Review of the key Fiscal and Business Indicators for Upstream Petroleum Industry

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Abstract

In this paper, the key fiscal elements of upstream petroleum agreements will be presented in detail. Besides the key business indicators that are used to determine the best investment opportunity for both government and the foreign oil and gas companies will be investigated. These indicators include but are not limited to net cash flow (NCF); net present value (NPV); internal rate of return (IRR) and payback period.

1. Key Fiscal Outflows for Upstream Agreements

Each government developed its fiscal instruments to capture the appropriate rent from its nonrenewable resources. These instruments include but are not limited to bonuses, rentals, royalties, and income tax. Some instruments are contract-specific like the cost recovery limit and profit: sharing mechanism between the host governments and the foreign oil companies.

1.1 Bonus

A bonus is an amount payable by a producer when a certain event occurs. The amount payable is determined either by host country regulations or by agent interaction (negotiated between the producer and the state. Bonuses take many forms. However, the most common types are:

1.2 Signature bonuses

A signature bonus is paid by the contractor when it is awarded the license, permit, or contract. This bonus may be several hundred million dollars for highly prospective exploration areas. Thus, signature bonuses can strongly influence a producer's decision whether to proceed with a project or even to bid for the right to do so. They can also act as barriers to entry, keeping the smaller entities out and limiting competition for the larger companies [1]

1.3 Commerciality bonuses

A commerciality bonus is paid when the investor declares the commerciality of the field and decides with the government's approval to develop the field. Declaration of commerciality often occurs after the success of the exploration efforts and the wells have been tested and the recoverable reserves are estimated.

Commerciality means there are enough reserves to be economically produced under the estimated market price and fiscal terms to provide the investor with sufficient economic rent. This point can be determined by using preliminary economic modeling under prevailing regulations. At this point, a field development feasibility study and development plan, incorporating reserves, production, and cost profile projections are proposed to the government[1].

1.4 Bonuses payable at first commercial production

These bonuses are paid upon first commercial production so that it is called in many fiscal systems as production bonuses. Production bonuses are often quite small in monetary terms but they can be especially important to governments using production sharing agreements as they help offset the early perception that the producer is getting "too sweet" a deal.[1]

1.5 Cumulative production bonuses

These bonuses are paid when cumulative production reaches a specified level, also called a "milestone" or threshold. In some cases, like Africa, this bonus may be paid as a percentage of the gross revenue of such cumulative production rather than a predetermined amount of money.

1.6 Bonuses based on the production rate for a specified period.

These bonuses are the most common type. These bonuses are paid only once when the average production rate for any given period exceeds a certain limit

1.7 Royalties

Royalty is one of the key fiscal instruments developed by the host government to maximize its economic rents from non: renewable resources. Royalty is a payment made by the license holder to the government either in cash or kind. The royalty is paid as a specified percentage of the gross revenue before any deductions. This percentage may be defined by the regulations or negotiated with the oil and gas companies.

Royalty is one of the top deductions before any deductions or cost recovery so that it greatly affects the economic limit of any field. Appealing to governments as stable fiscal instruments to extract a reasonably steady levy from production that is unaffected by costs and other fiscal instruments[1].

Host governments developed various mechanisms to determine the royalty percentage. The simplest mechanism is fixed-rate royalty other mechanisms include variable-rate royalty determined by changes in production volumes, commodity prices, measures of profitability, or some combination of these factors. As an example, variable royalty rates based on daily production rate and commodity prices are shown in **tables 3.1, and 3.2 respectively**.

From KBOPD	To KBBL/D	Royalty Percentage %
0	5	5.00%
>5	10	7.50%
>10		12.50%

Table 3. 1: Production based royalty for Nigerian shallow water concessions[2]**.**

Oil Price at wellhead $/bbl		Royalty Rate %
>=	<	
0	10	0.0%
10	15	5.0%
15	20	7.5%
20	30	10.0%

30	50	12.5%
50	75	15.0%
75	100	17.5%
100	120	20.0%
120		25.0%

Table 3. 2: Price based royalty *[1]*.

