Application of option based revenue sharing model for hydrocarbon block auction in India under Open Acreage Licensing Policy

Akshay Pai[1], Sameer Gujar[2]
[1]Symbiosis Centre for Management and Human Resource Development, SCMHRD, Symbiosis University (Deemed University), SIU, Hinjewadi, Pune, Maharashatra, India.
[2]Symbiosis Centre for Management and Human Resource Development SCMHRD, Symbiosis University (Deemed University), SIU, Hinjewadi, Pune, Maharashatra, India.
[1]akshay_pai@scmhrd.edu, [2] sameer_gujar@scmhrd.edu

ABSTRACT

Hydrocarbon exploration block auctions (excluding marginal fields) in India face decreasing private participation from despite implementation of the Open Acreage Licensing Policy (OALP) by Directorate General of Hydrocarbons (DGH), in charge of auctions. Research indicates participation is limited by uncertainty, limited information, and failure of past projects in different development scenarios in the sector. The initially promising Krishna-Godavari basin block shutdown with technical difficulties is an example. The current DGH revenue-sharing model limits flexibility of real options analysis by forcing constant commitment irrespective of the on-ground scenario.
The objective of this paper is to develop a flexible 'revenue-share model' to increase private participation in DGH Hydrocarbon block auctions under OALP using flexible bidding parameters. The flexible parameter uses revenue-share under predetermined scenarios baselined for evaluation by DGH. The revenue share is contingent on actual conditions, and is expected to cover risks during the project life. A new model is suggested based on the Marketed Asset Disclaimer (MAD) theory which addresses these concerns. This demonstrates efficacy of revenue-share flexibility, and the contractor pays revenue-share proportional to unfolding conditions in project lifetime.The results indicate that if DGH implements an option-based revenue-sharing model, the attractiveness of OALP regime will improve to increase private sector participation

Keywords
Oil & Gas Hydrocarbon Exploration, Real Options Analysis, Open Acreage Licensing Policy, Project Feasibility, Hydrocarbon Block Auction

Article Received: 10 August 2020, Revised: 25 October 2020, Accepted: 18 November 2020

Introduction

The Oil and Gas value chain comprises the ecosystems of upstream Oil and Gas exploration and production from reserve fields, midstream transportation of produced crude and gas to refining locations and downstream refining of transported crude and gas into desired end products followed by the markets for products and services.
The enterprises operating in this value chain aim to maximize shareholder value in a complex and uncertain business environment dictated by volatility in oil and gas prices and demand and uncertainty in production.
The Oil and Gas value chain has an ecosystem of complex ventures requiring coordination, complicated investments, technological challenges, legal and environmental challenges. This complexity links the Oil and Gas sector's decision making under insufficient or inaccurate information to value in a very direct and unforgivable manner.
Enterprises in this sector are looking for accurate and relevant tools and techniques to significantly analyze, assess, and manage the impact of uncertainty on their investments. The industry has incorporated the relationship between asset valuation and strategic advantage as a major business tenet. However, this industry is amongst the most heavily regulated ones, and the various Governments and their nodal agencies are major stakeholders in hydrocarbon value chain prosperity.
The regulatory environment is a major influencer on project success or failure in upstream production, especially in the upstream exploration and production segment and as such the advantage taken of these new valuation techniques is proportional to the flexibility conferred by the regulatory environment.
Oil and Gas production from a typical hydrocarbon field block is overwhelmingly carried out in the four stages of: **Exploration and Appraisal, Development, Production** and **Decommissioning,** with each phase consisting of a number of interrelated operational, techno-commercial and technical activities.
The **Exploration and Appraisal** stage involves collecting, collating and analyzing seismic data related to the oilfield. The application of geological sciences on this data can generate a detailed elaboration of the possible hydrocarbon significant zone/area. To obtain information about the nature of hydrocarbons contained in this zone, exploratory oil-wells are drilled and the hydrocarbons (if obtained) are appraised for their physical and chemical properties to establish the characteristics – dimensions, quality of reserves, category of the hydrocarbon field.

The **Development stage** involves drawing inferences to make business decisions based on the data obtained and confirmed through the Exploration and Appraisal exercise. The decisions are made on quantifying the size of the hydrocarbon reservoir in terms of commercial viability of production. These decisions involve the extent of work program to be implemented to produce hydrocarbons from the given field which includes – the production methodology, numbers and type of production wells, hydrocarbon processing infrastructure, logistics and utilities. The work program is then implemented by preparing the field for production through development wells.

The **Production** stageinvolves managing the actual management of day to day production of hydrocarbon resource from the field. The size and prolific characteristics of the hydrocarbon reserve dictate the producer’s manner and strategy by which production is carried out in the field with the aim of extracting maximum proportion of Hydrocarbon in Place balancing against commercial viability. It may be technologically feasible to extract most of the Hydrocarbons in Place in the field (30-70%), but the extracted hydrocarbon has to be at a cost that of production that allows for profitability weighted against the price of that particular hydrocarbon in the destination market.

The **Decommissioning** stageinvolves the efficient and environmentally prudent dismantling of the development and production infrastructure at the end of the project life cycle by design, or reserve depletion.

This elaboration of the activities, processes and phases involved in the complete lifecycle of development of an oil and/or gas field shows that the projects have the characteristics of being intensive – with large investments in time, money, technology and resources. These investments are further based on imperfect and uncertain information. Both these characteristics combine to make oil and gas exploration projects inherently risky with a unique phase-based structure to the risks involved.

This risk intensive characteristics and the structuring of risks over phases makes real options a natural fit for the oil industry management decision problems. This application of Real Options Analysis is done through two well established methods, which are the Black Scholes model and the Market Asset Disclaimer model. Both these models offer advantages over the conventional Directorate General of Hydrocarbons (DCF) approach of evaluating cashflows and risks for uncertainty ridden oil and gas projects. The real options models make the use of ‘project’ analogues of the six levers of financial option as opposed to DCF which uses just 2 levers of cash flows and fixed costs.

The current Open Acreage Licensing Policy framework currently in use in India for Exploration and Production (E&P) auctions corrects has liberalised tendering over the previous Hydrocarbon Exploration and Licensing Policy (HELP) regime. The OALP regime offers the feature of allowing prospective bidders to form their own oil blocks by carving together acreages on offer in a common database. This too is an application of real options where the value of the 5 points awarded to block originator in actual block is weighted against the cost of data analysis and block carving. However, this is the only application of real options present in the current OALP regime. Apart from the option to carve blocks as originator the OALP regime offers very few instances for practical application of real options analysis even if the contractor uses real options analysis to value their bids. The OALP regime thus causes a mismatch between project evaluation and selection and project execution.

Literature Review

As per (William, 2002)the unique characteristics of the oil and gas industry by virtue of the capital and risk intensive environment it operates in. The author establishes the phase-based structure and the implied decisions, risks and payoffs combined with capital intensive infrastructure requirements in almost all phases as the reason the Oil and Gas industry is unique in its characteristic of being an industry where risk analysis dominates the business landscape. The Oil and Gas industry has considerably enormous investments in time, capital, resources and technology which are made based on imperfect, uncertain, incomplete information. Few other industries demonstrate the downside exposure inherent in the hydrocarbon exploration and production sector.

