee Meetings. It is in meetings like this where significant insight can be gained into IOC decision making as well as industry standards and practices. Also, NOC personnel can gain experience. This can be especially powerful for new governments with little experience in the oil industry.

Royalties and Profits-Based Mechanisms

The other two (of the four) main means by which governments get a piece of the pie include royalties and profits-based elements. These are the heart-and-soul of most arrangements between IOCs and host governments and constitute around 90% of the rent received by host governments around the world. The following discussion as well as flow diagrams and cash flow model illustrate where these elements fit in the typical hierarchy of operations that exist when hydrocarbons are sold, revenues are generated and the pie is divided. The following discussion, flow diagrams and cash flow model are all based on the following assumptions:

Basic Assumptions

Field Size	100 MMBBLS
Oil Price	$80/BBL
Costs[3]	20% of Gross Revenues

In order to illustrate how similar the basic systems can be, this discussion compares a PSC with an R/T system which are similar except for a few things; terminology and one mechanical aspect (the cost recovery limit).

First: Gross Revenues (or Gross Production)

Fiscal System Analysis

PSC Terminology	R/T Terminology
Royalty (10%)	Royalty (10%)
Cost Recovery Limit (60%)	No Limit to Tax Deductions
Gvt. Share of P/O (50%)	First Tax (50%)
Income Tax (30%)	Second Layer of Tax (30%)

3 This includes both capital expenditures (Capex) and operating costs (Opex) "full-cycle" i.e. over the life of the field.

Fortunately the determination of gross production is relatively easy to measure and/or monitor. Gross revenues on the other hand can be a bit more daunting if hydrocarbons are not sold in an "arms-length" transaction. In the event of non-arms-length sales many PSCs or R/T systems require an artificial measure of price based on a "basket" or "cocktail" of known "marker crudes" adjusted for crude quality.

Second: Royalty

In the language of the industry, royalties come "right off the top." Royalty determination can be a bit more complicated because often hydrocarbons are typically not sold at the wellhead. Instead they are often sold downstream from the wellhead. So many governments will allow the contractor (or IOC) to deduct transportation costs associated with getting the hydrocarbons from the point-of-valuation for royalty determination purposes (the wellhead) to the point of sale. If the government allows the full range of deductions associated with the transportation function they will consist of three basic components:

1. Capital costs associated with the transportation function (depreciated)
2. Operating costs
3. Cost of capital

Note: Neither the flow diagram nor the economic model have assumed any "netbacking" or deductions for royalty determination purposes.

Third: Cost Recovery and/or Deductions

After royalty payments the IOC is allowed to "recover costs" or take tax deductions. These costs consist of two components:

1. Capital costs (depreciated)
2. Operating costs

It is typically this aspect of a petroleum agreement that will undergo scrutiny by government auditors to ensure that only legitimate costs are included. Almost all systems have specific costs that will not

Table 2: "Typical Fiscal System" | Cash Flow Projection | $80.00/BBL | 100 MMBBL Field

Year	Annual Oil Production (MBBLS)	Oil Price ($/BBL)	Gross Revenues ($M)	Royalty 10% ($M)	Net Revenue ($M)	Capital Costs ($M)	Opex ($M)	Deprec-iation ($M)	C/R C/F ($M)	Cost Recovery ($M)
	A	B	C	D	E	F	G	H	I	J
1	-	$80.00	-	-	-	50,000	-	-	-	-
2	-	$80.00	-	-	-	175,000	-	-	-	-
3	-	$80.00	-	-	-	275,000	-	-	-	-
4	1,172	$80.00	93,760	9,376	84,384	200,000	33,457	140,000	-	56,256
5	11,750	$80.00	940,000	94,000	846,000	125,000	64,663	165,000	677,201	564,000
6	10,693	$80.00	855,440	85,544	769,896	-	61,544	165,000	302,864	364,408
7	9,730	$80.00	778,400	77,840	700,560	-	58,704	165,000	-	58,704
8	8,854	$80.00	708,320	70,832	637,488	-	56,119	165,000	-	56,119
9	8,058	$80.00	644,640	64,464	580,176	-	53,771	25,000	-	53,771
10	7,332	$80.00	586,560	58,656	527,904	-	51,629	-	-	51,629
11	6,672	$80.00	533,760	53,376	480,384	-	49,682	-	-	49,682
12	6,072	$80.00	485,760	48,576	437,184	-	47,912	-	-	47,912
13	5,525	$80.00	442,000	44,200	397,800	-	46,299	-	-	46,299
14	5,028	$80.00	402,240	40,224	362,016	-	44,833	-	-	44,833
15	4,576	$80.00	366,080	36,608	329,472	-	43,499	-	-	43,499
16	4,164	$80.00	333,120	33,312	299,808	-	42,284	-	-	42,284
17	3,789	$80.00	303,120	30,312	272,808	-	41,178	-	-	41,178
18	3,447	$80.00	275,760	27,576	248,184	-	40,169	-	-	40,169
19	3,138	$80.00	251,040	25,104	225,936	-	39,257	-	-	39,257
	100,000		**8,000,000**	**800,000**	**7,200,000**	**825,000**	**775,000**	**825,000**		**1,600,000**

be allowed for cost recovery or allowed as deductions.

In this example it is assumed that costs as a percentage of gross revenues are 20%. A relatively typical percentage for projects during the 1980s and 1990s worldwide was from 30 to 40%. For example with an oil price of $20.00/BBL 30% comes to $6.00/BBL which would likely consist of capital costs on the order of $3.00/BBL and operating costs of around $3.00/BBL. For most conventional developments during these decades operating costs and capital costs were often about equal (full cycle). Now with higher oil prices, costs have increased significantly. Assuming that costs are equal to 20% of gross revenues with $80/BBL crude (in these examples) equates to roughly $8.00/BBL each for Capex and Opex ($16.00/BBL total).

The contractor under a PSC would be reimbursed at this stage (after royalty) with oil called "cost oil". The contractor would expect to receive cost oil during the life of the contract. During the early years of production capital costs would represent most of the cost oil. Operating costs would be recovered throughout the life of the contract. The same is true of a R/T system but instead of cost recovery or cost oil it would be called deductions.

The one truly significant difference between R/T systems and PSCs (mechanically speaking) is that PSCs typically have a cost recovery limit (also called cost recovery ceiling, cost stop, capped cost recovery rate, and cost cap). In the example PSC cost recovery is limited to 60% of gross revenues (i.e. a cost recovery limit of 60%). If operating costs, and depreciation amount to more than this in any given accounting period, the balance is carried forward and recovered later just like a tax loss carry-forward (TLCF). It simply means there is a limit to the amount of deductions that can be taken in any given accounting period for the purpose of determining the profit oil split. PSCs typically allow virtually unlimited carry forward (C/F). From a mechanical point of view, the cost recovery limit is the only

Yr	Total Profit Oil ($M)	Gvt. Share 50% ($M)	IOC Share 50% ($M)	Tax Loss C/F ($M)	Taxable Income ($M)	Income Tax 30% ($M)	Contractor Cash Flow ($M)		Government Cash Flow ($M)	
							Un-discounted	12.5% DCF	Un-discounted	12.5% DCF
	K	L	M	O	P	Q	R	S	T	U
1	-	-	-	-	-	-	(50,000)	(47,140)	-	-
2	-	-	-	-	-	-	(175,000)	(146,659)	-	-
3	-	-	-	-	-	-	(275,000)	(204,857)	-	-
4	28,128	14,064	14,064	-	(103,137)	-	(163,137)	(108,024)	23,440	15,521
5	282,000	141,000	141,000	103,137	372,200	111,660	403,677	237,601	346,660	204,041
6	405,488	202,744	202,744	-	340,608	102,182	403,425	211,069	390,470	204,291
7	641,857	320,928	320,928	-	155,928	46,778	274,150	127,496	445,547	207,206
8	581,369	290,684	290,684	-	125,684	37,705	252,979	104,578	399,222	165,033
9	526,405	263,202	263,202	-	238,202	71,461	191,742	70,456	399,127	146,661
10	476,275	238,137	238,137	-	238,137	71,441	166,696	54,447	368,234	120,275
11	430,702	215,351	215,351	-	215,351	64,605	150,746	43,767	333,332	96,778
12	389,272	194,636	194,636	-	194,636	58,391	136,245	35,161	301,603	77,836
13	351,501	175,751	175,751	-	175,751	52,725	123,025	28,222	272,676	62,552
14	317,183	158,592	158,592	-	158,592	47,578	111,014	22,637	246,393	50,242
15	285,973	142,986	142,986	-	142,986	42,896	100,090	18,142	222,490	40,327
16	257,524	128,762	128,762	-	128,762	38,629	90,133	14,522	200,703	32,336
17	231,630	115,815	115,815	-	115,815	34,745	81,071	11,610	180,872	25,903
18	208,015	104,008	104,008	-	104,008	31,202	72,805	9,268	162,786	20,723
19	**186,679**	**93,339**	**93,339**	**-**	**93,339**	**28,002**	**65,338**	**7,393**	**146,445**	**16,571**
	5,600,000	**2,800,000**	**2,800,000**	**103,137**	**2,696,863**	**840,000**	**1,960,000**	**489,690**	**4,440,000**	**1,486,296**

difference between R/T systems and PSCs.