For production: based royalty, two different mechanisms can be used to determine the royalty by this method:

- Top rate method in which a single royalty rate for a given period is determined by the highest production level in that period.
- Sliding scale or tranche method in which multiple royalty rates can apply within a given period, where tranches are different bands of production, each associated with a different royalty rate

For example, assuming the average daily production of 12 KBOPD referring to **table 3.1** tope rate royalty will be 12.5 % while sliding scale royalty can be calculated as following:

$$\text{Sliding scale royalty} = \frac{5000 \ast 5\% + 5000 \ast 7.5\% + 2000 \ast 12.5\%}{12000} = 7.292\%.$$

Sliding scale royalty is just rate average royalty and always lower than the top rate royalty. Some authors prefer to call the sliding scale royalty as a blended royalty rate. As shown in **table 3. 2** that as the price increases, the royalty percentage increases. To make the applicable royalty percentage more sensitive to both the production rate and the commodity prices, some fiscal systems use two: dimensional sliding scale royalty model that depends on both the production rate and the crude price at the same time as shown in **table 3.3.**

Oil Price	From $/bbl	0	30	60	90
	To $/bbl	30	60	90	>90

Price Tranche no.			1	2	3	4
Production Tranche no.	>= KBOPD	<KBOPD	Royalty Rate			
1	0	25	2.5%	7.5%	12.5%	15.0%
2	25	50	7.5%	12.5%	15.0%	17.5%
3	50	75	12.5%	15.0%	17.5%	20.0%
4	>75		15.0%	17.5%	20.0%	25.5%

Table 3. 3: Two dimensional (production & crude price) based royalty percentage *[1]*.

Assuming daily production rate 80 KBOPD and commodity price is 80$ /bbl, the royalty percentage can be calculated from price based tranche number three passing through the whole production tranches as:

$$\text{Royalty} = \frac{25*12.5\%+25*15\%+25*17.5\%+5*20\%}{80} = 15.3125\%$$

Some fiscal systems use cumulative production or the length of the production period as a basis for royalty calculations as shown in **tables 3.4 and 3.5** respectively. These two mechanisms are not preferred to the contractor because they are highly regressive as the royalty depend mainly on what is produced, and since the oil production starts high at the early life of the field then falls dramatically in later life so that applying the highest royalty rates when the production volume is very low near the economic life of the field[1].

Cumulative Oil Production MMBBL		Royalty Rate %
>=	<	
2	4	5%
4	10	7%

10	15	8%
15	25	10%
25	35	12%
35	45	14%
45	55	16%
55	65	18%
65	75	20%
>=75		22%

Table 3. 4: Cumulative production based royalty[1]**.**

Years of Production		Royalty Rate
>=	<	%
0	6	0%
6	7	6%
7	8	7%
8	9	8%
9	10	9%
>=10		10%

Table 3. 5: Production time based royalty [1]**.**

Modern fiscal systems link the royalty with project or investor profitability using what is called the ratio method or simply the R factor. Each government defines the economic basis for calculating its R factor. The most used R factor is the ratio between the cumulative revenue to the cumulative costs. When the R factor is zero meaning that the contractor incurred accost with no revenue, and this happens usually before production starts. When the contractor breaks even or the cumulative costs equal to the cumulative revenue, the R factor becomes one. Investors begin to make a profit when the R factor is greater than one. In general, the royalty percentage increases with the R factor. An example for R factor based royalty is the Tunisia concession model contract as shown in **table 3.6 [3]**

R: factor		Royalty Rate %
>=	<	
0	0.5	2%
0.5	0.8	5%
0.8	1.1	7%
1.1	1.5	10%
1.5	2	12%
2	2.5	14%
>=2.5		15%

Table 3. 6: R factor based royalty *[1]*.