It is posited that the use of real options analysis in exploration and production of hydrocarbons is to hedge against the risks and uncertainty of the industry. The real options concept can be utilized to reduce the gap between conventional valuation techniques such as Discounted Cash Flow analysis which neglect flexibilities and the strategic considerations of enterprises which aim to take advantage of flexibilities. The DCF valuation technique is proven to ignore real world possibilities and hence undervalues prospective investments, especially those involving information evolution(Babak & Reidar Brumer, 2009).

The use of real options in exploration and production takes advantage of the following decision-making flexibilities followed by managers in actual projects:

Wait-to-Invest Flexibility

Real Options Analysis confers the flexibility to postpone an investment decision to a suitable time when conditions are decidedly more favorable with respect to value creation or risk management. The value conferred by the flexibility may arrive from decrease in production costs, new technology, change in regulatory landscape, increased hydrocarbon prices, or increased availability of information.

This flexibility is not confined to the initial period of investment and can be applied all through the project lifecycle. For instance, the results of the exploration and appraisal phase can guide the decision making for development phase, if a suitable reserve is not commercially exploitable the developer can wait for the market situation to improve or the regulatory landscape to change (example: discovery of tight oil reserve in a country where shale hydrofracking is not permitted as yet).

Termination Flexibility

Since investment decisions are made under uncertain and incomplete information the assumptions about project scope and lifecycle made in the initial stages may not hold as the project commences and more information unfolds. In certain upstream projects, the feasible project life may show a deviation compared to the initially agreed or contracted project life and it might be economical to wind-down and abandon production activities sooner than the projected lifetime. Sometimes abandoning a project early in its life with certain safeguards can ensure the reserves may be commercially exploited at some later date with the advent of new technology, greater demand, better prices, or a change in the regulatory landscape.

The Discovered Small Fields auction in India, carried out by the Directorate General of Hydrocarbons in 2016, consisted of 67 marginal oil and gas blocks previously surrendered for lack of commercial production viability under the previous conditions, technology and regulatory framework. These DSF I and II auction are a classic example of termination flexibility for oil and gas blocks.

Temporary Start/Stop Flexibility

Real Options analysis recognizes the tendency to stop production activities if revenues fall short of operating costs and net cash flows are tending to negative. Given a technological possibility to stop production in a safe manner, such that production can be resumed when required at short notice and low costs, it may be optimal to stop production temporarily in favour of increasing production from other fields or sources. This option is more suited to gas fields with their ease of workover characteristics rather than oil fields in which workover is difficult. However, in situations such as the post coronavirus pandemic wrought wipe-out of global crude demand coupled with a supply glut due to OPEC+ policies, start/stop options have been explored for oil fields especially for shale production which is only profitable if global oil prices remain at a certain high mark.

Operational Flexibility

Operational flexibility can be imparted in production duration and production levels. When preparing the work program, the enterprise can opt for higher levels of production by drilling and utilizing a greater number of development and production wells. The production duration is related to the field depletion rate and production characteristics and any change in production activity levels will impact durations. Though DCF valuation would insist on higher production in the initial lifetime to take advantage of time value of money, real world options consider the technological, commercial and contract-compliance feasibility of such goals.

An enterprise operating in an Indian deep-sea oil block which is maturing and due for an abandonment after evacuation of commercially recoverable Oil Initially In Place OIIP (in one year) acquires a production solution that boosts output by 500,000 barrels per year at an implementation cost of $7.5 million**.** Assuming the enterprise has discount rate 7% for that year, cost of production per barrel is 25$ and the spot oil price for that blend of crude is 40$ as of day and predicted high/low oil prices in the succeeding year is predicted as 60$/20$.

The following NPVs would be obtained by applying conventional rules of DCF and ROA to the given scenario:

Equation 1: Application of DCF to a conventional E&P problem

DCF application

Initial Investment at Time 0; Additional Revenue from 500000 barrels of oil discounted to present

$$NPV = \frac{-7.5}{1} + \frac{0.5(40-25)}{1.07}$$

$$= -0.5 \text{ million dollars}$$

The inflexible application of DCF to calculate NPV arrives at a negative value of 0.5 million dollars lost in this business effort considering the expected price of extracted crude at E(P) = 40$ per barrel. As per the conventional rules of NPV analysis the negative result should indicate to the enterprise that implementing the technological advancement implies more costs than benefits given the internal rate of return and is 'not worth the risk to invest in', therefore the enterprise should forego this investment and should not undertake the technological advancement project. The DCF analysis fails to reconcile with real world strategic implications, the management has the flexibility to wind down and cease the production if crude prices fall to such a level that lead to costs outweighing the risk adjusted benefits.

In the Real Options analysis method to obtain the NPV we can assume the management has the option to cut production if crude prices fall (in the real world winding down production and safely decommissioning the oil field to a state where production can be resumed in future with workover implies a cost which we shall neglect in this simplistic overview.)

Equation 2: Application of ROA to conventional E&P Problem

ROA application
- Best Case: Oil Price rises to 60$/barrel
- Worst Case: Oil Price falls to 20$/barrel

Best Case

Initial Investment at Time 0; Additional Revenue from 500000 barrels of oil discounted to present

$$NPV = \frac{-7.5}{1} + \frac{0.5(60-25)}{1.07}$$

$$= 8.85 \text{ million dollars}$$

Worst Case

Initial Investment at Time 0; Enterprise would not carry out production at cost > oil price, even though capital is sunk in project

$$NPV = \frac{-7.5}{1} + 0$$

$$= -7.5 \text{ million dollars}$$

Assuming in the simplistic case that the probability of each event happening is 0.5 the average NPV would be 0.675 million dollars. Whereas the actual returns would be between 0.675 and 8.85 million dollars as the management can opt to reduce production or wind down if/when the crude prices are below 25$ mark. This example serves to indicate the value of flexibility in decision making and how this value has to be considered in project evaluation for accurate analysis.

In the real world if there is an opportunity to alter the course of a project, the management can interdict and change the course of the project to impart greater value. The real options method transforms uncertainty into not just a 'probability of loss of value' but also incorporates opportunity to create value. The investments get amplified from being simple go/no-go decisions to having a range of possible outcomes based upon decisions and consequently resulting in creating an ecosystem with higher potential for exploiting opportunities. It can be observed that without real options methodology management would not have a handle on business uncertainty in the real world (Tom & Jon, 1990).