Note: Many PSCs (nearly half) do not require depreciation for cost recovery purposes. The other half of the world's PSCs do require depreciation. However, almost all PSCs require depreciation for tax calculation purposes.

Fourth: Profit Oil Split or First Layer of Tax

Revenues remaining after royalty and cost recovery are referred to as profit oil or profit gas. The analog in a concessionary system would be taxable income.

In this example, the contractor's share of profit oil is 50%. This could easily be a service agreement where the contractor would receive a 50% share of revenues at this stage. Like cost oil, profit oil is denominated in terms of "barrels" and will thus constitute part of each party's "entitlement". The contractor's entitlement will typically consist of two components: cost oil and profit oil. The government's entitlement will consist of royalty oil and profit oil. Taxes typically do not affect lifting entitlement as they are not based on barrels - they are paid in cash.

Usually it is this aspect of a system that is governed by a sliding scale such as production-based sliding scales

A) Production Profile Thousands (M) barrels/year
B) Crude Price ($/BBL)
C) Gross Revenues Thousands of dollars ($M)
D) Royalty 10% = (C * .10)
E) Net Revenues = (C – D)
F) Capital Costs
G) Operating Costs (Expensed)
H) Depreciation of Capital Costs (5-year SLD)
I) Cost Recovery C/F (if G + H + I > 60% of C)
J) Cost Recovery = (G + H + I) up to 60% of C
K) Total Profit Oil = (C – D – J)
L) Government Share P/O 50% = (K * .50)
M) Contractor Share P/O 50% = (K – L)
O) TLCF (See Column P)
P) Taxable Income = (C – D – G – H – L – O)
Q) Income Tax (30%) = [if P > 0, P * .30]
R) Company Cash Flow = (E – F – G – L – Q)
T) Government Cash Flow = (D + L + Q)

- Based upon average daily rates of production
- Based upon accumulated production
- Payout-based sliding scales "R factors"
- Internal-rate-of-return (ROR)-based sliding scales

These sliding scales are designed to provide the host government a greater share of profits for larger and/or more profitable fields. The example systems used in this paper do not include a sliding scale. Approximately 80% of the systems worldwide have some form of sliding scale governing the profits-based rent extraction mechanisms such as profit oil split or special petroleum taxes.

Fifth: Corporate Income Taxes

The tax rate of 30% in the flow diagram appears to apply to the profit oil. It is acceptable to do this when thinking in terms of "full-cycle" economics. On average over the life of a field the accounting profits subject to ordinary taxes will be equal to the company share of profit oil. However, the profit oil ordinarily does not constitute the tax base unless it is defined as with the Russian PSCs. In any given accounting period, a company will receive a share of profit oil if there is a cost recovery limit but the company may not necessarily be in a tax paying position. This is important when considering the royalty effect of the cost recovery limit. (Discussed later under "Effective Royalty Rate").

There are quite a few PSCs that have the taxes paid for and on behalf of the contractor out of the national oil company's share of profit oil. These are known as "taxes in lieu". The Egyptian-type PSCs as well as the Philippine RSAs are characterized by this. Some analysts believe that having taxes in lieu provides for a more stable agreement because if taxes change it only affects the NOC.

Table 3: Division of Revenues/Production Accounting Hierarchy (Full-cycle)

		PSC Terminology	R/T Terminology
A	100%	Gross Production	Gross Production
B	-10	Royalty (10%)	Royalty (10%)
C	90	Net Production	Net Revenues
D	-20	Cost Recovery[4]	Tax Deductions
E	70	Profit Oil (P/O)	Taxable Income
F	-35	Gvt. Share of P/O (50%)	1st Tax (50%)
G	35	IOC Share of P/O (50%)	After-tax Income
H	-10.5	Income Tax (30%)	2nd Layer of Tax (30%)
J	24.5	Contractor (IOC) Cash Flow	Company (IOC) Cash Flow
		Government Take [(B+F+H)/(A-D)]	
		Company Take [J/(A-D)]	
	80%	**Total Cash Flow (A-D)** (shared 70.4/30.6% between Gvt. and IOC)	

4 It is assumed that costs (Capex and Opex "full cycle") equal 20% of Gross Production or Gross Revenues.

Contractor and Government Cash Flow

Almost all fiscal arrangements (R/T, PSC or RSA) allow the IOC a means of recovering costs (reimbursement) and receiving a share of profits (remuneration). In the examples used here the expected capital and operating costs (20% of gross revenues or production) are recovered by the contractor as revenue is generated. In addition, the contractor would receive remuneration in the form of after-tax profit oil amounting to 24.5% of revenues (or production). Total cash flow generated by the entire project comes to 80% of gross revenues (gross revenues less costs-100% - 20%).

For comparison, the flow diagram below (Table 3) also shows the distribution of production and/or revenues over the life of the project or license. It also depicts the 100 MMBBL scenario found in the "Typical PSC" cash flow in Table 2. It honors the accounting operations (arithmetic) that would be expected in any given accounting period yet this is an analysis of the distribution of all revenues i.e. "full cycle". The flow diagram treats all production or revenues as if they were all generated in a single accounting period. This kind of analysis is a bit abstract but for analytical purposes it is useful. Every number on a flow diagram like that found in Table 3 can represent numbers found in a detailed economic model like Table 2.

In the flow diagram and in the economic model, costs as a percentage (%) of gross revenues equals 20%. The diagram honors the hierarchy of arithmetic or distribution of production/funds that would be expected in any given accounting period. Each step in the process is discussed below.

Government Take

The division of profits is one of the most important and central aspects of any agreement. This may be particularly true of the capital-intensive petroleum exploration business.

Both the Table 2 economic model as well as the back-of-the-envelope example in Table 3 the total economic profits or cash flow (which some refer to as "rent") amount to 80% of production (or revenues) (100% revenues - 20% costs). The contractor share of economic profits amounts to 24.5% of revenues. Contractor take is 30.6% (24.5%/80%). In addition to recovering its costs, the company receives another 24.5% of gross revenues. Therefore, the contractor's share of gross revenues (or production) is equal to 44.5% (20% + 24.5%).

Government take is 69.4% [(10% + 35% + 10.5)/80%]. The Table 3 summary essentially represents full-cycle economics but also honors the hierarchy of accounting operations that would be expected in a single accounting period. Even though none of the rent extraction mechanisms (royalty, profit oil split and tax) are actually based on true economic profits, the government take statistic represents the effective tax rate of this system-as if it had a single levy based on true economic profits. This then provides the best means of comparing one system with another and the government take statistics are widely used for this purpose. However, the statistic does have weaknesses.[5] Government take can range from as low as 30% to over 90% as illustrated in Figure 3. Furthermore, the market for acreage and projects is very dynamic with considerable change

5 Johnston, D., "Government Take – Not a Perfect Statistic" Petroleum Accounting and Financial Management Journal, Summer 2002, Vol. 21, No. 2, pp. 101-108.

taking place these days (also depicted in Figure 3).

Effective Royalty Rate

While the government take statistic demonstrates "how much" the government may receive in a project, the effective royalty rate (ERR) provides insight into "how" and "when" the government receipts will be received. It is also an excellent measure of how "front-end" loaded a system is. The ERR statistic represents the minimum share of gross revenues or production a government will receive in any given accounting period for a given project and does not normally include the National Oil Company (NOC) or Oil Minister's working interest share of production although for some purposes including this aspect provides useful perspective. The ERR is an important index that adds dimension to the "take" statistics-it is an important "companion statistic".

The ERR captures the effect of royalties and/or a cost recovery limit (in combination with the profit oil split) on the distribution of revenue (or production) especially during the early years of production-the "capital cost recovery phase".