1.8 Corporate Income Tax

Most petroleum fiscal systems include corporate income tax as one of their features. Petroleum taxes are based on the net income or profit generated by the company. Corporate tax rates applicable to petroleum activities vary widely around the world, from a low of zero in some tax haven states to a high of 85% for certain operations in Nigeria. However, most states impose a corporate tax in the range of 25% to 35%[4].

Each fiscal system will be defined precisely the tax basis besides the allowed tax deductions or tax allowances during any accounting periods. Most fiscal systems permit tax loss to carry forward in cases of negative taxable income for the investors.

Two different tax regimes are defined worldwide depending on the tax law of the government in interest. These two regimes are. ring-fence and consolidated tax regimes. In-ring: fence regimes, the tax looks only at the activities within the defined area so that other gains, losses, or costs outside the ring-fence are excluded. On the other hand, in the consolidated tax regime, activities across multiple contract areas are treated on a combined basis.[4].

World average Corporate Income Tax (CIT) is between 30: 35%. However, many PSCs have taxes paid “in lieu” – “for and on behalf of the Contractor” out of National Oil Company’s share of profit oil[5]. In most fiscal systems, the tax rate is constant throughout the license period but in some countries tax rate may vary according to:

- How many years a license has been producing.
- The production rate.
- Whether the commodity produced is oil or gas
- Water depth, for offshore developments.
- According to R-factor

2. Key Fiscal Elements of Production Sharing Contracts

The previously mentioned fiscal elements i.e. bonus, royalty, and taxes, are mostly used in all fiscal systems. As it is previously mentioned in chapter II that production sharing contracts define a portion of the production as a cost oil or cost gas from which the contractor is allowed to recover his costs and the other portion as a profit oil or profit gas which is shared between the government and the contractor according to pre-agreed percentage defined in the contract.

2.1 Cost Oil or Cost Recovery Limit

PSC contracts defined what's called the cost recovery mechanisms which determine which costs are eligible to be recovered and how these costs will be recovered. Cost oil is the maximum amount available to the contractor to recover the costs which have been incurred.

Some countries allow for a 100% cost recovery limit but in general, the world average limit for cost recovery ranges from 30: 60% of gross revenue, which means, for any given period the maximum level of costs recovered is 60% of revenue[6]. Ring: fencing concept is also applied here which means that costs incurred in any block should only be recovered from the revenue generated within this block.

To attract foreign investments, some governments allow the contractor to recover the costs quickly by making the cost recovery limit higher.

2.2 Profit Oil Sharing Mechanisms

Profit oil is the share of production remaining after cost oil has been delivered to the IOC. This profit oil is divided or shared between the host government and the IOC according to a predetermined percentage. This shared profit to the IOC is what is subjected to the income tax. The most typical share that goes to the government is 50: 60% of profit oil, however, some countries apply higher shares[7]. Assuming 100 $/ bbl, the gross revenue distribution under the production sharing contract is shown on **Fig.3.1** [1]. Each government developed its profit sharing mechanisms either fixed or variable as discussed in the following section.