The research suggests the ideal sequence of procedures involved in production and development of an oil and gas block is a classic case of real options usage. The exploration license is first acquired, cost sensitive exploration activities are carried out and if the results obtained are positive, the reserve is appraised and depending on the result of appraisal development and production activities are carried out. This ideal scenario must be allowed to play out in a flexible contracting regime, if the contract obligates the enterprise to maintain levels of production regardless of the information obtained from one stage or market and business conditions then the contract essentially nullifies the essence of real options. The mantle of real options can be conferred on all business decisions, in that the decisions grant management the rights (without obligations) to take business initiatives in the future(Judy). In effect a restrictive regime that prevents the full extent of real options to be applicable restricts business options and initiatives for that enterprise.

The advantages of the real options analysis method over conventional DCF especially the suitability of real options for the risk and uncertainty ridden oil and gas exploration sector has been exhaustively established (Leslie & Michaels, 1997). The authors propose oil and gas project analogues to the six levers of financial/real options present in the Black Scholes Formula:

Option price for financial/real options is derived by the Black Scholes Formula:

Equation 3: Black Scholes Model for option value

$$Se^{-\delta t} * \{N(d_1)\} - Xe^{-rt} * \{N(d_2)\},$$
$$\text{where } d_1 = \{\ln(S/X) + (r - \delta + \sigma^2/2)t\}/\sigma * \sqrt{t},$$
$$d_2 = d_1 - \sigma * \sqrt{t},$$

Where:

S represents the stock price/PV of cashflows
t represents time duration for option
X represents exercise price/PV of Fixed costs
r represents the risk-free rate in the appropriate market
σ represents uncertainty in cashflows
δ represents dividends/Value lost over duration of option
N(d) represents the cumulative normal distribution function

The oil and gas project analogues for the financial option levers are:

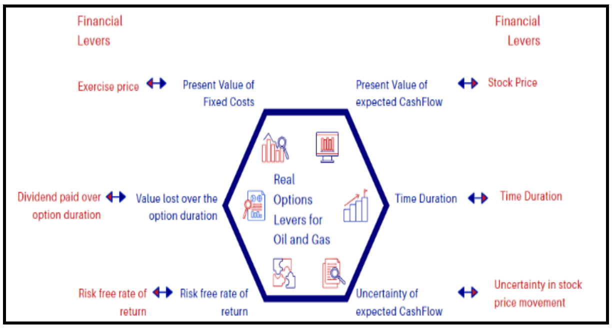

Figure 1: Real Option levers in Project Evaluation

The article conclusively proves the deficiencies in conventional DCF NPV analysis as only two levers are considered, i.e. the present value of expected cash flows over project duration and the present value of fixed costs without lending credence to the other 4 levels which influence real projects. The research demonstrates the effect of a 10% improvement in each lever for a demonstration case of oil and gas option worth $250 million.

Table 1: Effect of improvement in Lever on Option Value, McKinsey Quarterly

Real Option Lever	Improvement in Lever	Sensitivity of Option Value
Present Value of CashFlows	10%	26%
Present Value of Fixed Costs	10%	16%
Uncertainty of Future CashFlows	10%	11%
Time Duration	10%	6%
Loss of Value during option period	10%	4%
Risk free rate of return	10%	4%

The changes in duration, loss of value during option period and risk-free return rate have less impact on the value of the option than changes made to PV of expected cash inflows and PV of fixed cost and level of uncertainty in predicting cashflows. This primitive analysis supports the production cycle followed in most oil and gas exploration and production projects which is a steep rise in production, peak and long decline. The ROA would suggest it is profitable to focus on increasing revenue rather than decreasing cost. This can be observed in the **Reliance Industries Limited Krishna Godavari Basin case** where the operator has been suspected of gold plating costs to take advantage of an investment multiplier concept in the contract and extracting precedent breaking gas in the early cycle of the project followed by low to nil production in the later cycles at high capital cost (Varman, 2013)

There are multiple cases from the oil and gas industry which evaluate multi-phased tactical and strategic investment decisions in projects and establish that valuation function is distinctly different from conventional avenues of corporate financial management. The author draws attention to the importance of strategic implications of real options while evaluating the completeness of decision making in the oil and gas sector. This strategic implication asserts that Real Options cannot be applied by the enterprise in an isolated bubble, the success of such a valuation depends on the environment in which it is applied. If the project selection environment is conducive to the application of real options analysis it emerges as a strategic value if the environment prevents the flexibility of real options to be fully realized through constraints in project selection process then it becomes a strategic deadweight (Angelien, 1993).

The importance of the project selection environment in enabling the true benefit of flexible decision making conferred by real options is explored in detail (Amram & Kulatilaka, 1999). The authors suggest a four-level process that culminates in the final step being the establishment of system and procedures to maintain control of the real options procedure, review the results in business context and enable the selection of the right project and to have this selection validated. The first three levels correspond to the project valuation – where the enterprise generates list of influencing factors for anticipated cash flows, strategic growth plan – where value of flexibility from the enterprise capabilities in alignment with real options method can be established, competitive strategy – value is determined by position with respect to competition position. The fourth level establishes the environment which best supports real options functionality and allows for the value of flexibility to be realised by allowing scenarios calculated in real options analysis to be played out in actuality. This environment can be a contractual framework that is rigid and denies the contractor from varying levels of productive activity in accordance with project conditions or a flexible framework that allows such flexibility in decision contingent on an effect on some other contract parameter in defined proportion.

The importance of frameworks in which real options can be used as a strategic tool is researched in depth and the extent of suitability of real options in handling financial and strategic project evaluation criteria and the role played by the business environment is enunciated (Andrea, 2015). The author details the extent of suitability of real options in handling financial and strategic project evaluation criteria and the role played by the business environment. The research reveals a dissociation in coordination of investment valuation and investment ecosystem. The author attempts to invent a framework to enable the evaluation and analysis of strategic real options criteria. The model is fundamentally based on the real options approach while placing significance on the organizational and operation environment. The strategic model conceived if employed would enable the enterprise to develop scenario handling processes considering the organizational and business characteristics.

Research on portfolio selection for oil and gas projects being a fundamental function of capital budgeting, corporate goals and business environment proposes validated portfolio selection models based on real options theory (Zefu & Jianyue, 2007). Real options method applied through Black-Scholes model is shown to be theoretically more effective for oil and gas project selection compared to conventional DCF based NPV. However, in actuality this effectiveness is predicated upon the projects being selected in a contract framework that allows real use of academic options. If, for example the contract signed for a particular project forbade the operator from reducing work commitments or production in unfavorable times, the real options project selection framework modelled with the assumption that production can be scaled down will not be as effective.

The Indian Hydrocarbon Exploration and Production Scenario

The Indian hydrocarbon exploration and production landscape is identified by the following characteristics-

(i) Domination of sector by NOCs – Oil and Natural Gas corporation of India (ONGC), and Oil India Limited (OIL) along with Indian Oil Corporation Limited (IOCL), and Gas Authority of India Limited (GAIL) dominating the midstream and refining landscape.

(ii) Heavily regulated sector now moving towards streamlined regulations and policies and greater ease of doing business.

The oil and gas sector is a major driver for the GDP growth of India in recent times and the demand for oil and gas products has made investment in E&P and downstream capabilities a lucrative investment option. There is an emphasis on revamping the regulatory framework in E&P to attract foreign investment and private players to boost domestic production.