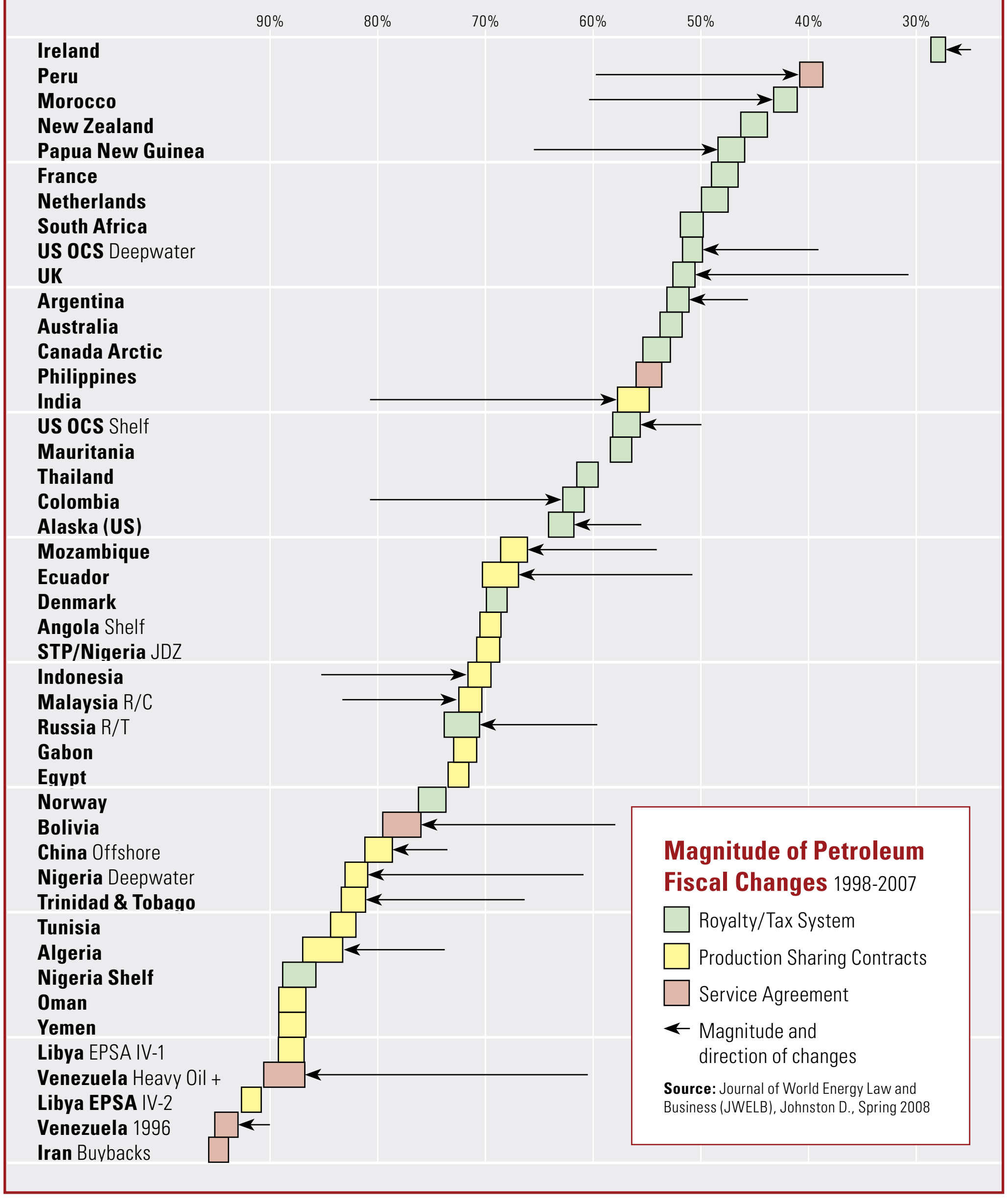
The world average guaranteed share of revenues (ERR) in any accounting period for a government is around 20%.[6] For royalty/tax systems it is less, around 10% or so and for PSCs it is closer to 30%. Some guaranteed share of revenues for the government is actually in the interest of both parties.

A government could receive nothing in a given accounting period if the contract or system has no royalty or cost recovery limit. This can happen even with profitable fields during the early years of production when substantial exploration and development costs are being recovered. This could be politically dangerous for a national oil company and if it is dangerous for the NOC it could be dangerous for the IOC-the parties can be fairly well aligned on this issue.

The complement of ERR, "access to gross revenues" (AGR), provides an important oil company perspective.

6 Johnston, D., "Index useful for evaluating petroleum fiscal systems", Oil & Gas Journal, 1 Dec., 1997. pp. 49-51.

Figure 3: Government Take for Oil



AGR is the maximum share of revenues a company or consortium can receive relative to their working interest in any given accounting period. It may be limited by government royalties, and/or cost recovery limits and profit oil split.

In a royalty/tax system without a cost recovery limit, the royalty is the only government guarantee. In that case the ERR is the royalty rate and AGR is limited only by the royalty. In most royalty/tax systems in any given accounting period there is no limit to the amount of deductions a company may take and companies can have no taxable income. However, this is also true of PSCs with direct taxes.

PSCs with a cost recovery limit guarantee the NOC a share of profit oil every accounting period because a certain percentage of production is always forced through the profit oil split. Thus both royalties and cost recovery limits guarantee the government a share of production or revenues regardless of whether or not true economic profits are generated.

ERR/AGR calculations require a simple assumption-that expenditures and/or deductions in a given accounting period (relative to gross revenues)

Table 4: Effective Royalty Rate (ERR) Calculation | Government Share of Revenues at Saturation (Single Accounting Period)

		PSC Terminology	R/T Terminology
A	100%	Gross Production	Gross Production
B	-10	Royalty (10%)	Royalty (10%)
C	90	Net Production	Net Revenues
D	-20	Cost Recovery[7]	
E	30	Profit Oil (P/O)	
F	15	Gvt. Share of P/O (50%)	
ERR		**25% (B + F)**	**10% (B)**

Table 5: Effect of Saving a Dollar
Resulting Division of Revenues (Single Accounting Period or Full Cycle)

		PSC Terminology	R/T Terminology
D	$1.00	Savings	Savings
E	$1.00	Increased P/O	More taxable income
F	-.50	Gvt. Share of P/O (50%)	First Layer of Tax (50%)
G	.50	IOC Profit Oil (P/O)	IOC After-Tax Income
H	-.15	Income Tax (30%)	Second Layer of Tax (30%)
	.35	IOC Share (D – F – H)	IOC Share (D – F – H)
	35%	**Company Savings Incentive (Index)**	
	35¢	**on the dollar saved**	

are unlimited. Therefore cost recovery is at its maximum (saturation) and deductions for tax calculation purposes yield zero taxable income. Situations like this can occur in the early stages of production, with marginal or sub-marginal fields, or at the end of the life of a field. The object of the exercise is to test the limits of the system.

In the example "Typical PSC", the government is guaranteed a minimum of 25% even though the royalty is only 10%. This is because the combination of the cost recovery limit and the profit oil split guarantees the government an additional 15%. With sufficient deductions (consistent with the key assumption underlying the ERR calculation) the company would pay no tax in that accounting period.

Keeping Costs Down

The Savings Index

Governments have a keen interest in seeing costs kept as low as possible, but so do IOCs. In this area there is clear alignment of interests, although there are varying degrees of incentive. And, it can be measured. One must simply ask:

"If costs are reduced by one dollar, who benefits and by how much?"

There are two profits-based fiscal elements in the example "Typical PSC" used here. These elements are the only ones that will affect the contractor incentive to keep costs down. If the company saves a dollar there will be one dollar less cost oil and an extra dollar of profit oil. The Government share of this extra dollar of profit oil is 50%. This leaves the company with 50% of the profit oil but with a tax rate of 30% the contractor will ultimately end up with only 35% of the savings. The savings index then is 35¢ on the dollar. This statistic represents, to a large extent, the contractor's incentive to keep costs down. Thus the IOC benefits from keeping costs down and so does the government. From a present value point of view the IOC benefit is often greater than the "undiscounted" savings index (of 35% in this case) would indicate. Any time there are profits-based mechanisms in a fiscal system there will likely be an incentive to keep costs down. This index (35¢) is fairly typical-close to world average. It constitutes mathematical proof that within a structure like this (which is so common), there is incentive to keep costs down and it is the same for either a PSC or an R/T system. It depends on the profits-based levies.

Typically, if a dollar is saved the IOC will end up with about 30-40 cents on the dollar. It may not sound like much, but it works. In Indonesia under the old standard oil PSC the contractor received only about 15 cents on a dollar saved. This is near one end of the spectrum and the other end is upwards of 69-75 cents on the dollar (UK and Ireland respectively).

The term "goldplating" often arises in the context of those countries like Indonesia where the savings index is quite low. However, true goldplating is where a company is encouraged to spend more. The more they spend the more they make. However, this kind of arrangement is extremely rare. Most systems are not that inefficient.

However, if a company receives only 15 cents on a dollar saved then the incentive to save is certainly mitigated. Why not drive a Rolls Royce for a company car if it only really costs about 15 cents on the dollar? However, the simple calculation above does not account for time-value of money. When this is taken into account an undiscounted index of say 15% may easily increase to 40% or so. Oil companies therefore have many incentives to keep costs down and this is one measure.

Lifting Entitlement

As mentioned earlier, the IOC lifting entitlement (the hydrocarbons the IOC "takes title to") often has an influence on the amount of reserves the IOC will "book". "Booking barrels" is the common term that refers to the reserves a company will report to shareholders that it has found or acquired. These "booked barrels" will then influence the IOC "finding costs" and "reserve replacement ratio" which stock analysts follow closely. It influences the IOC stock price and therefore it is very important to them. The general rule is: Companies book barrels according to their (legal) "lifting entitlement". There are however exceptions to this general rule.