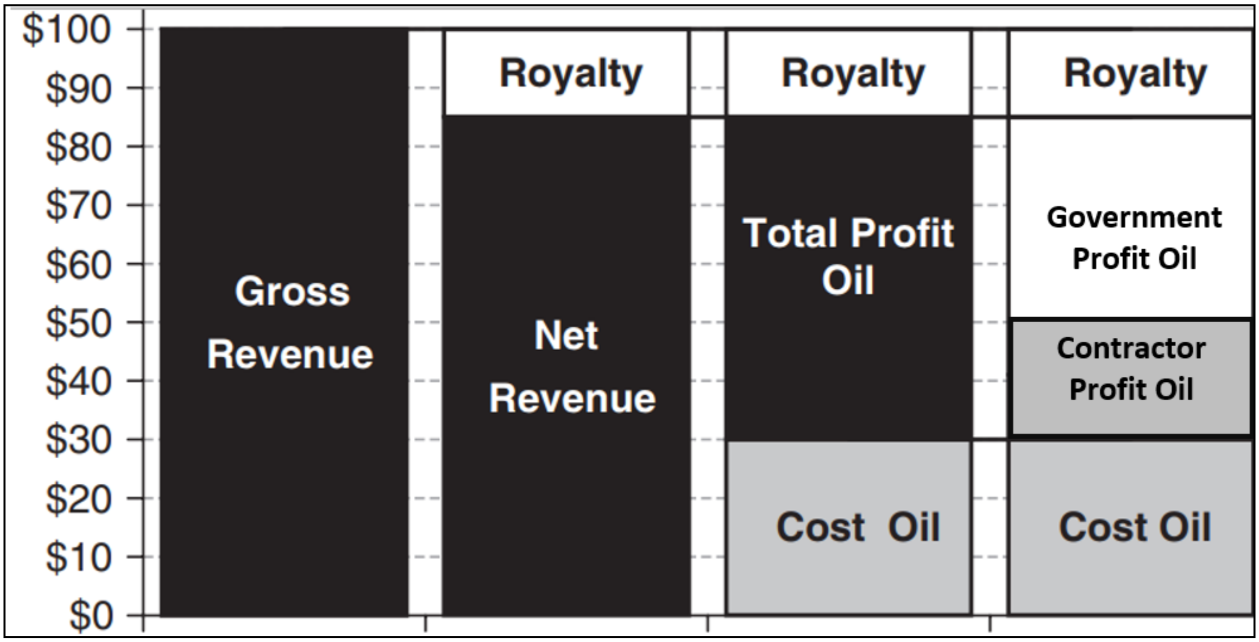

Fig.3. 1: Gross revenue distribution under production sharing contract *[1]*.

2.3 Fixed Profit Sharing

The first government to create the production sharing contract was Indonesia where the IOC as 'contractor' would receive a recovery for costs incurred out of a maximum of 40% of production (the 'cost oil limit'), and the balance of production would be shared between PERTAMINA as to 60% and the contractor as to 40% (the 'profit oil share').

If costs are less than the cost oil limit, the excess is treated as profit oil and shared by the parties in their respective profit oil shares. In other words, the cost oil allocation to the IOC is the lesser of the 40% cost oil limit and the actual unrecovered costs[4].

2.4 Price Based Profit Sharing.

In this technique, the contractor’s and government’s share of total profit oil varies as a function of the oil price. The contractor’s share is inversely proportional with the price where the higher the price the lower the contractor’s share. While the government sharing increases with the price. The philosophy behind such a mechanism is to give the contractor incentives to develop and produce when prices are low while giving the government an increasing share of PSC profits as prices rise. An example of price based profit sharing is shown in **table 3.7[1].**

Oil Price at wellhead $/bbl		Profit Sharing %	
>=	<	Contractor	Government
0	20	90%	10%
20	40	75%	25%
40	60	60%	40%
60	80	45%	55%
80	100	30%	70%
100	150	20%	80%
>=150		15%	85%

Table 3. 7: Price based profit sharing *[1]*.

2.5 Profit Sharing Based on Production Rate.

In this mechanism, the host government and the contractor profit sharing is based on the production rate, where the government profit sharing is directly proportional to the level of production rate. Profit sharing can be calculated either by the top rate or sliding scale method. Profit sharing based on production rate is commonly used in Malaysia. A summary of the profit sharing between PETRONAS and the IOC for the Malaysian fiscal system is presented in **table 3.8[8].**

Because often production profiles, after an initial build. up, tend to peak in the early years and then decline over time, in such cases this mechanism will provide the contractor with a lower percentage share of profit oil in early years than in later ones[1].

Gross Production KBOPD		Profit Sharing %	
>=	<	Contractor	PETRONAS
0	10	50%	50%
10	20	40%	60%

>=20	30%	70%

Table 3. 8: Production based profit sharing *[8]*.