India's lack of well-developed E&P sector clearly establishes India as a major oil importing nation with imports of over 270 million metric tonnes in 2019 balanced against export of 65 million metric tonnes with the deficit worth 5800 Billion ₹(Petroleum Federation of India, 2014).

The regulatory landscape in E&P involves the enterprises and the Directorate General of Hydrocarbons DGH, the Oil Industry Development Board OIDB and the Petroleum and Natural Gas Regulatory Board. The DGH established under Ministry of Petroleum and Natural Gas is the entity responsible for oil and gas industry from a safety, technical, economic and environmental overview. The DGH regulates E&P and is in charge of the auction of discovered oil blocks and establishing work programs and production/revenue sharing contracts under the aegis of various programs such as the current OALP and DSF programs and historically the NLP NELP and HELP programs. The PNGRB regulates downstream processes from refining to sale of products. The DGH and PNGRB work in tandem to maintain a free and fair competitive oil and gas industry.

Corporate research on the hydrocarbon sector establish that the Indian E&P regulatory environment is heading towards some liberalization to increase ease of doing business and attract private participation. The current Oil and gas block auction in India take place under the Hydrocarbon Exploration and Licensing Policy (HELP) regime which includes the Open Acreage Licensing Policy OALP. HELP was introduced in 2016 as a revamp aimed at addressing industry concerns stemming from the decades long NELP regime which faced issues of stifling growth and production through bureaucracy and red tape. HELP seeks to streamline E & P in India by providing a uniform licensing regime for production of all discovered hydrocarbons, a central database of geospatial information called the National Data Repository NDR, an Open Acreage Licensing Policy for companies to bid for blocks of their choice, and marketing & pricing freedom for produced hydrocarbons. This was in complete contrast to NELP which had selective hydrocarbon license, pricing was regulated by several contrary pricing mechanisms, and companies could only bid on blocks offered as a part of NELP rounds instead of having the option to carve blocks for themselves (Nitish, 2018).

Of these initiatives the OALP is the most potent revamp as it aims to increase domestic production and private participation by expediting the appraisal and contracting of oil and gas blocks through access to its data in the NDR. OALP introduces flexibility for E&P players to create their own exploration blocks through the open and autonomous process, without waiting for blocks to be offered in roadshows and auctions. Expression of Interest are allowed to be made at any time over the year, with bidding blocks formed from the basis of Expression of Interest offered in biannual periods. The dismal private participation in NELP rounds has proven beyond reproach that liberalizing regulatory burden and streamlining oil block auction and allotment is required to boost private sector participation. The research establishes that thought the Government of India has made tremendous effort and progress in revamping hydrocarbon auction with the implementation of Open Acreage Licensing through HELP, procedural hurdles like restrictive revenue sharing models still remain. The 'one price point/work share model fits all' solution currently being implemented is not the best recourse in hydrocarbon block auction and allotment as a single parameter-based production or revenue sharing contract cannot cover all the risks inherent in these projects. The prices and exploration commitments once fixed remain fixed for the specified term, or for project lifecycle and provide little flexibility to adjust to technological, environmental, or market challenges or unforeseen geological risks thus negating the effect of real options analysis for project evaluation though it may be carried out on the contractors side (Anne-Sophie, Shahid, & Dsouza, 2018).

An analysis of **Directorate General of Hydrocarbon** India's OALP oil block auction documentation for bid rounds I through IV reveals that the initial gains made in private participation through streamlining regulatory and procedural requirements and improving auction procedure have been wiped out in subsequent bid rounds. The main reason for reduction in private participation gathered from statements made in official PIB releases can be traced to inflexible and in some cases model revenue sharing agreements under the OALP regime. The model revenue sharing agreement which ties into the bid evaluation criteria does not allow for complete realization real options analysis as a project evaluation tool in the OALP regime (Directorate General of Hydrocarbons India, 2020).

For Bid Round V which is in progress, data has been obtained from DGH documentation on "**Summary of Bids received against offered blocks"**as on **June 30 2020**

Table 2: Bids won by Private Companies in DGH OALP rounds, Data from DGH Bid Allotment Details

OALP Bid Round	Number of Blocks on Offer	Blocks won by private sector	% Blocks won by private sector
I	55	39	71%
II	14	6	43%
III	18	5	28%
IV	7	0	0%
V*	11	0	0%

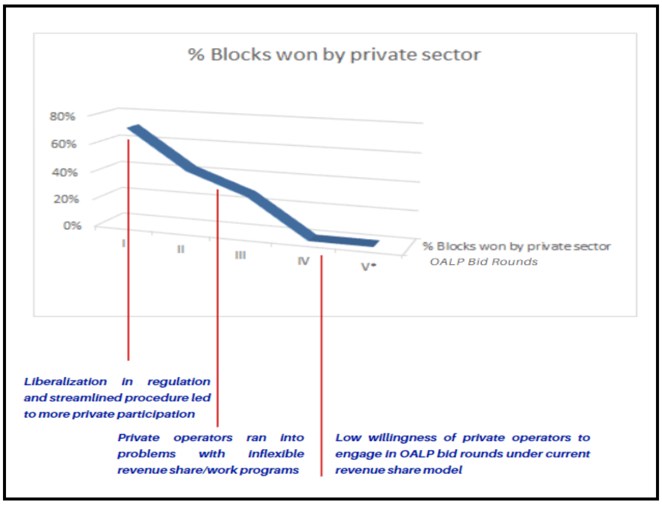

Figure 2: Timeline of reducing Private Participation in OALP bid rounds

The common minimum requirements that an implemented revenue-sharing model should incorporate to be equitable and fair are researched and highlighted. Economic Rent is the highest surplus of an economic nature that is produced from the hydrocarbon resources at efficient operation. The 'Rent' earned by the E&P industry based on 'windfall gains' by extracting 'bounty of nature' as such the citizens to whom these resources nominally belong have to be provided returns which is in the form of Royalties paid to the Government which represents the citizens. The concepts of Economic Rent and Cost Reimbursement are present in the OALPs Revenue-Sharing model and the third important concept of Equitable Development is missing as options are limited by committing to work program and revenue share at the stage of uncertain incomplete information(Winston & et, 2009).

Research presented by Government of India instituted panels have carried a critical examination of each article and mechanism of the model revenue sharing contracts used by the DGH in the OALP bid rounds under the aegis of the MPNRG(Petroleum Federation of India, 2014). The PetroFed's report highlights the proposed Model Revenue Sharing model involves mechanisms which will reduce the attractiveness of OALP bid rounds to foreign and private oil players, especially since the mechanisms fail to provide flexible redressal in case the field developments are challenging technologically or technically and involve additional costs. The report notes that thought the MRSC is an improvement over the PSC in assuring GoI revenues the PSC was better suited to the Indian oilfield development modalities, cost recovery provided an assurance to E&P players against the risks of investment. The MRSC model can be skewed to align with GoI aims of revenue recognition and would deteriorate investment in E&P by foreign and private players (which has been observed in practice in the 4th and 5th bid rounds).