The three main exceptions are: (1) Many companies book barrels under service agreements even though (by definition) they do not take title to any hydrocarbons. (2) With Egyptian-type contracts where taxes are paid "in lieu", companies "gross up" their actual entitlement and book the reserves they

7 It is assumed that costs (Capex and Opex "single accounting period") equal 200% of Gross Production or Gross Revenues. This happens in early years of production where accumulated past costs (for cost recovery or tax deductions) by-far outweigh gross revenues. Early years therefore are often characterized by large cost recovery carry-forwards and/or tax-loss-carry-forwards (TLCFs) thus no taxes in these accounting periods.

would have lifted had they paid taxes themselves. With these systems the company's taxes are paid "for and on behalf of the Contractor" out of the national oil company (NOC) share of profit oil. Thus they book more barrels than they are legally entitled to "lift". (3) In some countries the government will exercise its option to take royalty "in cash" instead of "in kind". Therefore the IOC would "lift" the government's royalty oil as well and would also likely "book" these barrels too.

The components of IOC entitlement for the example PSC and R/T system are shown in Table 6. It gets a bit abstract because the components from a cash flow model are in cash (not barrels). However, if contractor cost oil (in $) and profit oil (in $) are divided by gross revenues ($) the percentage will yield the IOC lifting entitlement as a percentage of gross production (%).

Alignment of Interests

A critical aspect of most agreements (PSCs, SAs or R/T systems) is the alignment of the various parties' interests. In most international negotiations there is considerable lack of alignment prior to contract signing. Obviously, both the IOC and the government want to get as large a share of profits as possible (within reason). Furthermore, the government would like to ensure it gets a healthy share of production (or revenues) each and every accounting period (i.e. effective royalty rate). Conversely, IOCs would like to see a low ERR. However, if the contract is efficiently and appropriately crafted there should be substantial alignment or "mutuality" of interests as soon as the contract is signed. Once a contract is signed then theoretically the issue of such things as (1) division of profits, and (2) effective royalty rate are no longer relevant because they are agreed upon. After the agreement is signed, the natural instincts of an IOC are usually well aligned with the host government.

Once a contract is signed the interests of the parties are usually fairly well aligned:

1. The IOC wants to make a significant discovery as soon as possible.
2. The IOC wants to start production quickly.
3. The IOC wants to maximize profitability.
4. The IOC wants to keep costs as low as possible (within reason). (Keeping safety and maximum efficient production rate in mind)

These issues are also important to Host Governments and NOCs.

Incremental Production Contracts (IPCs)

Most of the history of the international petroleum industry and the science of fiscal system analysis and design involve exploration agreements. However, more and more non-exploration projects are entering the international market in various forms. Incremental production contracts include enhanced oil recovery (EOR), improved oil recovery (IOR), and "rehabilitation" or redevelopment contracts. They have been around for years but not in large numbers. In 1998 China signed their first such contract with Husky Oil. At that time there were three main regions worldwide where these contracts had been used most: the former Soviet Union (FSU), Indonesia (under the JOB-type contracts), and to a lesser extent in the Eastern Block countries. However, in the future there will be more of these kind of projects. The focus of Project Kuwait (the proposed Operating Service Agreement) is for this kind of project. Typically these agreements can be quite similar to exploration agreements but often negotiations focus on existing (base or primary) production including an assumed decline rate and treatment of any production beyond the projected declining base production (called incremental production). The incremental production will likely be governed by royalties and taxes or the equivalent as discussed above.

Allocation and License Promotion

While most of the acreage in the US is allocated or awarded on the basis of bonus bidding, this is not the case in most of the rest of the world. Just as there is a wide diversity of systems that exist, the means by which governments allocate acreage (or projects) is also diverse. The two main approaches governments use are: bid rounds and negotiated terms.

Bid rounds worldwide have many similarities including the process of gazetting (officially announcing), and marketing the acreage or projects on offer. The big differences are in the bid parameters. The potential bid items are diverse and can consist of a number of elements depending on the country and the license round. The potential bid items include:

- Work program
- Signature bonus
- Royalties
- Profit oil/gas split
- Local Content (for goods and services)
- Government Participation (Carry)
- Tax Rate (rare)

By the mid to late 1990s acreage began to take on more of the characteristics of a commodity because more acreage and projects became available. Over three times as much acreage is available today as there was 25 years ago. In the past two decades the Soviet Union became the "former" Soviet Union (FSU) and

Table 6: Lifting Entitlement
Accounting Hierarchy (Full-cycle)

		PSC Terminology	R/T Terminology
A	100%	Gross Production	Gross Production
B	-10	Royalty (10%)	Royalty (10%)
C	90	Net Production	Net Revenues
D	-20	Cost Recovery[8]	
E	70	Profit Oil (P/O)	
F	- 35	Gvt. Share of P/O (50%)	
G	35	IOC Share of P/O (50%)	
H	-10.5	Income Tax (30%)	
J	24.5	Contractor (IOC) Cash Flow	
IOC Lifting Entitlement		**55% (D + G)**	**90% (A – B)**

8 It is assumed that costs (Capex and Opex "full cycle") equal 20% of Gross Production or Gross Revenues.

much of Africa and the Eastern-block Countries have opened up. With more aggressive and specific relinquishment provisions in contracts the market for acreage or projects is more dynamic and robust. Countries are competing with more than just their neighbors for capital and technology and they have become much more sophisticated and aware of what the market can bear.

Fixed or Negotiated or Bid terms

This issue is of huge concern to many governments and it affects the IOCs as well. Many governments, through legislation, will "fix" the key fiscal terms (such as royalties, profit oil share and taxes). With "fixed terms" there is no bidding or negotiation of the "terms" and the bid items or negotiable elements will include such things as work program, signature bonus, or local content either separately or in combination.

Some governments authorize their national oil company or oil minister to negotiate various elements in the system such as the profit oil split as well as bonuses and work programs and other elements. There is of course concern about the greater potential for corruption with negotiated deals relative to a transparent bid round. The problem is that some countries do not have sufficient geological potential to provide for the luxury of having a typical "bid round". There are few things more embarrassing for a Minister or NOC to hold a bid round and have nobody submit bids- a "failed license round".

There is considerable pressure these days from the World Bank, the International Monetary Fund and even Tony Blair's Extractive Industry Transparency Initiative (EITI) for oil companies and governments to be more open and disclose more information, to be more transparent and "publish what they pay". With these initiatives there is a strong push for governments to be more transparent and allocate acreage on the basis of public auctions similar to the highly publicized EPSA IV rounds in Libya in 2005-2007.

The problem is that unless the acreage is particularly interesting, the industry has been relatively unwilling to face the kind of magnified "head-on" competition that a "sealed bid" type license round (like Libya) provokes. In many circumstances it is naïve and unrealistic to expect a government to allocate acreage and projects on the basis of sealed bids. There is nothing worse than a "failed license round" for a NOC official or oil minister.

Allocating licenses through "negotiated deals" can be fair and efficient too. Government officials (Energy Ministry or NOC) become aware of what the market can bear as they entertain various proposals and offers.

Key Contract Provisions

Work Program

It is typical with agreements (R/Ts, PSCs or S/As) in the international sector that exploration rights are divided into two or three phases with separate and distinct work commitments, sometimes with bank guarantees.

The work commitment is a critical aspect of international exploration. It is usually measured in terms of (1) wells drilled and/or (2) seismic data acquired, processed and interpreted. It embodies most of the risk of petroleum exploration. The other component of the risk capital is the signature bonus. With most exploration efforts taxes are never experienced because so many wildcats are dry. There is perhaps only a 10 to 15% chance of ever getting beyond the work commitment. Negotiators focus a lot of attention on the work commitment.

Crude Pricing

One of the things that government and/or royalty owners fear most is "transfer pricing." In this context it refers to pricing of oil or gas in transactions between associated companies. This is often referred to non-arms-length sales. Almost all agreements or petroleum laws either do not allow this or they may require that the price be market-based by basing prices for oil or gas sales (for royalty and tax calculation purposes) on a quality-adjusted "basket" of crudes or "crude cocktail" of known "marker crudes" such as Brent, Urals, Minas, Fatah, Saudi Light, and West Texas Intermediate.

Royalty Determination

Just as in the United States there is diversity worldwide with respect to just how many deductions can be taken for royalty calculation purposes. The diversity ranges from situations where no deductions are allowed to full "net back" to the wellhead including deductions for (1) operating costs, (2) capital costs (depreciated), and (3) cost of capital for the transportation function from the wellhead (point of valuation) to the point of sale. These are the same basic components used for tariff determinations by regulated utilities. The wellhead price then would be the price used for royalty and tax calculation purposes.

Taxes in Lieu

Production Sharing Systems with taxes "in lieu" where taxes are paid "for and on behalf of the Contractor" out of the National Oil Company's share of profit oil are common: Egypt, Syria, Oman, Qatar, Trinidad, Philippines etc.