2.6 Profit Sharing Based on Cumulative Production

This mechanism allocates profit oil to the contractor and government based on the license's cumulative production, measured at the end of the accounting period. An example of cumulative production based profit sharing is the Colombian production sharing contract as shown in **table 3.9 [3].**

Cumulative Production MM BBL		Profit Sharing %	
>=	<	Contractor	Government
0	60	50%	50%
60	90	45%	55%
90	120	40%	60%
120	150	35%	65%
>=150		30%	70%

Table 3. 9: Colombian cumulative production: based profit sharing*[3]***.**

This mechanism works in the opposite direction to the profit sharing based on average production rates, which we covered in the previous section. Since for newly developed fields the production rate starts to be high at the early life, the contractor's percentage sharing will be low as it is discussed previously. In contrast, the mechanism based on cumulative production provides the contractor with a higher percentage share of total profit oil in the early years, which decreases as cumulative production grows over time. For the government's share of profit oil, the opposite is true.

2.7 Profit Sharing Based on Profitability

We previously discussed the R-factor as a measure of cumulative profitability. If the profitability of the project has not been achieved or low, the fiscal system should be lenient to the investor especially in the early days when the production starts but as the profitability increases the fiscal system should be less lenient. For low R- factor, the contractor should receive a higher percentage of profit sharing and the opposite is true for high R: factor. An example for R- factor based profit sharing is the India PSC model contract as summarized in **table 3.10**

R: Factor		Profit Sharing %	
>=	<	Contractor	Government
0	1.5	100%	0%
1.5	2	90%	10%
2	2.5	85%	15%
2.5	3	80%	20%
3	3.5	75%	75%
>=3.5		60%	40%

Table 3. 10:R: factor profit sharing *[3]***.**

2.8 Profit Sharing Based on ROR

To provide a high degree of progressivity and flexibility, modern fiscal systems are based on project or contractor rate of return (ROR) (also referred to as the internal rate of return or IRR). ROR based reflects any change in production profiles, commodity prices, project costs, and operating costs [9]. ROR based profit sharing for Equatorial Guinea is summarized in **table 3.11[3].**

Contractor ROR		Profit Sharing %	
>=	<	Contractor	Government
0	30%	100%	0%
30%	40%	60%	40%
40%	50%	40%	60%
>=50%		20%	80%

Table 3. : ROR based profit sharing*[3]***.**

3 Field Outflows

Field costs can be classified into three categories: capital expenditures (CAPEX), operating expenditures (OPEX), and abandonment costs. The abandonment cost is considered to be a special category of cost because it is associated with environmental safety and does not produce any future profit for the company[9].

Classification of costs as CAPEX or OPEX differs from company to company according to the nature of the project and the fiscal regime. The tax law or the petroleum law determines which costs will be capitalized and which costs will be expensed or the capitalization criteria.

Capital costs account for a minimum of 40% up to a maximum of 60% of field cost while the operating costs account for a minimum of 35% up to a maximum of 55%. The environmental nature of the project area plays a major role in determining the contribution of capital cost to the total cost. In general, offshore petroleum projects require more costs than onshore projects.

3.1 Capital Costs (CAPEX)

CAPEX includes the costs of services and/or long: life assets. These costs may be incurred before production starts as an initial investment to get the field ready to produce; typically include exploration and development costs.

The exploration cost or (G&G) cost includes the costs of geological and geophysical studies besides the costs of drilling exploration wells either made by the company itself or by other parties like service companies[10].

The development cost includes the costs of development wells, production facilities, and flow lines. These costs differ from one concession to another concession depending on terrain such as onshore/offshore, technologies available, reservoir rock, and fluid properties.

CAPEX may also be incurred after production starts to keep the production at a sustainable level like “recompletions” and “workovers”; these costs are usually incurred only occasionally[1].