A widely accepted panel report recommends strengthening the PSC model which it views as superior to the restrictive RSC model especially for deep sea blocks which are capital intensive. The committee recommends the E&P contract between DGH and E&P players must incorporate balanced risk reward paradigm. The committee notes the Revenue Sharing Model is susceptible to diverging interests of the contractor and GoI, with the contractor being unlikely to expeditiously invest in recovery from field under unfavorable conditions(Dr. Vijay, 2013).

The literature review clearly establishes the oil industry as a classic case for industry with investments made on uncertain information, that will shift over the project lifecycle, and with a wide range of downside exposure. The review establishes that real options with their enabling of flexible decision making can be used in the industry to enable strategic consideration of managerial decisions and choices (reactive elements) while conducting project evaluation and selection.

The review also establishes for the use of real options analysis to result in selection of viable projects and strategies, the academic options considered in the model must be allowed to take place in the real-world situation. Real options analysis would not be an effective way to adjudge project evaluation and selection (and thus chances of project success) if constrained by contract or bidding provisions that mandated a fixed level of input, or output without recourse to scenario-based options. A specific review of OALP revenue share policies contrasted against recommended practices suggests that OALPs model revenue sharing agreement limits flexibility and discourages private participation which has resulted in a fall in private participation from 71% in round I to 0% in round V.

Methodology

The research methodology followed in the paper involves the following steps-

Part A. Analyse and characterize existing model with a sample case to identify deficiencies.

Part B. Developing real-option enabling revenue sharing model based on secondary research conducted in literature review.

Part A

1. Analysis of the existing DGH Revenue sharing Model

Title:"Model Revenue Sharing Contract MRSC between the Government of India and XYZ limited under the Hydrocarbon Exploration and Licensing Policy with respect to contract area Block ______"

Scope: Revenue Sharing agreement for the category I basins

Observations: We observe the Bid Evaluation Criteria is a composite of a work program component worth 70% of evaluation points and revenue sharing component which is worth 30% of the evaluation points.

Evaluation Criteria	Evaluation Metrics	Points - 100		Mechanism
Work Program Commitment	2D Surveys in LKM	13	65	Bidders quoting highest weighted seismic programme are assigned top marks
	3D Survey in SKM			
	Number of Exploratory Wells	52		Bidders quoting highest number of exploratory wells are assigned maximum marks
Revenue Share Commitment	Revenue Sharing	30	35	Bidder with highest NPV of revenue offered to GoI is assigned top marks
Miscellaneous	Originator Incentive	5		Block originator gets 5 marks

Figure 3: Current OALP bid evaluation mechanism

The Revenue share is defined as "all amounts that are accruing to the Contractor, net of taxes on sales, on account of the Petroleum Produced and Saved from the Contract Area for the month; LESS Royalty for that Month calculated by applying the weighted average selling price for the relevant month at the Delivery Point".

The revenue share is calculated through a complicated LRP-HRP mechanism, this mechanism is different from the one deployed in Telecom contracts in that it utilizes a Bid criterion composed of two bidding points defined by the Government.

Mechanism:

Part I: Determination of Project NPV and based on that the revenue that bidders can profitably share with the GoI.

A. The bidders calculate the following parameters from the NDR field data received:

1. In Place Reserves
2. Conversion Factor
3. Project Timeline
4. Cost Parameters: CAPEX per Well, OPEX
5. Production profile including Ramp up, Plateau and Decline
6. Royalty and Cess based on Field Type (Category I or II, III)
7. Oil/Gas/CBM price for the field life

B. Based on the Field Development parameters, and the bidders WACC or internal hurdle rate calculated above the Bidders arrive at probable NPV, IRR and RoI values for the field

C. Based on justifiable returns, and how it is to be divvied up between the GoI and the contractor the bidders can determine the revenue share for the Government at Lower Revenue Point and Higher Revenue Point.

Part II: Determination of Revenue share and top awardee by the DGH

A. The OALP MRSC requires bidders to define revenue shared to the GoI at two revenue points such that revenue share at HRP> revenue share at LRP

LRP is defined as Average Daily Revenue of $0.05 million
HRP is defined as Average Daily Revenue of $ 7 million
These revenue points have been defined based on data obtained on production from Indian fields developed in previous (NELP HELP DSF OALP) rounds.
B. The GoI Revenue share is determined by the following procedure
For all Average Daily Revenue <= LRP, GoI Revenue share = Revenue share X input by bidder at LRP.
For all Average Daily Revenue >= HRP, GoI Revenue share = Revenue share Y input by bidder at HRP.
For all Average Daily Revenue between HRP and LRP, GoI Revenue share is determined by the formula Revenue Share (Z) = X + [(Y-X) x (R-LRP) / (HRP – LRP)]
C. The Revenue Share values are multiplied by average daily revenues to arrive at Annual Revenue profile for the GoI for project lifecycle. This Revenue profile is calculated for 4 different revenue scenarios to arrive at four NPVs the average of which is the **bid evaluation criteria**
D. The bidder with highest average NPV to the GoI is accorded 30 points and the other bidders are accorded points proportional to NPV on a prorate basis.

Sample

Procedure is shown for an oilfield bid involving 4 Bidders with Bidder B being the block originator carving the block from NDR database of available basins.

Table 3: DGH Bid Evaluation Mechanism

Bid Identification	A	B	C	D
Number of Wells (simplifying LKM SKM)	22	20	15	18
LRP %	5	12	10	15
HRP %	25	28	20	35
Block Originator	No	Yes	No	No
Average Share of GoI NPV	528	751	572	939
Marks for Exploration Program	65	59	44	53
Marks for Revenue Share NPV	17	24	18	30
Marks for Block origination		5		
Total	82	88	63	83
Rank	3	1	4	2

The given scenario plays out with the originator B winning the bid on the basis of a well-balanced exploration profile and revenue share and the originators advantage. The originator receives a 5-point advantage having purchased the original NDR data to carve out the block being bid upon.

2. Testing model to identify deficiencies and loopholes

Consider the following evaluation carried out by an E&P enterprise for a category 1 Oilfield with estimated Total Reserves of ~200 MMT (1460 Million Barrels). The project life is assumed to be 5 years to simplify the analysis. Actual projects can have life cycles ranging from 10-25 years with the initial few years devoted to exploration and no production taking place. The enterprise estimates total recoverable reserves at 50% based on field characteristics obtained from NDR data and the technology the firm has. WACC for the firm is assumed at 10%. Oil prices for the years 2020-2025 are derived from **EIA short term oil price outlook**. Conversion factors and Field thumb rules are derived from **PPAC database.**
The enterprise estimates annual production in the lognormal distribution that follows ramp up, plateau, and decline. The estimated average daily production is estimated at 90000, 120000,100000,60000,30000 barrels per day BPD for the five years.