With taxes in lieu, companies receive a lower entitlement in these systems than they otherwise would had they paid the taxes directly (in cash). So companies are "grossing-up" the contractor share of profit oil by dividing by (1-tax rate) and they are booking this "imputed" entitlement instead of their actual entitlement.

For example, assume in Egypt the statutory tax rate is 40% but this tax is paid out of the NOCs share of profit oil (taxes in lieu). Also assume that the Contractor (actual) entitlement (of expected "proved barrels") is 20 MMBBLS cost oil and 15 MMBBLS profit oil for a total of 35 MMBBLS.

For booking purposes the Contractor would book the equivalent of 20 MMBBLs of cost oil + 25 MMBBLS "imputed" profit oil [15 MM/(1-0.4)] or a total of 45 MMBBLS.

Initially the taxes in lieu approach caused problems in the US with the tax credit system and potentially created "double taxation". This was a huge issue in Indonesia in 1976 and an IRS ruling nearly shut down exploration in Indonesia that year. To get around this Indonesia issued its then second generation PSC which required companies to pay taxes directly. Today it is not such an issue - formalities are required such as the taxes actually being paid and the contractor receiving a tax receipt from the NOC which is reported to the IRS. Problems with possible double taxation are remote these days in the US. The IRS is familiar with taxes in lieu.

Ringfencing

One aspect that American oil companies are typically not familiar with is "ringfencing". This is a cost center based fiscal (or contractual) device that forces contractors or concessionaires to restrict all cost recovery and or tax deductions associated with a given license (or sometimes a given field) to that particular cost center. Essentially if a government ringfences this means that they do not allow "consolidation" of accounts between licenses or fields (cost centers). The cost centers may be individual licenses or on a field-by-field basis.

For example, with typical ringfencing, exploration expenses in one non-producing block could not be deducted against income for tax calculation purposes in another block. Under a PSC ringfencing acts in the same way-cost incurred in one ringfenced block cannot be recovered from another block outside the ringfence. Most countries use ringfencing.

Ringfencing ordinarily refers to "space" (i.e. area and/or depth) but it can also be based on "time" and categories of costs. It can also apply to specific reservoirs or reservoir depths and exploration vs. development expenditures.

Stability Provisions

Of all the various political/country/commercial/currency/social risks that exist (there are numerous categories), one of the greatest is the risk that a government might change the rules (taxes or royalties) once a discovery is made-or worse yet-once production begins. In many Western countries it is often believed that the commercial and social risks and the ordinary inconveniences of doing business are minimal. There is mainly the risk that petroleum related fiscal changes or additions (again taxes and/or royalties) can be legislated or decreed.

In many other (non-OECD) countries not only is there the full range of risks and inconveniences, they are magnified. Of this full range, the one over which the government usually has greatest control is the risk of changing the rules. The bottom line is that while the government may not have control over many risk elements it will provide a guarantee or a measure of guarantee against this particular category of risk in order to make themselves more competitive. Therefore, many governments will provide stabilizing provisions in their agreements with IOCs. These take various forms but there are three main categories of stabilizing provisions:

- Freezing clauses
- Equilibrium clauses
- Taxes in lieu

Freezing Clauses

In many PSCs (few R/T systems) contract language will stipulate that the agreement will be governed by the laws in-place (including tax laws) at the time of the agreement - regardless of new laws or changes in the law. This approach is generally considered to be outmoded or at least "the old way."

Equilibrium Clauses

These are becoming the preferred approach and are considered to be the direction of the future. These also go by other names such as "economic equilibrium" or "intangibility clauses." Typical language of an equilibrium clause would stipulate for example that if there is "a discriminatory measure" instituted by the government that has a negative financial impact on the contractor then the profit oil split is adjusted to maintain the economic balance.

Taxes in Lieu

This approach is believed to provide a measure of stability. The general view is that if taxes go up this is already handled in the agreement that the NOC will pay taxes "for and on behalf of the contractor." Some believe that approach is superior to a freezing clause.

There is often other language and elements found in the "Definitions" in the agreements that contribute to the provisions intended to stabilize an agreement.

Dispute Resolution Provisions

There is always the potential for disagreements between parties to an agreement. In many countries the parties agree to resolve disputes through international arbitration (instead of the host country courts). Arbitration can be just as costly as ordinary litigation in the courts but usually it is not. And, with arbitration unlike typical court systems, the proceedings can be kept confidential. While there are numerous authorities and/or conventions used, the three main arbitration bodies include: UNCITRAL (United Nations Commission on International Trade Law), ICSID (International Center for Settlement of Investment Disputes), and the International Chamber of Commerce (ICC).

Table 7: Different Situations | Different Considerations

	Enhanced Oil Recovery	Development Projects	Exploration Acreage	Frontier Acreage
Degree of Risk	Low	Low	High	Highest
Block Size Acres (km2)	Field 4,000 or so (16)	Smaller 3,000 - 5,000 (12 - 20)	Large 1-2 MM+ (8,000)	Very Large 3-4 MM+ (16,000)
Work Program (s)	1) Feasibility Study 2) Pilot Program 3) Development	1) Appraisal 2) Development	Exploration Program	Exploration Program
Focus of Negotiations/ Analysis	IRR	IRR	Take	Take
Most Common Allocation Strategy	Negotiated deals	Negotiated deals	Competitive Bidding	Competitive Bidding

Appendix 1: Abbreviations and Acronyms

$	United States Dollar
$M	Thousands of Dollars
$MM	Millions of Dollars
AGR	Access to Gross Revenues (complement of ERR)
BBL	Barrel
BCF	Billion Cubic Feet (Gas)
BOPD	Barrels of Oil per day
Capex	Capital Expenditures
CIF	Cost, Insurance, Freight
Cum.	Cumulative
C/F	Carry Forward (as in CR/CF)
C/R	Cost Recovery
C/R C/F	Cost Recovery Carry Forward
DCF	Discounted Cash Flow
Dev.	Development
DDB	Double Declining Balance
DMO	Domestic Market Obligation
EITI	Extractive Industries Transparency Initiative
EOR	Enhanced Oil Recovery or EOR Contract
EPC	Engineering, Procurement, and Production
EPSA	Exploration Production Sharing Agreement
EPSA IV	Exploration Production Sharing Agreement 4th Generation (2005)
EPSA IV-1	Exploration Production Sharing Agreement 4th Generation (April, 2005)
EPSA IV-2	Exploration Production Sharing Agreement 4th Generation (October, 2005)
ERR	Effective Royalty Rate
FSU	Former Soviet Union
Gvt.	Government
G&A	General and Administrative (Costs)
IC	Investment Credit
ICC	International Chamber of Commerce
ICSID	International Center for Settlement of Investment Disputes
IDC	Intangible Drilling Cost
IOC	International Oil Company
IOR	Improved Oil Recovery
IPC	Incremental Production Contracts
IRR	Internal Rate of Return
IRS	Internal Revenue Service
JDA	Joint Development Area (same as JDZ)
JDZ	Joint Development Zone (as in between countries like the STP/Nigeria JDZ)
JOA	Joint Operating Agreement
JOB	Joint Operating Body
JOC	Joint Operating Committee
JV	Joint Venture
JWELB	Journal of World Energy Law and Business
km2	Square Kilometers
LIBOR	London Inter-bank Offered Rate
M	Thousand
MCF	Thousand Cubic Feet (Gas)
MM	Million
MMBBLS	Million Barrels
MMBOE	Million Barrels of Oil Equivalent
MMBOPD	Million Barrels of Oil per Day
MMCFD	Million Cubic Feet (of Gas) per Day
NELP	National Exploration and Licensing Policy
N/A	Not available or Not applicable
No.	Number
NOC	National Oil Company
OECD	Organization for Economic Cooperation and Development
Opex	Operating Expenditures (Operating Costs)
P/O	Profit Oil
PSA	Production Sharing Agreement (Same as PSC)
PSC	Production Sharing Contract (Same as PSA)
REDPSA	Redevelopment Production Sharing Agreement
R Factor	Ratio Factor (Ratio of cumulative receipts to cumulative expenditures)
ROR	Rate of Return (same as IRR) as in "Rate of Return Systems"
R/C	Receipts divided by Costs (From 1998+ vintage Malaysian PSAs)
RSA	Risk Service Agreement
R/T	Royalty Tax
SA	Service Agreement
SLD	Straight Line Decline (depreciation or amortization)
STP/Nigeria	Sao Tome e Principe/Nigeria
TAC	Technical Assistance Contract
TCF	Trillion Cubic Feet (Gas)
TLCF	Tax Loss Carry Forward
UNCITRAL	United Nations Commission on International Trade Law
US	United States
US OCS	United States Outer Continental Shelf
%	Percentage
¢	Cents
°	Degrees (as in Centigrade)