For fiscal and tax purposes CAPEX is further classified as intangible and tangible costs. Intangible CAPEX consists of items that cannot be touched such as seismic data and its processing and interpretation; a facilities plan; the drilling of a wellbore, etc. Intangible CAPEX is usually "expensed for tax purposes."

Tangible CAPEX, on the other hand, can be touched – for example, the steel casing which is placed in the wellbore; well platforms and facilities, pipelines, compressor stations, etc. Tangible CAPEX is "capitalized for tax purposes," which means that the tax allowances which arise from tangible CAPEX will be phased over time via depreciation. [1]

3.2 Operating Costs (OPEX)

The operating cost (OPEX) represents the cost of operating and maintaining the petroleum project or keeping the system running. Operating costs may be classified on a different basis such as time basis, the nature of the element incurred, traceability, and changes in volume [11].

Based on the time, OPEX can be classified into historical costs and predetermined costs. Historical costs are determined after their occurrence while predetermined costs are predicted or standard costs. Depending on the element incurred, OPEX may be classified into Labor, services, consumable materials, utilities, overhead, and transportation costs. Based on traceability, OPEX may be directly related to the operation such as the wages for workers on the well or indirectly such as like overhead staff cost. According to the production volumes, the costs may be fixed or variable. Fixed costs do not change with changes in production level such as overhead costs. While variable costs always vary continuously according to production volumes. expressed on a unit basis such as cost per barrel of oil production.

3.3 Abandonment Costs

Abandonment costs – also called decommissioning costs and/or site restoration costs. These costs are incurred when production has finished or at the end of the economic life of the field usually by plugging disused wells and dismantling facilities. [1].

Although rules for funding abandonment take many forms, there are two basic kinds of abandonment regimes. One requires a single "lump sum" payment at the end of the production. The other kind of abandonment regime also requires a single abandonment payment to be made at the end of production but requires – or permits – the payment to be funded in advance, by periodic contributions which the producer makes over the production period, before the actual abandonment payment is due. These periodic contributions are called abandonment contributions[1].

By comparing several studies, CAPEX accounts for a minimum of 40% up to a maximum of 60% of field cost while OPEX accounts for a minimum of 35% up to a maximum of 55%. The breakdown structure of the field costs is shown on **Fig 3.2** [9, 10].