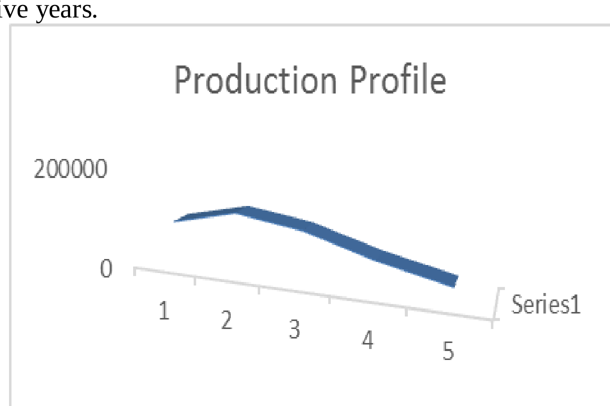

Figure 4: Production Profile For Oil Block

The enterprise develops the following Revenue profile: With Project NPV $674 million and an MIRR of 21% calculated at WACC and Reinvestment rate = risk free rate.

Table 4: Revenue Calculation

Year	**Average Oil Production B/Day**	**Oil Price $/B**	**Average Daily Revenue Million$/Day**	**Annual Revenue Million $**
0				
1	90000	38	3.42	1248
2	120000	48	5.76	2102
3	100000	58	5.80	2117
4	60000	68	4.08	1489
5	30000	79	2.37	865

The Revenue shares determined by the Enterprise at LRP, HRP are derived using game theory, and would be influenced by the company's financial position, the company's other fields and the stages of maturity they are in, the field profile, the estimated number of companies bidding for the field, presence or absence of NOCs.
Assuming an LRP revenue share at 15% and at HRP revenue share as 40%
We arrive at the following revenue recognition for the GoI, with the contractor getting profitability at 26%

Table 5: GoI Revenue Shares

Oil Production B/Day	Revenue Million$/Day	Government Share of Revenue	Annual Government Revenue
90000	3.42	27%	339
120000	5.76	36%	747
100000	5.80	36%	755
60000	4.08	29%	439
30000	2.37	23%	202

To analyse the model for flexibility and inducement of production consider the following scenario –

1. Testing for more aggressive and passive production strategies we observe: If the contractor seeks to carry out a passive production strategy, the contractor's profit increases by 9% but the crude produced in the immediate future (3 years) decreases by 34%

If the contractor implements an aggressive production strategy the contractors profit decreases by 4% however the crude produced in the immediate future increases by just 6%

This is in line with the PetroFed report's conclusion about the inadequacy of the MRSC to boost domestic production as it promotes stifling immediate production, to maximise enterprise revenue share and profit. While the MSRC does not allow contractor to jack up costs under the cost recovery Investment multiplier model in the Production Sharing Contract PSC that was alleged to have happened in KG Basin fields the MRSC encourages a production profile which will ensure less oil for GoI over the next few years, even if it increases the NPV of revenue shared.

2. The MRSC in conjunction with the Bid Evaluation criteria is flawed in that it lets the Bidder decide a revenue share profile anchored on the LRP and HRP revenue share, and then the revenue share profile is applied to 4 different scenarios from optimum to worse to arrive at NPV share of revenue in each case. The simple average of the NPV is the governing parameter to award 30 points to the bid with highest average revenue share NPV to the GoI.

This is duplicitous as the GoI via the OALP evaluation mechanism essentially tests its revenue streams under 4 different conditions and awards the points to the bid that provides it the best possible revenue stream by considering the average of all 4 scenarios. However, there is no reciprocal mechanism in the MRSC to allow LRP and HRP revenue share determined by the bidder to be changed as per the development scenario.

Using a bleak scenario for our chosen LRP HRP revenue share of 15%,40% we observe:

If the cost of extraction increases 25% owing to technical difficulties or reservoir characteristics unforeseen during bidding or exploration, and production levels remain constant. The contractor serves to lose 49% of its profit even as the government revenue remains constant. Though the contractor does have marketing and pricing freedom under OALP regime, market prices for crude blends are governed by supply and demand. The increased production costs will have to be offset by the contractor's other fields where production is easier.

The risk-reward balance for contractor is more challenging in the Revenue Share model, complications from 'as-bid conditions' increase the gap between economics in both sets of contracts (PSC and RSC). This would result in more risk averse contractors filtering out at bidding stage and even the more adventurous contractors will back out of production after investing in exploration. Thus, the losses suffered by contractors discourages further investments in subsequent rounds, if the contractors do not actively pursue exploration in subsequent rounds the contractors will not get the advantage of possessing oilfields in different levels of maturities further contracting their pricing options.

This is in line with the Kelkar Committee report's observation which noted the revenue share model developed with GoI focus on obtaining revenue from T=0, would result in a risk-reward structure and restricting of options causing private exploration in India to grind to a halt. This is reflected in the last two OALP auctions with zero private E&P winners.

Part B

To provide a flexible bid parameter that enables the contractor to shift into a lower revenue share regime to offset losses we utilize real options, specifically the Marketed Asset Disclaimer (MAD) model. Copeland and Antikarov's Real Options describes the Marketed Asset Disclaimer approach which assumes the current financial value of the project under evaluation or consideration as a 'project without flexibility' is by itself an asset with underlying value and can be used to calculate option value.

The Methodology for MAD involves three steps:

1. Calculate Present Value of the project without Flexibility,

$$PV = \sum_{i=0}^{i=n} \frac{C_i}{(1+r)^i}$$

Where, PV represents Present Value of Project, I represents year in project lifecycle from 0 to n, Ci represents cash flow in the year I and r is the discount rate.

2. Estimate volatility of the project either through Monte Carlo simulation for the project or for the project sector.

The cash flows are discounted to year 1 as:

$$PV_1 = \sum_{i=1}^{i=n} \frac{C_i}{(1+r)^{i-1}}$$

Annual returns are computed as:

$$z = \ln \frac{V_1}{V_0}$$

Where standard deviation of the simulated Zt represents volatility of sector or project.

3. The binomial lattice of values is devised on the assumption of variations in value of project following Geometric Brownian Motion. The established model determines the understated change in asset value based on downturn and upturn coefficients during project lifecycle.

The MAD based revenue share model –

The Proposed Revenue Share Model is built up over the following steps:

1. The DGH builds a most likely scenario Financial model based on the NDR data for each field, this model is specific to each block under that bid regime. The DGH arrives at PV of future cash flows for each block in the most likely scenario. DGH engages in Monte Carlo simulation for each oil block or for the E&P sector as a whole, the simulation determines the volatility of project or block of projects in the bid round.
The values determined are plugged into a model that converts the standard deviation input obtained from Monte Carlo simulation to up and down movements in the binomial lattices.
The efficacy of Monte Carlo simulation is already established by the Kelkar Committee Report.
2. From the model the DGH obtains a range of valuations, which then become the cut-off valuations at which LRP HRP bid for by the contractor can change. It is recommended that only the downtick coefficient is used to reduce the LRP HRP bid points and LRP HRP are not raised in case of uptick or increase in valuation of project (windfall gains)
In effect instead of asking for one LRP HRP bid from the contractor and applying it to a range of generic scenarios not considering individual characteristics of the field bid for, the DGH is inviting a 'bid profile' with a series of LRP – HRP bids for each scenario.
3. The DGH auction mechanism compares LRP and HRP values (entered as separate bid profile tables) for all companies and awards 1 point to the bidder with highest revenue share in each profile point and awards points to other bidders on a pro rata basis.
In the case of a tie, the bidder with the highest overall points at LRP across the profile gets awarded the contract.