Appendix 2: Example Block Sizes Worldwide

Province/Block	Acres	km2
Gulf of Mexico 5,000	20	
Qatar RDPSA	24,700	100
United Kingdom	57,600	233
New Zealand (PEP 38719 – Swift 1996)	87,840	356
Norway	102,400	415
Venezuela Lasmo Dacion EOR 106,000	429	
Equatorial Guinea – grid blocks 125,000	506	
Dutch North Sea	134,000	543
Sao Tome e Principe/Nigeria JDZ (average) 230,000	931	
Venezuela – Gulf of Paria West 281,000	1,138	
Trinidad Block 27	291,000	1,178
Trinidad Block 89/3 Offshore 311,000	1,259	
Oman Conquest	343,300	1,390
MTJDA 370,500	1,500	
Venezuela – La Ceiba	430,000	1,741
Turkmenistan Negit-Dag/5 444,600	1,800	
Ecuador Block 19 (and others) 494,000	2,000	
Bulgaria 500,000	2,024	
China Bohai Bay Block 9/18 578,000	2,340	
Vietnam Block 04-2	640,000	2,591
Belize	650,000	2,631
Gabon Offshore	700,000	2,834
Nigeria OPL 214 Deepwater 748,000	3,028	
Angola Block 17	834,366	3,378
Cambodia 860,000	3,482	
China Bohai Bay Block 11/19 934,000	3,781	
Chile Onshore 1,235,000	5,000	
Angola Block 32	1,405,000	5,688
Uganda 1,450,000	5,870	
Cambodia	1,850,000	7,490
Uganda 2,200,000	8,907	
Bangladesh Average Onshore 2,220,000	8,989	
Greenland Shell 1996	2,340,000	9,474
Malaysia Block F Offshore 2,400,000	9,717	
Bangladesh Block 21 Offshore 3,076,000	12,453	
Myanmar Blocks M5 and M6 (average)	3,230,000	13,077
Pakistan – Badin Block 1977 4,416,000	17,878	
Egypt Block G Central Sinai 4,500,000	18,218	
Saudi Area A (Lukoil) 2004 7,400,000	29,960	
Saudi Area B (Sinopec) 2004 9,600,000	38,866	
New Zealand (PEP 38602 - Conoco)	12,000,000	48,583
Saudi Area C (Eni-Repsol) 2004 12,800,000	51,822	
Indonesia NorthWest Java (NWJ) 1966	14,000,000	56,680
Indonesia Southeast Sumatra (SES) 1966	32,000,000	129,554
Saudi (Total 30%, Shell 40%) Rub Al-Khali 2003	49,400,000	200,000

Appendix 3: Examples of Contract Duration Worldwide

Province/Block	Exploration Years	Production Years
Abu Dhabi	3 + 2 + 2	33
Ajman	2 + 2 + 2	35
Albania	2 + 3 + 1.5	24
Algeria	5 + 2	15 - 30
Algeria	5 + 2	20 - 25
Australia	6 + 5	42
Beliz	8	25
Benin	2 + 2 + 2	25 + 10
Bolivia		30 Max
Brunei	8	38 + 30
Brunei Offshore	17	40 + 30
Cambodia	3 + 2 + 1	22
Congo Br.	4 + 3 + 3	30
Congo Br.	10	30
Cote d'Ivoire	2 + 2 + 2	25
Czech Rep.	4 + 4	20
Dubai	3 + 2 + 3	35
Ecuador	4 + 2	22
Egypt	8	20
France	5 + 5 + 5	5 + 5 + 5
Gabon Deepwater	5 + 3	10 + 5 + 5
Gabon	3 + 2 + 2	25
Ghana	7	18 (25 Total)
Guyana	4 + 3 + 3	25 + 5
Honduras	4 + 2	20 + 5
Hungary	2 + 2 + 1	25
India	3 + 2 + 2	25 + 5
Indonesia	3	20
Liberia	3 + 3	25 + 10
Madagascar	8	15 + 5
Malaysia	3 + 2	2 + 2 Dev 15
Malaysia R/C	5	29 Total
Netherlands	10	40
Nigeria	3 + 3 + 4	20
Oman	2 + 2 + 2	20 + 10
Peru	7	30
Poland	3 + 3	20 + 5 + 5
Rep. of Guinea	5	21 (Max 25)
Senegal	3 + 2 + 2	25 + 10
South Africa	4 + 3 + 3	as long as is profitable
Syria	3 + 2 + 1	20 + 10
Vietnam	3 + 1 + 1	20 (total not to exceed 25)
Zambia	8	25
Average/Typical	3 + 2.5 + 2 (7.5)	25

Appendix 4: Example Agreements

ANGOLA

Offshore mid 1990s PSC

Area	4,000 - 5,000 km2 (1-1.2 MM acres)			
Duration	Exploration	3 years + 1 + 1 + .5 + .5 4 years + 2 for deepwater		
	Production	20 years from date of discovery		
Relinquishment	All except development areas	after 5 years onshore after 6 years deepwater		
Exploration Obligations	Conoco	1986	$60 MM	4,000 km Seismic + 6 wells
Negotiable	Total	1989	$9 MM	Seismic + 2 wells
Signature Bonus Rentals	$300/km2 for development areas			
Royalty	None			
Cost Recovery	50% limit 40% Uplift on development costs			
Depreciation	Exploration costs expensed Development costs 5 year straight line (was 4 years)			
Profit Oil Split (Typical)	MBOPD	Company		
	0 - 25	50-60%		
	25 - 50	30		
	50 - 100	20		
	> 100	10		
Taxation	In lieu - paid by Sonangol (50%) With economic equilibrium/stability clause			
Ringfencing	For cost recovery Around license for exploration Around field for development			
DMO	Pro rata option/right up to 40% of production			
Gvt. Participation	Up to 51% in early contracts (assumed here) After 1997 typically 20% "Heads up"			
Other	Price cap formula Government takes 100% above $32/BBL (1991)			

AUSTRALIA - Federal

Royalty/Tax

Area	Various sizes offshore up to 10,000 sq nautical miles - 400 graticular blocks - No limit to number of permits	
Duration	Exploration	6 + 5 (possible extension)
	Production	21 + 21 (possible extension)
Relinquishment	50% of remaining area at end of each renewal	
Exploration Obligations	Work Program bids	
Bonuses	None	
Royalty	See Resource Rent Royalty (below) A$50/block/year exploration; A$18,000/block/year production	
Taxation	36% Corporate Income Tax Since 1995 40% Petroleum Resource Rent Tax (PRRT) - project based,	

Applies on a project basis to all "Greenfields" after 6/94 offshore except Timor Gap area "A" and the NW Shelf project areas WA-1-P & WA-28-P [Does not apply onshore]

Uplift for Exploration = Long-term bond rate + 15% (23% (1998))
Uplift for Development = Long-term bond rate + 5% (13% (1998))
Previously PRRT covered only virgin offshore areas
Levied before company tax (corporate income tax) and is deductible against company tax.

Depreciation	E&D expenses; Dev 8 Yr SLD; Facilities 20% DB
Ringfencing	Offshore exploration costs deductible from PRRT company wide.
Other	15% Withholding
Gvt. Participation	None

Until 1 July, 1990 the Crude Oil Excise and Royalty Regime applied to areas other than: Greenfield Areas where the PRRT applied, and Barrow Island where a Resource Rental Royalty applied.

AZERBAIJAN

Onshore REDPSA (April, 2003 Gaffney Cline and Assoc. Report to Trade Partners UK)

Area		
Duration	Exploration	Typically 10 years
	Production	Typically 20 years
Relinquishment		
Bonuses Rentals?	Yes, various	
Royalty	Not for new PSCs (12.5% in some Contracts). Also specific rate royalties for some government operations	
Cost Recovery Limit	100% OPEX 50% CAPEX * * Limited to 50% of what is left over after OPEX recovery. Interest cost recovery at LIBOR + 1%	
Profit Oil Split	"R" Factor Based	P/O Split
	0 - 1.00	50/50%
	1.00 - 1.50	55/45%
	1.50 - 1.75	60/40%
	1.75 - 2.25	65/35%
	2.25 - 2.50	70/30%
	2.50 - 2.75	80/20%
	> 2.75	90/10%

"R" = [(Cum. Capex recovered + Interest + Cum. Profit)/Cum. Capex]

Taxation	32% General Tax Rate (creditable -- paid on behalf of contractor by SOCAR)
Depreciation	
Ringfencing	Yes
DMO	Essentially "Base Production" determined by decline curve analysis
Gvt. Participation	Yes, 10-20% SOCAR backs in when production over 4 Qts is 1.5 times greater than the year before the REDPSA was signed.