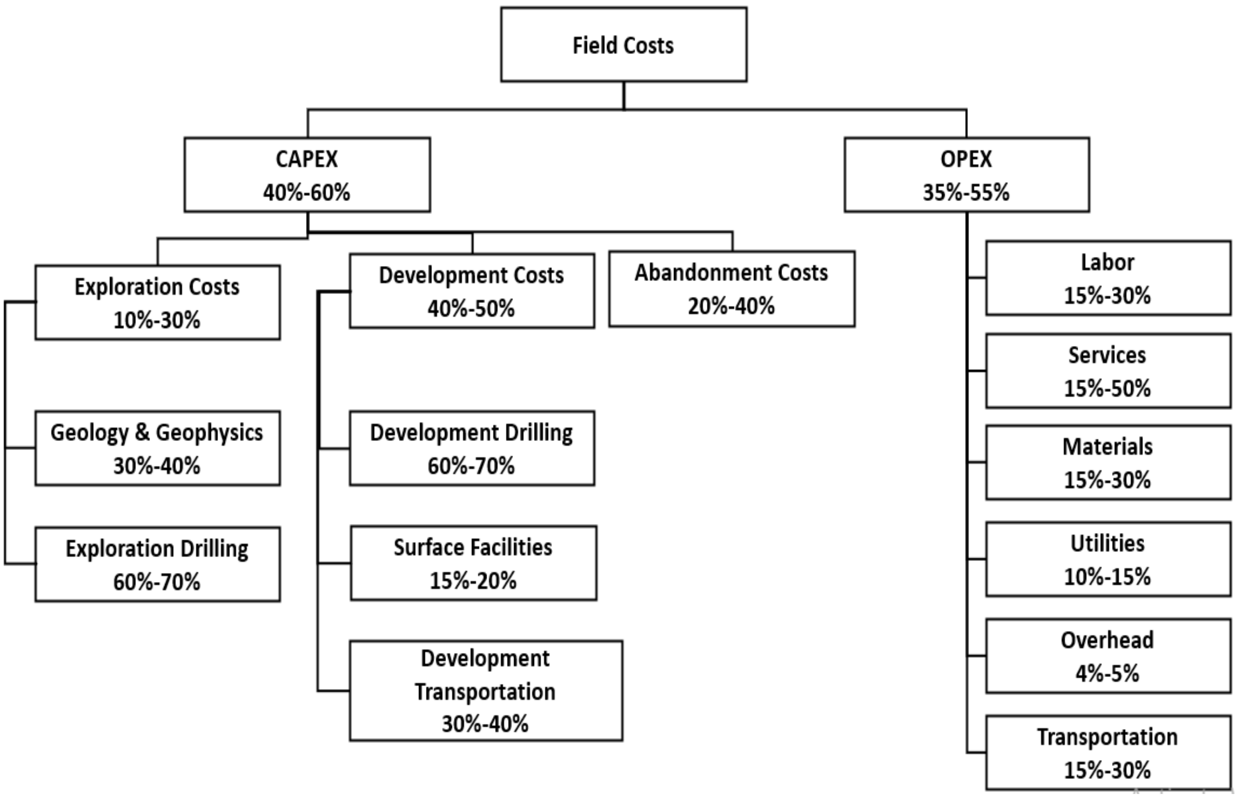

Fig.3. 2: Field costs breakdown structure.

3.5 Key Business and Economic Indicators

Several methods are employed in the assessment of petroleum fiscal systems, cash flow models are commonly used to evaluate the profitability of a capital investment project. The cash flow is usually preferred for economic analysis because it employs discounted cash flow concepts that take into consideration the timing of cash flows and the economic opportunity cost on capital [2, 4, 5, 14, 15].

3.5.1 Net Cash Flow (NCF)

Simply, net cash flow is just cash income minus the cash outflow. In the following section, the net cash flow (NCF) for ideal concessionary systems, production sharing contract (PSC), and Iranian risk service agreements will be presented.

3.5.2 Net Cash Flow for Concessionary System

As it is previously discussed in chapter II that the basic elements for a simplified concessionary system or royalty tax systems (R/T) are royalties, deductions, and the tax. Calculation of net cash flow of both the contractor and the government are summarized in **table 3.12** [1, 3, 9]:

Gross Revenue		Total Oil and Gas Revenue
Royalty		Royalty percentage * Gross Revenue
Net Revenue		Gross revenue * Royalty
Claimable Deductions		OPEX Depreciated Tangible CAPEX Intangible CAPEX Abandonment Contributions Historical Costs (if allowed) Tax Loss Carry Forward (LCF) Other Costs
Taxable Income		Net revenue + Claimable Deductions
Tax		Tax rate * Taxable Income
Contractor NCF (NCF_{con})		Gross revenue - Royalty - CAPEX - OPEX – Tax- Other
Government NCF (NCF_{gov})		Royalty + Tax + Other income

Table 3. 11: Concessionary system net cash flow.

3.5.3 Net Cash Flow for Production Sharing Contracts (PSCs)

As it is previously mentioned in chapter II that the basic elements for a typical PSC contract are royalties, cost oil, profit oil, and tax. calculation of both the contractor and the government net cash flow is summarized in **table 3.13** [1, 3, 9]:

Gross Revenue		Total oil and gas revenue
Royalty		Royalty percentage * gross revenue
Net Revenue		Gross revenue * royalty
Cost Recovery (Cost Oil)		OPEX Depreciated tangible CAPEX Intangible CAPEX Abandonment contributions Un Recovered Costs Carried Forward
Profit Oil		Net Revenue *Cost Recovery
Contractor Profit Oil		Contractor Profit Oil Percentage * Profit Oil
Government Profit Oil		Government Profit Oil Percentage * Profit Oil
Contractor Income		Cost Oil + Contractor Profit Oil
Tax Claimable Deductions		OPEX Depreciated tangible CAPEX Intangible CAPEX Abandonment contributions Historical Costs (if allowed) Tax loss carry forward (LCF) Other costs
Taxable Income		Contractor Income - Tax Claimable Deductions
Tax		Tax Rate * Taxable Income
Contractor NCF (NCF_{con})		Contractor Income – CAPEX: OPEX: Tax: Other

Government NCF (NCF_{gov})		Royalty + Government Profit Oil + Tax + Other

Table 3. 12: Production sharing system net cash flow.

3.5.4 Net Cash Flow for Risk Service Contracts

As it was mentioned in Chapter II that for risk service contracts, the contractor only recovers his costs besides an additional fee for the provided services. The net cash flow for a simplified Iranian risk service contract is summarized in **table 3.14** [12].

Gross Revenue		Total Oil and Gas Revenue
Cost Recovery (Cost Oil)		OPEX Depreciated tangible CAPEX Intangible CAPEX Abandonment contributions Un Recovered Costs Carried Forward
Revenue After Cost Recovery		Gross Revenue* Cost Recovery
Contractor Fee		Contractor Fee Rate * Revenue After Cost Recovery
Income Tax		Income Tax Rate * Contractor Fee
Contractor NCF (NCF_{con})		Contractor Fee – Income Tax
Government NCF (NCF_{gov})		Revenue After Cost Recovery + Income Tax – Contractor Fee

Table 3. 13: Net cash flow for Iranian Risk Service Contracts*[12]***.**

3.5.5 Profitability Indicators

Common profitability measures adopted include net present value (NPV), internal rate of return (IRR), profitability index (PI), Contractor and Government take [5, 6, 9, 13-15].

NPV is calculated by discounting all the cash inflow and the cash outflow and is given by Eq.3.1.

$$NPV = \sum_i^n \frac{(NCF)_i}{(1+id)^i} \text{ ....Eq.3.1}$$

Internal rate of return (IRR) is the discount rate at which NPV is equal to zero. If the project IRR is higher than the cost of capital or the company: specific criteria, the project will be economically viable. To calculate IRR we equate Eq.3.1 with zero as shown by Eq.3.2.

$$\sum_i^n \frac{(NCF)_i}{(1+IRR)^i} = 0 \text{ ....Eq3.2}$$

The profitability index (PI) is used as an indicator of the investment efficiency in terms of how many dollars were gained per dollar invested in the project. The profitability index (PI) is given by Eq.3.3.

$$\text{Profitability index (PI)} = 1 + \frac{NPV_{con}}{Present\ value\ of\ investment\ costs} \text{ ....Eq 3.3}$$

After computing the respective net cash flow for the contractor and the government, their respective undiscounted takes can be computed by Eq.3. 4 and Eq.3.5, respectively:

$$Undiscounted\ Contractor\ Take\ (NCF\ \%) = \frac{NCF_{con}}{NCF_{con}+NCF_{gov}} \text{ ....Eq.3.4}$$

$$Undiscounted\ Government\ Take (NCF\ \%) = \frac{NCF_{gov}}{NCF_{con}+NCF_{gov}} \text{ ....Eq3.5}$$

Considering the time value of money, the discounted contractor and government take can be computed by Eq.3.6 and Eq. 3.7, respectively:

$$Discounted\ Contractor\ Take (NPV\ \%) = \frac{NPV_{con}}{NPV_{con}+NPV_{gov}} \text{ ....Eq.3.6}$$

$$Discounted\ Government\ Take (NPV\%) = \frac{NPV_{gov}}{NPV_{con}+NPV_{gov}} \text{ ....Eq.3.7}$$

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