Sample:

For a project in which DGH estimates the NPV of the project at $1000 million based on NDR data and market conditions at time t = 0. Monte Carlo simulation carried out in Kelkar Committee report taken as the baseline data. The simulation provides a volatility of 30% for E&P sector in India. Using these indices, we arrive at switchingvalues of $1000 million in year 1, $694 million in year 2, $481 million in year 3, $334 million in year 4, $232 million in year 5. Wherein if the PV of project in these years is less than cut-off values (based on revenues), then the LRP HRP defined in the bid profile for that period will apply.

Table 6: Binomial Lattice model for particular oil block

Inputs to Bionomial Lattice model						
Standard Deviation SD =	**30%**					
Risk Free Rate =	**5.76%**					
Dividend =	**8%**					
NPER =	**1**					
Binomial Coefficients						
Binomial Uptick =	**1.26187663**					
Binomial Downtick =	**0.69253258**					
Present Value	**$1,000.00**					
Value T+1	$1,261.88	**$692.53**				
Value T+2	$1,592.33	$873.89	**$479.60**			
Value T+3	$2,009.33	$1,102.74	$605.20	**$332.14**		
Value T+4	$2,535.52	$1,391.52	$763.68	$419.12	**$230.02**	
Value T+5	$3,199.52	$1,755.93	$963.68	$528.88	$290.25	**$159.29**

Company A and B submit the following Bid Profile:

Company		Bid Profile					Summation	Bid Criteria
Company A	LRP	10%	8%	5%	4%	4%	31%	
	HRP	40%	35%	30%	25%	20%	150%	
Company B	LRP	15%	12%	10%	8%	4%	49%	
	HRP	35%	30%	25%	20%	15%	125%	
Company A Evaluation	LRP Eval	0.667	0.667	0.500	0.500	1.000	3.333	
	HRP Eval	1.000	1.000	1.000	1.000	1.000	5.000	**8.333**
Company B Evaluation	LRP Eval	1.000	1.000	1.000	1.000	1.000	5.000	
	HRP Eval	0.875	0.857	0.833	0.800	0.750	4.115	**9.115**

The Evaluation Steps involved are as follows –
1. The bids are evaluated, highest HRP & LRP in each revenue profile point is avoided 1 point and the other bids are avoided points on a pro rata basis.
2. The points are totalled.
3. Bid is awarded to the company with the highest points given the understanding that bid profile submitted by B will be enforced for each revenue cut-off point if it is breached.
4. If two bids are matching Bid will be awarded to company having better HRP bid profile reflected through its score.
This method ensures the bids for each field are evaluated and contextualized to that particular field, that the real options available to the operator during project execution and supported and allowed by the contract structure.

Results

The Performance of the existing and proposed contracts were mapped over the following parameters to assess whether the proposed MAD based contract would improve upon the existing RSC contract and assuage industry concerns identified in the literature review.

Parameters	Existing Contract Model	Proposed Contract Model
Flexibility	Low - Rigid Structure of Bid Parameter	Medium - Bid Profile at defined Revenue points
Accuracy	Low - Single HRP, LRP for all fields	High - All contract parameters specific to block on auction
Operational Flexibility	Low - Once contract is signed Works Program to be maintained, revenue to be shared	High - Program and Revenue share can increase/ decrease if revenue crosses switching values
Government Audit	Audit Requirements are less than PSC Contract	Higher Audit Requirements compared to existing contract
Leverages NDR	No	Yes

Bid Transparency	Low - Bids are evaluated at various NPV scenarios but contractor has no choice in profiling bid to scenarios	High
Private Sector Risk Concerns addressed?	No	Yes
Scope for Bid Disputes	Lower	Higher

The results indicate that on 6 out of 8 parameters mapped the proposed MAD based real options enabling contract is in line with private contractor's expectation. Additionally, the analysis carried out suggests the existing RSC contract model is out of touch with the DGH's stated aim of incentivizing production as it disincentivizes contractor to produce more when oil prices are low.

It is interesting to note the two shortfalls of the proposed contract with respect to RSC contracts, that is in Scope for disputes to arise and higher auditing requirements can be covered with ease by ensuring the DGH and other regulators are strengthened to international standards.

Recommendations

The evaluation highlights the following points/deficiencies:

- Real Options analysis is decisively superior to DCF based methods for analysis and evaluation of oil and gas E&P projects. However, the ability to apply real options in actual project lifecycle has to be supported by the contracting framework.
- The Revenue Sharing model currently in use for OALP bid rounds promotes revenue share from day 1 and assures income to the Government if the project goes as planned but exposes the contractor to higher downside risks for unforeseen technical or commercial difficulties. The model promotes contractor to adopt a passive production strategy to maximize profits and revenue share which is contrary to the administrations vision of increasing domestic production to limit crude import to 50% of domestic demand by 2030. The bid evaluation mechanism also creates 'faux flexibility' by testing a single bid criterion at 4 different conditions without allowing the contractor the right or remedy to vary the bid criteria according to the conditions tested. The model is common for all oilfields of a particular category regardless of actual oilfield conditions.

It is therefore recommended to use a Real Options based revenue sharing model that corrects these deficiencies

- The Real Options based Revenue Sharing model provides DGH a method to contract for each oilfield specifically and to provide a flexible contracting regime. The DGH determines project value-based n NDR data and creates a binomial lattice of probable project values at all stages of project lifecycle over the project life time. Cut off values are defined and 'bid profiles' are invited accordingly.
- The option-based model allows the contractor to cut revenue share to Government by predetermined, bid and agreed to amounts in case of low revenues arising from technical and commercial difficulties. The option-based model also ensured the MRSC is signed for each field keeping the field characteristics in mind and would result in better price discovery for each field in the auction raising chances of project success.

Providing this flexible model, in conjunction with strengthening the DGH regulatory policies will increase private participation in the E&P sector, by eliminating major roadblocks to successful private project implementation in a risk prone and dynamic sector.

Conclusion

Exploration and Production is a unique endeavor with risk analysis dominating its business and operating landscape unlike other industries where risk analysis plays a peripherally disrupting role. Projects for development of an oil and/or gas field show the characteristics of being risk intensive – with large investments in time, money, technology and resources.

Oil and gas exploration projects are inherently risky with a unique phase-based structure to the risks involved. Real Options Analysis is a natural fit for oil industry management decision problems, and is utilized in oil and gas project evaluation and selection. However, to allow the operational use of these 'Real Options' utilized to evaluate a project and determine it suitable for investment given the presence of these options, the contract framework has to enable the options to be used in practice.