BANGLADESH

1997 PSC

Area	Designated Blocks 8 - 10,000 km2	
Duration	Exploration	3 years + 2 2-year extensions (total 7 years) +5 years for gas market development phase
	Production	20 years for Oil from date of dev. plan approval 25 years for Gas

Relinquishment	25% after 3 years and 25% after 5 years If well is drilled in first phase 1st relinquishment waived
Exploration Obligations	With seismic options first phase is 2 years not 3
Bonuses Negotiable Production Bonus	Discovery and production bonuses $100K annual training fee $50K contract service fee 5,000 BOPD - US$ 0.5 MM 10,000 BOPD - 1.0 MM 15,000 BOPD - 1.5 MM 20,000 BOPD - 2.0 MM
Royalty	None
Cost Recovery Sliding Scale:	Up to 20,000 BOPD 50% Limit 20,001 + 40% Interest cost recovery on loans up to 50% of overall project cost
Depreciation	4 Yr SLD
Profit Oil Split Negotiated - example	Production BOPD — Split % Up to 20,000 — 60/40 20,000 - 40,000 — 65/35 40,000 - 60,000 — 70/30 > 60,001 — 75/25
Taxation	In Lieu paid by Petrobangla 3¢/BBL or 4¢/MCF R&D fee from contractor profit oil or gas
DMO	25% of crude at up to 15% discount from market price
Ringfencing	Yes
Gvt. Participation	None

CHINA

Deepwater PSC - 1994/5

Duration	30 years Exploration 7 years Production 15 years + extensions with approval
Relinquishment	25% after Phase I, 25% of remaining after Phase II, Remaining at end of Phase III excluding development areas.
Exploration Obligations and Bonuses	
Royalty	Oil BOPD — Gas MMCFD Up to 20,000 0% — Up to 195 0% 20,001 - 30,000 4% — 195 - 338 1% 30,001 - 40,000 6% — 338 - 484 2% 40,001 - 60,000 8% — 484 + 3% 60,001 - 80,000 10% 80,001 + 12.5% (BOPD converted from Tons/Year at 7:1) (MMCFD converted from MM m3/year at 35.3:1)
Pseudo Royalty	5% Consolidated Industrial and Commercial Tax CICT replaced 1/1/94 with 13% VAT for Chinese companies and 5% VAT for foreign companies - but still based on Gross Revenues
Profit Oil Split (Negotiable) Example Split ("X" factor)	BOPD — Gvt/Contractor Up to 10,000 — 3/97% * 10,000 - 20,000 — 4/96% 20,000 - 40,000 — 6/94% * Some contracts start at 95% 40,000 - 60,000 — 7/93% ("X" factor) and slide to 45% 60,000 - 100,000 — 25/75% > 100,000 — 36/64%
Cost Recovery Limit	50% All costs expensed
Taxation	30% Income Tax (15% in Hainan Province) 10% Surtax Contractors must also pay vehicle and vessel usage, license tax and individual income tax.
Depreciation	6 Year SLD for Development costs, Exploration costs expensed
Ringfencing	Yes for cost recovery but not for income tax
Gvt. Participation	Up to 51% upon Commercial Discovery No repayment of past exploration costs.

COTE D'IVOIRE

27 June, 1995	Block CI-11 PSC Pluspetrol
Area	335,179 acres
Exploration Obligations	Phase I 1.5 yrs 1 well $4 MM Phase II 2 yrs 2 wells $8 MM Phase III 2 yrs 2 wells $8 MM
Appraisal Exploitation	2 years for oil discovery 4 for gas + 6 month ext. 25 years + option to extend 10 years
Relinquishment	25% of original after Phase II & Phase III
Bonuses	Signature $300K in vehicles and office equipment Production $1, 3, 5, & $10MM @ 10, 20, 30 & 50 MBOPD Gas 6:1
Royalty	None
Cost Recovery Limit	40% all costs expensed (75% of interest costs and fees are recoverable, Bonuses not cost recoverable)
Profit Oil Split	Production* MBOPD — Contractor Share — Production MMCFD (Qtr) — Contractor Share Up to 10 — 40% — Up to 75 — 40% 10 - 20 — 30 — 75 - 150 — 30 20 - 30 — 20 — Over 150 — ? Over 30 — 10 * Avg. production rate during quarter
Taxation	Paid by Nat. Oil Co. on behalf of contractor (50%)
Ringfencing	Yes
DMO	10% of Contractors crude at 75% of market price
Gvt. Participation	Around B1-8X 40% + outside special area Gvt. carried through exploration 10% + option to purchase 10%
Other G&A	75% Minimum Employment Quota: $100K/yr training > $150K/yr During expl/appraisal 4% of costs Development 3% up to $3MM: 2.5% 3-$6MM: 1.5%> $6MM

INDIA - NELP V

Deepwater licenses	
Bonuses	None
Royalty	12.5% Onshore Oil 10.0% Onshore Gas

	10.0% Offshore (Oil and Gas) 5.0% Offshore > 400 meters for first 7 years
Cost Recovery	90% All costs expensed
Profit Oil/Gas Split	Investment Multiple (Slightly similar to an "R" Factor) Cumulative Net Cash Flow/ Exploration & Development Costs

Investment Multiple	Government Share
0 to 1.5	10%
1.5 to 2.0	16
2.0 to 2.5	28
2.5 to 3.0	85
3.0 to 3.5	85
over 3.5	85

IM = Accumulated C/O + P/O - Opex - Royalty/(Expl + Dev Costs)

Taxation	35% Corporate Income Tax for Foreign Oil Companies
Depreciation	25% predominantly
Ringfencing	Yes
Gvt. Participation	0%
DMO	"None"

MALAYSIA

R/C PSC Model 1997±

Duration	29 years from effective date; Exploration 5 years Production 20 years for oil or expiry of the contract 20 years + 5 year holding period for gas
Relinquishment	No interim relinquishment
Exploration Obligations	Bid items
Bonuses	None
Royalty	10% + 0.5% Research Cess

Profit Oil Split and Cost Recovery

Contractor's R/C Ratio	**Cost Oil** (Gas Limit)	**Petronas Share Profit Oil (and Gas)** Cumulative Production Below THV: Unutilized C/O Split	Cumulative Production Below THV: Normal P/O Split	Cumulative Production Above THV: Unutilized C/O Split	Cumulative Production Above THV: Normal P/O Split
0 - 1.0	70%	N/A	20%	N/A	60%
1.0 - 1.4	60%	20%	30%	60%	70%
1.4 - 2.0	50%	30%	40%	60%	70%
2.0 - 2.5	30%	40%	50%	60%	70%
2.5 - 3.0	30%	50%	60%	60%	70%
> 3.0	30%	60%	70%	80%	90%

Individual Field Total Hydrocarbon Volume (THV) = 30 MMBBLS or 0.75 TCF

Price Cap Formula 70% of value of Contractor P/O or P/G above Base Price paid to Petronas. Base price is US$25.00/BBL or $1.80/MMBTU increased by 4% commencing on the 1st anniversary of the Effective Date. But the Price Cap Formula only "kicks-in" if the R/C > 1.0.

Taxation (Assumed)	40% Petroleum Income Tax 20% Duty on Profit Oil Exported (with 50% Export Tax Exemption)
Depreciation	?
Ringfencing	Each License Ringfenced
DMO	None
Gvt. Participation	Up to 15% Petronas carried through all expl. expenditures (Assumed)

MAURITANIA

PSC with Sonatrach (from Barrows 17 April, 2008)
30 November, 2007, Sonatrach's subsidiary, SIPEX
(Sonatrach Int'l. Petroleum E&P BVI)

Blocks 1.30.31.35 in the Taoudenni Basin.

Relinquishment	
Bonuses	
Royalty	None
Cost Recovery Limit	62% Oil 65% Gas

Profit Oil Split

MBOPD	MMCFD	Contractor Share
Up to 25	0 - 150	70%
25 - 75	150 - 450	65
75 - 100	450 - 600	60
> 100	> 600	50

Taxation	27%
Depreciation	G&G & startup 100% assumed Most other 20% Drilling equipment 33% Interest is deductible
Ringfencing	Around the contract area for C/R and Tax purposes
Gvt. Participation	13% at Commerciality (ordinary carry) + 7% at 100,000 BOPD State reimburses out of up to 50% of its share of production (assumed)
NOC	Ste. Mauritanienne des Hydrocarbures (SMH)

NEW ZEALAND

Royalty/Tax New Minerals Programme 1995

Area	Designated Blocks for official blocks offers The range for designated blocks is huge. Frontier Offers - no set area but up to 25,000 km2 offshore (~6MM acres) and up to 2,000 km2 onshore
Duration	Exploration 5 years + 5 years Production up to 40 years + (for the life of the field)
Relinquishment	Generally 50% after 5 years
Obligations	Blocks offers - 1 Well in 5 years
	Frontier Areas - 1 Well in 3 years
Signature Bonus Rentals	No Roughly 2¢/acre
Royalty (Hybrid)	Either 5% Ad Valorem Royalty (AVR) Or 20% Accounting Profits Royalty (APR) whichever is greater in any year
Taxation	33% Income Tax (Resident Companies)

	15% Withholding Tax 38% Income Tax (Non-resident Companies)
Depreciation	For income tax calculation purposes Onshore 7 yrs SLD starting "when placed in service" Offshore 7 yrs SLD starting "when spent" Exploration Costs Expensed No Depreciation for APR calculation
G&A	2.5% offshore; 1.5% onshore
Ringfence	Licenses ringfenced for Royalties Income Taxes consolidated
Gvt. Participation	None

PAKISTAN

Onshore Royalty/Tax
Awarded by Signature Bonus Bidding
Draft Law 2007 (crude)

Duration	5 years exploration (with extensions) 25 years Production Lease…renewable for 5yrs.
Relinquishment	30% year-end 2 30% (remaining) year-end 4 20% year-end 5
Block Size	617,500 acres (maximum)
Bid Items	Work Program (80%) & Gas Price Factor (20%) (in addition, bids awarded on experience and financials)
Bonuses	$500,000 at startup $1.0 MM @ 30 MMBOE, $1.5 MM @ 60 MMBOE $3.0 MM @ 80 MMBOE, $5.0 MM @ 100 MMBOE
Training / Social Welfare	exploration: $25,000 per year
	lease period: $50,000 & $50,000 to $ 700,000 (Production)
Royalty	12.5 %
Domestic Market Obligation	gas only
Taxation Windfall Levy (WLO)	40% Corporate Income Tax 50% for price in excess of $30/bbl (with $0.25 base price escalation/yr)
Depreciation	none
Ringfencing	None for corporate tax calculation
Gvt. Participation	Zone 1: 15% min. All participation, "carried" Zone 2: 20% min. Zone 3: 25% min. All zones: Gvt has right to extra 10% interest. GHPL (Gvt) can "make-up" remaining interest, if any exists

Russian 2005 Royalty Tax Regime Summary

The basic features that govern most of the economic aspects of production from a Russian license include: export tariff, royalty, income tax, withholding tax and other minor taxes.

Export Tariff (also called Export Duty)

The Export Duty is based on a two-month average of URAL CIF NWE and URAL CIF Med. However, the Export Tariff/Duty in the Total economic model is based on the quality adjusted Brent price delivered to Rotterdam which requires deduction of shipping costs:

$25.00	Brent price
- 1.40	Quality adjustment
- 3.50	Shipping costs to Rotterdam
$20.10	Quality adjusted oil price delivered to Rotterdam

The duty is a function of 4 different tiers of adjusted oil prices:

Export Duty

Tier			Rate
Ural CIF	<	$15/BBL	0
$15/BBL	< Ural CIF <	$20/BBL	35% (Ural CIF - $15)
$20/BBL	< Ural CIF <	$25/BBL	45% (Ural CIF - $20) + $1.75
Ural CIF	>	$25/BBL	65% (Ural CIF - $25) + $4.00

Two examples are shown to demonstrate how the export duty is calculated:

1. A Brent price of $25/BBL quality adjusted (-$1.40) and shipped to Rotterdam (-$3.50) = $20.10 (which equates to Ural CIF).
2. A Brent price of $54/BBL quality adjusted (-$3.02) and shipped to Rotterdam (-$3.50) = $47.48 (which equates to Ural CIF).

Export Tariff Oil

$20.10/BBL	$47.48/BBL
= ($20.10 - $20.00) * 45% + $1.75	= ($47.48 - $25.00) * 65% + $4.00
= ($0.10 * .45) + $1.75	= ($22.48 * .65) + $4.00
= $0.04 + $1.75	= $14.61 + $4.00
= $1.79	= $18.61

Export Tariff Gas = 5% of customs value (but not less than 2.50 Eu/000 m3)

Royalty 16.5% (AKA Mineral Extraction Tax "MET")

The royalty is based on the quality adjusted Brent price less Export tariff as follows:

$25.00	Brent price
- 1.40	Quality adjustment
-3.50	Shipping costs to Rotterdam
$20.10	First sales
- 1.79	Export Duty
$18.31	Basis for Royalty determination - Revenues
- 3.02	16.5% Royalty

Value for royalty determination ($/BBL) = Netback price - VAT - excise tax - insurance costs. Netback price is the "first sales" price less transport and export tax (field consumption is included). The excise tax is zero for crude oil.

Profit Tax

Profit Tax of 24% is levied on taxable income defined as:

Taxable Income = Revenues
- Royalty
  (Mineral Extraction Tax or Temporary Mineral Production Tax)
- Costs (E&A, Opex, Abandonment)
- Depreciation (Development costs)
- Excise Tax (if applicable)
- Asset Tax
- Acreage Tax
- Financial costs[1]

[1] Limited by maximum deductible interest rate or Thin Capitalization Rule

Depreciation

Depreciation period for different classes of assets are:

Wells	10-15 years (double-declining balance "DDB")
Surface Facilities	5-7 years (DDB)
Buildings	30 years (straight-line decline "SL")
Pipelines	20-25 years at a maximum rate of 5%

(main pipe: SL only; other pipe: SL or DDB)

Withholding Tax

A withholding tax of 5% is levied on dividend distributions. In the total economic model it is assumed that all investor's after-tax income is subject to the tax, defined as:

Withholding Tax Base = Revenues
- Mineral Extraction Tax
- Costs (E&A, Opex, Abandonment)
- Depreciation
- Asset tax
- Income tax

Asset Tax 2.2%

The asset tax set at 2.2% is based on annual average net book value.

Value Added Tax 18%

The VAT rate was 20% in 2003 (18% in 2004 onward) and it is based on both Capex and Opex including import tax (deductible VAT on domestic and imported purchases), domestic sales (Russia and CIS - collected VAT). Deductible VAT is (theoretically) refunded as follows:

1st Step	deduction against the collected VAT
2nd Step	deduction of the VAT against the federal share of the other taxes
3rd Step	cash reimbursement by Gvt. within 3.5 months with interest (LIBOR)

Land Tax (Local Tax)

The tax rate is 1.5% of "value of land" as stated in the state land register.

Rentals (payments for use of mineral resources)

Approximately 120 to 360 RR per km2 during prospecting and evaluation of mineral deposits, from 5,000 to 20,000 RR per km2 during exploration of mineral resources. At 28.8 Rubles/$ (Circa 2006) = around 2-6¢/Acre during prospecting and 70¢-$2.80/ acre during exploitation.

RUSSIA - Royalty/Tax system - 2005

Obligations	$50 MM Appraisal	
Bonuses Signature	$6 - $20 MM	
Rentals Payments		
Royalty	16.5% (Also known as Mineral Extraction Tax "MET")	
Cost Recovery Limit		
Production Sharing		
Taxation	24% Profit Tax	
Depreciation	Various Wells	10-15 years (double-declining balance "DDB")
	Surface Facilities	5-7 years (DDB)
	Buildings	30 years (straight-line decline "SL")
	Pipelines	20-25 years at a maximum rate of 5%
	(main pipe: SL only; other pipe: SL or DDB)	
Withholding Tax	5%	
Asset Tax	2.2% of average annual net book value	
Value Added Tax	18% (assumed to be mostly neutralized by VAT creditability)	

Export Duty	Tier	Rate
	Ural CIF < $15/BBL	0
	$15/BBL< Ural CIF < $20/BBL	35% (Ural CIF - $15)
	$20/BBL< Ural CIF < $25/BBL	45% (Ural CIF - $20) +$1.75
	Ural CIF > $25/BBL	65% (Ural CIF - $25) +$4.00
Export Tariff Gas	= 5% of customs value (but not less than 2.50 Eu/000 m3)	
Ringfencing	Yes (assumed)	
Gvt. Participation	41%	

TURKMENISTAN

Petronas PSC 2 July, 1996

Area	Block I Gubkin + Barinov Fields		
Duration	26 years from "Effective Date" 2.5 years for G and B fields to start up Exploration 3+ 2 Production 20 years (Gas is different)		
Relinquishment			
Obligations	2,500 km2 2-D 2 W/C wells 5,500 km2 3-D 2 Appraisal wells "Allocate" US$45 MM		
Bonuses	"Execution" Bonus $13 MM		
Royalties	Oil BOPD	Royalty	Gas 10%
	Up to 25,000	3%	
	25,000 - 50,000	5	
	50,000 - 75,000	7	
	75,000 - 100,000	10	
	> 100,000	15	
Cost Recovery Ceiling	60% for development fields; 70% for Unexplored Structures		
Depreciation	All costs expensed (Assumed)		
Production Sharing	P/C Ratio	Profit Oil Split	
	0 - 1	35/65%	P/C = X/Y
	1 - 1.5	50/50%	X = Contractor revenues
	1.5 - 2	60/40%	from sales
	2 - 2.5	80/20%	Y = Total Costs
	2.5 +	90/10%	
Taxation	25%	TLCF 5 years	
Depreciation	5 year SLD		
Ringfencing	Yes for cost recovery not for tax		
Gvt. Participation	None		

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