The current Open Acreage Licensing Policy (OALP) framework currently in use in India for E&P oil and gas block auctions offers some flexibility in allowing oil blocks to be carved from an existing repository. However, once the blocks are carved and ready to option the tendering and contracting procedure exhibits pseudo flexibility. Bids are evaluated over a procedure that seems to consider various options of production profile, however the bid itself remains inflexible once chosen. The RSC type contract model used in the current OALP regime thus causes a mismatch between project evaluation and selection and project execution by reducing the operational flexibility available to contractor.

Real options analysis and their applications provide private enterprises a tool to navigate the risk strewn landscape of exploration and production in India. The viability of real options should be enabled by a real option based contracting arrangement between the DGH and private/public contractors. The real option-based revenue sharing model suggested in this article can boost private investment by limiting rigid exposure of contractor to downside risks, while keeping revenue interests of the GoI relatively intact. The implementation of suggested model can be successful if accompanied by a strengthening of the DGH and its regulatory standards and policies as recommended by the Kelkar Committee report on E&P sector in India.

This is in line with the Kelkar Committee's recommendations to implement a third type of E&P contract to correct the flaws in the erstwhile PSC model and the current RSC model. The specific points raised by the Kelkar

Committee addressed through the real options-based contract are -

- Contract must attract E&P Companies for bidding
- Contract must incentivize aggressive exploration for hydrocarbon
- Energy Security being of paramount concern, the Government must not make revenue sharing the sole focus as a biddable parameter
- Companies must be incentivized to invest in capital intensive production activities such as IOR/EOR for fields that are very mature.

Limitations

The fundamental principle for the proposed contract model is the need to ensure energy security of the country rather than increasing certainty of Government revenues from the E&P activities. Private sector participation is required to achieve enhanced levels of production and more private participation will result in more corporate income tax, sales tax, royalty in the long run. The proposed contract if implemented would boost private sector participation by enabling E&P companies in India to employ the same risk mitigating operational decisions as their counterparts in the west – backed by a contract framework that enables such decision making to be applied. However, the suggested framework is not without its limitations, some of these limitations have been highlighted in the Kelkar Committee report as ‘noteworthy issues’ which a new contract other than the RSC would face and which would have to be addressed through external measures. The issues themselves concern with the regulatory and business environment of the E&P sector in India and not with the contract structure itself.

- Although the new contract provides a transparent system with easy to monitor bid profile for tendering, the quality of geoscientific data on the oil and gas blocks has to be comprehensive for estimation of production profile and HRP-LRP switching revenue points.
- The new contract model requires higher level of resilience to corruption during bidding process, adherence to standards, practices, compliance norms and higher levels of regulatory effort. To function optimally the contract requires regulatory functions of DGH to be strengthened by –

1. OIDB cess utilization to fund strengthening of DGH, as needed
2. Creation of a talent pool for DGH
3. Back Regulatory Powers of DGH by law

Leverage Digital Technology like Blockchain enabled e-tendering for seamless, immutable, incorruptible tendering process with low chances of disputes

References

[1] Adam, B. (2003). Real Options Analysis: Where are the Emperor’s Clothes? . Presented at Real Options Conference. Washington DC.

[2] Amir H., S., & Richard, H. (2017). Real options and the value of oil and gas firms: An empirical analysis. Journal of Commodity Markets, Elsevier.

[3] Amram, M., & Kulatilaka, N. (1999). Real Options – Managing Strategic Investment in an Uncertain World. Harvard Business School Press.

[4] Andrea, R. (2015). Real Option as a Potential Link between Financial and Strategic Decision-making. Procedia Economics and Finance Elsevier.

[5] Angelien, K. (1993). Case Studies on Real Options. Financial Management JSTOR.

[6] Anne-Sophie, C., Shahid, H., & Dsouza, S. (2018). The Challenges Facing India on its Road to a Gas-Based Economy. The King Abdullah Petroleum Studies and Research Center.

[7] Ashok, B., Soubhik, C., & Brij Bhushan, G. (2011). Decision making framework for investments in oil industry: An application of real options. Indian Institute of Management Working Paper .

[8] Babak, J., & Reidar Brumer, B. (2009). Real Options Analysis in Petroleum Exploration and Production. Society of Petroleum Engineers.

[9] Directorate General of Hydrocarbons India. (2020). Model Revenue Sharing Contract and Modalities for operation in OALP. Ministry of Petroleum & Natural Gas, Government of India.

[10] Directorate General of Hydrocarbons India. (2020). Notice Inviting Offers for OALP bid round V.

[11] Dr. Rangarajan, C. (n.d.). Report on PSC Mechanism in Petroleum Sector. Economic Advisory Council of India.

[12] Dr. Vijay, K. (2013). Roadmap for Reduction in Import Dependency in Hydrocarbon Sector by 2030. Ministry of Petroleum & Natural Gas, Government of India Committee.

[13] Edith, I., Keith D., B., & Desislava, D. (2018). 25 Years of Real Option Empirical Research in Management. European Management Review.

[14] Jaewook, J., & Taehoon, H. (2015). Model for Evaluating the Financial Viability of the BOT Project for Highway Service areas in South Korea. Journal of Management in Engineering.

[15] José, M., Rui Cunha, M., & Carlos Oliveira, C. (2013). Real Options in Infrastructure: Revisiting the Literature. Journal of Infrastructure Systems.

[16] Judy, L. (n.d.). Scientific management at Merck.

[17] Leslie, K. J., & Michaels, M. P. (1997). The real power of real options. The McKinsey Quarterly .

[18] Liying, X., Betty, S., Jim S., D., & Kamy, S. (2012). Application of Real Options to Valuation and Decision-making in the Petroleum E&P Industry. Society of Petroleum Engineers.

[19] Maryam, A., Matteo, M., & Mehdi, S. (2019). The investment-uncertainty relationship in the oil and gas industry. Resources Policy, Elsevier.

[20] Nitish, D. (2018). Regulatory, Legal and Tax aspects of Oil and Gas. Nitish Desai and Associates.

[21] Petroleum Federation of India. (2014). Draft Model Revenue Sharing Contract (MRSC). Ministry of Petroleum & Natural Gas, Government of India Committee.

[22] Tom, C., & Jon, W. (1990). Proactive Management of Uncertainty. McKinsey Quarterly.

[23] Varman, R. (2013). Cowboy Capitalism: Curious Case of Reliance KG Basin Gas Business. Alternative Economic Survey.

[24] William, B. (2002). Schlumberger on Real Options. In M. Johnathan, Real Options Analysis. John Wiley and Sons.

[25] Winston, M., & et, a. (2009). Crafting an Oil Revenue Sharing Mechanism. Acode Policy Research.

[26] Zefu, L., & Jianyue, J. (2007). The Portfolio Selection Model of Oil/Gas Projects Based on Real Option Theory. Springer-Verlag Berlin Heidelberg.